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An Efficient Model for Evaluating Gas Field Gathering System Design

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Introduction

It has long been recognized that gas well deliverability is a function of three pressure drops; these occur in the reservoir, in the production strings, and in the surface piping and compressor network. Actual gas well deliverability and, consequently, total field deliverability can be computed only when all three pressure drops are considered simultaneously. Because each of the pressure drops is associated with a different flow system, three different simulation equations are involved. To obtain meaningful results from compression studies, reservoir studies, or gas gathering system design, one must integrate these three simulation segments in such a manner that the flows and pressures balance at each node in a multiwell gathering system.

The most common approach to gathering system design does not account for interwell interference and its effect on a well's deliverability. At best, the standard approach consists of imposing one or more backpressure curves on a piping network system. So long as all the wells are being produced at constant rates, this approach does not introduce large errors. However, in general, individual well rates do fluctuate for various reasons. Many systems are produced by floating part of the wells (that is, producing at capacity) and choking others, and in the course of a performance prediction many of the wells are floating on the system in order to meet total contract obligation. When this occurs, the calculated deliverability of each well must be updated according to the transient reservoir pressures, and the appropriate backpressure of each well must be used at all times during the prediction. One shortcoming of the older approach to design studies is that a steady-state backpressure curve fixes the drainage radius of a well, and when used over long prediction periods it can introduce large errors in the determination of compression location and timing. Further, the standard approach does not readily permit the evaluation of infill drilling as an alternative for enhancing gas-field deliverability.

A rigorous approach to gathering system design must consider all the reservoir, piping, and compression data together. By subjecting this total-system description to a calculation procedure that integrates the various components, the influence of a modification to any one component is properly taken into account throughout the entire system. Consequently, compression alternatives, variations in line sizes and loops, infill drilling, and combinations of these can be evaluated while the effects of interference with the reservoir are being considered.

Calculation Approach

Since the flow rates and pressures must balance at each node in the system, one can choose either of these as the iterate and compute the remaining variable directly. An approach that considers flow rate as the iterate gives the best results, and the discussion below is based on the formulation. The general iteration scheme for calculating total system per-

This simulation model permits accurate and efficient evaluation of gas field gathering system design. It provides simultaneous integration of three pressure drops — reservoir, tubing, and gathering-system — associated with gas production. This complete simulation permits more accurate determinations of deliverability than are possible with the standard approach to compression studies.

formance is depicted in Fig. 1.

The global iteration controls the over-all solution process within each time step of the simulation. The subglobal iteration determines a balance between rates and pressures within the piping network, and the reservoir simulation segment solves the pressure-flow problem within the reservoir. The rates obtained from the subglobal iteration are applied as boundary conditions in the solution of the reservoir flow problem. An updated pressure distribution within the reservoir, based on these rates, will affect the deliverabilities at the various wells. Therefore, if any well is floating, the flows through the piping network must be adjusted to reflect these changes in deliverability, and an updated pressure distribution within the piping network must be obtained. The subglobal iteration scheme and the reservoir simulation are alternately repeated until the flow rates and pressures are consistent throughout the entire system.

The calculation procedure for the subglobal iteration is illustrated in Fig. 2. First an estimate is made of the deliverability of each well. Then the flow through each component of the gathering system is determined according to these estimated rates, and the line pressures, tubinghead, and bottom-hole pressures are computed. At each well the bottom-hole pressure determines the rate for the well, according to the reservoir pressure and well properties. If the difference between the estimated and calculated rates is not within a prescribed tolerance for each well, the estimates are adjusted and the process is repeated. The iterative technique of Coats[3] is used to adjust the estimated well rates.

When all wells in the system are producing at specified rates the subglobal iteration simply consists of calculating the pressures in the piping system, so only one iteration is required. A more difficult problem is one in which wells are floating, hence are declining during a time step as a result of a declining reservoir pressure. As the rate of one well declines it may affect the deliverability of others through the piping network. When wells are floating on the system, typically somewhere between 10 and 40 iterations are required to converge in the subglobal iteration. From one to five global iterations are usually adequate.

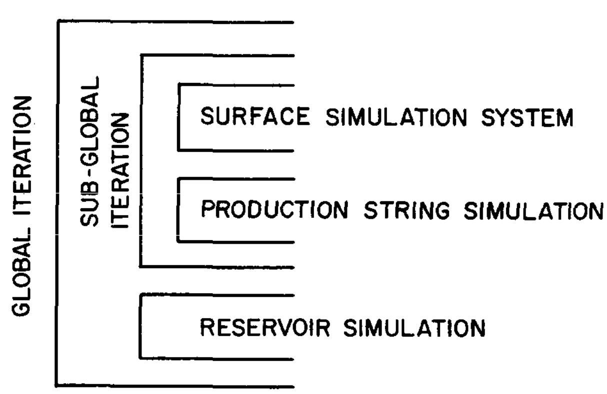

Fig. 1—Global iteration diagram.

The surface and production string simulation systems are constructed as a single subroutine. Invocation of this subroutine returns a rate for each well, the amount of flow through each segment of the gathering system, and the pressure distribution in the piping system as a function of the rates. The effective rate at a well is equal to the well's calculated deliverability unless constrained by a maximum allowable production rate specified for the well or calculated according to contract considerations. These values are calculated implicitly over a time step, thus represent the "average day" or specified throughput of the system.

Instantaneous Deliverability

Instantaneous deliverability is defined as the maximum available throughput of the system with all wells floating at a point in time. The resultant rates represent the capability of the entire system as constrained only by the production facilities and surface design. The way to calculate this is to (1) fix the pressure distribution in the reservoir at a point in time, say at the end of a time step, and (2) set specific rates to a very large number so that the deliverability of each well is lower than this value, and access the subglobal iteration scheme shown in Fig. 2. Although the instantaneous deliverability does not consider allowables and overproduction or underproduction, it does represent the actual total field deliverability enhancement when specific design alternatives are being compared.

Reservoir Simulation

Single-Phase

The single-phase reservoir simulation is a numerical solution[1] of the following equation, which is obtained by combining Darcy's law and the continuity equation.

$$\nabla\, kh\, \nabla R - q_g = \phi h \frac{\partial\,(p/Z)}{\partial t}\,, \quad . \quad . \quad . \quad . \quad (1)$$

where

$$R = \int_{p_b}^{p} \frac{p\,dp}{z\mu}\,.$$

Two-Phase

The two-phase reservoir simulation is a numerical solution[4,5] of the following equations with the concept of vertical equilibrium invoked. The calculations are based on continuity equations for both fluid phases and on Darcy's law including relative permeability.

$$\nabla \bullet k\, k_{rw}\, \rho_w^2\, \nabla\, \Phi_w - q_w = \phi\, \frac{\partial}{\partial t}(\rho_w S_w)\,, \quad . \quad . \quad (2)$$

$$\nabla \bullet k\, k_{rg}\, \rho_g^2\, \nabla\, \Phi_g - q_g = \phi\, \frac{\partial}{\partial t}(\rho_g S_g)\,, \quad . \quad . \quad (3)$$

where

$$\Phi = \int_{p_b}^{p} \frac{dp}{\rho} - \frac{D}{144}\,.$$

Simulation of Surface Piping

Single-Phase

The program uses a continuous network of pipe segments to simulate the surface configuration of a gas gathering system. Each segment is handled independently with respect to upstream pressure calculation, using the Generalized Flow Equation.[2]

$$Q = \frac{CT_s}{p_s}\left[\frac{(p_2^2 - p_1^2)\, d^5}{G\bar{T}\, L\bar{Z}\, f}\right]^{0.5} \quad . \quad . \quad . \quad . \quad (4)$$

An iteration is performed on Eq. 4 until successive calculated upstream pressures (p_2) agree within 0.5 percent. Typically, no more than two or three iterations are required.

Two-Phase

Calculation of pressure losses for gas-water flow in the surface network of pipe segments is based on the Eaton *et al.*[7] correlation. The correlation is valid for pipe sizes between 2 and 17 in. ID and for most flow conditions encountered in operating situations. Single-phase gas simulation is used when the gas-water ratio is greater than a specified ratio and when the Eaton energy-loss factor correlation is beyond certain limits of validity.

The basis for the Eaton correlation is the following equation:

$$\Delta L = \frac{2\, g_c\, d}{\bar{v}_m^{\,2}\, \bar{f}_E}\left[\frac{144\, \Delta p}{\bar{\rho}_m} - \frac{\bar{M}_w \Delta(v_w^2) + M_g \Delta(v_g^2)}{M_T\, 2\, g_c}\right] \quad . \quad . \quad . \quad (5)$$

The upstream pressure is obtained by starting at the downstream pressure and calculating successive values of ΔL from Eq. 5 for given pressure increments. Both increments are summed until $\Sigma\Delta L$ equals the length of the pipe segment. $\Sigma\Delta p$ then becomes the total pressure drop in the pipe segment. When the pipe segment is located in hilly terrain, the Flanigan[8] correlation is used to estimate the additional pressure loss due to hills. This correlation assumes that two-phase flowing pressure losses incurred when going up hills are not regained when going down hills. The uphill pressure losses are based on liquid density and a correction factor that is a function of superficial gas velocity. The additional pressure loss due to hills is given by:

$$\Delta p_{\text{hills}} = F\, \frac{\bar{\rho}_w}{144}\, \Sigma H \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (6)$$

Simulation of Production String

Single-Phase

The Smith equation[2] for vertical flow in pipes is used for the production string calculation.

$$Q = 200\left[\frac{d^5}{G\bar{T}\,\bar{Z}\, fX}(p_2^2 - e^s\, p_1^2)\frac{s}{e^s - 1}\right]^{0.5}, \quad . \quad . \quad . \quad (7)$$

where $s = 0.0375\ G\ X/\bar{T}\ \bar{Z}$. Eq. 7 is solved iteratively using average properties over the entire production string. Refinement of the calculation by incrementing the production string into many integration segments gives minimally different results in most cases. However, if the geothermal temperature gradient deviates considerably from a linear function, a smaller segment of integration should be used.

Two-Phase

A modified Hagedorn-Brown[6] correlation is used to calculate pressure losses in the production string when the gas-water ratio is less than a specified ratio. The equation used is

$$\Delta L = \frac{144\, \Delta p - E_K}{\frac{g}{g_c}\, \bar{\rho}_m \cos\theta + \tau} \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (8)$$

When bubble flow exists, the Griffith[9] bubble-flow correlation has been found to be more accurate than the Hagedorn-Brown correlation and is used when applicable. The only differences between the two methods are in the evaluation of liquid holdup and the friction term, τ. Griffith and Wallis[10] determined that bubble flow exists when: $\bar{L}_B > \frac{\bar{v}_{sg}}{\bar{v}_m}$,

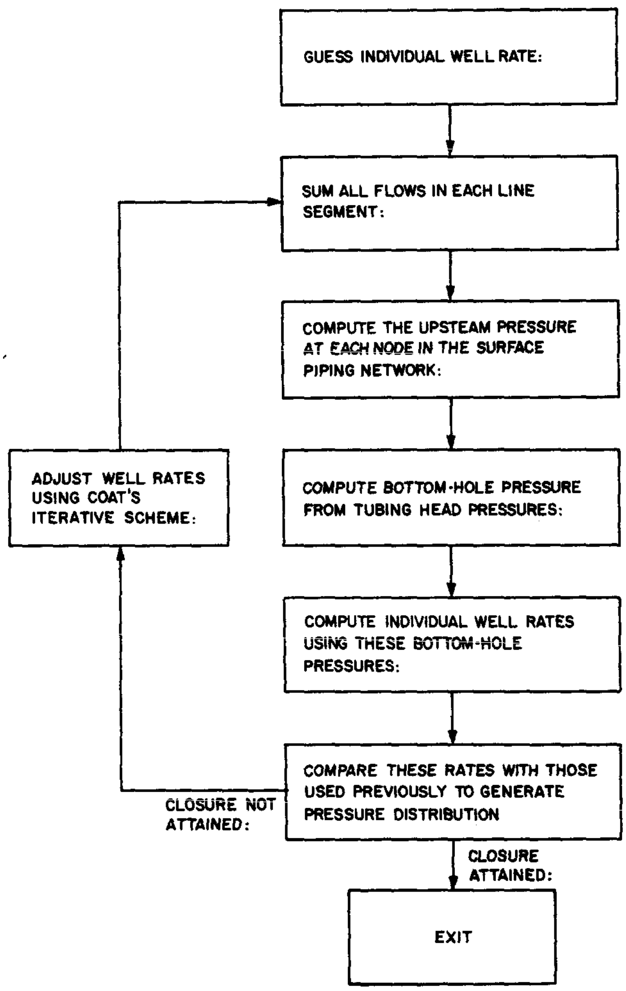

Fig. 2—Subglobal iteration diagram.

where $\bar{L}_B = 1.071 - \frac{(0.2218\,\bar{v}_m^2)}{d}$, with the limit $\bar{L}_B \geq 0.13$.

The bottom-hole flowing pressure is obtained by starting at the wellhead and calculating successive values of ΔL from Eq. 8 for given pressure increments. Both increments are summed until $\Sigma\Delta L$ equals the depth of the well. $\Sigma\Delta p$ then becomes the total pressure drop in the production string.

Use of Other Flow Simulators

Because of the modular construction of the system, replacement of either the Smith equation or the Generalized Flow Equation with different flow simulators (for example, the Panhandle A Equation) is accomplished with only a very minor programming effort. Substitution of other two-phase correlations for the Eaton or Hagedorn-Brown equations is also easily done, provided the desired correlation has previously been programmed. That is, integration of any precoded routine into the model is straightforward. If the desired correlation is not available in coded form, the amount of work required to incorporate it into the model will depend upon the complexity of the correlation.

Example Application, Field A

Fig. 3 illustrates the field outline, well locations, and surface piping network for Field A. This field consists of two gas pools with three separate gathering systems. Because one of the gathering systems collects gas from both pools, the production of each pool will influence the deliverability of the other. To obtain accurate deliverability predictions it is necessary to account properly for this influence; thus a total system study is required.

Pool 1 is a long, heterogeneous sand body currently with 27 producing wells. Pool 2 is much smaller than the first and contains only three wells. The initial pressure of each pool was about 400 psi, and there has been very little or no water influx.

The objective of this study is to maintain contract delivery volumes through the three terminal points of the gathering system. The total initial contract volume was 20 MMcf/D. Fig. 4 shows the performance history and a prediction of Field A's total deliverability (instantaneous) vs the contract requirements for the field. The first history segment of the deliverability curve shows performance with no compression added; that is, the initial wells are produced against the mainline pressure of 250 psi. Contract obligation is met until the fifth year, when terminal compression is added to decrease the backpressure by 50 psi. Production capacity exceeds contract obligations until Year 9, when five development wells are drilled, which extends the field limits and considerably increases the proved reserves. Thus, the contract obligations are increased from 20 MMcf/D to nearly 30 MMcf/D.

With these additional wells and existing horsepower, the field is predicted to meet its objective until Year 13, at which time additional terminal compression is added to further decrease the backpressure on the field by an additional 50 psi.

From this point, runs are made increasing field deliverability at Year 16 by infill drilling or further compression installation, or both. The last two segments shown in Fig. 4 depict the field deliverability profile for two cases: (1) only infill drilling and (2) only compression installation. A combination of infill drilling and additional compression does not appreciably affect the profile and is uneconomic when compared with the case of additional compression alone. Further, an inspection of the pressure drops throughout the piping network reveals that block compression would not be applicable. Skid-mounted, wellhead compression could possibly apply in this field, but was not investigated during this study.

Because of the impact that terminal compression has on the entire field (typical for low-pressure systems) the decline in deliverability is much slower than it would be with infill drilling. The additional com-

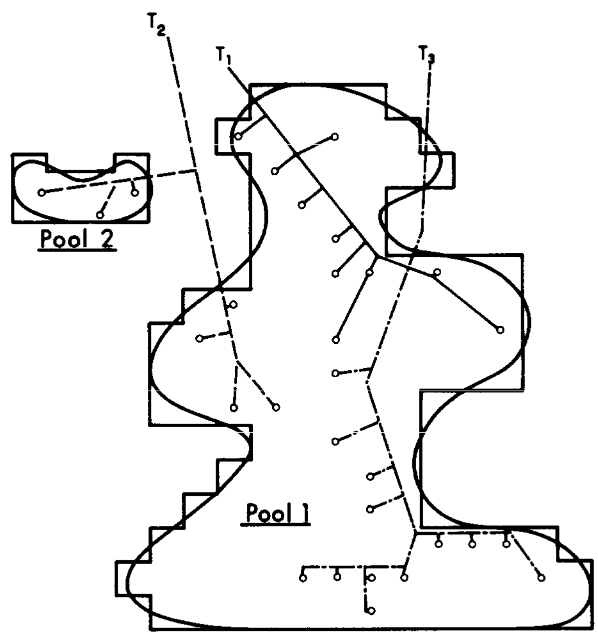

Fig. 3—Schematic of Field A surface network.

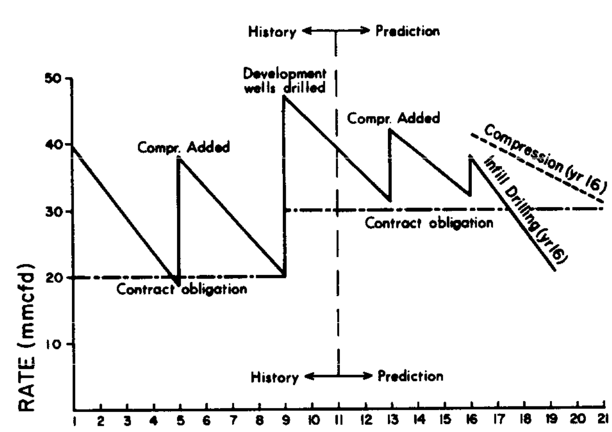

Fig. 4—Field A performance vs contract obligation.

pression required is approximately 60 hp staged over time. Installed horsepower in this area costs approximately \$475/hp with 50 to 60 percent salvage, assuming it can be relocated. Wells in this area cost approximately \$100,000 completed, with very little salvage. Using the company's in-house economic system, the case of adding only terminal compression in Year 16 shows double the rate of return when compared with the case of infill drilling.

This study was conducted using a single-phase dry gas, two-dimensional reservoir simulation model with single-phase surface simulation. The reservoir model grid is 17 × 16 for a total of 272 cells. The three gathering systems are represented by 63 segments, including flow lines, compressors, and delivery point. Each component of the gathering system is completely described to the model on one data card.

It requires only about 1 man-hour to code the complete surface gathering system and record it on data forms suitable for keypunching. Once coded, introduction of modifications to investigate design alternatives is very easy. For example, installing, removing, or changing the horsepower on a compressor involves changing only one of the 63 data cards. To tie in an additional well requires the addition or modification of one to four cards. Computing time requirements are about 77 seconds of Univac 1108 time for each run.

Example Application, Field B

Field B is a single, dry gas pool, highly heterogeneous, containing 18 wells. Thirteen of these wells produce into one gathering system and five produce into a completely separate system. Fig. 5 shows the field limits and a schematic of the two gathering systems. The delivery point for each gathering system is a mainline, therefore each gathering system operates at different specified backpressures.

The objective of this deliverability study is to meet the contract obligation of the 13-well system for 10 additional years with minimum investment. Although the smaller system is not of primary interest in this study, it must be considered because production from its five wells will affect the reservoir pressure and deliverability of the 13 wells of interest. This problem is easily handled by including both gathering systems in the total simulation system. The reservoir interference effects due to the production from each well are then properly taken into account.

Using the total simulation model, several 10-year predictions were made. In these predictions the production from the second system was taken at a fixed predetermined rate as long as its deliverability permitted; thereafter, the five wells were produced at their capacity. The first few runs investigated single-point compressors of various sizes (installed at Point A). An examination of the pressure distribution in the pipe network indicated that Point B would be a potential block compressor location, and several runs were made with the compressors located there.

A comparison of the single-point compression case with the block compression case is shown in Fig. 6. This figure shows that although the single-point compressor enhances the total system deliverability at a higher level, the block compressor allows the contract obligations to be met for nearly the same period of time. The resultant savings between these two alternatives are some 600 hp required in Year 12. Total horsepower savings for the 10-year period are 1,050.

Additionally, sensitivity studies of the other gathering system's effects under various take profiles were made. This information allows management to assess the impact of deliverability loss due to another system's overproduction. This analysis may dictate design safety requirements if this particular field is critical to a pipeline's gas supply operation.

For this study the reservoir is modelled with a 23 × 10 calculation grid. The smaller gathering system is represented by nine components, and the larger one by 26. As in the study for Field A, coding both complete gathering systems requires less than an hour of man-time. Variations in compression installation involve changing one to two cards. Varying the offtake

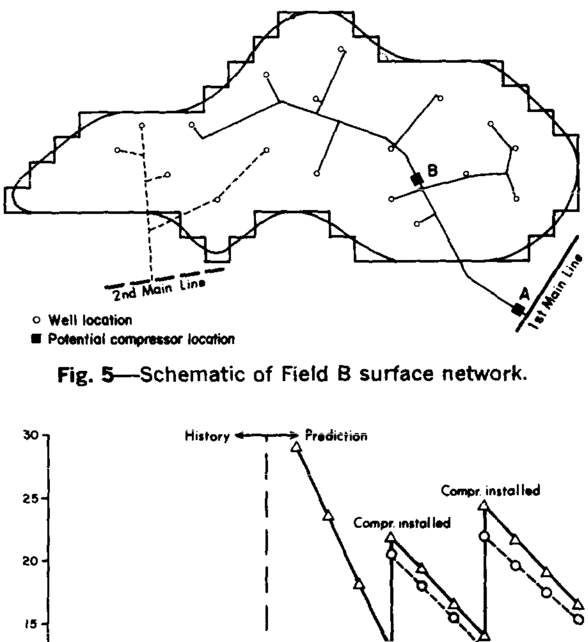

Fig. 5—Schematic of Field B surface network.

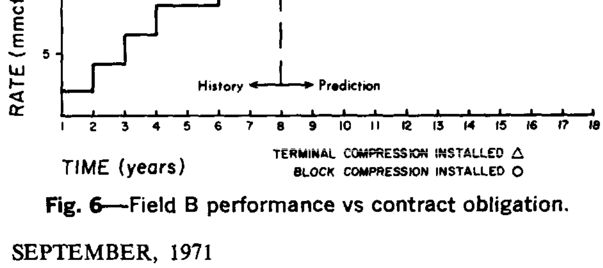

Fig. 6—Field B performance vs contract obligation.

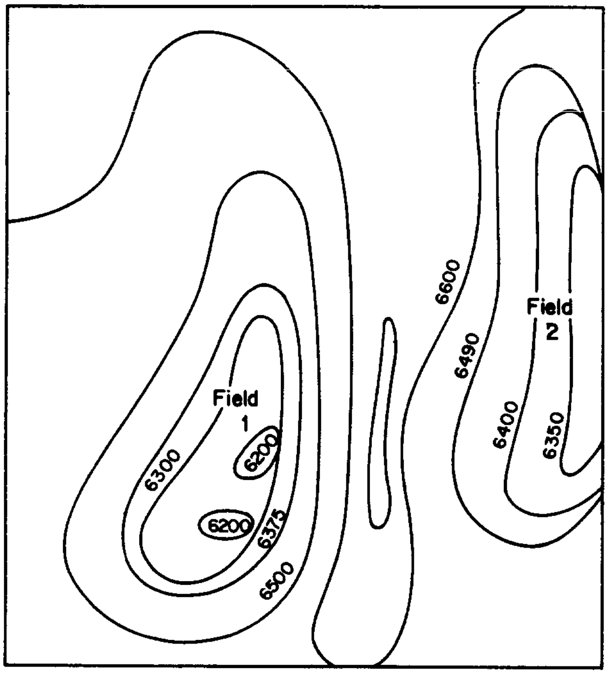

Fig. 7—Structure of Gas Field C—aquifer system.

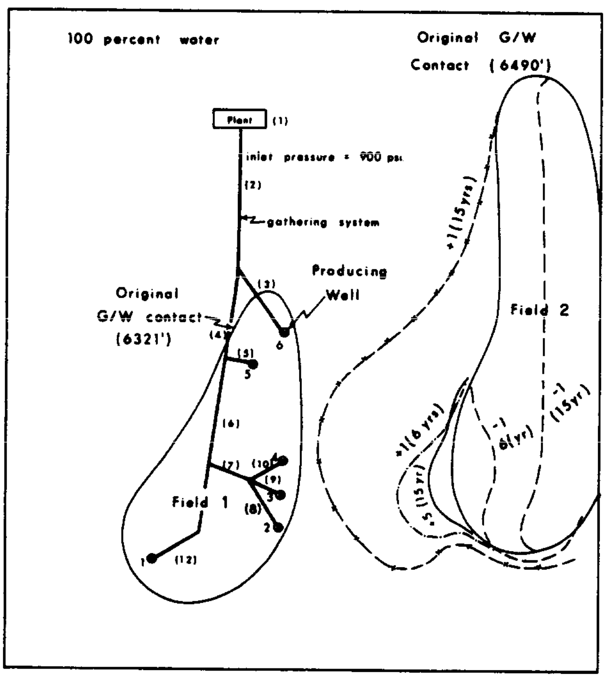

Fig. 8—Effects of multiple gas pools producing from a common aquifer—Field C.

SEGMENT	LINK	P2	P1	FLOW RATES GAS (MCF/D)	FLOW RATES WATER (BBL/D)
1	0	900.0	900.0	69310.9	1057.6
2	1	1021.6	900.0	69310.9	1057.6
3	2	1074.3	1021.6	14768.2	0.0
4	2	1879.0	1021.6	54542.6	1057.6
5	4	1888.8	1879.0	11676.9	0.0
6	4	1950.9	1879.0	42865.8	1057.6
7	6	1980.7	1950.9	36226.1	468.6
8	7	1982.8	1980.7	5518.1	53.8
9	7	2001.0	1980.7	4679.4	414.8
10	7	2025.2	1980.7	26028.7	0.0
11	6	1992.2	1950.9	6639.6	589.0
12	11	2020.0	1992.2	6639.6	589.0

Fig. 9—Calculated pipeline flows and pressures.

level of the second system involves changing one card for each well in the second system, or five cards per case. Computing requirements for each 18-year run in this study are about 52 seconds of Univac 1108 time.

Example Application, Field C

Field C is a large aquifer with two gas fields located on structural highs. Fig. 7 shows the structure. The original gas-water contacts are 6,321 and 6,490 ft subsea for Fields 1 and 2, respectively. The reservoir and fluid properties, production data, and completion intervals are given in Ref. 4.

A two-dimensional gas-water simulation with an internal vertical equilibrium analysis and a two-phase surface simulator was used for the study. The reservoir containing the two gas fields was defined by an 18×20 grid of 1,000-ft-square blocks.

The study had two objectives. The first was to study the interference effects that a producing field would have on an adjacent field; since the two gas fields share a common aquifer, the production from Field 1 causes transients that are transmitted through the aquifer to Field 2. The second objective was to evaluate the effects on system deliverability of moving the produced water through the gathering network to a plant-site separator. Fig. 8 shows a schematic of the gathering system in question.

Fig. 9 illustrates a portion of the computer printout from the two-phase model. The heading SEGMENT identifies each segment or component of the gathering system by its assigned sequence number. LINK specifies the component to which the segment connects on the downstream side, with a zero value (such as for Segment 1) indicating a terminal point operating at a specified pressure. P2 and P1 are pressures at the upstream and downstream ends of the segment, respectively. The RATES columns indicate the total amount of gas and water flowing through each system component. An examination of the data presented in Fig. 9 reveals a great pressure drop (about 857 psi) in Segment 4, which is due to the large amount of water flowing through the line. Additional runs indicated that line looping could eliminate this tight spot, making it possible to move the produced water to the central site without undue loss of deliverability. Poor reliability, as well as climatic and geographic factors, makes the operation of wellhead separators economically unattractive.

Fig. 8 depicts the interference effects. This figure shows a time sequence contour of change in gas-bubble thickness. The +1-ft contours at 15 years indicate that gas from Field 2 is migrating downstructure toward Field 1. The lateral extent of Field 2 after Field 1 has been producing for 15 years is some 60 percent larger than it was originally. Because of residual gas saturation, recovery from Field 1 will be lower than if both fields had been discovered and produced simultaneously.

The implications of the gas-water contact movement downstructure, of the existence of a pressure gradient in Field 2, and of the decrease in average bubble pressure during the production history of Field 1 are as follows:

1. Production from Field 1 is causing gas in Field 2 to migrate down the west flank.

2. Because of the pressure sink caused by production from Field 1, the pressure in Field 2 declines and its gas bubble expands laterally; thus when Field 2 does come on production its deliverability, as a result of this pressure decline, will be considerably reduced, as will its ultimate gas recovery.

3. If Field 1 continues to produce with Field 2 shut in, the gas migrating downstructure will soon reach the structure saddlepoint (Fig. 9) and start "leaking" into Field 1.

Conclusions

1. Simultaneous consideration of three interacting pressure drops encountered in gas production is now possible in a practical and efficient model, permitting accurate predictions of deliverability.

2. Engineering efficiency and performance are greatly enhanced through the use of this model.

3. The engineer's ability to rapidly evaluate single-point compression, block compression, wellhead compression, infill drilling or combinations of these while simultaneously considering reservoir transients results in greatly improved designs compared with those obtained from the standard approach. Examples of actual design studies demonstrate the flexibility of the system and the resultant economic savings.

4. Field operating strategies as well as design alternatives are easily evaluated.

5. The results of deliverability studies made with this model, combined with appropriate economic analyses, will provide an accurate estimation of actual economically recoverable reserves.

6. Deliverability reductions due to water production into the gas gathering system can be taken into account. The ability to evaluate liquid removal at a central site and at wellhead locations results in an improved over-all systems design.

Nomenclature*

C = units constant
d = inside diameter of tubing or pipe
D = formation depth
E_K = kinetic energy term
f = friction factor (e.g., Moody)
f_E = friction factor from Eaton correlation
F = Flanigan correction factor
g = gravity acceleration
g_c = gravitational constant
G = gas gravity
h = reservoir thickness
H = surface terrain elevation
k = absolute permeability
k_r = relative permeability
L = length of pipeline
M = mass flow rate
p = pressure
p_s = standard pressure
p_1 = downstream or wellhead pressure
p_2 = upstream or bottom-hole pressure
q = production rate
Q = flow rate
S = fluid saturation
t = time
T = temperature
T_s = standard temperature
v = actual fluid velocity
v_s = superficial fluid velocity
X = depth from wellhead to perforations
Z = gas compressibility factor
ΔL = pipe length increment
Δp = pressure increment
$\Delta(v^2)$ = difference in the square of the fluid velocities at the ends of a pipe segment
θ = angle of inclination from vertical
μ = viscosity
ρ = density
ΣH = sum of pipe rises throughout the entire segment
τ = Hagedorn-Brown friction term
ϕ = porosity

Subscripts:

g = gas
m = mixture (gas and water)
T = total (gas plus water)
w = water

*A bar over a term indicates an average value for the segment or increment.

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