QUANTIFYING WELL-TO-WELL INTERFERENCE IMPACTS ON PRODUCTION: AN EAGLE FORD STUDY

A Thesis

by

AUSTIN PARKER WRIGHT

Submitted to the Office of Graduate and Professional Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

Chair of Committee,	Duane A. McVay
Committee Members,	Michael King
	Thomas A. Blasingame
Head of Department,	A. Daniel Hill

August 2017

Major Subject: Petroleum Engineering

ABSTRACT

Since the turn of the century, North American E&P companies have sought to increase production from unconventional reservoirs. This is due to the value added by horizontal drilling and hydraulic fracturing. Infilling wells, or the process of drilling and completing new wells between existing producing wells, has also resulted in increased hydrocarbon recovery. However, infill drilling can result in well-to-well interference, sometimes detectable through deviations in forecasted production. Heterogeneity, variable stress fields, pressure depleted zones, and unknown fracture geometries from completion techniques introduce significant uncertainties in determining an optimal well spacing design for these types of reservoirs. The goal of this study was to quantify well-to-well interference impacts on production so future work might use the results to optimize well spacing for select areas in one of the most popular plays in North America, the Eagle Ford Shale play.

Data gathered from 1,996 horizontal hydraulically fractured wells in South Texas' Eagle Ford Shale play was used in this research. This involved gathering public well data, including monthly production volumes, completion information, and directional surveys from Western Karnes County and Northern La Salle County, Texas. These areas surround acreage held by Matador Resources, the primary source of support for this research.

Through the use of decline curve analysis and regression techniques, the effects on production of existing producing wells due to new offset completions revealed statistically significant differences in production forecasts performed before and after an offset completion. Results indicated tighter well spacings in both study areas generally increased the magnitude of impacts from well-to-well interference. However, existing producers are impacted both positively and negatively, and it is difficult to predict the direction of impact and how this impact varies with well spacing. New infill wells showed positive interference impacts on their production in the Western Karnes County area, but were inconclusive in Northern La Salle County. The methodologies employed in this work to assess interference effects yielded considerable uncertainty in results and conclusions, which limit their application.

DEDICATION

This thesis is dedicated to my mother, Deborah Lynn Perkins, whose support and understanding throughout my journey as a graduate student has never wavered. Although this work is my own and the following pages have been written by me, I hope that you can vicariously share in the success and pride that I feel, knowing that this is truly an accomplishment. “For God so loved the world, that He gave His only begotten Son, that whosoever believeth in Him should not perish, but have everlasting life” (John 3:16, *KJV*).

ACKNOWLEDGEMENTS

I would like to thank my committee chair, Dr. McVay, and my committee members, Dr. King and Dr. Blasingame, for their guidance and support throughout the course of this research. I would also like to thank Professor Peter Bastian for his kindness and candid conversations that have helped me during my tenure as his teaching assistant. Additionally I would like to thank Brad Robinson, and all those at Matador Resources that have made this research possible.

Thanks to my father, Ted Wright, for his willingness to always be available in any situation and ensure that failure never be an option. He has been a strong motivator in my life and I now firmly believe “can’t” is not in my vocabulary. Thanks to my mother, Debbie Perkins, for her support and understanding. I would also like to thank my wife, Jolee Wright, for her patience, love, and encouragement.

Thanks also go to my friends and colleagues for making my time at Texas A&M University a wonderfully exciting experience.

CONTRIBUTORS AND FUNDING SOURCES

Contributors

This work was supervised by a thesis committee consisting of Dr. McVay and Dr. King of the Petroleum Engineering Department and Dr. Blasingame of the Petroleum Engineering & Geoscience Departments. The proprietary well data and public well data used to perform the study were gathered with the direction of Brad Robinson from Matador Resources Company, the supporting company for this research, through the use of in-house software and databases. Additionally, the decline curve analysis Microsoft Excel (2013) workbook used to perform all of the regressions in the pages that follow was initially created by Professor Peter Bastian from the Petroleum Engineering Department. Upon receiving the workbook, the student manipulated VBA and Microsoft Excel (2013) algorithms so that the tool could meet the research objective needs.

All other work for the thesis was completed and or created independently by the student.

Funding Sources

There are no outside funding contributions to acknowledge related to the research and compilation of this document.

TABLE OF CONTENTS

LIST OF FIGURES

Page

LIST OF TABLES

Page

1. INTRODUCTION

1.1 Statement and Importance of the Problem

Production decline in U.S. conventional reservoirs has led to interest in unconventional plays. Advances in horizontal drilling and hydraulic fracturing technology have been used in an effort to replace the diminishing supply. The industry continually works towards determining the optimal completion strategies and well spacings that should go hand in hand with these new technologies to maximize an operator's rate of return.

This task is difficult because significant uncertainty exists in reservoir quality from play to play and even internally within a play from location to location. Unless costly studies are performed, factors that have major impacts on well recovery, like existing natural fractures and variable stress fields, are not easily identified. Common practices to optimize completion techniques and well spacing include a trial-and-error process, where operators may modify or drastically change strategies from lease to lease to see what will return the highest profits. Unfortunately, this technique is a sub-optimal technique that can lead to an inefficient use of limited capital and recoverable hydrocarbons left in place. Operators need to know the parameters that have the largest impact on recovery with the limited data they currently have available. Unless considerable investments are made to gather data or drill more wells, operators must turn to publicly published well information and compile databases to compare their strategies against other operators in the region.

One company in particular, Matador Resources Company, the primary source of data for this study, consistently works towards improving their completion and well-spacing strategy in order to bring greater value to shareholders. Matador has a portfolio of plays in which they operate, but the majority of their operated wells reside in the Eagle Ford Shale, where a large percentage of their wells have produced for six months or longer. Their acreage extends across several counties in primarily the liquid-rich regions. Motivation for this research stems from cases where neighboring wells interfere with one another's production at smaller well spacings. This interference is assumed to be a combination of the well spacing intervals and the size of the completion design. Rather than sacrifice completion designs, Matador engineers are interested in determining if the reduction in a single well's rate of return, affected by impacts on production from well-to-well interference, financially out-weighs the decision to drill more wells at a tighter spacing interval. Tighter well spacing intervals, smaller distances between completed laterals, are assumed to increase the chance that offset wells will interfere with one another; on the other hand, tighter spacing leads to an increase in the number of wells an operator can drill in a predefined lease.

Eagle Ford acreage is developed by drilling horizontal wells and completing them through hydraulic fracturing techniques. Research performed on improving completion performance in the Eagle Ford listed multi-staged hydraulic fracturing stimulation as critical to the economic viability of shale wells in the region (Pope, Palisch, and Saldungaray 2012). Operators develop lease acreage by drilling and completing several wells at a spacing interval they think is optimal. The wells in the first generation in an area are generally referred to as parent wells. At a later date new wells are drilled and completed next to and in between those previously producing parent wells and generally industry considers these newer wells as infill wells. These new wells are developed to try and recover some of the hydrocarbons left in place by the parent wells. When developing an area, an operator begins to manipulate and improve their completion design and as a result they learn more about the completion strategies that consistently perform the best. By spacing parent wells and infill wells at different distances, operators are trying to find the spacing that maximizes their return on investment. They are continually evaluating the costs of different spacing intervals and testing to see if this increases that return on investment. Using completion designs and spacing strategies that improve recovery in unconventional reservoirs has led to an increase in well-to-well interference, which has resulted in both improved and diminished production.

Matador has noticed two stages in a well’s life cycle in which the interference has taken place. The first stage is interference that has occurred during the fracturing treatment, where a previously producing parent well produced for some time and was shut in so that a well could be hydraulically fractured. In a few cases, engineers noticed uncharacteristic pressure increases in the shut-in parent well while hydraulically fracturing the neighboring well. Alternately, cases occurred where offset-well proppant was thrust back into the parent well-bore. To re-establish production rates, engineers have had to rig up a work-over rig or coil-tubing unit to clean out the parent well. Once offset completions were finished and the parent well was brought back online the engineers witnessed, in some cases, that the parent wells had reductions and occasionally increases in the forecasted production due to the offset stimulation. The positive impacts were unrelated to a brief increase in production regularly seen after a pressure build-up period due to the parent well being shut in. In cases where production dropped unexpectedly, wells recorded roughly 50 to 100 BOPD immediately lost when brought back on-line and steeper pressure declines than before the offset completion. In one specific instance, a test of the production fluids from the parent well also indicated that fluid tracers sent downhole during offset completions were reaching the parent well.

In the second stage of interference two neighboring wells have drainage boundaries that start to interact. These wells did not indicate a change in forecasted production due to offset stimulation. In this instance the two wells produced long enough and were spaced close enough that their drainage boundaries started to reach one another. Since these drainage boundaries interact during the production of each well, the interference is considered to occur during production.

If on a case-by-case basis well-to-well interference reduces the rate of return of an individual well but the lease's rate of return is increased by a tighter well spacing strategy (more wells in a pre-defined area), then engineers will continue to develop acreage with tighter spacing strategies until the spacing reaches a point of diminishing returns. Insight into the well spacing strategies that lead to well-to-well interference and the quantification of that interference is the primary interest of this research.

1.2 Review of the Literature

The data for this study consists of completion information for wells located in South Texas in the Eagle Ford Shale formation. Matador Resources Company, the data supplier, has as of December 31, 2015, just over 115 operated wells in their South Texas region with nearly 100% completed in the Eagle Ford formation (Lancaster 2015). **Fig. 1** displays the different regions that Matador operates as well as several representative statistics over those areas.

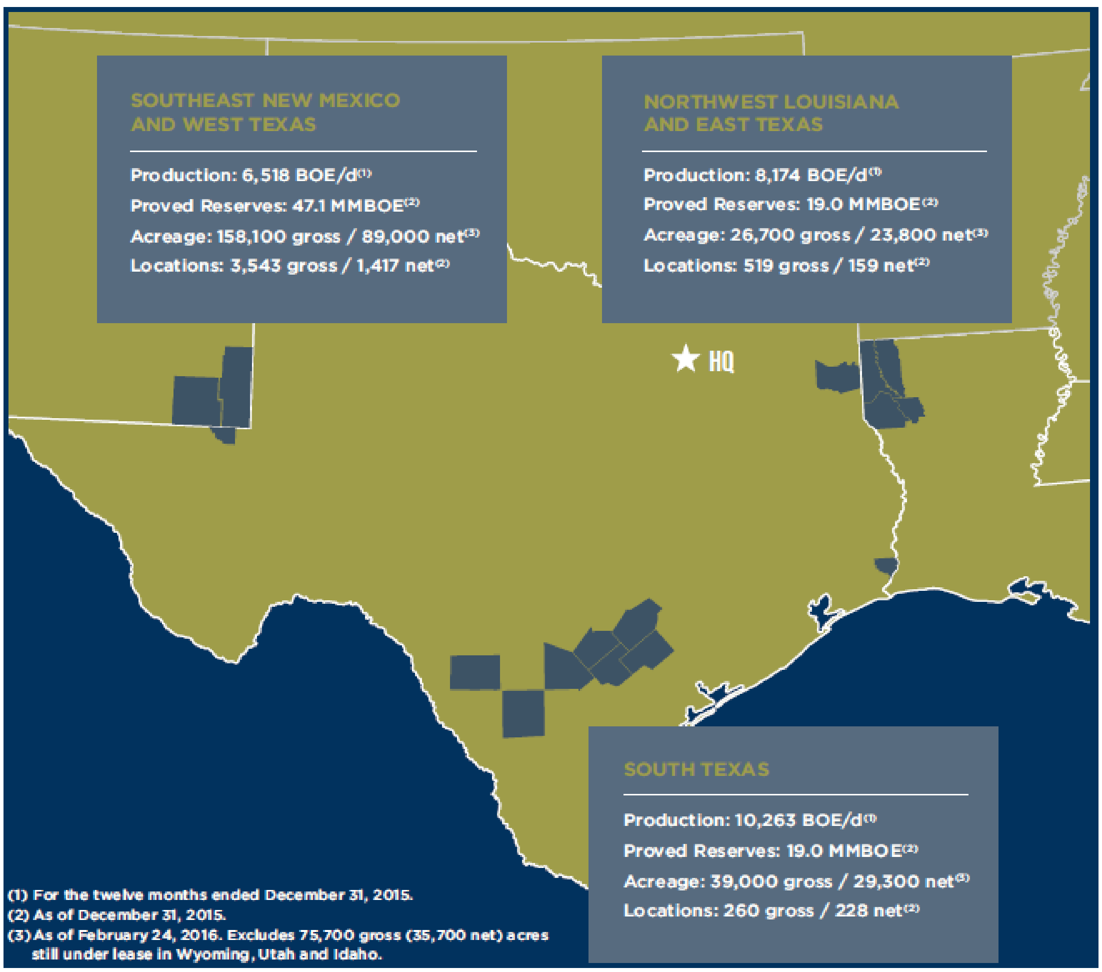

Fig. 1─Matador Resources Company areas of operation for 2015, (Lancaster 2015)

1.2.1 Eagle Ford Shale

With oil prices above $80 for the majority of the last 10 years and technology used in unconventional reservoir development advancing, it would seem that the Eagle Ford Shale play is an attractive asset to operators. From the first horizontal well completed in 2008 in La Salle County, Texas (Fan et al. 2011) the number of horizontal wells completed each month has grown exponentially (**Fig. 2**).

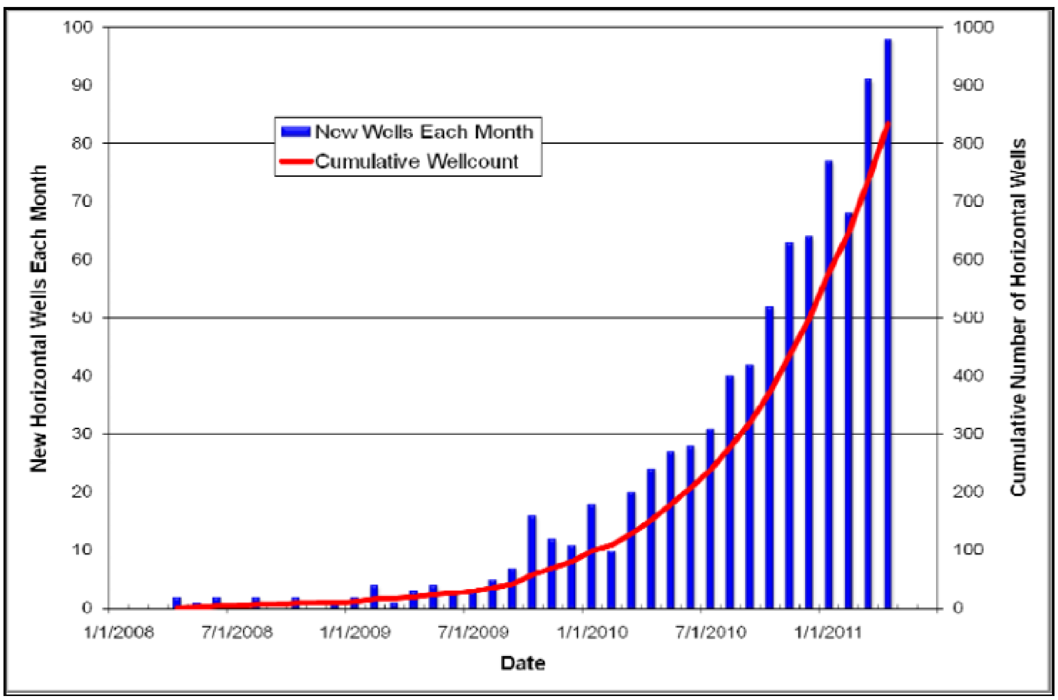

Fig. 2─The number of horizontal wells coming on line each month (blue) and the cumulative well count (red) in the Eagle Ford Shale play (Fan et al. 2011, from Fig. 10)

From 2011 to 2012, U.S. daily output increased by 826,000 BOPD with more than a quarter of the production increase originating from the Eagle Ford play, which provides evidence that operators have viewed this play as a target for increasing their production (Gong et al. 2013). Research performed on improving completion performance in the Eagle Ford listed multi-staged hydraulic fracturing stimulation as a critical design component for shale wells in the region to be economically viable (Pope, Palisch, and Saldungaray 2012). **Fig. 3** shows the number of drilling permits issued from 2008 through October 2016 in Texas' Eagle Ford Shale. The recent price drop that occurred in 2014 has this region's development started to decline. Crude oil prices below $50 has made it much more difficult for new wells in the Eagle Ford to remain economical.

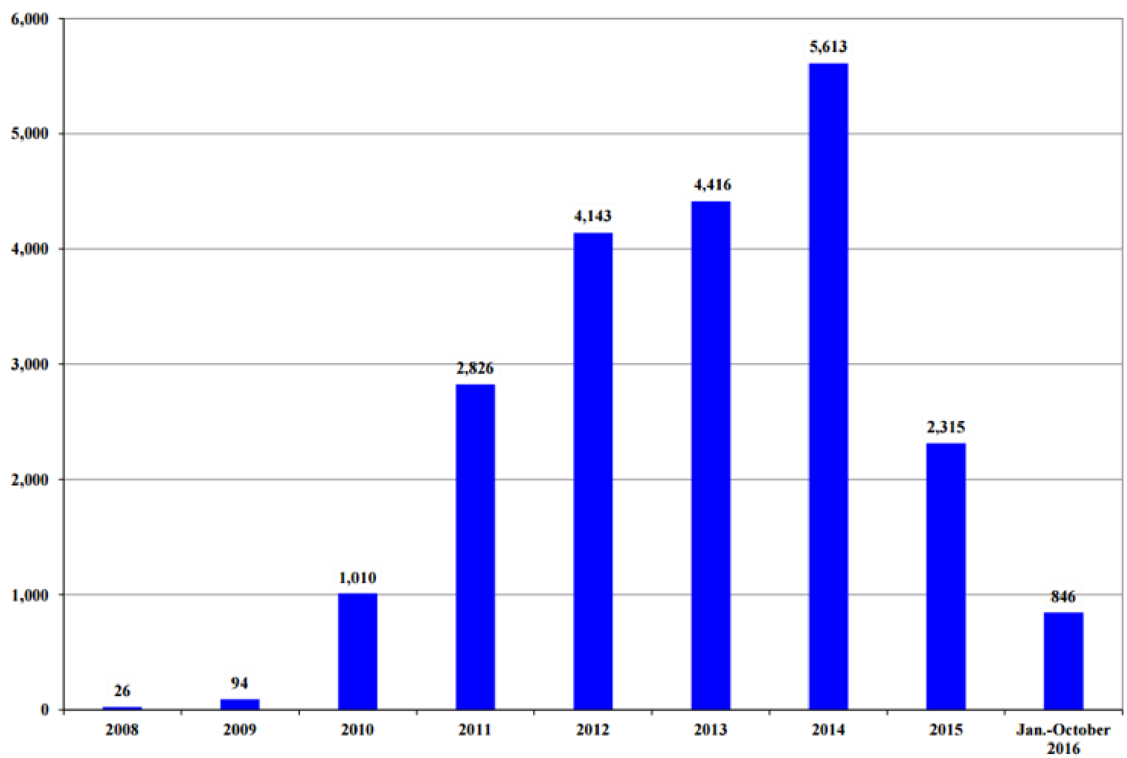

Fig. 3─Texas Eagle Ford Shale drilling permits issued from 2008 through October of 2016, Texas Railroad Commission (2016)

The Eagle Ford Shale play consists of approximately 11 million acres from the Texas/Mexico border to the eastern borders of Lavaca and Gonzales Counties (Fan et al. 2011). The play has been defined by Hentz and Ruppel (2010) as having a more carbonate-rich upper Eagle Ford Shale layer existing almost entirely south of the San Marcos Arch and a more organic-rich Eagle Ford Shale layer that exists from South Texas to the most northerly and easterly limits of the San Marcos Arch. **Fig. 4** displays the stratigraphic extent of the play and major structural features.

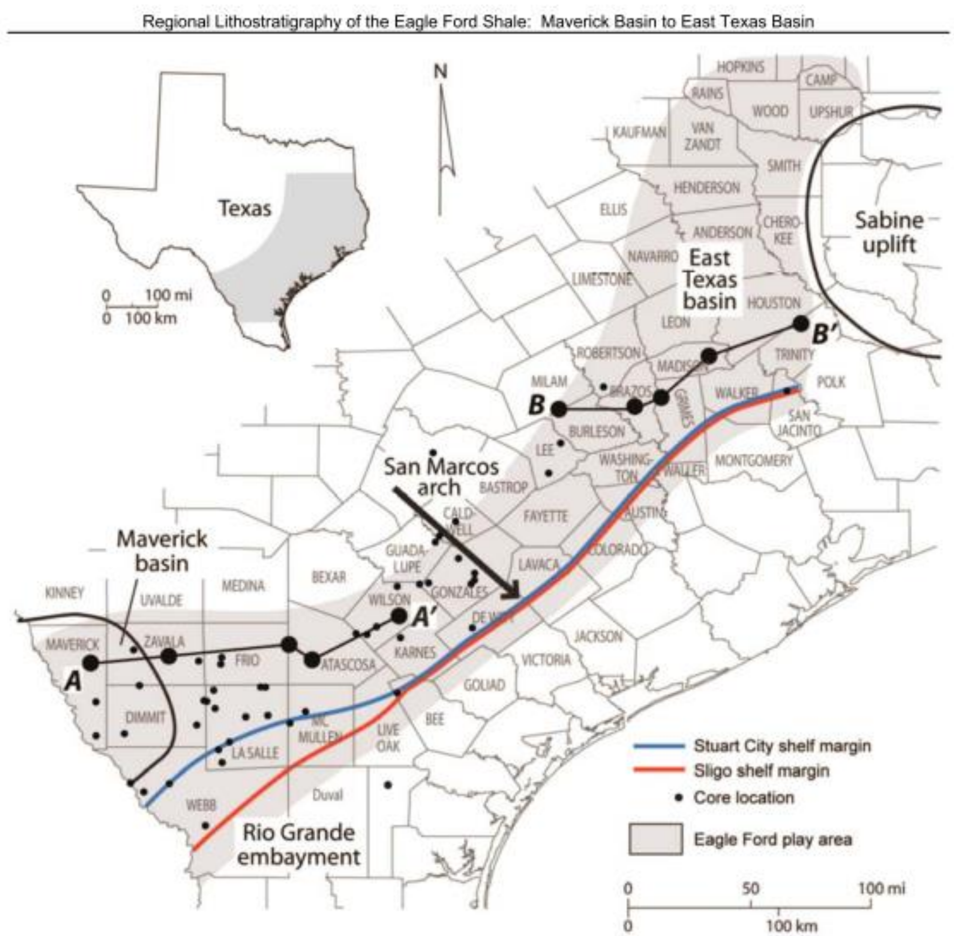

Fig. 4─Eagle Ford play area and structural features (Hentz and Ruppel 2010)

More recent research extended the partition of the Eagle Ford Shale by differentiating the upper Eagle Ford Shale layer into the upper-upper Eagle Ford and the lower-upper Eagle Ford based on different gamma-ray and resistivity responses (Tian, Ayers, and McCain 2012). The dip of the play is in a southeastern direction from the northern part of the Maverick basin towards the Gulf of Mexico, and the thickness of the play varies from 50 feet in the northeastern portion by the San Marcos Arch along the strike direction to about 300 feet in the southwestern portion of the Maverick basin (Fan et al. 2011). With formation tops varying in depths from as shallow as 1,500 feet to around 13,500 feet (Fan et al. 2011, from Fig. 3), the play consists of completed wells in different maturation windows producing primarily black-oil wells up dip in the northern counties to primarily dry-gas wells down dip in the southern counties with volatile oil wells and gas condensate wells in between (**Fig. 5**).

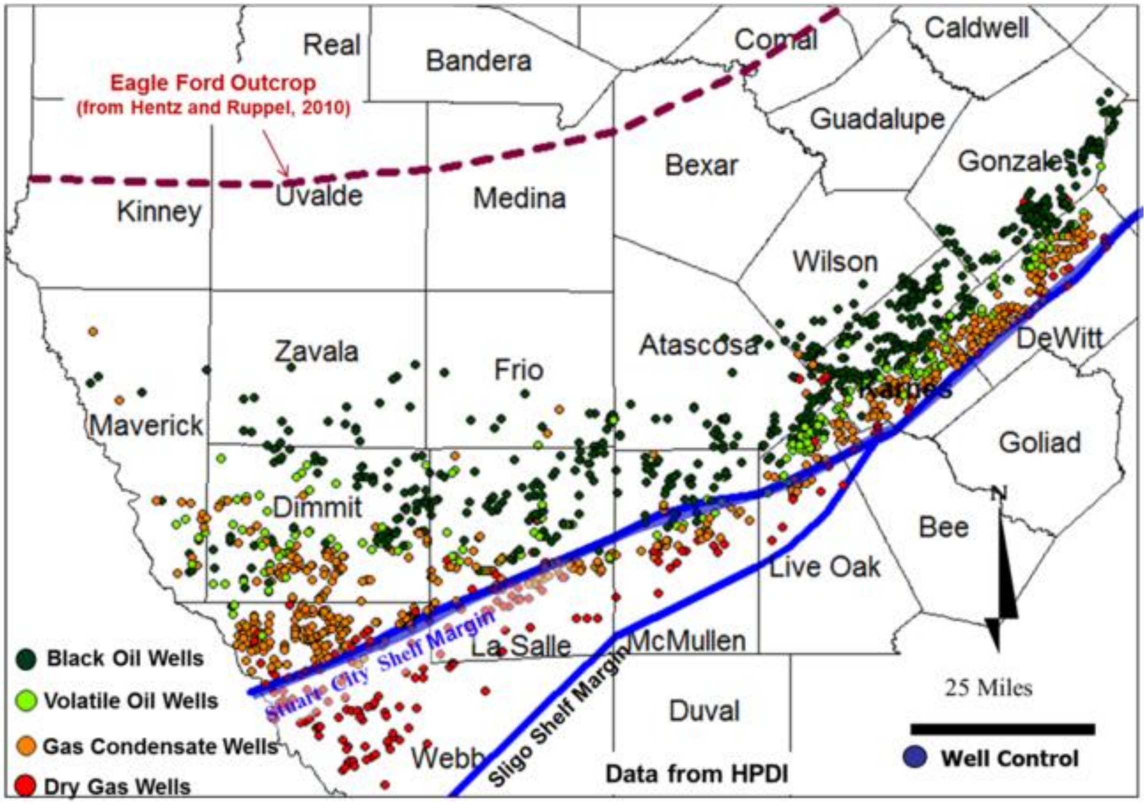

Fig. 5─Fluid types of Eagle Ford shale wells based on the average gas to oil ratios from the first three months of production (Tian, Ayers, and McCain 2013)

1.2.2 Defining Well-to-Well Interference and Identification

The literature is limited on well-to-well interference studies in unconventional reservoirs for horizontal hydraulically fractured wells. As operators drill infill wells, they are encountering situations where well-to-well interference begins to negatively affect production. Research performed by Awada et al. (2015) on Horn River pad wells aids in defining the term “interference.” The authors divide interference into two categories: when it occurs, a classification based on time, and where it occurs, a classification based on location. Interference during fracture treatments, an operation in the time category, is more commonly referred to as “frac hits,” which are observed as dramatic pressure increases in a parent well that has been shut in. As the stimulation of one well finishes, the fracturing pressure decreases and drops below the closure pressure of the reservoir—the pressure a fracture must overcome to open the rock. Frac hits that do not imply strong connectivity with another well can have un-propped fractures close due to the fracturing pressure depletion around the communication channels. Occasionally an increase in water production in the parent well after an offset completion has indicated a frac hit.

Interference during production, also a time categorized operation, occurs during the productive life of a well. This interference can originate when wells that did not indicate a change in production during stimulation have produced long enough and were spaced close enough that their drainage boundaries have started to interact. As a well begins to drain a reservoir a pressure disturbance is created that propagates outward with time; Lee (1982) described the term “radius of investigation” which he defined as the distance that the “peak” of the pressure disturbance is away from the sink, in this case the producing well. The drainage boundary is the “peak” pressure front. In this instance of production interference multiple wells have their pressure fronts meet. The pressure differential created between the two sinks, the two producing wells, means that the hydrocarbons are flowing to both wells rather than one. Here hydrocarbons that could be produced with one well are now being produced by two and in a less efficient manner.

Locational fracture interference, the “where interference occurs,” refers to communication in the reservoir when a hydraulic connection is created between wells such that some of the fractures from each well extend and adjoin (**Fig. 6**, Case 1) (Awada et al. 2015). Fig. 6 is a representation of how hydraulic fractures can interfere in different configurations between two wells.

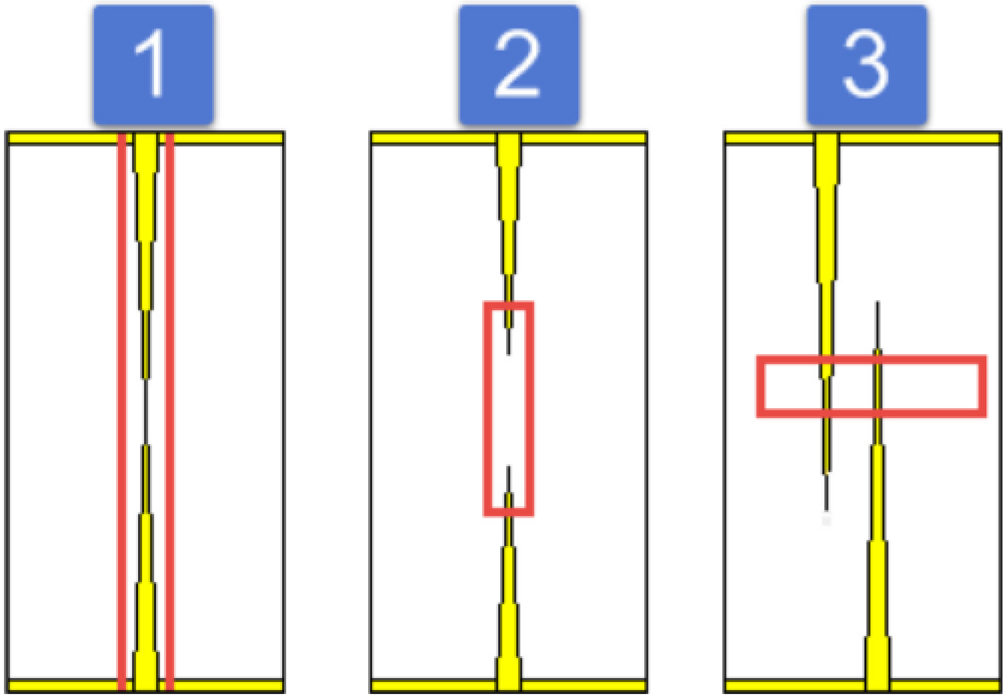

Fig. 6─Hydraulic fracture configurations that can lead to interference (Awada et al. 2015, Fig. 4)

Cases 2 and 3 portray locational interference from fractures of neighboring wells through the rock matrix. **Fig. 7** displays Case 4, where there is vertical separation between hydraulic fractures originating from different wells. Awada et al. (2015) points out that Cases 2 through 4 are “indistinguishable” due to anisotropic permeability in the three-dimensional space. Various combinations of distances and reservoir permeabilities can lead to the same observable response.

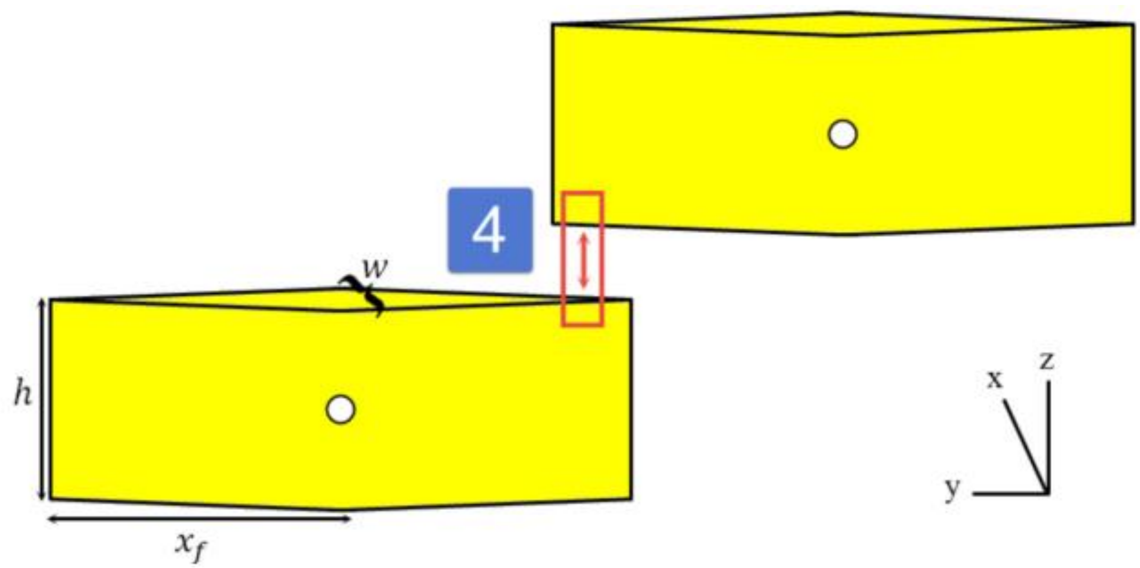

Fig. 7─Interference Case 4 of locational fracture interference (Awada et al. 2015)

Ajani and Kelkar (2012) state that there are few studies on interference between wells completed in shale plays. Their study of 179 horizontal gas wells in the Arkoma Basin of the Woodford shale determined that previously producing offset wells are impacted by infill wells. The infill wells are those drilled and completed between producing offsets in the same horizon. The impact depends on the distance and age of the previously producing offset well. Pressure depletion that surrounds the offset wells can lead to fracture fluid from the infill wells preferentially entering those depleted zones. They also found that the wells that have interference are most often consistent with an offset well in the direction of the maximum stress and that the infill wells, when they have impacted offsets, do not produce similar volumes compared to those previously producing offsets.

The study performed by Ajani and Kelkar (2012) highlights a need to better understand how producing parent wells can affect fracture growth from infill and offset wells. Mukherjee et al. (1995) studied vertical infill wells in the Frontier formation of the Moxa Arch area in Wyoming. The authors describe fractures preferentially growing asymmetrically with one wing of the fracture extending into a depleted area that develops significant length and conductivity, which is controlled by the location and azimuth of a recently completed parent well. This is due to the pore pressure depletion from the parent well causing stress gradients in the drainage area, with higher stresses near the parent well's drainage boundary and lower stresses surrounding the parent well's initial fracture surface. The fracture preferentially grows into the pressure depleted zone because of a reduced closure stress, the stress that must be overcome for a fracture to be generated and opened.

Roussel, Florez, and Rodriguez (2013) point out that "the principal stresses, which govern the propagation direction of hydraulic fractures, are thus modified not only in magnitude but also in direction" due to production from producing parent wells causing anisotropic pressure decreases. The authors performed simulations and claim that "the maximum horizontal stress decreases [as the well drains the reservoir] faster than the minimum horizontal stress causing" stress reversal near the fracture where the minimum and maximum horizontal stresses switch directions. They add that the "direction of maximum horizontal stress in the near-wellbore reoriented stress region will be perpendicular to the direction of highest drawdown." The distance the pressure depletion has occurred as well as the time it took to get to that point adds to the complexity of the situation. The point in time when stress reversal from the drainage of the parent well begins to occur can severely affect the fracture growth direction and magnitude of offset and infill wells. The authors go on to explain that smaller differences between maximum and minimum horizontal stresses can lead to hydraulically induced fractures branching out and interacting with natural fractures. This creates more complex fracture networks. More connectivity between fractures can possibly lead to similar fluid paths between parent and offset or infill wells resulting in fracture-to-fracture interference.

Uncertainty in the initial fracture volume and geometry from the parent well stimulation remains high. Identifying reservoir parameters, including fracture half-lengths, through techniques like micro seismic does not constitute a full description of size and shape of the fractures. According to Friedrich and Milliken (2013), micro seismic is limited in that it identifies where rock has failed during hydraulic fracturing, but does not indicate if proppant has been placed there and that the fracture will remain open. These authors define the volume surrounding micro-seismic events as the Stimulated Reservoir Volume (SRV) and the portion of the rock that has been stimulated as the Contributing Reservoir Volume (CRV). The CRV, according to the authors, will be responsible for the production coming from the reservoir.

In a study performed by Manchanda, Sharma, and Holzhauser (2014) micro-seismic events are identified as “induced unpropped (IU) fractures beyond the primary propped fracture” and their study shows that these types of fractures close over time. Their work considered four horizontal wells drilled on the same pad in the Eagle Ford, but their objective was to observe the effects that time between successive completion stages played when generating fractures along the same wellbore during a fracture operation. Their findings did not include the fracture behavior for infill wells next to previously producing parent or offset wells.

Establishing a relationship between well spacing and well-to-well interference requires a review of techniques aimed at the optimization of well spacing in addition to interference studies. Considering well spacing studies in the Eagle Ford, Lalehrokh and Bourma (2014) identified reservoir permeability and fracture area as the two most important factors to consider regarding well-spacing optimization in shale reservoirs through simulations and economic modeling. They noticed that it takes more wells to develop a shale reservoir rather than a conventional reservoir because of the lower permeability rock; additionally, wells should be placed closer together when the fluids, like black oil rather than dry gas, are heavier and more viscous because of a reduction in fluid mobility. Lalehrokh and Bourma (2014) mentioned that the acceleration in production from drilling more wells in an area, i.e., closer well spacing, is economically justified when commodity prices are higher for liquid hydrocarbons. Although the authors conveyed that there well spacing should be a design considering reservoir permeabilities, they were limited in their description of different ranges of spacing and permeabilities and they did not quantify the uncertainty in the study. Additionally, operators do not have control over the existing permeabilities in a reservoir. As a result, completion designs and well spacing must change with fluid type and economic environments to generate the greatest value.

Previous research stresses defining the volume that has been stimulated due to hydraulic fracturing. Identifying the original drainage volume of a hydraulically fractured well is not possible with today's technology; the volume and geometry is regularly assumed. If the initial stimulated reservoir volume and reservoir properties are known, simulations similar to that performed by Fujita, Datta-Gupta, and King (2015) would have very accurate representations of drainage boundary propagation. These authors can compute the well drainage volume of shale and tight oil and gas reservoirs efficiently using a Fast Marching Method and by introducing the concept of "Diffusive Time of Flight." This modeling technique gives the user the ability to model the pressure front propagation much more rapidly when compared to conventional modeling techniques while still providing sufficient resolution. Unfortunately, assumptions must be made or information must be gathered regarding reservoir permeability, fracture half-lengths and rock compressibility at the expense of the operator.

1.2.3 Quantification of Well-to-Well Interference

In a study on the Marcellus shale, Yaich et al. (2014) quantified interference between gas wells on an economic basis by using "projected future five year cumulative production using Arps decline curve, Rate Transient Analysis and Pressure Normalized Rate methods." The combination of these tools found that at well spacings greater than 1,500 feet, interference was still detected but not significant. Well spacing strategies less than 1,500 feet led to a 5% to 25% decrease in the productivity index. The authors provided only one method for quantifying interference and optimizing well spacing through the use of that method, but they did not report the number of wells in their study nor quantify the uncertainty in their estimates. This leads one to believe that their results can only be attributed to the wells in their sample and not necessarily to the entire Marcellus shale.

The authors Kurtoglu and Salman (2015) developed a methodology that shows "how to analyze pressure and rate responses from fracture interference data" by calculating changes in well productivity and estimating production losses and/or gains in the existing producing parent well. They identified the factors that have the most impact on fracture interference as "(1) areal variation of reservoir properties, (2) pressure depletion due to the initial generation of wells, and (3) distance between producer and infill wells." Their study analyzed several multi-stage horizontal wells from the Eagle Ford and Bakken formations. Through the use of decline curve analysis, the authors were able to "provide a meaningful way of estimating interference impact on economics." They suggest using the impacts of well-to-well interference, indicated by well pressure, to review changes in the reservoir connectivity and the lost or gained area that contributes to production. The results indicated that a "comprehensive development plan" should account for the potential upside or downside scenarios from fracture interference. Unfortunately, they developed their techniques using only two wells in the Eagle Ford and applied it to the North Dakota and Montana Bakken reservoirs.

The research discussed up to this point highlights several theories behind the behavior of fracture growth in unconventional reservoirs. Variable stress fields as well as propped versus unpropped fractures can have critical effects on the volume of hydrocarbons that are able to contribute to production. The literature is limited in quantifying well-to-well interference and how it is related to the well spacing and completion designs of offset and infill wells. A major hurdle in the literature involves having to make several assumptions about reservoir characteristics due to the heterogeneous nature of unconventional plays. None of the authors effectively addressed the uncertainty in fracture lengths, permeability, reservoir volume contributing to production (CRV-propped volume), stimulated reservoir volume (SRV-fractured volume), and the time for the onset of stress reversal. Unless a significant amount of data is gathered over an area, a well-spacing strategy will still have a large amount of uncertainty.

The cost to gather reservoir information over large areas is uneconomical for many operators, yet determining relationships between completion techniques, well spacing and the effects of well-to-well interference is still important. Previous authors decided to work with larger public data bases to combat this issue. Well spacing studies that are applicable to large geographic areas incorporate information from multiple wells. Smaller sample sets like individual well studies will not return results that can be applied to large geographic areas because they are localized by nature. Generating vast areal solutions can only be obtained with data publically available or an operator must consider a significant amount of investment.

Izadi, Zhong, and LaFollette (2013) applied multivariate statistical modeling techniques hand in hand with Geographic Information Systems (GIS) software to expand on previous Bakken data-mining efforts. Due to the lack of reservoir information that is publically available, the authors utilized well location as a proxy for reservoir quality in a study of over 3,500 wells. Through the use of modeling techniques, they found that geographic well location is one of the most important variables for the prediction of a well's production and efficiency metrics. This study provides information on the completion parameters that have significant impacts on their models. The authors did that by comparing models using data gathered basin wide and from models that used data in a single area compared to other areas. They did not discuss using the models as a predictive tool or describe the uncertainty involved in doing so.

Gong et al. (2011) developed a decline-curve-based reservoir model that considers uncertainty in the production forecasts by correlating well spacing and completion parameters with performance indicators from 64 horizontal wells in the Barnett Shale play. They found that the oil and gas production declines of the shale wells could be correlated with completion/stimulation parameters and well spacing, but the correlations among the parameters were low and significant uncertainty resulted. The reservoir model incorporated multivariate linear relationships between Arps decline curve parameters as well as completion and well spacing information. Due to the uncertainty in the models, the authors suggested economics should be considered to optimize well spacing strategies but they did not consider the cost of tighter well spacing and the effects it would have on the expected returns.

Voneiff et al. (2013) collected completion reports on 425 wells in the Montney formation of British Columbia. The authors performed a multivariate linear regression analysis of the average production during the best year of production and found that they could effectively determine the impact of several completion parameters on production, even when 2-D regression analysis had weak correlations. Using the weakly correlated completion parameters led to greater uncertainty in any prediction of production than using strongly correlated completion parameters. A follow-up study, Voneiff et al. (2014), took the information from Voneiff et al. (2013) and developed a methodology that predicts the performance of horizontal gas wells in unconventional reservoirs using only publically available completion data. The authors converted the deterministic regression coefficients in the multivariate models to probabilistic distributions to account for parameters that are not considered in the original regression analysis. They concluded that they could take the predictive multivariate linear regression model from Voneiff et al. (2013) and manipulate the range of predicted outcomes by adjusting the linear regression coefficients until they could fit 95% to the actual results. These papers, Voneiff et al. (2013) and Voneiff et al. (2014), highlight the possibility of developing predictive models from public data and at the least justify the usefulness of public data. However, other plays, like the Eagle Ford, do not have large amounts of quality, detailed data like that of Montney in British Columbia, and using more detailed parameters is only possible by obtaining proprietary completion information from each operator.

Ultimately, previous research has developed several tools and methodologies that can be used to quantify well-to-well interference and perform studies with public data on the Eagle Ford shale. The previous work did not attempt to quantify well-to-well interference effects for a large number of wells using public data. The literature focused on a small set of wells and the uncertainty in interference impacts that were recorded were not quantified.

1.3 Research Objectives

The specific objectives of this research are to quantify the effects of well-to-well interference on the production of horizontal, hydraulically-fractured wells for two study areas in South Texas' Eagle Ford Shale play and then describe the uncertainty associated with the interference. The study will use data from wells that are drilled and completed in the Eagle Ford and in an area encompassing the acreage held by Matador Resources Company. This research is part of a larger goal to optimize well spacing in this area.

1.4 Overview of Methodology

Due to the fact that Matador Resources operates 115 wells in the Eagle Ford Shale and the need to use large data sets to effectively quantify any uncertainty in this studies' results, the decision was made to gather public data. The information reported to the Texas Railroad Commission (TRC), the Texas' state agency that regulates the oil and gas industry, lacks the quality and detail retained in any operators' well files. However, only the data required by the TRC is available to the public. Additionally, the decision to use public data means that a well pressure record is nonexistent. Reported production volumes will be used in place of well pressures for describing potential well-to-well interference. An Arps' decline curve regression of the production data was used in this study to quantify interference and its effects on production forecasts (Arps 1944). Wells were separated into those that could have experienced a potential impact on production and those that potentially caused an impact on production.

Quantifying the impacts on production by other wells was performed in two ways. The first was a comparison of two forecasts obtained from a regression of monthly production rates: one regression used the average production rate in each month up to the nearest neighboring well's offset completion date; the other regression used the average production rate in each month that was publically available. The differences in the forecasted production from the date of the nearest neighboring well's offset completion date out to 60 months were normalized and compared to well spacing. The second comparison used the same two forecasts; however, initial cumulative production in these forecasts for the first 12 and 36 months were normalized and compared to well spacing.

For those wells that potentially caused an impact, an analysis was performed to quantify any impacts that might be seen through their production. This, too, was performed in two ways. The first method obtained a forecast by regressing the average production rate in each month and comparing the initial cumulative production for the first six months for wells in a study group to a control group. The second method used the same forecast for each well and compared a ratio, initial cumulative production in the first six months versus the first month, for wells in a study group to a control group.

2. DATA PREPARATION FOR ANAYLSIS

2.1 Initial Data Processing

Monthly production data, well completion information, and directional surveys were collected on 1,996 wells, including 65 wells operated by Matador. This information was placed in a Microsoft Excel (2013) workbook and analyzed. To try and maintain similar characteristics like vertical depth, and fluid type, the wells selected for analysis were completed in the same area that a significant amount of net acreage held by Matador Resources exists. This created two areas where well data was collected. LaFollette and Holcomb (2011) applied practical data-mining methods to large shale-gas data sets to learn key lessons that are not necessarily seen with smaller data sets in the Barnett Shale. They found that a "geographical approach to isolation of similar wells was successful in isolating an area of interest where cross plot and regression analysis could be successfully applied." They studied groups of areas that were relatively homogeneous in terms of reservoir characteristics. Displayed in **Fig. 8**, the two areas in the work by LaFollette and Holcomb (2011) shows wells primarily in Western Karnes County (WKC) and Northern La Salle County (NLSC) in the predominantly oil producing region of the Eagle Ford.

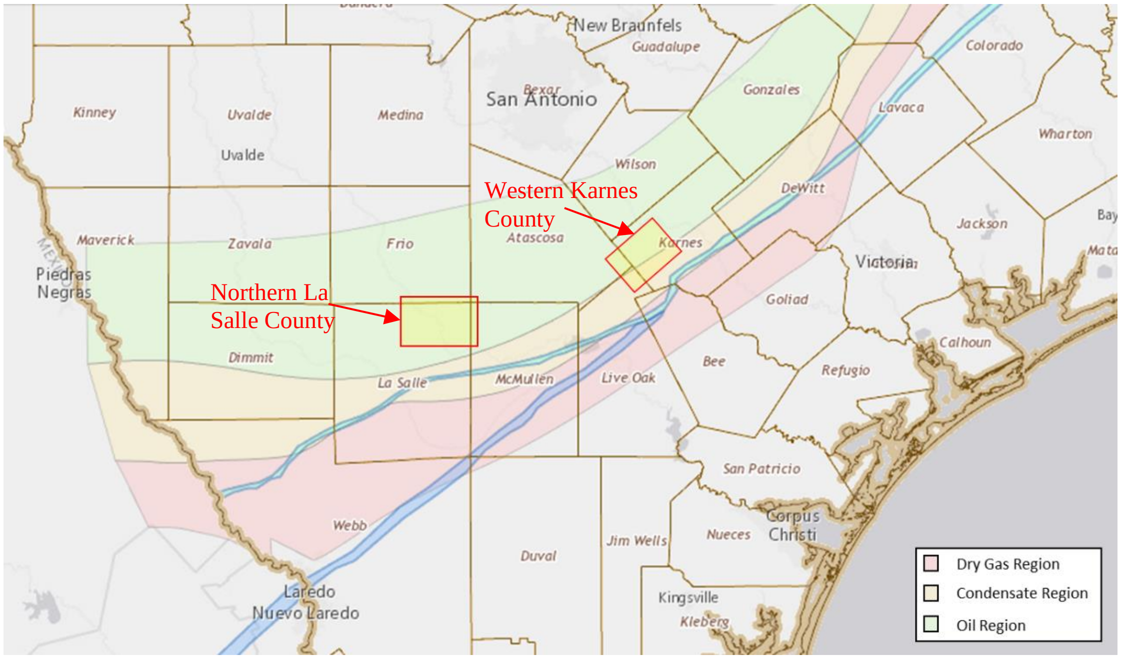

Fig. 8─Areal plot showing the oil, condensate, and dry gas regions of the Eagle Ford with the two areas included in this study highlighted in yellow.

The wells studied were initially selected based on two criteria. One, they surrounded Matador acreage, and two, they were completed in the Eagle Ford Shale formation. Wells were eliminated from the study if they were not horizontal and hydraulically fractured. Only an analysis of similar or identical completion types, i.e., horizontal and hydraulically fractured wells, will provide meaningful results.

Wells with missing information, like monthly production volumes or completion data, were eliminated from the well spacing study, but the directional surveys were kept. When a well with missing information was removed from the study, the utility of its directional data remained to obtain a well spacing for neighboring offsets. The neighboring wells left in the study still needed that information to analyze effects on production by those wells that were removed. In order to extrapolate results from the interference study each well would need offset well information; thus, wells on the external perimeter of the selected regions were also eliminated from the study. Their directional surveys, however, were kept so that they could again serve as offsets for the rest of the wells. Additionally, wells were eliminated in the event their completion data was incomplete, e.g., hydraulically fractured wells with no record of proppant pumped.

To ensure each well in a prospective area had similar fluid phases, wells with average monthly gas-oil ratios, GOR, greater than 4,000 scf/bbl (standard cubic feet per barrel) were eliminated from the study. The elimination of any well with an average monthly GOR over 4,000 scf/bbl limits the fluid types to black oil and volatile oil wells. In a paper published by Tian, Ayers, and McCain (2013), the authors listed gas condensate wells in the Eagle Ford Shale as having average monthly GOR increase from initial production to an eventual range from 4,000 to 20,000 scf/bbl. After removing wells with GORs over 4,000 scf/bbl, the study group consists of wells with an average monthly GOR from 120 to 3,880 scf/bbl.

After the initial processing of all data selected for the study, the study well set of 1,996 was reduced by 908 wells to 1,016 wells.

2.2 Identifying Well Spacing

At this point additional information was needed with regards to completion and production dates. Well spacings were calculated from the directional surveys collected through downhole tools when drilling the well. The directional surveys are reported as northings and eastings by the Universal Transverse Mercator system, UTM, where the measurements are recorded in feet. The survey lengths from all 1,996 wells were compared to the lateral lengths reported in the public well files; wells that had mismatched information, hundreds of feet difference in lateral length, were eliminated from the study. First an algorithm was developed to identify each well's nearest neighbor. Well spacing was calculated by comparing the study well's directional data to the two neighboring wells' directional data to get a well spacing for both neighbors. Horizontal wells in this study were relatively parallel and each well has a well on either side.

Fig. 9 displays an example of a horizontal well that has directional survey points not in the completed interval represented as black dots and the points along the completed (perforated) interval represented as black dashes. The surveys collected while drilling are recognized as a northing and easting, Fig. 9, in addition to the total vertical depth sub-sea, TVDSS.

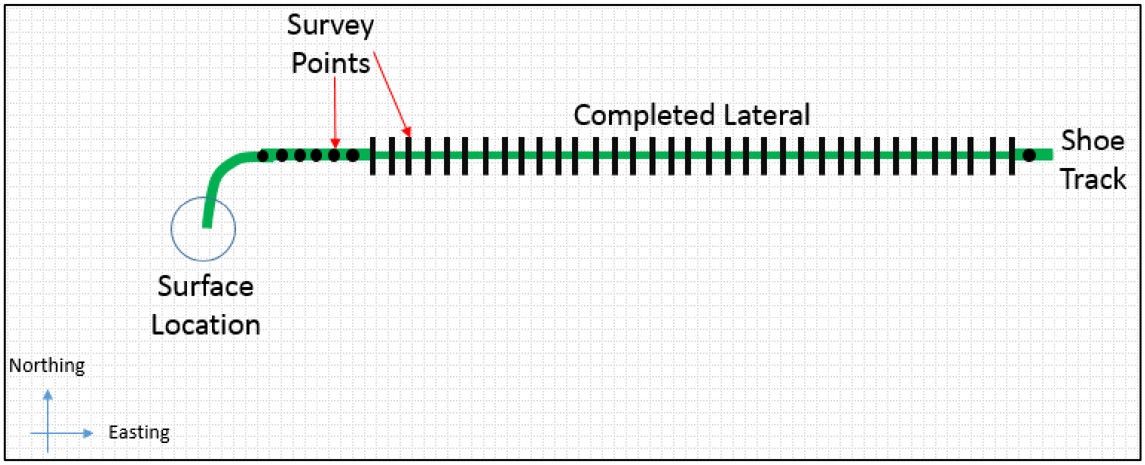

Fig. 9─Aerial view of completed lateral showing directional survey points

The data was then truncated, **Fig. 10**, to only the completed laterals because this is the actual length of lateral that would contribute to production and therefore interference.

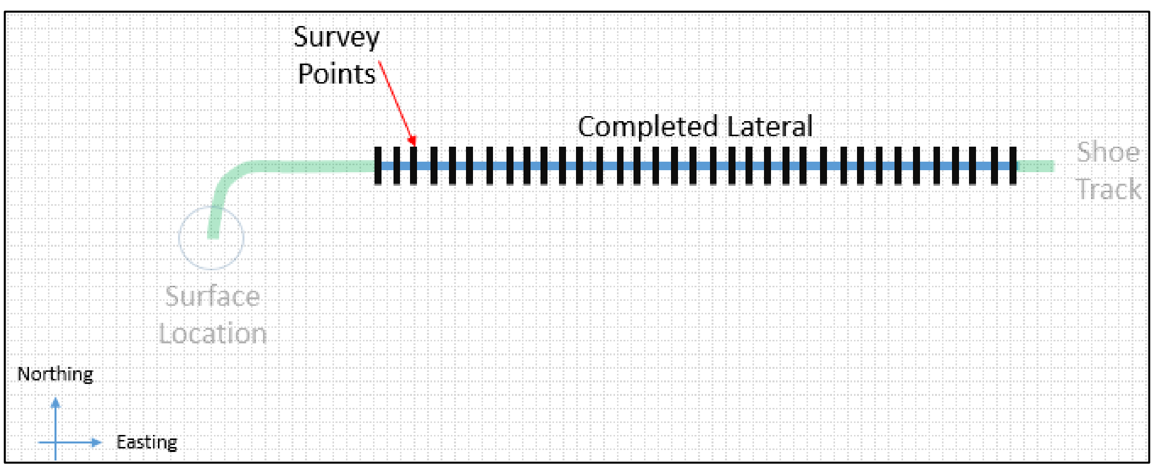

Fig. 10─Aerial view showing only the completed lateral length and directional survey points

The first and last survey points' northing and easting in this completed length were represented as points along a line, X_1, Y_1 and X_2, Y_2 (**Fig. 11**). For the purpose of identifying a well's nearest neighboring well the actual well deviation and drift along the well's path can be ignored; well surveys regularly do not look as linear as the image in Fig. 11. Typically a well is drilled within a small range in terms of the azimuth, roughly 50 feet. A majority of the nonlinearity of a horizontal well's path occurs in the inclination rather than the azimuth. Wells in this study that vary far from the linear line projected through the first and last survey points will not affect this analysis in terms of well spacing because actual survey points were used to get well spacing rather than the line. It is important to note that the survey points used to obtain the well spacings do not consider the uncertainty in surveys taken and that uncertainty will be inherent in the results.

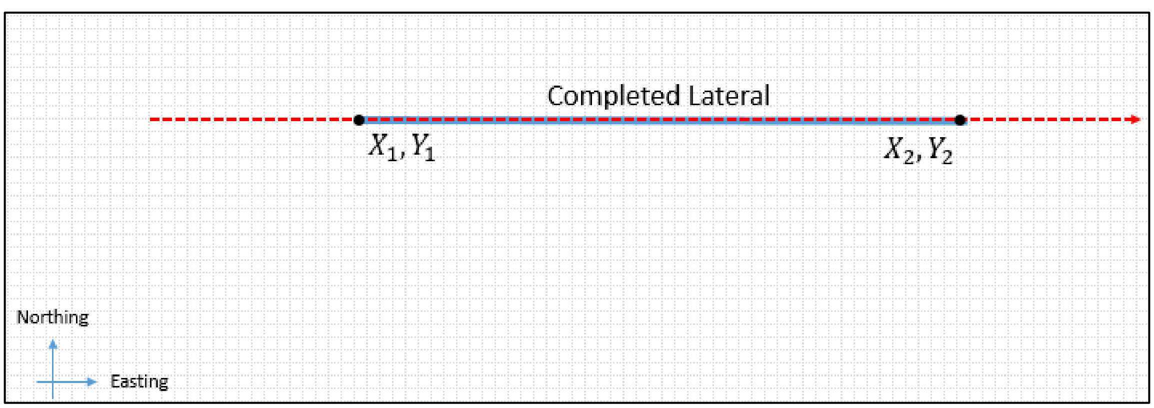

Fig. 11─Line along the length of the lateral connecting the first and last survey points in the completed lateral

With these two points the equation of a line can be found in Eq. 1, with the slope represented through Eq. 2 and the y-intercept, also widely known as variable b, through Eq. 3.

$$Y = m \cdot X + b \quad (1)$$

$$m_{Study} = \frac{Y_2 - Y_1}{X_2 - X_1} \quad (2)$$

$$b_{Study} = Y_1 - m_{Study} \cdot X_1 \quad (3)$$

For each well the end points of the completed lateral, the slope of the line between them, and the y-intercept were recorded. A midpoint along the completed lateral was determined with Eq. 4.

$$Midpoint = \left(\frac{X_1 + X_2}{2}, \frac{Y_1 + Y_2}{2}\right) \rightarrow (X_{mid}, Y_{mid}) \quad (4)$$

To identify the nearest neighboring well, three perpendicular lines passing through the midpoint and two endpoints along the study well's completed lateral were used in conjunction with offset well lines to determine if these lines intersected. **Fig. 12** represents an example case of how the lines created for study wells intersect the neighboring well.

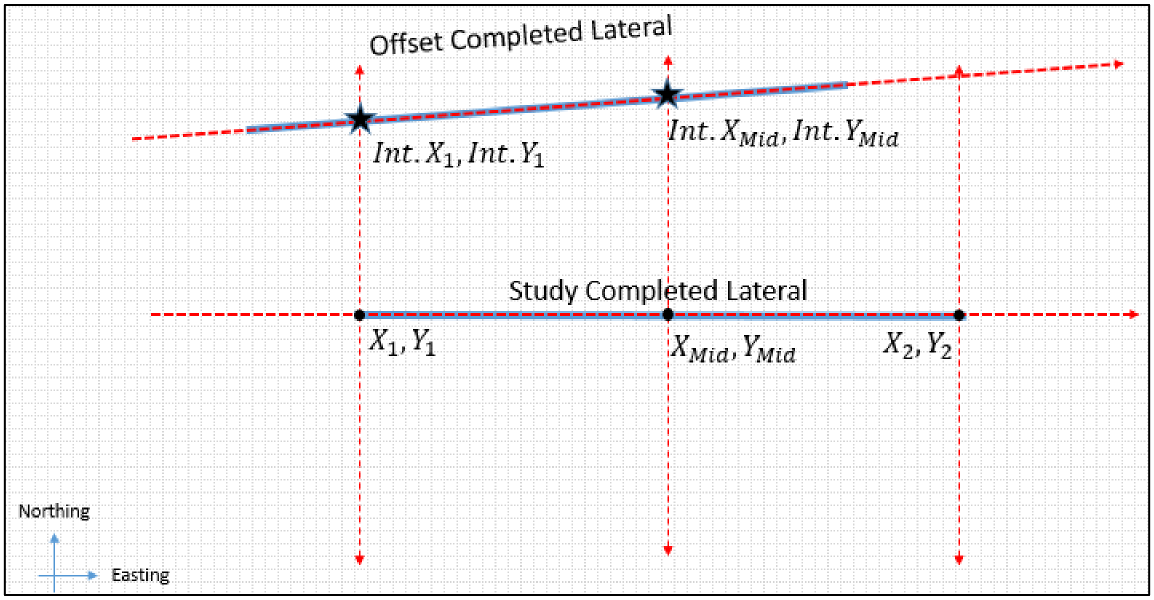

Fig. 12─Determining if perpendicular lines along the study well's completed lateral intersect other offset completed lateral lines

Perpendicular lines that protrude from the study well's completed lateral line were calculated by taking the negative inverse slope, Eq. 5, of the study completed lateral line,

$$m_{inverse} = -\frac{1}{m_{Study}} \qquad (5)$$

and then re-solving for the y-intercept with Eq. 3 for each point. Each well in the data set has an established, completed lateral line along the trajectory of the completed lateral and hereby an associated slope and y-intercept is retained for that line. The slope and y-intercept for perpendicular lines traveling through each laterals' completed endpoints and midpoints are documented so that the information can be used in a VBA macro. VBA is Microsoft Excel's (2013) programming language that allows users to perform tasks within the Excel environment. Within the program the intersecting points along the offset line, marked by a star in Fig. 12, are used to then calculate the distance between the offset and study lines.

$$Int.X_{1/\text{Mid./2}} = \frac{(b_{Offset} - b_{Study})}{(m_{Study} - m_{Offset})} \quad (6)$$

$$Int.Y_{1/\text{Mid./2}} = m_{Offset} \cdot Int.X_{1/\text{Mid./2}} + b_{Offset} \quad (7)$$

Eq. 6 and Eq. 7 are the formulas used to determine the intersecting points on the Offset Completed Lateral line with those lines perpendicular to and protruding from the Study Completed Lateral line at endpoint "1" on the Study Completed Lateral. After the intersecting points are determined then calculating the distance between the offset intersecting points and the points from the study well's line was performed through the use of Eq. 8.

$$A = \left(Int.X_{1/Mid./2} - X_{1/Mid./2}\right)^2$$

$$B = \left(Int.Y_{1/Mid./2} - Y_{1/Mid./2}\right)^2$$

$$C = \left(Int.TVDSS_{1/Mid./2} - TVDSS_{1/Mid./2}\right)^2$$

$$Dist._{1/Mid./2} = \sqrt{A + \mathrm{B} + C} \quad (8)$$

Eq. 8 incorporates three dimensions by also including the vertical distance between wells, calculated with TVDSS. The nearest neighbor was selected based on the minimum distance calculated among the three perpendicular lines. Two wells were identified by establishing the nearest neighbor on either side of the study well's line. A comparison of the directional data for the two neighboring wells defined the well spacing. Beginning with the first survey point along the study well's completed lateral, the minimum distance was calculated between that point and the first survey point along the offset's completed lateral (**Fig. 13**).

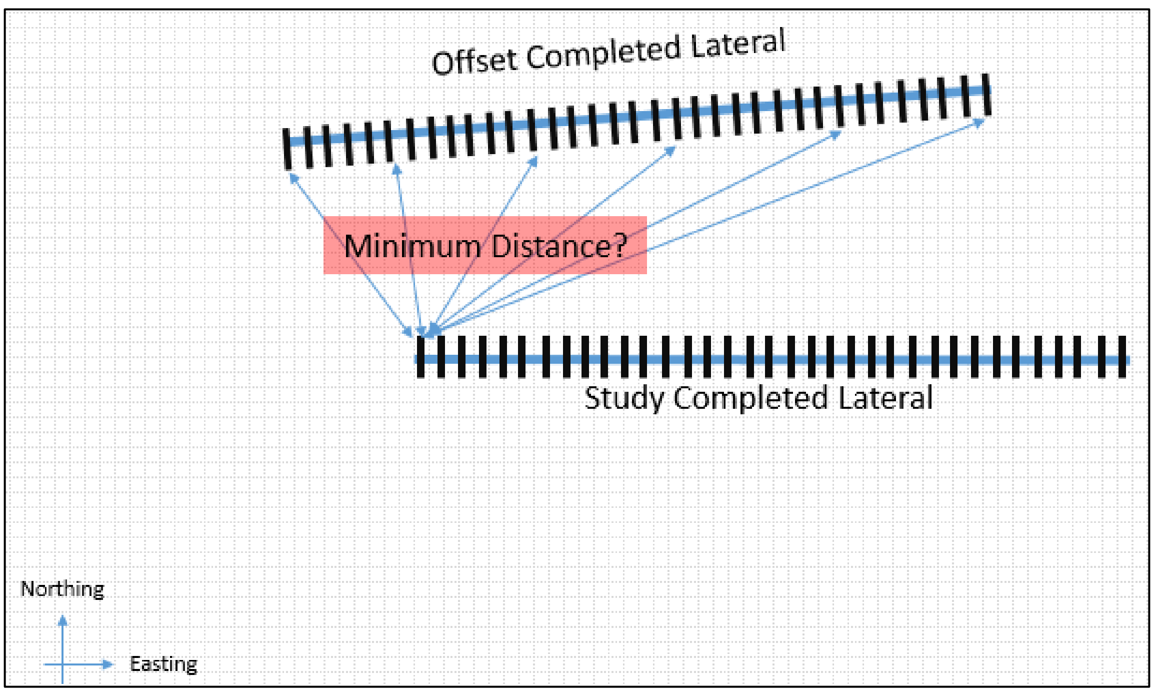

Fig. 13─Comparison of survey points between an offset and study well along the completed intervals

This was performed for each point along the offset completed lateral before moving to the next point in the study completed lateral. Then the process was repeated until each survey point had been compared and a final minimum distance was identified; **Fig. 14** shows an example where 300 feet was identified as the smallest distance between the offset and study well. This distance is assigned as the well spacing for one of the two well spacings for the considered study well.

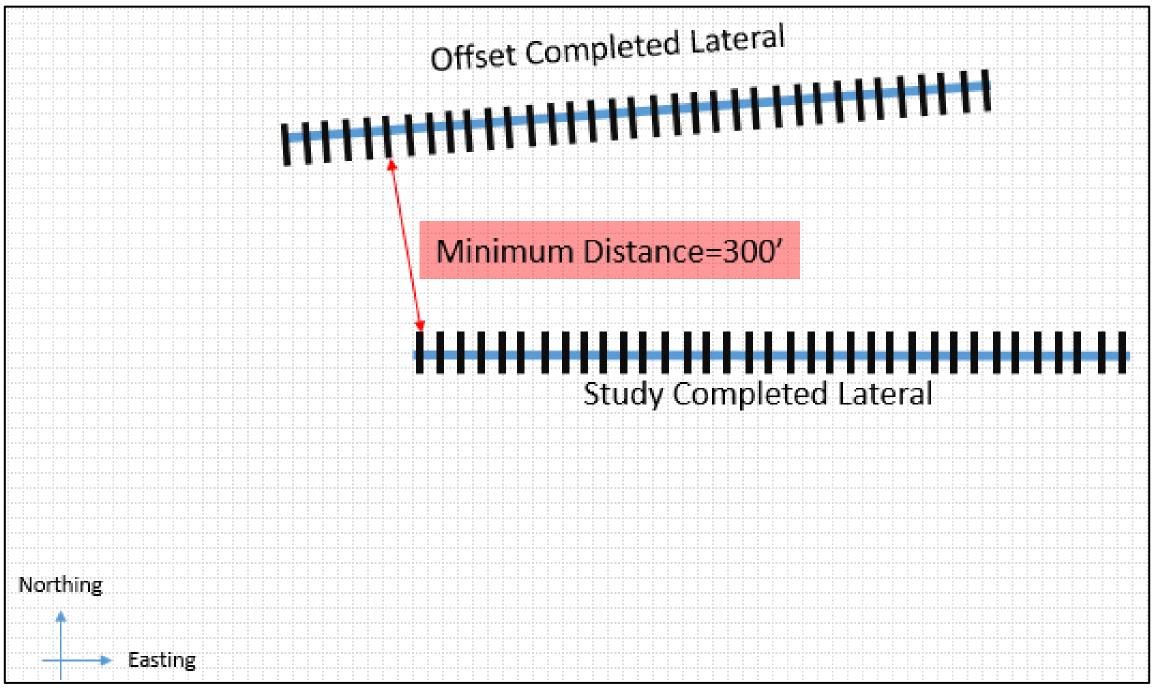

Fig. 14—Identified minimum distance between a study well and offset

Local maximum stress directions, heterogeneous reservoir characteristics, and sequential hydraulically fractured stages prevent uniform fracture growth along any given lateral. This means that a complexity of hydraulic fracture growth in terms of length and width and unknown local fracture growth directions leads to the assumption that the alignment of the two wells in Fig. 14 can be represented like that in **Fig. 15**. This assumption is necessary because the geometry of hydraulically induced fractures cannot be determined accurately with today's technology. A significant number of different fracture geometries could occur and the prediction of those geometries are not within the scope of this work.

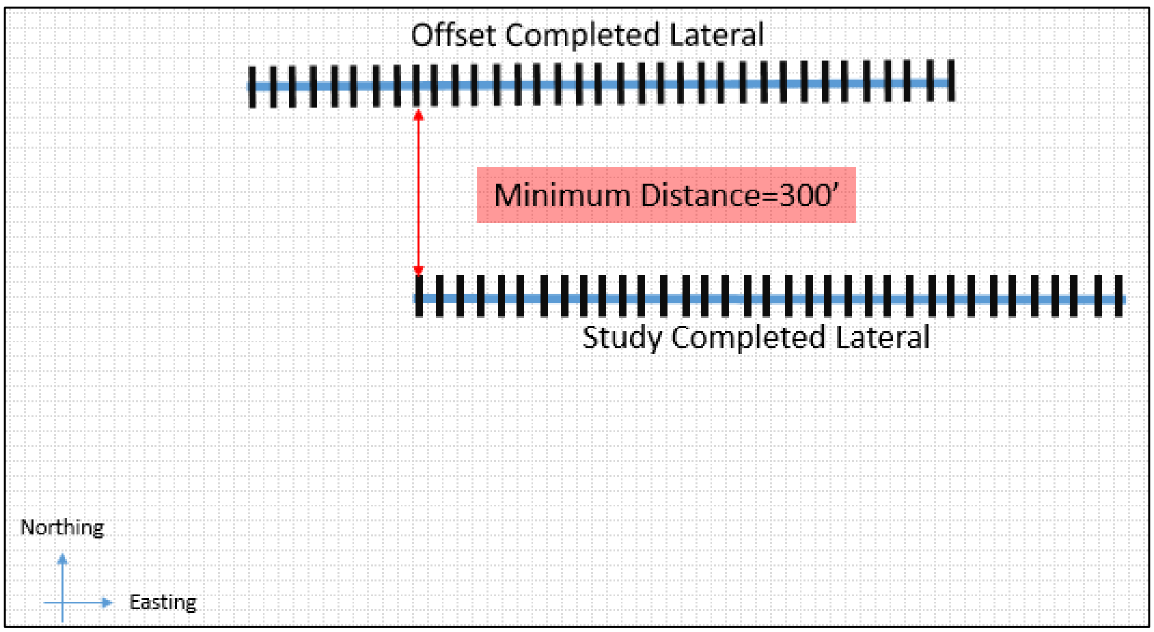

Fig. 15─Representation of study and offset wells in a parallel fashion at the minimum spacing distance

2.3 Primary Regression Analysis and Interference Classification

Since the study group was reduced to black-oil and volatile-oil wells, primarily liquid producing, the production data was limited to using only monthly oil production volumes. The TRC public data base lists the barrels of oil a well has produced throughout its life. These volumes input into a Microsoft Excel (2013) spreadsheet to perform a best-fit regression of the data using Arps' decline curve analysis assuming a hyperbolic decline with a minimum decline rate. J. J. Arps (1944) developed rate-time equations to describe observed production decline profiles. Eq. 9, Eq. 10, and Eq. 11 describe the exponential, hyperbolic, and harmonic decline rates that he plotted with recorded production on a semi-log plot.

Exponential, ($b = 0$):

$$q = q_i e^{-tD_i} \quad (9)$$

Hyperbolic, ($0 < b < 1$):

$$q = q_i (1 + bD_i t)^{-1/b} \quad (10)$$

Harmonic, ($b = 1$):

$$q = \frac{q_i}{(1+D_i t)} \quad (11)$$

The variable q represents the rate, q_i is the initial production rate, D_i is the initial decline rate, t is time (usually in months), and b is the degree of curvature. Typical ranges for minimum decline rates are from five to ten percent. The minimum decline rate used in this study was an eight-percent nominal decline rate per year. A comparison of the regressions using six and ten percent nominal decline rates per year only affected the estimated ultimate recovery by two or three percent on average. In addition to the minimum decline rate, a rate limit of ten barrels of production per day was imposed to coincide with the realistic expectation that a well would be shut in below an economic operating rate. Performing a regression of the data involved minimizing the square of the difference between the natural logarithms of actual monthly rates and those simulated with the Arps' decline curve equations. This was done using the built-in Solver function in Microsoft Excel (2013). Limits of zero and two were imposed on the degree of curvature, *b*, and the nominal decline rate was restricted to values greater than zero. Determining the best fit for each production data set was done through an automated process but then visually inspected. Data sets that showed production rates less than ten barrels per day were manipulated to omit those points because they tended to severely impact or prevent a best fit regression from occurring; wells with rates less than ten barrels per day rarely appeared. The month with the highest production rate was identified and was used as the first data point in time when performing the regression. The regression started by using data points from this highest producing month and the months that followed. Beyond omission of months with rates less than ten barrels per day and the months prior to the month with the highest production rate, each data set was unchanged and the regression algorithm was used to mitigate any subjectivity in the regression. Each well's regression was checked visually to ensure that the results were plausible. **Fig. 16** shows an example of production rates from a well analyzed in the study plotted versus time, API #: 42-013-34670. The decline curve analysis (DCA) best fits for rate in barrels per day and cumulative production in barrels are also shown.

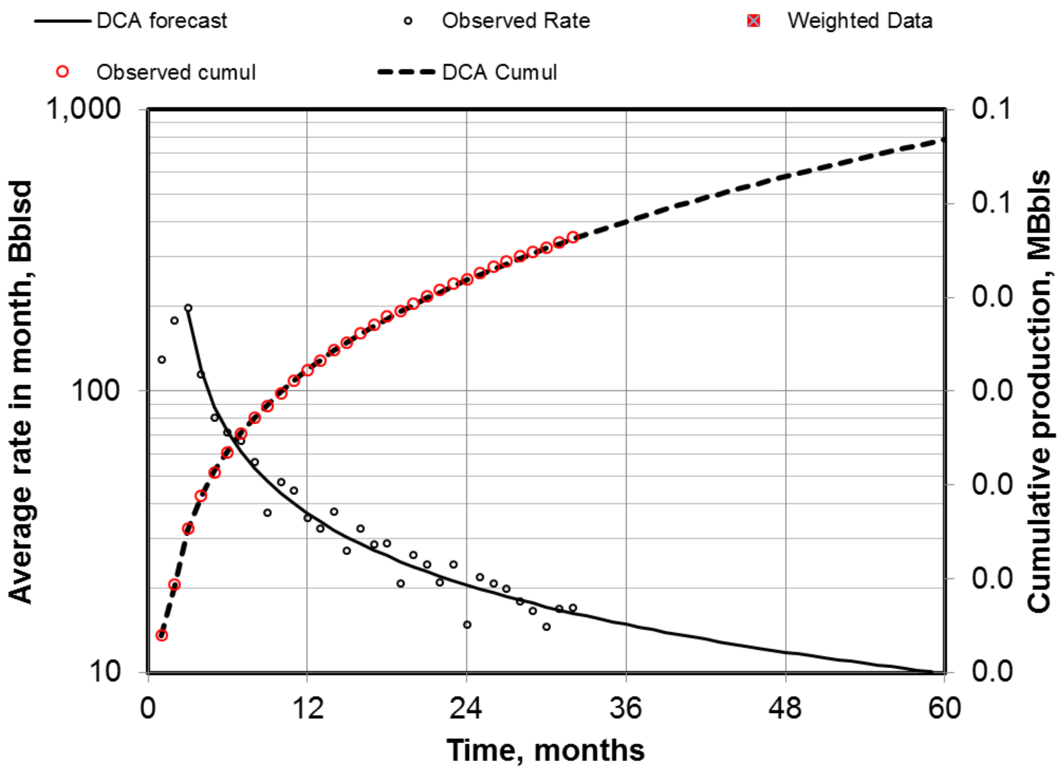

Fig. 16─Best fit rate and best fit cumulative for study well 42-013-34670

Following the initial regression of every well's monthly oil production, a categorization of situations regarding how well-to-well interference occurs was performed. Each well's production date was compared to its neighboring wells' completion date to establish whether or not it could have potentially been impacted by that offset fracture stimulation. In this situation a well would be placed in the "Potentially Being Impacted" group or PBI. For this study 474 wells were identified as having either one or both nearest neighbors that could have potentially impacted the production.

Successively a well's completion date was compared to its neighboring wells' production date to establish whether or not it could have potentially impacted the existing producer. For this situation a well would be placed in the "Potentially Impacting" group or PI. For this study 574 wells were identified as having either one or both nearest neighbors that could have potentially been impacted due to this wells completion.

3. WELLS POTENTIALLY BEING IMPACTED, PBI

3.1 Introduction of Methodologies

Quantifying the impact on production due to offset completions was performed in two different ways to effectively shed light on different production periods in a well's life cycle. In either case the initial regression performed using all of the available data assumed that any production change due to interference was captured through the best fit of that production data. These regression results that utilized all available monthly production rates were labeled as the Potentially Affected Well Regression or PAWR. A regression utilizing production data up to the month of an offset completion was also performed for each study well. This additional regression is labeled as the Unaffected Well Regression or UWR, and it assumes every recorded month up to the month where the offset completion occurs is unaffected by that offset well's stimulation. The UWR utilized only the monthly production rates prior to the offset completion date. In cases where both neighboring wells were completed after the study well was opened to production, two UWRs were recorded and the larger of the two impacts on production were used to quantify the effects. **Fig. 17** shows the two curves, PAWR and UWR, for a study well. This case will be referred to as study well with API #: 42-255-31886 in this section and the subsequent sections that follow to provide a visual example. In Fig. 17 the legend lists the "Observed Rate" and "Weighted Data." Both of these are reported data points for the average monthly rate for study well 42-255-31886. The UWR is only regressed through the “Observed Rate” data points and the PAWR is regressed through both the “Observed Rate” points and the “Weighted Data” points.

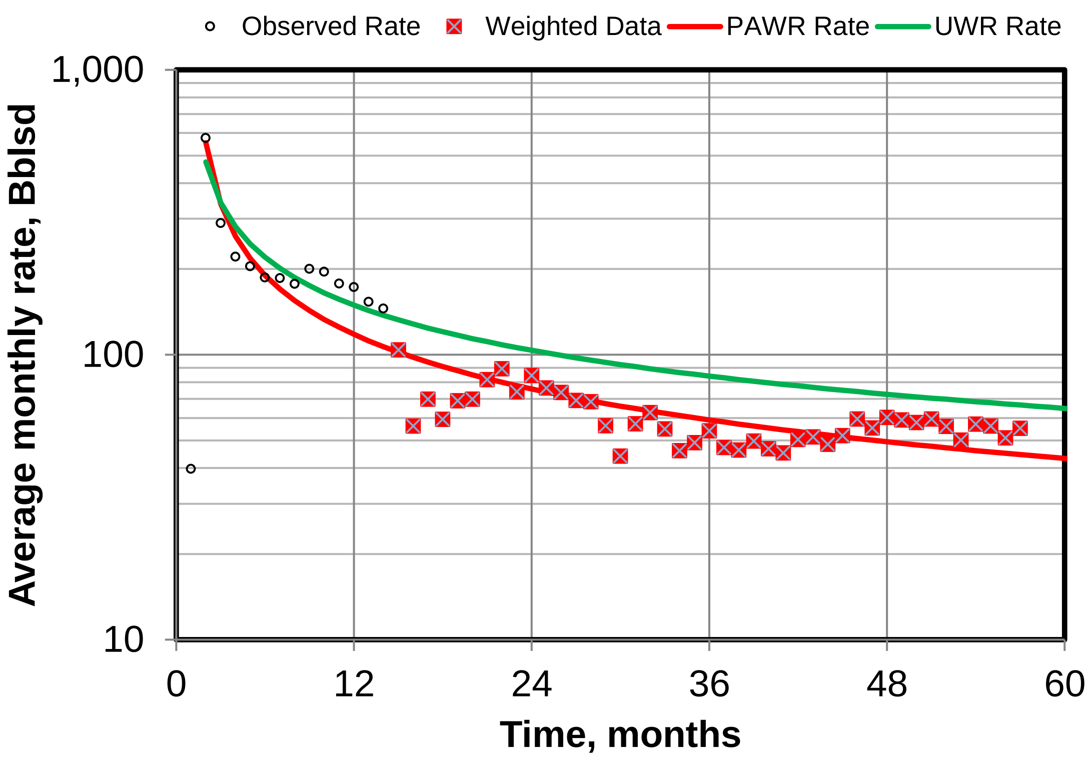

Fig. 17─Regression example of UWR and PAWR curves for study well 42-255-31886

Since comparing these impacts to well spacing is important in this work, control groups were established to quantify the differences between PAWR and UWR curves that cannot be related to well-to-well interference. The differences between the PAWR and UWR curves in the control group are due to an assortment of different completion designs and reservoir/fluid characteristics. In this case it was assumed that wells with nearest offset neighbors spaced farther than a section away, 5,280 feet, would not impact the production profile of a producer. Nano-darcy permeability regularly found in unconventional reservoirs like the Eagle Ford prevents black oil and volatile oil fluids to travel such distances, 5,280 feet, during the lifetime a well produces. Wells in this study group that qualify as PBI wells were placed in a control group when the spacing was larger than 5,280 feet. On average, PBI wells had an offset that was completed eight months following initial production of the PBI well. Cases where a PBI well had two offsets completed after the PBI well started producing had the second well completed 13 months, on average, after initial production.

Recorded impacts that were considered outliers, those with extreme impacts caused by few monthly rates, were removed to mitigate any conclusions that would not accurately represent the data trend. From Devore and Peck (1996) "an observation is an outlier if it is more than 1.5 [interquartile range] from the closest end of the…" interquartile range. The interquartile range consists of the difference between the upper quartile and the lower quartile of each data set, or the top and bottom 25%. Those wells with impacts greater than or less than 1.5 times the interquartile range beyond the bounds of the interquartile range were investigated. The wells with extreme impacts were identified to be a result of a limited number of average monthly rates for the UWR curve to regress with, less than six months. It is assumed that the impacts recorded for the wells that are considered outliers are a result of having the few data points for the UWR curve to regress with and does not accurately portray forecasted production before potentially being impacted by an offset completion. This is an instance of an insufficient amount of data in that too few data points were available to obtain an accurate forecast using Arps decline curve analysis, but just enough data points were available to still obtain a UWR curve.

3.2 Quantifying Effects of Offset Completions

The production from the PAWR and UWR curves were compared from the offset completion date out to 60 months (Fig. 17). Uncertainty in the forecasts of the PAWR and UWR curves increased when a smaller number of monthly data points were available to create the PAWR and UWR curves from regression. In an effort to reduce the effects caused by uncertainty in the forecasted curves, 60 months was selected as an acceptable projection point rather than comparing curves with an estimated ultimate recovery.

Instead of comparing the production that the PAWR and UWR curves show on a barrel-to-barrel basis, the difference between the production forecasted with the PAWR curve and the production forecasted with the UWR curve during the time period from the date of the offset completion up to 60 months was normalized on a percentage basis to establish a percent increase or decrease in production resulting from the offset completion. Eq. 12 displays the percent change in projected cumulative production ($\%\ Change\ Proj.\ CP_{DoOC:60}$) between the DoOC and 60 months and how it was determined. $PAWR_{DoOC:60}$ represents the number of barrels produced in the regression from the offset completion date to 60 months on the PAWR curve, and $UWR_{DoOC:60}$

represents the number of barrels produced in the regression from the offset completion date to 60 months on the UWR curve.

$$\%\ \boldsymbol{Change\ Proj.\ CP_{DoOC:60}} = \frac{\boldsymbol{PAWR_{DoOC:60} - UWR_{DoOC:60}}}{\boldsymbol{UWR_{DoOC:60}}} \qquad (12)$$

In some cases UWR curves could not be obtained because offset well completions took place in the months prior to the month with the highest producing rate, the starting point for each well regression. Also UWR curves could not be obtained in some cases because the offset completion date occurred early in the life of the PBI well's production, which provided too few data points to regress with. These wells were removed from the study groups. Outliers, i.e., wells with impacts greater or less than 1.5 times the interquartile range, and wells for which it was not possible to perform a regression due to a limited number of data points were also removed. The data set was reduced to include 257 wells in the study group and 20 wells in the control group. This is down significantly from the 474 wells that met the PBI criteria.

Fig. 18 displays the percent change between the projected cumulative production between the eighth month and the 60th month from the UWR curve and the PAWR curve for wells in the control group at different well spacings. The eighth month was selected because it was the average month that offset completions occurred after a well was brought on to production. Since the underlying assumption for the control group is that offset completions did not have an effect on production, a particular month had to be used to get the UWR curve. The figure shows the scatter in the change between a PAWR and UWR curve for these wells in both areas. This scatter's fluctuation is a result of uncertainty captured by varying geology, different completion designs, and reservoir/fluid characteristics. It does not reveal any clear trends in the data; it is essentially random and unpredictable. This is more desirable because it implies that these wells are unrelated to impacts that could potentially be caused by offset completions, the main assumption for the control group.

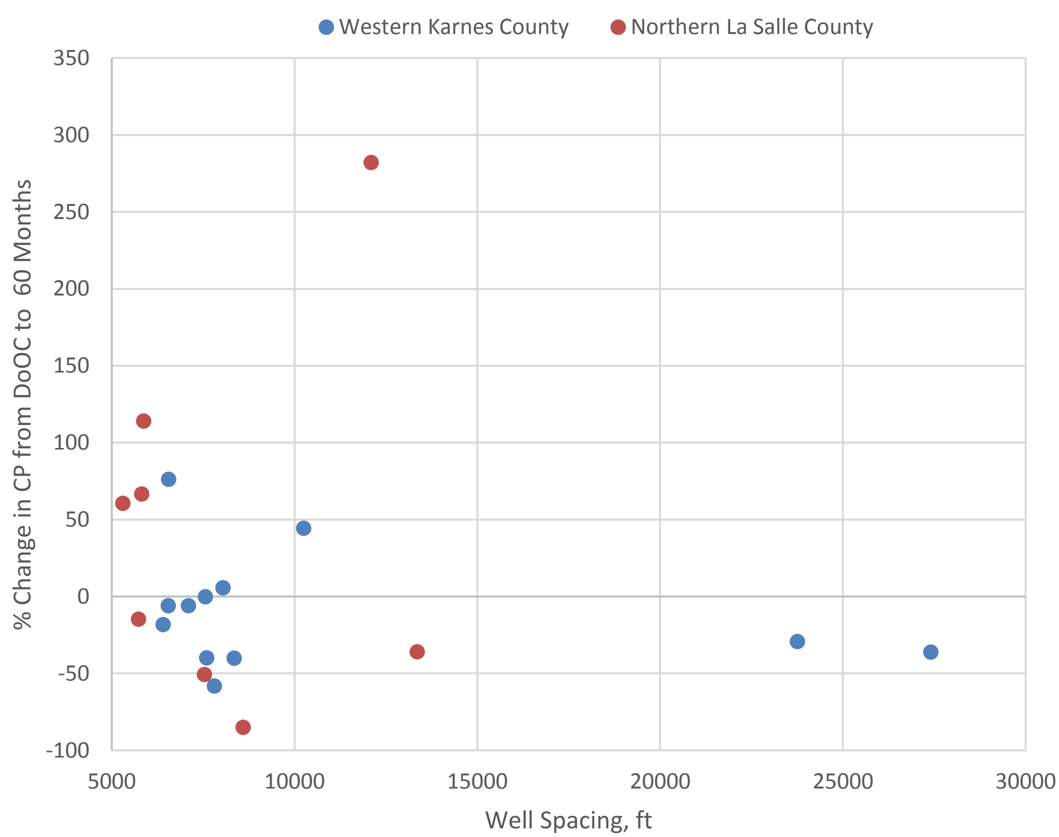

Fig. 18─Percent change in projected cumulative production between the PAWR and UWR curves from the eighth month to 60 months for the control group versus well spacing

The difference between the projected cumulative production from the eighth month to 60 months for both the PAWR and UWR curve was normalized to the UWR curve, meaning the difference in the production during that time period on each curve was divided by the production occurring from month eight to 60 on the UWR curve. Now the impacts can be shown as how much the affected well regression changed in reference to the unaffected well regression on a percent basis. Representing the results in this way showed that the projected cumulative production by the PAWR curve could be several hundred percent greater than the projected cumulative production by the UWR curve. On the other hand the projected cumulative production change is limited in that the projection by the PAWR curve can only forecast 100% less than the UWR curve. **Fig. 19** portrays study well 42-255-31886 that was previously discussed in Section 3.1 to show how the PAWR curve could have projected growth or reduction when compared to the UWR curve. This example shows very unlikely cases, never seen in the results, to emphasize the point that the results can be skewed using this methodology. In the event an uncharacteristic change in average monthly rates occurs, the PAWR curve was regressed through all data points, capturing the uncharacteristic change in average monthly rates, or, the change is so dramatic that a regression could not be obtained. Since well production is driven by economics and a decline in well production would not increase without some sort of artificial lift system or external energy source increasing the reservoir pressure, the average monthly rates would not deviate from a natural decline. Additionally, a well producing without the aid of an artificial lift system would not be shut-in unless extraneous circumstances exist.

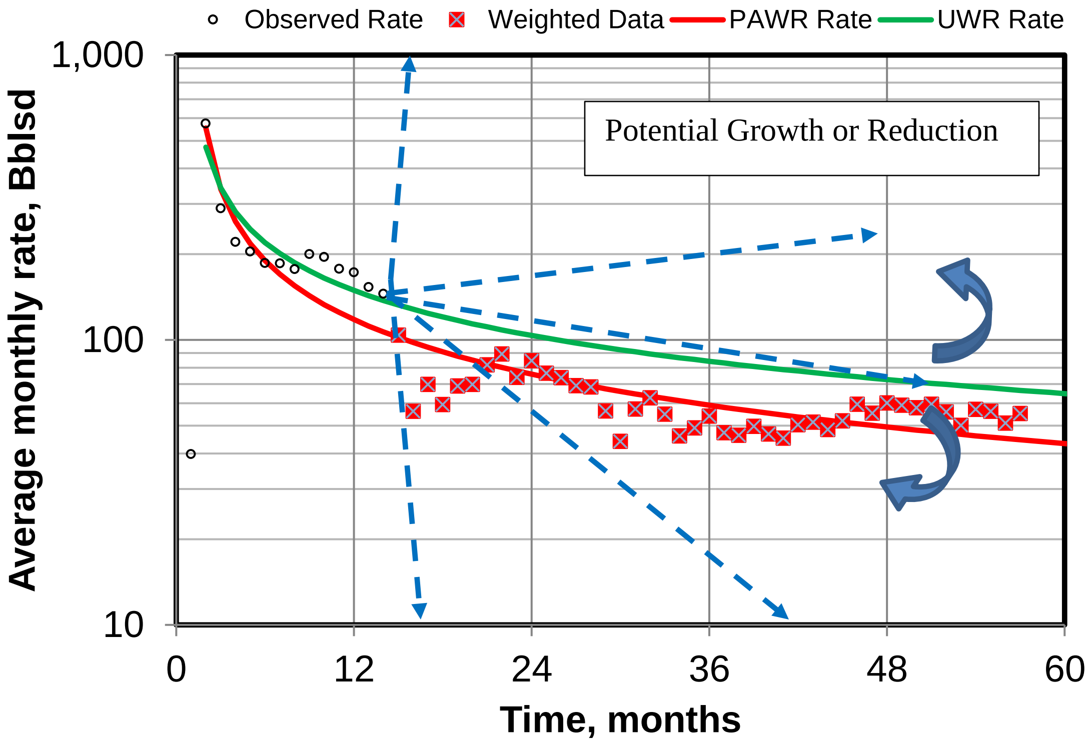

Fig. 19─Study 42-255-31886 well showing the potential PAWR curve increase or decrease compared to the UWR curve

Fig. 20 shows the distribution of results for the control group. The control group shows 65% of the data have a negative change from the UWR to the PAWR curve, yet the average of the control group is an 11.4% increase between the curves. Fewer average monthly rates available to create the UWR curve and the higher decline rates seen while a well remains in transient flow introduced forecasts for the UWR curve that terminated much earlier when compared to the PAWR. The PAWR curve by definition had more data points to regress against and thus the forecasted curve that is created is flatter. Early on it was discovered that the methodology in this section returned a lognormal distribution of results in the control group that results in an average that is positive. Quantifying the effects of interference in this way results in frequency distributions that are skewed to the right and, thus, the median value of the data set is a better representation of the central tendency for those wells in the control group. That is why the median, a value of -10.4% for all control data points, is a better tool for comparing results rather than the average in the control group for both areas.

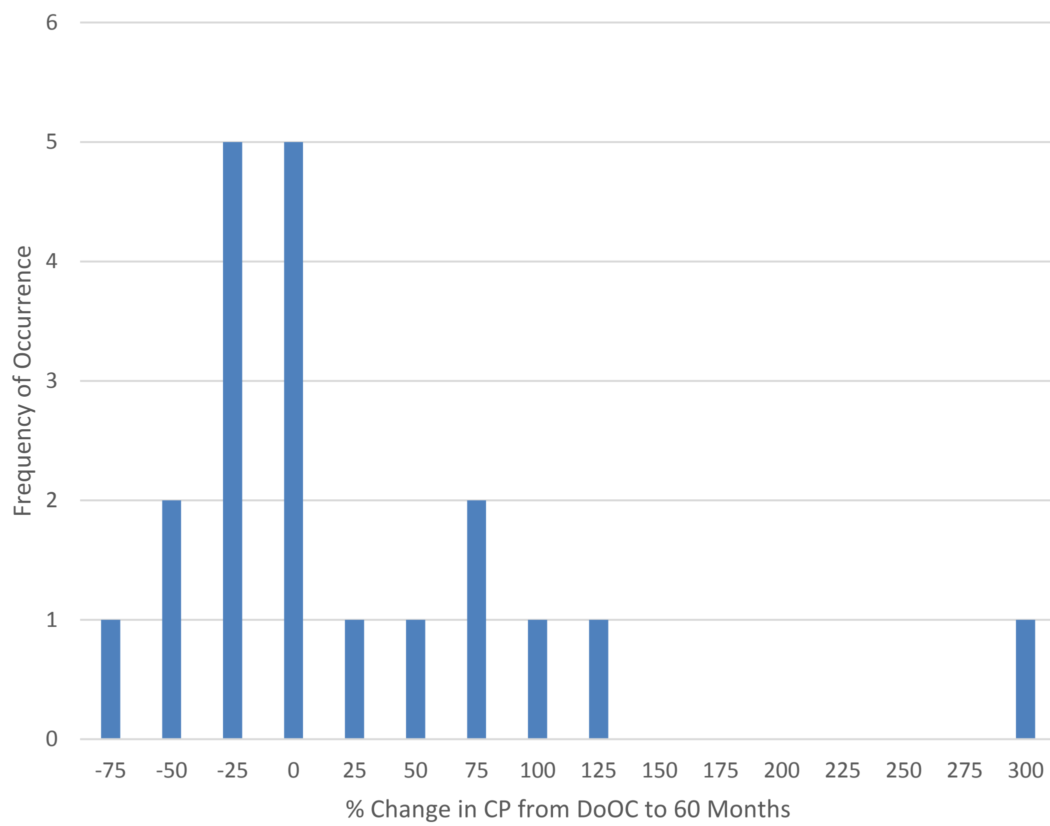

Fig. 20─Frequency distribution showing percent change in projected cumulative production from the DoOC to 60 months for the control group

Table 1 presents the median, 10^{th}, and 90^{th} percentiles for the control groups in both areas. The difference between the 10^{th} and 90^{th} percentile contains 80% of all the data points in the distribution. Western Karnes County has 80% of its data fall between a decrease in the projected cumulative production of 40% and an increase in the projected cumulative production of 40% with the central tendency at a decrease of 12%. Northern La Salle County has 80% of its data fall between a decrease in projected cumulative production of 61% and an increase in projected cumulative production of 164% with the central tendency at an increase of 23%.

Table 1─Control group statistics for Western Karnes County, WKC and Northern La Salle County, NLSC

	10^{th} Percentile, Control	Control Median	90th Percentile, Control
WKC	-40%	-12%	40%
NLSC	-61%	23%	164%

The difference between the 10^{th} and 90^{th} percentiles for NLSC is much larger, 2.8 times that for WKC. Additionally, the central tendency of the data for NLSC is positive, unlike WKC. The wells in the control groups for these areas have different distributions. This difference between the wells in the control groups for NLSC and WKC is due to noise in production data, forecasted production and the low number of wells (12 for WKC and eight for NLSC).

Considering the study group, **Fig. 21** displays the resulting study group for WKC. Each sample in the study group for the Western Karnes County area is shown and represents the difference in barrels produced between the UWR curve and the PAWR curve during the same time period, in this case, from the Date of Offset Completion, DoOC, to 60 months. Just like the control group, the study group for this WKC area had a median, average, 10^{th} percentile, and 90^{th} percentile that is provided in Fig. 21 (solid curves in different shades of green). The figure plots the percent change in projected cumulative production against well spacings out to 5,500 feet to encompass spacings that include one section, an area that is one square mile with sides 5,280 feet apart. Because it is assumed the control group is not impacted by well spacings under 5,280 feet, the 10^{th} percentile, median, and 90^{th} percentile of just the control group in WKC is plotted for all spacings (horizontal dashed lines). The study set distribution is hypothesized to change dynamically with well spacing; thus, the 10^{th} percentile, median, and 90^{th} percentile were calculated for each well spacing with a 40-acre spacing resolution. This resolution means the 10^{th} percentile, median, and 90^{th} percentile were determined by grouping all results within 165 feet on both sides of the spacing in question. Lower resolutions would smooth the trends, but higher resolutions capture changes that may occur at smaller spacings. The 40-acre spacing resolution was a subjective decision.

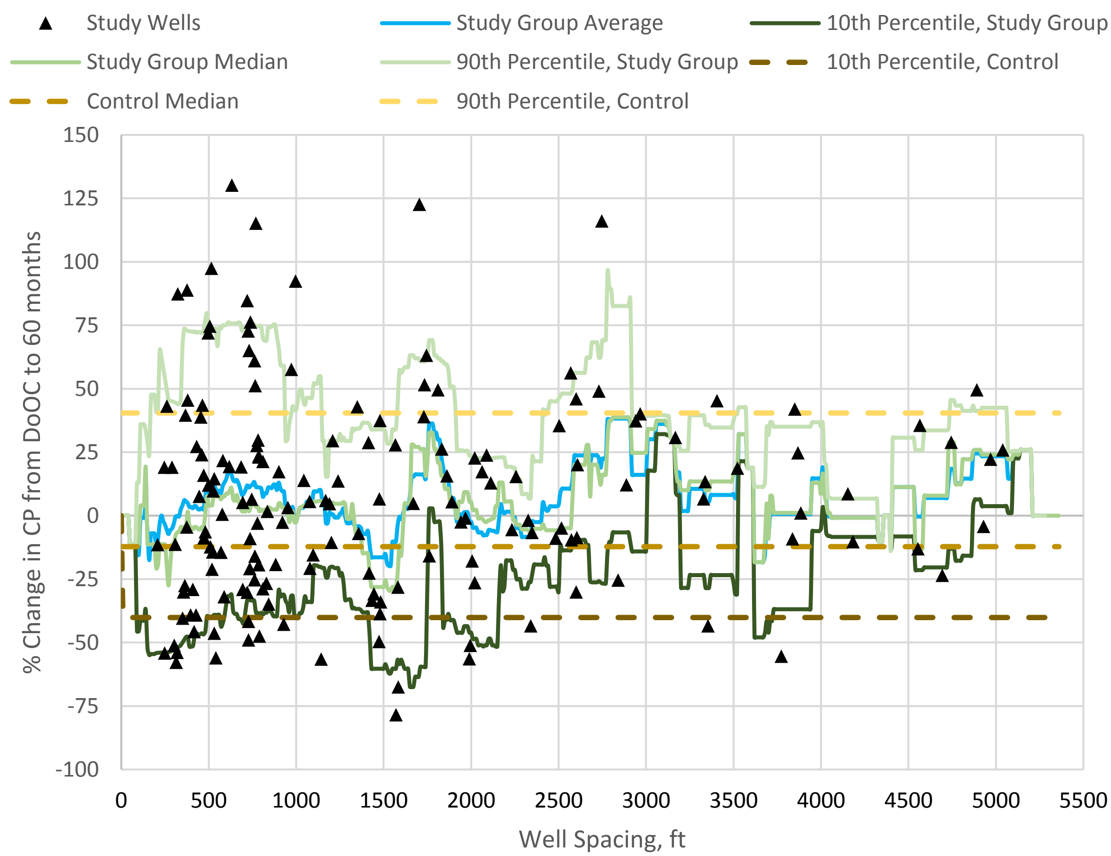

Fig. 21─Western Karnes County percent change in projected cumulative production after the DoOC due to offset completions for different well spacing intervals

An initial review of Fig. 21 shows that the results are limited in providing data points for all well spacings. Extremely low spacings and those beyond 2,500 feet have few or zero sample points to help describe the study distribution. The figure shows that the range between the 10th and 90th percentiles of the study group generally increases as the spacing interval decreases. This reveals that as spacing decreases, a greater variability in the impacts caused by well-to-well interference exists. From Fig. 21 it is apparent that the distribution for the study group exceeds that of the control group in the negative direction from roughly 0 to 500 feet, 1,400 to 2,200 feet, and briefly from 3,600 to 3,700 feet. This also occurs in the positive direction from 250 to 1,100 feet, 1,600 to 1,900 feet, and 2,400 to 2,900 feet. Based on these spacing intervals from Fig. 21, spacings under 3,000 feet return statistically significant results for well-to-well interference. This means offset completions appear to have an impact on wells in this area of WKC; however, it is difficult to predict whether these impacts will be positive or negative. For spacings above 3,000 feet the study group distribution falls within the range of the control group and seems to vary in range and central tendency, with the central tendency remaining between 25% and -25% for the most part. There does not seem to be any statistically significant indication of well-to-well interference for spacings above 3,000 feet. Fig. 21 also shows a weak downward trend in the central tendency of the study group as spacings get tighter and under 3,000 feet. Specifically, spacings under 600 feet show the entire distribution moves in the negative direction. This trend is consistent with what might be expected from tighter well spacings, but the results also show peaks in the central tendency's trend at roughly 1,700 feet and 600 feet for spacings under 3,000 feet. These couple of fluctuations in the plot makes it hard to say if the downward trend is significant or not. Overall significant impacts exist below 3,000 feet spacing; however, it is difficult to predict from what is shown in Fig. 21 how intense the impacts could be and whether or not they are positive or negative.

Fig. 22 for the NLSC area shows that the study group's distribution does not vary beyond the control group's distribution in the negative direction for any well spacing to a significant degree; i.e., statistically significant results are nonexistent in the negative direction. The control group's 90th to 10th percentile range is much larger compared to that of WKC, meaning that statistically significant results would have to be more impactful in order to be captured for the NLSC area. Fig. 22 does show that the study group distribution exceeds the control group distribution in the positive direction from roughly 0 to 1,000 feet, 1,700 to 2,500 feet, and 5,000 to 5,200 feet. The spacing interval from 5,000 to 5,200 feet may be an anomaly, but it is difficult to say. Clearly under 2,500 feet the data shows statistically significant impacts in the positive direction, but the trends in the distributions are not very clear. From roughly 700 feet to zero well spacing, the distribution of the study group for NLSC is very flat and does not have a decreasing trend as the spacings get tighter like the wells in the WKC area did. The relationship between well spacing and well-to-well interference is even less clear for the NLSC area than what it was for the WKC area. This could be due to the limited number of wells for the NLSC area (88 for the study group, and 8 for the control group). Except for the interval from 1,250 to 1,500 feet, the NLSC area's central tendency of the study group shows positive impacts under 2,500 feet. For the control group, specifically, 50% of the wells returned positive impacts while the other 50% were negative. The positive results could be a result of phenomenon discussed earlier in this section. It could be that the UWR curves do not forecast the flatness one might see with a PAWR curve because the UWR curve has fewer data points to obtain the regression with. Unfortunately, since the data sets are so small and since the WKC results had negative central tendencies it cannot be concluded what caused the positive central tendencies for the NLSC area.

Again, like the WKC area, the NLSC study group limits the ability to create distributions at lower spacings and not much, if anything, can be said for these areas, roughly under 250’. From the results provided in Fig. 22 the distribution created by the control group masks any conclusions that can be made about negative impacts. Since the range of the 10^{th} percentile case for the study group does not exceed that of the control group for any well spacings, the study group did not capture significant impacts from well-to-well interference that negatively affected production more so than what can be considered noise.

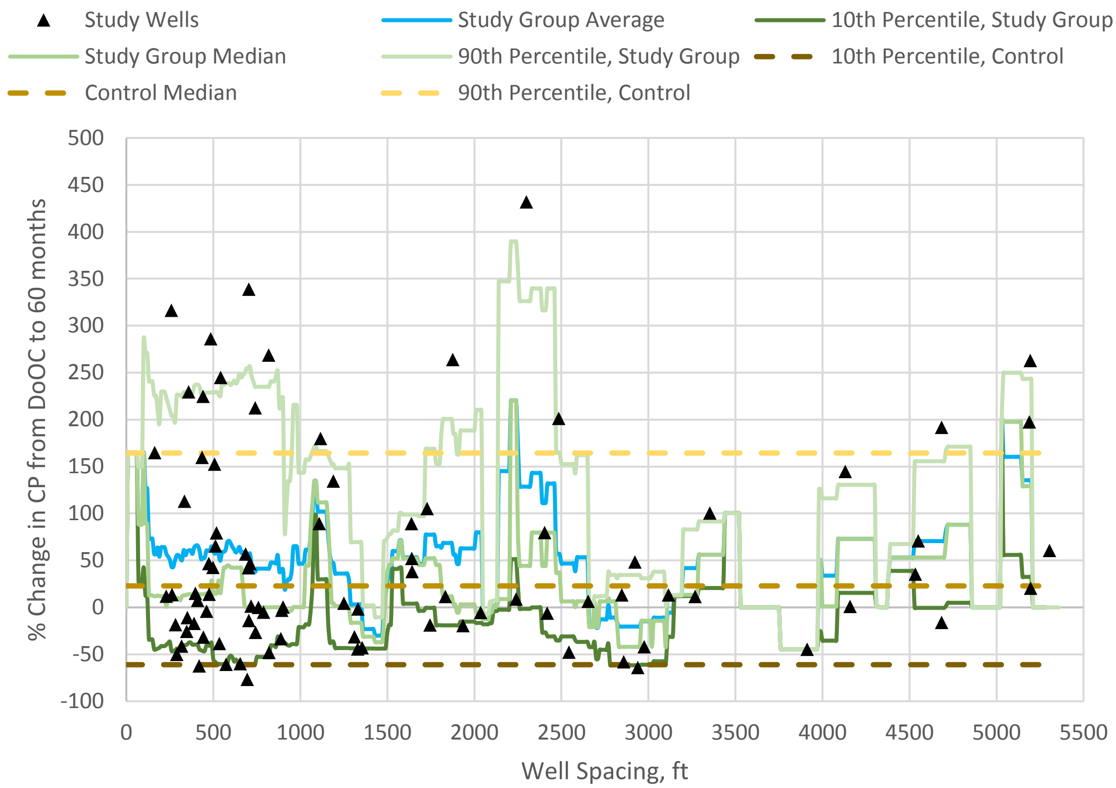

Fig. 22─Northern La Salle County percent change in projected cumulative production after DoOC due to offset completions for different well spacing intervals

It is important to note the difference in the number of wells for the study group and control group between the two areas. The WKC area had 169 wells in the study group and 12 wells to make up the control group; the NLSC area had 88 wells in the study group and 8 wells to make up the control group. An increase in the number of data points in each area could have provided additional information that would better describe each area's behavior. The limited number of wells also affects the ability to draw firm conclusions regarding the impact offset completions and offset production can have on well performance. There exists uncertainty in these results as well as the conclusions from this research.

To summarize what has been discussed above, the WKC and NLSC study group distributions show impacts that are outside the distributions created by the control groups and imply for several spacings that well-to-well interference has an impact on the production projected cumulative production after an offset well has been completed. Both areas show that, generally, as spacings decrease down to 250 feet the range between the 10^{th} and 90^{th} percentiles increases. This also means that, assuming future development in these areas reflect the results recorded in this research, the uncertainty in whether the impact is positive or negative and the magnitude of the impact increases as well spacing decreases. For WKC significant impacts can occur under 3,000 feet but the type and intensity is inconclusive. For NLSC significant positive impacts occur under 2,500 feet but none exist in the negative direction. The large uncertainty in the control group for NLSC also limits the ability to conclude the type and intensity of impacts that could occur for wells spaced under 2,500 feet.

3.3 Quantifying Effects of Offset Completions Using Cumulative Production Metrics

In a separate effort to describe how offset completions affect production, different cumulative production (CP) metrics were determined. These process for obtaining these metrics included taking the total barrels produced in the first month, first three months, first six months, first 12 months, first 36 months, and first 60 months from the UWR and PAWR curves and comparing them. **Fig. 23** highlights with vertical blue lines the different points along the UWR and PAWR curves where total production would be truncated in the study well 42-255-31886 example. Cumulative production was determined up to these points.

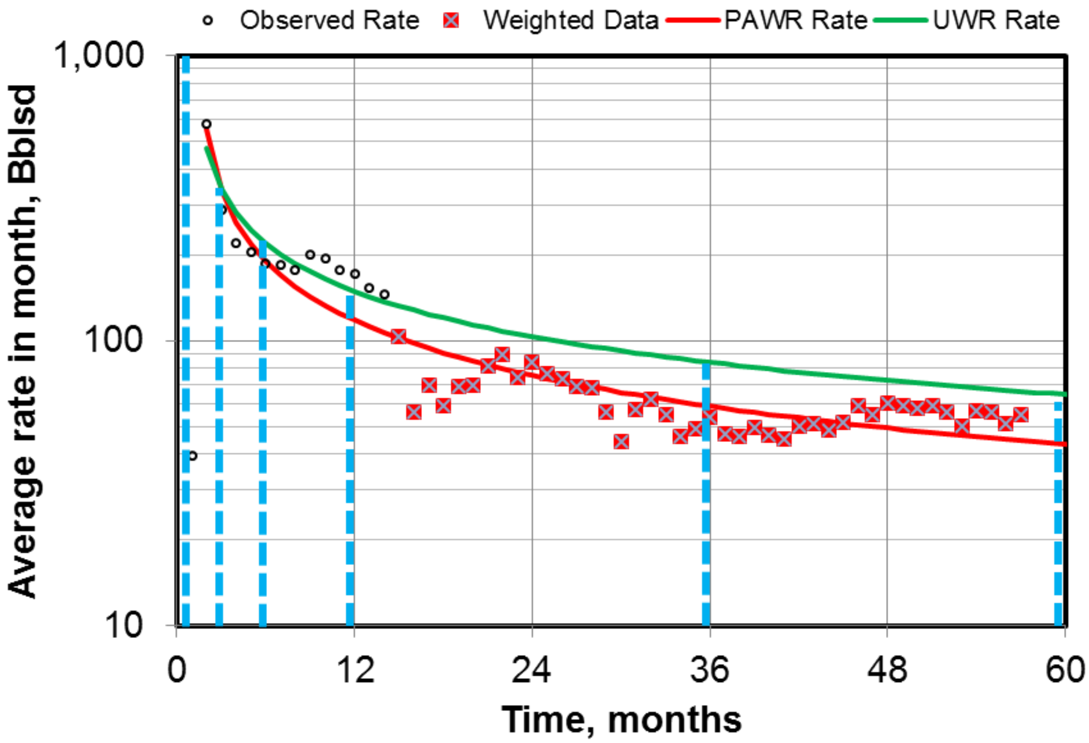

Fig. 23─Study well 42-255-31886 PAWR and UWR curves with the 1-month, 3-month, 6-month, 12-month, 36-month, and 60-month CP points shown

Calculations in this methodology were performed according to Eq. 13 and Eq. 14,

$$\%\ \boldsymbol{Change\ Proj.\ CP_{metric}} = \frac{\boldsymbol{PAWR_{CPmetric} - UWR_{CPmetric}}}{\boldsymbol{UWR_{CPmetric}}} * \boldsymbol{Prod.Ratio} \text{ ...(13)}$$

$$\boldsymbol{Prod.Ratio} = \frac{\boldsymbol{PAWR_{EUR} - PAWR_{Bbls@DoOC}}}{\boldsymbol{PAWR_{EUR}}} \text{ ....(14)}$$

where $\boldsymbol{PAWR_{CPmetric}}$ is the total production up to a given month on the PAWR curve and $\boldsymbol{UWR_{CPmetric}}$ is the total production up to a given month on the UWR curve. The difference between the CP metric on the PAWR curve and UWR curve is determined and referenced to the CP metric on the UWR curve so that the result is a percent increase or decrease. It was noticed that an earlier DoOC affected the difference between the $\boldsymbol{PAWR_{CPmetric}}$ and the $\boldsymbol{UWR_{CPmetric}}$ substantially. Earlier DoOCs made less data available to regress with for the UWR curve and more data available to regress with for the PAWR curve. Cases where the DoOC occurred earlier in the well's productive life affected the difference in the PAWR and UWR curves to a greater degree than those with many more months before the offset completion date. This is because the UWR curve can be wildly different from the PAWR curve as the curve is projected forward in time. Fewer data points available for the UWR curve to be created from makes it less likely that the UWR curve will be forecasted over the PAWR curve. Consequently, earlier DoOCs seemed to amplify any recorded impacts. Due to this observation the fraction in Eq. 13 is then multiplied by the production ratio ($Prod. Ratio$) defined in Eq. 14 to provide a dampening effect on the results. This is an attempt to try and mitigate the effects caused by earlier DoOCs. The *Prod. Ratio* is the percentage of barrels yet to be produced from the PAWR curve forecast. It is calculated by taking the difference between the expected ultimate recovery, $PAWR_{EUR}$, and the total barrels produced up to the DoOC, $PAWR_{Bbls@DoOC}$ and then dividing that term by the $PAWR_{EUR}$. For this study the expected ultimate recovery is the total production up to the month where the average monthly rate reaches 10 bbls/day.

While collecting the different CP metrics it was difficult to determine which one would represent the impact the best. **Fig. 24** displays the results for each CP metric. During the calculation of the 36-month and 60-month CP metrics, it was noticed that some of the forecasted curves terminated at the 10-bbl minimum limit that was imposed before reaching these months. These wells were removed from each group so that the results would not be skewed. Fig. 24 shows the shape of the scattered data for the percent change in each CP metric. It appears that the shape of the scatter does not change depending on which metric is used, but the range of each percent change in CP metric increases with an increase in the number of months used to make the CP metric.

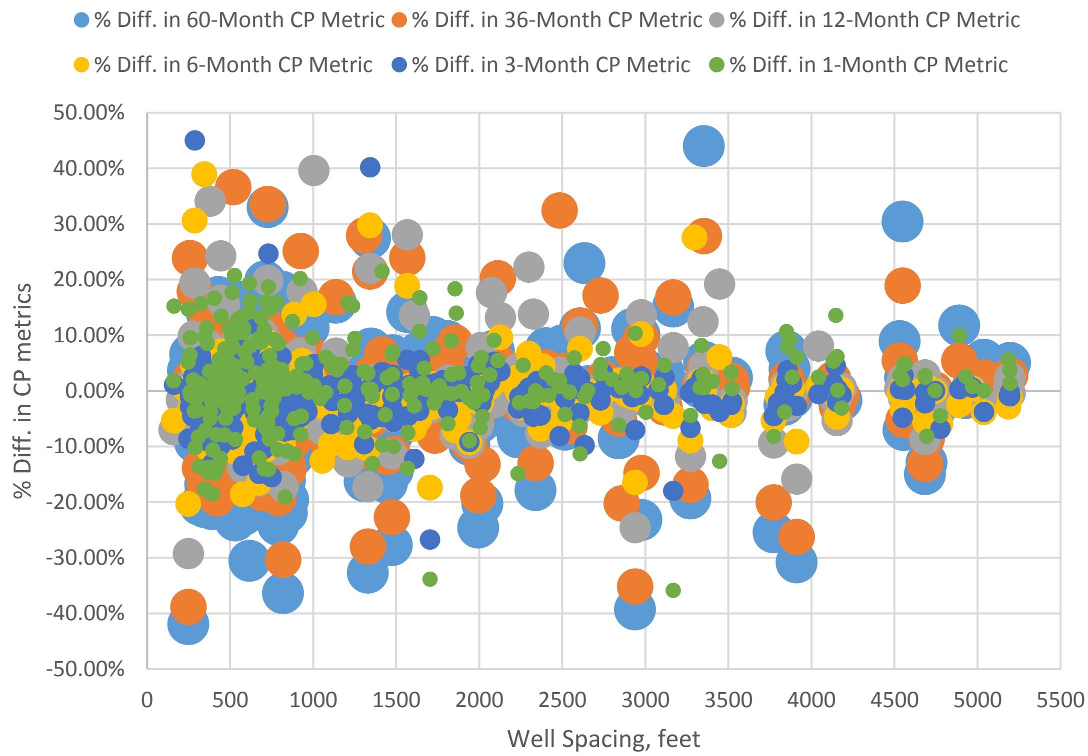

Fig. 24─Comparison of the percent difference in CP metrics recorded on the UWR and PAWR curves for different time periods plotted with well spacing for the study groups in both areas

Also provided in **Fig. 25,** as more months are used to make up the cumulative production metric the average of the percent difference in that metric decreases. A linear trend line was plotted in Fig. 25 to show this decline. It seems that using more months of cumulative production will return increasingly negative percent differences between the UWR and PAWR curves. Since the UWR and PAWR curves spread further apart as they are projected forward, it is rational that the magnitude of impacts are seemingly more detrimental on average.

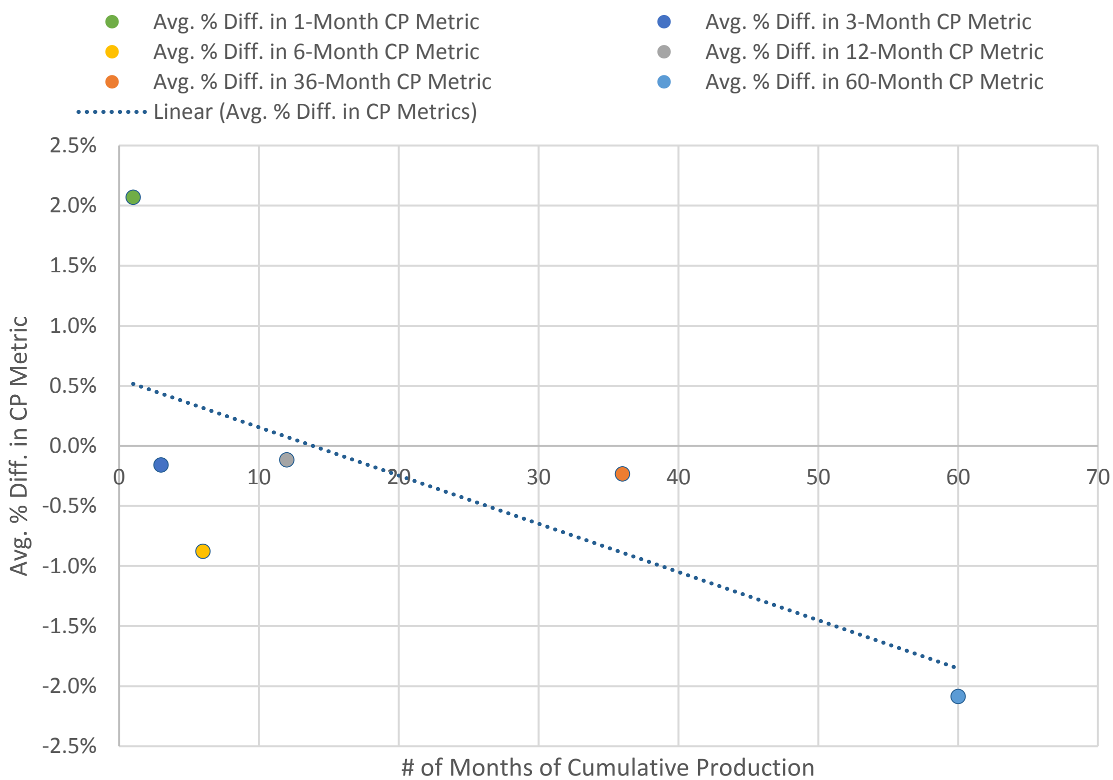

Fig. 25─Average of the percent difference in each cumulative production metric for the study groups combined from both areas

The decision was made to then move forward with the 12-month CP metric and the 36-month CP metric to effectively provide an extensive description of the effects on production while simultaneously trying to include the largest data sets. The 12-month CP metric includes 56 more wells in the study group compared to the 36-month CP metric; however, the 36-month CP metric utilizes three times the number of monthly data points. Also, it is important to point out again that in Fig. 24 the range between the 10th and 90th percentiles in the results increases as the well spacing interval decreases and that for this methodology the results are both positive and negative. The previous methodology from Section 3.2 also had both a large scatter of both positive and negative impacts.

Fig. 26 and **Fig. 27** displays the control groups in both research areas for the percent change between the PAWR and UWR curves for the 12-month CP and 36-month CP. They show the scatter in the results for wells that had offset completions greater than 5,280 feet away. The resulting scatter is assumed to be a result of the number of months available to the PAWR curve for the forecasted production and noise in the production data. Smaller amounts of monthly production data points could impact the difference between the PAWR and UWR much more significantly. Similar to the study groups in Fig. 24, the control groups in Fig. 26 and Fig. 27 have data with positive and negative results. The control groups should not capture any interference effects since that is the fundamental assumption in selecting them. Similar to that shown in Fig. 24, the percent change in the 36-month CP for the control group has a larger range, roughly -15% to 9%, versus the percent change in the 12-month CP for the control group, roughly -11% to 8%. Since there is a flattening affect, a decreasing rate of change, with the production data recorded for wells in the Eagle Ford, the PAWR curve will have a tendency to flatten out more than the UWR curve because it has more data points to obtain the curve. Ranges will differ when comparing the percent change in the 12-month CP to the percent change in the 36-month CP because the 36-month CP captures production three times as long on the curves than the 12-month CP. This gives the curves more time to spread apart and seems to amplify any recorded impacts. The amplification may highlight instances where small impacts that occur early on in a well's life cycle have greater effects on the well's total production later on.

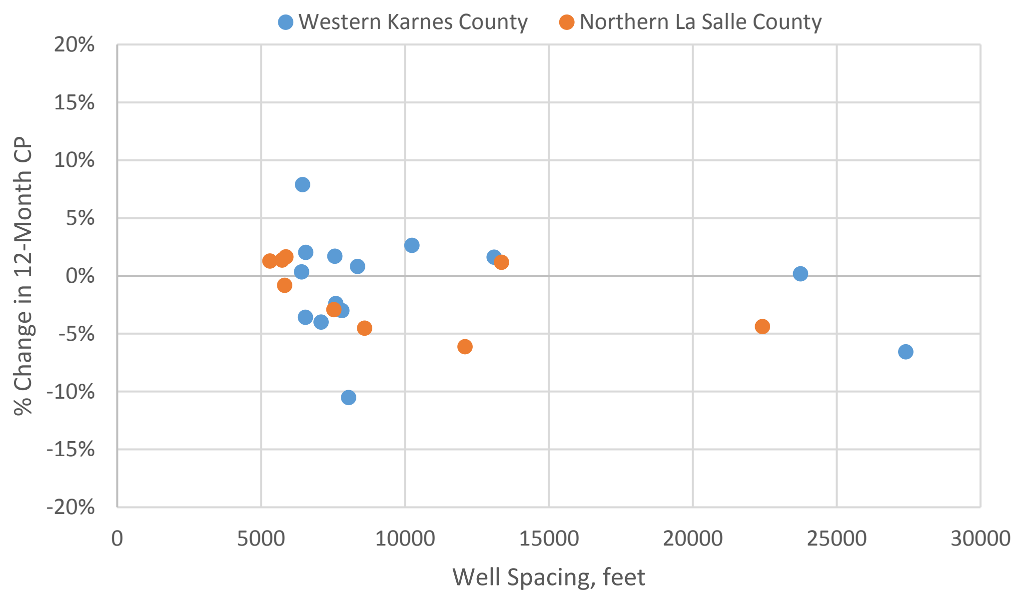

Fig. 26─Percent change in projected cumulative production for the 12-month CP metric between the PAWR and UWR curves for both areas in the control groups

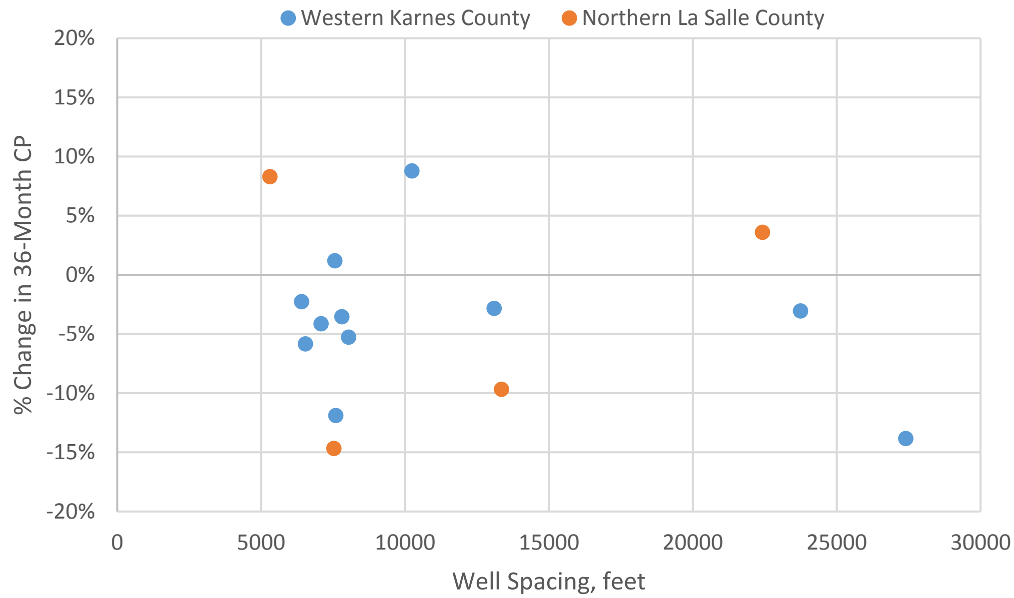

Fig. 27─Percent change in projected cumulative production for the 36-month CP metric between the PAWR and UWR curves for both areas in the control groups

Fig. 28 shows the distribution of the percent change in the 12-month CP for the control group with the wells combined from both areas. If the control groups are normally distributed then the average of the results represents the center of the control data for the percent change in the 12-month CP. Distributions of the percent change in the 12-month CP were made for both areas separately, but due to a limited number of wells in both areas (nine for NLSC and 14 for WKC) the two separate distributions (not provided here) did not provide any additional information. As an additional effort the percent change in the 12-month CP for both areas were combined to, again, see if any additional information about the distribution could be gathered. Unfortunately, the distribution shown in Fig. 28 does not provide any additional information about the percent change in the 12-month CP for the control groups when combined. This process did not have any effect on the results, but it potentially could have provided additional information about the percent change in the 12-month CP for the control groups. **Table 2** shows the control group's 10th percentile, the average, and the 90th percentile for both areas and the percent change of the two CP metrics between the PAWR and UWR curves. The average for both areas is slightly negative; however, it is not clear why this is the case.

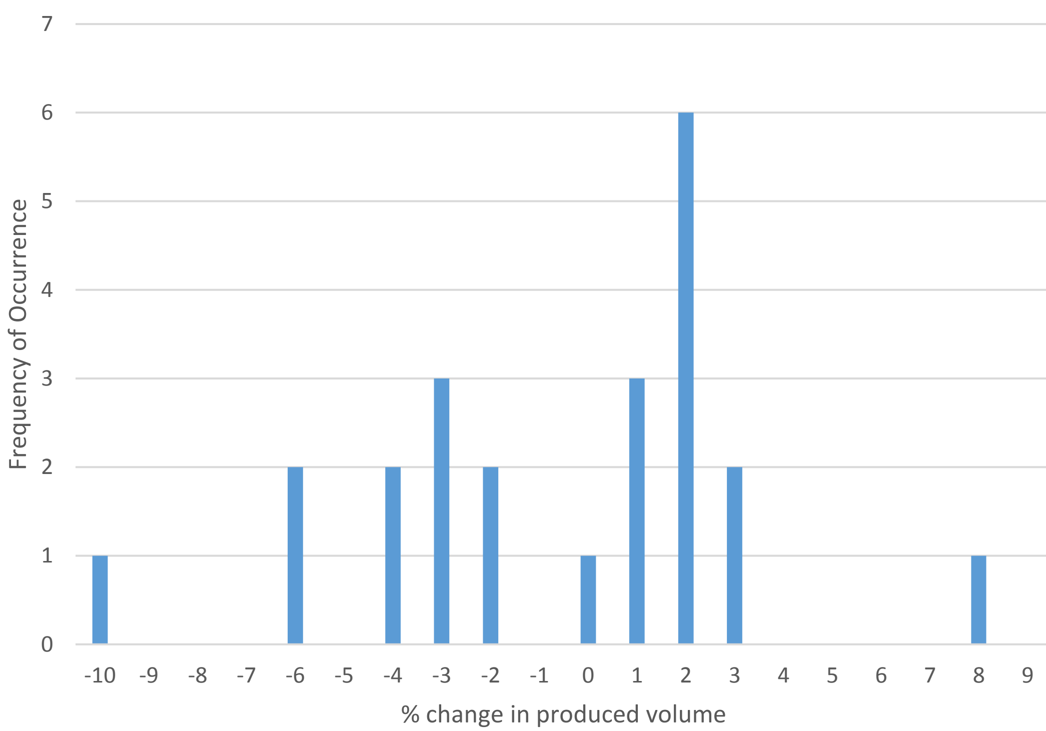

Fig. 28─Distribution of percent change in produced volume for the 12-month CP metric between the PAWR and UWR curves in the control group for both areas

Table 2─Control group statistics for Western Karnes County, WKC and Northern La Salle County, NLSC for the 12-month and 36-month CPs

	10th Percentile	Average	90th Percentile
WKC,12-Month CP % Change	-5.8%	-0.9%	2.5%
WKC, 36-Month CP % Change	-11.9%	-3.9%	1.2%
NLSC, 12-Month CP % Change	-4.8%	-1.5%	1.4%
NLSC, 36-Month CP % Change	-13.2%	-3.1%	6.9%

Fig. 29 shows the distribution of the percent change in the 36-month CP for the control groups of the wells from both areas. As was the case with the percent change in the 12-month CP metric, Fig. 29 did not provide any additional information about the control group distribution for the percent change in the 36-month CP metric. Again, separate distributions, not provided, were made for the percent change in the 36-month CP metric of wells in the control group for each area, but due to the limited number of wells in each area (four for NLSC and 11 for WKC) the distributions did not provide any additional information to this work.

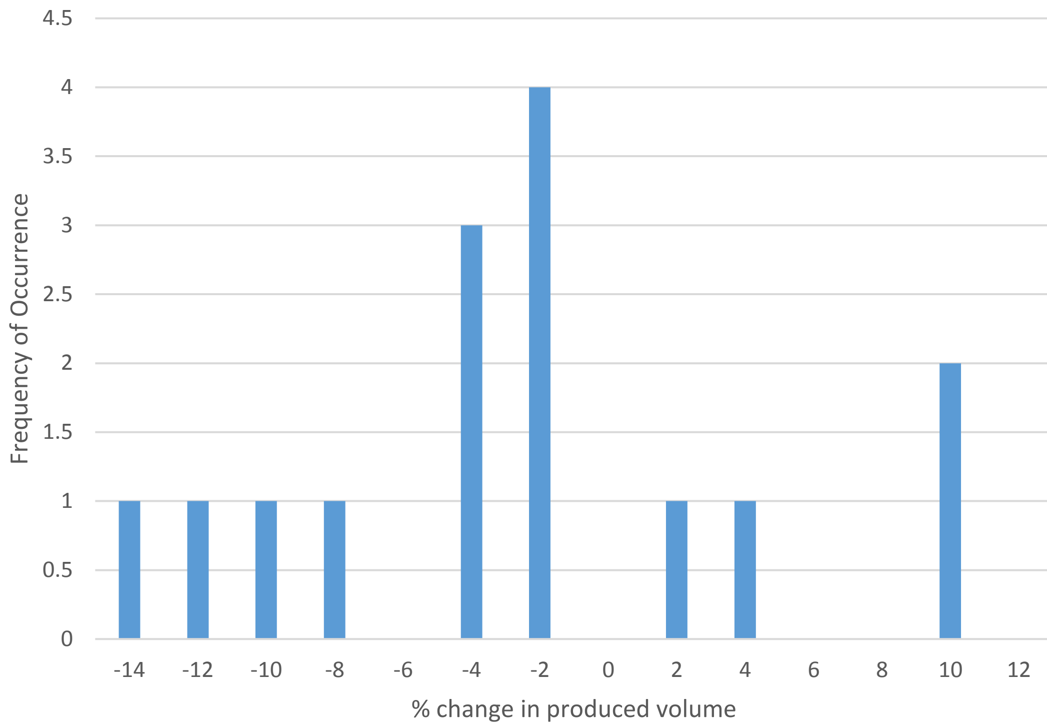

Fig. 29─Distribution of percent change in produced volume for the 36-month CP metric between the PAWR and UWR curves in the control group for both areas

Fig. 30 displays the percent change in the 12-month CP results for the Western Karnes County area. The percent change between the PAWR and UWR curve for the 12-month CP metric are provided for each sample as well as the median, average, 10th percentile, and 90th percentile for different well spacings. The previous section attempted to quantify well-to-well interference on projected production after the DoOC. This section differs in that it attempts to quantify the effects of well-to-well interference on projected cumulative production during the first 12 and 36 months. Unfortunately, the trend revealed in Fig. 30 for the percent change in the 12-month CP metric for WKC is ambiguous. Except for spacings less than roughly 1,500 feet, the overall trend as spacings increase or decrease appears to be random. The data also shows that as well spacing decreases below 1,500 feet, the well-to-well interference reduces or becomes increasingly positive. This trend is weak and not what is expected; tighter well spacings are thought to increase negative cases of well-to-well interference. This may well be the case for extremely small spacings, but due to the limited number of samples below 250 feet, strong conclusions cannot be drawn. For spacings roughly under 4,500 feet several spacing intervals show significantly impactful results beyond the control group distribution in both the positive and negative direction. This implies that the wells in the study group are influenced by offset completions; however, the small number of wells in the control group makes it difficult to form any strong conclusion.

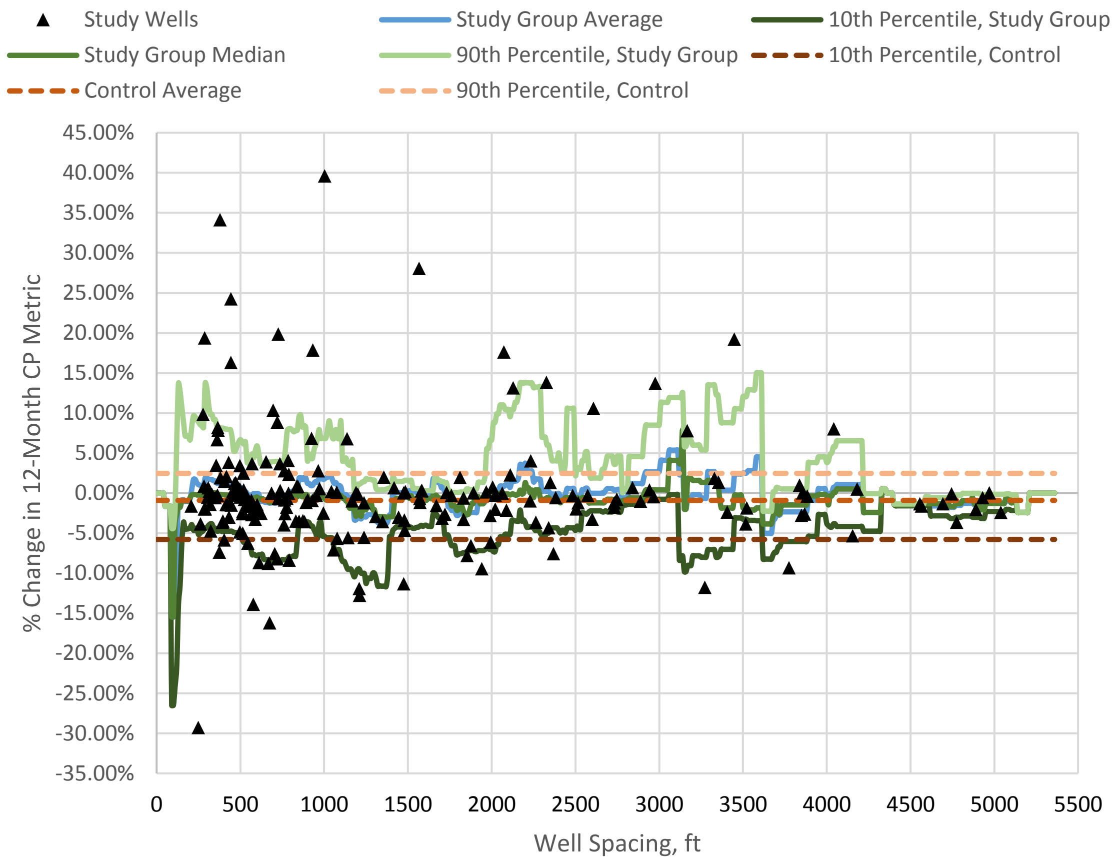

Fig. 30─Western Karnes County percent change in projected cumulative production for the 12-month CP metric due to offset completions for different well spacings

The results for the percent change in the 36-month CP metric for WKC is provided in **Fig. 31**. The two figures, Fig. 30 and Fig. 31, show that the percent change in the 12-month CP and 36-month CP metric for WKC have very similar trends; the percent change in the 36-month CP reveals larger ranges between the 10th and 90th percentile results and greater impacts than that of the percent change in the 12-month CP. It is important to note again that the number of samples below 250 feet are essentially nonexistent, so drawing strong conclusions from the trends in these intervals are not recommended. Not much can be observed or concluded about how well-to-well interference will affect production with well spacing below 250 feet. Similar to the percent change in the 12-month CP results for WKC, these results do not appear to have much of a trend and large uncertainty in the results exist. Since the percent change in the 36-month CP potentially captures the same impact to a greater degree than the percent change in the 12-month CP did, the same interpretations apply except for a few things. There does not seem to be any positive or negative trend in the study group for the 36-month CP results and significant impacts only exist in the positive and negative directions roughly below 4,000 feet. Below this depth the study group's percent change in 36-month CP distribution for WKC is significantly more impactful than what is recorded by the control group distribution. This, again, implies that the study group is positively and negatively influenced by well-to-well interference, but the limited number of wells in the control group makes this a weak conclusion.

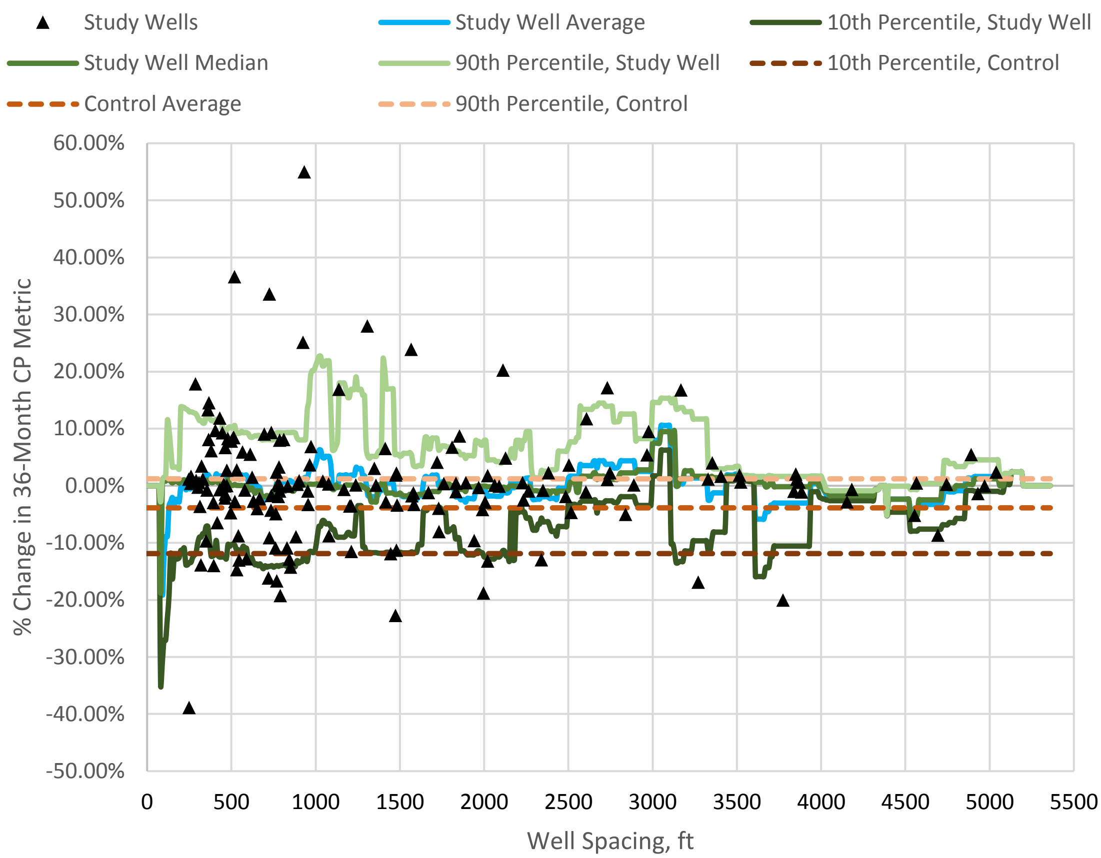

Fig. 31─Western Karnes County percent change in projected cumulative production for the 36-month CP metric due to offset completions for different well spacings

Fig. 32 and **Fig. 33** present the results for the Northern La Salle County area. Fig. 32 displays the percent change in the 12-month CP metric between the PAWR and UWR curves and Fig. 33 displays the percent change in the 36-month CP. From these figures it seems both significant positive and negative results exist roughly below 5,000 feet. These figures also show what appears to be a random trend for spacings roughly above 3,000 feet and no conclusions can be drawn from spacings above that spacing. From roughly 3,000 feet to 2,000 feet and from roughly 1,000 feet to 250 feet a weak trend in the positive direction occurs. This does not follow expectations, but from roughly 2,000 feet to 1,000 feet a weak trend in the negative direction occurs. Just like WKC and the previous section's results, samples at very small spacings, in this case under 250 feet, are almost non-existent. Drawing conclusions from the trends seen in these areas are not strong and more than likely not reliable. The impacts are positive and negative in the NLSC area using this methodology just like the WKC area. There is an implication that significant well-to-well interference impacts exist at spacings below 5,000 feet, but strong conclusions about the relationship between well spacing and interference cannot be formed.

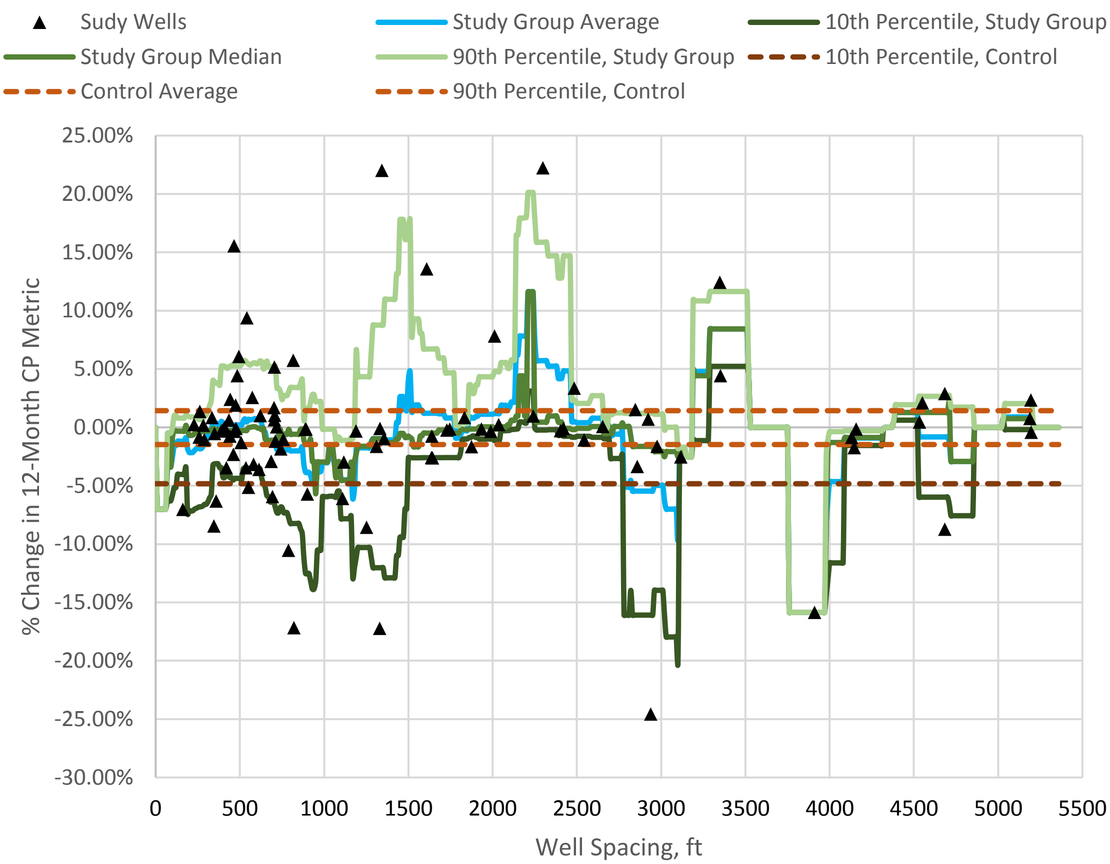

Fig. 32─Northern La Salle County percent change in projected cumulative production for the 12-month CP metric due to offset completions for different well spacings

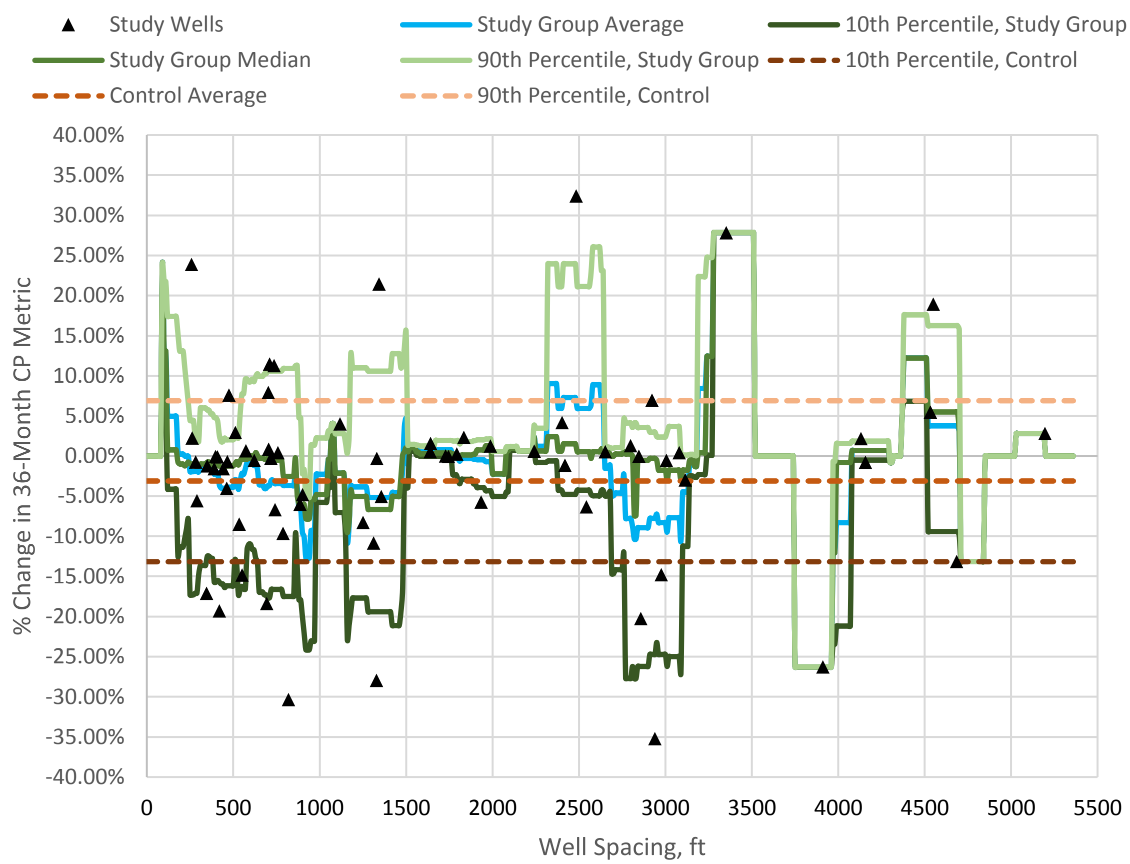

Fig. 33─Northern La Salle County percent change in projected cumulative production for the 36-month CP metric due to offset completions at different well spacing intervals

This section's results show that significant positive and negative impacts are recorded by the percent change in the 12-month and 36-month CP metric. Similar to the methodology in Section 3.2, a great amount of uncertainty in the results exist, but unlike Section 3.2 an increase in the range between 10th and 90th percentiles as the well spacing decreases down to 250 is less apparent. In this section, the percent change in the 36-month CP for both areas appears to be an amplification of the impacts recorded by the percent change in the 12-month CP in that the shapes of the distributions and trends for the average, median, 10th percentile, and 90th percentile are similar, but the distributions for 36-month CP are wider. Both areas show that CP metric central tendency varies with well spacing and a significant linear trend does not exist with an increase or decrease in well spacing from 5,280 feet to zero.

4. WELLS POTENTIALLY IMPACTING OFFSET WELLS, PI

4.1 Introduction of Methodologies

Quantifying the impact on production for the wells that are completed next to a previously producing parent well involved using similar cumulative production metrics to those in Section 3.3. Out of the available 574 wells in this study, the PI group consisted of 23 wells that could be separated into a control group, wells spaced further than 5,280 from their nearest producing neighbor; only five were in the Western Karnes County area and the other 18 were in the Northern La Salle County area. The study groups were divided into two different categories based on if they could have potentially impacted a producing parent well on one or both sides. For the Western Karnes County area, 257 wells could have potentially impacted one of its nearest parent neighbors and 41 wells could have impacted the nearest parent neighbor on both sides. For the Northern La Salle County area, 226 wells could have potentially impacted one of its nearest parent neighbors and 25 wells could have impacted the nearest parent neighbor on both sides. Situations where a well could have potentially impacted both of its nearest parent neighbors involved assigning the well a spacing consisting of an average of the two spacings from both sides. In cases where one of the intervals was greater than 5,280 feet, the smaller spacing was used.

The following analysis involved using the PAWR curves (Fig. 17) obtained from all available production data. Well-to-well interference impacts for wells in the PI group affect the entire PAWR curve and a well that is affected by extensive fracture growth into a depleted zone of an existing producing well is expected to produce less or have a steeper decline rate than surrounding wells in the area.

All of the data sets that follow had outliers eliminated if the metric used to compare the impacts were beyond the upper and lower quartiles by 1.5 times the inter-quartile range, discussed previously in Section 3.1. For the PI wells the outliers were identified as having insufficient data to obtain accurate forecasts and thus created irregular values for the metrics that were used to compare the impacts. The outliers included only 11 wells from the NLSC area and zero from the WKC area. A review of the study group with and without the outliers found that the 11 wells did not have any significant impact on the results for the NLSC area. Distributions of results for the control and study groups were compared utilizing a Kruskal-Wallis test through a Real Stats add-in to Microsoft Excel (2013) . The Kruskal-Wallis test is a "nonparametric statistical procedure for comparing more than two samples that are independent or not related" (Corder and Foreman 2014). The study and control groups in this research are assumed to be independent. In Eq. 15 below, the Kruskal-Wallis H-test statistic can be calculated by "combining all the samples and rank ordering the values together."

$$H = \frac{12}{N(N+1)} \sum_{i=1}^{k} \frac{R_i^2}{n_i} - 3(N+1) \quad (15)$$

In the equation "N is the number of values from all combined samples, R_i is the sum of the ranks from a particular sample, and n_i is the number of values from the corresponding rank sum." The Kruskal-Wallis H-test statistic is calculated and then compared to a tabulated set of critical values to determine significance. In the event a tie occurs when ranking values, Eq. 16 is a way of calculating a "new H statistic by dividing the original H statistic by the tie correction."

$$C_H = 1 - \frac{\sum(T^3 - T)}{N^3 - N} \quad \text{(16)}$$

In Eq. 16 "C_H is the ties correction, T is the number of values from a set of ties, and N is the number of values from all combined samples." When the test leads to significant results, then the study group and control group are deemed to be different because of well spacing and not due to the random performance of the wells in the study.

4.2 Quantifying Effects on the Six-Month Cumulative-Production Metric for PI Wells

The first six months of cumulative production for each well in the Potentially Impacting, PI, case represents a well's six-month CP metric. The variability in the six-month CP metric for wells in the control group during this time period is assumed to result from differences in geological characteristics, lateral lengths, and completion design, and not from well-to-well interference. **Fig. 34** shows the six-month CP from the PAWR curve that was fit using all available average monthly rates for each of the wells in the control group for both areas. This figure shows the range for wells in the NLSC area in the control group is roughly 70,000 barrels and the range for wells in the WKC area in the control group is roughly 33,000 barrels. Also more than half, ten out of 18, of the wells in the NLSC area that are in the control group have six-month CPs greater than the well with the greatest six-month CP in the WKC area. The production from the PAWR curve was used rather than actual production to remove the effects of partial production during the first month. Typically a well is not consistently brought to production on the first of each month and, as a result, production is recorded for only a portion of the first month.

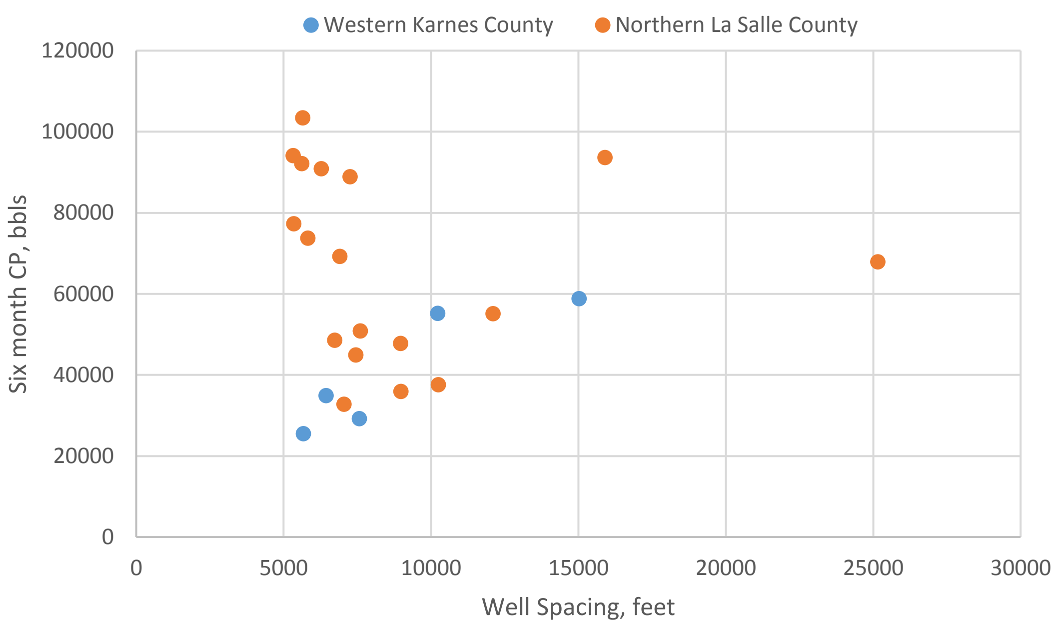

Fig. 34─Six-month CP of the control group for both areas

Table 3 provides information on the six-month CP of the control wells in both areas. This table shows that the average of the NLCS area is roughly 16,000 barrels higher than the WKC area. It is important to note that with such small data sets for the control groups (five wells in WKC and 18 in NLSC), each control well significantly impacts the descriptive statistics of the distribution more so than a data set with a large number of wells.

Table 3─Descriptive statistics for the six-month CP of the control wells in both areas

	10th Percentile, bbls	Average, bbls	90th Percentile, bbls
WKC, Control	26,960	40,709	57,344
NLSC, Control	37,055	66,898	93,733

Fig. 35 and **Fig. 36** display the results for Western Karnes County and Northern La Salle County when comparing the study group to control group. Both figures plot the six-month CP obtained from the PAWR curve of each well versus well spacing. The six-month CP is influenced by several uncontrollable factors and a comparison of the study group to the control group attempts to account for these factors. These include things like varying lateral lengths, different completion designs, geological characteristics, and reservoir properties. For example, a well completed and spaced at 500 feet could have twice the lateral length and make double the production in the first six months than a well with 1000-foot spacing simply because the lateral length provided more access to the reservoir. Impacts on the six-month CP from the factors listed above could not be isolated for the wells classified as PI in the study group. This methodology differs from the analysis performed on PBI wells in Section 3. The wells in the PBI group captured interference effects in their production at different spacings based on the analysis performed with a comparison of the differences in the PAWR and UWR curves. In this

section, however, wells are potentially impacting, PI, producing offsets and well-to-well interference effects on the PI well's production are recorded by the PI well's PAWR curve.

In the Western Karnes County area, the six-month CP metric shows that for study-group wells (well spacing under 5,280 feet), the initial cumulative production is predominately greater than control-group wells (Fig. 35). The control group distribution and study group distribution in the Northern La Salle County area are very similar in spread and there is not much difference in the distributions between the study group and control group (Fig. 36).

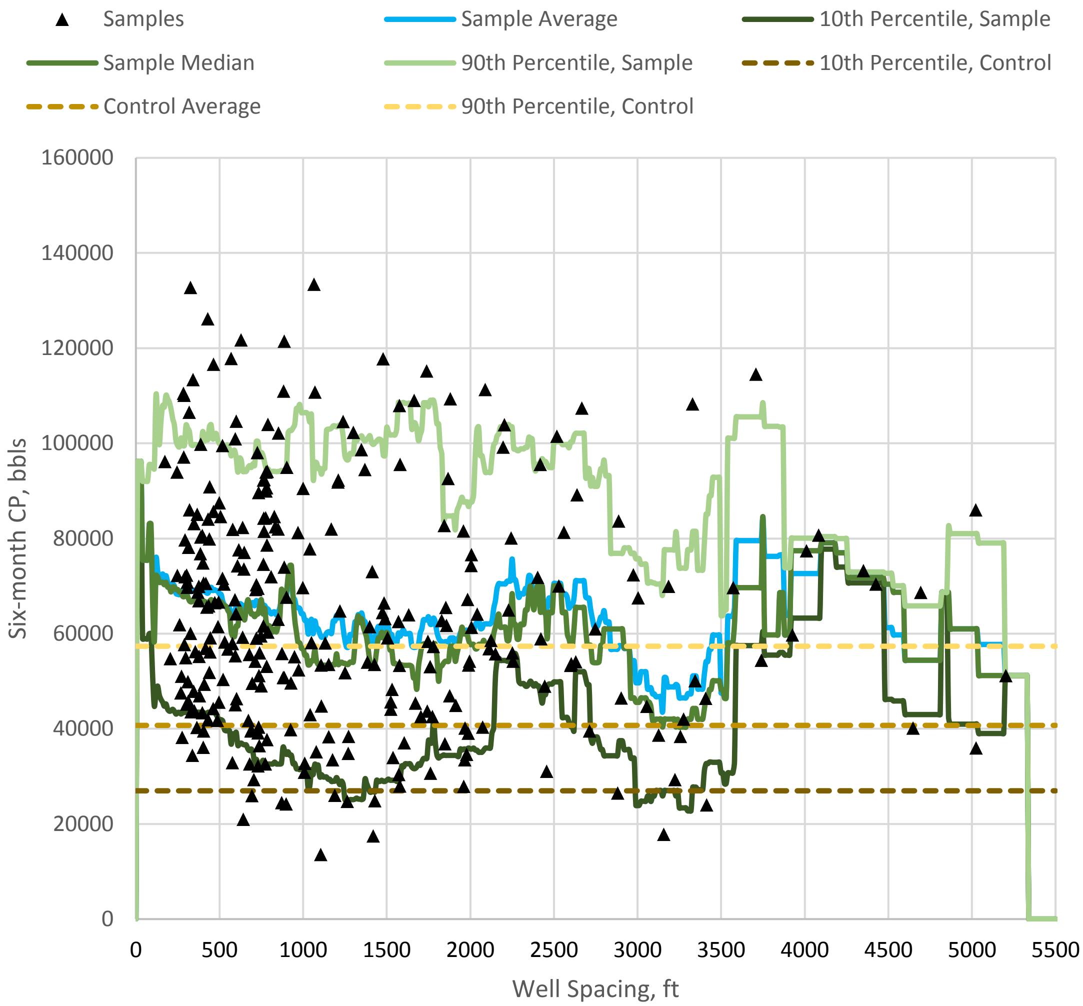

Fig. 35─Six-month CP for the study wells in the Western Karnes County area plotted with different well spacing intervals

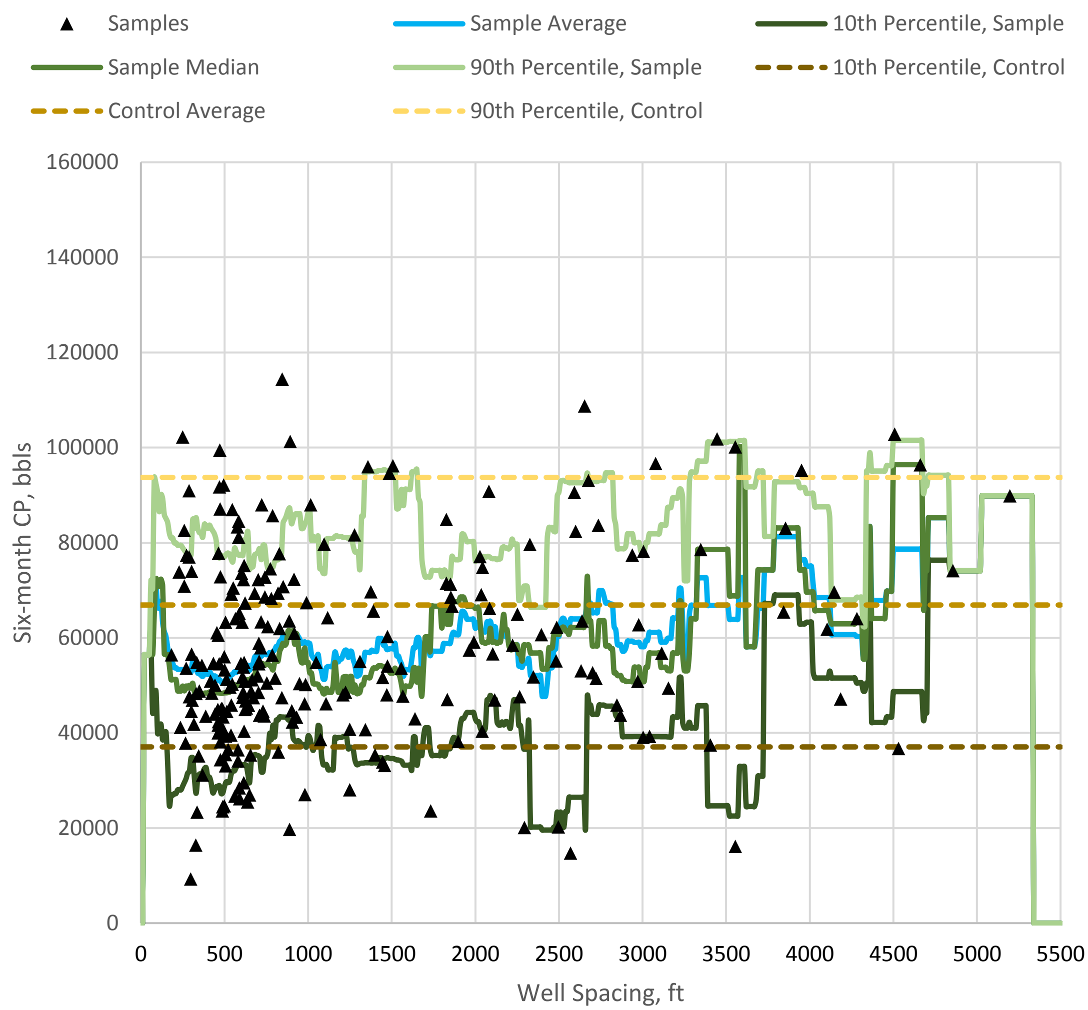

Fig. 36─Six-month CP for the study wells in the Northern La Salle County area plotted with different well spacing intervals

The conclusion that study-group wells in WKC have greater cumulative production in the first six months than control-group wells and that the wells in NLSC do not cannot be made with confidence, primarily because the control groups do not contain large numbers of wells (five wells in WKC and 18 in NLSC). Therefore, a Kruskal-Wallis test, which takes into account the small number of samples for the control groups, was applied to determine if there was a statistically significant difference between impacts on study-group and control-group wells for both areas. Kruskal-Wallis test results comparing the six-month CP metric for the control group distribution and the six-month CP metric for the study group distribution in the WKC and NLSC areas are presented in **Table 4** and **Table 5**, respectively. The p-value is a "measure of inconsistency between the hypothesized value for a population characteristic and the observed sample." If the p-value is greater than the pre-defined alpha value of 0.05, then the null hypothesis is accepted and the two distributions only differ because of the samples used to make each distribution. These tables reveal that the difference between the control group distribution and study group distribution are not statistically significant for the NLSC area (p-value = 0.11), but show the study group distribution and control group distribution for the WKC area differ to a statistically significant degree (p-value = 0.026).

Table 4—Real-Stats Kruskal-Wallis Test output for the control and study groups in the Western Karnes County Area

Kruskal-Wallis Test

	Control	**Study**	**Outputs**
median	34918.16	61171.23	
rank sum	327	45729	
count	5	298	303
r^2/n	21385.8	7017253	7038638.958
H-stat			4.967034617
H-ties			4.967034617
df			1
p-value			0.025834904
alpha			0.05
sig			Yes

Table 5—Real-Stats Kruskal-Wallis Test output for the control and study groups in the Northern La Salle County Area

Kruskal-Wallis Test

	Control	**Study**	**Outputs**
median	68543.43	53980.98	
rank sum	2819	30592	
count	18	240	258
r^2/n	441486.7	3899460	4340946.989
H-stat			2.554096954
H-ties			2.554096954
df			1
p-value			0.110008656
alpha			0.05
sig			No

Back to a review of the trend in Fig. 35 shows that PI study wells in WKC area will have greater six-month cumulative production than control-group wells for spacings below 5,280 feet. It appears for the WKC area that the six-month CP central tendency has an increasing trend as spacings decreases from roughly 2,000 feet down to 250 feet, the point at which spacings for wells in the study group were not recorded. This is not an expected trend; however, the NLSC area study distribution has a decreasing trend in the six-month CP as well spacing decreases from roughly 4,500 feet down to 250 feet that is more expected (Fig. 40). As well spacings decrease it is expected that production will be impacted negatively.

To summarize, the comparison of the cumulative production in the first six months for wells in the study and control group aims to account for the effects of varying lateral lengths, different completion designs, geological characteristics, and reservoir properties. It appears that for the WKC area statistically significant results indicate well-to-well interference impacts increase the six-month CP of PI wells for spacings under 5,280 feet. This result is unexpected; however, there were only five wells in the control group and almost 298 in the study group. For the NLSC the results were not statistically significant and conclusions could not be drawn as to how well-to-well interference affects the six-month CP metric. Again for the WKC area, results showed that as spacings decreased from roughly 2,000 feet down to 250 feet, the six-month CP increased and for the NLSC area as spacings decreased from roughly 4,500 feet down to 250, the six-month CP decreased. The trend in the NLSC is expected, but the increasing trend in the WKC is not. Uncertainty exists because the results and conclusions between the WKC and NLSC areas cannot be adequately explained. These differences and the low number of wells in the control groups make it difficult to form any strong conclusions.

4.3 Quantifying Effects on Decline Rate for PI Wells

A secondary attempt to describe the effects of well spacing on the production of the PI wells was performed by using a ratio that approximates the initial decline rate. Gong et al. (2011) used "the ratio of cumulative production 6 months to 1 (CP6to1)" as a proxy for the initial instantaneous decline rate in the Arps decline curve equation. This term is "averaged over a long period of time" when compared to the instantaneous decline rate, but it is still a good reflection of the average initial decline for each well. The cumulative production for the first six months compared to that of the first month's cumulative production was calculated for each well and plotted versus well spacing. **Fig. 37** shows the CP6to1 ratio for the wells in the control group for both areas. These results do not reveal any obvious trend for wells in the control groups.

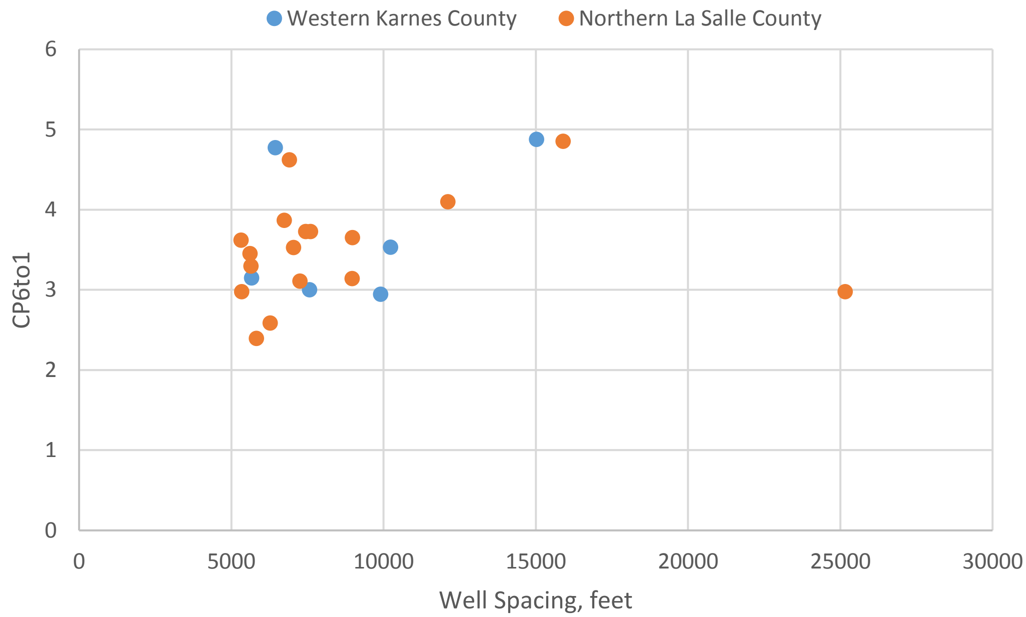

Fig. 37─Ratio of cumulative production in month six compared to one for the control wells in both areas

The control-group CP6to1-ratio distributions are plotted in **Fig. 38** and **Fig. 39** for both areas. The distribution for the Northern La Salle County area looks to be normally distributed but the distribution for the Western Karnes County area does not have a clear distribution form. **Table 6** lists the average, the 10^{th} percentile, and 90^{th} percentile for the control groups in both areas. The results show that both areas are similar in their descriptive statistics.

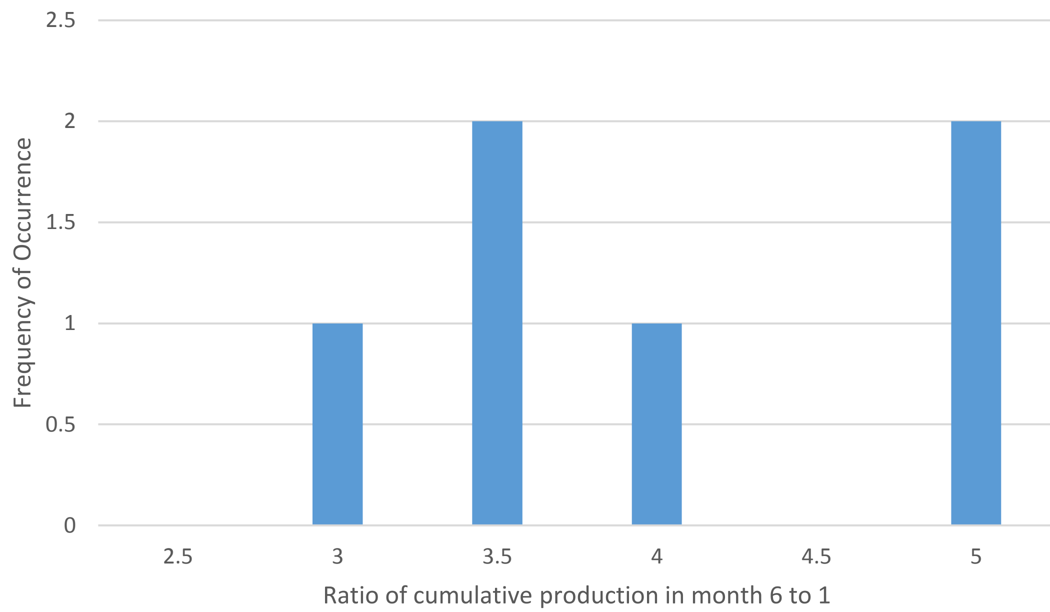

Fig. 38─Distribution of the CP6to1 ratio for the control wells in the Western Karnes County area

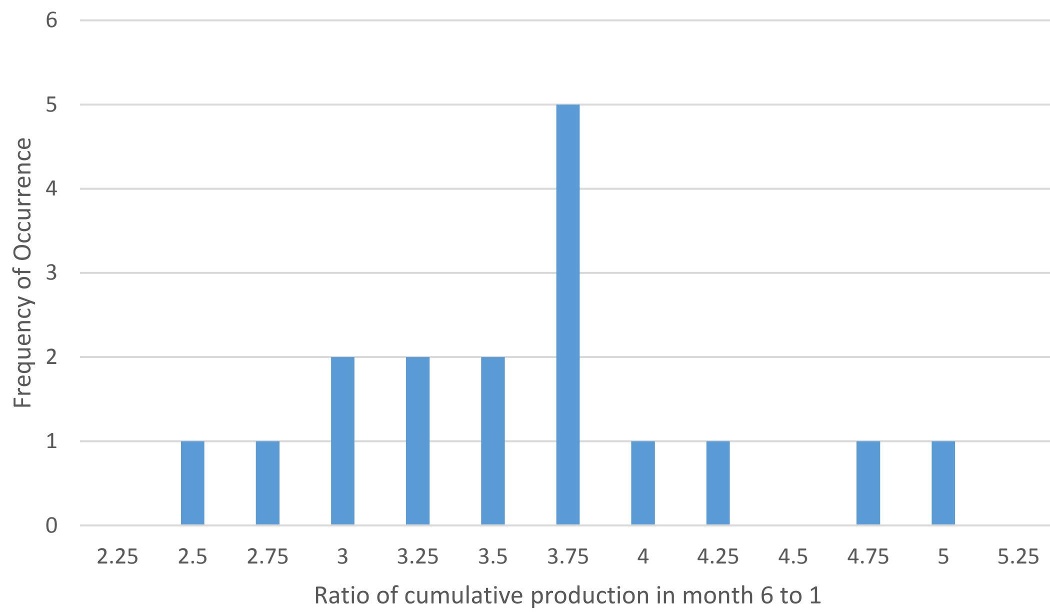

Fig. 39**─Distribution of the CP6to1 ratio for the control wells in the Northern La Salle County area**

Table 6─Descriptive statistics for the CP6to1 ratio for control groups in both areas

	10th Percentile	Average	90th Percentile
WKC, Control	2.97	3.71	4.83
NLSC, Control	2.82	3.51	4.31

Fig. 40 and **Fig. 41** provide the distributions of CP6to1 for each area plotted against well spacing. The distribution of results for the study groups and that of the control groups do not appear to be different for the WKC area, but it looks like results in the NLSC for the study group distribution exist beyond the bounds of the control group to a greater degree. The results for the NLSC area in Fig. 41 show that as well spacing

decreases from roughly 2,250 feet to 250 feet the CP6to1 ratio has a weak decreasing trend in its central tendency; whereas, the results for the WKC area do not seem to have a strong trend in any direction as well spacing decreases. Similar to the discussion in Section 4.2, the CP6to1 ratio for the wells in the study group were compared to those in the control group to try and account for the external uncontrollable factors that might have an inherent impact on PI wells. These factors again include varying lateral lengths, different completion designs, geological characteristics, and reservoir properties. For an example, one well that is spaced at 500 feet may have had a slickwater hydraulic fracturing design that resulted in a greater decline rate than a well with a crosslinked hydraulic fracturing design spaced at 1,000 feet. In this instance these design differences could not be accounted for in the results presented in Fig. 40 and Fig. 41 and drawing conclusions about well-to-well interference are difficult due to the small number of wells in the control groups. To try and determine if well-to-well interference effects are significant a statistical test was necessary.

This check for well-to-well interference impacts involved using the Kruskal-Wallis test again. The test was performed to identify any statistically significant differences between the control groups and study groups for both areas.

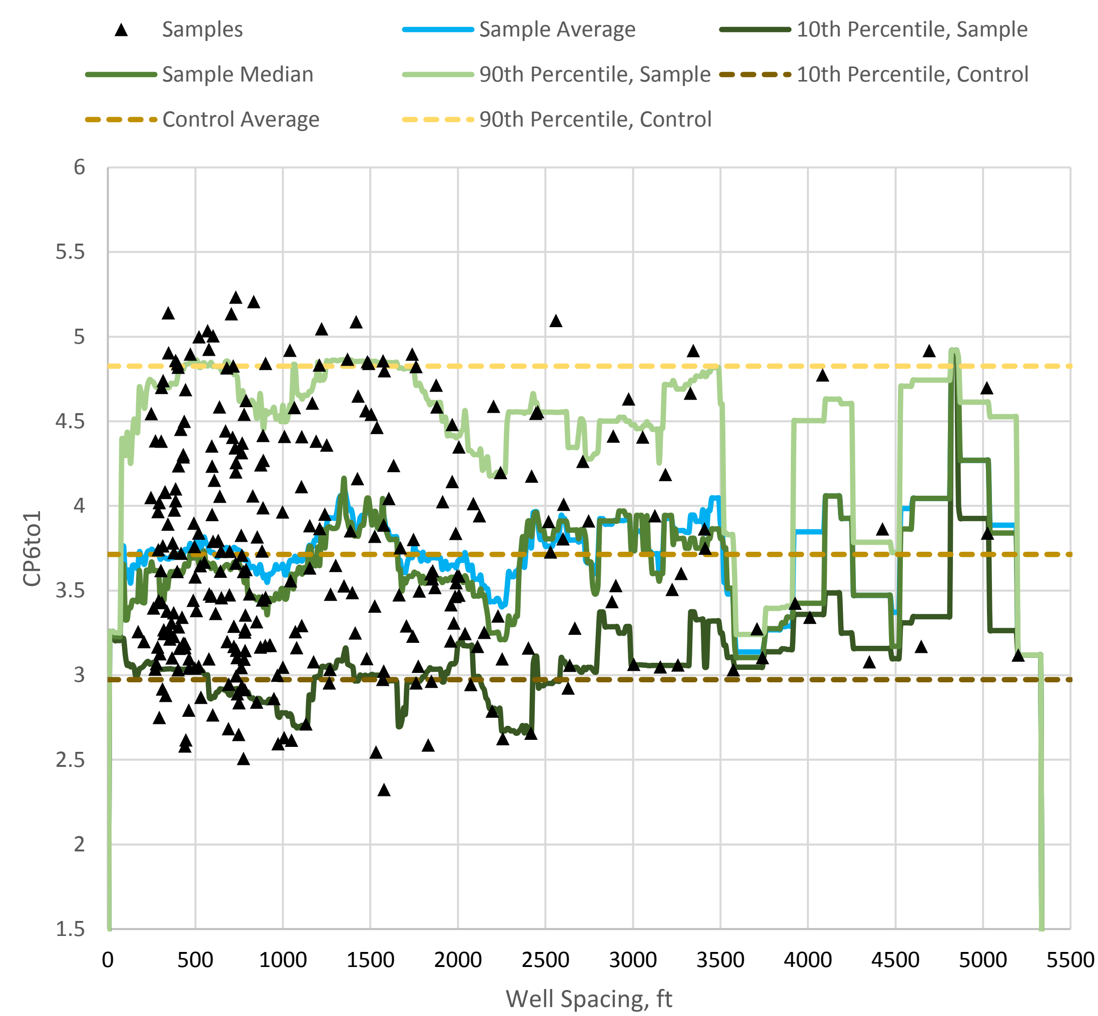

Fig. 40─CP6to1 ratio for wells in the Western Karnes County area versus well spacing

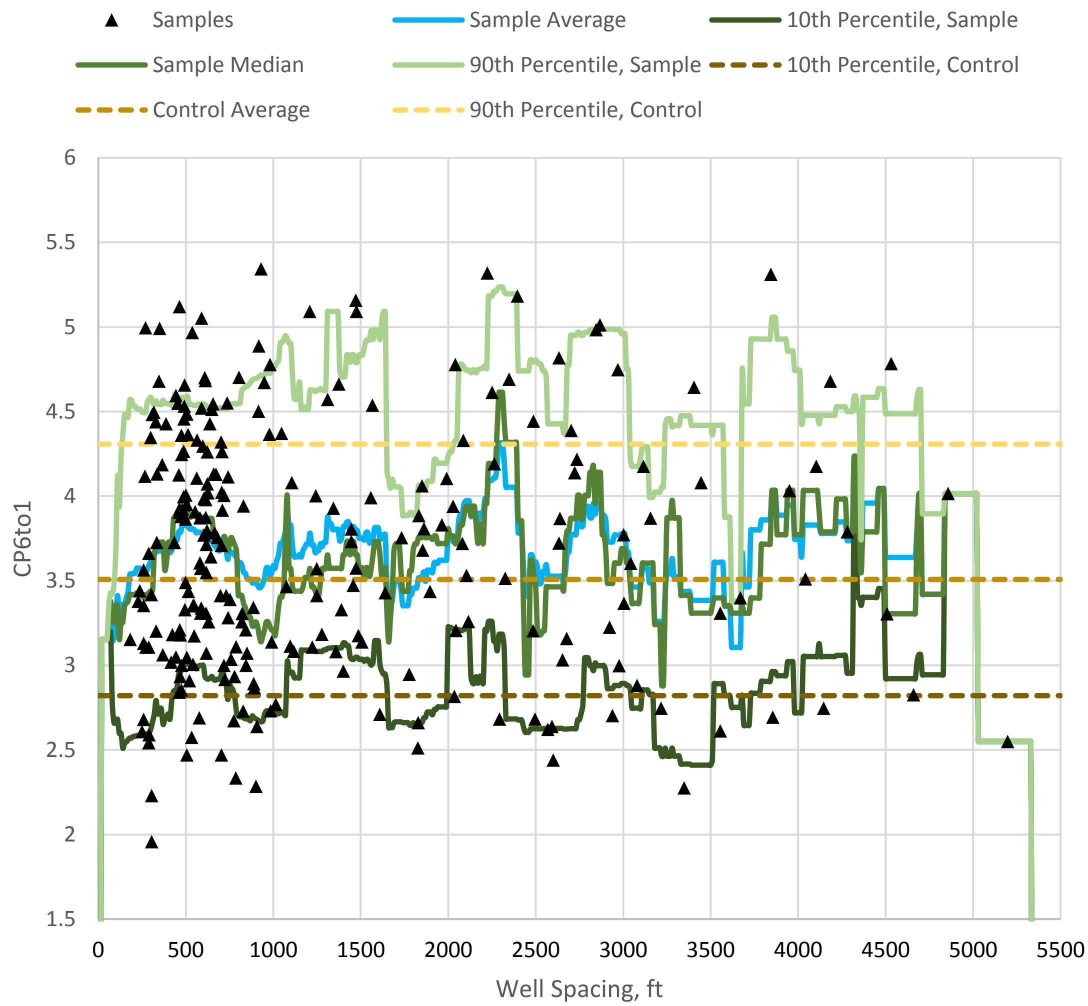

Fig. 41─CP6to1 ratio for wells in the Northern La Salle County area versus well spacing

Comparisons of control groups to study groups using the Kruskal-Wallis test are provided in **Table 7** and **Table 8**. The test results show that well-to-well interference does not exhibit a statistically significant impact on the initial decline rate of wells that could have potentially impacted existing producing wells.

Table 7─Real-Stats output for the Kruskal-Wallis test between the control and study group CP6to1 ratios for the Western Karnes County area

Kruskal-Wallis Test

	Control	**Study**	**Output**
median	3.341247	3.615548	
rank sum	838	45522	
count	6	298	304
r^2/n	117040.7	6953867	7070908.063
H-stat			0.130465398
H-ties			0.130465398
df			1
p-value			0.717949986
alpha			0.05
sig			No

Table 8─Real-Stats output for the Kruskal-Wallis test between the control and study group CP6to1 ratios for the Northern La Salle County area

Kruskal-Wallis Test

	Control	**Study**	**Output**
median	3.529771	3.70939	
rank sum	1981	34065	
count	17	251	268
r^2/n	230844.8	4623204	4854048.848
H-stat			0.975727965
H-ties			0.975727965
df			1
p-value			0.323255784
alpha			0.05
sig			No

5. DISCUSSION OF RESULTS

This research provides an analysis of public data that attempts to quantify the effects of well-to-well interference on production and describe the uncertainty associated with the interference in Western Karnes County and Northern La Salle County. Quantifying well-to-well interference effects involved using two well regression curves, the PAWR and UWR curve. It was discovered through the process of obtaining the PAWR and UWR curves that the two curves cross one another in their projections for approximately 75% of the wells. One curve may have more curvature than the other due to the number of months that are used to create the UWR curve, as well as due to well-to-well interference impacts. **Fig. 42** shows the frequency distribution of the month in which the PAWR and UWR crosses for all the wells in the study groups. On average the two curves cross at month 21.

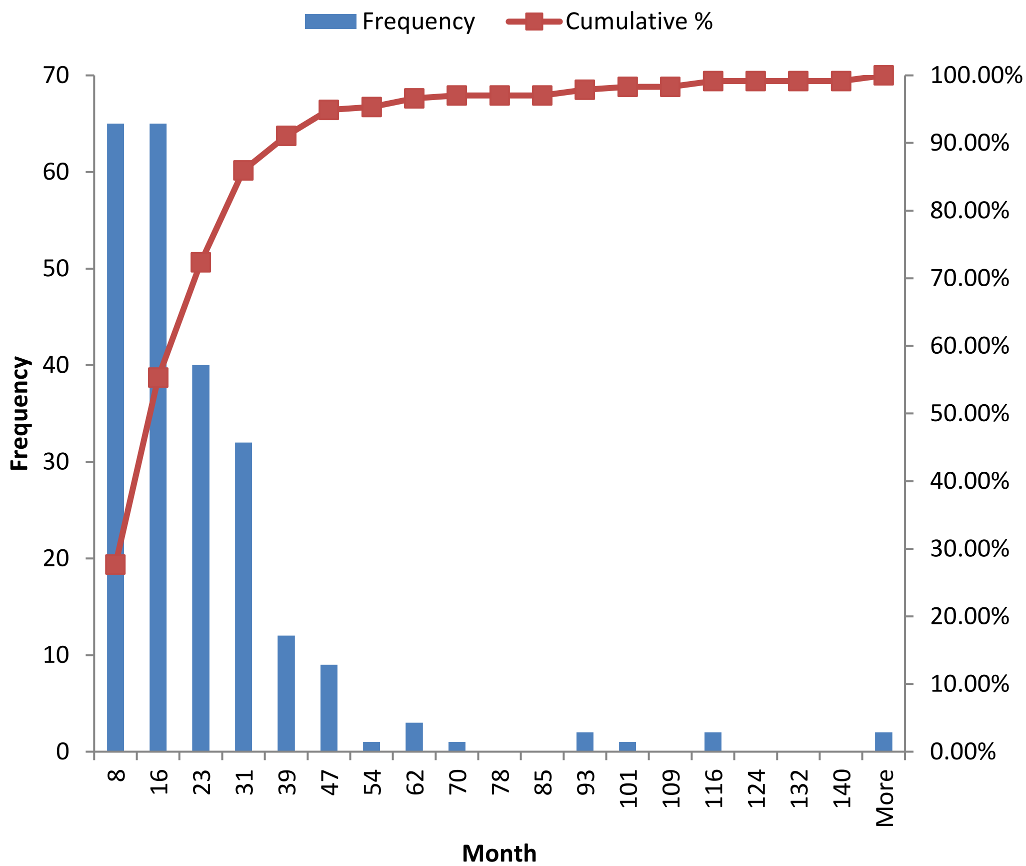

Fig. 42─Frequency distribution of the month where the PAWR and UWR curves cross for all wells in the study groups of both areas

Fig. 43 shows an example of a UWR cumulative production curve crossing a PAWR cumulative production curve at month 14. This example reveals that impacts before this month where the curves cross are recorded as negative impacts and positive impacts after. Cases exist where the opposite is true; positive impacts are recorded before the month where the curves cross and negative after. Since the curves can cross and lead to impacts in either direction, the process of identifying positive and or negative well-to-well interference is much more complicated and uncertain.

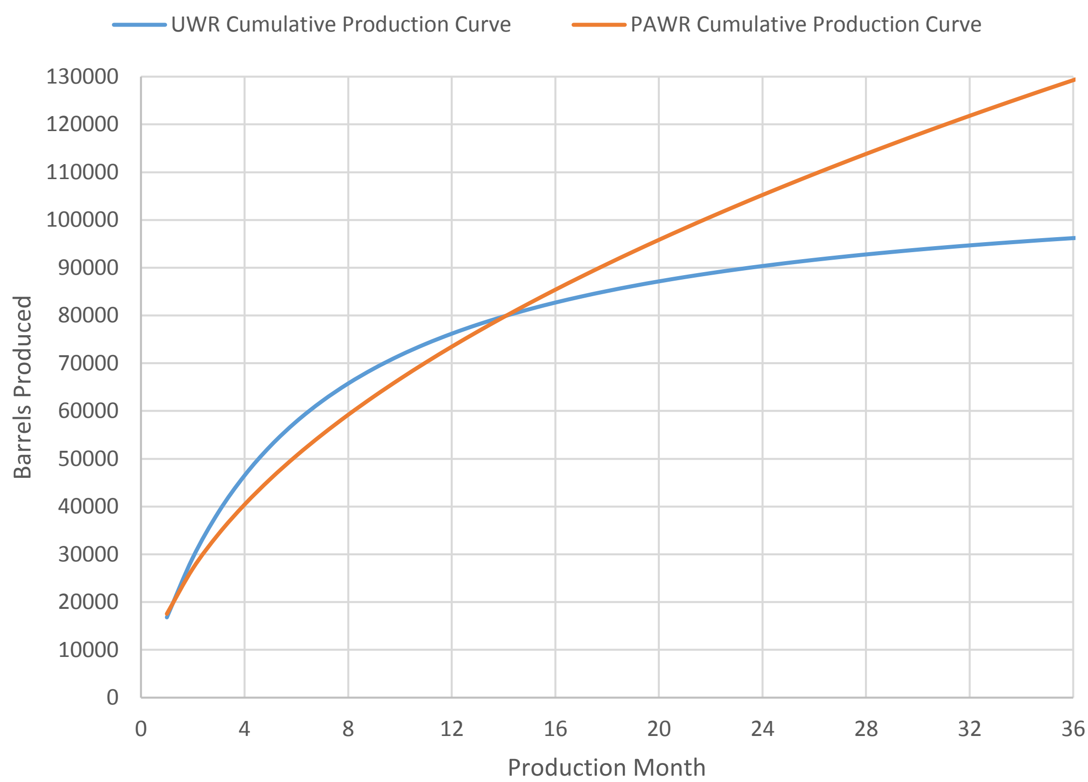

Fig. 43─Example of UWR and PAWR curves crossing

First, each well's production decline begins in transient flow and the more months included in a CP metric, the flatter the PAWR curve becomes. As time increases after offset completion, the differences between the PAWR and UWR curves are affected more by differences in transient decline behavior than by interference effects. Thus, metrics that compare well-to-well interference impacts will be less affected by the curvature of the curves when the metric is comparing production during the early stages of a well's life. With that in mind, the analysis performed in Section 3.2 compared differences in production between the PAWR and UWR curves from the Date of Offset Completion out to 60 months. Since the average Date of Offset Completion, the eighth month, occurred before the average month where the PAWR and UWR curve cross, Month 20, it is likely that the results from this section were impacted by the different flattening of the PAWR and UWR curves in addition to well-to-well interference. Additionally, Section 3.3 compared the difference between the 12-month and 36-month CP metrics. Because the transient decline behavior affects the differences in the curves much more at later times, the 36-month CP metric may not represent the well-to-well interference impacts as well as the 12-month CP metric. Ultimately, the issue of the PAWR and UWR curve crossing adds to the uncertainty of these results throughout Sections 3.1 and 3.2 and indicates that early time metrics may have more validity than late time metrics.

Table 9 below summarizes the results from each section of this research. It describes, for each well category, the methodology used to quantify well-to-well interference for each associated area, if the study group was statistically significant or not and, if so, then whether the impacts were positive or negative.

Table 9─Summary of comparisons between study and control groups for determining interference effects

Well Category	Methodology: How well-to-well interference was assessed	Location	
		Western Karnes County	**Northern La Salle County**
PBI Wells	Cumulative prod. from the DoOC to 60 months	Positive and Negative impacts	Positive impacts
	% difference in the 12-month CP metric	Positive and Negative impacts	Positive and Negative impacts
	% difference in the 36-month CP metric	Positive and Negative impacts	Positive and Negative impacts
PI Wells	6-month CP metric	Positive impacts	Not statistically significant
	CP6to1	Not statistically significant	Not statistically significant

The results for the WKC area showed currently producing wells can potentially experience interference from newly completed infill wells for spacings up to approximately 4,000 to 4,500 feet while the NLSC area experiences interference up to 5,000 feet. From the well-to-well interference results provided in Table 9, it cannot be concluded that tighter well spacing intervals increase the chance or the intensity of well-to-well interference in either area. The table shows that well-to-well interference is both positive and negative for PBI wells in both areas; however, due to the conflicting results it is difficult to draw conclusions with much certainty. Wide ranges for results associated with the control groups meant that wells in the PBI study groups had to be impacted to a great degree to be considered significant. For PI wells the results imply that a newly completed infill well's production can be positively impacted, at least in the WKC area up to 5,280 feet. From the literature, other studies pointed out that PI wells experienced negative impacts, so the results in this research were unexpected. This conflict and the considerable uncertainty associated with these results makes drawing firm conclusions about PI wells difficult.

Table 10 summarizes observations of well spacing effects as well spacings get tighter, i.e., the distance between laterals decreases. The results are summarized for each well category and are organized by the methodology used to quantify well-to-well interference for each associated area.

Table 10─Summary of well spacing effects as spacings get tighter

Well Category	Methodology: How well-to-well interference was assessed	Location	
		Western Karnes County	**Northern La Salle County**
PBI Wells	Cumulative prod. from the DoOC to 60 months	Positively and negatively trending impacts	Positively and negatively trending impacts
	% difference in the 12-month CP metric	Positively and negatively trending impacts	Positively and negatively trending impacts
	% difference in the 36-month CP metric	Positively and negatively trending impacts	Positively and negatively trending impacts
PI Wells	6-month CP metric	Positively trending impacts	Negatively trending impacts
	CP6to1	Neither strong positive or negative trend	Neither strong positive or negative trend

From the observations recorded in Table 10 there exists significant uncertainty in the trends for the PBI wells in both areas, as they have both positive and negative impacts depending on the well spacing. Thus, it cannot be concluded that tighter well spacings impact previously producing parent wells in either the positive or negative direction. For wells in the PI group, positively trending impacts were seen in the WKC area, but negatively trending impacts were seen in the NLSC area. This adds to the uncertainty for wells in the PI group. While the results in the NLSC area are what is expected, the results in WKC are contradicting. This again makes it difficult to form firm conclusions regarding how PI wells are affected by tighter well spacing intervals overall.

From the results for the PBI and PI wells for both areas it is difficult to recommend a well-spacing strategy. Overall strong trends do not exist and the uncertainty is large in both areas. Based on these results, there does not exist a compelling argument that tighter spacings are increasingly detrimental. While the range in intensity of well-to-well interference impacts changes with well spacing, an overall trend in either the positive or negative direction does not increase with tighter well spacings.

6. CONCLUSIONS AND RECOMMENDATIONS

This purpose of this research was to quantify the effects of well-to-well interference on production from horizontal hydraulically fractured wells in the Western Karnes County and Northern La Salle County areas of the South Texas' Eagle Ford shale play. These areas encompass acreage held by Matador Resources Company, the primary source of data and support for this study. The important conclusions from this work are:

- The methodologies employed in this work to assess interference effects yielded considerable uncertainty in results and conclusions.
- Generally, as well spacings get tighter in both areas, the range of impacts due to well-to-well interference increases; however, the direction of the resulting impact is unpredictable.
- Results implied that production of newly completed infill wells can possibly be positively impacted by well-to-well interference, at least in the Western Karnes County area.
- For newly completed infill wells in the Northern La Salle County area well spacing effects are increasingly detrimental as spacings get tighter; whereas, the opposite is true for the Western Karnes County area.

7. LIMITATIONS AND FUTURE WORK

The methodologies used in this research as well as the data available for analysis had several limitations. The few weak relationships that were discovered through this work were a function of the limited information that was available. Things like production allocation, artificial lift systems, and un-reported well interventions have impacts on production interference. Their effects lead to increased uncertainty in the results. Additionally, localized changes in geological characteristics and reservoir properties, as well as different completion designs, added to the uncertainty in these results. Accounting for these with a multivariate analysis of the data may reduce the uncertainty.

The process of comparing the different CP metrics using the PAWR and UWR curves captured impacts due to both well-to-well interference and different transient decline behaviors. The more months included in the CP metric the more flattening behavior in the data that are fitted. Thus, CP metric comparisons using a smaller number of months may capture less of the effects caused by the changing decline and more of the impacts from well-to-well interference. Alternative metrics that avoid this issue should be considered in future work.

These results and methodology do not predict the occurrence or lack of well-to-well interference that would be expected in the future development of these areas. The small number of wells available that make up the control groups could potentially be influenced to a significant degree by any additional wells drilled and completed in the future. It is an underlying assumption that the analysis of the currently available well data can be used as an aid when optimizing well spacing. To predict future impacts on existing or planned wells, an accurate forecasting model that predicts the likelihood and magnitude of interference would be beneficial.

A lack of data from well spacings less than 250 ft reduces the descriptive power in this research. More wells drilled at small spacings would increase the number of data points that could be used to help explain well-to-well interference at small spacings. Developing acreage at such small spacings could potentially be economical for many operators; however, this study does not have conclusive evidence to support whether or not small spacings are economical. Operators would need to evaluate further if extremely small spacings experience interference and if the results are still economical.

Based on this research and a review of the literature, it is a combination of completion design, well spacing, and pressure depletion that has an impact on the extent to which positive or negative well-to-well interference occurs. An understanding of local stress magnitudes, maximum stress directions and how maximum stress directions change with time due to the drainage of a reservoir is important for avoiding negative well-to-well interference. Operators need to be able to predict when negative well-to-well interference is likely to occur so they can avoid drilling at that spacing and to drill at particular spacings when positive well-to-well interference is likely. This prediction will involve understanding how the stimulated and contributing reservoir volumes for each well changes with past and present completion designs. Unfortunately, fracture half-lengths, SRVs, CRVs, pressure depleted areas, and principal stress directions are often highly uncertain and, yet, these are the most crucial characteristics to solving this problem. If by chance all of that information was known, the economic effects from well-to-well interference would need to be considered when deciding whether or not to drill and complete wells at tighter well spacings.

NOMENCLATURE

bbls	Barrels
BOPD	Barrels of Oil Produced per Day
b	b-Factor
CRV	Contributing Reservoir Volume
CP6to1	Cumulative Production at month 6 divided by that at month 1
DCA	Decline Curve Analysis
GOR	Gas-Oil Ratio
GIS	Geographic Information System
IU	Induced Unpropped
CP	Cumulative Production
NLSC	Northern La Salle County
PAWR	Potentially Affected Well Regression
PBI	Potentially Being Impacted
PI	Potentially Impacting
Scf/bbl	Standard Cubic Feet per Barrel
SRV	Stimulated Reservoir Volume
TRC	Texas Railroad Commission
TVDSS	Total Vertical Depth Sub-Sea
UWR	Unaffected Well Regression
UTM	Universal Transverse Mercator

VBA	Visual Basic for Applications
WKC	Western Karnes County

REFERENCES

Ajani, A. A., Kelkar, M. G. 2012. Interference Study in Shale Plays. Presented at the SPE Hydraulic Fracturing Technology Conference, The Woodlands, Texas, USA, 6–8 February 2012. SPE-151045-MS. DOI: 10.2118/151045-MS.

Arps, J. J. 1944. Analysis of Decline Curves. Houston, Texas, USA. SPE-945228-G. Pages 228-247. DOI: 10.2118/945228-G.

Awada, A., Santo, M., Lougheed, D. et al. 2015. Is That Interference? A Workflow for Identifying and Analyzing Communication Through Hydraulic Fractures in a Multi-Well Pad. Presented at the Unconventional Resources Technology Conference, San Antonio, Texas, USA. SPE-178509-MS. DOI: 10.2118/178509-MS.

Corder, G. W., Foreman, D. I. 2014. *Nonparametric Statistics : A Step-by-Step Approach (2)*. Somerset, USA, Wiley.

Devore, J., Peck, R. 1996. *Statistics: The Exploration and Analysis of Data*, Third Edition edition. Pacific Grove, California, United States of America, Brooks/Cole Publishing Company.

Fan, L., Martin, R. B., Thompson, J. W. et al. 2011. An Integrated Approach for Understanding Oil and Gas Reserves Potential in Eagle Ford Shale Formation. Presented at the Canadian Unconventional Resources Conference Calgary, Alberta, Canada. SPE-148751-MS. DOI: 10.2118/148751-MS.

Friedrich, M., Milliken, M. 2013. Determining the Contributing Reservoir Volume from Hydraulically Fractured Horizontal Wells in the Wolfcamp Formation in the Midland Basin. Presented at the Unconventional Resources Technology Conference Denver, Colorado, USA. SPE-168839-MS. DOI: 10.1190/URTEC2013-149.

Fujita, Y., Datta-Gupta, A., King, M. J. 2015. A Comprehensive Reservoir Simulator for Unconventional Reservoirs Based on the Fast Marching Method and Diffusive Time of Flight. Presented at the SPE Reservoir Simulation Symposium Houston, Texas, USA. SPE-173269-MS. DOI: 10.2118/173269-MS.

Gong, X., McVay, D., Bickel, J. E. et al. 2011. Integrated Reservoir and Decision Modeling To Optimize Northern Barnett Shale Development Strategies. Presented at the Canadian Unconventional Resources Conference, Calgary, Alberta, Canada, 15–17 November 2011. SPE-149459-MS. DOI: 10.2118/149459-MS.

Gong, X., Tian, Y., McVay, D. A. et al. 2013. Assessment of Eagle Ford Shale Oil and Gas Resources. Presented at the SPE Unconventional Resources Conference-Canada Calgary, Alberta, Canada. SPE-167241-MS. DOI: 10.2118/167241-MS.

Hentz, T. F., Ruppel, S. C. 2010. Regional Lithostratigraphy of the Eagle Ford Shale: Maverick Basin to East Texas Basin. Austin, Texas. *Gulf Coast Association of Geological Societies Transactions* **60**: Pages 325-337.

Kurtoglu, B., Salman, A. 2015. How to Utilize Hydraulic Fracture Interference to Improve Unconventional Development. Presented at the Abu Dhabi International Petroleum Exhibition and Conference Abu Dhabi, UAE. SPE-177953-MS. DOI: 10.2118/177953-MS.

LaFollette, R. F., Holcomb, W. D. 2011. Practical Data Mining: Lessons-Learned From the Barnett Shale of North Texas. Presented at the SPE Hydraulic Fracturing Technology Conference and Exhibition The Woodlands, Texas, USA. SPE-140524-MS. DOI: 10.2118/140524-MS.

Lalehrokh, F., Bouma, J. 2014. Well Spacing Optimization in Eagle Ford. Presented at the SPE/CSUR Unconventional Resources Conference - Canada Calgary, Alberta, Canada. SPE-171640-MS. DOI: 10.2118/171640-MS.

Lancaster, D. 2015. Matador Resources Annual 2015 Form 10-K, United States Securities and Exchange Commission, Washington, D. C. 20549 (February 29, 2016).

Lee, W. J. 1982. *Well Testing*. Richardson, TX, Society of Petroleum Engineers.

Manchanda, R., Sharma, M. M., Holzhauser, S. 2014. Time-Dependent Fracture-Interference Effects in Pad Wells, The Woodlands, Texas, USA, 10–12 April 2013. SPE-164534-PA. Pages 274-287. DOI: 10.2118/164534-PA.

Mukherjee, H., Poe, B., Heidt, H. et al. 1995. Effect of Pressure Depletion on Fracture Geometry Evolution and Production Performance. Presented at the SPE Annual Technical Conference and Exhibition, Dallas, Texas. SPE-30481-MS. DOI: 10.2118/30481-MS.

Pope, C. D., Palisch, T., Saldungaray, P. 2012. Improving Completion And Stimulation Effectiveness In Unconventional Reservoirs- Field Results In The Eagle Ford Shale Of North America. Presented at the SPE/EAGE European Unconventional Resources Conference and Exhibition Vienna, Austria. SPE-152839-MS. DOI: 10.2118/152839-MS.

Roussel, N. P., Florez, H., Rodriguez, A. A. 2013. Hydraulic Fracture Propagation from Infill Horizontal Wells. Presented at the SPE Annual Technical Conference and Exhibition New Orleans, Louisiana, USA. SPE-166503-MS. DOI: 10.2118/166503-MS.

Texas Railroad Commission. 2016. Texas Eagle Ford Shale Drilling Permits Issued 2008 through October 2016. Texas Railroad Commission Drilling Permit Query. Texas Railroad Commission Website. Texas Railroad Commission

Tian, Y., Ayers, W. B., McCain, W. D., Jr. 2012. Regional Analysis of Stratigraphy, Reservoir Characteristics, and Fluid Phases in the Eagle Ford, South Texas. College Station, Texas. *Gulf Coast Association of Geological Societies Transactions*. Pages 471-483.

Tian, Y., Ayers, W. B., McCain, W. D., Jr. 2013. The Eagle Ford Shale Play, South Texas: Regional Variations in Fluid Types, Hydrocarbon Production and Reservoir Properties. Presented at the International Petroleum Technology Conference Beijing, China. IPTC-16808-MS. DOI: 10.2523/IPTC-16808-MS.

Yaich, E., Diaz De Souza, O. C., Foster, R. A. et al. 2014. A Methodology to Quantify the Impact of Well Interference and Optimize Well Spacing in the Marcellus Shale. Presented at the SPE/CSUR Unconventional Resources Conference - Canada Calgary, Alberta, Canada. SPE-171578-MS. DOI: 10.2118/171578-MS.