RAILROAD COMMISSION OF TEXAS

HEARINGS DIVISION

OIL AND GAS DOCKET NO. 10-0275277

THE APPLICATION OF QUESTA ENERGY CORPORATION TO AMEND FIELD RULES FOR THE PANHANDLE, WEST FIELD, CARSON, GRAY, HARTLEY, HUTCHINSON, MOORE, OLDHAM AND POTTER COUNTIES, TEXAS

HEARD BY: Richard D. Atkins, P.E. - Technical Examiner
Michael Crnich - Legal Examiner

APPEARANCES:	**REPRESENTING:**
APPLICANTS:	
David Gross Dale E. Miller Margaret Allen Dale W. Rufenacht Scott Herrick	Questa Energy Corporation and Pantera Energy Company
Flip Whitworth D. Davin McGinnis James M. Clark Rich Frazier Byron Solarte Megan Lichtenwalter	Linn Operating, Inc.
INTERVENOR:	
George C. Neale Christopher S. Hotchkiss Wayman T. Gore, Jr. Brad Michalchuk Gary Edge	Pioneer Natural Res. USA, Inc.

PROTESTANTS:

Jamie Nielson Tim George Ron Schultz Richard F. Strickland Steve Towns Heather Caramanica Stephen Duncan Raymond Mitchell Dwayne Purvis	ConocoPhillips Company
David E. Jackson John McBeath	Travelers Oil Company

OBSERVERS:

Brian R. Sullivan Sandra Bolz Buch	BP America Production Company
Thomas Burdett	Sullivan - Wells and Huff Minerals, Ltd.

PROCEDURAL HISTORY

Application Filed:	March 20, 2012
Notice of Hearing:	March 30, 2012
Protest Received:	April 9, 2012
Hearing Held:	March 3-15, 2013
Transcript Received:	April 30, 2013
Record Closed:	May 21, 2013
Proposal for Decision Issued:	September 5, 2013

EXAMINERS' REPORT AND PROPOSAL FOR DECISION

STATEMENT OF THE CASE

Field Rules for the Panhandle, West Field were adopted in Final Order No. 112, effective August 27, 1930, as amended. The current Field Rules are summarized as follows:

1. Boundary line between the Panhandle, West and Panhandle, East Fields;

2. 330'-660' well spacing;

3. 640 acre gas units;

4. Allocation based on 67% acres multiplied by shut-in wellhead pressure and 33% of twelve month peak ("TMP");

5. Separating device provisions;

6. Gas well testing provisions.

Questa Energy Corporation ("Questa"), Pantera Energy Company ("Pantera") and Linn Operating, Inc. ("Linn") request that the Field Rules be amended to provide for 640 acre gas units with optional 160 acre density and the allocation formula be suspended. Pioneer Natural Res. USA, Inc. ("Pioneer") requests 640 acre gas units with optional 320 acre density and has no position on the status of the allocation formula.

The application is protested by ConocoPhillips Company ("ConocoPhillips") and Travelers Oil Company ("Travelers") who were opposed to changing the existing density rule and suspending the allocation formula.

The examiners recommend that the Field Rules for the Panhandle, West Field be amended to provide for 640 acre gas units with optional 160 acre density, as requested by Questa, Pantera and Linn. The examiners recommend that suspension of the allocation formula be denied.

DISCUSSION OF THE EVIDENCE

The Panhandle Field was discovered in 1918 at an average depth of 4,200 feet. After discovery, the field was divided into the Panhandle, East and Panhandle, West Fields. Both fields originally operated under Field Rules that provided for 330'-660' well spacing and 160 acre gas units. However, in September 1948, the density in the Panhandle, West Field was amended to 640 acre gas units.

In the Panhandle, East Field, there are 1,452 producing gas wells carried on the proration schedule. In the Panhandle, West Field, there are 2,239 producing gas wells carried on the proration schedule. Both fields have an allocation formula based on 67% acres multiplied by shut-in wellhead pressure and 33% of TMP. Cumulative gas production from the Panhandle Field is estimated at 40 TCFG with remaining gas reserves of approximately 4 TCFG.

The Panhandle, West Field encompasses approximately 1.2 MM acres and 4,190 wells have been drilled in the field, resulting in an average field development density of 295 acres per well. The field is 95 years old and is expected to produce for another 50 years. The parties at the hearing own approximately 53.4% of the wells and 57.1% of the total acreage in the field. They have also drilled 56.5% of the total wells in the last 25 years.

Drilling during the last 25 years has been primarily to replace plugged out wells and infill drill wells under Statewide Rule 38 exceptions or non-concurrent production restrictions.

Questa/Pantera's Evidence

Geology

The Panhandle Field area is a complex structural trap that overlies the Amarillo Uplift. The field occupies a broad anticline formed by drape over the uplift, which is bounded on the north by the Anadarko Basin and on the south by the Palo Duro Basin. The irregularity of the Amarillo Uplift surface coupled with the presence of numerous block faults and grabens has resulted in complex fold and fault controlled closure across the field. Most of the gas production comes from Wolfcamp dolostone and limestone.

The rocks were deposited on a shallow marine carbonate platform that developed along the margins of the Amarillo Uplift and later extended completely across the area including the now buried Amarillo Uplift. The carbonate consists of skeletal or ooid grainstone and burrowed mudstone or wackestone deposited in repeated upward shallowing sequences. These rocks contain locally well developed intergranular and intercrystalline pore space that results in high values of porosity and permeability. The cyclic character of these deposits results in marked lateral and vertical variations in porosity and stratigraphic variability. Studies of the deposits indicate that considerable reservoir heterogeneity and compartmentalization may be present.

The reservoir is composed of discrete and usually identifiable formations, which include the Panhandle Lime (the top seal), Brown and White Dolomite, Moore County Lime, Arkosic Dolomite and Lime, Granite Wash and the basal fractured granite. The field is generally productive of hydrocarbons in all of the formations that are encountered at any particular location. The maximum total thickness is 1,400 feet and ranges from -200 feet to +1,200 feet subsea depth. Up to 1,000 feet of structural variation has been observed in a distance of only a few miles. Questa's geological expert submitted several structure maps, type logs and cross-sections depicting the varying formation depths, thicknesses, continuity and graben areas that have been encountered in the Panhandle Field.

The original reservoir pressure was 465 psia and has generally declined to less than 30 psia today. Most of the wells in the field are connected to a vacuum pump and produce under a vacuum. The pressure and production data suggest that all of the reservoir units in the Panhandle Field are in some vertical communication, which would effectively constitute a single reservoir. Although the Commission has prorated the field as a single reservoir, there are heterogeneous or highly faulted areas of the field that have varying bottomhole pressures that can be as high as 200 psia.

Optional 160 Acre Density

Questa's engineering expert analyzed the February 2013 gas proration schedule and determined that there were 3,023 wells listed. However, only 2,695 wells had acreage assigned and only 2,239 wells had an allowable assigned and are shown on the proration schedule as producing. Of the wells that had acreage assigned, 1,377 had 640 acres or more assigned and 1,318 wells had less than 640 acres assigned, which is 51% and 49%, respectively, of the total wells. There were 605 wells that had 160 acres or less assigned, which represents 22% of the total.

Questa's engineering expert submitted a tabulation of the Statewide Rule 38 cases for the Panhandle, West Field from 1983 to date. There have been 313 Statewide Rule 38 cases submitted and 232 cases, or approximately 73%, have been granted. Only two cases, or approximately 1%, have been denied. The remaining cases have been dismissed or withdrawn. The expert opined that since 1983 there have been 232 Statewide Rule 38 cases granted by the Commission, which indicates that it is time for an optional density field rule.

There were 328 wells that did not have any acreage assigned and the expert opined that these wells were probably shut-in with a non-concurrent production clause or temporarily abandoned. So, on hundreds of occasions, operators have elected to obtain non-concurrent production permits and shut-in a well that was still capable of production at a low rate and drill a new well which would produce at a higher rate. The expert stated that the non-concurrent production permits indicate that although the field is on 640 acre density, the operators don't believe that the original well is effectively and efficiently draining the reserves under 640 acres.

Questa's engineering expert analyzed four study areas, the Cole, Morton, Sanford and Sneed, to determine an average density and additional gas recovery from any infill or replacement wells. The expert counted any multiple horizontal lateral wells as separate wells for the density calculation. The four study areas have an average density of development, including the horizontal laterals, of 262 acres and the field average density is 295 acres. The expert opined that the next logical step for development in the field is the proposed optional 160 acre density, as the proposed 320 acre optional density has already been exceeded.

The Cole study area encompassed a nine section area that contained nine original wells and ten replacement wells. The average density was calculated at 320 acres with 89% of the sections on 320 acre density or less. The estimated ultimate recovery ("EUR") for the original wells was 119.2 BCFG and the EUR for the replacement wells was an additional 19.9 BCFG that would not have been recovered by the original wells. The additional gas recovery represents a 17% increase in gas reserves for the study area.

The Morton study area encompassed a twelve section area that contained 17 original wells and 16 replacement wells. The average density was calculated at 254 acres with 89% of the sections on 320 acre density or less. The EUR for the original wells was 282.9 BCFG and the EUR for the replacement wells was an additional 23.3 BCFG that would not have been recovered by the original wells. The additional gas recovery represents an 8% increase in gas reserves for the study area.

The Sanford study area encompassed a nine section area that contained 14 original wells, six replacement wells and three Statewide Rule 38 wells. The average density, including horizontal well laterals, was calculated at 254 acres with 89% of the sections on 320 acre density or less. The EUR for the original wells was 291.4 BCFG and the EUR for the replacement and Statewide Rule 38 wells was an additional 8.7 BCFG that would not have been recovered by the original wells. The additional gas recovery represents a 3% increase in gas reserves for the study area.

The Sneed study area encompassed a twelve section area that contained 13 original wells, six replacement wells and five Statewide Rule 38 wells. The average density including horizontal well laterals was calculated at 221 acres with 67% of the sections on 320 acre density or less. The EUR for the original wells was 156.1 BCFG and the EUR for the replacement and Statewide Rule 38 wells was an additional 37.3 BCFG that would not have been recovered by the original wells. The additional gas recovery represents a 24% increase in gas reserves for the study area.

Suspension of the Allocation Formula

Of the 2,239 wells on the February 2013 gas proration schedule that had an allowable assigned, 574 wells had a TMP of 100 MCFGPD or more and 1,665 wells had a TMP of less than 100 MCFGPD, which is 26% and 74%, respectively, of the total wells. As a result, 74% of the wells that had an allowable assigned were exempt from the allocation formula, as they were automatically assigned the field minimum allowable of 100 MCFGPD. In addition, only 19 gas wells in the field were actually being prorated and 9 of the prorated gas wells had a zero allowable assigned despite having a TMP gas rate because they either had a zero shut-in wellhead pressure or no acreage assigned to them. Four of the remaining ten prorated wells had a TMP greater than 100 MCFGPD and were assigned an allowable less than the field minimum allowable of 100 MCFGPD. Based on this analysis, only six wells are being effectively prorated, which is only 0.2 % of the total wells assigned an allowable. Questa's engineering expert believed that there was a 100% market demand for all of the gas produced in the field and, as a result, the allocation formula should be suspended.

Linn's Evidence

Optional 160 Acre Density

Linn's engineering expert submitted a base map showing the entire Panhandle, West Field, which is bounded to the north by the Texas Hugoton Field and to the east by the Panhandle, East Field. The expert selected three nine section study areas in the Panhandle, West Field. Recent well logs and pressure history information was the criteria for selecting the study areas. Inputting the well log and pressure data, the expert calculated drainage areas for all of the wells in the study areas using a gas material balance equation for a pressure depletion drive gas reservoir. Only wells that had high initial wellhead pressures were selected in order to avoid any potential errors that would be introduced by an extremely low wellhead pressure.

Study Area 1 was located in Moore County and eleven wells were selected for analysis. The drainage areas ranged from a low of 152 acres up to a maximum of 526 acres. Three wells, or 27%, drained less than 240 acres and five wells had an initial wellhead pressure of 380 psi with gas recoveries varying between 7.4 BCF and 15.0 BCF. Study Area 6 was located in Carson County and 14 wells were selected for analysis. The drainage areas ranged from a low of 140 acres up to a maximum of 895 acres. Three wells, or 21%, drained less than 240 acres and six wells had an initial wellhead pressure of 400 psi with gas recoveries varying between 6.8 BCF and 36.3 BCF. Study Area 7 was located in Hutchinson County and 31 wells were selected for analysis. The drainage areas ranged from a low of 90 acres up to a maximum of 739 acres. Twelve wells, or 39%, drained less than 240 acres and seven wells had an initial wellhead pressure of 400 psi with gas recoveries varying between 3.8 BCF and 36.0 BCF. The expert opined that the disparate well performance demonstrated the highly variable reservoir quality and supported the 160 acre optional density.

Linn's engineering expert also submitted a graph plotting the measured gas gravities in Study Area 7 from 1948 through 2012. Initially, the measured gas gravity was 0.7, but the trend over the last 40 years has the measured gas gravity increasing significantly to 1.15. The expert believed that the gas contained the heavier liquid components, because oil had been condensed in the reservoir through retrograde condensation. As a result, a phenomena that is not often observed in a reservoir occurs when the reservoir gets to extremely low pressures like the Panhandle, West Field. On the phase behavior diagram, a second dew point line is crossed which causes the condensed liquids to revaporize back into the gas phase, resulting in higher gas gravities and BTU values per standard cubic feet. In fact, Pantera and other operators have been receiving 13 to 14 dollars per MCF for gas sold from their leases. This pricing structure also supports the 160 acre optional density, so reserves that have been stranded in the reservoir can be economically developed.

Linn's engineering expert referenced a Moving Domain Study that was performed for Pioneer by Schlumberger Consulting Services. The study found that the reservoir pressure and drainage area have significantly declined with time in the Panhandle, West Field. More recent gas wells are draining only 40 to 60 acres per well and the square of reservoir pressure minus the square of bottomhole flowing pressure is directly proportional to gas rate. In addition, the gas rate is inversely proportional to the logarithm of the drainage radius. Since the reservoir pressure has declined from 465 psia to less then 30 psia today, then effectively the square root of reservoir pressure minus the square root of flowing bottomhole pressure is about 0.4 percent of its initial value. This is similar to the effect of lowering permeability from 100 millidarcies to 0.4 millidarcies. The low reservoir pressure has the same effect on drainage area as low permeability would have in the reservoir. The wells can't drain large areas and a 0.4 millidarcy field would normally be developed on 80 acre density.

The study area was comprised of 508,365 total developed acres and Schlumberger concluded that 105,451 acres will ultimately remain undrained without further development. The study identified a total of 492 Pioneer single infill locations which can be combined to lay out infill replacement and re-entry multi-laterals with a total estimated ultimate recovery of 75.6 BCFG. Linn's engineering expert believed that the decline in reservoir pressure had significantly lowered the effective drainage area and the identified infill locations demonstrate that there are areas of the field that are not being effectively drained under the current rules. He also agreed with the study's conclusions that a significant amount of the field needed further development and supported the need for down spacing on an optional basis in the Panhandle, West Field.

Suspension of the Allocation Formula

Linn's engineering expert submitted a tabulation and graph of proration factors and market demand shown on the header of each proration schedule from January 2003 until August 2012. Each month the proration schedule shows a calculated reservoir market demand of 80 percent of the total TMP production of each individual well and cannot exceed 97 and one-half percent of the total field capability. The calculation is a percentage of past production and does not show anything about a purchaser's need or desire to purchase gas from the field.

The expert noted that there were periods where the acreage and reservoir market demand factors were changing dramatically and these changes did not make any sense. The reservoir market demand graph in 2005 and 2006 fluctuated between five and seven BCF per month and the acreage factor varied by a factor of three within 12 month periods. The expert did not believe that the market demand for gas or the acreage factor, which is simply shut-in wellhead pressure times proration unit size, could change that dramatically over short periods of time.

The expert felt that the existing allocation formula was not accurately setting the field allowable to reflect the market demand for gas from the field. The way the market demand is calculated, based on a percentage of the TMP not to exceed 97 and one-half percent of the total field capability, does not accurately reflect a purchaser's demand for gas. In addition, the expert was not aware of any purchaser of gas from the field that did not have a market for all the gas that could be produced from the field or any operator that did not have a 100 percent market demand for their gas. As a result, the expert believed that the allocation formula should be suspended.

Pioneer's Evidence

Geology

Pioneer's geological expert stated that the Panhandle West and East Fields are geologically analogous with similar reservoir facies and structural complexity that is due to faults, fractures, folds, compaction and dissolution. As a result, reservoir architecture varies dramatically across the field, which includes hydrocarbon column height, structural features, stratigraphy, fluid contacts and reservoir quality. Stratigraphic heterogeneity is observed across the field and the reservoir includes a variety of carbonate and clastic facies with complex stacking and uneven lateral distributions. In addition, many of the lithofacies, lenses and formations are separated by muds, shales or other impermeable layers. Structural complexity, variations, faults, fractures, folds and different fluid contacts indicate that the reservoir is compartmentalized. Pioneer's geological expert submitted a series of closely spaced cross-sections for wells at roughly a 640 acre density. The cross-sections demonstrated a lack of correlation between facies and lenses in the wells and indicated that the reservoir units are not fully connected and that both lateral and vertical flow barriers prevent hydraulic communication between zones.

The expert selected five cores form a field-wide core analysis of 29 cores performed by ConocoPhillips. The selected cores indicated that the reservoir porosities and permeabilities varied significantly not only areally, but also vertically throughout all of the productive formations. Diagenetic and evaporitic minerals often reduce pore-throat size, which decreases reservoir quality and leads to lateral and vertical barriers to effective and efficient hydraulic flow. The core analysis also showed that the lateral permeability is generally much higher than vertical permeability and fractures were observed to be closed and filled with anhydrite.

The expert also submitted a five well cross-section within one section that was prepared by Mr. Tom Bay for a 1987 Panhandle Field hearing. The cross-section illustrates the structural complexity, as two wells which are only 980 feet apart have over a thousand feet of fault throw. In addition, the thickness of the Granite Wash Formation is several hundred feet in the middle wells and virtually nothing in the well furthest to the west. The same situation exists in the fault block shown on the east side of the cross-section. All of the wells on the cross-section were completed in May and June of 1964, but the gas-oil ratios varied dramatically between 771 and 83,000 standard cubic feet per barrel. The expert opined that the cross-section explained the compartmentalization phenomenon nicely, as all of the wells are in one section, all of the wells are perforated at roughly the same depths and all of the wells have radically different gas-oil ratios, indicating the varied nature of the hydrocarbons found at each location.

Optional 160 Acre Density

Pioneer's engineering manager submitted pressure data on their lateral drilling program that was commenced in 1999 and concluded in 2006. During this time, Pioneer drilled over 440 sloped laterals from over 280 existing vertical wells that were spread across Pioneer's entire 240,000 acreage position. Generally, Pioneer would drill two sloped laterals from the existing vertical well on a 640 acre tract. The sloped laterals were drilled through all of the productive formations that were believed to be above the existing saltwater contact. Pioneer did not require Rule 38 exceptions for the laterals, since the Commission does not count laterals as separate individual wells. If the vertical well and the two laterals were counted as three separate wells, Pioneer's acreage would have an average density of 213 acres.

To evaluate the success of the sloped lateral drilling program, Pioneer measured the shut-in pressure and flow rate of the existing vertical well and the newly drilled laterals. The vertical well shut-in pressures averaged approximately 15 psia and ranged from a low of a vacuum up to a maximum of 120 psia and the flow rates averaged approximately 200 MCFGPD and ranged from a low of 0 MCFGPD up to a maximum of 1,200 MCFGPD. The lateral well shut-in pressures averaged approximately 15 psia and ranged from a low of a vacuum up to a maximum of 200 psia and the flow rates averaged approximately 350 MCFGPD and ranged from a low of 0 MCFGPD up to a maximum of 11,000 MCFGPD.

Pioneer's engineering manager stated that pressure variances are widespread across Pioneer's 240,000 acres and they are a testament to the compartmentalization, heterogeneous nature and lenticular nature of the reservoir. He believed that the shut-in wellhead pressures were strongly influenced by high-permeability interval properties and did not accurately represent all interval pressures, which was the result of layered reservoirs that are differentially depleted with minimal pressure data for the individual layers. Pioneer performed a decline curve analysis prior to and after the lateral drilling program. The aggregated decline curve analysis established incremental reserves of 147.3 BCFG from its acreage. Pioneer opined that this substantial volume of gas would not have been produced without its aggressive lateral drilling program.

Pioneer's engineering expert detailed the number and type of wells that were identified as wells approved as exceptions to Statewide Rule 38. There were 298 Rule 38 exceptions that had been approved and the exception wells were spread evenly across the subject field. The expert believed that the need for down spacing is field wide and not a localized issue. In addition, the vast majority of the Rule 38 exception wells represent second wells on 640 acres, which would be an effective density of 320 acres per well. Only 7% of the Rule 38 exception wells represented a third well on 640 acres, which would be an effective density 213 acres per well.

The expert analyzed the Rule 38 exception wells applied for by ConocoPhillips. There were 12 examples of wells that were drilled with non-concurrent production restrictions on an existing well that generated an incremental aggregate recovery of approximately 6.7 BCFG. There were a series of 23 Rule 38 exception wells that all had exceptions approved based solely on pressure differentials. The range of pressure differentials in the 23 wells was similar to the range of pressure differentials observed by Pioneer in its lateral drilling program, which controverted ConocoPhillips's theory that the subject field is at a common pressure and that only slight pressure variations exist across the subject field.

An analysis of Pioneer's parent and replacement wells found that there were 12 pairings showing incremental recovery of 20.2 BCFG and 5 parings showing no incremental recovery. None of the offset wells that were reviewed were found to have been detrimentally affected by the replacement wells. The volume of incremental reserves represented gas that would not have been produced by the existing wells and constituted recoverable gas that would otherwise be wasted. In addition, an analysis of stabilized shut-in pressures for parent and replacement wells operated by Pioneer showed that the shut-in times ranged from 2 to 15 years and that the stabilized shut-in pressures ranged from 1 to 144 psia. The expert opined that the range in reported shut-in pressures confirms not only compartmentalization, but also the lack of effective and efficient drainage of gas from the subject field.

Pioneer's engineering expert agreed with ConocoPhillips that the reservoir model introduced and described as a "mechanistic" model used to demonstrate principles was not intended to represent any particular area of the subject field. The expert felt that the series of input parameters that was assigned to the model was so uniform and unrealistic that the output is not representative of the subject field or of any analogous field and provided little support for ConocoPhillips' position. In order to understand how unrealistic the parameters for the models were, the expert submitted a list of assumptions made in one or both of their models: 1) only the Brown Dolomite was included as a producing formation; 2) all permeabilities below 0.1 millidarcies were excluded; 3) all production formations were assumed to be 200' thick; 4) the model assumes identical lateral and vertical permeability; 5) the model assumes no vertical or horizontal flow barriers; 6) the model assumes an orthogonal fracture every 500; 7) a constant water saturation of 10% was assumed throughout the entire subject field; and 8) the assumed wells in the model had unrealistic production-related assumptions that each well was drilled in the center of a one section tract, all of the wells commence production simultaneously, all wells produce exactly 1,510 MCFGPD every day for 20 years and each well has an EUR between 17.5 BCFG and 22.1 BCFG.

The expert believed that pressure readings did not consistently or accurately represent the production in the subject field. The only accurate and correlatable evidence to know how a field will perform is through production data and the theory that pressure is an indicator of production in the subject field is a fallacy. The expert introduced a publication detailing the dangers and difficulties of using commingled pressures measured at the surface to attempt to determine reservoir characteristics in fields similar to the subject field. Specifically, the authors cite two main obstacles to determining gas in place: 1) wellhead shut-in pressures, which are strongly influenced by high-permeability interval properties, do not accurately represent all interval pressures; and 2) the reservoir, being layered and differentially depleted, has minimal pressure data for the discrete layers. The subject field has the same layered and differentially depleted characteristics as the nearby, similar fields described in the paper. The commingled wellhead shut-in pressures do not provide the necessary data to determine depletion rates and the substantial incremental recoveries belie the artificially depleted pressures.

Through expert testimony on its extensive geologic, engineering and production studies, Pioneer explained that the subject field is a very unique compilation of reservoirs, which clearly require adoption of an optional density unit to allow effective and efficient drainage of the recoverable gas reserves. Additionally, Pioneer showed that its lateral drilling program found a substantial quantity of recoverable gas reserves in the subject field and requests the adoption of a 320-acre optional density unit to aid in the recovery of additional reserves.

Suspension of the Allocation Formula

Pioneer did not have a position on the suspension of the allocation formula, but acknowledged at the hearing that if the allocation formula is suspended, such action would have little or no effect on the wells they operate. Pioneer explained that it had undertaken a study to understand the implications of the proposed suspension of the allocation formula and the study revealed that, due to the location of wells offsetting Pioneer's acreage and the large number of existing special allowable wells with a minimum allowable of 100 MCFGPD, their wells would not be affected. Further, Pioneer explained that the proposed suspension would not negatively impact its correlative rights.

ConocoPhillips' Evidence

Optional 160 Acre Density

ConocoPhillips believes that the request for optional units should be denied. Adoption of an optional unit would lead only to acceleration of production and not result in any incremental reserves. Adoption of an optional unit will strip away property rights protections currently in place across this field of over a million acres. An operator can currently apply for an exception to Statewide Rule 38 for those locations where it thinks an infill well is justified. Adopting an optional unit would eliminate the right of offset property owners to receive notice of proposed infill wells and the opportunity to protest infill wells that would excessively drain neighboring tracts.

ConocoPhillips contends that the evidence proves that there are very few local areas or intervals where conditions might warrant an additional well to justify a field-wide optional unit rule. The pressures from wells in this field consistently demonstrate that production under the 640-acre unit rule has drained gas from large areas in the field. The consistently low, drawn-down pressures measured all across the field prove that drainage under the current unit rule has been effective and efficient. In contrast, there is no proof of any substantial area or interval in the field that has been un-drained by wells drilled under the current unit rule. There is also no proof that any later-drilled well has encountered new or "incremental" gas that was not already in the pressure-depleted drainage areas of earlier wells.

ConocoPhillips argues that the evidence demonstrates that there is no need for an optional unit rule and confirms that current pressures in the field are generally depleted to less than 5% of original reservoir pressure. This fact demonstrates the degree to which gas is being effectively and efficiently recovered from all across this field under the current unit rule. ConocoPhillips' engineering expert submitted isobaric maps demonstrating the pressure depletion of the field over time. The expert described the pressure sink created by Pioneer's lateral wells, which were drilled and produced under the current 640-acre density. Pioneer drilled an extensive 200 mile network of horizontal wells across the entire extent of its acreage. The pressure trends shown by the isobaric maps indicate that these wells have drained gas away from other areas of the field toward Pioneer's wells and tracts, across long distances in the field.

As Pioneer drilled its extensive network of horizontal wells, it gathered pressures in multiple intervals across large portions of the field. In its entire drilling program, however, Pioneer never encountered a single original pressure. All the pressures were substantially depleted. In fact, the highest pressure recorded by Pioneer was only 200 psi, less than half of original pressure. Most of Pioneer's pressures were far less than 5% of original pressure. Pioneer's pressures prove that every interval and area penetrated by Pioneer's network of laterals had already been depleted by prior wells producing under the current 640-acre unit rule.

ConocoPhillips' expert stated that the initial pressures encountered by replacement and Rule 38 wells demonstrate that later-drilled wells consistently encountered a reservoir that was already in the drainage area of an existing well. None of the later wells encountered original reservoir pressure or any un-drained reservoir. Each of the wells encountered a portion of the reservoir where gas had already been drained away in response to production from other wells producing under the 640-acre unit rule.

ConocoPhillips acknowledged that there are differences in the geologic conditions within this large multi-pay field, but explained that those differences are insignificant because the porous and permeable reservoir rock is sufficiently interconnected to allow gas to drain toward producing wells across large areas and intervals. These differences have been touted as "heterogeneity", but heterogeneity just means the value is not the same point-to-point in space. A careful consideration of the detailed correlations shown by geologist Tom Bay illustrates the continuity of porosity both vertically and laterally across miles and miles in this field. ConocoPhillips' expert described how the stratigraphic cross sections prove that, while the porosities can be called heterogeneous, the important focus from these illustrations should be on the large expanses of continuous porous and permeable rock that extend over great distances in all directions.

Although there is variable porosity and permeability, those variations in reservoir geology do not impede flow. ConocoPhillips' expert used vertical flow calculations to demonstrate that large amounts of gas will flow through the low permeability intervals. Comparing the flow calculations to the laterally continuous porosities and the core permeability data, the expert concluded that the resulting flow of gas laterally and vertically in the field is completely at odds with the concept of compartmentalization. Although the field is heterogeneous, it is not "compartmentalized" such that there are field-wide areas or intervals that are not in pressure communication with wells producing under the 640-acre unit rule.

ConocoPhillips urged that the higher producing rates of replacement or Rule 38 wells does not prove new or incremental gas. Each new replacement or Rule 38 well encountered a portion of the reservoir that was shown by the pressure data to have been already substantially drained by production from prior wells. The comparisons of new wells with surrounding prior wells illustrate that new wells were drilled into reservoir rock that was previously drained by prior wells. The increased production rate of the new well results from better completion efficiency or reservoir rock quality. The evidence of lateral continuity in combination with the flow calculations illustrates the reservoir characteristics that afford great opportunity for migration and drainage in response to offset production.

ConocoPhillips' engineering expert opined that the real world examples of infill drilling in the Ted True and B&B Farms areas demonstrate the severe consequences to nearby wells and tracts from harmful cross-leaseline migration to offset wells. The Pioneer pressure sink shown on the 2011 Isobaric map also confirms that such migration can occur, even under the current rules. The expert submitted a mechanistic model to illustrate the drainage that could occur across lease lines with horizontal wells drilled in the Brown Dolomite under the proposed optional rule.

The expert felt that the effects of the optional unit density rule would be greatly exacerbated by the current spacing rule and the proposed suspension of the allocation formula would enable new wells to produce without allowable limitations only 330 feet from lease lines. With the resulting migration and drainage, an operator would not be able to produce the recoverable gas currently in place beneath its tract and would need to drill additional wells solely to protect against neighboring wells producing on optional units. The drilling of those otherwise unnecessary wells would result in economic waste due to the expense of drilling those wells and physical waste due to the increased economic costs of recovery, resulting in the earlier abandonment of wells.

The Rule 38 exception process affords notice to affected persons and requires the applicant to demonstrate that an infill well is truly needed to prevent waste or confiscation. In ConocoPhillips' opinion, the applicants want the Commission to eliminate the Rule 38 exception process through the adoption of an optional unit. The most reasonable conclusion is that the proponents of an optional unit cannot justify that infill wells are needed to prevent confiscation of their gas or prevention of waste. No party has shown that they do not have the opportunity to recover their fair share of gas under the current field rules and no party has shown that there are areas where waste will occur under the current 640-acre density. The expert believed that the push for an optional unit is merely an effort to dodge the Rule 38 burden of proof and should be rejected.

Suspension of the Allocation Formula

ConocoPhillips' allocation expert stated that suspending the allocation formula requires an evaluation of whether each operator in the field has a market for 100% of the TMP for its respective wells. The question is not limited to whether there are purchasers willing to buy all the gas offered to them from the field. There must also be sufficient gas transportation opportunity for the gas to enter the marketplace and be available to a willing purchaser. There is no difference between an operator who cannot produce the capacity of its wells because of the lack of a willing purchaser and an operator who cannot produce the capacity of its wells to a purchaser because of inadequate transportation. In both cases, circumstances beyond the control of the producer result in a lack of market for the productive capacity of its gas wells.

ConocoPhillips contends that the actual market demand for the field is reflected in the monthly production from the field because it is the genuine reflection of the desire of purchasers to take gas and the ability of producers to meet that demand. The limited market demand is not restricted to the wells of ConocoPhillips, but is a characteristic of the field. There is not 100% market demand for all of the wells in the field, as demonstrated by the continual and substantial spread between field market demand (production) and field TMP. For the months of January 2009 through October 2012, the market demand ranged from only 69 % to 83% of TMP. This chronic, substantial shortfall of market demand compared to productive capability of wells in the field requires that the allocation formula remain in effect for the field.

The Protestants believe that there are significant interruptions in transportation services in the field that prohibit operators from delivering the productive capacity from their wells. ConocoPhillips contends that it does not have 100% market demand for the productive capacity of the gas from its wells because there are significant and re-occurring interruptions in gas transportation that are due to plant downtime and other occurrences outside of its control. In calendar year 2012, ConocoPhillips was unable to produce 782,656 MCFG from the field because of the failure of the gathering and processing facilities to be able to take available gas from its wells. ConocoPhillips' expert opined that there is simply not a market for anywhere near 100% of TMP for ConocoPhillips' wells in the field.

ConocoPhillips' expert stated that the proponents of suspension claim that proration should be eliminated because only a few wells in the field are prorated. In his opinion, a small number of wells in the field that are prorated has no bearing on whether the allocation formula should be suspended. The allocation formula was adopted by the Commission in 1999 for the specific purpose of protecting correlative rights by providing each owner with a reasonable opportunity to produce its fair share of gas. Whether the number of wells regulated by that formula is large or small does not eliminate the need for the formula's protection of correlative rights, particularly in the face of less than 100% market demand. Regardless, the true scope of proration is not represented by the number of prorated wells, but on the wells within the drainage areas of prorated wells, as these are the wells that benefit from the allowable restrictions on neighboring prorated wells.

ConocoPhillips believes that if the Commission adopts an optional unit, whether a 320-acre or a 160-acre unit, the Commission should not suspend the allocation formula. The allocation formula becomes a safe harbor for protection of correlative rights in the face of down spacing through an optional unit. The protections afforded mineral owners by the allocation formula will be vital to protect against undue drainage from highly productive wells on small tracts. It would be premature to consider eliminating proration from the field when an optional unit will result in immediate re-activation of existing shut in wells followed by the drilling of additional infill wells in the field.

By ConocoPhillips' estimation, the proponents only case for suspension is their belief that the assignment of allowables is sometimes confusing to them and that there are not many prorated wells in the field. These arguments are legally meaningless. The application to suspend the allocation formula must be denied because the proponents for suspension did not provide any evidence that all operators in the field have a market for all of the gas produced and that suspension is needed to prevent waste or to protect correlative rights.

Travelers' Evidence

Travelers opposes adoption of an optional density rule for the field and also opposes suspension of the allocation formula. The requests for both optional units and suspension of the allocation formula should be denied by the Commission because of the inevitable harm which would result to the correlative rights of Travelers and other operators in the field.

Travelers is a small operator in the field, operating 23 wells listed on the proration schedule, with 8 to 10 newly drilled wells soon to be added. The majority of Travelers' wells are on large acreage units of typically 640 acres. Travelers is a family owned company that has operated in the Panhandle area since the 1920s and Travelers is vitally concerned that the field be developed and managed in a way that avoids waste and premature abandonment of wells.

Reservoir pressure has declined across the field from a discovery pressure of approximately 465 psia to current pressures in most wells of below 25 psia. Most wells now produce at or near vacuum. All operators in the field are dependent on various gathering and compression systems and processing plants, all of which are critical not only for gas production but also for transportation of the gas to market.

Optional 160 Acre Density

The adoption of optional units in the field, where the lease line spacing rule is only 330 feet, would result in drainage of Travelers' acreage, and would force Travelers either to accept the consequences of that drainage or to drill an uneconomic well as an offset. Similarly, suspension of the allocation formula would remove the protections currently provided by an acreage-based allocation formula. If optional units are ultimately approved by the Commission, the correlative rights protection provided by the allocation formula is even more important since multiple wells could be drilled on acreage offsetting Travelers' units.

Travelers recognizes that some limited areas of the field may need to be developed on less than 640-acre density, but the adoption of optional units is not the appropriate way to address that need in this field at this stage of its life and development. The appropriate mechanism to address the need for more dense development in the portions of the Field where it can be justified already exists in the form of Rule 38. Today, under existing field rules, Rule 38 provides all operators with a mechanism to seek approval of new wells on less than 640-acre density where such need can be proven. Equally significantly, Rule 38 gives adjoining property owners something that optional rules do not, which is notice and the right to a hearing in the event the adjoining operator believes the well will cause drainage and harm to correlative rights.

Travelers believes that increased density will not result in incremental recovery of gas, but only in accelerated recovery of gas from the field. Travelers engineering expert submitted a 1947 field-wide pressure map presented in a 1948 Railroad Commission hearing, as well as the series of isobaric maps sponsored by ConocoPhillips. Even given the heterogeneity of the field, pressure responses from production have been seen for decades over long distances within the field. Travelers' expert felt that the field is connected both horizontally and vertically and acts as a single reservoir. These fundamental facts are also demonstrated by the pressure sink resulting from the Ted True drilling on ConocoPhillips acreage and by the 200 miles of laterals associated with Pioneer's lateral drilling program.

The expert stated that the historical and current pressure evidence debunks the assertion of the applicants that the field is compartmentalized and that there are undrained or inadequately drained compartments within the field. He believes that the overwhelming evidence is that pressure responses in this field are seen over extremely long distances and that there is not field-wide compartmentalization. Similarly, the evidence is that optional density is not needed field-wide for incremental recovery and Rule 38 exceptions should be used where those exceptions can be proven.

Travelers' expert opined that there can be no doubt that drilling close to lease lines will result in legitimate concerns about drainage and correlative rights. When the drainage concern is matched up with a 330 foot lease line spacing rule, the concerns are magnified. Travelers' expert submitted hypothetical and real world examples of how 320-acre optional density could affect two of Travelers' existing 640-acre units. The examples show that with optional rules, a Travelers unit could potentially be surrounded by offset wells at 330' from the lease line. Unlike in the Rule 38 process, the offsetting wells could be permitted without any showing that they are necessary to prevent waste or protect correlative rights.

Should Travelers be faced with offset operators drilling optional unit wells adjacent to Travelers acreage, Travelers will be faced with either accepting the consequences of potential drainage, or drilling an uneconomic protection well. Travelers' expert submitted economic projections using cost and production rates based on Travelers recently drilled replacement wells. Four separate economic runs using initial production rates of 60, 90, 110 and 120 MCFGPD showed that each well either lost money or was so marginally profitable that it is unlikely an operator would invest the capital.

In Traveler's opinion, Questa's own evidence shows that the Rule 38 process works, as they summarized the Rule 38 applications made in the field from 1983 to 2013. The data shows that, of the 313 Rule 38 applications filed during that period, only 2 applications, or less than 1%, were denied by the Commission. Seventy-three percent of the Rule 38 applications were approved by the Commission, and the balance were either withdrawn or dismissed. A tabulation of a sampling of approved Rule 38 applications in the field shows that numerous Rule 38 applications have been approved on the basis of waste prevention or prevention of confiscation. The information demonstrates that operators in the field understand the Rule 38 process and how to successfully assemble the information required for approval.

The summary of Rule 38 results proves that the Rule 38 process is working and is not an unreasonable burden on operators. The Rule 38 process is working in the field in two important ways. First, it is allowing increased density of development in those areas of the Field in which such development can be justified under applicable Commission legal standards of waste prevention and/or prevention of confiscation. Second and even more importantly, the Rule 38 process is working to weed out applications that cannot be proven based on waste or prevention of confiscation.

Suspension of the Allocation Formula

Travelers referred to the ConocoPhillips position for its detailed discussion of why the request for suspension of the allocation formula should be denied. The parties advocating suspension of the allocation formula wholly failed to meet the required burden of proof for suspending the allocation formula. The proponents of suspension did not provide any evidence that all operators in the field have a market for the gas from each of their wells, or that suspension is necessary to prevent waste or protect correlative rights. Based on these omissions alone, Travelers believes that the application to suspend the allocation formula should be denied.

Travelers also stated that it does not have a 100% market demand for all of the productive capacity of its wells, because of the downtime of the gathering system to which its wells are connected. For one subset of its wells studied, Travelers determined that in 2012 its wells were down an average of 35% of the time and Travelers was unable to produce its gas to the market because of the gathering and transportation issues from third party gatherers. Travelers' lack of 100% market demand is also a basis for denial of the suspension of the allocation formula.

Questa/Pantera's Rebuttal Evidence

Questa's engineering expert analyzed the February 2013 proration schedule to determine the number of wells that were actually being prorated. The proration schedule contained 2,239 active gas wells and 19 prorated gas wells. Of the 19 prorated gas wells, 9 wells had a zero allowable assigned despite having a TMP gas rate because they either had a zero shut-in wellhead pressure or no acreage assigned to them. Of the 10 prorated gas wells, only three gas wells had a TMP over 350 MCFGPD, with two of the wells owned by ConocoPhillips and one well owned by Pioneer. Four of the ten prorated wells were assigned a gas allowable below the minimum gas allowable of 100 MCFPD and three of the prorated gas wells produced less than 210 MCFGPD.

Questa's engineering expert also submitted a tabulation of the assigned allowable gas production and actual field gas production from January 2009 through October 2012. For 26 of the 46 months shown, the actual field gas production exceeded the assigned allowable gas production. Based on the actual field gas production and the fact that only six gas wells were actually being prorated, the expert opined that there was a 100% market demand for all of the gas produced from the field and that the allocation formula was not effective and should be suspended.

Questa's engineering expert performed a decline curve analysis of the 35 Section Study Area 15 that was presented by ConocoPhillips. In 1985, ConocoPhillips projected that the study area had remaining recoverable reserves of 30 BCFG. ConocoPhillips believed that the infill wells that had been drilled were only accelerating the recovery of gas and not increasing the total gas recovery from the area. However, Questa's engineering expert showed that, since 1985, 16 new gas wells and 26 horizontal drainhole laterals had been drilled in the area. The recovery since 1985 had been 73.9 BCFG with remaining reserves calculated to be 17.8 BCFG. The expert opined that, since the gas reserves had increased by threefold from the additional development, there were substantial additional reserves to be recovered from the field by infill drilling in areas that had not been effectively drained by the existing wells.

EXAMINERS' OPINION

Optional 160 Acre Density

The Panhandle Field is divided into the Panhandle, East and Panhandle, West Fields. Both fields originally operated under Field Rules that provided for 330'-660' well spacing and 160 acre gas units. However, in September 1948, the density in the Panhandle, West Field was amended to 640 acre gas units, but the Panhandle, East Field remained on 160 acre density. In fact, the dividing line has been moved several times by the Commission based on evidence presented at hearings. It is undisputed that both the Panhandle, East and Panhandle, West Fields are geologically analogous with similar reservoir facies and structural complexity and are in pressure communication across the entire producing formations. The reservoir architecture varies dramatically across the field in terms of hydrocarbon column height, structural features, stratigraphy, fluid contacts and reservoir quality.

The Panhandle, West Field encompasses approximately 1.2 MM acres and 4,190 wells have been drilled in the field, resulting in an average field development density of 295 acres per well. Recent development has been primarily to replace plugged out wells and infill drill wells under Statewide Rule 38 exceptions or non-concurrent production restrictions. In addition, Pioneer has drilled over 440 sloped laterals from over 280 existing vertical wells that were spread across Pioneer's entire 240,000 acreage position. Pioneer did not require Rule 38 exceptions for the laterals, since the Commission does not count laterals as separate individual wells. If the vertical well and the two laterals were counted as three separate wells, Pioneer's acreage would have an average density of 213 acres.

Stratigraphic heterogeneity is observed across the field and the reservoir includes a variety of carbonate and clastic facies with complex stacking and uneven lateral distributions. In addition, many of the lithofacies, lenses and formations are separated by muds, shales or other impermeable layers. Structural complexity, variations, faults, fractures, folds and different fluid contacts indicate that the reservoir is compartmentalized. The examiners believe that there is overwhelming geologic, pressure and production data to support reservoir compartmentalization.

Significant reserves have been developed and produced by infill drilling in the Panhandle, West Field by all parties participating in this hearing. To date, the average field development density is 295 acres per well and, counting a vertical well and two laterals as three separate wells, Pioneer has already developed most of its acreage down to an average density of 213 acres. Based on the evidence presented, the examiners believe that the proposed optional density of 320 acres has already been achieved for most of the Panhandle Field and recommend that the Field Rules for the Panhandle, West Field be amended to provide for 640 acre gas units with optional 160 acre density. This will allow operators to return to production hundreds of wells that are still capable of production at a low rate, which have been shut-in with non-concurrent production restrictions.

Suspension of the Allocation Formula

Pursuant to Statewide Rule 31(j), the allocation formula for a particular gas field may be suspended if each operator from that field has a market for 100% of the deliverability for its respective wells. The applicant requesting suspension of the formula bears the burden of proof on this issue.[1] Questa offered to admit evidence that may have been applicable to this issue, but that evidence was excluded, upon the objection of the Protestants, as inadmissible hearsay. The record of this case does not contain evidence that would allow the examiners to conclude that the Applicant established that each operator from the Panhandle, West Field has a market for 100% of the deliverability for its wells.

At the same time, the examiners do not believe that the Protestants established that there is not a market for 100% of the deliverability of wells; however, this is not the proper inquiry when determining if the allocation formula should be suspended. The original reservoir pressure in the field was 465 psia and has generally declined to less than 30 psia today. Most of the wells in the field are connected to a vacuum pump and produce under a vacuum. Of the 139 operators carried on the proration schedule, only the two Protestants, or 1.4% of the total operators, claim that there is not a market demand for 100% of gas deliverability from the Panhandle, West Field. However, the Applicants, not the Protestants, have the burden of proof, and that burden was not met based on the record in this proceeding.

ConocoPhillips and Travelers, citing the *MW Petroleum* case, contend that downtime experienced by gathering equipment and processing facilities has prevented operators from having a market for 100% of the deliverability of their wells. The examiners agree that *MW Petroleum* stands for the general principle that insufficient gathering systems causing significant downtime may indicate that there is not a market for 100% of the deliverability of each operators' respective wells. But, the examiners disagree with the Protestants' contention that application of this principle to this case compels the conclusion

[1] See Oil & Gas Docket No. 08-0205544: Application of MW Petroleum Corporation to Suspend the Allocation Formula in the Emperor (Devonian) Field, Winkler County, Texas (Final Order Signed December 12, 1994) (Conclusion of Law No. 4: "MW Petroleum failed to meet its burden of proving that all operators in the Emperor (Devonian) Field have a market for 100% of the deliverability of their respective wells.")

that operators do not have a market willing and able to purchase all the gas that their wells can deliver. ConocoPhillips presented Exhibit 29R to support its claim that it was unable to produce 782,656 MCF of gas in 2012 due to the downtime of gathering and processing facilities. ConocoPhillips' calculation of "lost" gas in Exhibit 29R, by itself, does not prove that there was not a market demand for the deliverability of the wells, or even that these wells did not produce their deliverability for a particular month or year. Rather, the loss number is simply the product of the number of downtime days times daily TMP for a well. In *MW Petroleum*, the operator protesting the suspension of the allocation formula was able to prove that there was a positive correlation between gathering system downtime and reduced production numbers from the affected wells. For example, the protesting operator showed that an increase from 2% to 14% downtime per month coincided with a 17.7% decrease in actual production per month, and there was a similar correlation in the data for other months. The Protestants did not establish a verifiable correlation between percentage of downtime and decreases in actual production.

Further, one of the principles found in *MW Petroleum* is that whether a gathering system's downtime has the effect of reducing market demand to a point below 100% is a matter of fact that must be resolved by the facts peculiar to each individual case. The examiners believe that any gathering system downtime occurring in the Panhandle, West Field has not reduced market demand to a point below 100%. Gathering system downtime undoubtedly occurs for all operators in the Panhandle, West Field and in other Texas gas fields for which the allocation formula has been suspended. The existence of downtime for repairs or maintenance does not necessarily mean that the gathering systems in the field are inadequate to handle the field's production capacity. The examiners believe that there are inevitable downtimes, but this fact does not establish that the gathering system is insufficient to the extent that there is not a 100% market for the field's production capacity.

While the Applicants did not satisfy the necessary Rule 31(j) criterion for suspension, they did present a number of practical arguments to support suspension. Practically speaking, the suspension of the allocation formula would have little impact on most operators. Of the 2,239 wells on the February 2013 gas proration schedule that had an allowable assigned, 74% of the wells are exempt from the allocation formula and were automatically assigned the field minimum allowable of 100 MCFGPD. In addition, only 19 gas wells in the field are actually being prorated and 9 of the prorated gas wells had a zero allowable assigned despite having a TMP gas rate, because they either had a zero shut-in wellhead pressure or no acreage assigned to them. Four of the ten prorated wells had a TMP greater than 100 MCFGPD and were assigned an allowable less than the field minimum allowable of 100 MCFGPD. Based on this analysis, only six wells are being effectively prorated, which is only 0.2% of the total wells assigned an allowable.

Even Pioneer has acknowledged that if the allocation formula is suspended, such action would have little or no effect on the wells they operate. Pioneer's study revealed that, due to the location of wells offsetting Pioneer's acreage and the large number of existing special allowable wells with a minimum allowable of 100 MCFGPD, their correlative rights would not be negatively impacted. Thus, the examiners have serious doubts that the current allocation formula is effectively prorating field production. Moreover, the Applicants pointed out, and the examiners agree, that implementing the proration of wells in the field is a significant burden on the operators and the Commission staff. But, in the final analysis, the Applicants did not meet their required burden for suspending the allocation formula. Of course, if the allocation formula remains in effect, the Applicants have the right to petition again for suspension after the conclusion of this proceeding if new evidence is developed that would warrant suspension.

FINDINGS OF FACT

1. Notice of this application and hearing was provided to all persons entitled to notice at least ten (10) days prior to the date of the hearing.

2. The Panhandle Field was discovered in 1918 at an average depth of 4,200 feet.

   a. After discovery, the field was divided into the Panhandle, East and Panhandle, West Fields.

   b. Both fields originally operated under Field Rules that provided for 330'-660' well spacing and 160 acre gas units.

   c. In September 1948, the density in the Panhandle, West Field was amended to 640 acre gas units, but the Panhandle, East Field remained on 160 acre density.

   d. The dividing line between the two fields has been moved several times by the Commission based on evidence of the appropriate density.

   e. Both fields have an allocation formula based on 67% acres multiplied by shut-in wellhead pressure and 33% of TMP.

   f. In the Panhandle, West Field, there are 2,239 producing gas wells carried on the proration schedule.

   g. In the Panhandle, East Field, there are 1,452 producing gas wells carried on the proration schedule.

h. Both the Panhandle, East and Panhandle, West Fields are geologically analogous with similar reservoir facies and structural complexity and are in pressure communication across the entire producing formations.

i. The reservoir architecture varies dramatically across the field in terms of hydrocarbon column height, structural features, stratigraphy, fluid contacts and reservoir quality.

3. A Field Rule that provides for 640 acre gas units with optional 160 acre density is appropriate for the Panhandle, West Field.

a. The Panhandle, West Field encompasses approximately 1.2 MM acres and 4,190 wells have been drilled in the field, resulting in an average field development density of 295 acres per well.

b. Recent development has been primarily to replace plugged out wells and infill drill wells under Statewide Rule 38 exceptions or non-concurrent production clauses.

c. Pioneer Natural Res. USA, Inc. ("Pioneer") has drilled over 440 sloped laterals from over 280 existing vertical wells that were spread across the entire 240,000 acres operated by Pioneer.

d. Pioneer's laterals did not require Rule 38 exceptions, since the Commission does not count laterals as separate individual wells. If the vertical well and the two laterals were counted as three separate wells, Pioneer's acreage would have an average density of 213 acres.

e. Stratigraphic heterogeneity is observed across the field and the reservoir includes a variety of carbonate and clastic facies with complex stacking and uneven lateral distributions. In addition, many of the lithofacies, lenses and formations are separated by muds, shales or other impermeable layers.

f. Structural complexity, variations, faults, fractures, folds and different fluid contacts compartmentalize the reservoir.

g. Significant reserves have been developed and produced by infill drilling in the Panhandle, West Field by all parties participating in the hearing.

h. Based on the evidence presented, the proposed optional density of 320 acres has already been achieved for most of the Panhandle Field.

i. Continuation of the 640 acre standard unit size while allowing optional 160 acre units will allow efficient development of all acreage based on reservoir conditions under that specific acreage.

j. Optional 160 acre density will allow operators to return to production hundreds of wells that are still capable of production at a low rate, which have been shut-in with non-concurrent production restrictions.

4. The record evidence does not establish that the allocation formula for the Panhandle, West Field should be suspended.

   a. All operators in the field have not consented to suspension of the allocation formula.

   b. Two operators in the field, ConocoPhillips Company and Travelers Oil Company, asserted that they did not have a market for 100% of the gas deliverability from their wells.

   c. The applicants failed to provide probative evidence that each operator in the field has a market for 100% of the gas deliverability, as determined by the deliverability tests on file for all wells in the field.

CONCLUSIONS OF LAW

1. Proper notice of this hearing was issued.

2. All things have been accomplished or have occurred to give the Commission jurisdiction in this matter.

3. Amending the Field Rules to provide for 640 acre gas units with optional 160 acre density for the Panhandle, West Field is necessary to prevent waste, protect correlative rights and promote efficient development of the field.

4. The applicants did not carry the burden of proof in showing that the requirements for suspension of the allocation formula under the terms of 16 Tex.Admin.Code §3.31(j) had been met.

RECOMMENDATION

Based on the above findings of fact and conclusions of law, the examiners recommend that the Commission amend the Field Rules to provide for 640 acre gas units with optional 160 acre density for the Panhandle, West Field, as requested by Questa Energy Corporation, Pantera Energy Company and Linn Operating, Inc. The examiners recommend that suspension of the allocation formula be denied.

Respectfully submitted,

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