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INTERIM DIRECTOR

RAILROAD COMMISSION OF TEXAS
HEARINGS DIVISION

OIL AND GAS DOCKET NO. 10-0305153

COMMISSION CALLED HEARING TO REVIEW THE TEMPORARY FIELD RULES FOR THE BIVINS LIT (CANYON LIME) FIELD, OLDHAM COUNTY, TEXAS

HEARD BY: Karl Caldwell – Technical Examiner
Clayton Hoover – Administrative Law Judge

PROCEDURAL HISTORY

Notice of Hearing:	March 8, 2018
Pre-Hearing Held:	May 22, 2018
Hearing on the Merits Held:	June 20, 2018
Transcript Received:	July 12, 2018
Proposal For Decision Issued:	October 15, 2018

APPEARANCES:	**REPRESENTING:**
APPLICANT:	**APACHE CORPORATION**
Kelli Kenney, Attorney James Clark, P.E., Engineer	
PROTESTANT:	**BIVINS FAMILY ROYALTY**
David E. Jackson, Attorney Tim Smith, P.E. Engineer Mark Knisely Kerry Knorpp	

STATEMENT OF THE CASE

The Bivins Lit (Canyon Lime) Field, ("subject field" or "field"), Field ID No. 08490750, was discovered January 29, 2014. Temporary Field Rules for the field were established by Commission Final Order in Oil and Gas Docket No. 10-0291184 on January 27, 2015, with an expiration date of November 12, 2016, or until Commission Staff evaluates appropriate data after notice and opportunity for hearing. On May 31, 2017, the Engineering Unit staff sent a Notice of Administrative Review of Temporary Field Rules for the Bivins Lit (Canyon Lime) Field advising operators in the subject field

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of the opportunity to request a hearing regarding the temporary field rules currently in effect. A hearing was held to review the Temporary Field Rules previously established under Oil and Gas Docket 10-0291184 and to assess whether the temporary field rules should be modified, continued, or terminated.

One vertical well and about 20 horizontal wells have been drilled and completed in the field to-date. Apache operates the majority of wells in the field and considers the field to be young in terms of development, as the field is still in the experimental phase. Apache asserts the current field rules are sufficient and requests that the field rules be continued in a temporary status for an additional two years without modification.

The request to extend the current temporary field rules for two years is protested by Bivins Family Royalty ("Bivins"), which consists of mineral owners in this area of both unleased minerals and minerals that are subject to the Apache Lease and to other leases. Bivins is interested in the temporary field rules both as an unleased mineral owner and as a royalty owner who alleges its Lessee is not properly representing its interests in the temporary field rules for the efficient and effective development in the field. Bivins' position is that the formula in the current temporary field rules provides for proration units that are large compared to what wells can effectively drain. Bivins proposes: 1) reducing the standard proration unit size (from 160 acres to 80 acres), 2) either modifying the formula used to assign additional acreage to horizontal wells or defaulting to the table in Statewide Rule 86 to assign additional acreage to horizontal wells, and 3) modifying the method used to determine the oil allowable for wells in the field.

Based on the evidence in the record, the Technical Examiner and Administrative Law Judge (collectively, "Examiners") recommend the Commission enter an order extending the temporary field rules currently in effect for the Bivins Lit (Canyon Lime) Field for an additional two-year period.

APPLICABLE LAW

16 T.A.C. §3.43 (Application for Temporary Field Rules) (c) Temporary field rules will apply until permanent field rules are adopted.

DISCUSSION OF THE EVIDENCE

APACHE'S EVIDENCE

Action Requested

Apache contends the existing temporary field rules are sufficient and requests that the field rules be continued in a temporary status for two years without modification.

Field History

James M. Clark, P.E., a consulting petroleum engineer designated as an expert in petroleum engineering, appeared at the hearing as Apache's witness. The Bivins Lit (Canyon Lime) Field was discovered on January 29, 2014, and Apache is the operator of most of the wells in the field. Le Norman Operating LLC, operates one shut-in well and has recently completed an additional well that is not yet listed on the proration schedule.

The Commission approved the application of Apache for a new field designation for the Bivins Lit (Canyon Lime) Field in Oldham County, Texas and adopted temporary field rules in Final Order No. 10-0291184 on January 27, 2015. Mr. Clark appeared at that hearing as a technical witness representing Apache. Finding of Fact No. 7 in that case was that there was no stratigraphic equivalent production within 2.5 miles of the discovery well for the Bivins Lit (Canyon Lime) Field, while Finding of Fact No. 8 stated that the temporary field rules adopted for the field were modeled on and identical to those adopted for a similar stratigraphic interval in the Hartley West (Canyon) Field in Hartley County, Texas.

The temporary field rules previously established for the Bivins Lit (Canyon Lime) Field are summarized as follows:

Rule 1: A correlative interval from the top of the Cisco Formation at 7,593 feet, down to the top of the clastic Granite Wash. The field interval for the Bivins Lit (Canyon Lime) Field is the Canyon Lime carbonate.

Rule 2: Lease line spacing of 330 feet with no minimum between well spacing, dual lease-line spacing of 100 feet and 330 feet for horizontal wells, with other standard rules for horizontal wells, including no perf zones (NPZ) and a 50-foot box rule for horizontal wells.

Rule 3: The standard proration unit established to be 160 acres with 80-acre tolerance, and proration acreage assignable to a horizontal well of effective lateral length multiplied by 0.15 plus 160, ($A = L \times 0.15 + 160$), which is consistent with the density formula adopted in the Hartley West (Canyon) Field which the subject field rules were modelled after.

Rule 4: Daily oil allowable for a well in the field determined based on the 1965 Yardstick Allowable of 353 barrels of oil per day and the actual allowable for an individual well to be determined based on 95% acres and 5% per well.

Rule 5: Special provisions for stacked lateral horizontal drainhole wells.

Field Rules for a Nearby Field in the Same Formation

The basis for the new field discovery for the Bivins Lit (Canyon Lime) Field was that there was no production from the correlative interval within 2.5 miles of the discovery well for the field. The closest distance between a Hartley West (Canyon) Field completion and a Bivins Lit (Canyon Lime) Field completion is around 3 miles, as these two field have grown relatively close together.

Apache proposed mirroring the temporary field rules for the Bivins Lit (Canyon Lime) Field after the Hartley West (Canyon) Field in Hartley County, which contains a similar stratigraphic interval. The Hartley West (Canyon) Field was discovered a few years before the Bivins Lit (Canyon Lime) Field. The main difference between the Bivins Lit (Canyon Lime) Field and Hartley West (Canyon) Field is that the Hartley West (Canyon) Field has a broader field interval that includes the clastic Granite Wash facies and the Strawn, however, the two field have the same field interval top. For these reasons, the temporary field rules for the Bivins Lit (Canyon Lime) Field were modeled after the Hartley West (Canyon) Field rules. The Hartley West (Canyon) Field was considered an analog field to the subject field and the field rules for the Hartley West (Canyon) Field are still in effect for that field today.

Bivins Lit (Canyon Lime) Field Production

Field-wide production for the subject field using Drillinginfo data through early January 2018 shows cumulative production of about 1.1 million barrels of oil (MMBO), although Mr. Clark believes the cumulative production for the field is now closer to 2 MMBO, and the well count is approximately 20 wells. Mr. Clark estimates the monthly field production to be almost to 30,000 BO and a couple hundred thousand cubic feet of gas per month.

Wells Drilled in the Bivins Lit (Canyon Lime) Field

Of the approximately 20 wells that have been drilled in the subject field to-date, all are operated by Apache with the exception of two wells that are operated by Le Norman Operating LLC. Only one vertical well has been completed in the field, the Bivins-Lit Lease, Well No. 1101. The production of this well shows why this field is not a vertical play: an initial potential (IP) test conducted on February 15, 2014 resulted in 28 BOPD, 17 Mcfd gas, and 11 barrels of water (bwpd). Cumulative production through March 31, 2018 for this vertical well is 1,217 BO and 2,858 Mcf gas.

IP test results on horizontal wells completed in the field show variability in the producing rates of wells, from a couple hundred BOPD to almost 1,600 BOPD. Mr. Clark maintains that there are several reasons for the variation in well performance. Although all of the wells have been hydraulically fracture-stimulated, Mr. Clark represents that there are also natural fractures in this field. Along a given section of lateral there is a large degree of variability in the intensity, extent, and number of natural fractures. According to Mr. Clark, another source of variability in well production is that some wells have been drilled too close to each other, have interfered with each other, and this between well communication could be causing a decrease in production from some of the wells.

A review of the field development to date shows the older horizontal wells in the field were drilled on a north-south azimuth, while the more recent wells have been drilled on a more southwest to northeast trending azimuth. In Mr. Clark's opinion, the change in drilling azimuth is a result of analysis of the natural fractures in this reservoir and indicates that Apache has been trying to drill as close to perpendicular to the natural fractures as possible and in the direction that hydraulically induced fractures are going to propagate.

Mr. Clark's testified that operators are still in the experimental stage of exploration and development of this field. Apache is drilling new wells farther apart from existing production, drilling longer laterals, and stimulating the wells more heavily (an increase in the pounds of proppant per foot of lateral length). On average, well completions in the field show laterals have been drilled to a length of approximately 5,000 feet and completed in 20 to 25 frac stages with roughly 6 to 7 million pounds (lb) of proppant. The well cost is roughly $10 million to drill and complete. The most recent Apache wells completed in 2018 include the Bivins East 430, Bivins Lit 6201 and the Bivens Lit 1011H. The completions for these wells show Apache has increased the lateral length and also increased the amount of proppant per foot of lateral, indicating that Apache is moving towards longer laterals and more heavily hydraulically fracture-stimulated completions.

Well Spacing Studies

Apache has experimented with between well spacing since the discovery of the subject field. Apache conducted a 600-foot between well spacing study with the Bivins East "41" wells, and according to Mr. Clark, Apache was disappointed with the results. Apache also did a study in the area of the Bivins East "93" wells on 1,200-foot between well spacing, and that well spacing also appeared to be too close, causing communication between wells. More recently, Apache has drilled wells a greater distance from existing production.

600-Foot Between Well Spacing Results

The Bivins East 4101H well ("BE 4101H") was drilled on a north-south azimuth and completed in April 2014. Approximately one year later, the BE 4102H, 4103H, and 4104H were completed. These three wells (BE 4102H, 4103H, and 4104H) were drilled roughly 600 feet apart on a northeast-southwest azimuth (Attachment A). The closest of these three wells to the existing BE 4101H well is the BE 4102H, which is located 1,126 ft from one end of the BE 4101H lateral and 2,560 feet from the other end of the lateral. The BE 4101H had been producing for roughly a year, and its production showed an immediate drop in oil production and a large increase in water production when the BE 4102H, 3H and 4H were hydraulically fracture-stimulated. Apache identified a frac hit on the BE 4101H.

Mr. Clark defined a frac hit as communication, when you pump water into a well that is being hydraulically fractured-stimulated and that frac water is then recovered in an offset producing well. As a result of the frac hit, the BE 4101H saw an increase in water production from approximately 200 bwpd to over 1,000 bwpd, while the oil rate dropped from roughly 100 BOPD to less than 40 BOPD. In Mr. Clark's opinion, there is no question that these wells communicated. Apache did not run tracer on these wells, but from production characteristics, the hydraulic fracture-stimulation of the BE 4102H, 4103H, and 4104H wells did communicate with the existing BE 4101H at a distance of 1,126 feet to 2,560 feet away. Based on this evidence, Mr. Clark concluded that these wells are spaced too close together. Mr. Clark stated "You would not want to see communication between wells at this stage of field development."[1]

1,200-Foot Between Well Spacing Results

Apache investigated between-well spacing of 1,200 feet in an area of the previously drilled and completed Bivins East ("BE") 94-1H well by the drilling of the BE 93-2H, 93-3H, 93-4H, and 93-5H wells to the east of the BE 94-1H.[2] The BE 94-1H was completed on May 22, 2014, while the BE 93-2H, 93-3H, 93-4H, and 93-5H wells were completed between January 21 and 26, 2015. The nearest well to the BE 94-1H that was being hydraulically fractured stimulated was the BE 93-2H, which ranged in distance from 2,010 feet to 4,400 feet from the BE 94-1H (Attachment B).

Tracers injected during the hydraulic fracture-stimulation of the BE 93-2H, 93-3H, 93-4H, and 93-5H were recovered in the BE 94-1H. The tracer injected in every stage of the BE 93-2H, 4H, and 5H completions was recovered in the BE 94-1H well, whereas only tracer injected into the heel stages (Stages 20-24) of the BE 93-3H completion communicated with the BE 94-1H.

Changes in the BE 94-1H daily production rate was another indicator of frac hits and communication between the BE 94-1H and the hydraulic fracture-stimulation of the BE 93-2H, 93-3H, 93-4H, and 93-5H. The daily production for the BE 94-1H up until late-2014, when Apache started hydraulically-fracture-stimulating the BE 93-2H, 93-3H, 93-4H, and 93-5H wells was a very defined production trend. When the offset wells were hydraulically fracture-stimulated, a large increase in water production in the BE 94-1H occurred after those frac events. The daily water production for the BE 94-1H water increased from about 200 bwpd to over 1,000 bwpd, while the oil production dropped from about 150 BOPD to 20 BOPD. Later, the BE 94-1H production did start to approach the previous production rates in early 2015, up until the completion of the offset Quanah 95-1H later in 2015.

On August 4, 2015, the Quanah 95-1H well, located 1,260 feet to the west of the BE 94-1H well, and essentially parallel, (on the same north-south azimuth), was hydraulically fracture-stimulated and a frac hit was observed on the BE 94-1H well.

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[1] Tr. pg. 46, ln 4-5.

[2] Note: the BE 94-1H, 93-2H, 93-3H, 93-4H, and 93-5H are also referred to as the 9401H, 9302H, 9303H, 9304H, and 9305H, respectively.

Initially, both oil and water production increased in the BE 94-1H, but within a few months, both oil and water production began to decline sharply, and within 12 months after the completion of the Quanah 95-1H, oil production from the BE 94-1H was less than 10 BOPD. In 2016, the BE 94-1H died unexpectantly with oil going to essentially zero. The Canyon Lime zone was shut-in on the BE 94-1H on June 5, 2017 and the well was recompleted up-hole in the Wolfcamp Formation in the vertical portion of the wellbore. The BE 94-1H is the only horizontal well that has been drilled and completed in the subject field that is no longer producing from the subject field.

Mr. Clark contends that by hydraulically fracture-stimulating the Quanah 95-1H, and the BE 93-2H, 93-3H, 93-4H, and 93-5H, the fracture conductivity in the area of these wells was improved. However, in comparing the estimated ultimate recovery (EUR) for the Bivins East 94-1H prior to the adjacent wells being hydraulically fracture-stimulated to the actual ultimate recovery, a higher EUR would have been estimated than what the well actually produced before this well was recompleted up-hole. Mr. Clark believes that the adjacent wells stole reserves from the BE 94-1H well in communicating with the well. Mr. Clark stated,

> "I believe the ultimate recovery of the 94-1H was hurt by the offset completions. So those wells were drilled too close. They fracked. They communicated. Certainly they increased the overall production of the area but at a cost of $10 million a pop. I'm going to show you why I think those wells should not have been drilled. I mean, it's obviously a learning curve, but why the 93 wells should not have been drilled so close on subsequent exhibits."[3]

Decline Curve Analysis

Example 1: BE 94-1H and the BE 93-2H, 3H, 4H, and 5H (Section 93 wells)

Mr. Clark asserts the ultimate recovery of reserves from the BE 94-1H were hurt by the completion of the offset BE 93-2H, 3H, 4H and 5H, and the completion of the Quanah 95-1H. Based on an analysis of the monthly decline curve for the BE 94-1H, in late-2014 before the Section 93 wells and the Quanah well were hydraulically fracture-stimulated, the decline curve was a well-established trend. Prior to the offset completions Mr. Clark would have an EUR of almost 259.14 thousand barrels of oil (MBO) based on a hyperbolic decline projection out to an economic limit of 90 BO per month from the Canyon Lime interval. In actuality, when the well was abandoned from the Canyon Lime zone in mid-2017, the cumulative oil production of 125.14 MBO is what the well actually produced from the Canyon Lime interval and is the actual ultimate recovery from the Canyon Lime formation. The difference between the estimated EUR based on the original decline curve prior to hydraulically fracture-stimulating the offset wells and what the 94-1H actually produced is a decrease in the amount of 134,580 BO, which is the amount of

[3] Tr. pg. 52, ln 24 – pg. 53, ln 8.

additional oil Mr. Clark represents the 94-1H would have recovered had the offset development not occurred.

In addition to negatively impacting the 94-1H, the offset BE 93-2H, 3H, 4H, and 5H wells that were drilled and completed on 1,200-foot spacing are all fairly poor wells. The EUR for the BE 93-2H is 64.72 MBO and this well is already down to a monthly production rate of 200 BO per month, and at a cost of $10 million to drill and complete, this well is not going to pay out at $60 oil. The BE-93-3H has an EUR of 87.73 MBO, which is already below the economic limit of 90 BO per month, and is also a fairly poor well. The BE 93-4H is in a similar situation, with an EUR 40.74 MBO and a production rate below 90 BO per month, while the EUR for the 93-5H is 53.18 MBO. All of these Section 93 wells came on-line at the same time, and in Mr. Clark's opinion, these wells on 1,200-foot spacing were clearly drilled and completed too close together.

Example 2: Bivins East 99-1H and Bivins East 98-2H at 3,180 ft to 5,800 ft Spacing

In contrast to the Section 93 wells on 1,200 foot spacing that were very poor wells, Mr. Clark considers the Bivins East 99-1H (BE 99-1H) to be a very prolific well. The BE 99-1H has already produced 503 MBO and 1.3 billion cubic feet (Bcf) of gas, with an EUR in excess of 800 MBO and 2.1 Bcf of gas. The BE 99-1H was completed March 16, 2015. The Bivins East 98-2H was completed January 22, 2017. These two laterals were drilled on different azimuths, and the wells are roughly 3,180 feet apart at the closest point and 5,800 feet apart at the furthermost point perpendicular to the BE 99-1H (Attachment C).

The BE 99-1H was already drilled and completed before the BE 98-2H was completed. Chemical tracer was injected in the BE 98-2H when the well was completed, and the chemical tracer was measured in the BE 99-1H, indicating that these two wells did communicate. The tracer communication was observed at the toe stage of the BE 98-2H, which is approximately 5,800 feet from the BE 99-1H and not the heel, which is closer at 3,180 feet, which is not what one would expect. This is one of the reasons why Mr. Clark concludes that there are natural fractures contributing to production in this area. Mr. Clark believes the natural fractures are more developed toward the toe area at the location of the BE 98-2H and less developed toward the heel, because one would expect the heel, being closer to the 99-1H to have communicated, but did not, whereas the toe stage, which is further away, at about 5800 feet, did communicate. Based on the tracer results, Mr. Clark concluded that the wells are definitely in partial communication over certain stages, and the well communication between these two wells at greater distances between the laterals and not at the shortest distance is attributed to natural fracture development in the area.

The BE 99-1H had been on production for roughly two years at the time the BE 98-2H was completed. In addition to the tracer results, communication between these two wells is also observed in the well production. Immediately after the BE 98-2H was completed, a very large increase in the daily water production rate was measured in the BE 99-1H, from less than 100 bwpd to about 300 bwpd. According to Mr. Clark, this confirmed what the chemical tracer showed, and six months later, the water production in the BE 99-1H was still higher than it was prior to the frac of the BE 98 2H. Mr. Clark's conclusion based on the data, is that these two wells were in communication during stages of the hydraulic fracture-stimulation of the BE 98-2H.

In Mr. Clark's opinion, another indicator of well communication between the BE 99-1H and BE 98-2H is a difference in gas-oil ratio (GOR). The BE 98-2H encountered a significantly higher GOR than the BE 99-1H, which was not expected. Mr. Clark attributes the difference in GOR to the BE 98-2H location being partially depleted (in terms of reservoir pressure) at the time the well was drilled. The reservoir pressure at the location of the BE 98-2H was partially depleted by the production from the BE 99-1H, which indicates to Mr. Clark that these two wells are not only in hydraulic fracture communication, but in long-term production communication, at least partially. There is nothing else in the vicinity of those two wells that would account for that reservoir pressure depletion other than production from the BE 99-1H.

Based on the evidence, Mr. Clark concludes that the BE 99-1H and the BE 98-2H are definitely in production communication, at least partially, due to the tracer survey, well production, and GOR evidence. Mr. Clark stated,

> "So there's probably some production between the two wells that is not in communication, but only time will tell if it's going to justify drilling a $10 million well between these two wells to recover any remaining reserves after these two wells have depleted the reservoir with their production."[4]

On cross examination, Mr. Clark stated that he does not have any direct reservoir pressure measurements for wells in the field. Mr. Clark acknowledged that it is possible to see a higher GOR in an offset well due to the well being in a higher gas content area of the field as opposed to depleted pressure from original reservoir pressure.

Example 3: Bivins East 43-1H and Bivins East 41-3H

One of Apache's more recently drilled and completed wells is the Bivins East 43-1H (BE 43-1H), which was drilled in 2017 and completed in 2018. Apache located this well a greater distance away from existing wells to investigate whether there would be any between well communication. Apache drilled the BE 43-1H roughly 5,200 feet to almost 5,900 feet away from the existing Bivins East 41-3H (BE 41-3H). When Apache hydraulically fracture-stimulated the BE 43-1H, an immediate change in the oil production rate was observed in the BE 41-3H, as oil production dropped from roughly 80 BOPD to about 30 BOPD. This immediate change in oil production indicated to Mr. Clark that these two wells were in hydraulic fracture communication during the stimulation of the BE 43-1H. At the same time. the water production rate increased in the BE 41-3H, but not as drastically as the drop in oil rate.

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[4] Tr. Pg. 64, ln 13-18.

Well Spacing Summary

In summary, Apache is experimenting with well spacing in the subject field. Apache has drilled and completed wells with 600-foot spacing and experienced communication at 1,200-foot well spacing Apache also experienced communication. More recently, Apache experimented with greater than 5,000-foot spacing, and still observed a little communication, with the distance between two wells ranging from 5,220 feet to 5890 feet.

On cross examination, Mr. Clark stated that he didn't mean to imply anything by saying "a little communication." Mr. Clark clarified that there is production communication between the wells. Mr. Clark acknowledged that there is no reservoir pressure information on these wells.

Drainage Area Estimate

Mr. Clark estimated drainage area by examining the interaction and distance between the BE 98-2H and the BE 99-1H. The BE 98-2H frac hit the BE 99-1H well during hydraulic fracture-stimulation at distances ranging from roughly 3,180 feet to 5,800 feet. In Mr. Clark's opinion, the results of the tracer survey and production interference showed that the 98-2H and 99-1H wells are in pressure or production communication. These two wells are not drilled on the exact azimuth, the BE 99-1H is more southwest to northeast whereas the BE 98-2H is more north-south, but there is roughly 4,000 feet between these two wells. If the BE 99-1H is draining 4,000 feet in one direction Mr. Clark believes it is reasonable to assume the well is also draining 4,000 feet in the opposite direction, so there is a box of approximately 4,000 feet on both sides of the 4,867 foot lateral. Calculating this area and converting to acres yields a drainage area of around 900 acres. In Mr. Clark's opinion, the acreage allocation formula that was previously approved in the temporary field rules for the subject field is supported by this drainage calculation. Mr. Clark maintains that it is appropriate to continue the temporary field rules for the subject field at this early stage in the field development, including the horizontal well allocation acreage formula of $A = L \times 0.15 + 160$.

Apache has experimented with different between-well spacing and has encountered well communication on 600-foot between well spacing, 1,200-foot between well spacing, and have also experienced communication between wells as far away as 5,000 feet. In Mr. Clark's opinion, at this stage of field development it is reasonable to assume that wells are draining over these large areas. Understanding that hydraulic fracture-stimulation communication does not necessarily translate to long-term production communication because it's stimulated reservoir volume and hydraulic fracture lengths, as well as natural fractures that are going to determine long-term production. Mr. Clark asserts that if you were to drill a well between the 99-1H and the 98-2H right now, that well would take reserves from both the 99-1H and 98-2H, and each well costs $10 million to drill and complete.

On cross-examination, Mr. Clark defined a frac hit between two wells as production communication between the two wells. Mr. Clark acknowledged that it is unknown whether that pathway between the wells stayed open after the frac stimulation concluded. Mr. Clark does not agree that in the development of unconventional reservoirs, it is necessary to see frac hits in adjacent wells to know that you are close enough to drain all of the reserves. At this stage of field development, Apache is drilling wells at greater distances away from existing wells in an effort to avoid frac hits between wells.

On re-direct examination, Mr. Clark stated that frac hits and the communication observed from those frac hits is just one of the examples of communication between wells. Additional supporting evidence includes long-term production communication and differences in GOR.

In Mr. Clark's opinion, the matrix permeability of the Canyon Lime reservoir is very low, however, the natural fractures provide a significant flow conduit. Mr. Clark compares this interval to the Austin Chalk in that there is a dual porosity system, there are natural fractures that provide great conduits for production and there is matrix rock that is very low permeability. The shale content varies in the field, there are places where there is almost a clean limestone and there are places that are largely shaley. Mr. Clark would characterize the reservoir as anything from a clean carbonate to a shaley lime to 100% shale.

On cross examination, Mr. Clark confirmed that he believes the 41-2H, 41-3H, and 41-4H were drilled too close to one another. As far as the acreage assigned to each well, (880 acres for the 2H, 940 acres for the 3H and 960 acres for the 4H), the maximum acreage per the field rules is assigned to each well, which Mr. Clark considers to be a common practice. Based on the spacing of these three wells, Mr. Clark estimates that the middle well, the BE 41-4H, spaced 616 feet from the BE 41-2H and 570 feet from the BE 41-3H, is draining half-way to each of those wells since there is probably a no-flow boundary between the wells. The no-flow boundary is going to be created by production interference between the wells. At well spacing of approximately 600 feet the middle well will drain 300 feet on either side of the lateral; multiplying this by the length of the lateral and converting to acres would yield approximately 80 acres.

On re-direct examination, Mr. Clark stated that he would not reduce the acreage allocation for wells in the field for density purposes based on the poor wells in the field. Furthermore, Mr. Clark contends the poor wells are due to man-made, no flow boundaries as opposed to natural reservoir boundaries. The no-flow boundaries were created because the wells were drilled too close to each other. Mr. Clark believes the wells would have drained a greater distance from the wellbore, for example, if only one of the wells had been drilled. Mr. Clark would base the acreage allocation formula on the better wells that are draining greater areas at this stage in the field's development.

<u>Bivins Family Royalty Evidence</u>

Introduction

Bivins consists of mineral owners of both unleased minerals and of minerals that are subject to the Apache lease and to other leases. Bivins has compelling interest in the temporary field rules both as an unleased mineral owner and as a royalty owner who believes its Lessee is not properly representing their interests in the temporary field rules for the efficient and effective development of the Bivins Lit (Canyon Lime) Field. Bivins' position is that field rules should be based on available relevant technical evidence.

Bivins Proposed Changes to the Temporary Field Rules

Tim Smith, P.E., a consulting petroleum engineer designated as an expert in petroleum engineering, reviewed the existing temporary field rules for Bivins and has recommended changes for the temporary field rules on behalf of Bivins.

There are two rules where Mr. Smith recommends changes to the temporary field rules for the Bivins Lit (Canyon Lime) Field:

1) Rule No. 3 related to the standard proration unit size and the formula in which additional acreage can be assigned to horizontal drainhole wells.

2) Rule No. 4 related to the method used to determine the oil allowable for a well in the subject field.

In Mr. Smith's opinion, the formula in the current temporary field rules provide for proration units that are large compared to what wells can effectively drain. In the absence of data to show what wells can drain, other metrics such as analogies to other fields and other field rules should be used for guidance. According to Mr. Smith, the field rule that provides for large proration sizes is not based on what wells will effectively and efficiently drain, but the large proration unit size is necessary to seek an allowable to cover flush production. Therefore, Mr. Smith proposes to change the field rules for both the well allowable and density size. Mr. Smith maintains that the field rules proposed by Bivins will prevent waste in this field.

Field Rule No. 3: Acreage Assigned to an Individual Well

Mr. Smith represents that a standard proration unit size of 80 acres as opposed to the current field rule of 160 acres is supported. In Mr. Smith's opinion, 80-acres is frequently recognized in resources plays to avoid waste or creating gutters along lease-lines where hydrocarbons go unrecovered. Technically, based on rock mechanics, on analogy, and based on adopting 330-foot lease line spacing with predominantly 5,000 foot laterals in the field at this time leads to the recommended 80-acre density.

The second recommended change to field rule No. 3 is the method used to assign additional acreage to horizontal wells. Bivins' proposes two alternatives, A and B, to the current method:

Alternative A: Area equals the length of the lateral between first and last take points, multiplied by a factor of 0.048, plus the base density unit of 80 acres (A = L x 0.048 + 80).

Alternative B: Use the table in Statewide Rule 86 for assigning additional acreage. This method is utilized in many fields, including fields in the Eagle Ford.

In Mr. Smith's opinion, lowering the base proration unit size from 160 acres to 80 acres is consistent with 330-foot lease line spacing. With incremental acreage to be assigned to horizontal wells by either Alternative A or B would allow operators the flexibility to learn and apply technology. Mr. Smith claims that the field rule provisions proposed by Bivins will promote the efficient effective oil development in the field, and Bivins' proposed field rules are a much more sensible approach to avoiding confiscation.

Mr. Smith alleges that for a 5,000-foot lateral, a proration unit size of 320 acres would be more than sufficient, based on nano-permeability rock shale development through hydraulic fracture-stimulation in considering what the conductive stimulated reservoir volume may be. With Bivins proposed formula (Alternative A), a 10,000-foot lateral would result in a proration unit size of 560 acres.

In comparing Bivins' proposed formula (Alternative A) to the Statewide Rule 86 Table (Alternative B), operators in the field would be able to assign a maximum proration unit size of 360 acres for a 5,000 foot lateral and 600 acres for a 10,000 foot lateral. These areas are 40 acres greater than calculated using the Alternative A formula. In Mr. Smith's opinion, the table in Statewide 86 was developed for the purpose of handling the learning curve and changes in technology during the temporary field rule period.

Mr. Smith testified that Bivins proposed 80 acre base proration unit size and Alternative A and B provide a sufficient density rule and either alternative is sufficient to guide development for the next 18 months, at which time the temporary field rules can be reviewed to see what is happening regarding actual field development. Mr. Smith does not have an objection to a two-year time period for the temporary field rules as proposed by Apache as opposed to 18 months. What would be important would be to drill wells, get data, and see how the field rules can be improved, if needed. Mr. Smith acknowledged that development is going to be affected by oil prices and what commercial conditions are and whether it makes good sense to drill wells during the two-year period.

Frac Hits vs. Conductive Stimulated Reservoir Volume (or Effective Propped Volume)

Mr. Smith does not believe a density rule in a field should be set in order to eliminate frac hits. In Mr. Smith's opinion, frac hits are something that the industry has to deal with, but density rules for field rules should not be based on the extent of what a frac hit would be, which could be a mile. Mr. Smith stated, "The chemical tracer data that we said is a reflection of a frac hit or that there's communication a certain distance, but it's not a reflection of what the conductive stimulated reservoir volume is. That gets exacerbated if you have an environment such as it appears that the Canyon Lime is where there is some natural faulting or natural fractures that are before we ever induce the hydraulic fractures." The mechanics of hydraulic fracturing in these ultra-low permeability reservoirs is that frac lengths may be quite far, but what's important is the propped frac length after the frac pressure is released and the well starts to produce. Whether there is conductivity with the reservoir requires proppant in the hydraulic fractures created to be propped open, because the fractures can close and they can heal. In addition, it is not just a function of having proppant in the fracture, there must be a sufficient volume of proppant in the fracture to keep it open.

According to Mr. Smith, a frac hit indicates that there is hydraulic communication between wells but does not indicate a conductive reservoir. The tip of a hydraulic fracture can create communication between wells, and the fracture tip can reach long distances, but the fracture tip is not propped open after the hydraulic fracture-stimulation treatment is stopped, hydraulic pressure downhole is released, and fractures start to close and heal. The important aspect is the drainage area, and that is what is called the conductive stimulated reservoir volume or the effective propped volume (EPV), which is a small subset of the hydraulic fracture created.

Mr. Smith acknowledges that if there is hydraulic communication between wells it can be confirmed with chemical tracers. However, what cannot be confirmed is, what was effectively propped after the frac pressure is released. Chemical traces indicate the extent of the tip of the fracture but does not tell us what the ultimate drainage area is going to be. In this case, pressure information is not available to determine the pressure sink emanating out from the horizontal laterals to represent the drainage area. In Mr. Smith's opinion, looking at the chemical tracer frac hits is not a good way to determine the drainage area of the well. The chemical tracer results represent what you have hydraulically communicated, but it's not showing what the ultimate conductive, effective propped volume is after the pressure is reduced and the well starts to produce, which is the drainage area.

When the first completed well in an area or "parent" well has been on production for a period of time, there is a diminishment of reservoir pressure in the conductive stimulated reservoir volume of this well. When hydraulically fracture-stimulating subsequent or "child" wells nearby, the induced fractures tend to seek and find that pressure sink. According to Mr. Smith, in some cases, a frac hit from a child well to a parent well could result in a little uplift in production to the parent well, and in some cases a frac hit could result in a decrease in production to the parent well. Mr. Smith stated,

> "In more cases there's damages to it. So very frequently when there's a frac hit there's a diminishment in production to the parent well that doesn't mean there's a depletion of the zone. It may mean that there's actual physical damage and there's a number of theories on why that's happening. For some of my clients who are struggling with this they accept it as a reality of unconventional resource development. They have to put their wells on certain spacing to get the reserves out. They're going to encounter frac hits and where there's a parent/child where the parent is older, they know they are going to lose the well and they accept that. When we look at what happens in those wells mechanically, we frequently find a lot of fluid. There will be a huge increase in water production just like Mr. Clark's graph showed. There will be sand that gets knock(ed) into the wellbore and plugs it up, and sometimes those wells don't come back. Sometimes they can come back."[5]

In response to a question as to whether a frac hit that affects a well's production necessarily means drainage to the new well, Mr. Smith stated, "No, and that's an important point. When there's a frac hit there can be damage to production from a well but it doesn't mean that the child well is draining all the way to the stimulated reservoir volume of the parent well, and that's a very important point."[6] Mr. Smith did not see any evidence in his study to support a 900-acre density size in the subject field.

Current Proration Unit Density Rule

The proration schedule for the Bivins Lit (Canyon Lime) Field shows that the average proration unit size is 911 acres. In Mr. Smith's opinion, the proration unit density formula in Rule No. 2 of the current field rules provides for large proration units. Mr. Smith acknowledges that in unconventional reservoirs for temporary field rules purposes, there is a learning curve, but there have been advancements in technology even over the last two years since the temporary field rules were adopted that are changing the manner in which wells are completed, resulting in changes in well performance.

Based on the basic math and geometry, a 920-acre proration unit size would require a horizontal lateral of 5,200-feet of drainage along the lateral, and a drainage width of 3,850 feet on each side of the lateral. Mr. Smith concludes that this means reservoirs are being created on 330-foot spacing that is going 3,500 feet over the lease line. In Mr. Smith's opinion, the simple math behind the proration unit size is not consistent with what is happening in the field and what development is being proposed for development by Apache, and the actual 1,200-foot between well spacing and the 600-foot between well spacing that is currently in the field.

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[5] Tr. pg. 152, ln 20 – pg. 153, ln 14.
[6] Tr. pg. 153, ln 18 – 22.

Field Rule No. 4: Daily Oil Allowable for Wells in the Subject Field

Bivins proposes a field rule for oil allowable of 1,000 BOPD for a 40-acre proration unit size and 2,000 BOPD for an 80 acre proration unit size. Bivins also proposes an unlimited net GOR for the field since each well is in its own reservoir and there is no technical basis to restrict wells to a 2,000:1 GOR. In Mr. Smith's opinion, each well is its own reservoir and there are no waste issues, and there is no reason to constrain the wells to create an artificial limit on oil production or to worry about gas volumes associated with oil production.

Mr. Smith stated Bivins would agree with a higher BOPD than the 2,000 BOPD per 80-acre base proration unit size if Apache would prefer a higher number. Assigning the allowable in this manner would stop constraining the allowable to the 1965 Yardstick and the number of acres assigned, which requires the assignment of massive proration units that are not supported by what wells will effectively and efficiently drain. Mr. Smith believes the proposed allowable assignment proposed by Bivins is solved by the proposed field rule.

The initial potential (IP) test rate for the Bivens East 9302H was 1,593 BOPD, which was one of the highest test rate wells in the field. To get an initial allowable based on that rate using the current field rules would require assigning 760 acres to the well. According to Mr. Smith, landmen with Bivins have represented that the proration unit sizes in the subject field are large in order to cover the oil allowable. To rectify this, Mr. Smith proposes adopting field rule provisions that are representative of what wells will effectively and efficiently drain and proposes assigning an oil allowable based on a BOPD per base proration unit size as has been adopted in other unconventional fields.

Supporting Evidence for Bivins Proposed Field Rule Changes

With regard to the geology of this field, Mr. Smith believes that the reservoir rock in the field is predominantly ultra-low permeability, and would characterize this reservoir as a shale-type reservoir. In order to establish commercial production in the field, it is necessary to drill laterals and engage in multi-stage hydraulic fracture-stimulation treatments as shown in other unconventional resource plays in North America. Mr. Smith stated,

> "Like other unconventional resource plays, the Bivens Lit (Canyon Lime) is what I would call a continuous hydrocarbon accumulation....the reservoirs here -- and I define reservoir as storage capacity and flow capacity -- are man-made. So what that means is, we create these reservoirs by engaging in hydraulic fracture-stimulation, and what we end up with basically is one well per reservoir. So each well is in its own reservoir."[7]

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[7] Tr. pg. 116 ln 21 – Tr. pg. 17, ln 8.

Apache's Existing Well Spacing in the Bivins Lit (Canyon Lime) Field

In Mr. Smith's opinion, Apache has attempted to look at spacing issues in the field based on how Apache is actually spacing wells. The Bivins East 41 series, (Bivins East 4102H, 4103H, and 4104H) are on more or less 600-foot spacing. The 93 series wells (Bivins East 9302H, 3H, 4H, and 5H) are more or less on 1200-foot spacing. To the west of 93 series wells, the Quanah 9501H well is approximately 1,300 feet from the Bivins East 9401. Mr. Smith notes that Apache has delineated between an upper and a lower target interval, and the Quanah 9501H is not landed in the same depth interval of the Bivens Lit Canyon horizon as Bivens East 9401H. However, based on Apache's evidence, when the Quanah 9501H was hydraulically fracture-stimulated it frac hit the Bivens East 9401H which indicates the upper zone and the lower zone are in communication during the fracture-stimulation.

Mr. Smith does not consider a frac hit between wells completed in the upper and lower zones in the field to be a problem, Mr. Smith considers it useful. A frac hit is something that is discussed when talking about hydraulic communication between wells. Mr. Smith considers fracture communication to be useful information, as the more frac height and the more of the pay zone that can be encountered with hydraulic stimulation, the better.

Based on Apache's actual development in the field, there is nothing that indicates to Mr. Smith that Apache believes these wells should be spaced on 7,000-foot spacing. The objective is to space wells to recover all the hydrocarbons while not spending $20 million to recover hydrocarbons that you can recover by spending $10 million. The current well spacing in the field suggests that for right now there's an acceptance of a possible conductive stimulated reservoir volume half-length of 600 feet.

The South Texas Eagle Ford

Mr. Smith used the South Texas Eagle Ford as an analogous field to the Bivins Lit (Canyon Lime) Field, as Mr. Smith claims there are some similarities between the two fields. For example, Mr. Smith considers the South Texas Eagle Ford to be a calcareous-type geologic formation. There has been a significant amount of drilling development and analysis of what the conductive stimulated reservoir volume is in the South Texas Eagle Ford. Operators are measuring stimulated reservoir volumes and wells are spaced reasonably close. When wells are hydraulically fracture-stimulated in that field, there are frac hits on every stage on all wells on the same pad. Mr. Smith stated, "You want to drill wells so that you don't waste hydrocarbons and you recover everything under your lease or unit, but you don't want to drill wells such that one well would recover the same thing as another well, and therefore you spend 20 million to recover those reserves instead of 10."[8]

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[8] Tr. pg. 142, ln 7-12.

The Eagleville (Eagle Ford-1) Field is one of the fields Mr. Smith looked at as a potential example field for the Bivins Lit (Canyon Lime) Field. In comparing the existing field rules for the two fields, the field rules for the Eagleville (Eagle Ford-1) Field contains the same lease line spacing of 330-feet and no minimum between well spacing. One difference between the Eagleville (Eagle Ford-1) Field and the subject field is the standard proration unit size. The standard proration unit size in the subject field is 160 acres whereas the standard proration unit size in the Eagleville (Eagle Ford-1) Field is 80 acres with optional 40 acre units. In Mr. Smith's opinion, 80-acre units with optional 40 acre units makes sense based on the lease-line spacing of 330 feet. Based on the math, if you assume 330 feet to be the half-drainage length, which equates to a 660-foot drainage area (330 feet on each side of the lateral), for a 5,000 foot lateral, the math works out to roughly 80 acres. Therefore, Mr. Smith asserts that the appropriate thing to do for the Bivens Lit (Canyon Lime) Field is to adopt a minimum standard proration unit size that is less than 160 acres.

On cross-examination, Mr. Smith acknowledged that for an oilfield, if a field has special field rules with 330-foot lease line spacing, it does not automatically mean that the density will be 80-acres, and the density field rules could be larger than 80 acres.

Another difference in comparison to the field rules for the subject field is that in the Eagleville (Eagle Ford-1) Field, additional acreage may be assigned to each horizontal drainhole in accordance with the table Statewide Rule 86. Mr. Smith maintains that the standard table Statewide Rule 86 (Bivins Alternative B), would be appropriate for the subject field as a means to provide incremental acreage beyond the standard units for the learning curve and for changes in technology during the temporary field rules period.

One last difference between the field rules for the subject field and the Eagleville (Eagle Ford-1) Field, is field rule No. 4. In the Eagleville (Eagle Ford-1) Field, the maximum daily allowable is determined by multiplying 8,000 BOPD by a factor that acreage assigned to a well exceeds the standard proration unit size allowed for a vertical well in the field. In addition, the Eagleville (Eagle Ford-1) Field has an unlimited gas-oil ratio. Mr. Smith contends that an unlimited net-GOR is also appropriate for the Bivins Lit (Canyon Lime) Field because in an unconventional, ultra-low permeability reservoir, each well is its own reservoir so there is no energy loss in other wells, or in a broader reservoir by producing gas in any single well. This unlimited net GOR is also a provision in the Hartley West (Canyon) Field.

On cross-examination, Mr. Smith stated that he has made an analogy to the Eagle Ford fields in South Texas because there is a lot of data available for these fields whereas there is very little data available for the subject field. Mr. Smith considers the Eagle Ford field to be a calcareous shale, similar to the subject field. Mr. Smith acknowledged that the Eagle Ford shale is not a Canyon Lime shale, and that the analogy made by Mr. Smith is the relation of shale and silt stone between the fields. Mr. Smith acknowledged that the Eagle Ford shale fields are in South Texas and the subject field is located in the Texas Panhandle.

An Apache, North American update from November 20, 2014, illustrated 800 total well locations in the Canyon Lime area as a development strategy, in addition to a reference of the testing of a hazard polygon in this area. Mr. Smith noted that the oil price dropped at the end of 2014, so operations may not have occurred on the same schedule as Apache would have anticipated at the time the study was prepared. However, Mr. Smith concluded that at the time the study was prepared, Apache envisioned 1,200-foot and 600-foot between well spacing for ultimate development of the field based on this 2014 report. The report also shows a hazard polygon which Mr. Smith believes is a faulted zone that would be drilled through, and there was some concern whether Apache could successfully, mechanically complete wells in the hazard polygon.

On cross-examination, Mr. Smith estimated that Apache had drilled 13 wells as of the report date of November 2014. Mr. Smith did not know how many of these 13 wells had been completed at the time of that case study. Some of the completion paperwork was filed with the Commission in early-2015 and there can be months of lag time in filing the completion paperwork. Mr. Smith agreed that 13 wells is a small number compared to the potential 800 wells illustrated in the November 20, 2014.

Other Canyon Lime Fields in the Area

Other Canyon Lime fields in the vicinity of the Bivins Lit (Canyon Lime) Field include the Hartley West (Canyon) Field to the northwest and southwest, and the Amarillo North (Canyon Lime) to the southeast. All three of these fields are correlative, notwithstanding the fact that they occur at different depths in the region.

There are fewer wells in the Hartley West (Canyon) Field as compared to the subject field, so Mr. Smith cautioned against using the Hartley West (Canyon) Field as an analog, as there is less information to be gleaned from the Hartley West (Canyon) Field as compared to the subject field. The Amarillo North (Canyon Lime) Field, located to the south and east of the subject field, has some horizontal well development and additional permitted well development.

Mr. Smith would also look to these Canyon Lime plays in the immediate area as part of the analogy review to help frame what rules are appropriate for the Bivins Lit (Canyon Lime) Field going forward as temporary field rules. The proration schedule for the Amarillo North (Canyon Lime) Field shows that the correlative Canyon Lime interval in this field is at a shallower depth as compared to the subject field. The Amarillo North (Canyon Lime) Field is on Statewide Rules and the field has been designated as a UFT field per Docket No. 01-0299858. Under statewide rules, the standard proration unit size is 40 acres and additional acreage may be assigned to horizontal drainholes pursuant to the table in Statewide Rule 86. A UFT field designation is something Mr. Smith recommends for consideration for the subject field.

The proration schedule for the Hartley West (Canyon) Field shows that the correlative Canyon Lime interval in this field is at a depth of 7,330 feet which is also shallower compared to the Bivens Lit (Canyon Lime) Field. The proration schedule shows the allocation formula for the field is A = (L x 0.15) +160, which is where this formula in the field rules for the subject field originated. It is this formula that generates 1,000-acre proration units in the subject field The proration schedule for the Hartley West (Canyon) Field shows 880-acres is assigned to the LS Ranch North Lease, Well No. 1642H, but the majority of wells listed on the May 1, 2018 proration schedule are assigned 160 acres. In Mr. Smith's opinion, the acreage formula in this field and the subject field results in the assignment of an excessive amount of acreage that is beyond what is needed for effective and efficient drainage.

On cross-examination, Mr. Smith acknowledged that the LS Ranch North Lease, Well No. 1642H is assigned the maximum acreage, or close to the maximum acreage allowed under the field rules. Mr. Smith noted the other wells in the field are assigned less acreage per well. Mr. Smith does not know why operators are not assigning as much acreage to other wells in the field and acknowledged that it is possible that 160 acres may be assigned to several wells in the field because the well is on a 160-acre lease thereby only allowing 160 acres to be assigned.

On cross-examination, Mr. Smith agreed that operators and the Commission should err on the bigger side of what wells will effectively and efficiently drain for proration units for temporary field rules. For example, the table Statewide Rule 86 allows for incremental acreage to be assigned to horizontal wells.

Bivins' Comments on Apache's Evidence

Mr. Smith considered the testimony of Apache's witness, Mr. Clark, that Apache was not happy with results of 660-foot well spacing to be broad and not clarified. Mr. Smith works with clients that have frac hits or damaged wells with frac hits that are not happy with that result either, but they are still going to develop on certain well spacings to maximize the recovery of hydrocarbons. In Mr. Smith's opinion, there should not be an assumption that frac hits are a reflection of drainage area.

There is typically a broad range of EUR outcomes in unconventional resource plays because operators are dealing with very heterogeneous reservoirs with complexity in terms of a number of variables in terms of organic content, thermal maturity, frac-ability, clay content, completion efficiency. Therefore, Mr. Smith would not jump to a conclusion where there is variability in production results that there are wells draining common reservoir. There are many other explanations to explain that variability, and that variability is anticipated.

Mr. Clark's testimony was that the Bivens Lease 93 wells were inferior wells. Mr. Smith's understanding of Mr. Clark's testimony was that these wells were inferior due to drainage by another well in the area. In Mr. Smith's opinion, there are many things that cause inferior performance of some wells and inferior performance between wells is expected. These wells are located in series, next to each other, and were completed at the same time, so it is speculation that these wells have diminished production because of drainage. Mr. Smith urged caution about drawing conclusions that relate to what the conductive stimulated reservoir is based on well performance.

Von Gonten Report

Bivins presented a copy of a report prepared by William D. Von Gonten, P.E. ("Von Gonten"), dated July 31, 2015. Mr. Smith described the purpose of Von Gonten's report to be a determination of drainage area that could be expected from future development in the Canyon Lime formation based on available data. In the report, Von Gonten used data that included petrophysical analyses, reservoir simulation, numerical simulation, frac modeling, and probabilistic analysis using volumetrics to determine what the conductive stimulated reservoir volume or drainage area would be for wells in the Canyon Lime formation, including the subject field.

In Mr. Smith's opinion, the importance of this report as it relates to the review of field rules in this case is that Mr. Smith did his work independent of Von Gonten's analysis and did not adopt this report as the basis for his opinions. Von Gonten estimated drainage area ranging from a minimum of 60 acres, to 84 acres as a maximum, with a range of recovery factors from 10% to 16%. Mr. Smith stated,

> "What Mr. Von Gonten says in his report that his range of recovery efficiencies 10 through 16 are based on his reservoir simulation and his own experience as to what recovery efficiencies are appropriate for unconventional resource development. So it is the result of a comprehensive study, but for the probabilistics it then manifests as data entry. I would say the same thing about his reservoir half-widths. He does other analyses, frac modeling and other things to determine how far out he thinks the conductive stimulated reservoir volume is, but once he has that range of possibilities he then incorporates that as a data entry into his probabilistic analysis. So in his problematic analysis he's confining what the reservoir is because he's already considered frac mechanics and all the geomechanics associated with reservoir creation through hydraulic frac stimulation. What he's doing this probabilistic analysis on are ranges of outcomes, ultimate recoveries, what is possible within that container."[9]

To evaluate how data collected after the date of the Von Gonten report may potentially affect the conclusions reached in the report, Mr. Smith did his own assessment of EURs using decline analysis and estimated recoveries are 20% higher than that in the Von Gonten report. Therefore, if you were to expand the drainage area, you could assume it to be 20% higher if you are using the Von Gonten report as a yardstick. In Mr. Smith's opinion, the analysis supports starting with a standard proration unit that is smaller in size than 160 acres. Not only does Mr. Smith's work match the Von Gonten work, which was done separately, but it makes sense to Mr. Smith because it matches the other rules such as the 330-foot lease line spacing.

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[9] Tr. pg. 194, ln 7 – pg. 195, ln 4.

The Von Gonten report does not contemplate what the appropriate amount of acreage is to allow for proration units, recognizing that this is in the early stages of development, and Mr. Smith agrees with the conclusions of Apache on that issue. 20 wells completed on a 30,000-acre position is not a lot, and there needs to be some running room for an oil and gas producer to learn a bit more and to let technology advance. In Mr. Smith's opinion, sometimes technology drives to closer well spacing, the well spacing should be based on frac hits and should be based on the amount of acreage wells will reasonable drain, and what incremental amount of acreage should be allowed as latitude for the learning curve for temporary field rules.

On cross-examination, Mr. Smith acknowledged that the Von Gonten report was based on production data for all Apache Canyon Lime wells through March 2015. Mr. Smith stated that it is hard to determine the number of wells that would be producing as of March 2015, due to the completion paperwork filing times, but estimated there could have been up to 10 wells producing at that time. There are approximately 20 wells in the field at this time, so when this report was issued it was based on 50% of the wells at best, compared to the number of wells in field at this time.

Apache's Rebuttal Evidence

During a midday break on the day of the hearing, Mr. Clark spoke with Apache regarding the future development labelled as Bates Number 00085, that Bivins used as evidence to show Apache had future plans to drill wells on 1,200-foot between well spacing. Mr. Clark stated that Apache has no plans on drilling these wells and these wells have never been permitted.

In Mr. Clark's opinion, the Von Gonten report presented by Bivins overpredicted the reserves for wells completed in the Bivins Lit (Canyon Lime) Field because Von Gonten did not take between well production interference into account. For example, for the BE 94-1H, Von Gonten predicted cumulative production of roughly 150,000 BO after 600 days and an EUR type curve of 314,000 BO. The actual EUR of the BE 94-1H is known with essentially 100% certainty because the well has been depleted in the Canyon Lime, plugged back, and re-completed up-hole in the vertical section of the wellbore in the Wolfcamp formation. The BE 94-1H well only produced 125,140 BO in the Canyon Lime. In Mr. Clark's opinion, Von Gonten predicting a much larger recovery of oil based on the early time data prior to between well interference. Well interference was not taken into account at the time the report was prepared because the actual ultimate recovery for this well is now known, and it is less than half of what Von Gonten predicted in his report. Mr. Clark does not believe Von Gonten had the well interference information when he made his report, which is dated March 2015, because the nearby BE 93-2H, 93-3H, 93-4H, and 93-5H wells were completed in January 2015.

Mr. Clark contends that Von Gonten did not consider between well interference for the BE 93-2H, 93-3H, 93-4H, and 93-5H wells that were drilled on 1,200-foot spacing and completed in early 2015. For these wells, Von Gonten predicted EURs ranging from

399,000 BO to 226,000 BO. The estimated 600-day cumulative production for Von Gonten's 399 MBO type-curve (P10) estimates in excess of 160,000 BO at 600 days, whereas the 305 MBO type curve (P50) would be roughly 150,000 BO at 600 days and the 226 MBO type curve (P90) would be 120,000 BO at 600 days. Apache's actual decline curves for these wells show these wells are almost depleted. In looking at the actual performance of these wells, they have already produced for over 1,000 days. The cumulative recovery for the 93-2H after 1,000 days is about 55,000 BO, and this well had the highest IP in the field. The 93-3H has produced about 88,000 BO, and the 93-4H has produced about 41,000 BO, while the 93-5H has produced about 51,000 BO. The actual production after 1,000 days of production is much less than the estimated cumulative production at 600 days in the Von Gonten report. The Von Gonten report type-curves have the EUR for these wells ranging from 226,000 BO to 399,000 BO. In contrast, Mr. Clark's EUR projections for each of these wells are all less than 100,000 BO.

Mr. Clark concluded that the actual production data upon which Von Gonten relied to prepare the estimates in the report would appear to be between zero and 60 days of cumulative production. In Mr. Clark's opinion, Von Gonten's estimated cumulative production extrapolations were reasonable at the time he prepared the report based on the zero to 60 days production data. Mr. Clark's testified that the wells started to interfere with each other production-wise and that's basically why Apache does not plan on drilling wells on 1,200-foot between well spacing.

On cross-examination, Mr. Clark stated that there is another possible reason other than well interference to explain why these wells did not perform as well as the Von Gonten report had predicted, but Mr. Clark believes it is due to well interference. Mr. Clark confirmed that he did not have reservoir pressure information for these wells, but these four wells, (BE 93-2H, 93-3H, 93-4H, and 93-5H) were all drilled and completed basically at the same time, and these wells took reserves from the BE 94-1H.

EXAMINERS' ANALYSIS OF THE EVIDINCE

Temporary Field Rule No. 3: Standard Proration Unit Size and Assigning Additional Acreage to Horizontal Wells

Based on the evidence, the Examiners conclude that the previously-adopted 160-acre standard proration unit size and formula for assigning additional acreage to horizontal wells is appropriate at this stage of field development for the continuation of the temporary field rules for an additional two-year period.

In discussing field rules, the Commission's historic publication, "*Discussion of Law, Practice, and Procedure*" Part I. Railroad Commission Field Rules, Section B. Documentary Evidence, (page 2) states,

> **"Where limited data are available because the field is in its early stages of development, a list of nearby established fields in the same**

formation, along with the Railroad Commission field rules for those fields, should be submitted as an exhibit."

Section C. Temporary Field Rules (page 3) states,

"The purpose of permitting field rule applications based on limited well data is to encourage development to delineate more rapidly the limits of the reservoir and to prevent the wasteful clustering of wells near the discovery well."

Whereas Section D. Permanent Field Rules (page 3) states,

"Permanent rules are established for a field only where adequate information is available to determine the drainage abilities of wells in the field.... Evidence of pressure communication between wells in the field constitutes evidence of acreage being drained. Applicants requesting large proration units should prove that existing wells are draining the requested number of acres."

There are only about 20 wells in the field, and Bivins engineering witness agreed that 20 wells are not a lot on a 30,000-acre leasehold. Apache operates the majority of wells and considers the field to still be in the experimental phase of development. The evidence in the record shows Apache is still experimenting with well azimuth and well spacing. Well completions on 600-foot spacing and 1,200-foot spacing show indications of between well production communication, as evidenced by tracer study results and well production data. Apache's most recent wells have been drilled at greater distances from existing wells, including up to 5,000 feet from the nearest well, and Apache continues to experience frac hits and production communication between wells at this distance.

In this case, the previously adopted temporary field rules that Apache requests to extend for an additional two year period were modeled after the nearby Hartley West (Canyon) Field, which is in the same formation as the subject field, and the standard proration unit size and method for assigning additional acreage to horizontal wells is identical. Those same field rules are still in effect for the Hartley West (Canyon) Field. The only other nearby field in the same formation is the Amarillo, North (Canyon Lime) Field. According to the May 1, 2018 oil proration schedule, the Amarillo, North (Canyon Lime) Field was designated as an unconventional fracture-treated field (UFT) by the Commission in Oil and Gas Docket No. 01-0299858. At this hearing, Bivins proposed designating the subject field as a UFT field as an alternative to temporary field rules. The Examiners did not consider this proposal by Bivins to designate the subject field as a UFT field as it was outside the scope of the hearing. Statewide Rule 86 (i) 2 (B) (ii) and (iv) require all operators in the field to be given notice and an opportunity to object the proposed UFT designation.

Lastly, the evidence in the record shows the operator of the majority of wells in the field, Apache, is still experimenting with well azimuth and well spacing at this stage of field development and requests to extend the current temporary field rules for an additional period of time as opposed to adopting permanent field rules. Apache's evidence supports the acreage allocation formula currently in effect in the temporary field rules at this time for the subject field. The BE 98-2H frac hit the BE 99-1H well during hydraulic fracture-stimulation at distances ranging from roughly 3,180 feet to 5,800 feet. The evidence shows tracer recovery in the offset well and that the 98-2H and 99-1H wells are in production communication. Since these two wells are not drilled on the exact azimuth, there is roughly 4,000 feet between these two wells. If the BE 99-1H is draining 4,000 feet in one direction extending from the lateral, the Examiners conclude that Apache's assumption that the well is also draining 4,000 feet on the opposite side of the lateral, is reasonable. This creates a rectangular area of approximately 4,000 feet on either side of the 4,867 foot lateral and the rectangular area equates to a drainage area of about 894 acres. The proration schedule shows that under the temporary field rules Apache requests to extend for an additional two year period, 880 acres were assigned to the BE 98-2H. The Examiners conclude that the acreage allocation formula currently in effect for the subject field under the temporary field rules is supported by this evidence of production communication at this stage of development of the field.

The Commission's historic publication, *"Discussion of Law, Practice, and Procedure"* Section E. Well Spacing and Density, page 5 states,

> **"The density provision is intended to establish the acreage that wells in the specific field can drain effectively. At field rule hearings where density provisions are requested, reservoir pressure and production performance data are presented to indicate whether the wells are capable of draining the requested proration unit size. The supporting data for a density request should include pressure interference testing or material balance calculations based on production history or a pressure decline versus production curve."**
>
> **"For new or young reservoirs with few existing wells and a short producing history, it may be necessary to rely on experience in nearby, similar fields, which may be useful in predicting what to expect from the new field. The Commission, however, takes into account the effect of new completion techniques including fracturing or other stimulation."**

In this case, Apache did not present any reservoir pressure data other than inferring reservoir pressure depletion as shown by differences in producing GOR between two wells. Bivins rebutted this evidence, as there may be other reasons to account for the difference in GOR other than an offset producing well depleting the reservoir pressure at the location that a well is drilled and completed at a later date. However, Apache did present production performance data that indicates production interference between wells, as previously described above.

The Commission's publication "*Discussion of Law, Practice, and Procedure*", Well Spacing and Density section, recognizes that for new or young reservoirs with few existing wells and a short producing history, it may be necessary to rely on experience in nearby, similar fields, which may be useful in predicting what to expect from the new field. The proration schedule for the subject field shows the field was discovered January 29, 2014, and there are only about 20 wells completed in the field. This field is still in the early stages of development and the previously-adopted temporary field rules that Apache requests to extend for a two year period were modeled after a nearby field in the same formation, the Hartley West (Canyon) Field, and the standard proration unit size and method for assigning additional acreage to horizontal wells is identical. Again, the Examiners conclude that the evidence in the record and the request by Apache to extend the previously adopted temporary field rules for a period of two years is supported by the evidence in the record.

The Examiners conclude that Bivins' evidence to support reducing the standard proration unit size from 160 acres to 80 acres and the adoption of a Bivins-proposed formula to assign additional acreage to horizontal wells, or in the alternative, to default to Statewide Rule 86 to assign additional acreage to horizontal wells was not persuasive. Bivins supporting evidence for an 80-acre standard proration unit size is based on a common association with the current minimum lease line spacing rule of 330 feet which Apache requests to maintain for the temporary field rules. A calculation of rectangular area using a 5,000-foot drainhole length and assuming 330 feet of drainage on each side of the drainhole for a rectangle of 660 feet by 5,000 feet equates to a rectangular area of approximately 76 acres. In addition, Bivins considers an 80-acre standard proration unit size to be frequently used in field rules for resource plays, citing the field rules for the Eagleville (Eagle Ford-1) Field as an analog field. Lastly, Bivins claims the findings in the Von Gonten report, which are in close agreement with Bivins' own engineering witnesses' independent analysis, support a standard proration unit that is smaller than 160 acres.

The Commission's historic publication, "*Discussion of Law, Practice, and Procedure*" Part I. Railroad Commission Field Rules, Section E. Well Spacing and Density, 1. Generally, (page 4) states,

> **"Generally, well spacing is closely related to density."**
>
> **"Reservoir conditions which may require spacing not comparable to the density include lenticularity and faulting."**

The Examiners conclude that Bivins evidence fails to consider the effects of the unique characteristics of the subject field which includes natural fractures and faulting, and the effects these fractures may have on production.

Apache maintains that the matrix permeability of the correlative interval for the subject field is very low, yet the natural fractures provide a flow conduit. Bivins' engineering witness acknowledged that there are some natural fractures or faulting in the Canyon Lime that exist even before hydraulic fractures are induced during the frac stimulation process, and that these natural fractures exacerbate the frac hits and between well communication during hydraulic fracture-stimulation of offset wells. Bivins describes the flow capacity of the reservoir as man-made; a result of inducing hydraulic fractures that must be sufficiently propped open with a sufficient concentration, or volume of proppant to be conductive. The Examiners agree that hydraulically induced fractures must be propped open with a sufficient concentration, or volume of proppant to be conductive. However, the Examiners also recognize it may take less downhole or hydraulic pressure to extend existing natural fractures and open and sufficiently prop existing natural fissures than the amount of energy required to hydraulically induce fractures in a reservoir without existing natural fractures. As a result, the conductive stimulated reservoir volume may be more complex in the subject field than the South Texas Eagle Ford example Bivins presented for field rule guidance where no evidence or acknowledgement of natural fractures was presented.

The evidence presented of Bivins engineering witness and the Von Gonten report reaching similar conclusions on drainage areas for wells in the subject field using different data and methods is not persuasive, as both methods used similar assumptions, or constraints. In both analyses, a fixed container based on knowledge of unconventional reservoirs where fractures must be hydraulically induced and sufficiently propped to contribute to drainage is described as the drainage area. The evidence in the record shows this reservoir contains natural fractures and Bivins analysis does not contemplate whether these natural fractures contribute to production. Bivins dismisses the evidence of production communication between wells over several thousand feet during hydraulic fracturing, as Bivins' position is that these pathways will not be conductive after the downhole pumping pressure is released and the hydraulically induced fractures heal, and/or will not be sufficiently propped to contribute to production.

Furthermore, the evidence in the record shows the Von Gonten report overpredicted reserves using early time production data for the BE 94-1H, a well which has already been depleted in the Canyon Lime and completed uphole in a different formation. The report also overestimated EURs for the BE 93-2H, 93-3H, 93-4H, and 93-5H on 1,200-foot spacing. The evidence in the record shows that spacing the BE 93-2H, 93-3H, 93-4H and 93-5H approximately 1,200 feet apart has resulted in man-made no-flow boundaries between the wells. None of these four wells, at 1,200-foot spacing are projected to pay out at $60 oil at a cost of $10 million per well to drill and complete.

The Examiners do agree with Bivins assessment that there may be a broad range of EUR outcomes in unconventional resource plays due to the very heterogeneous nature of these reservoirs with complexity in terms of a number of variables in terms of organic content, thermal maturity, frac-ability, clay content and completion efficiency. In this field, the variability in the number, direction, and intensity of natural fractures must also be considered, and there are other explanations to explain variability in EURs other than between well interference. However, the Examiners conclude that the evidence in the record shows that the subject field is still in the early stages of development, as there are only about 20 total wells completed in the field, and four wells completed on 1,200-foot well spacing will not pay out at $60 oil.

Bivins stated that many operators in other fields such as the Eagleville (Eagle Ford-1) field accept frac hits and damage to parent wells by child wells as a reality of unconventional resource development. However, there are several differences between the Eagleville (Eagle Ford-1) Field and the subject field. The Eagleville (Eagle Ford-1) Field is not under temporary field conditions, an indication that the drainage capabilities of wells in that field have been determined. The evidence in the record indicates there have been thousands of wells drilled in the Eagleville (Eagle Ford-1) Field as compared to the 20 wells in the subject field. There is no evidence in the record of natural fractures in the Eagleville (Eagle Ford)-1 Field, which is another difference between that field and the subject field. Due to the greater number of wells completed in the Eagleville (Eagle Ford-1) Field, and since the field is no longer in the temporary field rule phase, the occurrence of frac hits may have been fully researched in that field. However, in the subject field, Apache's most recent wells show wells are being drilled at greater distances from existing (parent) wells to investigate how best to develop the field with the presence of natural fractures.

Lastly, both the section on field rules and the density and well spacing sub-section in the Commission's publication, "*Discussion of Law, Practice, and Procedure*" describe using nearby similar fields in the same formation for guidance on field rules for new or young reservoirs with few existing wells and a short producing history. The evidence in the record shows the subject field is located in the Texas Panhandle (District 10), and the closest well in the nearby field in the same formation that the previously-adopted temporary field rules were modeled after is about 3 miles away. The field rules that Bivins used as an analog, the Eagleville (Eagle-Ford-1) Field is located in South Texas (District 1) and the field interval is not the Canyon Lime. Based on the evidence in the record, the Examiners do not consider the Eagleville (Eagle Ford-1) to be a nearby field in the same formation as the subject field.

Temporary Field Rule No. 4: Oil Allowable

The Examiners conclude that the evidence in the record fails to justify amending the current Field Rule No. 4 which outlines the method used to determine a well's oil allowable. Apache requested no change, while Bivins requested rule change is predicated on reducing the standard proration unit in Field Rule No. 3, whereby a larger daily oil allowable multiple would be incorporated by a similar factor that the acreage assigned to a well would be reduced in Field Rule No. 3. The end result would be a comparable daily oil allowable as the current field Rule No. 4. The current field rule No. 4 is based on the 1965 Yardstick allowable for a 160 acre standard proration unit, of 353 BOPD, which is then multiplied by a two factor formula allocation based on 95% acres and 5% per well. Bivins proposed rule change uses 1,000 BOPD as the multiplier for a 40-acre unit standard proration unit size and 2,000 BOPD multiplier for an 80 acre proration size, and an unlimited net GOR.

FINDINGS OF FACT

1. Notice of this hearing was given to all parties entitled to notice at least ten days prior to the date of hearing.

2. The Bivins Lit (Canyon Lime) Field, (Field ID No. 08490750), was discovered January 29, 2014.

3. Temporary field rules for the Bivins Lit (Canyon Lime) Field in Oldham County, Texas, were established by Commission Final Order in Oil and Gas Docket No. 10-0291184 on January 27, 2015, with an expiration date of November 12, 2016, or until Commission Staff evaluates appropriate data after notice and opportunity for hearing.

4. On May 31, 2017, Engineering Unit Staff sent Notice of Administrative Review of Temporary Field Rules for the Bivins Lit (Canyon Lime) Field advising operators in the subject field the opportunity to request a hearing regarding the temporary field rules currently in effect.

5. A hearing was held to review the Temporary Field Rules previously established under Oil and Gas Docket 10-0291184, and to assess whether the temporary field rules should be modified, continued, or terminated.

6. Apache requests that the temporary field rules adopted in Final Order in Oil and Gas Docket No. 10-0291184 be continued in a temporary status for an additional two years without modification.

7. The request to extend the current temporary field rules for two years is protested by Bivins Family Royalty ("Bivins"), which consists of mineral owners in this area of both unleased minerals and minerals that are subject to the Apache Lease and to other leases.

8. Bivins requests to amend the current temporary field rules.

   a. Reduce the standard proration unit size from 160 acres to 80 acres.

   b. Modify the formula used to assign additional acreage to horizontal wells or default to using the table in Statewide Rule 86 to assign additional acreage to horizontal wells.

   c. Modifying the method used to determine the oil allowable for wells in the field.

9. There are approximately 20 wells in the Bivins Lit (Canyon Lime) Field.

a. Apache is the operator of most of the wells in the Bivins Lit (Canyon Lime) Field.

b. Le Norman Operating LLC, operates one shut-in well and has recently completed an additional well that is not yet listed on the proration schedule.

10. Field-wide production for the subject field using Drillinginfo data through early January 2018 shows cumulative production of about 1.1 million barrels of oil (MMBO).

11. Initial potential (IP) test results on horizontal wells completed in the field show variability in the producing rates of wells, from a couple hundred BOPD to almost 1,600 BOPD.

12. The Bivins Lit (Canyon Lime) Field is still in the experimental stage of development and exploration of the field.

a. Apache is drilling new wells further apart from existing production, drilling longer laterals, and stimulating the wells more heavily (an increase in the pounds of proppant per foot of lateral length).

b. Older horizontal wells in the field were drilled on a north-south azimuth.

c. Wells drilled more recently have been drilled on a more southwest to northeast trending azimuth.

13. For new or young reservoirs with few existing wells and a short producing history, it may be necessary to rely on experience in nearby, similar fields, which may be useful in predicting what to expect from the new field.

a. The closest distance between a Hartley West (Canyon) Field completion and a Bivins Lit (Canyon Lime) Field completion is around 3 miles, as these two field have grown relatively close together and contain a similar stratigraphic interval.

b. The main difference between the Bivins Lit (Canyon Lime) Field and Hartley West (Canyon) Field is that the Hartley, West (Canyon) Field has a broader field interval that includes the clastic Granite Wash facies and the Strawn, however, the two field have the same field interval top.

c. For these reasons, the temporary field rules for the Bivins Lit (Canyon Lime) Field were modeled after the Hartley West (Canyon) Field rules.

d. The Hartley West (Canyon) Field was considered an analog field to the subject field at the time temporary field rules were adopted for the Bivins Lit

(Canyon Lime) Field, and those field rules for the Hartley West (Canyon) Field are still in effect.

14. Generally, well spacing is closely related to density. Reservoir conditions which may require spacing not comparable to the density include lenticularity and faulting. The effect of new completion techniques including fracturing or other stimulation are also considered.

    a. All of the wells in the Bivins Lit (Canyon Lime) Field have been hydraulically fracture-stimulated.

    b. There are natural fractures in this field.

    c. Along a given section of lateral there is a large degree of variability in the intensity, extent, and number of natural fractures.

15. There is evidence of communication between wells during hydraulic fracture-stimulation and Apache is experimenting with different well spacing.

    a. Apache investigated between well spacing of 1,200 feet in an area of the previously drilled and completed Bivins East ("BE") 94-1H well by the drilling of the BE 93-2H, 93-3H, 93-4H, and 93-5H wells to the east of the BE 94-1H.

    b. The BE 94-1H was completed on May 22, 2014, while the BE 93-2H, 93-3H, 93-4H, and 93-5H wells were completed between January 21 and 26, 2015.

    c. Tracers injected during the hydraulic fracture-stimulation of the BE 93-2H, 93-3H, 93-4H, and 93-5H were recovered in the BE 94-1H.

    d. Changes in the BE 94-1H daily production rate was another indicator of frac hits and communication between the BE 94-1H and the hydraulic fracture-stimulation of the BE 93-2H, 93-3H, 93-4H, and 93-5H.

        i. The daily production for the BE 94-1H up until late-2014, when Apache started hydraulically-fracture-stimulating the BE 93-2H, 93-3H, 93-4H, and 93-5H wells was a very defined production trend.

        ii. When the offset wells were hydraulically fracture-stimulated, a large increase in water production in the BE 94-1H occurred after those frac events. The daily water production for the BE 94-1H water increased from about 200 bwpd to over 1,000 bwpd, while oil production dropped from about 150 BOPD to 20 BOPD.

iii. Later, the BE 94-1H production did start to approach the previous production rates in early 2015, up until the completion of the offset Quanah 95-1H later in 2015.

iv. On August 4, 2015, the Quanah 95-1H well, located 1,260 feet to the west of the BE 94-1H well, and essentially parallel, (on the same north-south azimuth), was hydraulically fracture-stimulated and a frac hit was observed on the BE 94-1H well.

v. Initially, both oil and water production increased in the BE 94-1H, but within a few months, both oil and water production began to decline sharply, and within 12 months after the completion of the Quanah 95-1H, oil production from the BE 94-1H was less than 10 BOPD.

vi. In 2016, the BE 94-1H died unexpectantly with oil going to essentially zero. The Canyon Lime zone was shut-in on the BE 94-1H on June 5, 2017 and the well was recompleted up-hole in the Wolfcamp Formation in the vertical portion of the wellbore.

vii. The BE 94-1H is the only horizontal well that has been drilled and completed in the subject field that is no longer producing from the subject field.

CONCLUSIONS OF LAW

1. Resolution of the subject application is a matter committed to the jurisdiction of the Railroad Commission of Texas. Tex. Nat. Res. Code § 81.051.

2. The proposed application is in compliance with all statutory requirements.

3. All notice requirements have been satisfied. 16 Tex. Admin. Code § 1.45.

4. Temporary Field Rules are appropriate at this stage of field development to more rapidly delineate the limits of the reservoir and to prevent the wasteful concentration of wells near the discovery well.

5. Temporary field rules will apply until permanent field rules are adopted. 16 T.A.C. §3.43 (c)

EXAMINERS' RECOMMENDATION

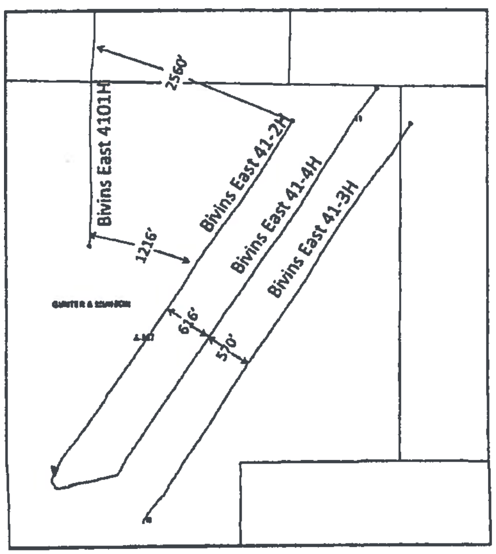
Based on the evidence in the record, the Examiners recommend the Commission enter an order extending the temporary field rules currently in effect for the Bivins Lit (Canyon Lime) Field for an additional two-year period.

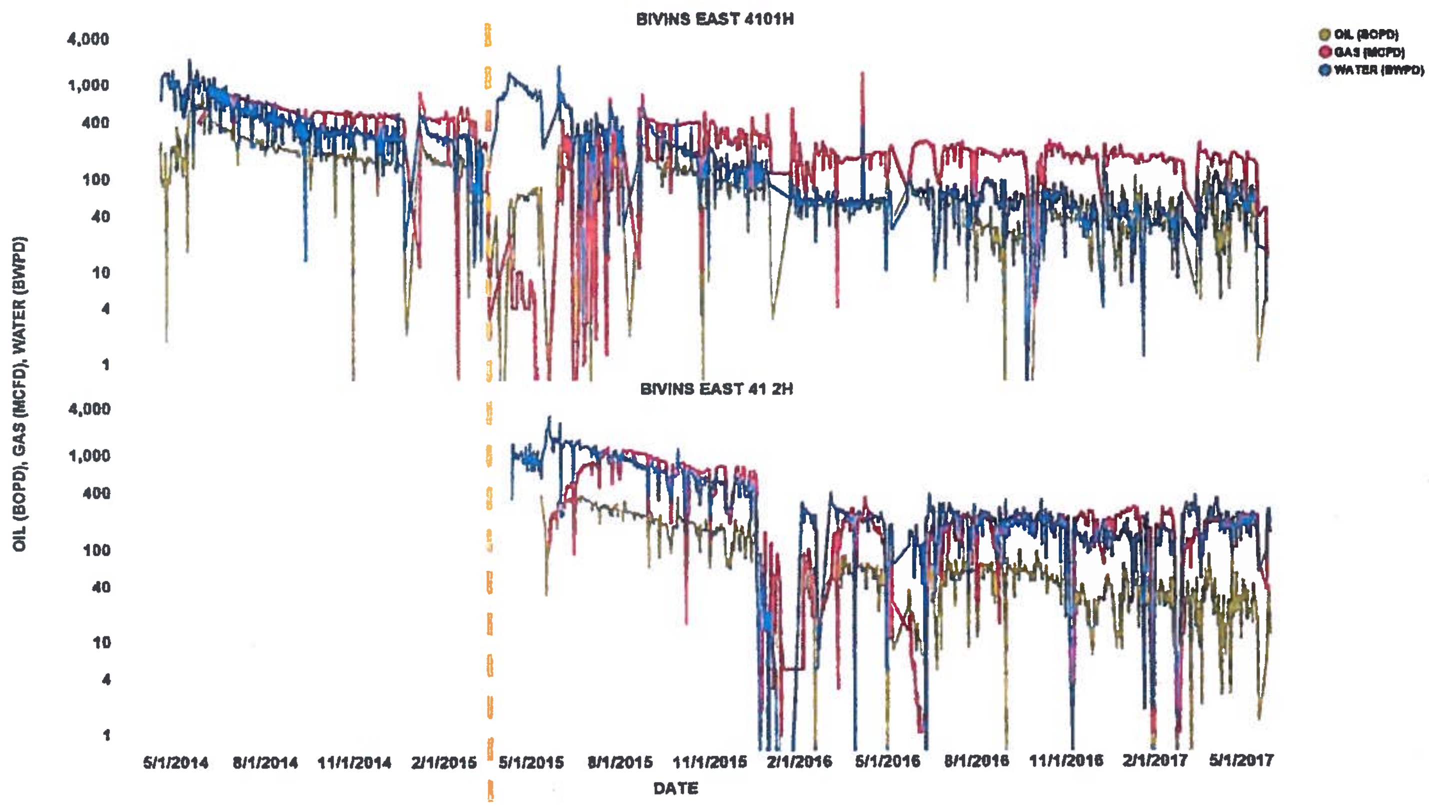
Respectfully submitted,

Karl Caldwell
Technical Examiner

Clayton Hoover
Administrative Law Judge

- Bivins East 41 #2H Frac: 3/25/2015
- Bivins East 41 #2H Prod Begins (Jet Pump): 4/8/2015
- Bivins East 41 #2H Prod Begins (ESP): 5/15/2015



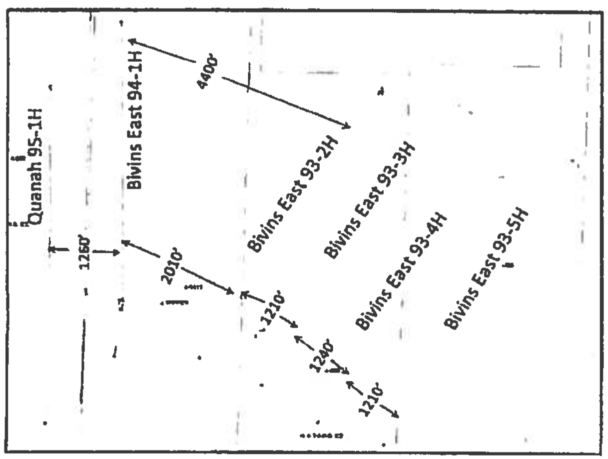


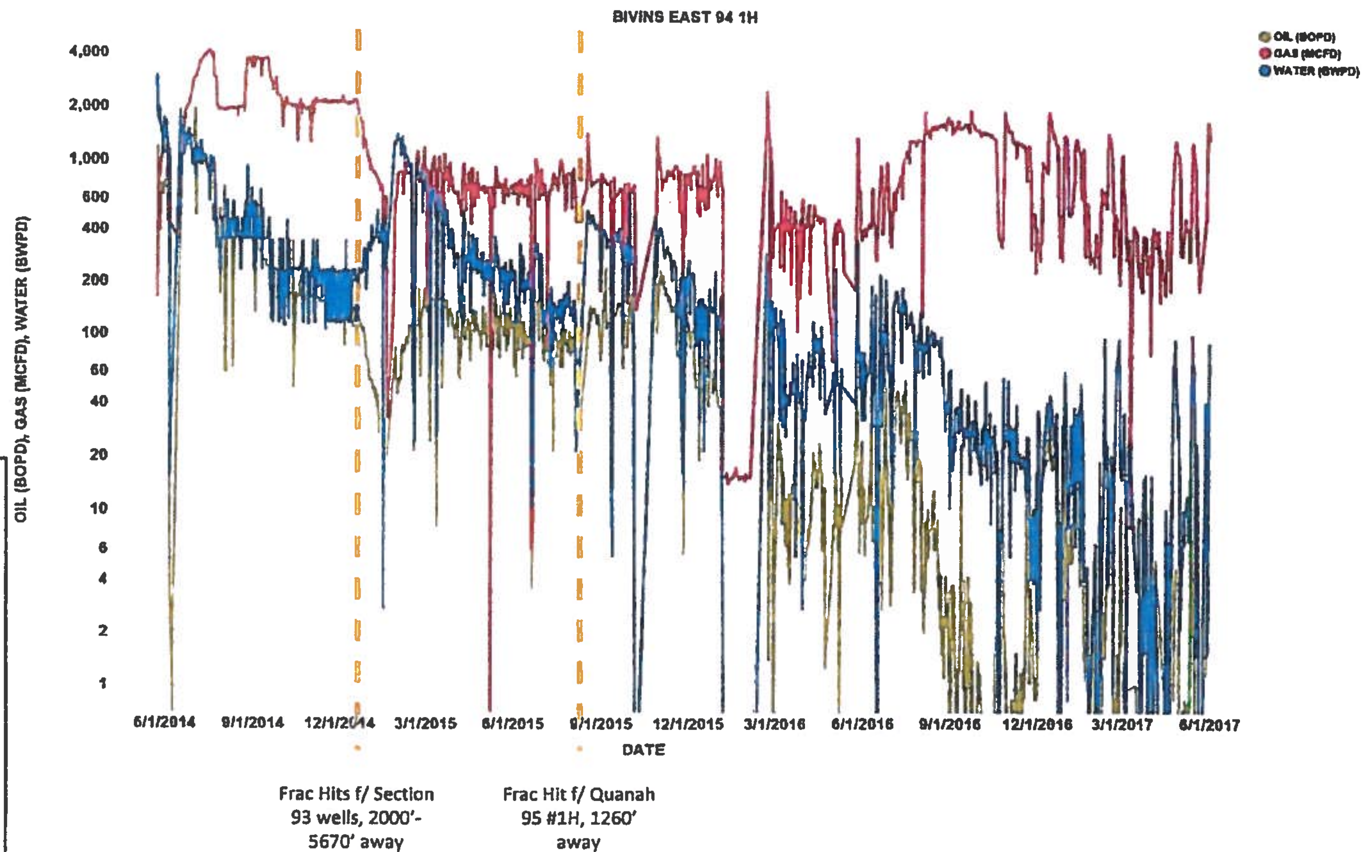
Frac Hit f/ BE 41 #2H, 1216'- 2560' away

Oil & Gas Docket No. 10-0305153
Attachment A

Apache Exhibit No. 10
Docket No. 10-0305153
June 20, 2018.

- Bivins East 93 #2H Frac: 12/15/2014
- Bivins East 93 #3H Frac: 12/21/2014
- Bivins East 93 #4H Frac: 1/3/2015
- Bivins East 93 #5H Frac: 1/10/2015
- All Section 93 Well Prod Begins (ESP/Jet Pump): February 1-5, 2015
- Quanah 95 #1H Frac: 8/4/2015
- Quanah 95 #1H Prod Begins (Jet Pump): 8/11/2015
- Bivins East 94 #1H: Canyon Lime zone shut in 6/5/2017

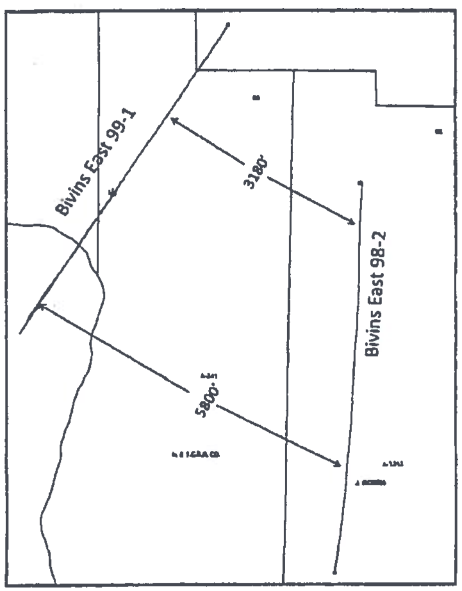


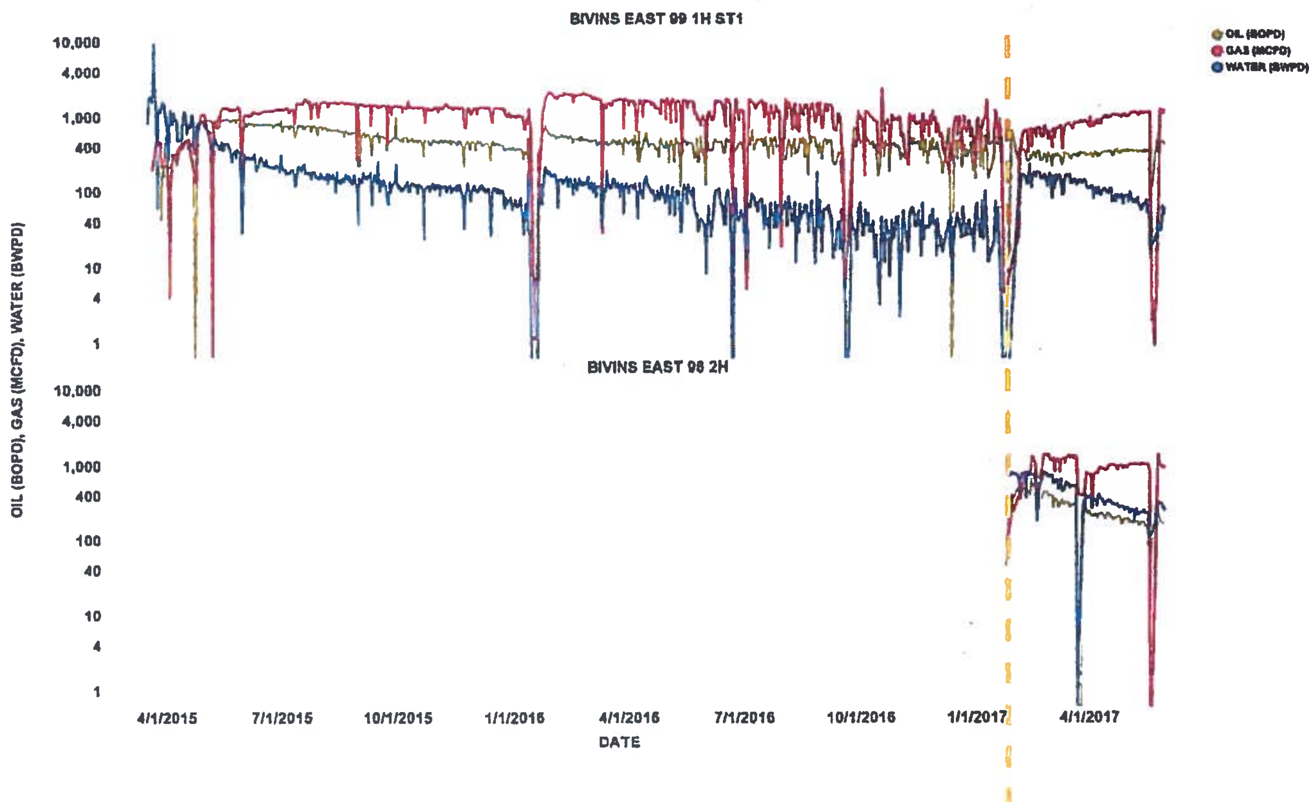


Oil & Gas Docket No. 10-0305153
Attachment B

Apache Exhibit No. 12
Docket No. 10-0305153
June 20, 2018.

- Bivins East 98 #2H Frac: 1/9/2017
- Bivins East 98 #2H Prod Begins (ESP): 1/24/2017
- Bivins East 98 #2H Prod Begins (Gas Lift): 3/25/2017





Frac Hit f/ BE 98 #2H, 3180'-5800' away

Oil & Gas Docket No. 10-0305153
Attachment C

Apache Exhibit No. 15
Docket No. 10-0305153
June 20, 2018.