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STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DIVISION
OIL CONSERVATION COMMISSION

APPLICATION OF THE NEW MEXICO OIL CONSERVATION DIVISION TO AMEND RULES OF THE COMMISSION CONCERNING THE DRILLING, SPACING, AND OPERATION OF HORIZONTAL WELLS AND RELATED MATTERS BY AMENDING VARIOUS SECTIONS OF RULES 19.15.2, 19.15.4, 19.15.14, 19.15.15, 19.15.16 NMAC; STATEWIDE.

Case No. 15957

VERIFIED PREHEARING STATEMENT

Jalapeno Corporation ("Jalapeno") files this Prehearing Statement in this matter pursuant to Rule 19.15.3.11(B)(3). Jalapeno is represented by the Gallegos Law Firm, P.C., J. E. Gallegos and Michael J. Condon.

PROPOSED TESTIMONY

WITNESSES	EST. TIME	EXHIBITS
Harvey Yates	45 minutes	See Attached

Mr. Yates is the President of Jalapeno. He has approximately sixty (60) years' experience in the oil and gas industry. His companies have operated over one-hundred vertical wells and have participated as a non-operator in over a hundred horizontal wells. In the course of his time in the industry he has done the work of a geologist, engineer, and landman. He also is a retired attorney who earlier concentrated his legal work in the area of oil and gas law. He has been recognized as an expert witness in proceedings before the OCD and the Commission, and has testified in other Commission rulemaking cases, most notably Case No. 14744, a 2011 case which involved an application by the OCD to modify the Commission's rules to address issues with horizontal wells. Mr. Yates testified there regarding the applicability of the compulsory pooling rules to horizontal drilling.

Jalapeno is an oil and gas operator which has a large non-operating position in leases in the Delaware Basin as well as large acreage positions in two New Mexico non-producing basins which will be explored using vertical well drilling but which, none-the-less, potentially, would be subject to confiscatory takings facilitated by the proposed horizontal rules. Further, in the Delaware Basin Jalapeno has been the subject of force pooling proceedings involving horizontal oil wells. One such case brought by Matador Production Company, Case No. 15363, is currently on appeal to the Santa Fe County District Court from a decision by the Commission.

Mr. Yates would testify generally about the adverse consequences under the proposed horizontal well rule both to small working interest owners and unleased mineral owners and to explorers using vertical well drilling technology. He would testify that many interest owners who are subject to horizontal drillers' force pooling proceedings effectively have had their leasehold interests, their mineral interests and their oil and gas reserves taken from them by Division orders and that the proposed horizontal well rule appears designed to facilitate and expedite further takings in violation of the US and New Mexico constitutions. Further, he would testify that under the proposed horizontal well rule further similar takings would be facilitated because:

1. The OCD and Commission have no objective evidentiary standard upon which to assess whether to grant a risk penalty or to determine the rational magnitude of the risk penalty and that this has led to a virtual automatic imposition of a 200%

risk penalty against hundreds of non-consenting parties though the evidence is clear that the actual risk is far less than the 200%. As an example of such impropriety, which would be continued and facilitated by the proposed horizontal rule, Jalapeno attaches to this pre-hearing statement as Exhibit 1 an engineering report done for Jalapeno regarding a four township area within the Delaware Basin wherein the OCD has imposed on non-consenting parties numerous 200% risk penalties even though, as indicated by the engineering report, greatly reduced risks penalties should have been imposed.

2. The risk penalties are regularly imposed without the OCD's and OCC's requiring the applicant to bear the burden of proof by competent evidence to support its requested risk penalties and instead, contrary to legal propriety, by chilling the willingness of small non-consenting parties -- which have included in the recent past the Boys Ranch, the Boy Scouts, trusts, widows and churches and other similarly situated small non-consenting parties -- to object to the force employed against them by placing on them the obligation to disprove the reasonableness of a 200% risk penalty even though they have little capacity to martial the information necessary to do so.

These issues were fully litigated in Case No. 15363, and Jalapeno adopts and incorporates herein its testimony and exhibits in that case on the issue of the impropriety of the current rules governing risk penalties.

Mr. Yates would testify that the proposed amendments do not correct the historic problem with the agencies' force pooling orders, i.e., they fail to protect the correlative rights of small working interest owners. He would also testify that some of the proposed amendments fail to protect the correlative rights of owners of vertical wells which will be impacted by horizontal wells, and fail to protect offset owners and operators. He would testify that the proposed amendments do not conform to the legal standards and procedures set forth in NMSA 1978 § 70-2-17(C).

PROPOSED MODIFICATIONS AND BASIS

Jalapeno's proposed modifications to the proposed rule changes and the reasons for Jalapeno's proposed modifications are as follows:

1. **Proposed Rule 19.15.16.7F.** This proposed rule defines a horizontal spacing unit as "the spacing unit dedicated to a horizontal well." This conflicts with Sections 70-2-12(B)(10) and 17, because the only authority granted by the Legislature authorizes the Commission and the Division to fix or create spacing units and pool interests within such spacing units. *See Rutter & Wilbanks Corp. v. Oil Conservation Comm'n.,* 1975-NMSC-6, 87 N.M. 286, 523 P.2d 582. The proposed amendment does not fix or create a spacing unit as required by Section 70-2-12(B)(10). Under this proposed definition, neither the Commission nor the Division fixes or creates a spacing unit. That authority is instead delegated to each operator/applicant, who has the right to establish non-uniform spacing units on an ad hoc basis. The definition allows an operator to include in a spacing unit acreage on which it has no right to drill in violation of Section 70-2-17(C). The vagueness of the definition allows for a horizontal spacing unit that is not bound or constrained by existing section and survey subsection lines. Compare Rules 19.15.15.1 through 16 NMAC.

Moreover, the proposed rule allows the applicant to create a horizontal spacing unit that overlaps with the spacing unit already dedicated to an existing well. This threatens the rights of the established owner's right to produce without waste his or her just and equitable share of the oil or gas, or both, in the pool.

2. **<u>Proposed Rule 19.15.16.15A(1).</u>** This proposed rule allows the well operator to establish a "standard horizontal spacing unit." However, there is no standard spacing unit for horizontal wells reflected in the rules. Again, this violates Section 70-2-12B(10). The Legislature has directed the agency, not operators, to fix or create spacing units. Under this definition, the Division/Commission have not fixed or created a spacing unit, but have instead delegated to each operator/applicant the right to fix or create spacing units, which are not uniform and on an ad hoc basis. This definition allows an operator to include in a spacing unit acreage on which it has no right to drill in violation of Section 70-2-17(C).

3. **<u>Proposed Rule 19.15.16.15A(1)(b).</u>** This proposed rule allows an operator of a horizontal well to include other quarter-quarter sections or tracts located within 330 feet of the proposed well's "completed interval." Because neither the Commission nor the Division is fixing or creating a standard spacing unit for horizontal wells as contemplated by Section 70-2-12(B)(10), this rule increases the risks that an operator will include in the acreage dedicated to the horizontal well acreage in which it has no right to drill contrary to Section 70-2-17(C). Moreover, the rule does not expressly require that owners of interests in the other tracts will be provided prior notice and an opportunity to object to the inclusion of their acreage in the proposed unit. In any case where an applicant seeks approval for a unit, the applicant has the obligation and burden to establish that such action will not impair the correlative rights of other owners,

and the Commission and the Division have the obligation to confirm that the burden has been met after notice and hearing.

4. **<u>Proposed Rule 19.15.16.15A(1)(d).</u>** This proposed rule concerns cases where a fourth quarter section or tract is excluded where it is already subject to a horizontal spacing unit. The rule should also apply to situations where the fourth quarter section or tract is subject to a vertical well spacing unit in order to prevent a taking of the vertical well owners' property without compensation. The rule should be amended to read " . . . shall not exclude the fourth such tract in the same section unless that tract is already dedicated to **a vertical well spacing unit** or a horizontal spacing unit for an existing or permitted horizontal oil well . . .".

5. **<u>Proposed Rule 19.15.16.15A(5).</u>** This proposed rule purports to set forth the procedure an operator must follow before filing an application for permit to drill and before commencing drilling. The rule should be deleted as it applies to the commencement of drilling. First, it is unnecessary because the provisions of Rule A (12), Pooling of horizontal spacing units, governs the procedure which should apply consistent with Section 70-2-17. Second, the rule appears to encourage the drilling of horizontal wells before an operator has either secured voluntary agreement of all interest owners or has obtained a compulsory pooling order contrary to the procedure provided in Section 70-2-17. Even if the rule were to remain, consent of only one lessee or owner of each tract is insufficient and contrary to the requirements of Section 70-2-17 and due process protections that apply in these matters. The consent of all owners should be required.

Moreover, the Commission's current rules on the risk penalty in force pooling procedures are contrary to Section 70-2-17. The applicant must bear the burden to establish by competent technical evidence that its requested risk penalty is justified. The standard should be objective, i.e., compensation for the true risk that the well will not achieve payout. Risk penalties should be minimal where productive horizontal wells have been drilled in the vicinity, and non-existent where productive wells have already been drilled in the same spacing unit or an adjacent unit.

6. **Proposed Rule 19.15.16.15A(6).** This proposed rule references "Non-standard horizontal spacing units." The reference is an oxymoron. That term is nowhere defined in the proposed amendments. An operator is authorized under these proposed rules to establish a "standard" spacing unit without reference to any objective standard, and without any acreage designation by the agency. How can a non-standard horizontal spacing unit be created if every unit proposed by an operator is standard? Even if there were a definition, Section 6(b) should be amended to add subsection (iii) to require notice to all owners of interests in the non-standard horizontal spacing unit.

7. **Proposed Rule 19.15.16.15(A)(11).** This proposed rule deals with "Subsequent wells in horizontal spacing units." As a general matter, any subsequent well should be authorized only with approval of all working interest owners of existing wells in spacing units, horizontal or vertical. The same standard for approval of the initial well should apply to any subsequent well in order to comply with Section 70-2-17. Sections A(11)(b)(i) and (ii) should be amended by deleting "or, in the absence of approval, pursuant to a division order." This modification is necessary to prevent the taking of behind the pipe reserves of vertical wells without just compensation, the

impairment of correlative rights of such owners, and the unconstitutional impairment of contracts where the vertical well producer has mortgaged producing or behind the pipe reserves to a lender.

8. **Proposed Rule 19.15.16.15(A)(11)(c).** The proposed rule would apply the provisions of rules 19.15.13.10 and 11 NMAC to an infill horizontal well. Those provisions hold that the risk charge approved for the initial well will apply to the infill well. However, the very fact that an operator or working interest owner proposes an infill well in a successful, existing horizontal spacing unit proves that there is minimal, if any, risk for the infill well. Rule 11(c) should be amended to read that the existing rules: "shall not apply to any proposal to drill an infill horizontal well in a horizontal spacing unit subject to a compulsory pooling order. A party seeking a risk penalty in connection with the drilling of an infill horizontal well must secure approval from the Division. The applicant has the burden to establish by competent evidence that a proposed risk penalty is warranted. The standard for establishing a risk penalty is based on the likelihood that the well will or will not achieve payout. Absent Division approval of a risk penalty, there shall be no risk penalty in connection with the drilling of an infill horizontal well."

9. **Proposed Rule 19.15.16.15(A)(12).** This rule deals with "Pooling of horizontal spacing units." The rule should expressly provide for amendment of the compulsory pooling rules involving assessment of risk penalties to comply with Section 70-2-17. The applicant must bear the burden to establish by competent technical evidence that its requested risk penalty is justified. The standard should be objective, i.e., compensation for the true risk that the well will not achieve payout. Risk penalties

should be significantly reduced where productive horizontal wells have been drilled and completed in the target formation in the vicinity, especially including wells drilled in the same spacing unit.

10. <u>Proposed Rule 19.15.16.15(A)(13).</u> This rule provides a right of protest for owners of adjoining tracts who believe that a horizontal well is or will impair the owner's correlative rights. The rule reverses the burden of proof and puts the cart before the horse. An applicant wishing to drill a horizontal well has the initial obligation to demonstrate that its proposed well will not impair the correlative rights of adjoining tract owners. The Commission and the Division are obligated to determine that a proposed horizontal well will not cause waste or impair correlative rights, and that determination must be made before the well is approved or drilled, with notice to affected parties, including adjoining tract owners, and an opportunity to be heard. To the extent these rules authorize the drilling of wells before such a determination is made, they are unconstitutional, and violate due process rights of affected parties, and are contrary to the Commission's enumerated powers in the Oil and Gas Act.

11. <u>Proposed Rule 19.15.16.15(B).</u> This rule deals with Setbacks. However, the setback distance is measured from an "outer boundary of the horizontal spacing unit." The definition of a horizontal spacing unit in these proposed rules is not tied to traditional section or survey subsection boundaries. The definition of a horizontal spacing unit and the setback provisions should be modified so that the setback provisions run from established survey boundaries, which is the current rule that applies to vertical wells.

12. **<u>Proposed Rule 19.15.16.15(B)(6).</u>** This rule deals with setback variances. Again, the rule is not tied to established section or survey subsection boundaries. The variance is based on the difference between the as-drilled and projected location. The rule allows horizontal well operators to encroach much closer to survey boundaries than vertical well owners are entitled to. The rules should not be written or applied to give this type of advantage to horizontal well operators vis-à-vis vertical well operators.

<u>Proposed Rule 19.15.16.15(C).</u> This rule, which deals with allowables, is another rule which assures a production preference to horizontal well owners and operators over vertical wells. The rules provide no objective allowable for horizontal wells, as they are only limited by the amount of oil and gas they can produce. The Division is, however, to assign to non-marginal proration units (vertical wells) an allowable equal to their productive capacity, subject to the Division's ability to assign a reduced allowable "to prevent waste." The rule thus does not treat horizontal and vertical wells uniformly. This threatens to impair the correlative rights of owners of interests in proration units, a result that is contrary to the Commission's primary duty to protect correlative rights. Section C(1) should be amended to delete the phrase "unless the division determines, after notice and hearing, that a reduced allowable must be assigned to the non-marginal unit to prevent waste."

13. **<u>Proposed Rule 19.15.16.15(D)(4).</u>** This rule, titled "Transitional provisions," is actually an attempt to provide retroactive approval under the new rules to horizontal wells drilled under the prior rules. It purports to approve without notice or hearing hundreds of non-standard horizontal spacing units areas dedicated to wells drilled prior to the adoption of these rules. This is unconstitutional ex post facto

adjudication. The proposed procedure is in violation of the United States and New Mexico constitutional guarantees of due process and is well beyond the Commission's enumerated powers as provided by the Oil and Gas Act. The rule should be deleted in its entirety.

Respectfully submitted,

GALLEGOS LAW FIRM, P.C.

By__________________________

J.E. GALLEGOS
MICHAEL J. CONDON
460 St. Michael's Drive, Bldg. 300
Santa Fe, New Mexico 87505
(505) 983-6686
jeg@gallegoslawfirm.net
mjc@gallegoslawfirm.net

Attorneys for Jalapeno Corporation

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served on counsel of record by electronic mail this 3rd day of April, 2018.

Michael H. Feldewert
Adam Rankin
Holland & Hart LLP
Post Office Box 2208
Santa Fe, NM 87504
mfeldewert@hollandhart.com
arankin@hollandhart.com

Jennifer L. Bradfute
Modrall Sperling
500 Fourth St. NW, Ste. 100
Albuquerque, NM 87103
jennifer.bradfute@modrall.com

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MICHAEL J. CONDON

VERIFICATION

STATE OF NEW MEXICO)
) ss.
COUNTY BERNALILLO)

Harvey E. Yates, Jr., President of Jalapeno Corporation, states on oath that he has read the foregoing Pre-Hearing Statement and states that the information stated is true and correct to the best of his knowledge.

Harvey E. Yates, Jr.

Subscribed and Sworn to before me this 3rd day of April, 2018, by Harvey E. Yates, Jr., President of Jalapeno Corporation.

Notary Public

My Commission Expires: May 5, 2018

OFFICIAL SEAL
Kathryn J. Reese
NOTARY PUBLIC - STATE OF NEW MEXICO
My Commission Expires: May 5, 2018

Hickman McClaine & Associates, Inc.

March 29, 2017

Jalapeno Corporation
PO Box 1608
Albuquerque, NM 87103

Attn: Mr. Harvey Yates

Gentlemen:

Re: Force Pooling Engineering Report
Airstrip 31-18-35 RN State Com Well 2H

This report was prepared by Hickman, McClaine & Associates, Inc. ("HMA") at the request of Jalapeno Corporation. Jalapeno asked HMA to determine the risk entailed in drilling a horizontal well proposed by Matador Production Company ("Matador") in Lea County, New Mexico. In addition, HMA was asked to determine the value of a forced pool interest at various imposed "risk" penalties that could be applied by the regulatory agency in New Mexico. The proposed Matador well was the Airstrip 31-18-35 RN State Com Well 201H located in Sec. 31 of T. 18 S, R. 35 E. NMPM.

Like many other states New Mexico has authorized "compulsory pooling." Thus, a company which wishes to drill a well may do so even if a party who owns an interest in the drilling block (proration unit) does not consent to the drilling of the well. New Mexico's regulatory agency has the authority to allow the company proposing and drilling the well the right to recoup the non-consenting party's proportionate cost of drilling and completing the well from the non-consenting party's share of the well's production. However, New Mexico and several other states go further. They seek to compensate the driller for the "risk" of drilling the well. They do this by tacking on a "risk penalty" which the driller can also recoup from the non-consenting party's share of the well's production.

The state has tasked the state's oil and gas regulatory authority, its Oil Conservation Division ("OCD") and Oil Conservation Commission ("OCC"), with determining the risk inherent in drilling a proposed well. This must be done in order to assign an appropriate "risk penalty" to the proposed well. Unlike most states, New Mexico, since 2003, has consistently assumed in almost all cases that there should be a 200% risk penalty for drilling a well whether it is an offset development well or a rank wildcat.

505 N Big Springs Suite 105 Midland, TX 79701
T (432) 683-4395

EXHIBIT
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Jalapeno #15957

Jalapeno Corporation disputes both the process of determining risk used by the regulatory authority and the results usually derived by that process. First, Jalapeno notes that, logically, not all wells can have a 200% risk related to the drilling of the wells. Second, Jalapeno, which has been analyzing risk associated with drilling wells in the Delaware Basin, suggests that drilling risk has changed since 2003. In 2003 virtually all wells drilled in New Mexico were vertical wells. Now, most wells being drilled are horizontal wells. Jalapeno notes that, consequently, the cost of drilling has markedly increased, but it also alleges that the risk of completing a producing well has fallen.

The first charge to HMA was to analyze all of the horizontal wells drilled in a four township area surrounding the proposed Airstrip 201H well. The study area is shown in **Exhibit 1** with the location of the proposed well shown as a north-south trending red line in the area where the four townships connect at a common point. This area was chosen because the four townships surround the proposed well, and the four townships also happen to contain a significant number of horizontal wells – of which the vast majority are Bone Spring wells. See **Exhibit 2**.

There are also a large number of vertical Wolfcamp penetrations in this area that essentially surround the Upper Wolfcamp well proposed by Matador. The analysis was performed to ascertain the number of horizontal dry holes drilled, the actual number of wells lost in drilling the horizontal wells, and to determine the average risk of not achieving payout in a well drilled in those four townships.

In addition, Jalapeno asked HMA to analyze all the horizontal Wolfcamp wells drilled in Eddy and Lea Counties, New Mexico to determine what the probability was of not achieving payout status in the Wolfcamp drilling conducted to date.

The results of the statistical analysis obtained from the data analyzed on the horizontal Bone Spring wells are graphically shown in **Exhibit 3** and is labeled Cumulative Probability vs. Log EUR for Bone Spring. This plot was constructed utilizing the data points obtained from the estimated ultimate recovery ("EUR") of 101 horizontal Bone Spring producers drilled in the four township study area. Another of HMA's charges was to determine if the Bone Spring could be considered a Resource Play by observing the resulting statistics that have evolved from the horizontal drilling.

"Resource Play" is a term used to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which when compared to a conventional play, typically has a lower geological and/or commercial development risk. As a practical matter, it is anticipated that Resource Plays will encompass more than 100 completed wells in the reservoir. There are two rationales for this: first, developing a usable statistical model in a Resource Play typically requires about 100 wells; and second, a reservoir that has sufficient areal extent to be considered a Resource Play will likely encompass a minimum of 100 wells. Being a resource play essentially ensures a very high probability that a well drilled within the play area will produce hydrocarbons.

From the Cumulative Probability vs. Log EUR for Bone Spring plot, the following information is obtained:

- P10 = 646 MBOE (10% of the wells are equal to or greater than this value)
- P90 = 99 MBOE (90% of the wells are equal to or greater than this value)
- P10/P90 = 6.5 (A value that is highly indicative that this is a resource play)
- Narrow scatter of points between the P90 and P10 points (In resource plays, straight lines are frequently observed between the P90 and P10 points)

There are numerous characteristics listed in literature that are nearly always observed in resource plays. Although not a complete list, some notable and important characteristics in resource plays in the areas evaluated are:

- Wells exhibit a repeatable statistical distribution of estimated ultimate recoveries (EURs)
- A continuous hydrocarbon system that is regional in extent
- Wells require extensive stimulation to produce at economic rates

A characteristic utilized in resource play evaluation is a calculation involving the results obtained from a statistical distribution. This calculation is made by dividing the P10 value by the P90 value derived from the plot of the statistical data. If the resulting value is greater than 10, then there is the high probability that 2 different distributions are being sampled (such as two distinct geological facies) or there is limited data. Literature on this subject reports that reservoirs within Resource Plays developed with horizontal wells exhibit a P10/P90 ratio typically ranging from 4 to 10. The statistics and values exhibited with the analysis of the horizontal Bone Spring wells are highly indicative that Bone Spring drilling in the study area constitutes development of a resource play.

As previously mentioned, these same literature resources also state that it is usually essential to have 100 data points or more to validate the shape of the distribution and the derived values at P90, P50 and P10. Just the number of horizontal Bone Spring wells alone in the study area met the number of data point's criteria.

HMA next began the analysis of the horizontal Wolfcamp wells drilled in Eddy and Lea counties, New Mexico to determine if the horizontal Wolfcamp wells fall into the resource play category. Although the total number of Wolfcamp wells analyzed is less than the minimum of 100 wells as recommended in literature, the early results are highly indicative that horizontal Wolfcamp drilling in the area is "Resource Play" development. Please see **Exhibit 4,** labeled Cumulative Probability vs. Log EUR for Eddy & Lea Co. Wolfcamp.

From the Cumulative Probability vs. Log EUR for Eddy & Lea Co. Wolfcamp plot, the following information is obtained:

- P10 = 1,385 MBOE
- P90 = 175 MBOE
- P10/P90 = 7.9
- 64 horizontal Wolfcamp wells included in the statistical analysis

Included within is a map labeled as **Exhibit 5** which shows the location of the horizontal Wolfcamp wells included in the analysis. It should be noted that this hydrocarbon deposit appears to be regional across southeast Eddy County and southwest Lea County.

Within the study area of the 4 townships, there have been numerous vertical wells that have penetrated the Upper Wolfcamp formation as shown on **Exhibit 6** labeled "Wells that Penetrate the Wolfcamp in Study Area." This soundly establishes the presence of the Wolfcamp reservoir at the proposed location.

Following Exhibit 6 is an exhibit from Matador's information exhibits filed with the OCD and/or the OCC (labeled Matador Exhibit 12) showing the structural position of the proposed well. The structure map shows where the data for the top of the Wolfcamp structure was derived – numerous Wolfcamp penetrations. A cross-section through 4 wells that penetrated the Wolfcamp is also included, and visibly demonstrates the presence of the Upper Wolfcamp at the location of the proposed well (see Matador Exhibit 13).

SUMMARY OF RESULTS

The following data that exists in the 4 township study area is summarized as:

- Only one horizontal well was lost during the actual drilling operations
- Only one horizontal well was considered a dry hole
- The ability to drill and complete a horizontal well has been proven in the area
- The available information indicates a high likelihood of the presence of reservoir quality rock in the Upper Wolfcamp
- The available information indicates the presence of a geo-pressured Wolfcamp reservoir as seen throughout the Delaware Basin

Based on the information and results stated above, we believe that there is a very high possibility that a horizontal Wolfcamp well can be drilled and completed at the proposed location with a productive well will being the result.

ECONOMIC RISK ANALYSIS

Bone Spring Wells

The next charge to HMA was to derive a breakeven analysis for horizontal Bone Spring wells in the area. We used an estimated a capital cost of $5,250,000 to drill and complete a horizontal Bone Spring well in the study area. For product value, we used the Bank of Oklahoma's September 2016 Price Deck to determine estimated oil prices. In addition, we derived expected operating expense from previous experience with multiple evaluations involving horizontal producers. The results of economic calculations using these data revealed a breakeven EUR of 210 MBOE (thousands of barrels of oil equivalent) for the average Bone Spring well in the study area.

The Bank of Oklahoma's September 2016 Oil and Gas Pricing Deck is summarized below:

- Starting 9-1-2016 and ending 8-31-2017 – Oil = $47.77/bbl and Gas = $3.08/mmbtu
- Starting 9-1-2017 and ending 8-31-2018 – Oil = $48.55/bbl and Gas = $3.03/mmbtu

- Oil base price escalates at 3% per year to a cap of $85/bbl
- Gas base price escalates at 3% per year to a cap of $6.00/mmbtu

We are aware that many of the 101 producing wells in the four townships cost more than $5,250,000 to drill and complete and that the price of oil when many of the wells were drilled greatly exceeded the Bank of Oklahoma's present forecast for oil prices. Our charge was to determine the drilling and economic risk and the chances of payout in today's environment. Drilling costs of the sort of wells examined have dropped to approximately $5,250,000 per well as a result of new efficiencies necessitated by the decrease in oil prices. The price drop also led to a lower demand for drilling goods and services which, in turn, resulted in a drop in the prices of those drilling-related costs. Thus, we based our evaluation on current circumstances.

When the breakeven value of 210,000 barrel oil equivalents ("BOE") or 210 MBOE is plotted on the regression line shown on the Bone Spring EUR statistical plot (Exhibit 3), the result indicates that 61% of the wells today would achieve payout under normalized conditions. Conversely, 39% of the wells would not reach payout, though all of the 101 wells produce oil, and many of the wells in the 39% category almost attain payout. As stated earlier, in the four township area there was only one horizontal well drilled as a dry hole, and there was only one horizontal well lost in the drilling process.

In determining a breakeven value for a horizontal Bone Spring well as stated above, we utilized the information gained from our analysis to determine the averages for oil and gas producing rates, estimated ultimate recovery, initial production rates, hyperbolic exponents, initial decline rates, etc. We would then scale the respective decline curve and producing components as needed to compute an economic breakeven value.

We also utilized another method to determine the percentage of wells within the study area that would achieve pay out status under <u>current economic conditions</u>. This method involved using the actual historical production to date for each individual well. The actual production along with the projected production decline established the production rate over the life of the well resulting in an estimated ultimate recovery for each well. We initiated the production from each of the wells at the same point in time and then performed an economic analysis based on current economic conditions. In essence, we normalized each of the wells to a common point in time with and applied current costs and prices to correspond to current conditions. Using this method, the calculations revealed that 66% of the normalized wells would achieve payout while 34% would not.

It should be noted that actual historical production from the wells on the lower end of the ultimate recovery spectrum tend to have a larger percentage of the oil volume component in the producing hydrocarbon stream relative to the volumes produced by the higher EUR wells. As a result, there will be some wells that have a payout value (as calculated by the second method) that have a lower EUR than the EUR of the average breakeven well as calculated in the first method. The difference can be attributed to the method used to calculate the BOE's and the relative amount of gas in the total hydrocarbon production stream. The industry standard for the conversion of gas to "oil equivalents" is done on a one-to-six ratio: one barrel of oil is equivalent to six MCF of gas. This ratio is derived from the comparative heating value of each of the two commodities. However, when the actual oil/gas price ratio is not one to six, relative amounts of "error" will be introduced and somewhat different results will be obtained.

In summary, as the volume of gas increases in the total hydrocarbon production flow stream, the relative value of that production will decrease due to the oil/gas price ratio disparity seen in the current product pricing environment. A well with a lower EUR can have a higher relative value due to the decrease in the volume of gas associated with the total hydrocarbon production.

WOLFCAMP WELLS

To calculate breakeven economics for a typical horizontal Wolfcamp well, the economic study used a capital cost of $6,500,000 to drill and complete a horizontal Wolfcamp well in the study area, the Bank of Oklahoma's September 2016 Price Deck, and the expected operating expense. The results from economic calculations revealed a breakeven EUR of 275 MBOE.

When the breakeven value of 275 MBOE is plotted on the regression line shown on the Wolfcamp EUR statistical plot (Exhibit 4), the result indicates that about 76% of the Wolfcamp wells would achieve payout today under normalized conditions. Thus, only 24% of the Wolfcamp wells would not reach payout.

For additional Wolfcamp analysis, we also utilized the second method, as described in the Bone Spring section above, even though the data set for the Wolfcamp was somewhat more limited.

The results of the horizontal Wolfcamp drilling analysis revealed that 87.5% of the normalized wells should achieve payout and 12.5% would not.

The greater disparity between the estimated Wolfcamp breakeven figures vs. the Bone Spring breakeven figures using the two methods is the result of the Wolfcamp wells having a greater variance in gas volumes in the total hydrocarbon production stream. Further, the sample set of the Wolfcamp wells (64) was smaller than the sample set (101) of the Bone Spring wells. However, utilizing the results from both of the methods, our analysis is that in the study area the average number of Wolfcamp wells which will not achieve payout lies in the range of 12.5% and 24%.

DRILLING & ECONOMIC RISK SUMMARY

Our review and analysis indicates that as to Bone Spring horizontal drilling in the 4 township study area, there is somewhat less than a 1% chance of drilling a dry hole or of losing a well.

Although the data set for the Wolfcamp is somewhat limited as previously described, Wolfcamp horizontal drilling in SE Eddy County and SW Lea County to date appears to have a similar chance of drilling a dry hole or of losing a well.

As to the horizontal Bone Spring wells in the present oil and gas prices and drilling costs environment, our analysis by the methods described in this report indicate that there is a range from a 34% chance to a 39% chance of not achieving payout. Respective to the horizontal Wolfcamp drilling, there is a range from a 12.5% chance to a 24% chance of not achieving payout.

HOW DOES THE FORCE-POOLED PARTY FARE?

The last charge to HMA was to perform an economic analysis under various non-consent penalties in order to determine how the force-pooled party fares under the rules as presently applied by the New Mexico Oil Conservation Division and the Oil Conservation Commission. Economic sensitivity cases were run on 3 typical horizontal Bone Spring wells and 3 typical Wolfcamp wells with different individual EURs.

The input parameters for each of the Bone Spring cases are:

- Capital costs = $5,250,000
- 10% Non-consent interest
- When designated risk penalty payouts are achieved, then the forced pool party receives income based on WI = 10% & NRI = 8%
- Pricing = Bank of Oklahoma September 2016 Price Deck

The economic cases summarized and shown on the next page indicate that if the EUR of a horizontal Bone Spring well falls on the regression line at or below the P50 value, the forced pooled interest will probably never see any value for their interest unless the non-consent penalty is **34%** or lower.

PROFIT MADE BY FORCE POOLER ON BONE SPRING HORIZONTAL WELLS IN DELAWARE BASIN, SE NEW MEXICO FROM A 10% FORCE POOLED INTEREST

* Figures are not discounted

Bone Spring EUR = 250 MBOE

(Approximately 50% of the wells are equal to or greater than 250 MBOE)

NON-CONSENT PENALTY	MONEY FORCE POOLER MAKES FROM FORCE POOLED PARTY'S INTEREST	FORCE POOLING PARTY'S RETURN ON INVESTMENT	MONEY MADE BY FORCED POOLED PARTY
200%	$200,748.00	38%	$0.00
133%	$200,748.00	38%	$0.00
66%	$200,748.00	38%	$0.00
34%	$178,491.00	34%	$22,257.00

Bone Spring EUR = 400 MBOE

(Approximately 26% of the wells are equal to or greater than 400 MBOE)

NON-CONSENT PENALTY	MONEY FORCE POOLER MAKES FROM FORCE POOLED PARTY'S INTEREST	FORCE POOLING PARTY'S RETURN ON INVESTMENT	MONEY MADE BY FORCED POOLED PARTY
200%	$768,382.00	146%	$0.00
133%	$698,215.00	133%	$70,167.00
66%	$346,508.00	66%	$351,707.00
34%	$178,524.00	34%	$589,858.00

Bone Spring EUR = 550 MBOE

(Approximately 15% of the wells are equal to or greater than 550 MBOE)

NON-CONSENT PENALTY	MONEY FORCE POOLER MAKES FROM FORCE POOLED PARTY'S INTEREST	FORCE POOLING PARTY'S RETURN ON INVESTMENT	MONEY MADE BY FORCED POOLED PARTY
200%	$1,049,963.00	200%	$441,962.00
133%	$698,138.00	133%	$793,787.00
66%	$346,300.00	66%	$1,145,625.00
34%	$178,374.00	34%	$1,313,551.00

Economic sensitivity cases were run on 3 horizontal Wolfcamp wells with different individual EURs. The input parameters for each of the Wolfcamp cases were:

- Capital costs = $6,500,000
- 10% Non-consent interest
- When designated risk penalty payouts are achieved, then the forced pool party receives income based on WI = 10% & NRI = 8%
- Pricing = Bank of Oklahoma September 2016 Price Deck

The economic cases summarized and shown below indicate that if the EUR of a horizontal Wolfcamp well falls on the regression line at or below the P50 value, the forced pooled interest will probably never see any value for their interest unless the non-consent penalty is **66%** or lower.

PROFIT MADE BY FORCE POOLER ON WOLFCAMP HORIZONTAL WELLS IN DELAWARE BASIN, SE NEW MEXICO FROM A 10% FORCE POOLED INTEREST

* Figures are not discounted

Wolfcamp EUR = 350 MBOE

(Approximately 65% of the wells are equal to or greater than 350 MBOE)

NON-CONSENT PENALTY	MONEY FORCE POOLER MAKES FROM FORCE POOLED PARTY'S INTEREST	FORCE POOLING PARTY'S RETURN ON INVESTMENT	MONEY MADE BY FORCED POOLED PARTY
200%	$256,083.00	39%	$0.00
133%	$256,083.00	39%	$0.00
66%	$256,083.00	39%	$0.00
34%	$220,998.00	34%	$35,085.00

Wolfcamp EUR = 500 MBOE

(Approximately 48% of the wells are equal to or greater than 500 MBOE)

NON-CONSENT PENALTY	MONEY FORCE POOLER MAKES FROM FORCE POOLED PARTY'S INTEREST	FORCE POOLING PARTY'S RETURN ON INVESTMENT	MONEY MADE BY FORCED POOLED PARTY
200%	$769,499.00	118%	$0.00
133%	$769,499.00	118%	$0.00
66%	$428,907.00	66%	$340,592.00
34%	$221,023.00	34%	$548,476.00

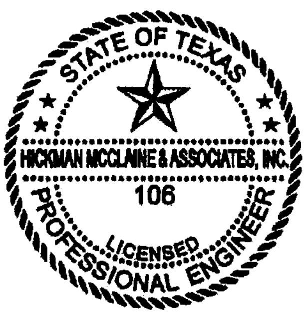
Wolfcamp EUR = 700 MBOE

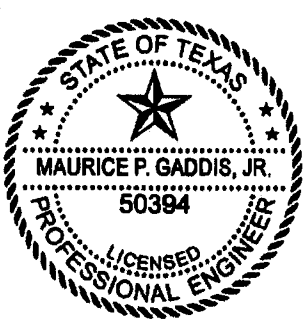
(Approximately 33% of the wells are equal to or greater than 700 MBOE)

NON-CONSENT PENALTY	MONEY FORCE POOLER MAKES FROM FORCE POOLED PARTY'S INTEREST	FORCE POOLING PARTY'S RETURN ON INVESTMENT	MONEY MADE BY FORCED POOLED PARTY
200%	$1,299,957.00	200%	$149,723.00
133%	$864,561.00	133%	$585,119.00
66%	$429,027.00	66%	$1,020,653.00
34%	$221,037.00	34%	$1,228,643.00

In summary, our analysis of the Bone Spring horizontal wells drilled in the 4 township study area demonstrates that at present prices and drilling costs a force-pooled party will receive no income from his leasehold or mineral interest in approximately 74% of the wells drilled if the OCD's standard 200% non-consent penalty is imposed (see exhibit case "Bone Spring EUR = 400 MBOE"). Conversely, the force pooler's ROI made on the force-pooled interest can range as high as 146% when a 200% non-consent penalty is imposed. Yet, as stated earlier in the report, Bone Spring wells drilled within the study area have only a 39% statistical probability (or a risk) of not achieving payout under current economic conditions. Utilizing the normalized method, Bone Spring horizontal wells drilled within the study area have only a 34% probability of not achieving payout under current economic conditions.

Respective to the Wolfcamp horizontal wells drilled in southeast Eddy County and southwest Lea County, our analysis reveals that at present prices and drilling costs a force-pooled party will received no income from his leasehold or mineral interest in approximately 52% of the wells drilled if the OCD's standard 200% non-consent penalty is imposed (see exhibit case "Wolfcamp EUR = 500 MBOE"). As shown on the exhibit, the force pooler's ROI made on the force-pooled interest can range as high as 118% when a 200% non-consent penalty is imposed. Although the number of horizontal Wolfcamp wells have not attained the minimum number of data points to satisfy a "Resource Play" criteria as described by the literature sources, the regression analysis resulting from the study yields a statistical probability (or a risk) that only 24% of the wells will not achieve payout. Utilizing the normalized method, Wolfcamp horizontal wells drilled within the study area have only a 12.5% probability of not achieving payout under current economic conditions.





Yours Very Truly,

HICKMAN McCLAINE & ASSOCIATES, INC.

Maurice P. Gaddis, Jr., P.E.

Attachment A

RESERVE DEFINITIONS

(Condensed from 2007 Petroleum Resource Management System)

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.

Reserves Category

Proved Reserves

Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

Reserves in undeveloped locations may be classified as Proved provided that:

The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive.

Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations.

For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the proved area and the applied development program.

Probable Reserves

Probable reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves.

It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves. In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the Proved plus Probable estimate.

Probable Reserves may be assigned to areas of a reservoir adjacent to Proved wells where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria.

Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Possible Reserves

Possible reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves.

The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible, which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the Proved plus Probable plus Possible estimate.

Attachment A

Possible reserves may be assigned to areas of a reservoir adjacent to Probable areas where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project.

Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.

Reserves Status

Developed Reserves

Developed Reserves are expected quantities to be recovered from existing wells and facilities.

Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

Developed Producing Reserves. Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves. Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production.

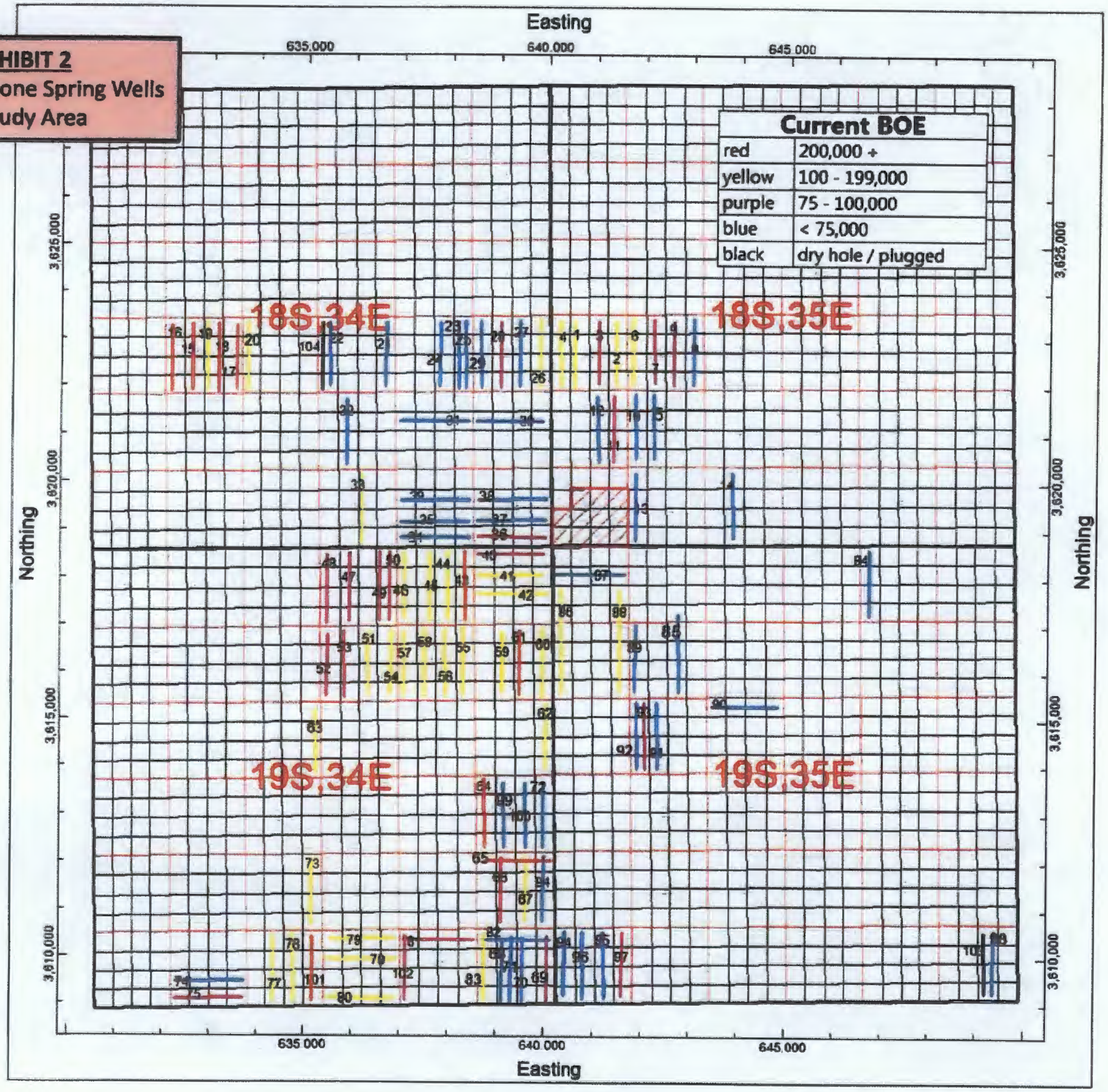
In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Undeveloped Reserves

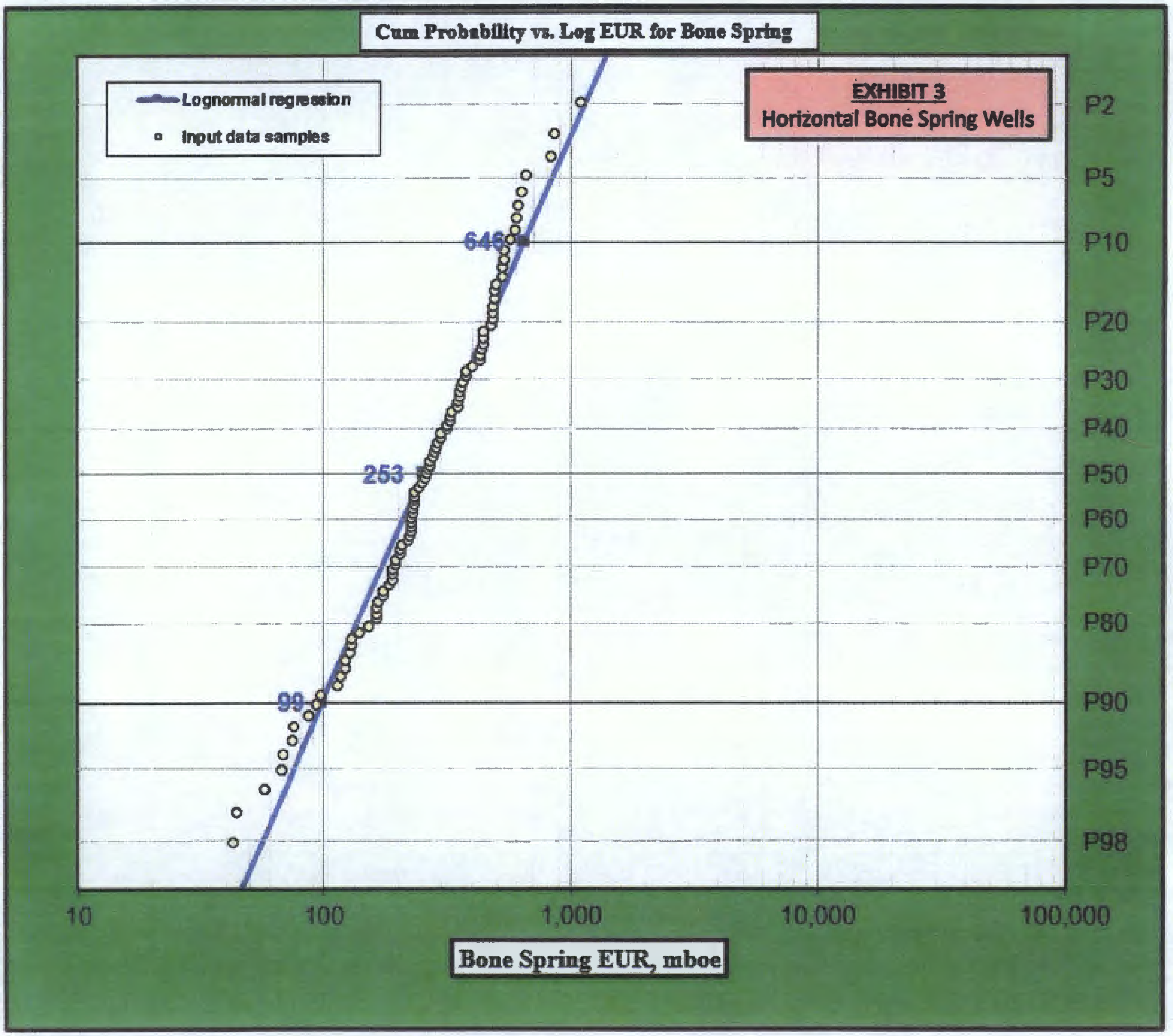
Undeveloped Reserves are quantities expected to be recovered through future investments (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary of improved recovery projects.


EXHIBIT 1
Study Area in Lea County & Location of Matador's Proposed Horizontal Wolfcamp Well
Airstrip 201H

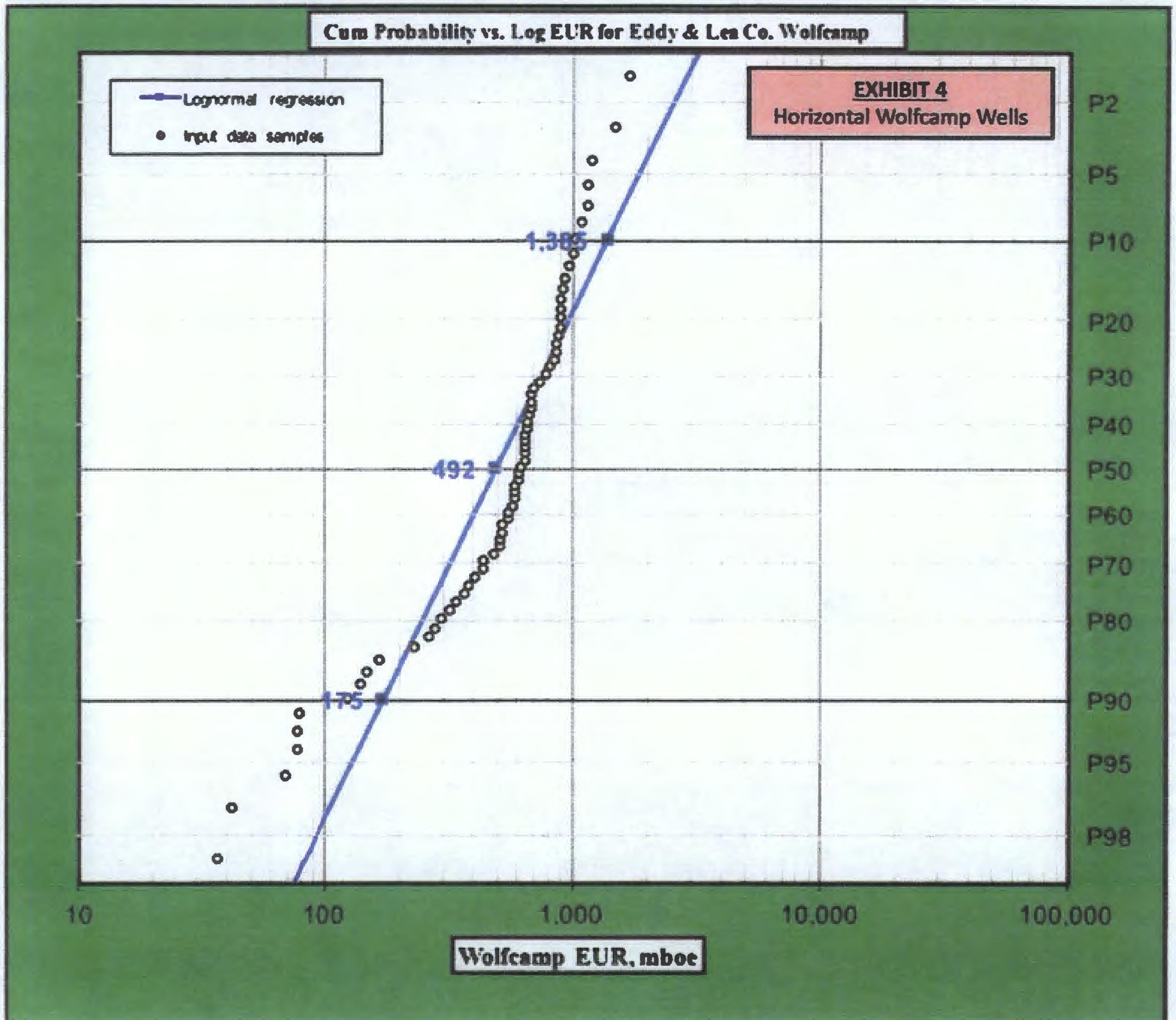
EXHIBIT 2
Horizontal Bone Spring Wells
in Study Area



Current BOE	
red	200,000 +
yellow	100 - 199,000
purple	75 - 100,000
blue	< 75,000
black	dry hole / plugged



Cum Probability vs. Log EUR for Bone Spring
Lognormal regression
Input data samples
EXHIBIT 3
Horizontal Bone Spring Wells
646
253
99
P2
P5
P10
P20
P30
P40
P50
P60
P70
P80
P90
P95
P98
10
100
1,000
10,000
100,000
Bone Spring EUR, mboe


Cum Probability vs. Log EUR for Eddy & Lea Co. Wolfcamp
Lognormal regression
Input data samples
EXHIBIT 4
Horizontal Wolfcamp Wells
1,385
492
175
P2
P5
P10
P20
P30
P40
P50
P60
P70
P80
P90
P95
P98
10
100
1,000
10,000
100,000
Wolfcamp EUR, mboe

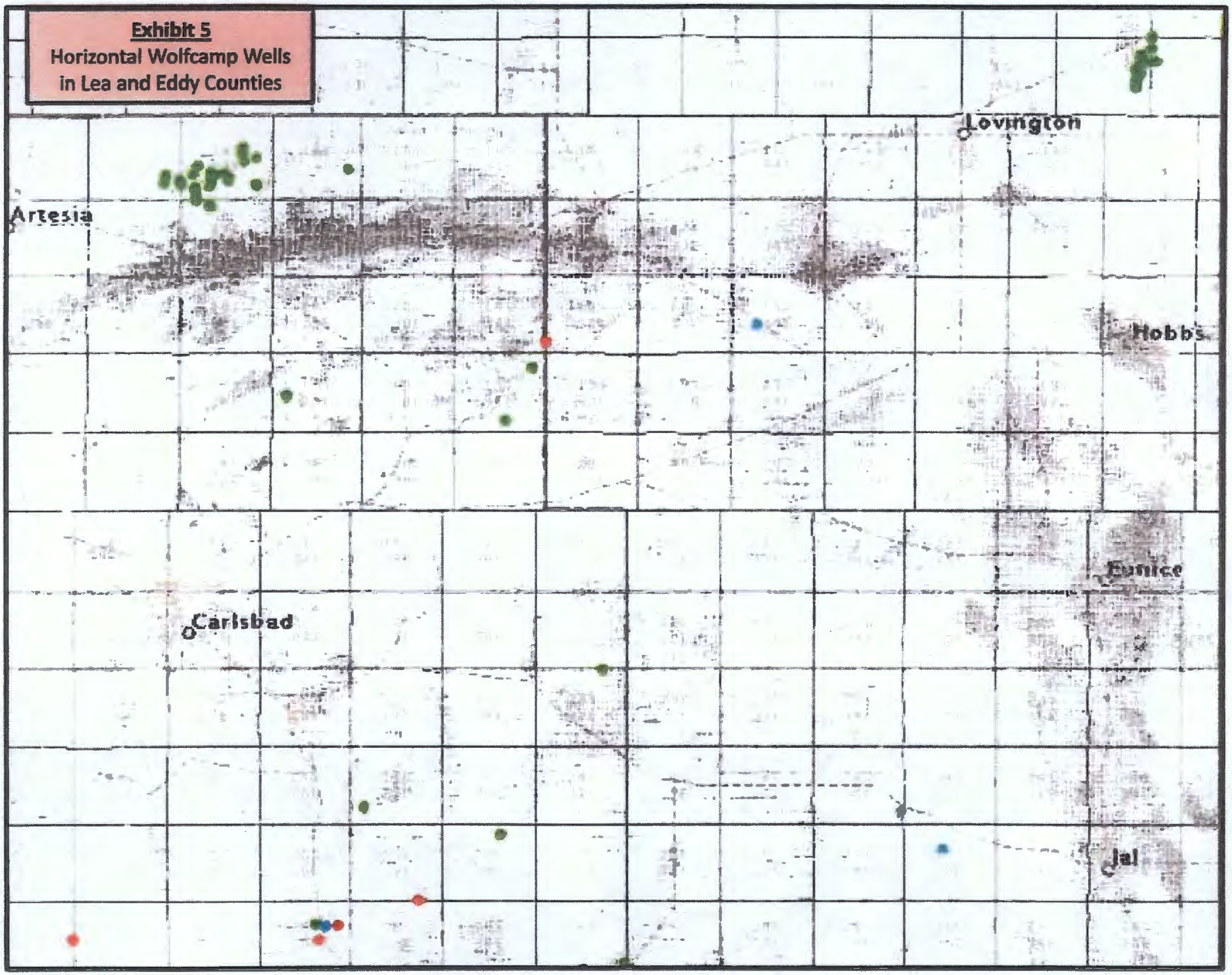


Exhibit 5
Horizontal Wolfcamp Wells
in Lea and Eddy Counties
Artesia
Lovington
Hobbs
Carlsbad
Eunice
Jal

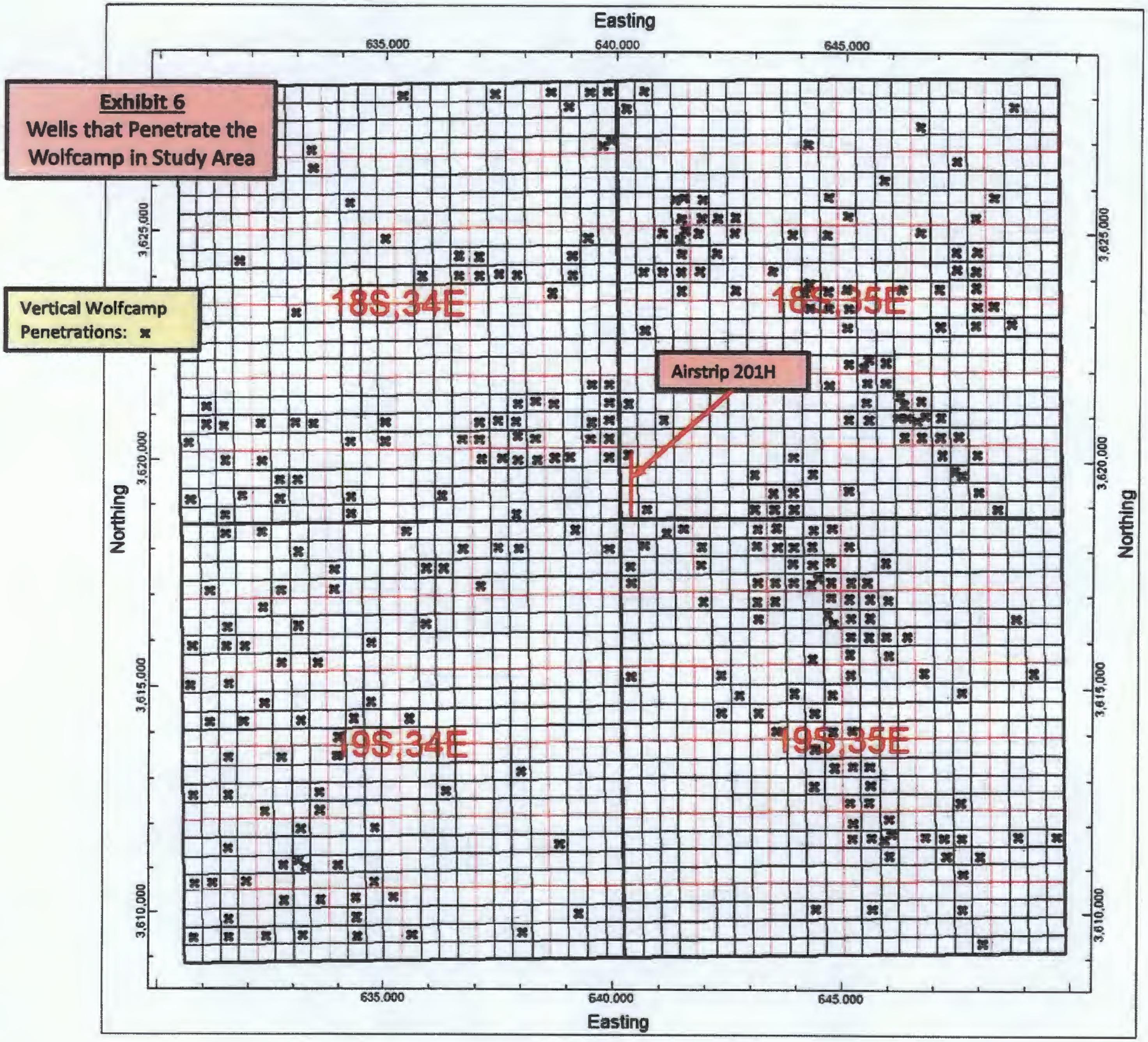
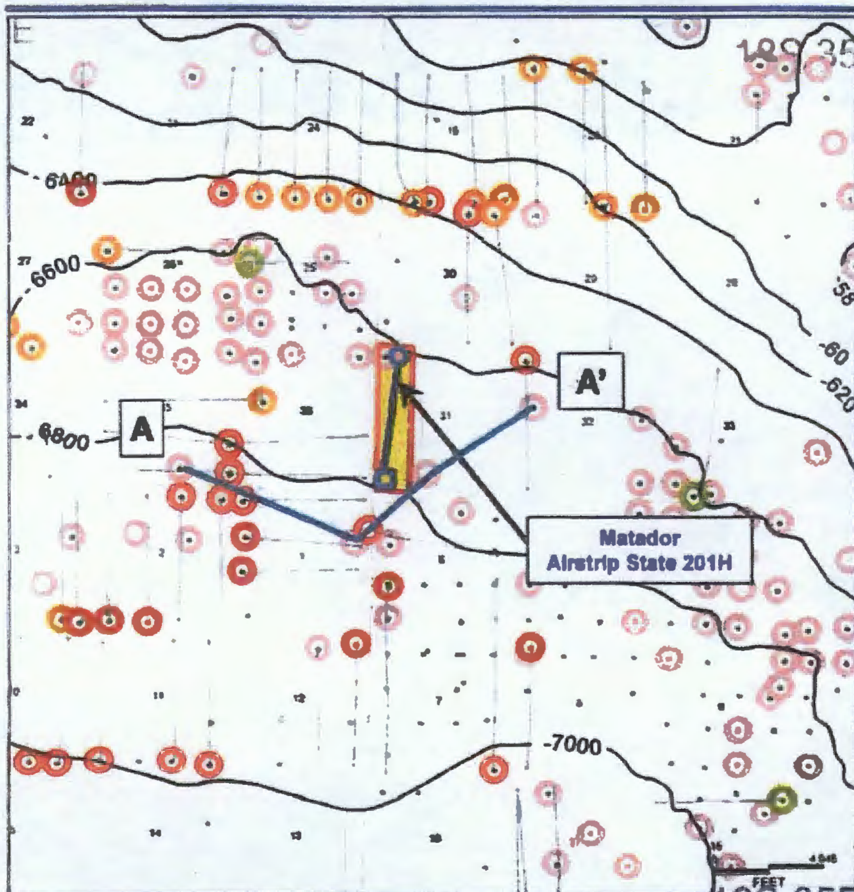


Exhibit 6
Wells that Penetrate the Wolfcamp in Study Area
Vertical Wolfcamp Penetrations:
Easting
635,000
640,000
645,000
Northing
3,625,000
3,620,000
3,615,000
3,610,000
18S,34E
18S,35E
19S,34E
19S,35E
Airstrip 201H

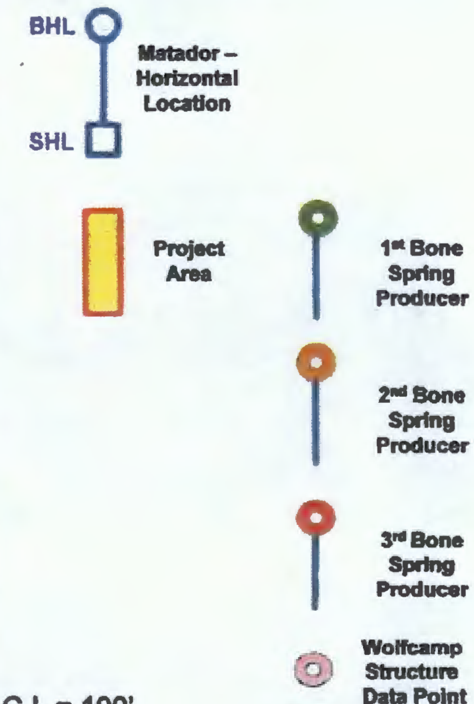
Matador
Exhibit 12

Airstrip; Wolfcamp Pool (Pool Code 970)
Structure Map (Top Wolfcamp Subsea)



Airstrip State Com 31-18S-35E #201H

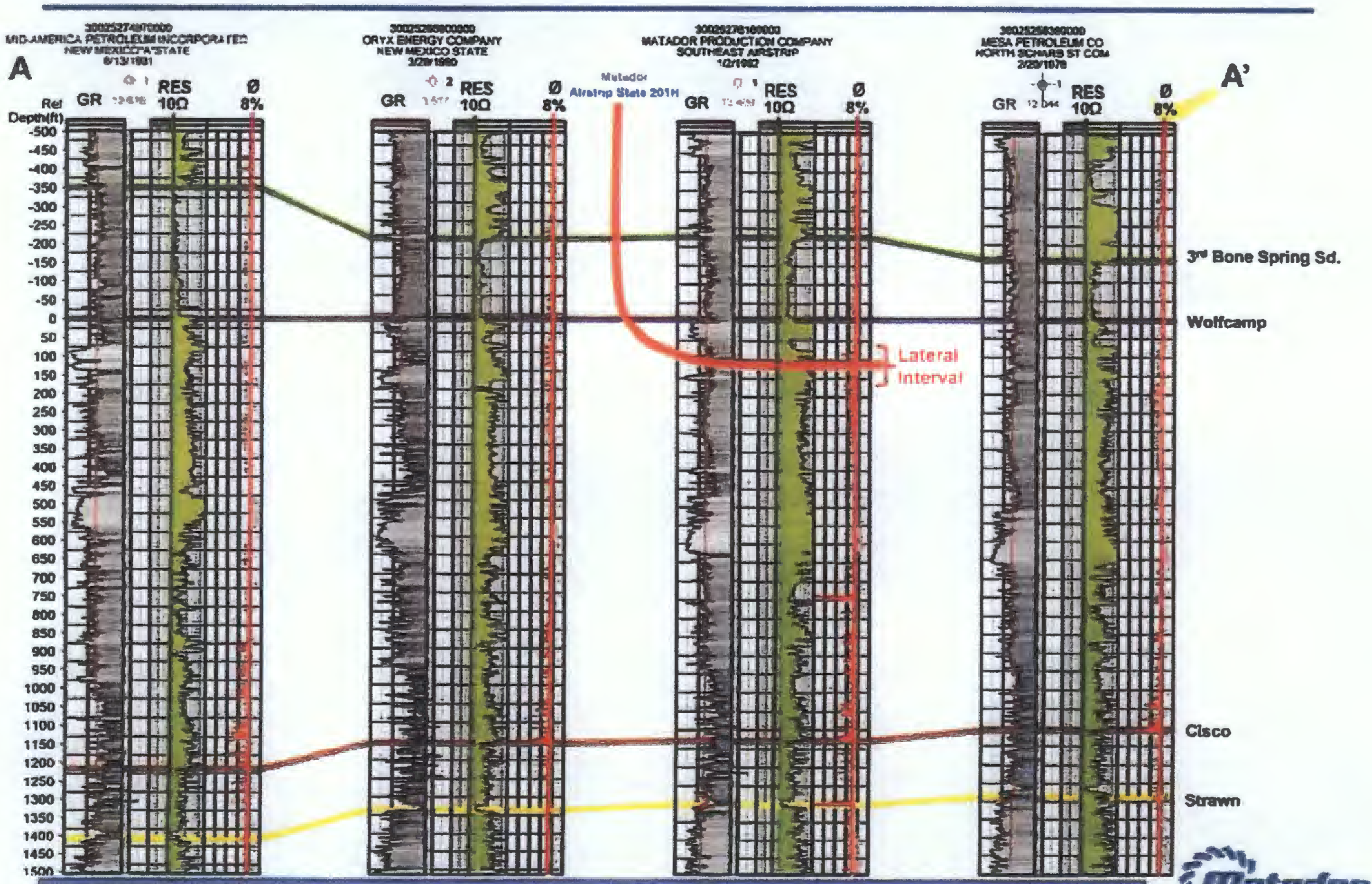
Map Legend



C.I. = 100'

Airstrip; Wolfcamp Pool (Pool Code 970)
Stratigraphic Cross Section A - A'

Matador
Exhibit 13



Airstrip State Com 31-18S-35E #201H