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A Field Case Study of Replacement Well Analysis: Guymon-Hugoton Field, Oklahoma

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SUMMARY

This study analyzed the initial pressure data and the performance results of replacement wells drilled in 72 sections of the Guymon-Hugoton Field, Oklahoma. Reservoir lateral continuity was confirmed and the current 640 acre well spacing was determined to be adequate for effective drainage of the field.

INTRODUCTION

A review of the replacement well results in the Guymon-Hugoton Field was prompted by hearings and a later decision by the Kansas Corporation Commission to permit increased well density in the Kansas Hugoton Field. The greater Hugoton Field (Fig. 1) has historically had 640 acre well spacing in Oklahoma, Texas, and Kansas. It is considered that initial responses from replacement wells would be analogous to infill wells unless the distances from the replacement wells and the original wells are so short that the wells are, for practical purposes, twins. All identifiable replacement wells were reviewed to determine the expected results of infill drilling if it were pursued in the Guymon-Hugoton Field. Infill wells are often presented as a method of increasing effective drainage and recovery plus accelerating the production from tight and/or heterogeneous reservoirs, particularly for oil reservoirs and especially those undergoing waterflooding. There have been reported oil field infill successes[1,2] and efforts to either evaluate or investigate potential candidates for infill drilling.[3,4] There has been very little published about the potential for infill drilling gas reservoirs, although it has been recognized that some very tight reservoirs could benefit by accelerating the rate of production where wells are in transient flow for extremely long times.[5]

References and illustrations at end of paper.

The replacement well review started with data from our own wells, but was then expanded to include all replacement wells within the Guymon-Hugoton Field. By using publicly available data bases, the majority of the identified replacement wells could be reviewed using production, official shut-in pressures, and official deliverability tests plus some completion records from scout tickets and other sources. Basic information to be determined from the study included:

1. Were replacement wells encountering any additional reserves not recoverable from the original well?
2. Were the replacement wells of higher or better deliverability than the original wells and if so, why?
3. Are there selected areas within the Guymon-Hugoton Field that are more applicable to successful replacement wells than other areas?
4. Can replacement well results be used to predict the outcome of an infill well and the combined production capability?

Utilizing mostly publicly available data, the questions above have been answered rather conclusively and when supplemented with additional studies,[6,7,8,9] the decision to pursue infill drilling within the Guymon-Hugoton Field can be rejected without concern for a possible missed opportunity. This, of course, does not preclude other infill drilling possibilities in gas fields where characteristics and circumstances are different. It should be noted that an infill well, as used in this paper, denotes an additional well completed within the same layer(s) and intended drainage area as another well or pattern of wells. In a review of oil field infill drilling results, Gould & Sarem[3] point out that without a good reservoir description, the risks of a successful infill project are high and even when there is good potential, you must know the reason for the original behavior. There are some circumstances, which if identified, can improve the chances of a successful infill well, but in general, these characteristics or circumstances are not evident in the Guymon-Hugoton Field.

GENERAL FIELD DESCRIPTION

The Guymon-Hugoton Field is a gas field located in Texas County, Oklahoma (Fig. 1), which originally contained an estimated 6.5 TSCF recoverable reserves and has produced approximately 5 TSCF through 1989. It is a portion of the larger Hugoton Reservoir which extends into both Texas to the south and Kansas to the north. The Guymon-Hugoton Field produces relatively dry gas (approximately 0.714 specific gravity) from the Lower Permian Chase Group which is more fully described by Siemers.[9] For the purpose of this discussion, the important characteristics of the Guymon-Hugoton producing formations include the following:

1. interlayered carbonates
2. layers of contrasting permeabilities
3. no effective cross-flow between layers
4. continuity of individual layers.

The Greater Hugoton Reservoir was first drilled in 1922 in Kansas, and the first well in what is now the Guymon-Hugoton Field was the Home Development Company, Allison No. 1, drilled in 1923. The general development of the Guymon-Hugoton Field did not take place until the late 1940's and early 1950's. Wells completed in the Guymon-Hugoton are generally producing from depths between 2700 and 3000 feet deep. As the ground elevation in the area is more than 3000 feet above sea level, the reservoir is at, or above, sea level. Original reservoir pressure was 475 psig. This value converts to approximately 445 psig at the wellhead and was used to evaluate whether any replacement well encountered virgin or untapped reservoir gas.

BACKGROUND

Wells were replaced for a variety of reasons, but for the most part, it was an effort to obtain a better completion for increasing productivity and/or eliminating operational problems. A few replacement wells were drilled during the 1950's and several more in the 1960's, but most of the replacement wells have been drilled more recently (Table 1). Most of the seventy-two sections with replacement wells (Fig. 2) had the original well located near the center of a 640 acre regular section within the 'section, township, range' land description survey of Oklahoma. The field rules for the Guymon-Hugoton Field require that the acreage allocated to a well be contiguous. Only seven original wells were more than 500 feet from the center of the section and none were more than 2000 feet from the center. The average distance of the original well from the center of the section, including all 72 wells, is 327 feet.

Eighty-six replacement wells were identified in the seventy-two sections specified above. There were additional sections in which more than one Hugoton well was drilled, but if the original well never produced, it was not classified as a producer and therefore the second well was not considered as a replacement. Ten such sections were found with multiple wells but were not included in this study. Approximately 80 per cent of the replacement wells were located more than 1000 feet away from the original producer and definitely would not be considered a twin well (Table 2). In fact, more than 70 per cent of the replacement wells are more than 1500 feet away from the original well with the average distance between the original well and the replacement well being 1657 feet. This average displacement is between half the distance from the center of a square section to a side (1320 feet) and half the distance from the center to a diagonal corner (1867 feet). Because those distances would represent probable relative locations for an infill well, then more than 70 per cent of the replacement well locations can be classified as similar to expected choices for any infill locations. Approximately 49 per cent of the replacement wells were located easterly from the original well, either NE or SE with the NE having a slight majority. A similar number were located westerly, but the NW selection was twice as frequent as the SW. This probably has no significance other than the relative position of the section with regard to the major portion of the field and with an operator either trying to increase productivity or to increase the distance away from an offset well.

Just as it was previously mentioned regarding some original wells that never produced, there are also six replacement wells that never produced. They are included in the study to illustrate that some alternative locations were tried but were not successful. Of the eighty-six replacement wells, eighteen were converted unsuccessful deep tests that utilized the new wellbores to either replace a troublesome existing producer or to provide production from a section where there was no longer an active producer.

The Krider and the commingled Herington-Krider are the principal producing zones for both original and replacement wells. However, the Winfield is productive in selective locations, particularly in the north part of the field, but generally becomes wet toward the south. The Herington, which was completed by itself in one original well and two replacement wells, is not very productive. Also, the Fort Riley which was commingled with other zones in three original wells and one replacement well is not a very productive zone. The Chase was used to identify completion zones which were not defined otherwise by the available records.

Thirty-nine of the 72 original wells were completely cased and perforated. The remaining wells produced from openhole zones or a combination of openhole and perforated zones. Eighty-one of the 86 replacement wells had casing set completely through the intervals and perforated. The other five were openhole for one or more layers.

Wells were usually stimulated by either having the zones isolated and selectively treated or by treating all of the zones at one time. The original wells were drilled during the period from 1930 to 1974. All except three were completed by 1955. Most of these wells were stimulated with acid ranging from 29 gals/ft to 1133 gals/ft with an average of 217 gals/ft. The replacement wells were drilled from 1953 to 1987 with most of these wells completed during the 1970's and 1980's. They were stimulated with 15% HCl acid or different types of water based frac fluids with and without sand. The amount of acid ranged from 15 gals/ft to 1000 gals/ft averaging 299 gals/ft. The water based frac fluids ranged from 111 gals/ft to 11,429 gals/ft averaging 1587 gals/ft. The amount of sand ranged from 214 lbs/ft to 11,429 lbs/ft averaging 2009 lbs/ft. Stimulation treatments of the replacement wells were larger than the original well stimulations and more reflective of recent stimulation technology, however, many of the original wells had excellent results whereas some of the more recent treatments were not as effective. This may be partially a result of the progressing differential depletion, particularly if commingled stimulation was attempted.

ANALYSIS OF REPLACEMENT WELL RESULTS

All of the wells cannot be shown, but selected examples will be described to illustrate various responses observed. During the discussion of each of the examples presented, the section will be identified by a reference number (RN) as shown on Table 3. Because of incomplete data in some cases, the explanation for a particular behavior may not be specifically supported by the available well information. However, other wells and calculated results from model studies[8,10] have indicated the probable cause of the effect observed. This will be more obvious in specific examples and will be brought to the readers' attention.

The Guymon-Hugoton Field has always been prorated in that the field delivery capability was considerably greater than the nominated production volumes which defines the allowable. Because of this condition, the field has been produced essentially at a constant rate until the mid to late 1970's, the beginning of the 'gas bubble', when production was restricted even further. This is important because the monthly rates are the most readily available data and are, in general, flat with no character to analyze from a rate decline aspect. Other data available from public sources, besides the monthly production, are the official shut-in pressures and deliverability test results. It was found that on a few wells, even these data were not easily obtained. In certain cases, completion and stimulation data are available from scout tickets and/or state governmental agencies. Some production records, particularly before 1967, were not available either from regulatory agencies or the commercially accessible databases. Analysis of the replacement wells was initially started with our own wells for which we had extensive data, but only thirteen of the eighty-six identified fell into that category. Our company records contain some limited amounts of data for other operators due to our early position as both producer and gathering system operator. Even with this supplemented data, there are still some gaps in the production and performance data plus many missing completion and stimulation details. For this review, it was not imperative that all of this information be obtained, but it would have been helpful and would definitely be beneficial to anyone designing a replacement well or considering an infill well.

One of the first questions to be answered was "Are the replacement wells finding any new reserves?." Three plots were considered important to answer that question for each of the sections containing replacement wells. A material balance plot of annual shut-in pressures (initially 72 hour shut-ins and beginning in 1975, 96 hour shut-ins) versus cumulative production was prepared for each original well. The pressures used were wellhead values as the reservoir is relatively low pressured, shallow, and dry. This makes the extrapolation of wellhead pressure to reservoir conditions simply a function of average gas density and unnecessary for this evaluation. Likewise, only pressure was plotted instead of the conventional P/Z. As a continuation on this first plot, the initial and subsequent wellhead pressures from the replacement well(s) were plotted, with different symbols, versus the section's total cumulative production (Fig. 3). A semi-log plot of the section's average daily production versus time was prepared using the monthly production values as reported to the State. A symbol was used to identify replacement well production (Fig. 4). The third plot was backpressure data from the deliverability test taken during official testing. Originally, a deliverability test was required each year, but current field rules only require flow test every other year with shut-in pressures every year. Again, different symbols were used to distinguish between the wells and this plot was superimposed on the pressure vs. cumulative production along with a section plat (Fig. 3). This section (RN70) is used to illustrate some of the concepts and it is not necessarily a typical example, although many are similar. There are many variations in the responses observed in the replacement wells. Some of the apparently 'abnormal' responses are quite explainable when sufficient information was obtainable. For example, some wells have water entry into the wellbore and the water restricts the gas flow plus it may cause lower than actual shut-in pressure to be measured. If the replacement well has a better completion, in regards to the water entry problems, the new well may exhibit a shut-in pressure higher than the last pressure recorded for the original well and it may have indicated performance better than the last tests for the original well. One needs to evaluate the entire performance history of all of the wells on the section before making a judgement. There are other conditions that can cause a higher reservoir pressure to be measured in a replacement well. In all replacement wells, not considered a twin well (one within a few hundred feet of the original well), there will be an initial reservoir pressure higher than the pressure at the old withdrawal point. This is due, of course, to the pressure gradient established in the drainage area while the well was producing. The value of this delta pressure is a function of the distance from the old withdrawal point, the reservoir rock, fluid properties, the rate of the original producer before shut in, and how long the old producer had been shut in plus whether the replacement well has been produced and for how long. For practical purposes, the delta pressure values observed and calculated in the Greater Hugoton Field average about 12 to 15 psi.[6,7,8] Another source of higher shut-in pressures is the very nature of the pressure being measured. The Guymon-Hugoton Field is composed of interlayered, no-crossflow carbonate formations with contrasting permeabilities.[9] This combination sets up the conditions for differential depletion which results in pressures in the various layers not being equal. Differential depletion is not a new concept, but in the context of such a large reservoir extent and in gas, it has not been seriously considered by many until recently.[10] It is quite common for oil field waterflood projects to be hampered by so called 'thief zones' which are formations considerably more depleted than other zones completed in the same wellbores. The vertical communication between these formations must be very restricted to set up this condition. Unfortunately, the waterflood cannot sweep the tighter, less depleted zone unless some way to isolate the 'thief zone' can be found. Almost invariably the zones are in communication at, and only at the wellbores (sometimes behind the pipe). This can then result in very difficult, and often expensive, workovers. The low permeabilities in these Guymon-Hugoton wells require stimulation which will often result in behind the pipe communication of the producing intervals within the reservoir near the wellbore through the induced vertical fracture. The importance of this situation to the replacement well analysis is that the measured wellbore pressure, during both production and shut in, will more nearly reflect the more permeable layer pressure as described by Fetkovich, et al.[10] This brings up the point about measuring a considerably higher pressure in a replacement well. There are a few wells in the replacement well analysis that appear to have reservoir pressures in excess of fifty psi above what would be estimated based on the original well history. Although these higher pressure values are significantly lower than the field discovery pressure (indicating considerable depletion), they require some additional investigation. Not surprisingly, some wells exhibiting higher pressure are wells close to either edge of the field. Of the 72 sections involved in the study, approximately one-half could be classified as edge wells. The reservoir quality declines as either the east or west field boundaries are approached[9] and because of this poorer rock quality, the producing capabilities in these areas are lower. This causes less depletion of even the more permeable of the zones when compared to the level of depletion toward the center of the field. An example of the possible response observable in some wells can be seen on Fig. 5 and Fig. 6.

There is another problem involved besides the flowing gradient in estimating what pressure to expect in a replacement well. That is the time delay between the last measured pressure on the original well and the first pressure available from the replacement well. In this last example, the time between the measurements is at most a year. A similar time interval applies to about fifty-seven per cent of the replacement wells, but four had intervals in excess of twenty years (Table 4). An approximation for this study has been used which involves the average field pressure as plotted from data obtained from the Kansas Conservation Commission (KCC) (Fig. 7). This plot is the annual, arithmetic average pressure versus time calculated from the individual wellhead shut-in pressures as reported to the Oklahoma Corporation Commission (OCC). Although the data were originally reported to the OCC, the KCC has consistently maintained a record of the values. Assuming that the Guymon-Hugoton Field is, for practical purposes, in pseudosteady state during normal production periods, the pressure at every point should decline by a like amount. Therefore, the pressure relative to any point in the reservoir would reflect a similar pressure decline as that indicated by the average. Of course, this would not necessarily hold true for short time periods at specific wells due to local proration, line pressure changes, or any number of conditions that might disturb a given drainage area or region and not immediately effect the field as a whole. In review of the usefulness of these assumptions, the initial pressure for each of the replacement wells was estimated and compared to the actual measured pressure. This was done by calculating the difference between the last measured shut-in pressure from the original well and the average field pressure for the same time. This difference was then added to the average field pressure at the time the replacement well was tested. Table 5 presents the results of such estimates and shows the per cent error between the estimated values and the measured values. Nearly half (44%) of the estimates were within ± 10% of the measured value. This would represent about 10 to 20 psi during the time most replacement wells became active (1970-1989). Thirty-four wells had estimated pressures within ± 15 psi of the measured values. Recall that this value has significance with regard to the flowing pressure gradient within the reservoir and the distance from the original well to the replacement well. Major differences in the estimated pressures and the measured pressures were investigated to account for any greater than expected error.

As referred to earlier, there are several conditions that can cause well pressures to be greater than the estimates and RN59 illustrates one of these conditions (Fig. 5 and Fig. 6). The original well was completed in the Herington and the Krider formations and was acidized as a commingled completion. After producing for approximately thirty-six years, the replacement well was drilled. It is unknown by us why it was decided to replace the original well, but possibly it had mechanical problems. Note the location of the original well was in the approximate center of the section (Fig. 5) and the replacement well is in the approximate center of the northwest quadrant. The stimulation of the new well was somewhat different than the previous producer, in that, the Herington and Upper Krider were acidized separately from the Lower Krider. Under normal circumstances, one would expect that to be a better stimulation method. As the Lower Krider is frequently more permeable, commingled stimulations may permit most of the acid to enter and react in that zone, leaving the tighter intervals with only minor stimulation, if any. The differential depletion as observed in the Guymon-Hugoton Field can cause this preferential stimulation situation to be even more pronounced as the pressure differences between the layers becomes greater. The measured pressure in the replacement well was 115 psi higher than estimated by the method described earlier. If one stops there, the replacement well looks to be a success. However, the productive capability of the replacement well is only about 5 per cent of the original well (Fig. 5). Based on limited specific data from the well and the expected behavior of no-crossflow layered reservoirs, it appears that the stimulation of the tighter, less depleted zones was successful, but that the more permeable zone was not stimulated and maybe even still have some completion damage. The higher pressure has declined during annual testing until it is near the previous trend line for the original well and very little additional production has been realized. Because the commingled well will reflect the pressure of the most permeable layer, or more precisely, the layer with the greatest $q_{(max)}/G_i$ value,[10] the new location and the stimulation process must have reversed the roles of the layers in this well. This replacement well has no significant additional reserves beyond what was produced by the original well, even though there was a higher pressure measured in the well. The indicated higher pressure in the tighter zone is expected and as predicted by the method discussed by Fetkovich et al.[10] They present that the vertical distance (in this case delta pressure on the P vs. G_p plot) between the total system value (volumetric average pressure here) and each layer value is inversely proportional to their volume ratios. Although the volumetric average pressure is unknown, it would be near, but higher than the measured pressure which is more nearly reflecting the higher permeability layer (probably Krider). The difference between the Herington pressure and the volumetric average pressure would be three to five times greater than the Krider difference and opposite in sign. In this particular case (RN59), the replacement well appears to have lost reserves based on the trend of the pressure versus cumulative production plot (Fig. 5). Because there is not clear evidence as to why the replacement well was drilled, the preceding comment may not apply, plus further production and/or additional stimulation may improve the well performance. RN59 illustrates that the assumption regarding the predictability of the replacement well pressure will not be valid if the production zones are not the same or if stimulation significantly alters the $q_{(max)}/G_i$ relationships between layers. It should be noted that there was less than one month between the last production of the original well and the first production of the replacement well in the RN59 section.

Another example, RN10, illustrates more definitively the above described response (Fig. 8 & 9). The replacement well on this section was drilled because of a casing leak in the original well, which was completed as commingled Herington-Krider. Performance of the original well was quite consistent until a few years before the leak was identified. The replacement well was completed only in the Winfield which was previously not producing in this section. Initial testing of the replacement well revealed the Winfield was about 277 psi depleted at this location when the replacement well was completed. It had a wellhead shut-in pressure of 168.1 psig. This is about 50 psi higher than would be predicted had the completion intervals been the same as the original well. Note that the difference in the pressure between the Winfield and the Krider-Herington (50 psi) is not as much as the apparent difference (115 psi) between the Herington and the Herington-Krider as indicated in the previous example (RN59). This is due to the better rock quality, especially the permeability,[9] of the Winfield as compared to the Herington.

The preceding two examples had replacement well pressures significantly higher than estimated using the original well and these results were explained by the difference in productive zones. RN40 also had higher measured pressure (196 psig) for the replacement well than predicted (82 psig) using the last reported pressure from the original well. Upon examination of the shut-in pressure (Fig. 10) and production (Fig. 11) data, it appears that the original well was suffering from an increasing liquid accumulation in the wellbore. This is particularly noticeable upon reviewing the last few years of production history and the last shut-in pressure. If one uses the next to last shut-in pressure to estimate the replacement well's initial pressure, the estimate is 193 psig compared to the measured 196 psig. It should be noted that for this example there was a four year non-productive period between the last production of the original well and the first production of the replacement well, whereas the previous three examples had, at most, three months of no production from the section. The RN40 original well was an open hole completion with a slotted liner producing from the Krider and Winfield formations. Although the well was plugged back through the Winfield, the source of water could have been from there, as it is very difficult to successfully isolate a zone in a completion such as this. The replacement well was completed higher and only in the Krider. It is not known whether the water shut-off was completely successful, but it appears to be based on the limited data available. However, the replacement well's productive capacity is not nearly as big as indicated for the original well prior to the apparent water problem. Even though the original well was a commingled well and the replacement well was completed in only the Krider, the expected pressure for the replacement should be closely related to the estimated pressure using original well values. These measured pressures will tend to reflect the Krider pressure because of its generally higher permeability values and the contrast between the permeabilities of the Krider and Winfield are not as great as between the Krider and the Herington. The loss in productivity is probably related both to the loss of the Winfield, as indicated by a reduction in apparent ultimate reserves (Fig. 10, P vs. G_p), and an increased skin on the Krider as a result of partial completion through that zone.

The following example section, RN21, had no production between April 1969 and October 1975, over 6 years. An open hole completion in the "Chase" which was acidized with 15% HCl (18000 gallons) is what is known about the completion. A review of the production data indicates no major problems until the mid-1960's. The performance appears to have dropped off quite badly based on the two backpressure points furtherest to the left on the plot (filled circles) (Fig. 12). The last two values on the pressure versus cumulative production plot appear to either be reflecting pressures too low (possibly liquid in wellbore) and/or indicating some drainage is occurring as compared to previous data. The replacement well was completed with selected, limited perforations in the Herington and Krider. Utilizing the method previously mentioned to estimate the replacement well's initial pressure resulted in an estimate of 153 psig as compared to the measured pressure of 160 psig. The value of the replacement well's pressure indicates that its drainage area continued to decline at approximately the same rate as the total field average during the 6 and one-half years of non-production from this section. It also implies that production is from the same intervals producing in the original well. This is confirmed by the pressure versus cumulative production plot continuing on a parallel trend to the early portion of the plot for the original well. Note that the backpressure points imply some reduced productivity, but with indicated performance improvement for the replacement well since the recent rate increase (Fig. 13) due to a higher gas allocation for the Guymon-Hugoton Field. However, even with the improvement, the productive capability is not as good as the original well. This is quite understandable with the limited perforations (only eight one-foot intervals perforated over the Herington and Krider layers). This could cause the total skin to be less negative as compared to the original well even though the replacement well was stimulated with 8000 gallons of 15% HCl.

The final Guymon-Hugoton Field example is RN63. More has been produced from this section than any of the other examples. The original well produced approximately 13 BSCF before it was replaced in 1982, probably for mechanical reasons (it was an open hole completion). Only about nine months elapsed between the last production of the original well and the first production of the replacement well. The estimated pressure was 151 psig compared to about 171 psig measured. The difference is only slightly larger than one would expect, so until combined with additional information it would be assumed that the replacement well was producing from the same interval as the original well. Comparing the backpressure data, it is obvious that the replacement well has more productive capacity than the original well which, of course, could be a result of the completion and stimulation. However, a review of the pressure versus cumulative production plot shows that a different drainage volume is involved and it is smaller. Without detailed information regarding these two wells, it is not possible to exactly determine the cause of this response. It could be the result of a partially damaged, more permeable zone being better stimulated, but at the same time losing the production from a lesser permeable zone (with significant hydrocarbon volume) because of the cased hole with limited perforations. This would account for the slightly higher than expected pressure and it could also account for the indicated increased productivity plus the decreased ultimate recovery.

DISCUSSION OF RESULTS

The last five examples described in the previous review were selected to illustrate some specific departure from expected results. The first example, RN70 (Fig. 3 and Fig. 4), had initial responses that we expected for a Guymon-Hugoton replacement (or even infill) well that was completed in the same layers with approximately the same simulation results. There was less than two months, at most, between the last production of the original well and the first production of the replacement well. Therefore, the pressure trend should continue, the well capability should be similar, and the indicated ultimate recovery should be consistent. All of these items are fulfilled in this first example, but many other wells could also have been used for this illustration as indicated by the considerable number (34) of replacement wells exhibiting less than ± 15 psi variance from the estimated pressure as compared to the measured pressure. Table 5 indicates that there was approximately as much overestimation of pressure as underestimation, at least for estimated pressures within ± 30 per cent of the measured values. This represents 75 per cent of all the values that could be compared. This tends to confirm that the replacement well pressures were not biased toward pressures higher than could be estimated from the general field pressure decline. In no case was there ever an observed shut-in pressure close to the 445 psig needed to represent virgin or original reservoir pressure. Only three replacement wells had measured pressures in excess of 300 psig with the maximum 350.7 psig. Earlier, the comment was made that approximately one-half of the replacement wells could be considered edge wells. This was, of course, referring to the edge of the reservoir and toward the portions on the east or west sides of the field where the reservoir rock quality degrades. There are also edges of the Guymon-Hugoton Field along both the Kansas and Texas state lines. These are not physical edges or boundaries as regards the reservoir, but there are replacement wells near these field 'edges' in similar densities as found near the reservoir edges (Fig. 2). In contrast, there are no identified replacement wells in the 10 to 12 townships covering the middle portion of the field.

Near the west edge of the field is a section (RN36 not shown) which has had three different producing wells. The original well was completed in 1953 and was produced until 1967. This original completion had a combination Herington and Krider perforated interval and was a small producer (less than 200 MMscf cumulative production. The first replacement well was reportedly completed in the Krider and Winfield in 1977 (10 years after original well shut-in). This well had an initial pressure higher than the last pressure of the original well, but then it was also completed in different layers. For some reason, the well produced less than one year after producing for short intervals and at very small rates (maybe wet). The second replacement or third well was completed in 1979 and was also perforated in the Herington and Krider layers, similar to the original well. Initial pressure value (167 psig) indicated that the drainage area of this well had declined 116 psi in the thirteen years since the original well ceased production. The average field pressure had declined approximately 101 psi over the same period which would indicate that this area is in communication with the major portion of the field. The higher pressure in the Winfield also confirms that no-crossflow is taking place in this area, at least between the Krider and the Winfield.

A situation similar to that described above, but on the east edge of the field, is RN43 (not shown). This section also had three different wells. The original well was an openhole, liner completion with probably the Herington and Krider producing. Being a very small well, it only produced for a little over one year (1955-1956). Another well, the first replacement well, never produced after it was completed in 1974 as a cased, perforated 'Chase' completion. In 1983, the third well (second replacement) was completed in the Krider. It, too, was a very small well plus it had an initial reported shut-in pressure of about 122 psig (240 psi decline). The field average pressure had declined approximately 192 psi since the original well stopped producing, therefore this section, like the one just previous, has declined more than the field average. Because this last replacement well was completed only in the Krider, it should be expected that the shut-in pressure would be somewhat smaller than if it were a Herington-Krider completion, such as the original well. Combined production on this section is only slightly over 100 MMscf. Both RN36 and RN43 information plus exhibits were presented to the OCC as part of a study to answer questions posed by the OCC regarding the advantages and disadvantages of infill drilling in the Guymon-Hugoton Field.

Based on 1) the observed pressure decline throughout the field being in general agreement with the average field pressure decline, 2) the lack of any observed original or virgin pressure in any replacement well, and 3) the explainable responses of higher than expected observed pressure, it has been concluded that no replacement well has encountered gas reserves not already in communication with existing producers. This would imply no additional reserves have been found by the replacement wells unless the replacement well can accelerate the gas production into an earlier period and that an increased recovery can be produced before the rate declines below an economic limit.

This re-introduces the question of whether better or higher deliverabilities are obtained from replacement wells. Given that most of the original producers were completed during the 1940's and 1950's, it seems reasonable that completion and stimulation techniques would have improved over this period and newer wells might have better productivities compared to the older wells. This does not appear to be correct based on our review of results. As a measure of the relative well productivity, the 'C' value was calculated for each of the replacement wells and original producers.

The 'C' value was calculated by using the backpressure equation

$$Q = C\,(P_c^2 - P_t^2)^{0.85} \qquad (1)$$

The exponent in this equation (0.85) is the value used by the OCC for the official deliverability evaluation and is fairly representative as indicated by the performance of most wells. Rearrange the backpressure equation and solve for 'C'

$$C = \frac{Q}{(P_c^2 - P_t^2)^{.85}} \qquad (2)$$

Using 'C' values for both the original and any replacement wells, a ratio of the replacement to the original well 'C' ratio can be evaluated.

$$CR = \frac{C_{replacement}}{C_{original}} \qquad (3)$$

Figure 16 has a plot of both the frequency distribution and cumulative frequency percentages of the calculated 'C' ratio values for the replacement wells. Note that approximately eighty per cent of the samples are less than or equal to 2 and that the most probable value is 1.02. The average value is 1.94, but it is biased by some single points that are greatly exaggerated. The four points with a ratio seven or greater were consolidated into one grouping for convenience to shorten the plot. These four points had large calculated 'C' ratios because the original wells tested extremely small productivities. The replacement wells had only small to medium production capabilities with expected recoveries from three of these sections being considerably less than 1 BSCF, while the other has already slightly exceeded 1 BSCF. The point is, that with a small well, even apparently dramatic improvement can still result in a small well with low recovery potential and the possibility that it is not economic. If the five smallest and the five largest values of 'C' ratio are eliminated, the arithmetic average value drops to 1.31. This is a more reasonable average and may reflect the improvements available by not completing open hole with commingled stimulations. It should still be noted that the probable 'C' ratio for a replacement well is 1.02 or a similar productivity as the original well. Because the exact intervals of completion are not always clearly identified, no effort was made in calculating the C ratio to separate out replacement wells that were apparently completed in layers different than the completion of the original well. Some of these effects were discussed with the various examples and will not be repeated here. Suffice it to say, it may be possible to increase the productivity from a section by drilling a replacement well, but the probability is that it will be similar to the original well unless an identifiable problem (mechanical, different layers, water entry) is being corrected. The same comments would apply to an infill well, that is, it should be expected that an infill well would be similar to the existing well unless they are producing from entirely different layers, which using our terminology is not an infill well.

C ratios of all magnitude occur in all portions of the field having replacement wells, so there does not appear to be a preferential portion of the field to drill a replacement well to obtain a favorable 'C' ratio. There are, of course, areas where one is more likely to have a large productivity well, but for this study a significant portion of that area is devoid of replacement wells. Reference is made to the middle of field where reservoir rock quality is better as opposed to the edges of the field where the reservoir quality decreases. Our review indicated higher pressures existing toward the field edges, but productivities were generally very low. Even there the pressure decline essentially reflects the average field pressure decline indicating depletion of the gas in those areas whether active wells are present or not.

As indicated earlier, it is not anticipated that infill wells in Guymon-Hugoton would find significant gas volumes not already being depleted or well productivities that would be effectively greater than the existing producer on a given section. Should one wish to evaluate the potential for infill drilling to accelerate recovery, there must first be a determination as to whether the existing well could accomplish the same purpose. Are all available layers perforated and effectively stimulated? Is the current production rate at maximum well capacity? Is the pipeline or delivery pressure as low as feasible: Are mechanical or liquid entry problems resolved or non-restricting? Assume the answers to all these questions are yes and there is a reasonable chance to have an allowable greater than what can be produced by the existing well. Then an estimate can be made by using the material balance plot (P vs. G_p) combined with the backpressure curve, similarly to what was done to evaluate the replacement wells. This would not provide an entirely accurate forecast because of drainage and interference between the original well and the infill well plus all other nearby producers. It would, however, permit the evaluation of whether an infill well can be economically completed in a section by providing an approximate total section withdrawal assuming conditions around that particular section were unchanged. This simple material balance method should be useful to eliminate cases where an infill well does not, either increase recovery over a given span or have acceptable incremental economics. For situations not eliminated by the above approximations, it is recommended that a multiwell, multilayered model[5,9] be used to forecast that total section recovery with the model including all surrounding wells for the history match portion and then adding the infill wells for predictions.

CONCLUSIONS

Based on our review and analysis of each of the 86 replacement wells completed in the Guymon-Hugoton Field, the following conclusions are presented:

1. Replacement wells' relative location within their own sections were appropriate for evaluating reservoir continuity over reasonable areal distances.

2. No replacement well exhibited virgin reservoir pressure. No indications were found that trapped or undrained reserves were encountered by a replacement well.

3. Reservoir characteristics, as indicated by the backpressure curve and the material balance plot, are generally similar between the original well and the replacement well. There is, of course, field-wide variations in reservoir properties.

4. Replacement wells completed in different layers from the original well have shut-in pressures that are significantly different which indicates the layers are not in vertical communication.

5. The current 640 acre spacing for the Guymon-Hugoton Field provides efficient and effective drainage of these gas reserves. Production could have been accelerated by larger allocations and allowables as indicated by the long plateau period.

NOMENCLATURE

$C_{gas\ well}$ = backpressure equation coefficient
G_i = original gas-in-place, MMscf [std m^3]
G_p = cumulative gas production, MMscf [std m^3]
P_c = wellhead shut-in pressure, psia [kPa]
P_t = wellhead flowing pressure, psia [kPa]
Q = surface gas flow rate, Mscfd [std m^3/d]
$q_{(max)}$ = calculated absolute open flow, Mscfd [std m^3/d]
Z = gas compressibility factor, dimensionless

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TABLE 1

DRILLING & COMPLETION SUMMARY

Years Drilled	Original Wells	Replacement Wells
1930-1939	1	0
1940-1949	35	0
1950-1959	33	5
1960-1969	1	9
1970-1979	2	38
1980-1989	0	34
Totals	72	86
Open Hole Completions	32	5
Acidized (only)	60	36
Hydraulic Fractured*	6	30
No Stimulation Record	6	20

* Most wells were acidized during a portion of the stimulation.

TABLE 2

DISTANCE BETWEEN REPLACEMENT WELL(S) AND ORIGINAL PRODUCER

Distance, Feet	Number of Wells
200 - 499	10
500 - 999	8
1000 - 1499	7
1500 - 1999	32
2000 - 2499	21
2500 - 3099	8
1657	average

TABLE 3

REPLACEMENT WELL REFERENCE TABLE

Ref. No.	Location Sec-T-R	Operator	Lease
1	36-1-10	Getty	Reynolds #1
		First Nat'l	Clark #1
2	21-1-12	Phillips	Gayle #1
			Gayle #2
			Gayle #3
3	24-1-12	Tascosa	Muller #1
		Phillips	Jones BB #1
4	27-1-12	Phillips	Krull #1
			Krull #3
		McKenzie	Hantla #1
5	36-1-12	Kerr McGee	Seright #1
		Apache	State #1
6	1-1-13	Phillips	McFadden #1
			McFadden #2
7	5-1-13	Amoco	Boston #1
			Boston #2
8	7-1-13	Amoco	Burrows B #1
		H & L	Etling #1
9	8-1-13	Amoco	Dick A #1
			Dick #1
		H & L	Hill #1
10	11-1-13	Phillips	Folder #1
			Folder #2
11	19-1-13	Amoco	Hungerford #1
			Hungerford #2
12	29-1-13	Amoco	Draper #1
			Draper #2
13	24-1-14	Phillips	Line #1
			Line #2
14	35-1-14	Phillips	Jerome #1
			Jerome #2
15	10-1-15	Phillips	Strat #1
			Strat #2
16	31-1-15	Phillips	Percy #1
			Percy #2
17	4-1-17	Santa Fe	Wall #4
			Wall #4A
18	7-1-17	Tascosa	Charles #1
		Phillips	Norton C #1
19	15-1-17	Phillips	Atkins A #2
			Atkins A #3
20	16-1-17	Phillips	Atkins A #1
			Atkins A #1R
21	20-1-17	Kerr McGee	Edith #1
		H & L	Wagner #1
22	24-1-17	Phillips	Ingles #1
		H & L	Lewis #1
			Lewis #1A
23	21-1-18	Kansas Neb.	Prewett A #1
			Prewett A #3
24	14-2-11	Cotton	Mayer #1
		Wallace	McCall #1
25	15-2-11	Cotton	Gear #1
		Wallace	Folkers #1
26	23-2-11	Tascosa	Mons #1
		Cotton	Sweet #1
		Wallace	Sweet #1
27	6-2-12	Cities	Stonebraker AG #1
		Wallace	CSC #1
28	7-2-12	Phillips	Gerald #1
		H & L	Davison #1
29	31-2-12	Phillips	Orv #1
			Orv #2
30	16-2-13	Kerr McGee	Owen #1
		JNC	Hiebert #1
31	29-2-13	Amoco	Jefferies #1
			Jefferies #2
32	20-2-17	Mapco	Grimmer #1
			Vanderwork #1
			Vanderwork #2
33	35-2-17	Amoco	Randles #1
			Stinson #2
34	22-2-18	Kansas Neb.	Tharp #1
			Tharp A #1X
35	32-2-18	Texola	Rhodes #1
			Rhodes #2
36	5-3-12	Cities	Enz A #1
		Tenneco	Enz #1
		Wallace	Enz #1
37	10-3-12	Cities	Robbins A #1
			Robbins A #2
38	3-3-13	Panhandle E.	Messinger #1
			Messinger #2
		Anabaco	Messinger #1
		H & L	Messinger #1
39	9-3-13	Cities	Stonebraker H #1
		H & L	Quilty #1
40	4-3-14	Conoco	Smith #1
		Kaiser F.	Myers #1
41	32-3-17	Cabot	Casto #5
			Casto #14
42	18-3-18	Panhandle E.	Enns #1
		Anadarko	Voth B #1
43	19-3-18	Panhandle E.	Fletcher #1
		Anadarko	Voth C #1
			Voth C #2
44	14-4-11	Panhandle Dev.	Hart #1
		Hinkle	D. Hart #1
45	8-4-12	Cities	Potts #1
		H & L	Hitch #1
46	13-4-12	Panhandle E.	Haley #1
			Shaffer B #2
47	24-4-13	Panhandle E.	Gable #1
			Elrod #1
48	25-4-13	Panhandle E.	Keenan #1
			Keenan #2
49	26-4-13	Panhandle E.	Smith #1
			Keenan A #4
50	8-4-14	Panhandle E.	Burris B #1
			OK State F #1
			Burris B #2
51	25-4-14	Mobil	Bartels #1
			Bartels #2
			Bartels #3
52	33-4-14	Cities	Ziegler #1
		Kaiser F.	Eaton #1
53	10-4-18	Kansas Neb.	Pauls #1
		Cotton	Sneed #1
54	35-4-18	Kansas Neb.	Schroeder #1
		Texas Energies	Friesen #2
55	10-5-12	Panhandle E.	Bevan #1
			Bevan #2
56	26-5-17	Santa Fe	Parham #1
			Parham #1A
57	2-5-18	Santa Fe	Duncan #1
			Duncan #1A
58	10-5-18	Texaco	Phillips #1
			Phillips #2
		H & L	Phillips #1
59	22-5-18	Santa Fe	Chrispens #1
			Chrispens #1A
60	34-5-18	Santa Fe	Hiebert #1
			Hiebert #1A
61	25-6-13	Mobil	Weeks #2
			Weeks #2-1
			Weeks #2-3
62	25-6-14	Mobil	Pearl Davis #1
			Pearl Davis #3
63	18-6-15	Mobil	Parker #1
			Parker #3
64	26-6-15	Mobil	Isham #1
			Isham #3
65	35-6-15	Mobil	Miller #1
			Miller #3
66	16-6-16	Mobil	Curtis #1
			Curtis #2
67	18-6-16	Mobil	Cope #1
			Cope #2
68	24-6-16	Mobil	Ebersole #1
			Ebersole #2
69	33-6-16	Mobil	Guest #1
			Guest #2
70	20-6-17	Mobil	Hoobler #1
			Hoobler #2
71	33-6-17	Santa Fe	Dore #1
			Blankenship #1
72	23-6-18	Plains	Cain #1
		Mapco	Cain #2

TABLE 4

TIME ELAPSED BETWEEN ORIGINAL WELL'S LAST PRODUCTION AND REPLACEMENT WELLS FIRST PRODUCTION

Time, Yrs	No. Wells	% of Wells	Cum %
< 1	34	39.5	39.5
≥ 1 < 2	15	17.4	56.9
≥ 2 < 3	4	4.7	61.6
≥ 3 < 4	2	2.3	63.9
≥ 4 < 5	4	4.7	68.6
≥ 5 < 10	6	7.0	75.6
≥ 10 < 20	10	11.6	87.2
≥ 20	4	4.7	91.9
Never produced	7	8.1	100.0
	86		

TABLE 5

± PER CENT DIFFERENCE BETWEEN REPLACEMENT WELL'S INITIAL ESTIMATED AND MEASURED PRESSURES

$$\% \text{ ERROR} = \frac{\text{ESTIMATED - MEASURED}}{\text{MEASURED}} * 100$$

	No. Wells	Range of error, %	Algebraic Average, %
≤ abs (10)	38	+ 9.6 to - 9.6	0.7
> abs (10) ≤ abs (20)	13	+ 14.9 to - 19.6	- 2.5
> abs (20) ≤ abs (30)	6	+ 23.8 to - 24.8	- 1.6
> abs (30)	19	+ 82.9 to - 66.4	- 11.6
Measured not available	10	———	
	86		

Fifty per cent of estimates were within ± 10% of measurements available.

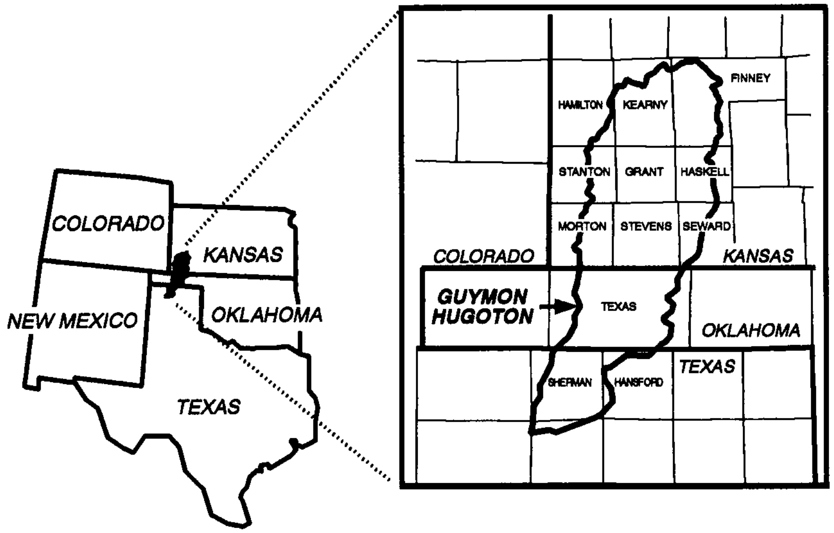

Fig. 1—Hugoton field regional map.

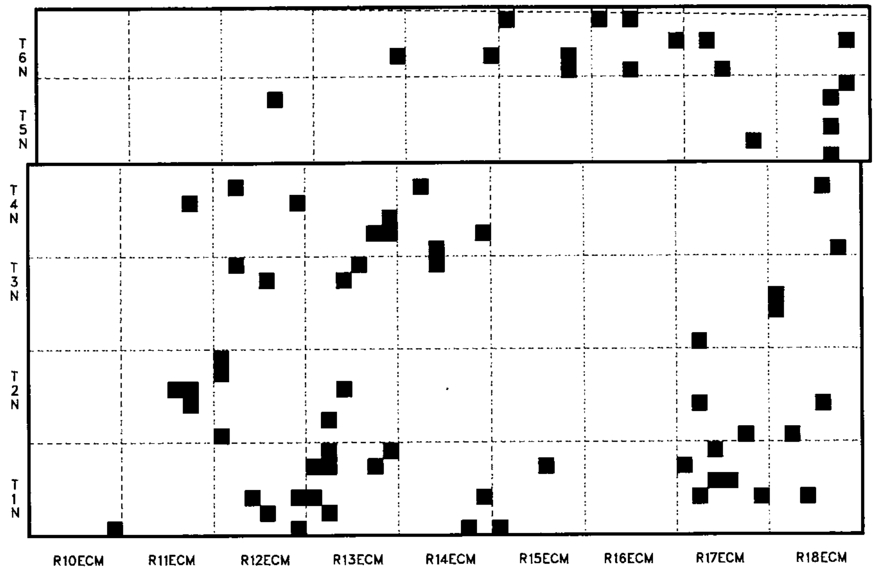

Fig. 2—Guymon-Hugoton replacement well map.

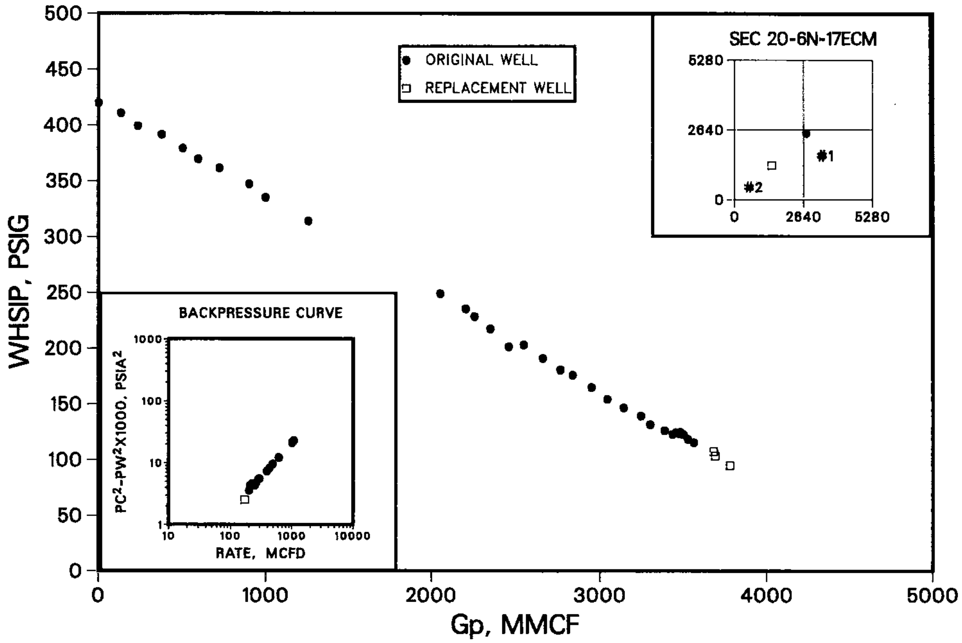

Fig. 3—RN70 pressure vs. cumulative production and backpressure plot.

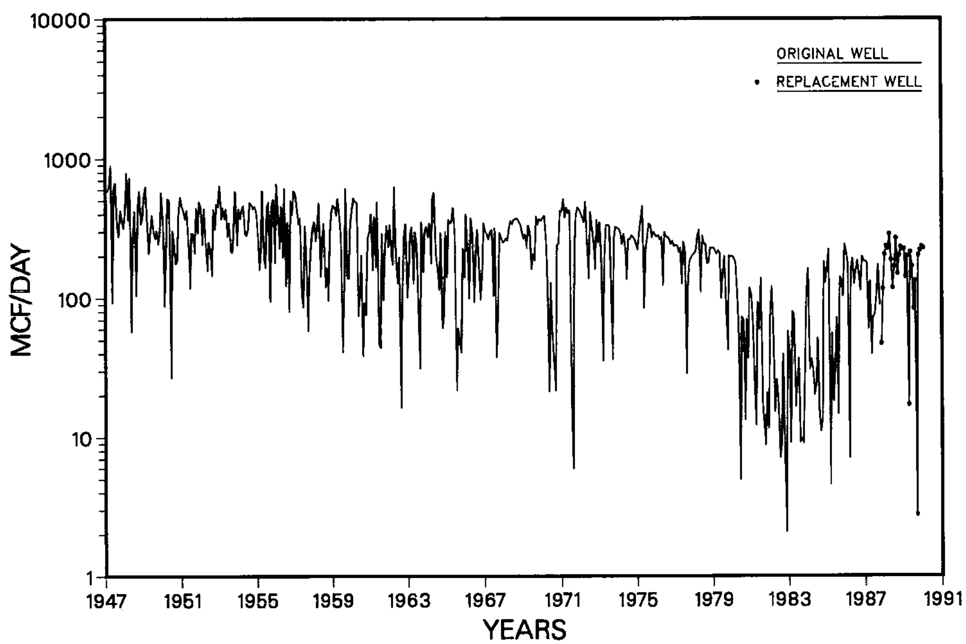

Fig. 4—RN70 production rate vs. time plot.

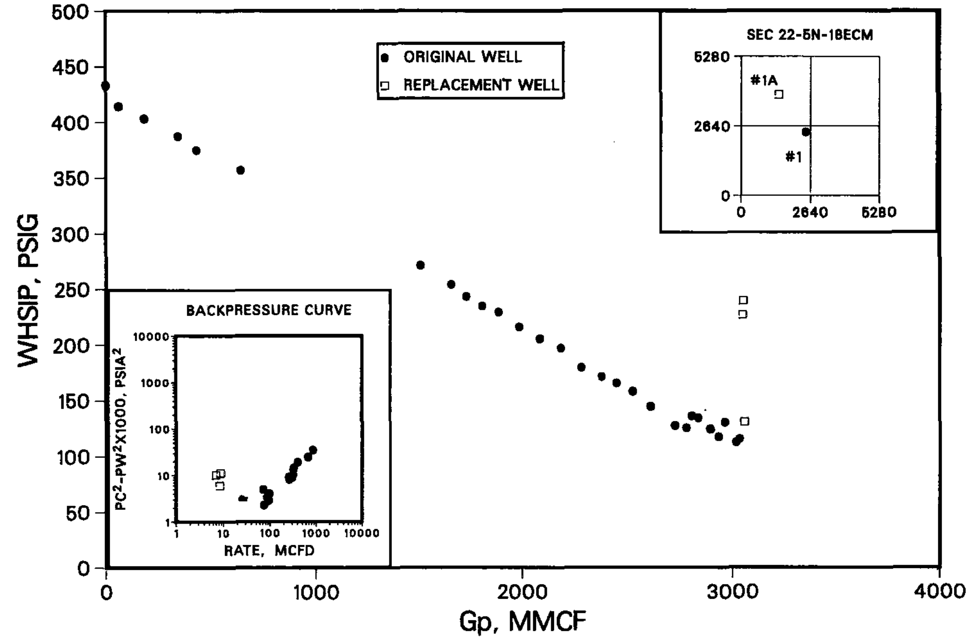

Fig. 5—RN59 pressure vs. cumulative production and backpressure plot.

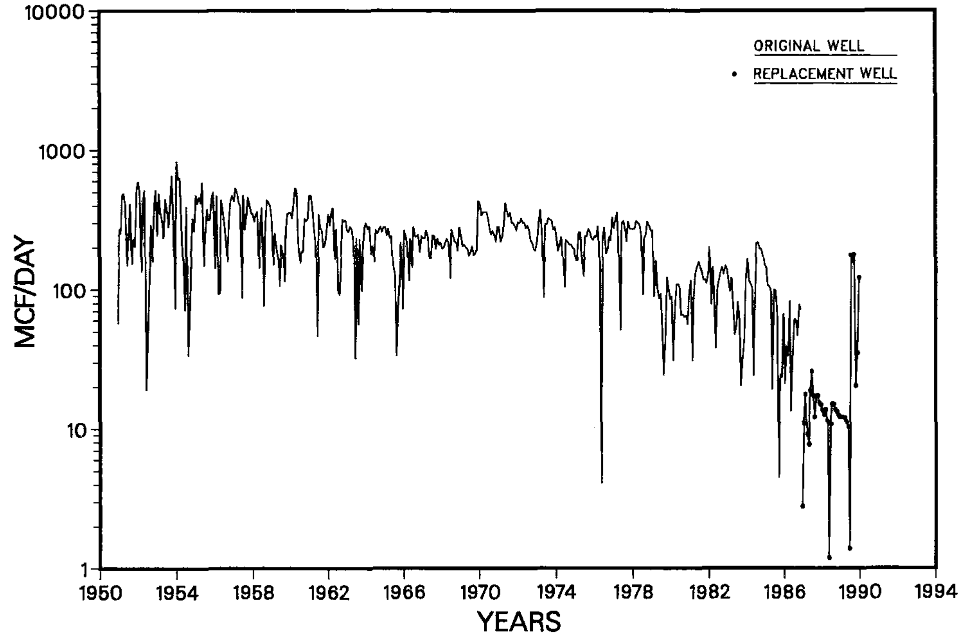

Fig. 6—RN59 production rate vs. time plot.

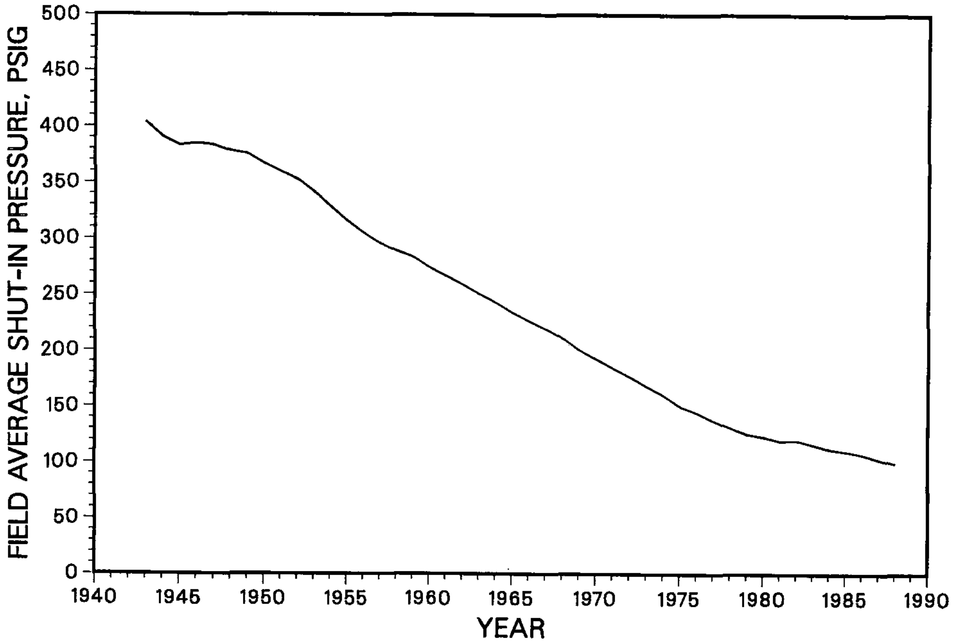

Fig. 7—Guymon-Hugoton field average shut-in pressure vs. time plot.

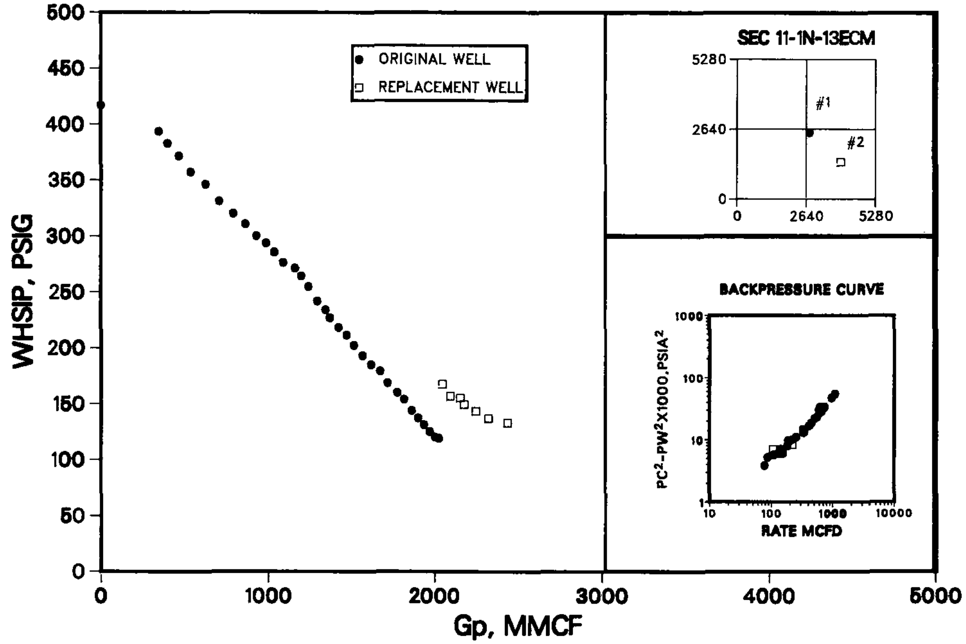

Fig. 8—RN10 pressure vs. cumulative production and backpressure plot.

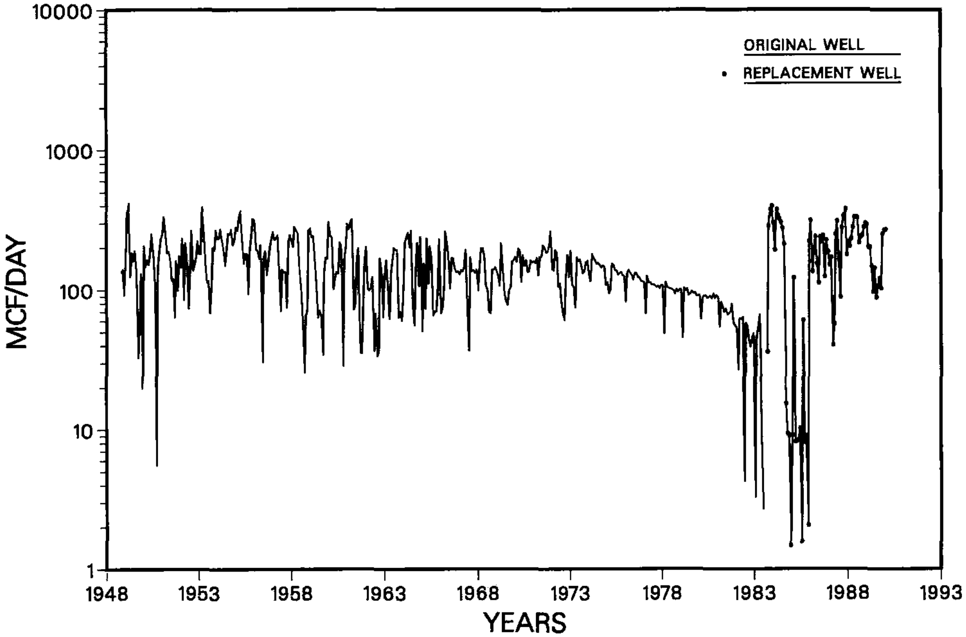

Fig. 9—RN10 production rate vs. time plot.

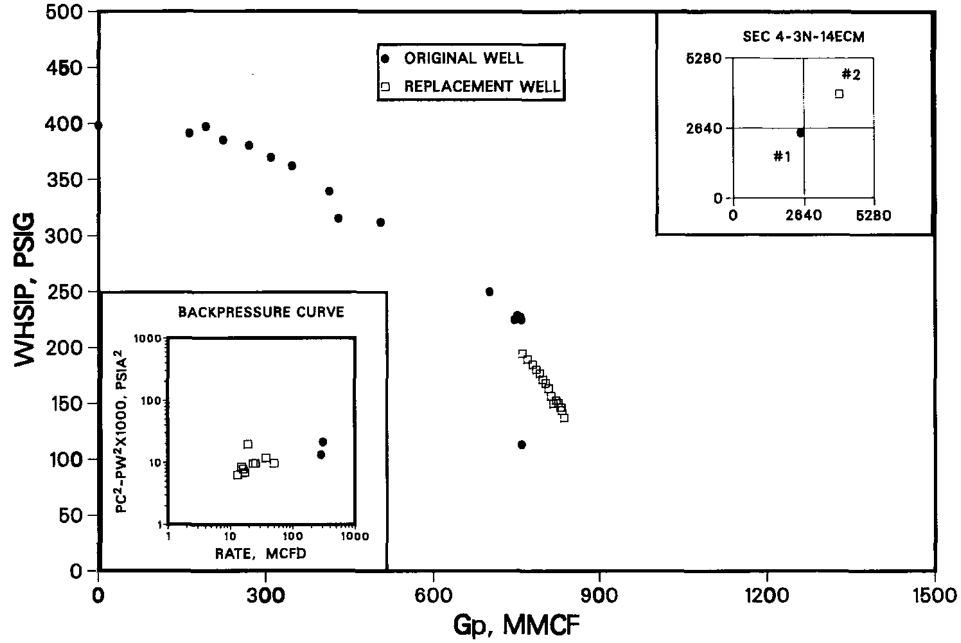

Fig. 10—RN40 pressure vs. cumulative production and backpressure plot.

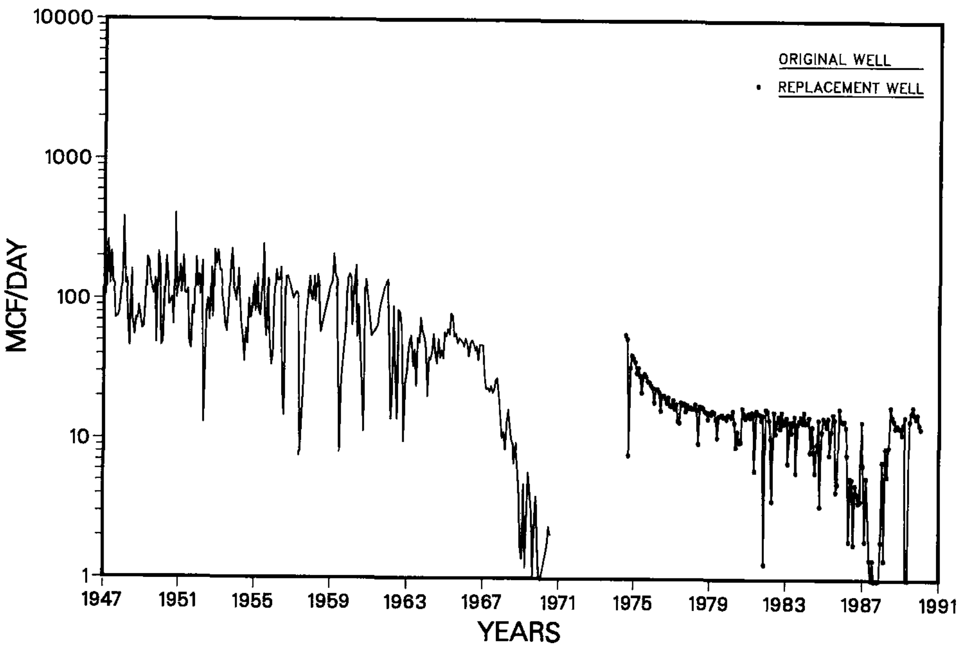

Fig. 11—RN40 production rate vs. time plot.

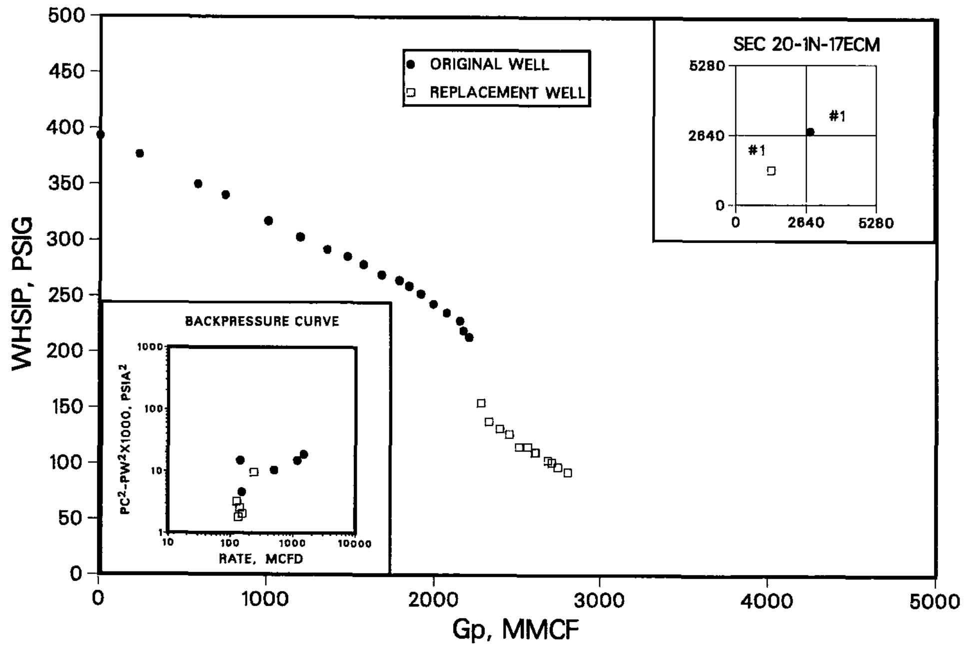

Fig. 12—RN21 pressure vs. cumulative production and backpressure plot.

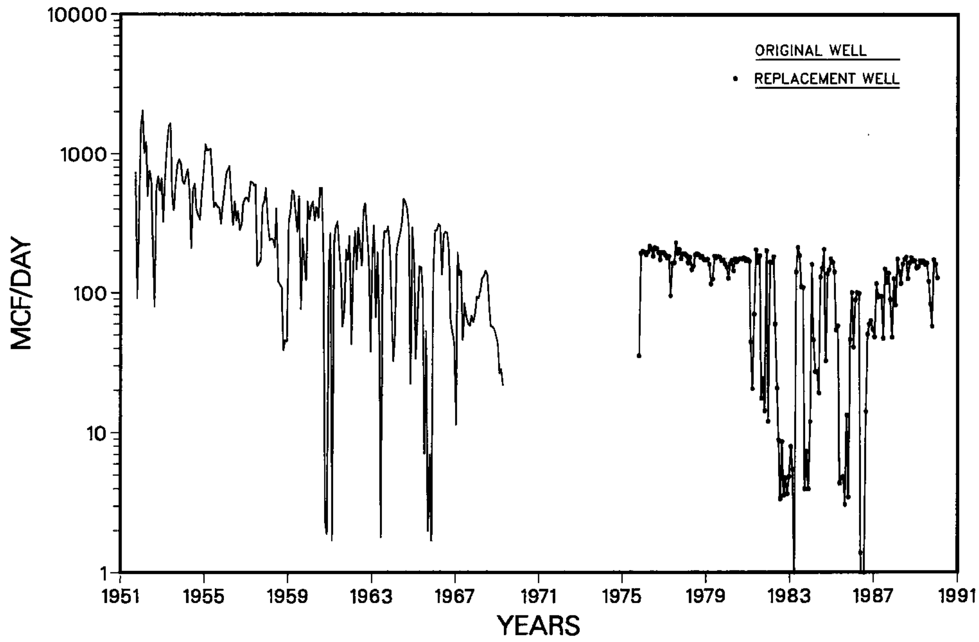

Fig. 13—RN21 production rate vs. time plot.

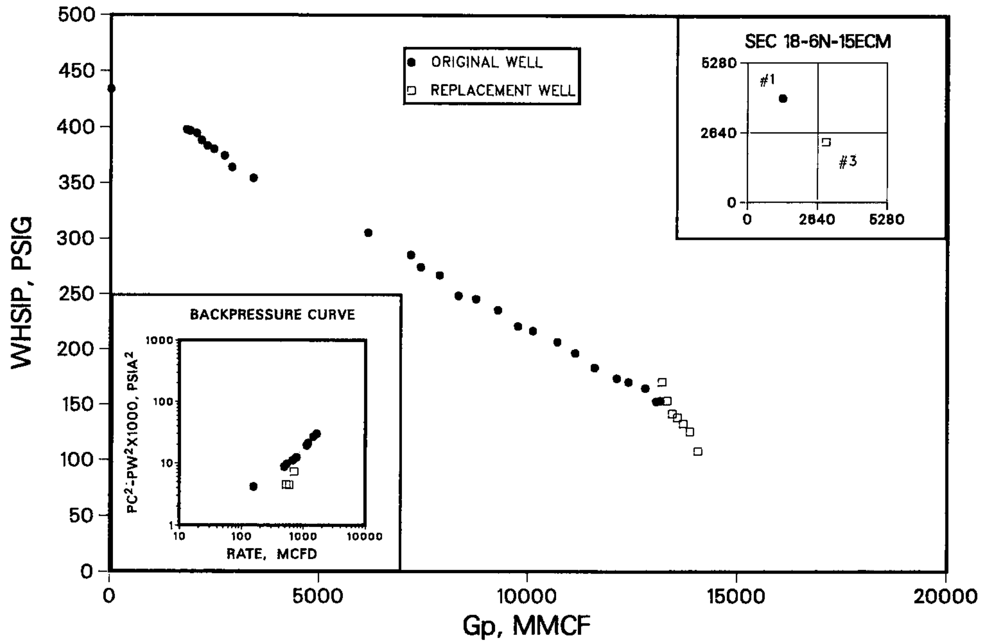

Fig. 14—RN63 pressure vs. cumulative production and backpressure plot.

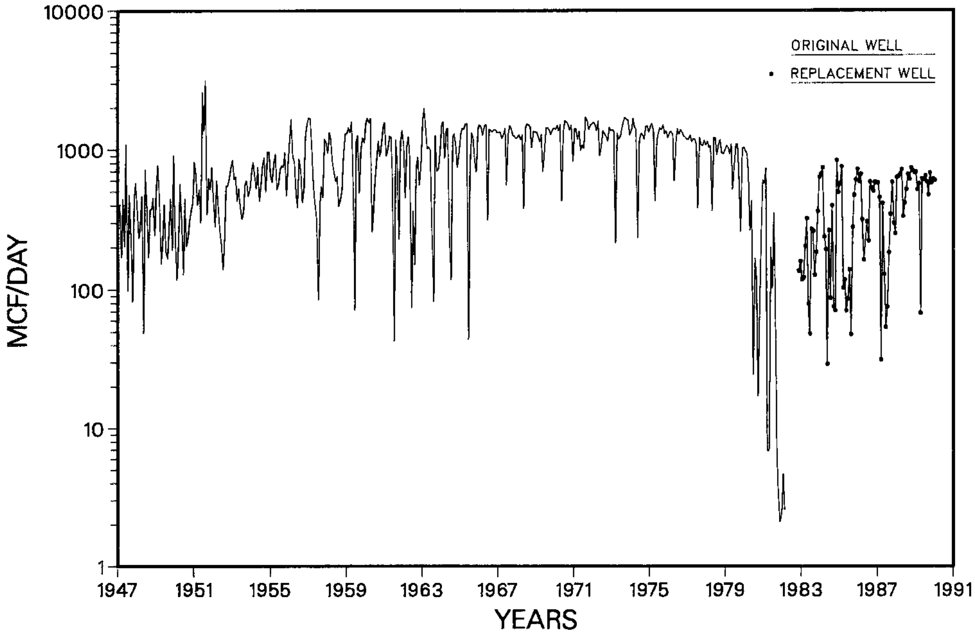

Fig. 15—RN63 production rate vs. time plot.

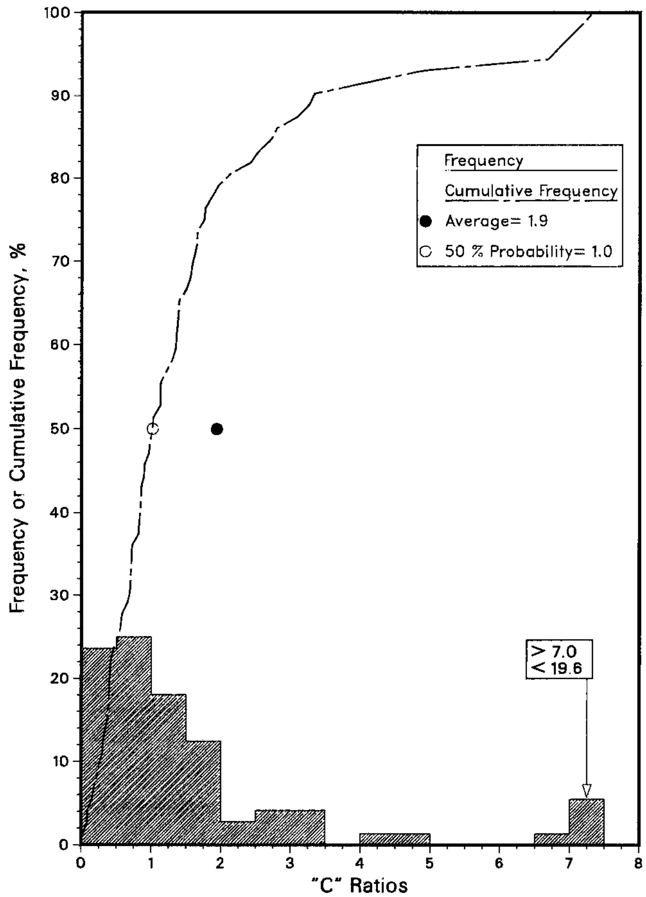

Fig. 16—Frequency distribution of "C" ratios.