Multiwell, Multilayer Model To Evaluate Infill-Drilling Potential in the Oklahoma Hugoton Field

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Summary. A 3D simulation was conducted on a portion of the Oklahoma Hugoton gas field to evaluate infill-drilling potential. The importance of understanding the behavior of layered, no-crossflow reservoirs is emphasized by matching detailed performance histories. Further insight into this long-lived field is obtained by forecasting performance, both for continued current operations and for infill drilling on each proration unit.

Introduction

On April 25, 1986, the Kansas Corp. Commission (KCC) issued an order[1] that allowed infill drilling in the Kansas portion of the giant Hugoton gas field. The order allows producers to drill a second gas well on each of the 4,163 proration units (nominally 640 acres). On the basis of geologic and engineering testimony, the KCC ruled that 3.5 to 5 Tscf of additional reserves could be recovered by drilling an infill well on most of the current 640-acre proration units. Initial and remaining gas in place (GIP) in the Kansas Hugoton field, indicated from pressure/cumulative production data presented at the hearing, were 30 and 12 Tscf, respectively.

In view of the infill-drilling order in Kansas, the Oklahoma Corp. Commission (OCC) initiated a proceeding to determine whether it should develop a plan to authorize drilling of increased-density wells in the Oklahoma portion of the Hugoton gas field. A Jan. 30, 1987, OCC notice of inquiry requested all interested parties to submit answers to questions related to infill-drilling potential on the present 640-acre spacing pattern. There are currently 1,340 active wells in the Oklahoma Hugoton field. Cumulative production to March 1, 1989, was 5.0 Tscf, with an indicated 1.5 Tscf of remaining recoverable reserves.

Phillips Petroleum Co.'s investigation of the effect of infill drilling on gas production and the potential of recovering additional reserves from the Oklahoma Hugoton field included four different studies.[2-5] One of the more comprehensive studies was a reservoir simulation study that is the subject of this paper. A three-layer, no-crossflow, 3D reservoir model was developed to simulate the performance of original and infill wells in a 12-section study area of Phillips' Oklahoma Hugoton acreage in the southern portion of the Oklahoma Hugoton gas field. We demonstrate how a unique history-match of performance data of the original wells was obtained with virtually no adjustment to the log-calculated input variables that determine original GIP and model performance. Any volumetric GIP adjustment would, of course, be crucial to the evaluation of infill-drilling potential. The performance data that were history-matched in our model study included (1) >40 years of official state test annual wellhead shut-in pressure with cumulative production data, (2) official state test annual 72-hour deliverability test rate and flowing pressure data, (3) individual layer pressure data obtained from an expendable well drilled in the 12-section study area, and (4) pressure/cumulative production and deliverability test performance data of a replacement well in the 12-section study area.

The history-matched model was used (1) to calculate the study area's total recoverable reserves and individual layer reserves, with and without infill wells, and (2) to forecast production rates for the study area, with and without infill wells, at current market demand and with all wells produced wide open. Study results show that a second well on a proration unit does not improve drainage or recovery compared with that of the current 640-acre spacing pattern and that the long life (108 years) associated with the Oklahoma Hugoton field is to be expected because of its layered, no-crossflow nature.

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Geology

Cyclical sedimentation in the Hugoton basin produced a Lower Permian section composed of successive cycles of laterally continuous and mappable, shallow marine carbonate intervals (Florence, Towanda, Ft. Riley, Winfield, Krider, and Herington limestones), each capped by reddish-brown terrigenous siltstones, mudstones, and shale intervals (Oketa, Holmesville, Gage, Odell, and Paddock shales).[6] Dolomitization of the carbonates has produced a continuous intercrystalline pore system that promotes good areal continuity of reservoir porosity and permeability in each carbonate interval. This areal reservoir continuity is supported by our various studies. Because of their low permeability and high threshold entry pressures, the intervening argillaceous units act as barriers to vertical flow between the carbonate units. Different pressures measured in individual layers by various operators confirm vertical heterogeneity or the layered, no-crossflow nature of the reservoir. **Fig. 1** illustrates north-south and east-west cross sections through the 12-section study area showing the basic layering and layer continuity.

In the southern part of the Oklahoma Hugoton field where the study area is located, the principal producing reservoirs are the Herington, Krider, and Winfield members. They constitute three no-crossflow gas producing layers in our reservoir simulation model. All geologic layers below the Winfield and the lower portion of the Winfield in this part of the field are wet.

Ref. 6 gives an in-depth discussion of the geology of the study area and the rest of the Oklahoma Hugoton field. A description of the geology and a similar Lower Permian layering within the Kansas Hugoton field are in the testimony and exhibits presented in the Kansas Hugoton hearing.[1]

Model Study Area

In selecting a study area, we looked for a location that was central to our block of acreage in the Oklahoma Hugoton field with a high number of more recently drilled wells penetrating through the formations of interest. A further consideration was to select an area whose outer boundaries reasonably coincided with no-flow boundaries as determined by proportioning offset-well producing rates. A model area of 12 sections surrounded by 18 additional sections was selected, and all the sections had at least one deep well. The deep wells were drilled in the early 1960's and logged with a suite of modern logs. Layer correlations and reservoir parameters ϕ, k, h, and S_w were ultimately developed from log analysis calibrated to core data for input into the reservoir simulation model. The 12-section study area also includes one section where a replacement well was drilled 2,259 ft from the original well in the extreme southwest quarter of its 640-acre section. Performance history-matching of a previously drilled replacement well with several years of production should verify the ability of our model to predict the performance of any infill wells drilled on a 640-acre section in our study area.

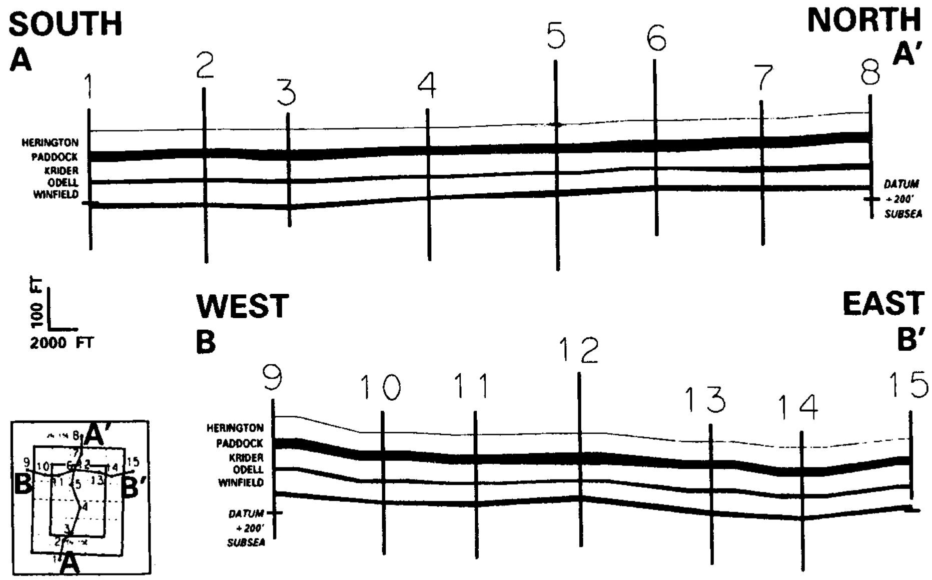

Fig. 1—Cross sections through the 12-section study area showing layering.

HERINGTON
p = 314 psia
k = 0.10 md
ϕ = 0.06
h = 58 ft
S_w = 0.76

KRIDER
p = 121 psia
k = 9.0 md
ϕ = 0.08
h = 50 ft
S_w = 0.60

WINFIELD
p = 141 psia
k = 3.3 md
ϕ = 0.08
h = 40 ft
S_w = 0.67

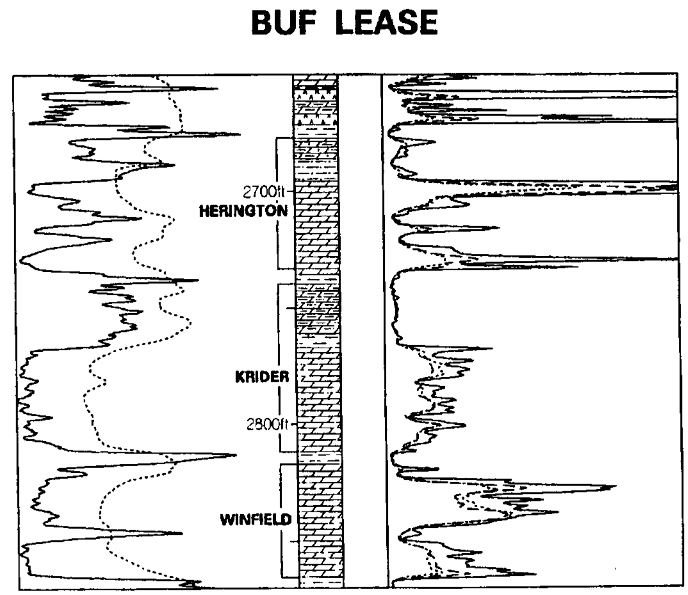

Fig. 2—Type log for the Chase interval, including reservoir parameters.

TABLE 1—INITIAL FLOW-AFTER-FLOW TEST RESULTS, 12-SECTION STUDY AREA

First Gas	Well	Date of Test	Number of Flows	Length of Each Flow (hours)	Pressure-Transient-Analysis Results Commingled Well: kh (md-ft)	Pressure-Transient-Analysis Results Commingled Well: s	72-Hour Deliverability Curve History-Match Skins (s)
Oct. 1946	Mayoe	Oct. 1946	3	24	637	–5.15	–5.55
Nov. 1946	Buf	Oct. 1946	4	24	589	–5.44	(–5.44)
Nov. 1946	Mutual	Sept. 1946	4	24	436	–5.33	(–5.33)
Sept. 1947	Vantine	April 1947	4	3	1,340	–5.05	(–5.05)
June 1948	Sheil	Sept. 1947	4	3	489	–5.08	(–5.08)
Nov. 1946	Christine	Sept. 1946	4	24	615	–4.69	–5.15
Aug. 1947	Dakar	Aug. 1947	4	3	395	–5.42	–5.00
Jan. 1947	Luman	Jan. 1947	3	24	650	–5.24	(–5.24)
Nov. 1946	Princess	March 1947	4	3	999	–4.49	(–4.49)
Aug. 1947	Atar	April 1948	4	3	703	–4.65	(–4.65)
Aug. 1946	Strat	Jan. 1947	4	24	527	–4.66	(–4.66)
Jan. 1947	Oella	March 1947	4	3	850	–4.49	–4.70

( ) indicates no change in *s*.

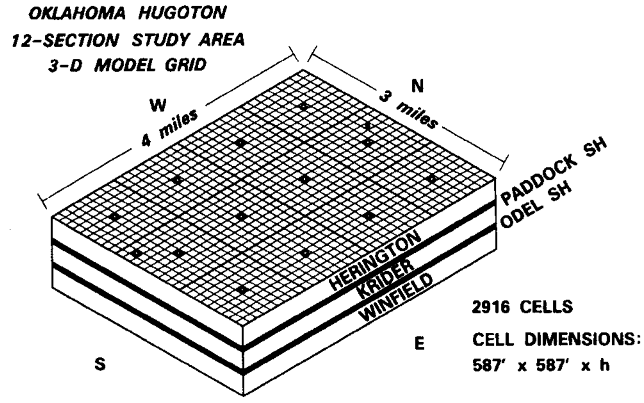

Fig. 3—Model grid, layering, and well locations.

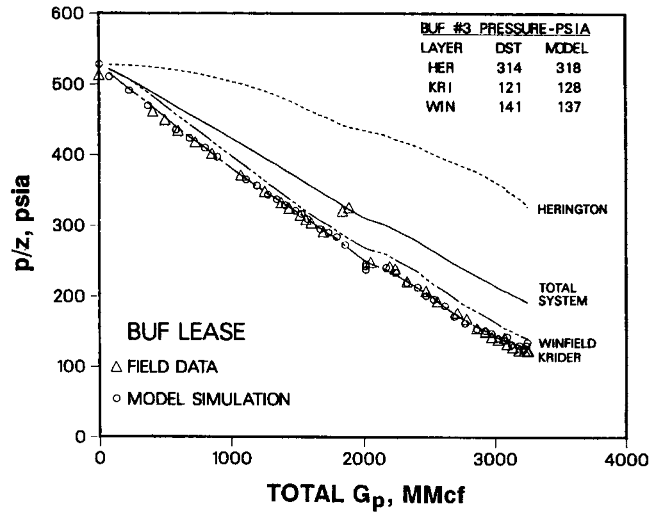

Fig. 4—Buf lease p/z vs. G_p history and layer pressure matches.

Log Analysis

Logs from the Chase producing wells drilled and logged in the 1940's and 1950's consisted of spontaneous potential and resistivity logs only and were inadequate for detailed log analysis. These logs were used, however, to correlate formation tops for cross sections.

Modern logs from 39 wells in the 30-section region were analyzed to define porosity, gross thickness, and water saturation values for input into the model cells. Typical logs from the 39 wells include induction electric, dual induction/laterolog, sonic, and, in a few wells, density logs. **Fig. 2** is a type log that includes individual layer pressures from recent drillstem tests (DST's).

The model was constructed as a gross model. Log analyses yield gross thickness values, with porosity reductions for shale content providing the only eventual hydrocarbon PV correction. Neither porosity nor water saturation cutoffs were used to alter the gross thicknesses or gross hydrocarbon PV's in the productive layers.

Mapping of Reservoir Parameters

Porosity, thickness, and water saturation values from log analyses on the 39 wells in the study area were mapped to provide grid-cell values for model input. The mapping extends over thirty 640-acre sections, including the 12 modeled sections and the 18 sections surrounding the modeled sections.

Herington permeability values were calculated at the 39 wellsites from core ϕ/k correlations calibrated to Well Buf 3 Herington DST results. These values were mapped, giving each Herington model grid cell a permeability. Krider layer permeabilities were then calculated for those wells completed only in the Herington and Krider by subtracting the ϕ/k-derived Herington kh from total well kh obtained from multipoint test analysis. The resulting Krider permeabilities for the 18 Herington-Krider wells (7 model area, 11 perimeter) were then mapped and gridpoint values obtained. This map was used to determine Krider well permeabilities for the 12 wells with Winfield completions. Herington and Krider permeabilities and thicknesses and the total well kh from the multipoint tests were used to calculate and map Winfield permeabilities.

Well Deliverability and Permeability Distribution

Total well kh and skins for the original 30 wells were calculated from multipoint flow-after-flow tests obtained on each well immediately after their initial completions in the late 1940's. All layers in each well were stimulated separately through perforations by acid fracturing (without proppants), with bridge plugs between each successive treatment. After all layers were stimulated, the bridge plugs were drilled out and a final commingled acid treatment conducted. The well was generally blown for cleanup and rested for at least 1 week before a commingled multipoint test was conducted. Tests generally consisted of three or four 24- or 3-hour flows. At the time that these initial tests were run, pressures in each layer should have been essentially equal, at or near their initial values of 490 psia. This is a significant point with regard to pressure-transient-test interpretation of kh and skin values obtained in layered, no-crossflow reservoirs when layer pressures are unequal.[7]

Our analysis of the multipoint tests included semilog drawdown and log-log type-curve analyses of the first flow of each multipoint test. The drawdown data for all wells analyzed for kh and skin were found to fit the constant-rate, infinite-conductivity type curve. A superposition analysis was then performed to use and fit all the multipoint test data. A zero non-Darcy flow term was ultimately used in our final superposition analysis; this lack of a non-Darcy flow term will be discussed later. The superposition analysis was most useful with the 3-hour flows because the semilog period was not present in a single 3-hour flow. **Table 1** summarizes the analysis results in terms of kh and skins for wells in the modeled 12-section study area. Eight of the 12 wells required no adjustments of skin to history-match all the 40+ years of official 72-hour deliverability tests. As Table 1 shows, only slight changes in skin were required to match the deliverability tests of the remaining four wells. Total kh from well tests were not adjusted in any of the cases in our history-matching efforts.

Model Development

A review of testimonies regarding the various model studies presented in the Kansas Hugoton infill-drilling hearing[1] was conducted. Several one-well, multilayer studies fixed the no-flow outer boundaries in all layers on the basis of a 640-acre proration unit. These fixed drainage boundaries resulted in apparent history-matched GIP numbers that were lower than model input volumetric numbers. This difference in GIP was interpreted to indicate the presence of lenses or pods of trapped and undrained gas. A multiwell, multilayer model study that did account for offset-well drainage effects did not attempt to match well deliverability performance, or more crucially, individual layer pressures. By not matching layer pressures, the multiwell study also determined similar differences between volumetric and pressure/cumulative-production history-matched volumes. Although the conclusions were the same, the differences were the result of two separate effects, which led us to the conclusion that no valid model study was performed that correctly evaluated the infill-drilling potential in the Kansas Hugoton field.

Therefore, we concluded that to evaluate and to predict the future performance and production from infill wells in the Oklahoma Hugoton field realistically, a multiwell, multilayer simulation study must be developed that should attempt to history-match all the following data.

1. Each well's annual official test shut-in pressure with cumulative production data.
2. Each well's official 72-hour deliverability tests.
3. Herington, Krider, and Winfield layer pressures in at least one well in the multilayer study area.
4. Performance match of History-Matches 1 and 2 on one or more replacement wells drilled on a 640-acre section in the multiwell study area.

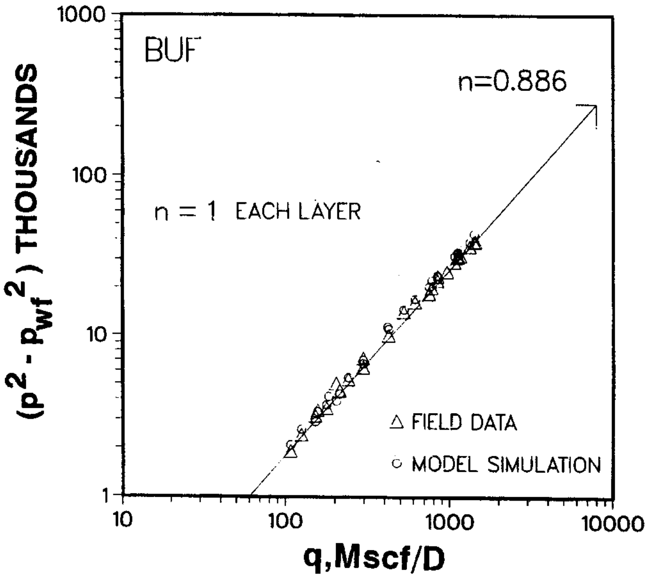

Fig. 5—Well Buf 1 72-hour official deliverability test matches.

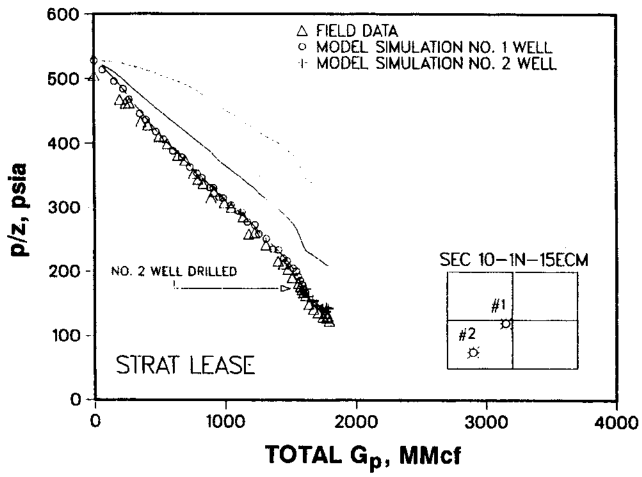

Fig. 6—Strat original and replacement well *p/z* vs. G_p match.

Fig. 3 shows the gridding (27 × 36 × 3) and well locations (12 original, one replacement, and one DST-cored wells) used in our Oklahoma Hugoton model study. This detail was required to simulate the official 72-hour shut-in and subsequent 72-hour drawdown tests correctly. Grid selection and timestep sizes were verified with a single-well, 50-cell per layer radial model. Our models were able to handle, without instability, the interlayer wellbore backflow that occurred between differentially depleted layers during surface shut-ins. The negative skins obtained from well stimulations were treated similarly in both models by including the skin in the well cell PI.

History Match

We found that matching layer pressures in layered, no-crossflow reservoirs is the most critical aspect in obtaining a unique history match. Fig. 2 shows layer pressures obtained at Well Buf 3 (expendable well 1,780 ft northwest of Well Buf 1). The 193-psi pressure difference between the Herington and Krider layers at Well Buf 3 clearly demonstrates differential depletion in this layered no-crossflow reservoir. Layer pressures at Well Buf 1 were also determined by use of a packer to isolate the Herington from the Krider and Winfield. The 11-day shut-in pressures were 222 psia for the Herington and 118 psia for the commingled Krider and Winfield. The gradient pressures between Wells Buf 1 and 3 over the 1,780 ft are commensurate with the layer permeabilities.

Pressure/Cumulative-Production and Deliverability Curve Matching

Using the multiwell model, we history-matched individual well 72-hour (96-hour after 1975) surface shut-in pressures calculated to bottomhole pressure (BHP) and the subsequent final 72-hour drawdown flow rate and flowing pressure calculated to BHP. The shut-in and drawdown periods represent annual official tests taken midyear and used by the OCC to allocate allowables in the Oklahoma Hugoton field. In the model study, all wells are simultaneously shut in, then flowed at their official test rates. Eight 9-hour timesteps were used to simulate each test period (shut-in and drawdown).

The p/z vs. total G_p plot of Well Buf 1 (**Fig. 4**) illustrates one of the key well matches from the final history-match of our multiwell model. The 34 triangles represent 44 years of field data. The model shut-in is effectively a wellhead shut-in that allows wellbore backflow between the differentially depleted layers during shut-in. The simulated shut-in pressure values obtained with the model are shown as circles in the figure. The solid lines in Fig. 4 represent the volumetrically averaged layer pressures and the total system average pressure over the 640-acre unit plotted vs. total cumulative production, G_p, produced from all layers. Note the excellent match of layer pressures at the model location of Well Buf 3.

Fig. 5 shows the 72-hour transient deliverability curve match of Well Buf 1. Reservoir or stimulation deterioration since initial completion is not indicated from these data. The quality of the overall match is excellent. Because the total well kh and skin are now correct in the model, model points will also lie along the backpressure curve established by field data even if a poor match of reservoir shut-in pressures is obtained.

This matching of the 72-hour tests was based on model input variables developed from an analysis of initial 3- and 24-hour multipoint tests. Only a few wells required minor skin adjustment, which was considered quite remarkable and speaks highly of modern well-test analysis methods and their application to quality test data taken in the mid-1940's. A significant point to note from the backpressure curve plots of model data is that, like the field data, a backpressure curve exponent $n = 0.886$ was obtained. This happened even though the model did not have a non-Darcy flow component in any of the layers for any well in the model. Well Mutual 1 (offsetting Well Buf 1) had the lowest value of exponent, $n = 0.799$.

Replacement Well Match

A history-match of the performance of Wells Strat 1 and 2 (on the same 640-acre proration unit) was an attempt to demonstrate the ability of the history-matched model to predict the results of drilling an infill well accurately. Well Strat 2 was completed in 1981 as a replacement well for Well Strat 1. Well Strat 1 was plugged and abandoned after completion (Herington and Krider) of Well Strat 2. Permeabilities, thicknesses, porosities, and water saturations at the Well Strat 2 cell were the same as those previously assigned from our initial model description (no pressure-transient testing was conducted on Well Strat 2). Well Strat 2 was assigned the skin value previously calculated for Well Strat 1, $s = -4.66$.

Fig. 6 shows the p/z vs. G_p match of Wells Strat 1 and 2, with a combined 44-year history. Note the match of the change in slope and the excellent match of Well Strat 2 pressures compared with the model values. No changes or adjustments were made to any Well Strat 2 reservoir parameters. Matching of Well Strat 2 confirms the model's ability to predict the performance of a well drilled in our history-matched study area.

Fig. 7 shows the history-matched deliverability curves of Wells Strat 1 and 2. The early 72-hour performance of Well Strat 1 and the current 72-hour performance of Well Strat 2, with pumping unit, show essentially the same deliverability-curve position for both wells. This indicates that the replacement well, equivalent to drilling an infill well in the 640-acre section, is no better or worse than the original well. Ref. 4 also illustrates that when the original wells are properly stimulated, or restimulated, the original and infill well performance will be virtually identical.

In our early attempts to estimate the deliverability performance curves for infill wells, we assumed that modern stimulation technology could result in a three- to four-fold increase in the deliverability curve of an infill well compared with that of an original well.

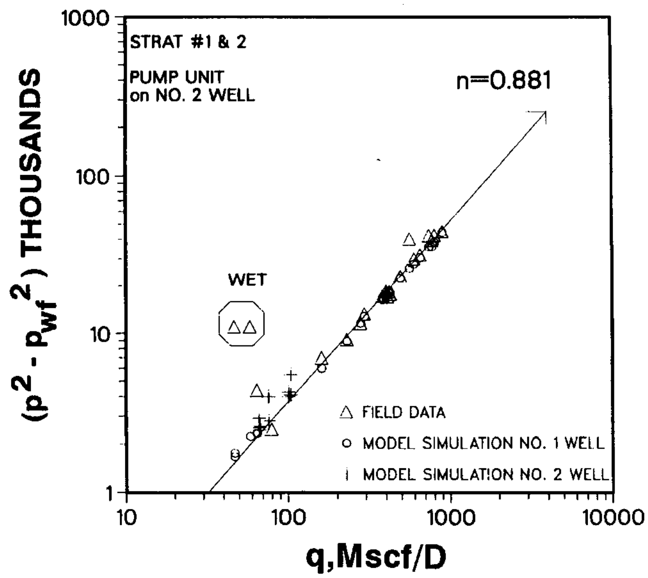

Fig. 7—Strat original and replacement well 72-hour deliverability test matches.

Considering the relatively successful negative skins we later found, averaging -5.0, new infill wells are unlikely to improve on the stimulation results obtained on our original wells. Furthermore, with the differential layer depletion currently existing, diversion techniques other than mechanical bridge plugs would tend to be less successful than when all layer pressures were equal.

12-Section Study Area Match

An excellent history match was obtained on all wells with the multiwell, no-crossflow, three-layered model. Virtually no changes were made to the original reservoir input variables, and no adjustment was made to the PV input data. Fig. 10 of Ref. 8 shows the final p/z vs. G_p match of all 12 wells, with five wells having Winfield production. In addition to individual well pressure matches, the Buf lease DST layer data was matched with the model layer pressures. The overall match covers 44 years of performance data.

Fig. 11 of Ref. 8 shows the 72-hour official deliverability test match for each well. The matches are excellent on all wells. The exponents of the deliverability backpressure curves range from a low of $n=0.799$ to a high of $n=0.908$. Recall that no non-Darcy flow term is in any model layer.

Closing Section Line Boundaries

No-flow boundaries were placed along all model section lines to illustrate the danger of attempting to study the infill-drilling potential of a layered reservoir with single-well model studies or analytical solutions. These closed boundaries converted the model into 12 separate one-well studies, any one of which could have been selected to study infill drilling. Flow rates from each individual layer are not available to proportion no-flow boundaries for each layer. Therefore, for individual well studies, one must assume that the drainage radii, r_e, for each layer are equal and are most likely to be that of the proration-unit spacing.

Closing all section line boundaries destroyed the history-match, clearly showing that areal communication exists throughout the study area (Fig. 12 of Ref. 8). Only four leases appear to have preserved their match.

Crossflow Case

A seemingly good history-match of p/z vs. G_p was obtained when crossflow between all layers was assumed. k_V/k_H of 0.005 between all layers was used. This case illustrated the necessity of obtaining and matching layer pressures in a layered, no-crossflow reservoir. With crossflow and a 20% PV reduction, the pressure/cumulative-production match on all wells appeared excellent. Similarly, individual well deliverability-curve matches also appeared to be as good as those obtained for the final no-crossflow history-match. Unlike our measured DST pressures, pressures for each of the three layers and for total system pressure were equal (Fig. 13 of Ref. 8).

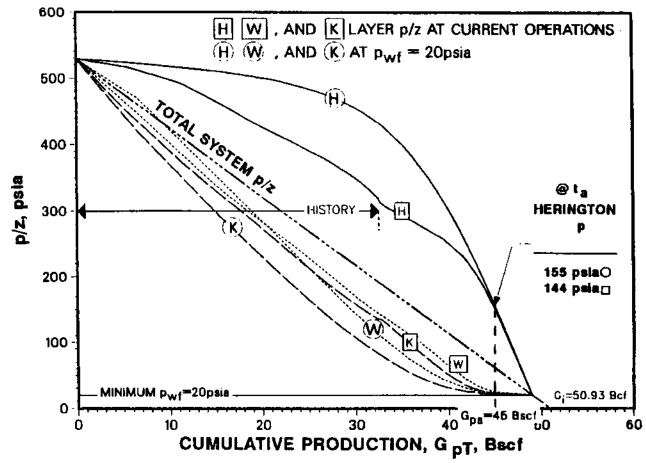

Fig. 8—Effect of rate of production on total 12-section study area layer *p/z*.

It may be more than coincidental that the 20% PV reduction necessary to match the p/z vs. G_p data is identical to that found in a Kansas Hugoton field multiwell study that matched only test pressure with cumulative-production data. The 20% difference between volumetrically derived and history-matched GIP (called "target" or "bypassed" gas) was used to justify infill drilling in the Kansas Hugoton field.

Future Performance Predictions

The history-matched multiwell model (with lateral communication and no crossflow) was used to forecast future production with and without an infill well drilled on each of the twelve 640-acre proration units. Infill wells were in the centers of the northwest quarters of the 12 sections and completed in the same layers as the original wells. The stimulation skin used for the original well was used for the infill well. All infill wells were expected to begin producing Jan. 1, 1990. The average allowable production was specified as a constant rate for each well until it eventually went on decline producing against a 20-psia limiting line pressure. For the infill well case, the section allowable remained the same (i.e., each well produced half the single-well section allowable). The Oklahoma Hugoton field well allowable is based on acres multiplied by deliverability. We considered it unlikely that field market demand would increase substantially in the future.

The total 12-section production rate used for prediction was 1,740 Mscf/D, which corresponds to a rate of take of 1 MMscf-D/29 Bscf of original GIP. This rate of take defines a 79-year period. A limiting case was run that assumed that the original *and* infill wells are permitted to produce wide open. On the basis of the 3D model predictions, economic analyses were performed to evaluate infill drilling economics. Even with the very optimistic production schedule of producing wide open, the economic analysis results of accelerated recovery from drilling infill wells were unacceptable.

The most surprising result of our studies is that no increase in recoverable reserves occurs with an infill well in each unit. In addition, the high abandonment pressure of the low-permeability Herington layer remains unchanged when an infill well is drilled in the section. **Table 2** summarizes the principal results obtained from the model forecasts projected to a 10-Mscf/D-well abandonment rate. Where each unit contains an infill well, results indicate a 45.12-Bscf cumulative production until 2055 for current operations and current spacing compared with 45.05 Bscf until 2023. This represents a recovery of 88.6% and 88.5%, respectively, indicating no increase in recoverable reserves as a result of drilling an infill well. Note also from Table 2 that, to an abandonment rate of 10 Mscf/D-well, an infill well does not deplete the low-permeability Herington layer

TABLE 2—SUMMARY OF 12-SECTION MODEL STUDY RESULTS																
	Jan. 1989			Current Operations (Constant Rate to p_{wf} = 20 psia)						Wide-Open Production From 1946 (Constant p_{wf} = 20 psia at t = 0)						
				No Infill Well			With Infill Well			No Infill Well			With Infill Well			
Layer	G_i (Bscf)	G_p (Bscf)	R (%)	$\bar{p}$, (psia)	G_p (Bscf)	R (%)	$\bar{p}$, (psia)	G_p (Bscf)	R (%)	$\bar{p}$, (psia)	G_p (Bscf)	R (%)	$\bar{p}$, (psia)	G_p (Bscf)	R (%)
Herington	15.09	6.30	41.7	144	10.90	72.2	142	10.94	72.5	155	10.55	69.9	153	10.62	70.4
Krider	25.40	19.03	74.9	23	24.28	95.6	25	24.21	95.3	21	24.38	96.0	21	24.37	95.9
Winfield	10.44	7.70	73.8	25	9.94	95.2	27	9.90	94.8	23	9.98	95.6	24	9.97	95.5
Total system	50.93	33.03	64.9		45.12	88.6		45.05	88.5		44.91	88.2		44.96	88.3
t_a* from 1946, years					108			76			82			41	
t_a* from 1989, years					65			33							

*At 10 Mscf/D-well.

($\bar{p}$ = 142 psia at abandonment) any more than one producing well per 640 acres depletes the layer.

Continuing the current method of operations results in a 108-year total producing life for our study area, or 65 years beyond 1989. Drilling an infill well will reduce the remaining life by half to 33 years, but this is uneconomical and will not result in additional recoverable reserves. As for the potential of contacting isolated pods or pockets of undrained gas, geologic studies,[6] our replacement well study,[2] and our comprehensive model history-match do not support such a concept (postulated in the Kansas Hugoton hearings[1]).

With the history-matched model, we were able to test two limiting cases: (1) produce the study area with one well per section wide open from production start (1946), and (2) drill an infill well in each section and produce both wells wide open beginning from 1946. Table 2 summarizes results obtained for these cases. Both cases result in recoveries that are slightly less than that obtained by current operations (88.6%): 88.2% and 88.3% recovery producing wide open since 1946 without and with infill drilling, respectively. In addition, at wide-open production starting in 1946, total producing life for one well per 640 acres would have only been reduced from 108 to 82 years. Layered, no-crossflow reservoirs that have contrasting layer deliverability, often defined by permeabilities, will have unusually long producing lives. The most significant observation to be made from the wide-open production results is that Herington layer pressure at abandonment is ≈10 psi higher, 2% to 3% less recovery, than constant-rate or current operation results. This indicates that current operations with one well per 640 acres is effectively and efficiently draining the Oklahoma Hugoton field. Layer p/z vs. G_p of the study area is sensitive to production rate (**Fig. 8**).

Effect of Layering on Depletion and Time to Abandonment

Two significant characteristics of layered, no-crossflow reservoirs with layers of contrasting permeabilities are (1) that the low-permeability layer(s) at well abandonment can have relatively high abandonment pressures and (2) that the producing life of these types of layered reservoirs can appear to be excessively long. These characteristics can be misleading in terms of justifying infill drilling. Table 3 of Ref. 8 summarizes depletion times and abandonment pressure results calculated for Well Buf 1 with the simple rate/time and cumulative-production/time equations of Ref. 9. The 3D model parameters used for Well Buf 1 and a 640-acre drainage area for each layer are used for these calculations. The calculated times of 78, 24, and 21 years for the Herington, Krider, and Winfield, respectively, are the producing times to a 10-Mscf/D abandonment rate. For this calculation, each layer is assumed to be produced separately and wide open against 0 psia flowing pressure. A commingled well producing all three layers and produced wide open against 0 psia flowing pressure would take 89 years to reach the 10-Mscf/D abandonment rate. Clearly, the long producing time of 89 years for the commingled well is dictated by the low-permeability layer. The calculated abandonment pressures of the Krider and Winfield layers are 10 and 15 psia, respectively, while the Herington layer abandonment pressure is relatively high at 211 psia. Initial layer pressure was 490 psia for all three layers. Because of the different pressures in the layers and because field measured shut-in pressure usually reflects that of the high-permeability layer, defining an abandonment pressure is difficult. Abandonment rate is therefore used to define recoverable reserves for layered, no-crossflow reservoirs.

The simple equations in Ref. 9 (for single-well application) are readily applied to multiwell problems with good engineering accuracy. Simply total the pseudo-steady-state $(q_{gi})_{\max}$ values of each well in a layer and use the total layer GIP, G_i. Table 4 of Ref. 8 shows calculated depletion times to an abandonment rate with these simple equations compared with 3D model results for the limiting case of wide-open production. This table also shows the times to abandonment rate after the 43 years of constant-rate production or current operations. Note that the total life of 108 years is only 26 years longer than the life expected under completely wide-open production from the beginning. The long producing life, therefore, is primarily the result of the layered, no-crossflow nature of the reservoir and not simply because of the low rates of take set for the field.

Limiting-case calculations with simple equations can be easily made for any number of layers in a layered, no-crossflow reservoir to obtain initial estimates of producing times and layer abandonment pressures. Also, the effect of infill drilling on times to abandonment and layer pressures can be readily calculated by representing $(q_{gi})_{\max}$ as the sum of two wells on 320-acre spacing. This will result in reducing the time to abandonment to one-half that achieved with one well on 640 acres; however, layer abandonment pressures will be identical to those obtained for one well as the $[(q)_{\max}/G_i]_R$ ratio does not significantly change with an infill well.

Conclusions

1. To predict the future performance and production from infill wells in the Oklahoma Hugoton field realistically, a multiwell, multilayer simulation study has been used to history-match each well's official test shut-in-pressure/cumulative-production data, each well's official 72-hour deliverability tests, layer pressures in one well in the multiwell study area, and performance match of one or more replacement wells drilled on a 640-acre section in the multiwell study area.

2. Because of wellbore backflow between layers, a valid history-match of a layered, no-crossflow reservoir should provide for the actual simulation of the shut-in pressures for p/z vs. G_p performance matching. Also, the flow periods and rates should be simulated for well productivity performance matching.

3. A single-well reservoir simulation model cannot realistically be used to evaluate the infill-drilling potential in the Oklahoma Hugoton field because of drainage effects from offset wells. No-flow boundaries between wells cannot reasonably be assigned to each individual layer. Each layer can have a different radius of drainage, r_e.

4. Trapped or bypassed gas does not exist owing to areal heterogeneity in the 12-section study area. We successfully history-matched layer pressures, all test performance data of the original wells, and one replacement well without any adjustment to the log-calculated input variables that determined the original GIP.

5. Forecast results show that no additional reserves are added by infill drilling an additional well per 640 acres starting in 1990. This conclusion applies even if infill drilling would have been initiated

in 1946 and the wells produced wide open from production start. Although infill wells do accelerate production, the shortened life is insignificant if the infill well is uneconomical to drill.

6. Our results demonstrate that the excessively long life of the study area (108 years) is characteristic of a layered, no-crossflow reservoir having contrasting layer deliverabilities. In addition, this unusually long life is the result, in part, of the low historical rate of take from the field.

7. The basic heterogeneity of the Oklahoma Hugoton field is that of layering, with no crossflow between layers. This layering effect may result in significant differences between layer pressures and may cause the reservoir recovery to be rate sensitive.

8. The p/z vs. G_p curves developed for the full 12-section study area show that effective and efficient drainage of the reservoir layers has been occurring. Under current operating conditions, layer pressure differences are less than they would have been under wide-open production.

Nomenclature

G_i = initial GIP, L^3, Bscf
G_p = cumulative gas production, L^3, Bscf
h = thickness, L, ft
k = effective permeability, L^2, md
k_V = effective vertical permeability, L^2, md
k_H = effective horizontal permeability, L^2, md
n = exponent of backpressure curve
p = pressure, m/Lt^2, psia
$\bar{p}$ = average reservoir pressure, m/Lt^2, psia
p_{wf} = wellbore flowing pressure, m/Lt^2, psia
q = rate, L^3/t, Mscf/D
q_g = surface rate of flow, L^3/t, Mscf/D
$(q_{gi})_{\max}$ = initial surface rate of flow from the stabilized curve, L^3/t, Mscf/D
q_a = abandonment flow rate, L^3/t, Mscf/D
r_e = drainage radius, L, ft
R = recovery, %
s = skin factor, dimensionless
S_w = water saturation, fraction
t_a = time to abandonment rate, t, years
z = gas compressibility factor, dimensionless
ϕ = porosity, fraction of bulk volume

Subscripts

a = abandonment
g = gas
i = initial
R = ratio of correlation parameters

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SI Metric Conversion Factors

ft	× 3.048*	E − 01	= m
ft^3	× 2.831 685	E − 02	= m^3
°F	(°F − 32)/1.8		= °C
gal	× 3.785 412	E − 03	= m^3
in.	× 2.54*	E + 00	= cm
md	× 9.869 233	E − 04	= μm^2
mile	× 1.609 344*	E + 00	= km
psi	× 6.894 757	E + 00	= kPa

*Conversion factor is exact.

SPERE

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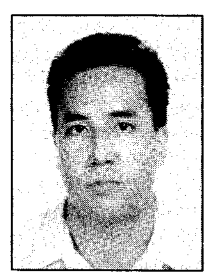

Voelker