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Potential of Infill Drilling to Increase Devonian Shale Gas Reserves in the Appalachian Basin

Volume I: Kanawha County, West Virginia, Case Study

Technical Note

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EXECUTIVE SUMMARY

This report presents results of two studies to evaluate the potential of infill drilling as a production strategy in the Devonian shales. Volume I is a case study that analyzed the infill drilling potential in Kanawha County, West Virginia. Volume II is a study to evaluate the feasibility of infill drilling in the Devonian shale formations of Ohio, Kentucky, and West Virginia.

The U.S. Department of Energy analyzed the potential of infill drilling as a production strategy to increase the reserve base of the Devonian shale formations in Ohio, Kentucky, and West Virginia. This case study (Volume I), completed in West Virginia, compares actual field data with simulations. Infill wells were placed in an existing field in an area of high flow capacity (determined by history matching). Results indicate that 50 percent more gas may be recovered over a 10-year period if infill wells are drilled in the more geologically favorable area of a field. Geologically favorable areas of a field are locations where high permeability and thickness have been calculated through history matching.

Volume II presents a study that uses data evolved during the Eastern Gas Shales research program to compile gas-in-place estimates and to analyze key production mechanisms. Each of the three states was partitioned into areas based on key geological parameters and tectonophysics that established the natural stress and fracture regimes. Within these partitioned areas, a simulation study of infill drilling was conducted to determine the impact of reduced well spacing on 40-year cumulative gas production. In this approach, one, three, and five infill wells were randomly located in a field of five existing wells that had been producing for 20 years. After 20 years of well production, the well recovery for each simulated infill well was evaluated.

A simplified economic analysis was performed to determine feasible infill scenarios. A Devonian-gas-shale economics model was used to evaluate the results of both studies. Required gas prices were calculated for a 20 percent rate-of-return on investment for each infill drilling scenario. Results determined that less than 80-acre well spacing was not economically feasible. A reduced number of wells spaced 80 acres or more apart was productive, in agreement with the state-wide study (Volume II). Accordingly, areas in West Virginia and Kentucky are candidates for infill drilling, but such areas of high flow capacity can only be found through a detailed geologic characterization with history matching.

1.0 INTRODUCTION

The in-place Devonian shale gas resource in West Virginia is estimated to be about 135 trillion cubic feet (Tcf) for these organically rich shales. The technically recoverable gas from the Devonian shales in West Virginia is estimated to range from 11 to 44 Tcf (Kruuskraa et al. 1985c). This range depends on the completion and stimulation techniques used in the wells, and on the producing formation of the Devonian shales. In the western portion of the State, production is primarily from the Devonian-age Huron and Rhinestreet formations. Here, 11 to 18 Tcf has been estimated as recoverable gas.

Because of the geologic diversity within the State, a variety of production strategies are required to provide efficient gas recovery from each location. For tighter, deeper, and less densely fractured areas in the northern and eastern portions of the State, closer well spacing, large propped hydraulic fractures, and rectangular well patterns should be used to improve recovery efficiency. Gas recovery from these areas could be increased by infill drilling to compensate for the elliptical drainage patterns caused by permeability anisotropy. Closer well spacing, combined with advanced stimulation treatments, may provide a significant increase in field productivity.

The Department of Energy's (DOE's) Eastern Gas Shales Project (EGSP) provided research to improve the understanding of production mechanisms in Devonian shale reservoirs. Studies completed in Meigs County, Ohio, used extensive field tests to investigate production mechanisms in the Lower Huron shale member (Frohne 1982). Results of the field tests determined the flow characteristics of gas in a fractured shale reservoir, the orientation and spacing of natural fractures, storage and release mechanisms of gas from the shale, and the impact of directional gas flow on well production. These results indicated that the conventional circular drainage pattern previously accepted by the gas industry is not accurate and that significant permeability anisotropy creates an elliptical drainage pattern. Information obtained from an offset well interference test indicated that development wells should be drilled to take advantage of the elliptical drainage patterns, and thus to improve recovery with fewer wells. In addition, high pressures obtained when the offset well was drilled close to the existing producing well, which had been producing for 22 years, indicated that desorbed gas exists and could be produced by development wells.

An earlier study used offset wells to analyze the feasibility of infill drilling (Horton 1982). The analysis utilized results of the offset well program to characterize shale gas wells located near the test site in Meigs County, Ohio. Results indicated that current infill drilling technology could enhance recovery by 11 to 35% after 35 years of existing well production, and that recovery could be enhanced by 23 to 60% if infill wells were installed early in the life of the field. In addition, conclusions indicated that optional development strategies require knowledge of permeability distribution and permeability anisotropy to maximize the recovery efficiency.

This study has been completed in an effort to further quantify the impact of reservoir properties on infill drilling. Infill drilling for an area in Kanawha County with 10 years of historical production was evaluated to identify the most feasible strategy for reduced well spacing in the Rome Trough area.

An objective of the EGSP was to improve the understanding of development strategies for existing Devonian shale fields. Efforts at DOE's Morgantown Energy Technology Center (METC) were focused on computer applications to assess the impact of reservoir properties and geology on infill drilling. As a part of this effort, an infill drilling study in Kanawha County was completed. The goal was to evaluate the impact of infill drilling in an area of established Devonian shale production.

The purpose of DOE/METC's continuing analysis of infill drilling is to expand on the previous study completed in Meigs County, Ohio, by investigating the impact of closer well spacing in additional areas of Devonian shale production. This effort will provide information on the influences of natural fracture spacing, permeability anisotropy, well spacing, and producing thickness to enhance gas production from the Devonian shales.

2.0 KANAWHA COUNTY STUDY

2.1 Site Selection and Data Collection

A set of defined criteria was used to determine if a candidate site was a feasible study location. Six categories were used as criteria to establish this study location: (1) area and site formation properties; (2) data quality and quantity; (3) the area's location in relation to the Rome Trough -- within, proximal to, or distant from the trough; (4) the cluster of identified wells was to be a set of 10 to 15 wells within a 6- x 6-mile area; (5) well spacing such that infill wells could be installed while still maintaining a feasible well spacing; and (6) the area had to be a site of active drilling. Within these categories, two types of data are required for stimulation and reservoir modeling: (1) adequate treatment records, including such essential parameters as pumping rate, fluid volume, treatment interval; and (2) instantaneous shut-in pressures. Selection criteria require reservoir parameters, including time and occurrence of shut-in, date and duration of measured rock pressure, a minimum of 10 years production, producing depth, and line pressure. A listing of data used to establish the site selection is shown in Figure 1.

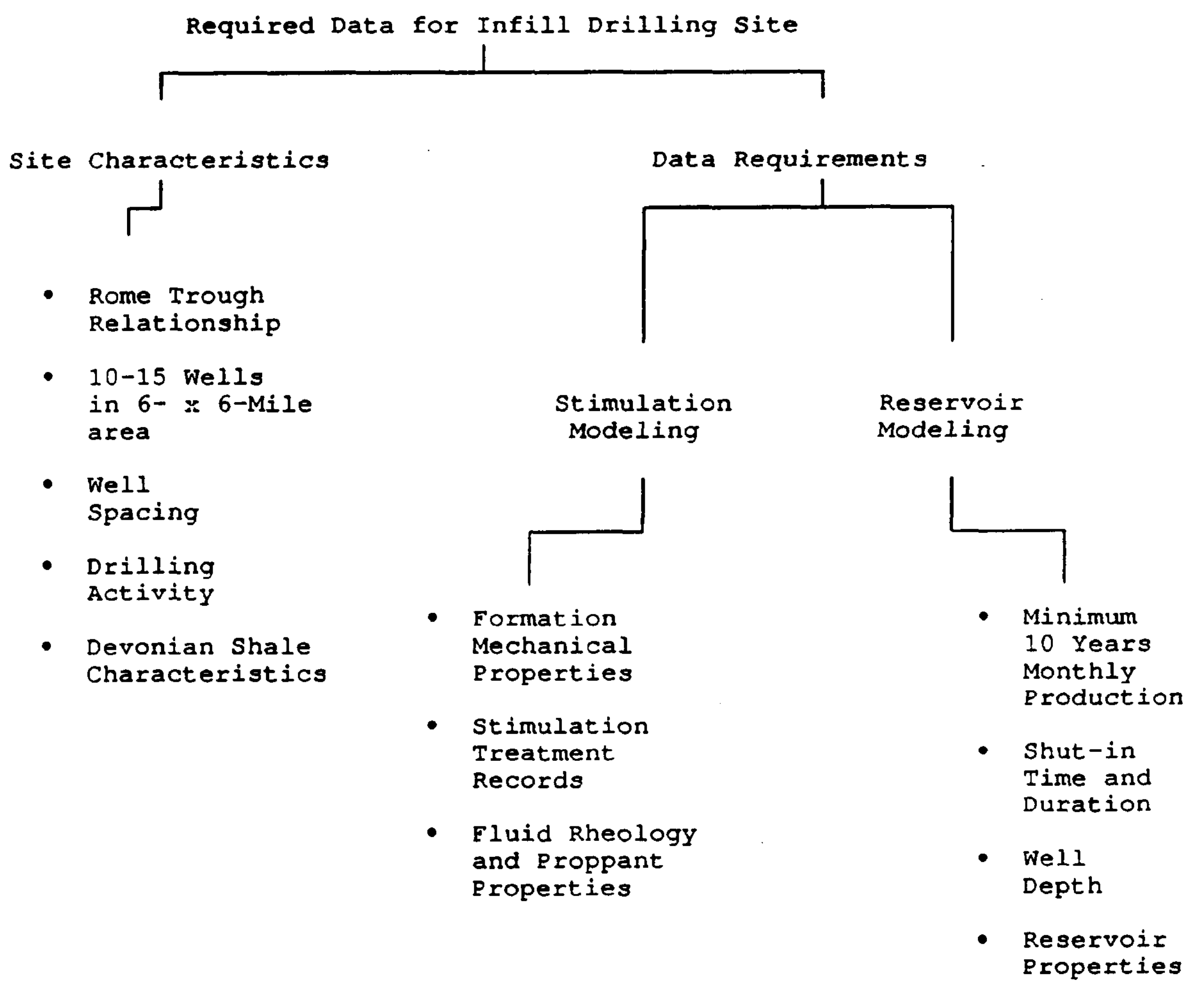

Figure 1. Site Selection Logic

Initial efforts at site selection focused on areas in and adjacent to the Rome Trough. Most areas of Devonian shale gas production are associated with the trend of the Rome Trough, a basement graben structure of Cambrian age. Economical gas production from Devonian shales in West Virginia depends on natural fractures because of the low permeability of the shales. The Rome Trough has an apparent influence on the formation of fractures, and a correlation exists between fracturing and low in-situ stress ratios. The location of the Rome Trough with respect to West Virginia counties is shown in Figure 2.

Devonian shale wells with the necessary data available were plotted to identify clustered areas of wells in or near the Rome Trough. As indicated on Figure 2, noticeable well clusters are located in Mingo, Lincoln, Logan, Kanawha, Roane, Putnam, and Jackson counties. The enlargement of sample clusters displayed as single symbols in Figure 2 is shown in Figure 3. The criteria of 15 wells in a 6- x 6-mile area (as derived from previous modeling studies) was arbitrarily established to select potential study sites. The cluster areas of Figure 3 do not show all wells present, but provided a starting point to identify locations of densely populated wells. Fifteen wells in a 10- x 10-mile area were selected and used as a criterion in the modeling studies.

After clusters were identified, a survey of well data availability and quality was initiated. The two major contributing data sources were the METC open files and the Gas Research Institute database. The wells finally selected were from the DOE/METC open files since the data are readily available and includes adequate field information from production companies such as Columbia Natural Gas. A cluster of 14 wells located in the Clendenin Quadrangle in Kanawha County, West Virginia, was chosen. Data in the DOE/METC open files included monthly production, shut-in periods and their duration, complete site selection criteria, hydraulic fracture records, prefractured interval thickness, well logs, and completion data. Unfortunately, the monthly data for five of the wells was missing for the years 1979 and 1980, and all data for one of the 14 wells was missing. The major advantage of the data set was that the production from each of the wells had been individually metered, unlike many of the producing wells in the area. This production record is mandatory if a study is to have a sufficient degree of reliability.

Post-fracture pressure build-up and drawdown test data and complete log analyses were not available. This information would have been valuable in that an improved stratigraphic cross-section could have been created, and a better prediction of skin factor permeability and stimulation performance could have been calculated. However, data required to execute the stimulation models was available in DOE/METC files.

As a part of the stimulation research effort, S. Advani of Ohio State University was funded under the EGSP to complete a finite-element model that included simulation of in situ stresses and fracturing in a multi-layered reservoir (Advani and Lee 1986). This model was applied to an area in Kanawha County by A. Andrews (1984). Andrews used gas production mechanisms, fracture mechanisms, and an analysis to determine whether regions in the Devonian shale developed low enough stress ratios to meet the failure criterion. This was

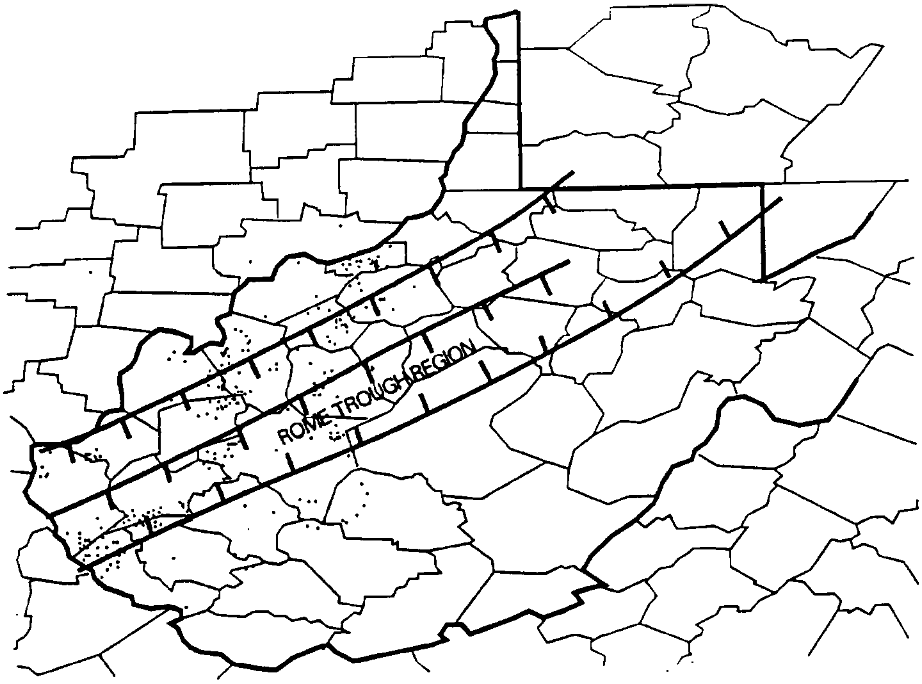

Figure 2. Well Cluster Locations Within and Adjacent to the Rome Trough

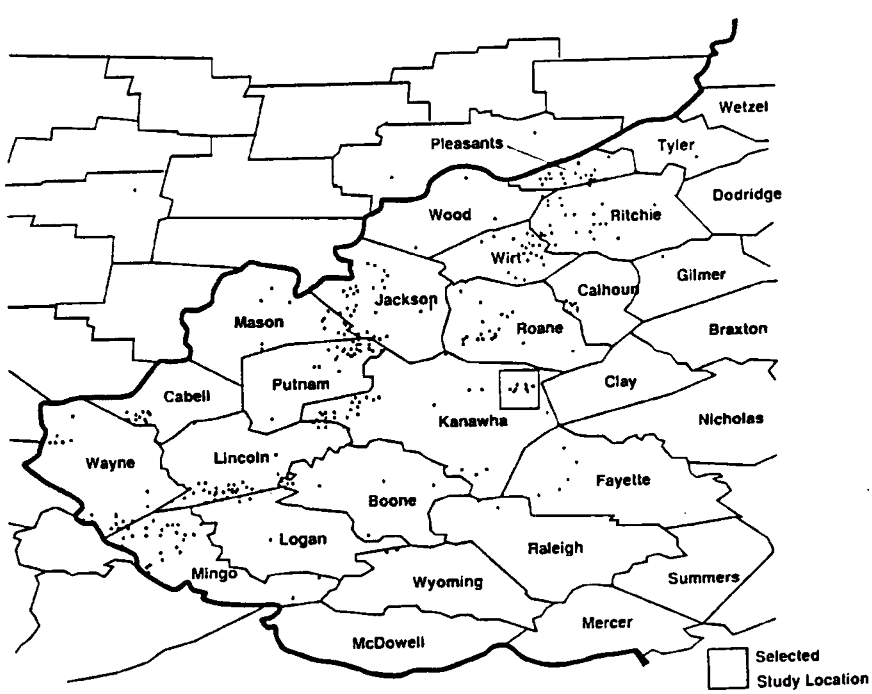

Figure 3. Well Locations for Wells Producing in the Devonian Shale

found to occur in a region with a stress ratio of less than 0.24, which indicates a naturally fractured area. Such regions in the Devonian shales have the greatest potential for gas production. Andrews' stress simulation study was in the Cabin Creek District in the southern portion of Kanawha County, approximately 15 miles from the selected study site in the Clendenin Quadrangle. The Andrews' thesis contains material properties for the shales that are essential for preselecting induced fracture geometry; these properties were used in this study. These properties are for the lower Huron or Rhinestreet Devonian shales and include Young's modulus, Poisson's ratio, and the modulus of rigidity.

Several measurements for Devonian shale properties were gathered by Blanton, Dischler, and Patti (1981) from wells in Lincoln County, West Virginia. Results of these studies indicated that the Devonian shales in the area showed no strong trends with respect to lithology, locality, or confining pressure. Values obtained from Andrews (1984) were used to derive an average value of the Young's modulus for Devonian shale of 4.4×10^6 psi. An average value for the Poisson's ratio of 0.21 was used. These values were similar to those measured by Blanton, Dischler, and Patti (1981) for Lincoln County cores. Accordingly, it was concluded that the Andrews' properties were sufficient for use in this study.

One of the criteria for choosing a study site was ongoing drilling activity in the location. Oil and gas drilling statistics for West Virginia for 1984 show the Elk-Poco field in Jackson County to be one of the most active fields in West Virginia. Ninety-four gas wells were completed in the Huron shale in this field (Avery et al. 1985). The 14-well cluster for this infill well study is north of the Big Sandy field in the Clendenin District, with wells completed in the Huron shale near the Elk-Poco field.

2.2 <u>Geologic Evaluation</u>

Completion records for the 14 wells indicate that they were drilled through the "brown shale" or more specifically, the Devonian shale. Well clusters are shown in Figure 3. To determine which formation or formations were produced, a preliminary geologic cross-section of the Appalachian Basin, which included the Clendenin Quadrangle, and the driller's completion records were used. Data used to generate this cross-section are shown in Table 1. The cross-sections and corresponding well location map are shown in Figures 4, 5, and 6.

Figure 5 indicates that all wells either penetrated or were completed in the Lower Huron formation, with Wells 2605, 2593, and 2595 reaching total depth in the underlying Onondaga and Oriskany sandstones. Wells that were completed by being explosively shot usually involved large intervals covering the Lower Huron as well as the upper undifferentiated portion of the Devonian shales. Some of these completion intervals included the gray-green shale in the Upper Devonian. These gray-green shales are considered less productive than the Lower Huron because of the lower organic content. Wells 2606

Table 1. Geologic Cross-Section Data

Well No.	Elevation (ft)	Sunbury (ft)	Upper Devonian (ft)	Huron (ft)
2621	750.72	1,965-1,987	2135	--
2605	1,242.3	2,460-2,492	2638-5662	5662-5779
2611	971.4	2,210-2,225	2307	--
2593	777.0	2,010-2,036	2115-5187	--
2594	739.0	1,950-1,980	2125	--
2595	1,153.9	2,403-2,419	2499-5572	--
2612	1,196.5	2,410-2,445	2523	--
2622	777.6	1,995-2,030	2312	--
2614	858.5	2,079-2,098	2176	--
2613	965.6	2,170-2,204	2282	--
2606	1,366.5	2,585-2,623	2765	--
2624	842.7	2,028-2,065	2144	--
2623	862.0	2,057-2,075	5233-5281	--
2667	892.0	2,027-2,070	5281-5326	--

Well No.	Onondaga (ft)	Tubing Depth (ft)	Perforation Depth (ft)
2621	--	4965	3400-4950
2605	--	5779	3800-1 4478-80
2611	--	--	4010-12
2593	--	--	4020-38 4260-78
2594	5187-5212	5212	3784-3800 3975-3980
2595	--	4788	4238-4242
2612	5572-5588	--	4588-4610
2622	--	5320	4000-5575
2614	--	4918	3370-78 3640-48
2613	--	5012	3156-64 4240-48
2606	--	--	4456-66
2624	--	5820	3600-5100
2623	--	5043	3350-5043
2667	--	5051	3370-5092

and 2623 were completed through the Marcellus shale. Water was found in the Onondaga and Oriskany sandstones in Well 2595. Wells 2605 and 2593 were perforated and stimulated in the Lower Huron, the target interval where gas production was indicated on well logs. However, gas shows did not occur in the sandstone intervals.

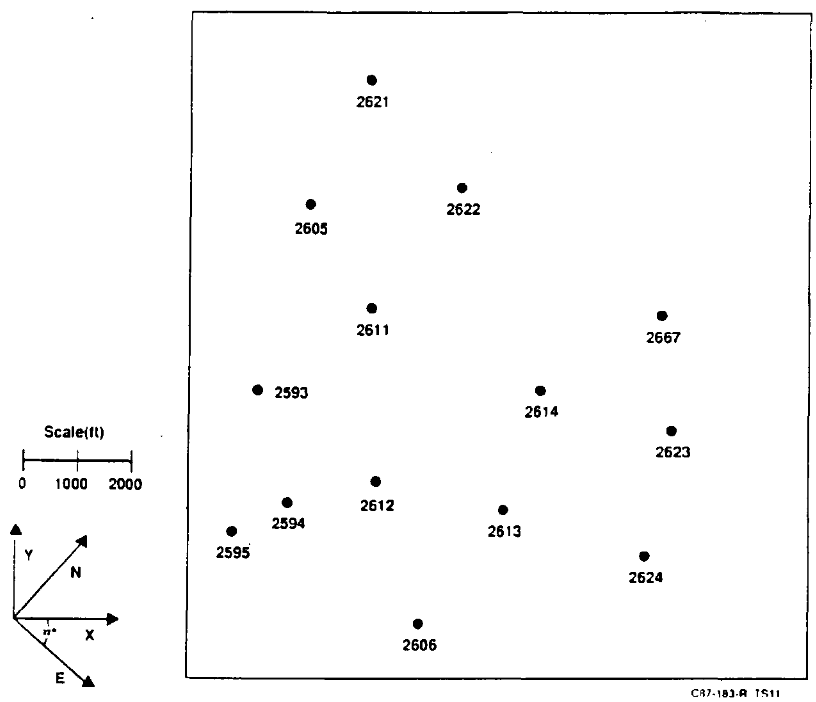

Figure 4. Areal Representation Used as Basis for Cross Section

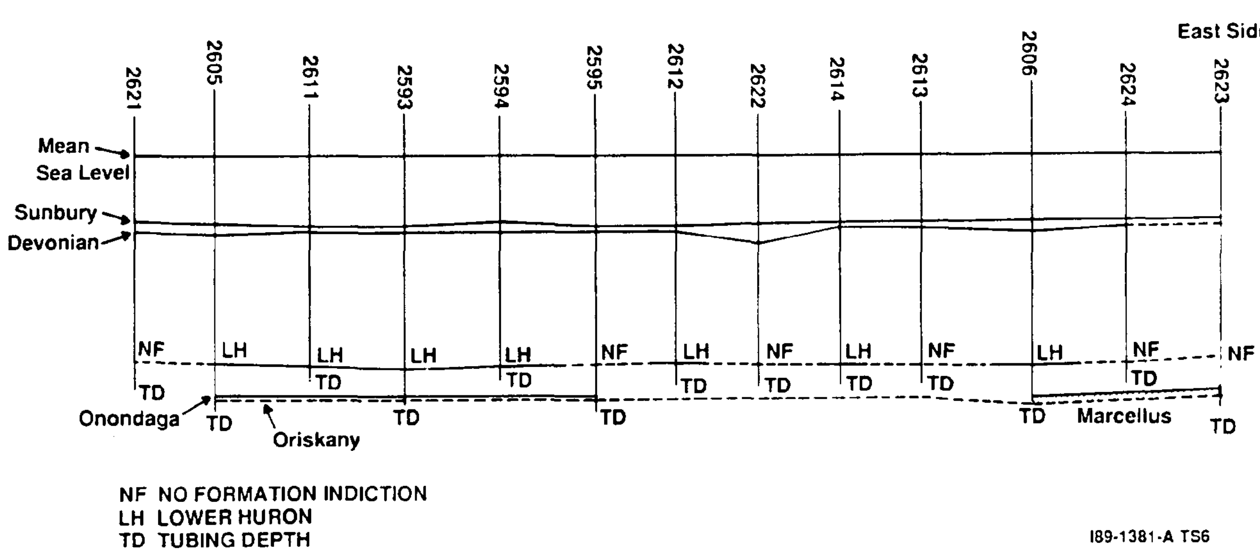

Figure 5. Cross Section of Wells in Kanawha County Study

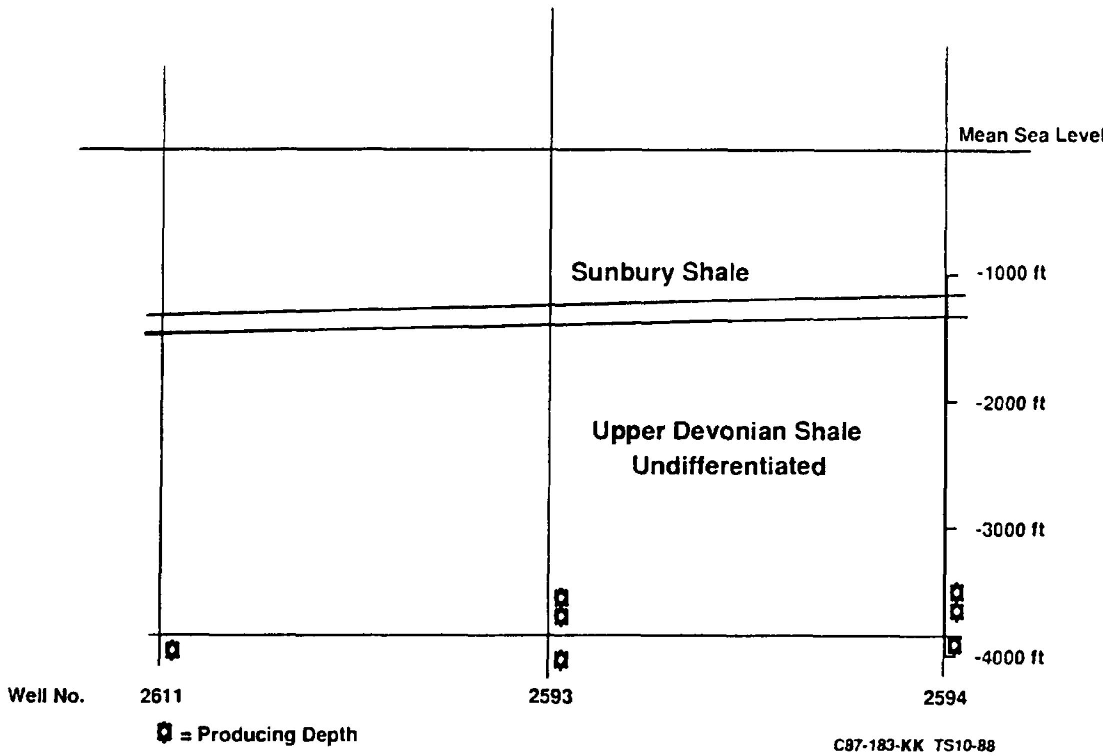

Figure 6. Generalized Stratigraphic Section for Three Wells at the Study Site

2.3 Stimulation Modeling

2.3.1 Hydraulic Fracture Prediction for Use in Reservoir Modeling

The first step in a modeling analysis is predicting the induced fracture geometries for those wells that have been hydraulically fractured. In the group of 14 wells under study, 8 of the wells were hydraulically fractured. The other wells were explosively shot.. Four of the hydraulically fractured wells were stimulated with gelled-water treatments, and two were fractured with gas-assisted water treatments. These fracture geometries were input into the reservoir models to assign productivity to each well.

In order to reliably predict fracture geometries from treatment records, high-quality data on material properties, treatment protocol, and fluid information should be available for each stimulation treatment.

Material properties are essential to determine the rock displacement that results from the fracturing fluid. Without appropriate material behavior, the predicted fracture may be too wide (and, thus, too short); or conversely, too thin (and, consequently, too long).

Many mechanical properties of the Devonian shales have already been determined. For example, Blanton et al. (1980) determined material properties from experimental analysis. The average value of the Young's modulus for gray shales was 4.6×10^6; the average value of the black shale Young's modulus was 4.4×10^6 psi. Blanton et al. (1980) stated that for modeling purposes and many engineering applications, average values may be used. This is true when differences in natural fracture density are not taken into account when comparing black shales from differing locations. However, the effect of natural fractures should be taken into account when attempting to describe bulk behavior. Black shales tend to be more highly fractured than gray shales. The presence of natural fractures tends to lower the Young's modulus of the rock mass.

The Kanawha County wells were completed primarily in the Lower Huron shales or what could be considered "brown shale." Jones et al. (1977) reported an average elastic modulus value of 4.4×10^6 psi and an average Poisson's ratio of 0.21 for Devonian shales. In accordance with the conclusions of Blanton et al. (1980), average values may be used for modeling purposes; these values were used in the stimulation calculations.

2.3.2 Model Description

The hydraulic fracture model used to predict induced crack geometries was the Ohio State University pseudo-3D model designated OSUFRAC-2 (Advani and Lee 1986). OSUFRAC-2 is a vertical-height-growth model developed for an isotropic, homogeneous, elastic medium. The model employs a numerical approach to solve coupled, nonlinear, partial differential equations for the fracture pressure and fracture dimensions. The fracture is first divided into a number of discrete vertical sections. Fracture width and pressure are evaluated by applying two-dimensional flow in the vertical direction to each vertical crack. The model then utilizes fluid flow along the horizontal direction to predict the fracture height and length. An iteration process is continued until a satisfactory convergence is attained.

The predicted fracture geometry is a vertical fracture with an elliptical cross-section.

2.3.3 Modeling Procedure and Application

Fracture geometries of the hydraulically fractured wells were predicted. These fracture geometries were incorporated into the reservoir simulation by representing the fracture with finite-difference grid blocks of high permeability and porosity in the single-well history matches.

In order to execute the OSUFRAC-2 model to predict hydraulic fracture geometries, data were gathered from treatment reports, service companies, and reports on rock mechanical properties. The treatment reports from service companies for each stimulation were available in DOE/METC in-house files. Some of the treatment fluids were not documented in the fluid rheology manuals from the service companies. Service companies were contacted to provide fluid properties of these fracturing fluids. In addition, fluid volumes, flow rates, perforated intervals, and stress measurements were derived from the treatment reports. Data derived from the treatment reports and fluid rheology manuals are shown in Table 2.

Mechanical properties were extracted from reports by Blanton, Dischler, and Patti (1981) and by Jones et al. (1977). Since there did not appear to be a large deviation in mechanical properties within the measured Devonian shale samples, average values were used in the modeling. The average and predicted fracture geometries are shown in Table 3.

Table 2. Stimulation Treatment Data

Type of Treatment	Volume and Rate of Treatment	Amount and Size of Sand	Perforated Interval (ft)	Height of Treatment Top-bottom Perforations (ft)	Production (Mcf/d)		
					Before	After	Ratio
Well No. 9778 Log-LPG-AL Gas Fracture	502 bbl 18 bbl/min	14,000 #20/40	4582-4610	28	539	539	1:1.0
Well No. 9805 Gas Fracture	555 bbl 30 bbl/min	5,000 #20/40	4030-4034 4260-4278	248	55	492	1:9.0
Well No. 9779 Water-Methanol	900 bbl 50 bbl/min	52,500 #20/40	3784-3800 3975-3980 4238-4242	458	42	239	1:5.7
Well No. 9806 Water-Methanol	700 bbl 46.7 bbl/min	35,000 #20/40	4710-4724 4860-4874 5070-5084	374	26	103	1:4.0
Well No. 9789 Water	900 bbl 40 bbl/min	37,500 #20/40	3532-3546 3570-3584 3627-3642	110	32	119	1:3.7
Well No. 9790 Water	782 bbl 54 bbl/min	42,000 #20/40	4712-4734 4760-4794	82	84	158	1:1.9
Well No. 9808 Water	840 bbl 49.4 bbl/min	50,000 #20/40	4222-4228 4322-4326 4768-4782	561	10	253	1:25.3

Table 3. Individual Well Data

Well No. (Company - API)	Well Depth (ft)	Formation Temperature (°F)	Initial Rock Pressure (psi)	Average Line Pressure (psi)	Type of Stimulation	Treatment Interval	Fracture Wing Length (ft)	Initial Open Flow (Mcf)
9778-2594	4,788	112	820	85	Gas Fracture	4582-4610	300	539
9779-2593	4,360	108	800		Hydraulic Fracture	3784-4242	300	239
9780-2595	5,575	120	840	77	Shot	4000-5565	600	119
9789-2605	5,807	123	980	84	Hydraulic Fracture	3532-4480	550	119
9790-2606	5,820	123	1,025	95	Hydraulic Fracture	4712-4794	600	158
9799-2621	4,965	114	790	76	Shot	3360-4800		603
9800-2622	4,918	114	810		Shot	3370-4460		103
9801-2623	5,328	118	890	80				215
					Shot	3350-5043		133
9802-2624	5,043	115	620	78				
9805-2611	5,036	115	830	79	Cryogenic Geo.	4030-4278	576	492
9806-2612	5,320	118	1,020		Hydraulic Fracture	4710-5084	153	103
9807-2613	5,100	116	620		Shot	3600-5100		103
9808-2614	5,012	115	1,040		Hydraulic Fracture	4222-4768	400	253

3.0 SINGLE-WELL ANALYSIS

The hydraulically fractured wells were stimulated in the "brown shale" of the Lower Huron. Since extensive stress measurements were not conducted at each well site, no variation of horizontal stress from the hydraulic fracture instantaneous shut-in pressure was assumed. The log depths in the completion record indicated that perforations were not placed near a shale-sand boundary or discontinuity. The results of the stimulation modeling are shown in Table 3. Fracture wing lengths varied from 153 to 600 feet. The longer wing lengths represent massive hydraulic fracture treatments. Although geometries seem optimistic, there have been no reliable studies to enable the stimulation modeler to account for natural fractures or other geologic features in the area that may reduce the predicted wing length. Future DOE/METC studies are planned to address this topic.

3.1 Single-Well History Matching

History matching with simulation modeling was used extensively in this study to evaluate the impact of infill well installation. History matching consists of adjusting input parameters for a model until the simulated well or field performance is close to the actual historical performance. The first step in a history match is to calculate the reservoir performance using the best available data and to compare the simulated performance with the actual recorded history of the well or field. If the agreement is not satisfactory, adjustments are made to the input parameters until a match is achieved.

The characteristics of a reservoir depend on many variables, some of which are measured. The reliability of a history match is subject to the quantity and quality of data available; the more measured variables available, the more reliable the history match. The combination of measured and unknown parameters gives a non-unique, calculated prediction of reservoir behavior. For example, while an estimated natural fracture spacing is fixed in the model, this uniform, parallel set of joints is typically not a perfect pattern in the actual reservoir. However, the history-matching parameters are often not the actual values found in the reservoir. They are the values required to characterize the reservoir while compensating for the estimated fixed-fracture pattern. The quality of the match and the confidence in it depends on the amount of actual data available.

3.2 Base-Case and History-Matching Variables

History matching requires a base-case set of data that is the best data available for the reservoir. The base case set for this study was derived from several sources: (1) DOE/METC in-house file data, which were originally obtained from Columbia Gas; and (2) from Kruuskraa et al. (1985a, 1985b, 1985c). Columbia Gas provided well data, and the Kruuskraa publications provided geologic data.

The Columbia well data included well location, formation type and depth, tubing dimensions, initial open flow, initial and annual rock pressures, treatment intervals, annual line pressures, annual days on line, annual and cumulative productions, well installation and stimulation costs, date of installation, and reservoir temperature.

Kruuskraa et al. (1985a, 1985b) provided initial fracture permeability (prior to varying for history matching), matrix porosity and permeability, fracture porosity, fracture spacing, fracture anisotropy, and percentages of gas-in-place by source (fracture, matrix, sorbed). The formation data was derived from a study of technically recoverable gas from the Devonian shales in West Virginia. The report partitioned West Virginia into three geological areas according to Devonian shale production targets: (1) the Huron-Rhinestreet shale, (2) the Marcellus shale where the Huron and Rhinestreet have thinned, and (3) where the Marcellus shale is the dominant member. The Kanawha County site falls in Geologic Setting I, where the Huron-Rhinestreet shales are the primary targets. The area covers the southwestern and western areas of the state and is characterized by thick, radioactive, and organically rich Huron and Rhinestreet Upper Devonian shales. The area has historically been the target for much of the State's Devonian shale production. The 14 wells are located north of the Big Sandy field.

The wells of interest were completed and stimulated between 3,300 and 5,500 feet in depth (approximately 2,200 to 4,500 feet below sea level). The formation classified as the brown shale in the Upper and Middle Devonian regions was the target area. This was the Lower Huron shale. Eight of the wells were hydraulically fractured, primarily in the upper portion of the Lower Huron shale. The shot wells encompassed large intervals in what appears to be both the Onondaga limestone and the Lower Huron shale.

Lewin divided Geologic Setting I into six partitions according to variations in production capacity and geology. The area of interest, Area V, contains Kanawha, Putnam, Roane, Calhoun, and Wirt counties. The area has a moderate net producing thickness and natural fracture spacing, and induced fractures are expected to occur parallel to the major natural fracture system. In addition, high permeability anisotropy and low fracture permeability exist in this area. This indicates that large, well-propped hydraulic fracture treatments are required to effectively recover the gas-in-place.

Data sources for Kruuskraa et al. (1985c) included historical gas production research, EGSP core wells and other test wells, the Mound Facility report (1982), Cliffs Minerals reports (1982), and the Schwietering report (1981). Historical production records were used to characterize Devonian shale wells in Geologic Area I from individually metered wells. The EGSP core and test wells were used as sources for permeability, porosity, permeability anisotropy, and fracture spacing. Free and sorbed gas contents were obtained from the Mound Facility report (1982). Permeability anisotropy, major and minor natural fracture orientation, and preferred orientation of induced fractures were extracted from the Cliffs Minerals report (1982). Finally, the Schwietering report (1981) was used to obtain stratigraphic data that served as the basis for the areal extent and thickness values for the Devonian shale intervals in West Virginia.

Kruuskraa et al. (1985a, 1985b, 1985c) distributed the data by dividing them into two categories. Values that did not vary were held constant across the State and, for the reservoir properties that were found to vary across the State, individual data values were collected on a county-by-county basis and extrapolated into the data-less counties. Kruuskraa used these data to calculate the formation thickness for each section of the reservoir for the history-matching. The data from Area V were used as base-case values for the individual well history-matching. The base-case data are shown in Table 4.

Table 4. History-Matching Data for Kanawha County Base-Case

<u>Constants</u>	
Fracture Permeability (mD)	0.07
Permeability Anisotropy	4:1
Fracture Spacing (ft)	15.0
Matrix Porosity (%)	1.0
Matrix Permeability (mD)	5×10^{-6}
Fracture Porosity (%)	0.09
Gas Content (Mcf/acre ft)	50-80
<u>Gas In-Place by Source</u>	
Fracture (%)	1.7
Free Matrix (%)	19.4
Sorbed Matrix (%)	78.9
<u>Initial Matching Parameters</u>	
Fracture Permeability (mD)	0.07
Productive Interval (ft) (varied according to stimulation type and annual shut-in rock pressures)	20-500

3.3 Reservoir Model Description

SUGAR-MD is a general purpose, two-dimensional reservoir simulator for gas reservoirs. The code can be used to study fractured reservoirs and will efficiently solve one- and two-dimensional problems in either cartesian or polar cylindrical coordinates. Boundary conditions are flexible in that any desired flowing pressure or gas flow rate, as a function of time, may be imposed at any interior or boundary block within the finite-difference grid. This permits simulation of fractured wells by any one of several options.

In the radial mode, SUGAR-MD may be used as a single well simulator. For example, it may be used to history match well test or production data, to study the effects of dual-porosity (primary or secondary) systems, or to forecast the production performance of individual wells. In the rectangular mode, the reservoir may be made virtually any shape using "zero permeability blocks."

Complete heterogeneity of reservoir properties can be specified by assigning a unique porosity value and unique permeability values in each of the coordinate directions (permeability anisotropy) to each grid block in the system.

A naturally fractured reservoir may be simulated by choosing this option and specifying rock matrix porosity and permeability values and element size (fracture spacing). Also, desorption of gas from pore walls of the matrix can be considered by entering an appropriate desorption isotherm. The term matrix denotes the less permeable portion of the formation that delivers its gas content into an existing natural fracture system. The matrix acts as a uniformly distributed source within the fracture system. A more detailed description of SUGAR-MD is available (Sawyer 1983).

3.4 History-Matching Procedure

Previous DOE/METC efforts focused on matching cumulative production and production rates to obtain a history match. This was accomplished by varying unknown parameters such as permeability or thickness. An obvious disadvantage to this methodology is that the match is not unique since numerous combinations exist that duplicate the actual recorded well history. However, engineering judgment may be used when determining the matching variables.

An improved history-matching procedure was used for this study. Cumulative production, as well as rock pressures measured after 10 years of production, were matched in the analysis. This procedure is more accurate than the previous methodology in that less judgment is incorporated into the results and more factual information is used to obtain the match. It is probable that only one realistic combination of shut-in time, producing interval, and fracture permeability will match the recorded cumulative production and rock pressure for a fixed SUGAR-MD modeling option. In this case, the pseudo steady-state matrix flow option was used.

The matching procedure held base-case parameters for each well at constant values (unpublished data from Columbia Gas and Kruuskraa et al. (1985a, 1985b, 1985c), while fracture permeability and producing interval were varied to match cumulative production and 10-year rock pressure measurements. The initial attempt was to match the entire set of rock pressures recorded after shut-ins throughout the 10-year period. It was concluded that the uncertainty built into the recorded shut-in periods and the time involved in the effort to match all rock pressures were too extensive for this analysis. Therefore, only the final rock pressure, or one of the most reliable rock pressure in the last 3 years of the production, was matched. The results of this matching depend on the reliability of the shut-in measurements recorded in the field by Columbia Gas personnel. Unfortunately, there may be some error in these values that would in turn reduce the reliability of the rock pressure matches. For this reason, the most logical values within the last 3 years were chosen. For some wells, a few shut-in periods were illogical or absent (e.g., rock pressures were measured that were higher than the initial rock pressure).

As the number of matches increased, the time required to match the wells decreased. The range of history-matching parameters for a given rock pressure and production history became familiar after a few matches were completed.

Well 9808 (Well 2614, 9808 is the company number) will be used as an example to outline the process of individual history matching. Prior to determining the impact of varying the thickness and permeability on changes in rock pressure, initial combinations of thickness and permeability were based on the producing interval and the general permeability of the area determined by Kruuskraa et al. (1985a, 1985b, 1985c). The matching was initiated with a producing thickness of 18 feet and a permeability of 0.10 mD as shown in Figure 7. An attempt to lower the rock pressure while increasing the production was made by increasing the permeability to 0.12 mD. As shown in Figure 8, the production curves were much closer, but they crossed and the rock pressures were too low. The attempted rock pressure match is shown in Figure 9. An increase to 0.20 mD was implemented to increase the production. As shown in Figure 10, the production was now too high, while the rock pressure remained low. Therefore, an increase in the thickness to 25 feet and a decrease in permeability to 0.12 mD were implemented to predict production. The simulation was interrupted by a computer failure, yet the results shown in Figures 11 and 12 indicate that the production was much too optimistic while the rock pressure was erratic compared to the actual pressures. A reduction of permeability to 0.08 mD is shown in Figure 13.

Figure 14 indicates that the rock pressures were still erratic and were optimistic during the early history, but pessimistic during the late production time. After several attempts to match production as well as total rock pressure history, it was concluded that the rock pressure match would be nearly impossible or time consuming. Therefore, a resolution to match the final or the most reliable end-time rock pressures along with production was established. Using the results shown in Figures 13 and 14, the permeability was reduced to 0.06 mD in an effort to reduce production and increase final rock pressure. A rock pressure of 560 psi was predicted; this was too low when compared to the 600 psi desired pressure. Only an increase in producing thickness and a decrease in permeability could maintain the production while increasing the rock pressure. With an increase in thickness to 50 ft and a decrease in permeability to 0.02 mD, the production was very close while the rock pressure was 590 psi. This is only 1.6% less than the desired value of 600 psi. The predicted cumulative production at 0.06 mD is shown in Figure 15, and Figure 16 shows the history match for cumulative production at 0.02 mD and a producing thickness of 50 ft.

The remaining wells were matched using the same procedure, but combinations of permeability and thickness varied according to the type of stimulation performed on the well. Also, the recorded rock pressures had a significant effect on this combination.

3.5 History-Matching Discussion

Well 2595 was a shot well in the Lower Huron shale. The treatment interval ranged from 4,000 to 5,575 ft, but only a 50 ft section of this interval was perforated and shot. The initial rock pressure of the well was 820 psi. Rock pressures recorded during the next 10 years averaged 250 psi after a 48-hr shut-in period. A rock pressure measured in 1980 was 440 psi after a 5-day shut-in period. The open flow of the well was 119 Mcf. This was not significant when compared to the 539 Mcf of Well 2594, which is located 1,200 ft from Well 2595. Interestingly, rock pressures for Well 2595 averaged 500 psi. The high initial open flow measurements indicate that the two wells are in a high permeability area, especially Well 2594. A high permeability and small formation thickness were required to match the low rock pressures and production of Well 2595.

One scenario that may explain this behavior is that a dense system of natural fractures intersected Well 2594, and this system of fractures was further enhanced by the stimulation treatment of the well. Wells 2595 and 2594 were put on line simultaneously, yet Well 2594 produced five times as much gas even without stimulation. The stimulation was completed 5 months later. It appears that Well 2595 did not intersect an area with as high a gas potential as did Well 2594. The small thickness, high permeability, and 80-acre drainage radius may be the single-well history-matching combination that predicts the behavior of a low-potential, small-drainage-radius well. The small drainage radius may be attributed to interference from Well 2594.

The logic behind Well 2595 intersecting a low density of natural fractures and Well 2594 intersecting a high density area of natural fracture is drawn from the production being five times greater in Well 2594 than in Well 2595, even before Well 2594 was stimulated. Since rock pressures and production were consistently higher for Well 2594, it appears that the well was interfering and draining gas from the Well 2595 reservoir. The contour of Wells 2595 and 2594 reflects this productive area. One parameter that may be causing an error in the history-matched permeability and thickness of Well 2594 is the predicted hydraulic fracture geometry. If the wing length was optimistically predicted, the permeability matched may be too low. The predicted wing length was 300 ft, but the initial open flow of the well indicates a dense fracture system. The fluid loss may have been greater than that calculated with larger permeabilities.

This would contribute to a shorter primary fracture length because of fluid loss to the natural fracture system. The uncertainty built into the predicted fracture length indicates that analyses should be performed to evaluate the most reliable method for simulating induced fractures for history-matching procedures. Finally, the skin factor used to calculate the effective wellbore for Well 2595 may have been incorrect. The lack of pressure build-up data after the stimulation meant that the appropriate well skin factor could not be calculated. It makes sense to assume that the skin factor is too low (or that instead of being -2, it should be -3 or -4) for Well 2595. This is hypothesized because the measured annual rock pressures were low for the well and because it is a productive well. Figure 17 shows the relationship of skin factor to effective wellbore radius. Figure 18 shows how thickness and principal permeability change to match cumulative production and rock pressure according to changes in the skin factor.

Single wells were matched with producing thicknesses ranging from 20 to 500 ft and fracture permeabilities ranging from 0.4 to 0.004 mD. This broad range of values is representative of the variable stimulation treatments, geological features, proximity of one well to another (some were spaced less than 80 acres apart), and the variable rock pressures recorded during the 10-year shut-in periods. The history-matching variables are those values that provide the correct combination of constant and variable parameters to match the history of the reservoir. The values do not always represent those that actually exist in the field. Matched producing thickness, maximum fracture permeability, and rock pressures in the final producing year are tabulated in Table 5. The history-matched cumulative production curves for the 14 wells are shown in Figure 19 through Figure 32. The most productive wells were those that were hydraulically fractured.

Table 5. Single-Well, History-Matched Thickness, Permeability, and Rock Pressure

Well Number	Thickness (Ft)	Permeability (mD)	Rock Pressure (psi)
2621	25	0.40	205
2605	100	0.004	656
2622	300	0.008	615
2667	50	0.08	435
2611	30	0.10	330
2612	20	0.08	470
2623	500	0.005	745
2614	50	0.02	650
2613	30	0.10	687
2624	125	0.01	516
2594	100	0.02	560
2595	20	0.50	440
2593	19	0.08	412
2606	55	0.01	518

3.6 Full-Field Simulation

Full-field simulations were carried out to represent the individual wells in the actual environment. The purpose was to evaluate the impacts of well interference, reservoir flow capacity, stimulation techniques, and well installation patterns on the feasibility of infill drilling in the existing reservoir. Two phases of full-field simulation were conducted because of improvements in the simulation method. The following steps were followed to conduct the full-field history-match from individual well matches.

1. A grid was formulated to simulate the full field with the reservoir model. The matched producing interval, maximum or principal (x-direction) permeability, and minimum (y-direction) permeability were contoured over the entire field.

2. Initial rock pressures were contoured over the field.

3. Wells were placed in the field in their respective locations and represented with 50 x 50 ft grid blocks.

4. Contoured permeabilities were adjusted until the full-field cumulative production matched the individual-well cumulative production.

5. Infill wells were simulated randomly throughout the existing field and represented with 50 x 50 ft grid blocks.

6. Five infill wells were simulated in the area of high flow capacity or high permeability thickness contouring.

The second phase of the simulation was conducted as a result of a model option analysis. A previous study had concluded that the productivity index (PI) did not function properly in the SUGAR-MD option that allows the user to simulate stimulated wells in a large reservoir. The PI is an option in which the user may use large grid blocks to simulate a given stimulation by assigning the well as a variable-rate node. The advantage of this option is that a reasonable grid array may be used to simulate a field of one or more stimulated wells. Otherwise, very small grid blocks are required for each well, and the capability of the simulator is then limited. The PI option advantage stems from the ability to use an array of large grid blocks to simulate several wells so that simulation run time is reasonable and so the solution will converge. Otherwise, a variable pressure-node option and a simulation consisting of 35 x 35 ft grid blocks would be used. Using the PI option, 100 x 100 ft grid blocks with the variable pressure node option can possibly be used.

It had been thought that this PI option was not functioning properly, leading to the 50 x 50 ft grid block analysis used in Phase One. However, soon after the first phase was completed, a second study to evaluate the reliability of the PI was completed. The results of this evaluation indicated that the old reliability study was incorrect, and that the PI for hydraulic fractures was a dependable SUGAR-MD modeling function. The reliability of the PI option for shot wells was also evaluated and was found to be reliable.

Wells simulated with the pressure node options were only 4% different from those simulated with the PI option. This is shown in Figures 33 and 34.

Figures 33 and 34 show the difference between full-field matches with 50 x 50 ft grid blocks and the PI option. Comparison of individual well productions that produced the full-field indicate that the 50 x 50 ft grid block (variable pressure node) wells did not match the actual individual well productions as did the PI-option-matched wells. The variable-pressure-node hydraulically fractured wells were underproducing while the shot well was overproducing. Therefore, the second phase of the full-field infill drilling analysis was completed with the PI option to ensure that the study was accurate.

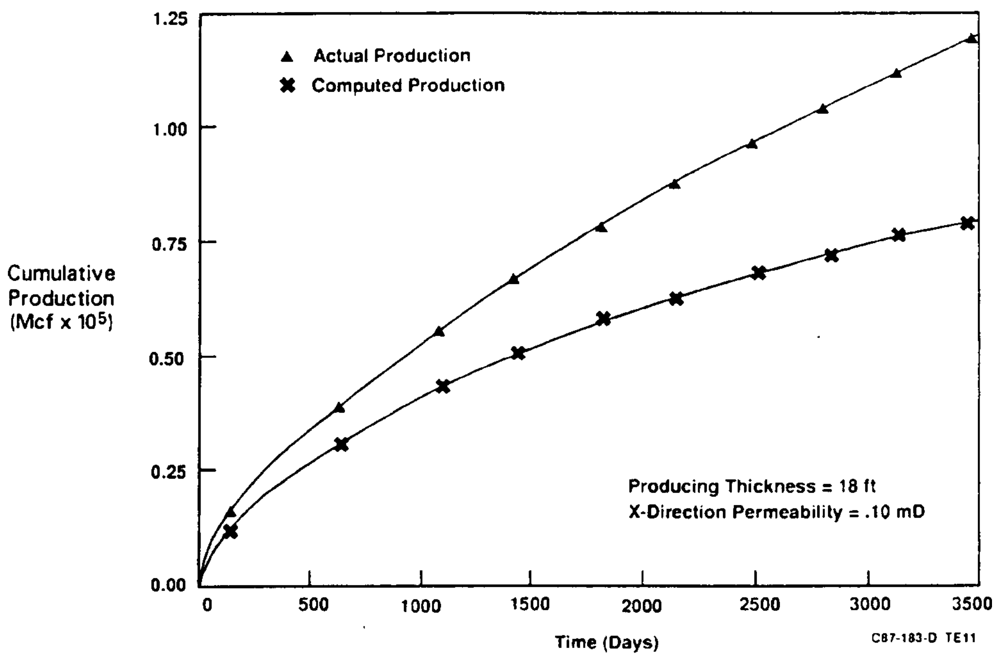

Figure 7. Well 9808 Cumulative Production at 18 ft Thickness and 0.10 mD Permeability

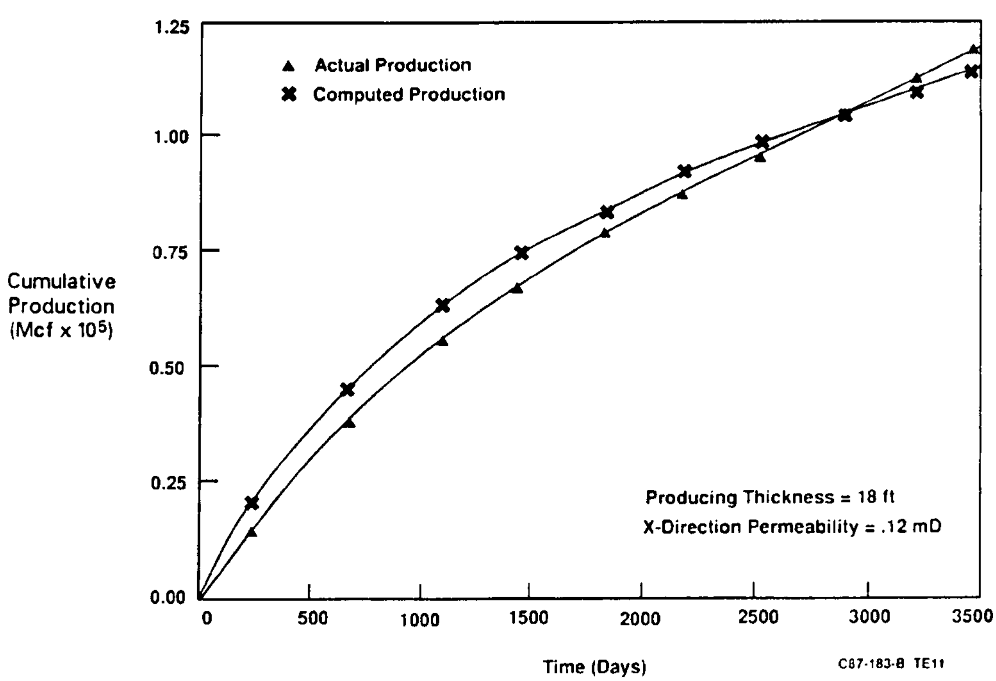

Figure 8. Well 9808 Cumulative Production at 18 ft Thickness and 0.12 mD Permeability

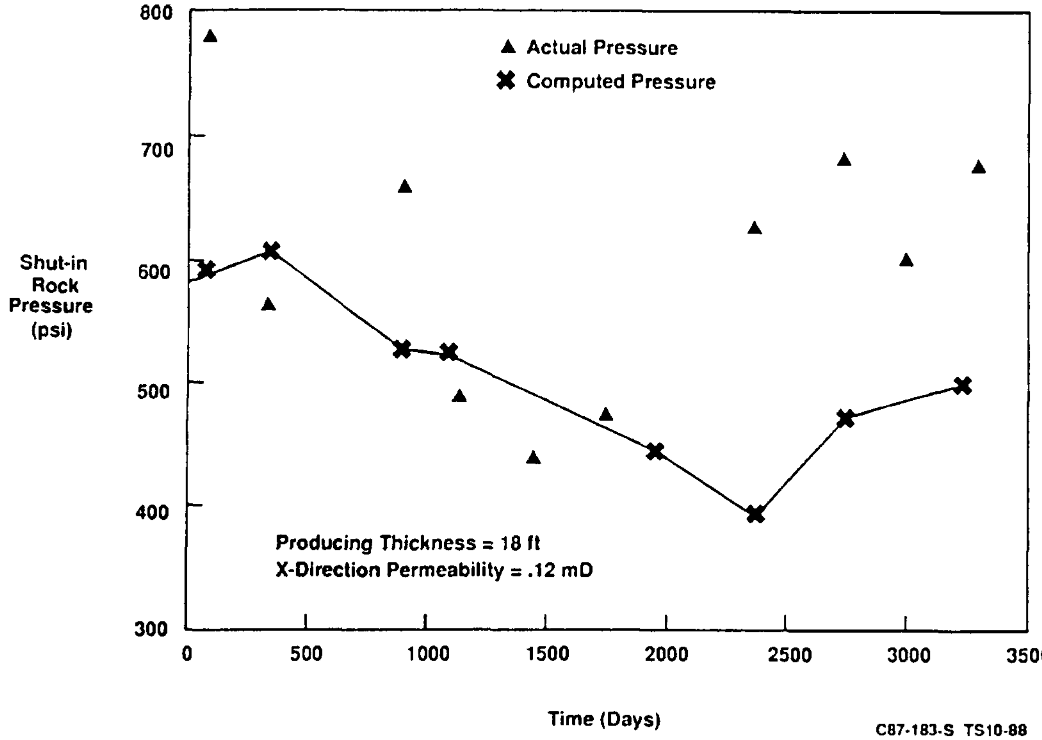

Figure 9. Well 9808 Rock Pressure at 18 ft Thickness and 0.12 mD Permeability

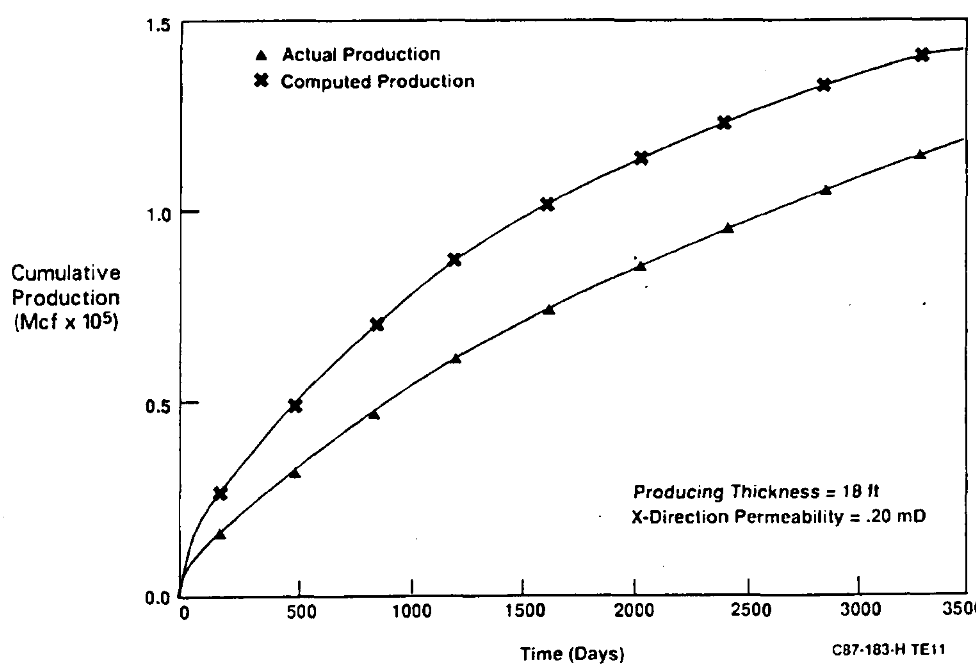

Figure 10. Well 9808 Cumulative Production at 18 ft Thickness and 0.20 mD Permeability

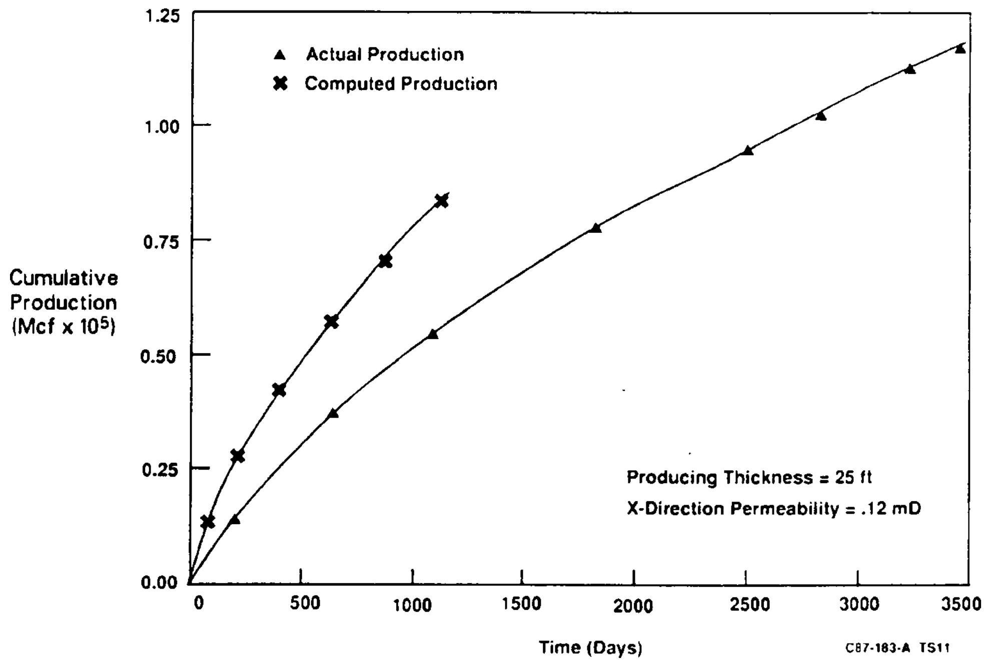

Figure 11. Well 9808 Cumulative Production at 25 ft Thickness and 0.12 mD Permeability

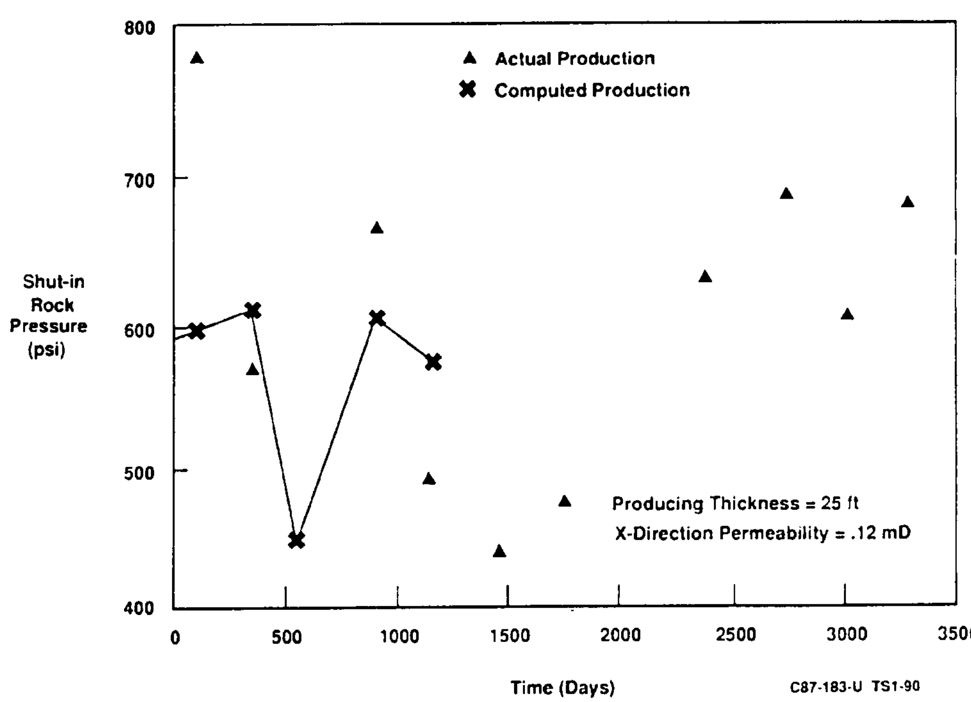

Figure 12. Well 9808 Rock Pressure at 25 ft Thickness and 0.12 mD Permeability

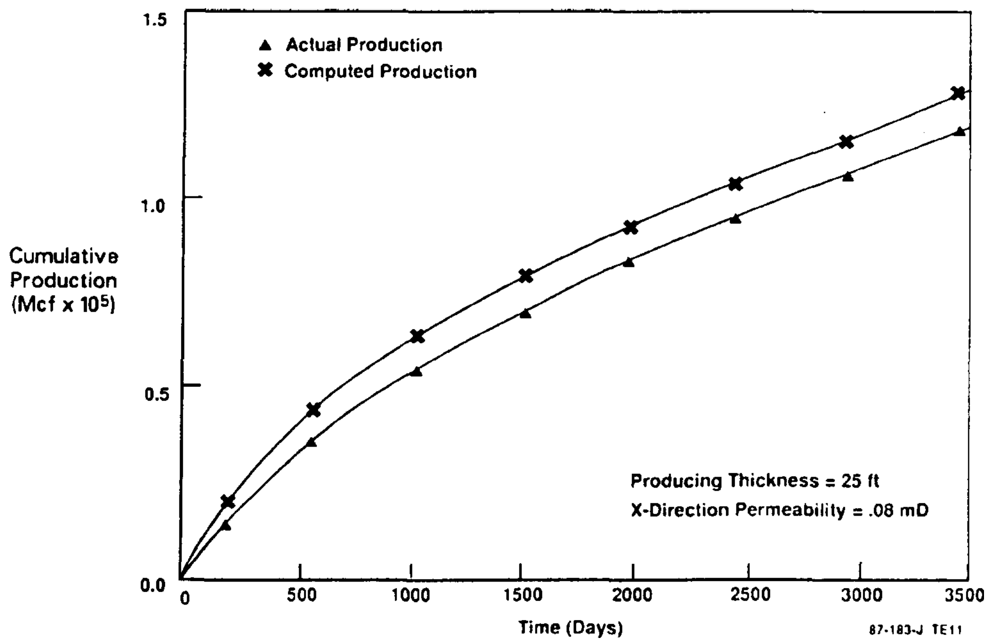

Figure 13. Well 9808 Cumulative Production at 25 ft Thickness and 0.08 mD Permeability

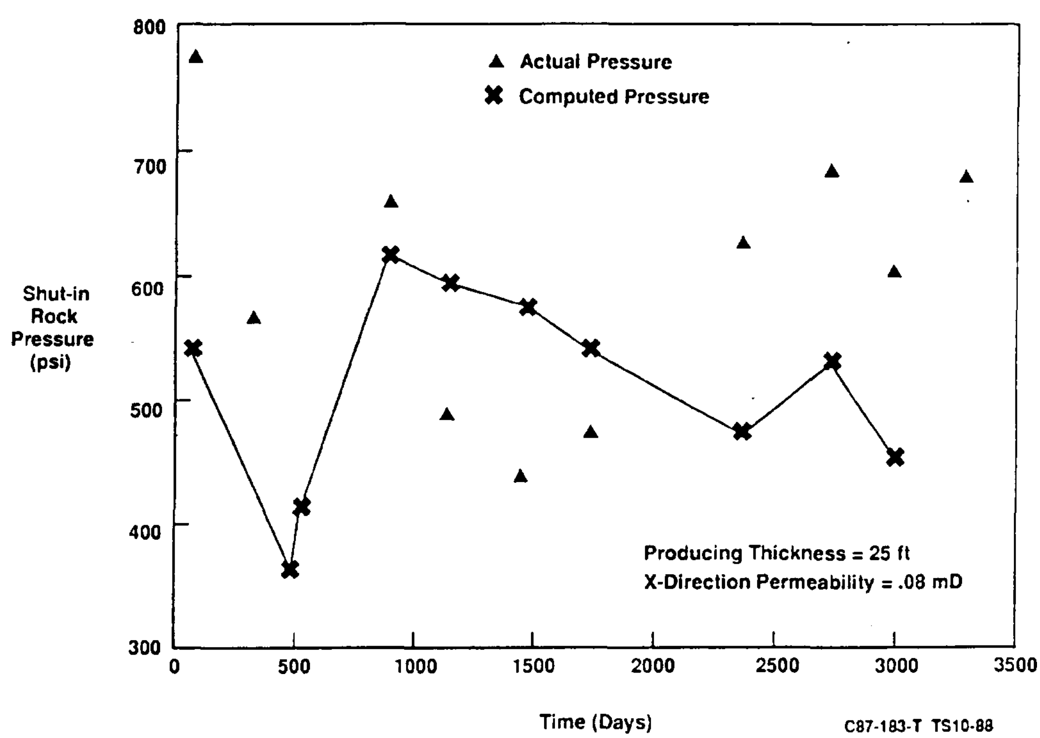

Figure 14. Well 9808 Rock Pressure at 25 ft Thickness and 0.08 mD Permeability

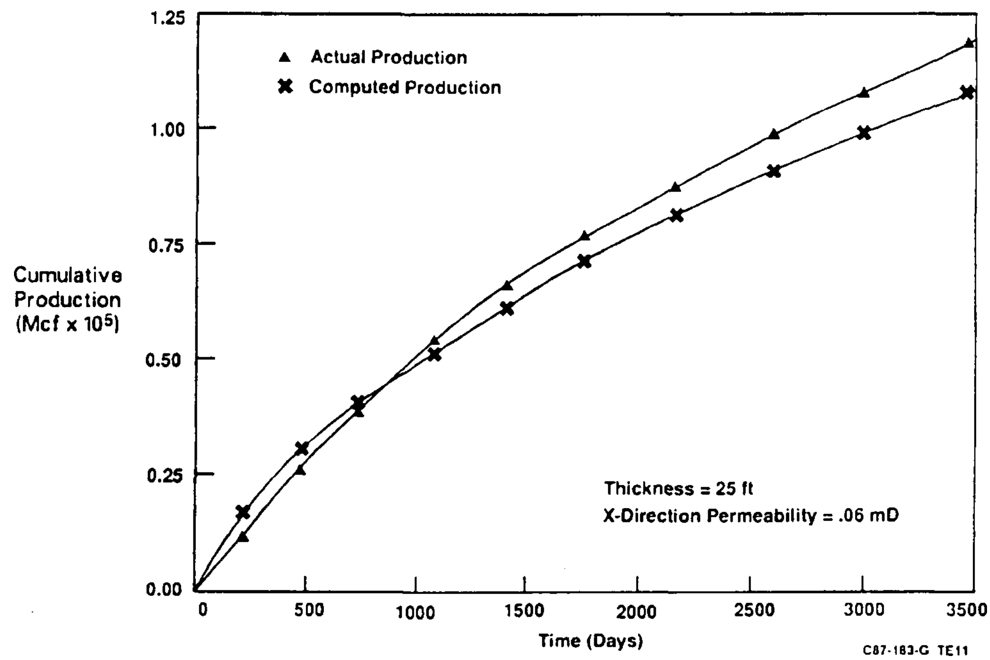

Figure 15. Well 9808 Cumulative Production at 25 ft Thickness and 0.06 mD Permeability

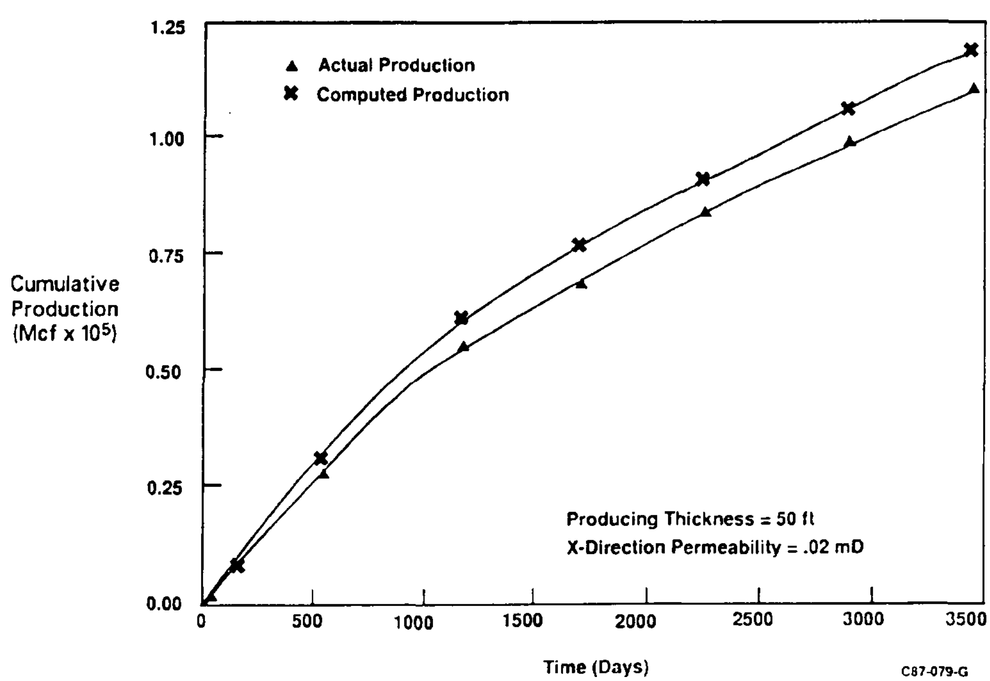

Figure 16. Well 9808 History Match at 50 ft Thickness and 0.02 mD Permeability

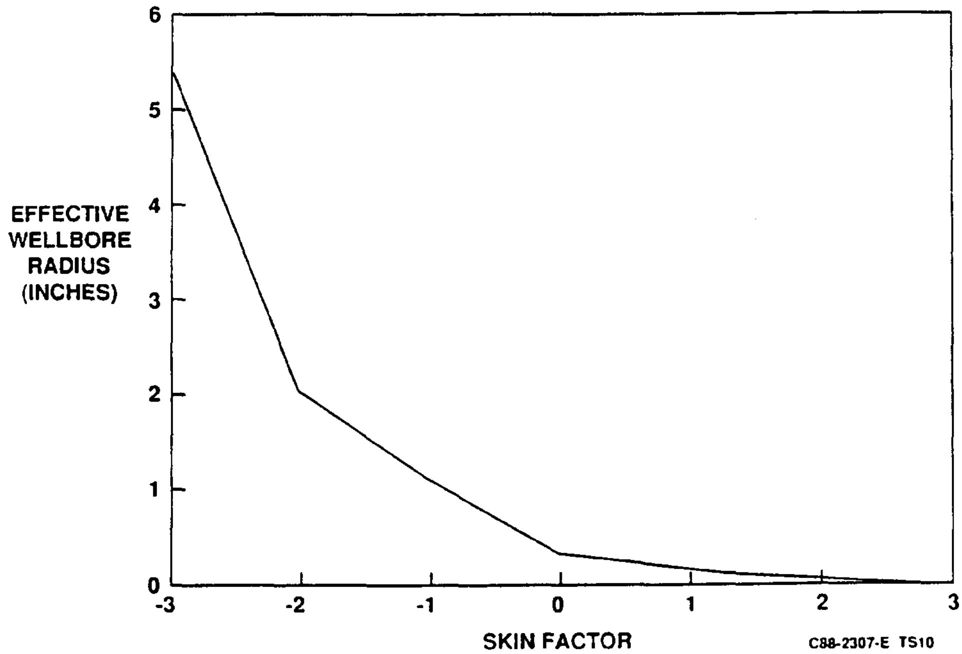

Figure 17. Relationship of Skin Factor to Effective Wellbore Radius

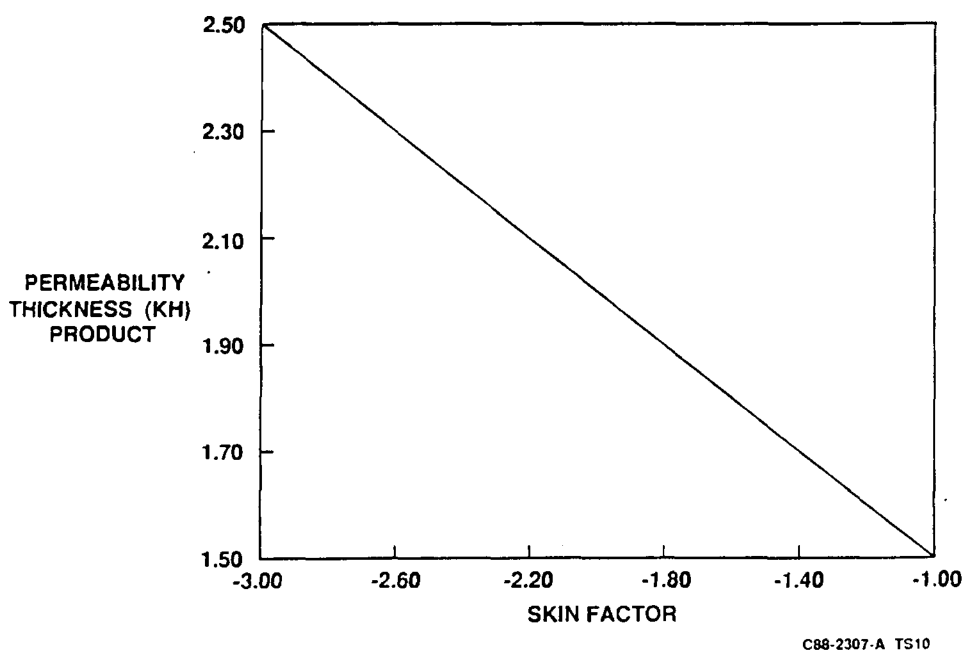

Figure 18. Effects of Thickness and Principal Permeability According to Skin Factor Changes

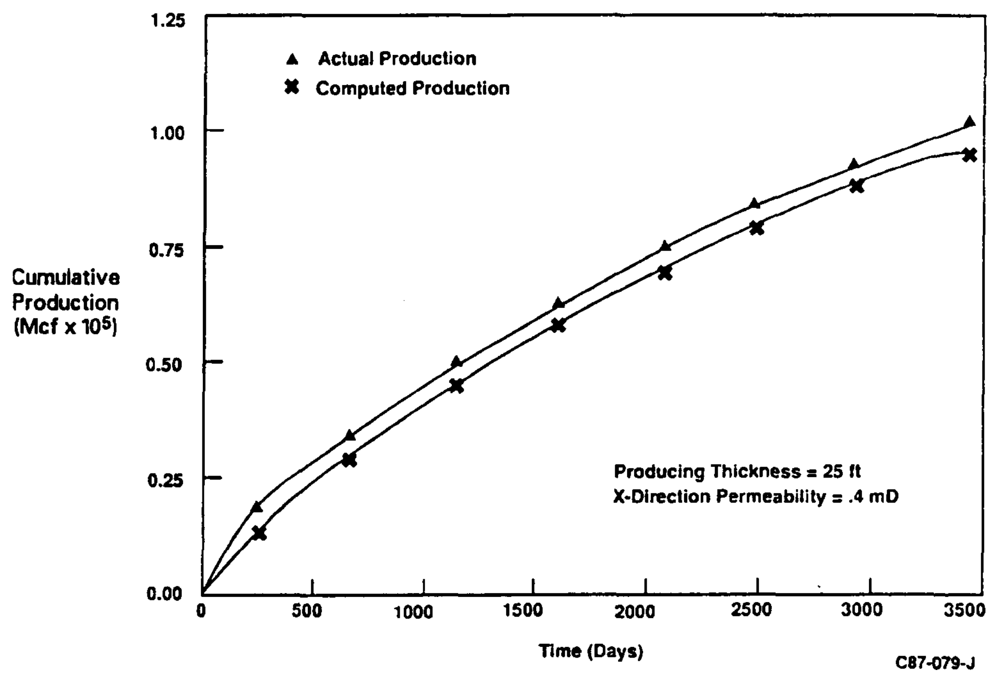

Figure 19. History Match for Well 2621

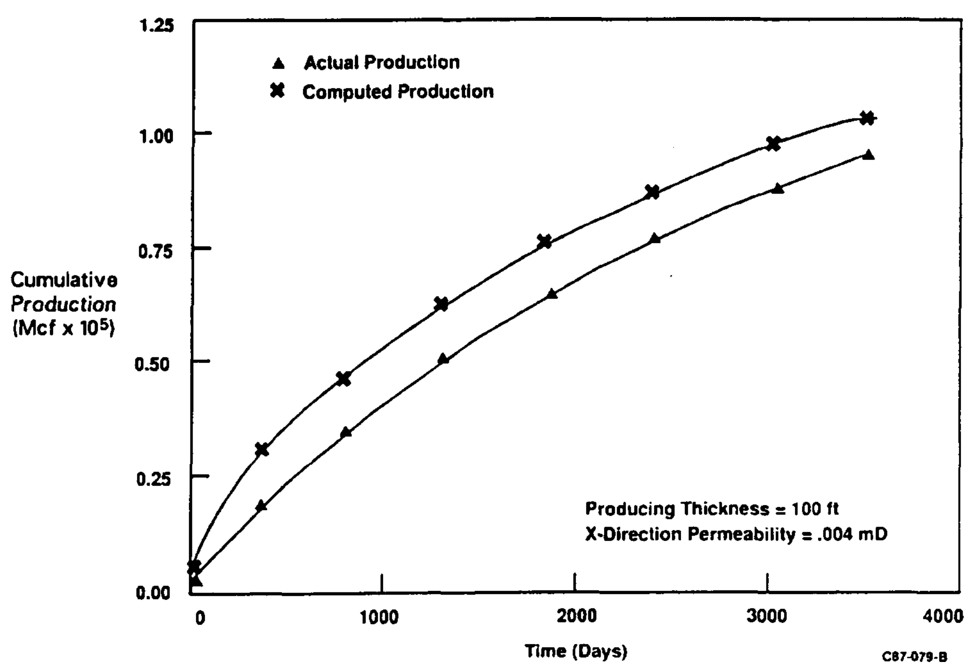

Figure 20. History Match for Well 2605

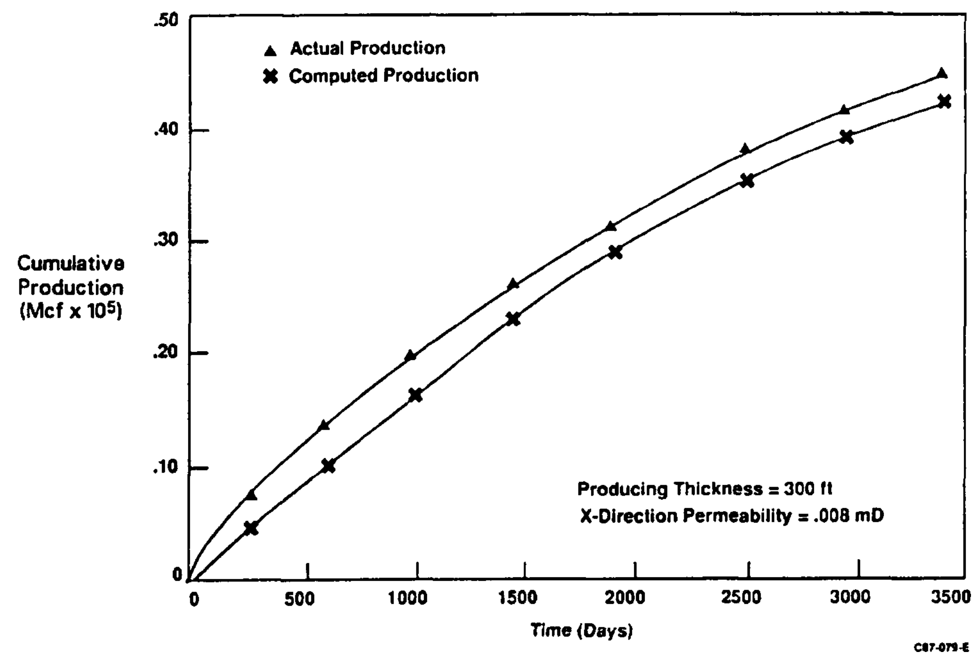

Figure 21. History Match for Well 2622

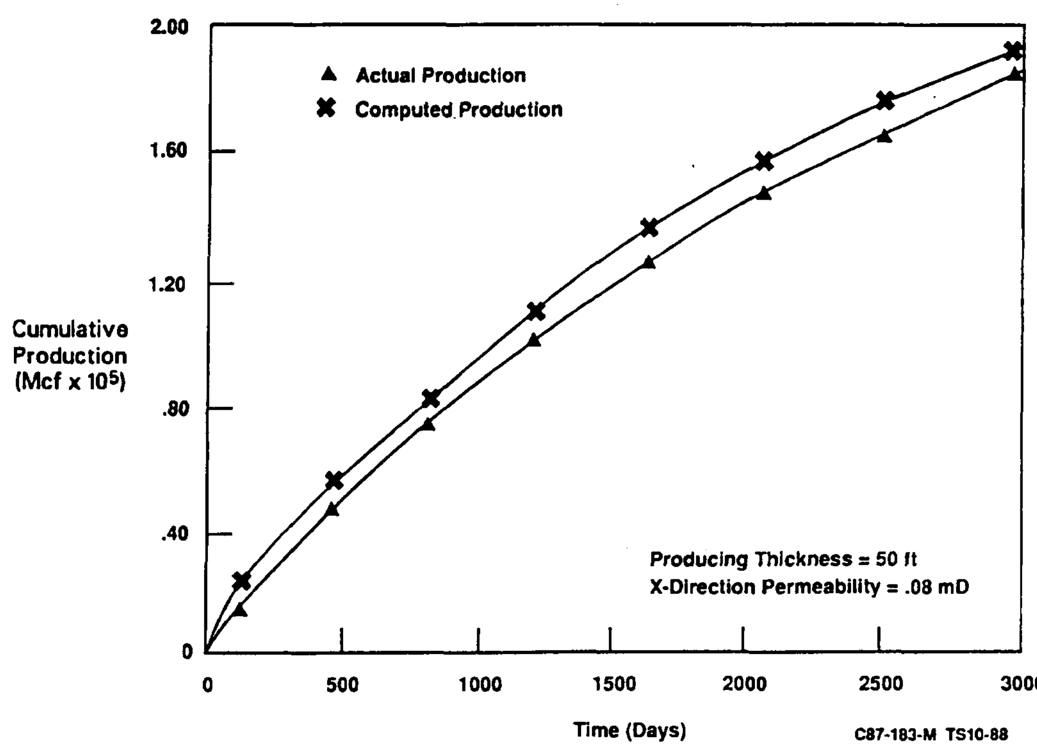

Figure 22. History Match for Well 2667

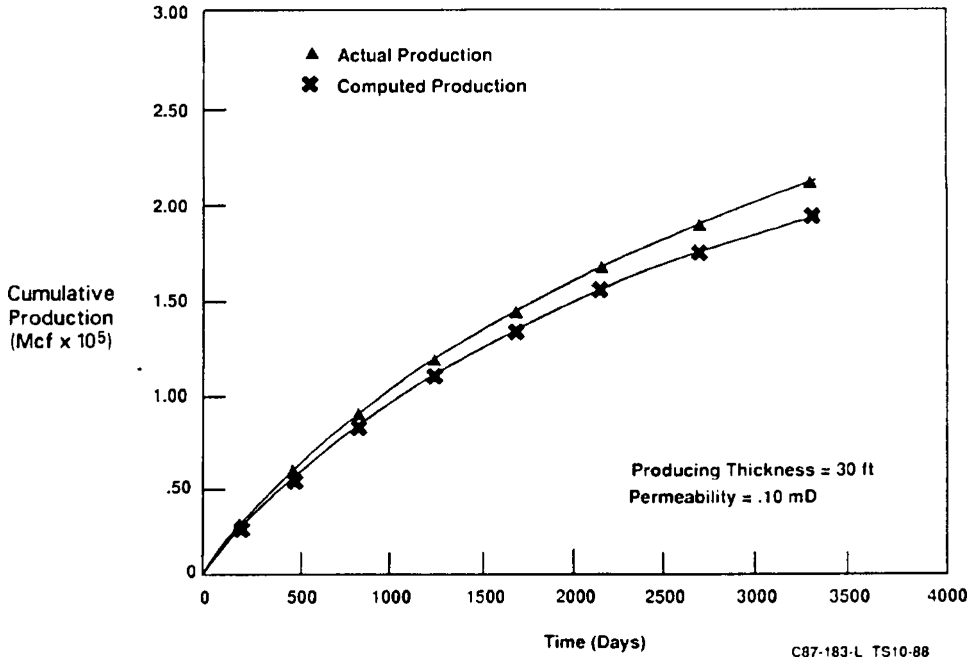

Figure 23. History Match for Well 2611

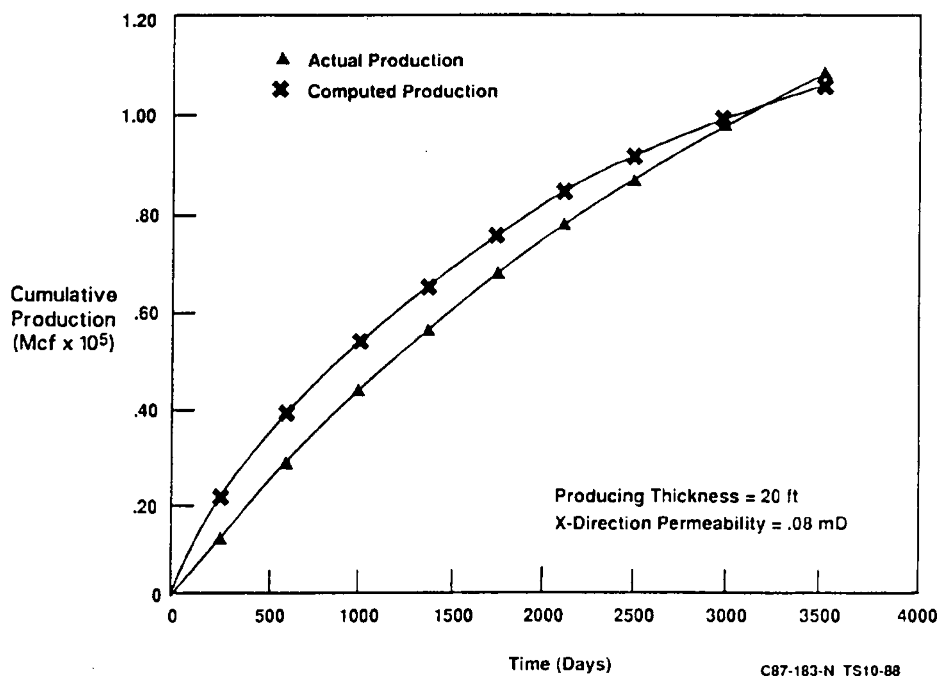

Figure 24. History Match for Well 2612

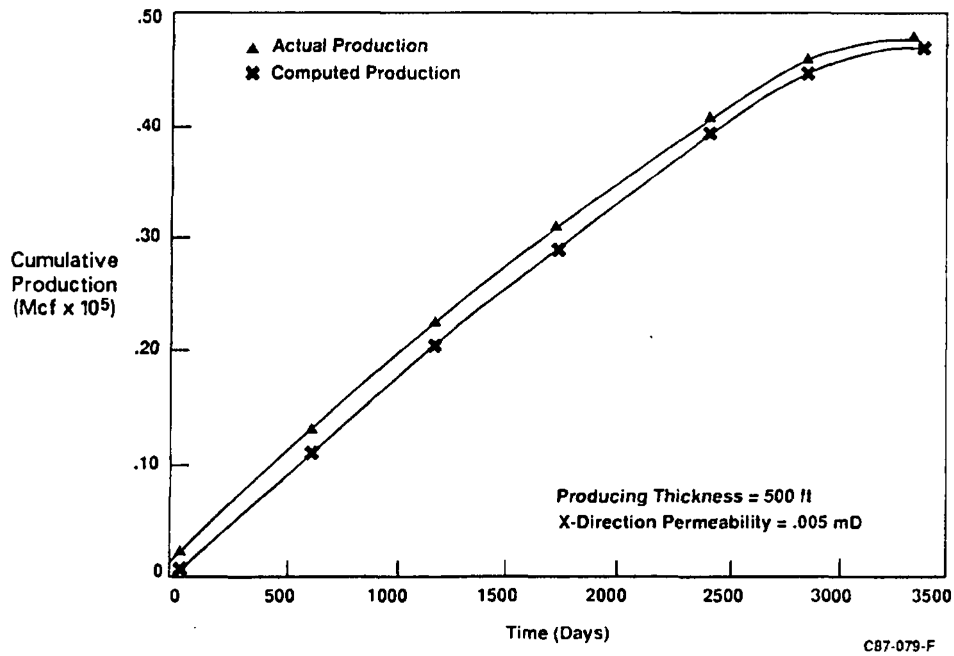

Figure 25. History Match for Well 2623

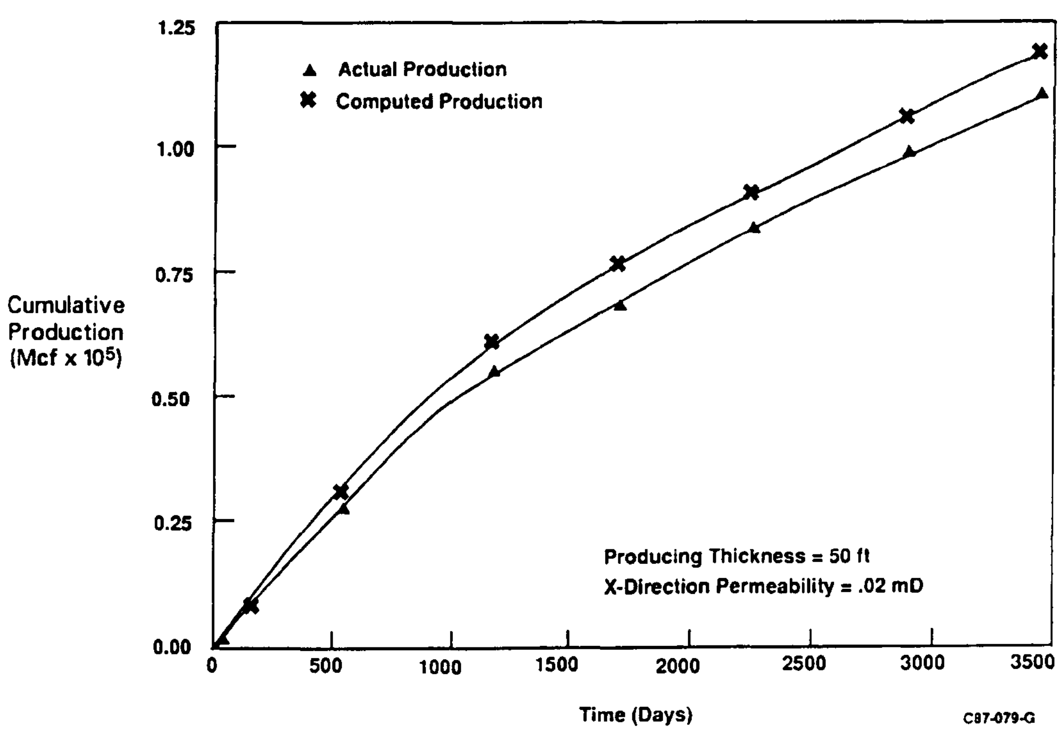

Figure 26. History Match for Well 2614 (Well No. 9808)

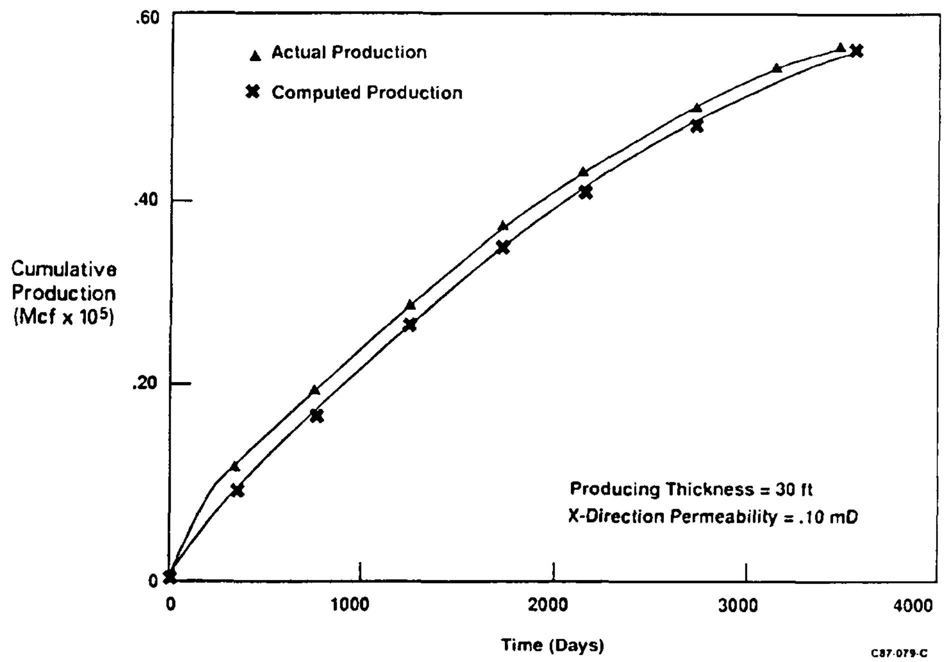

Figure 27. History Match for Well 2613

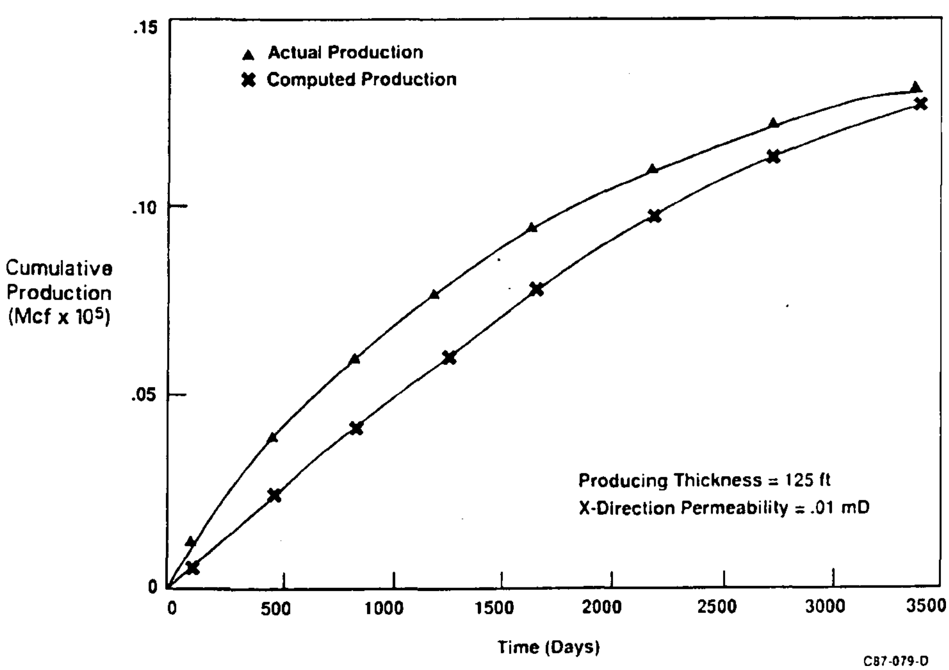

Figure 28. History Match for Well 2624

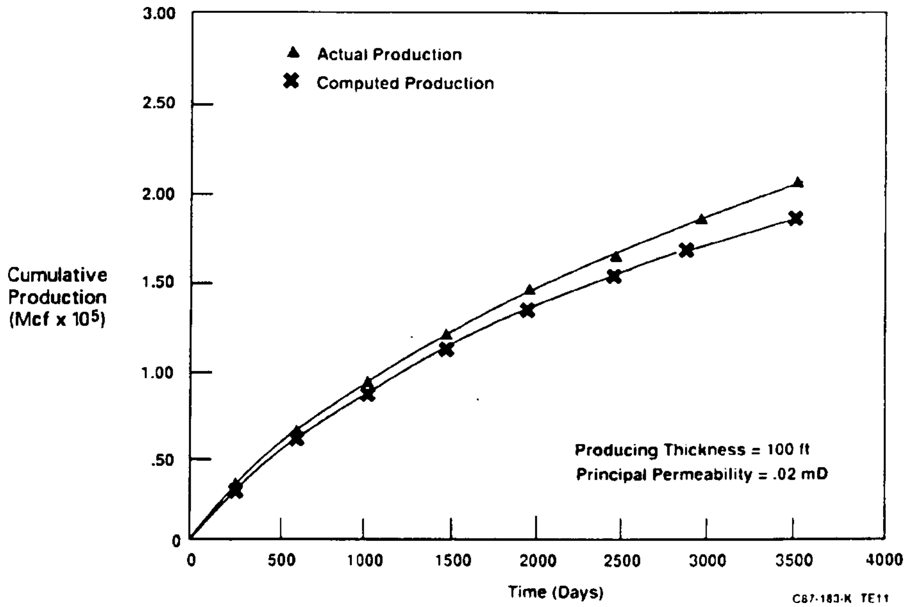

Figure 29. History Match for Well 2594

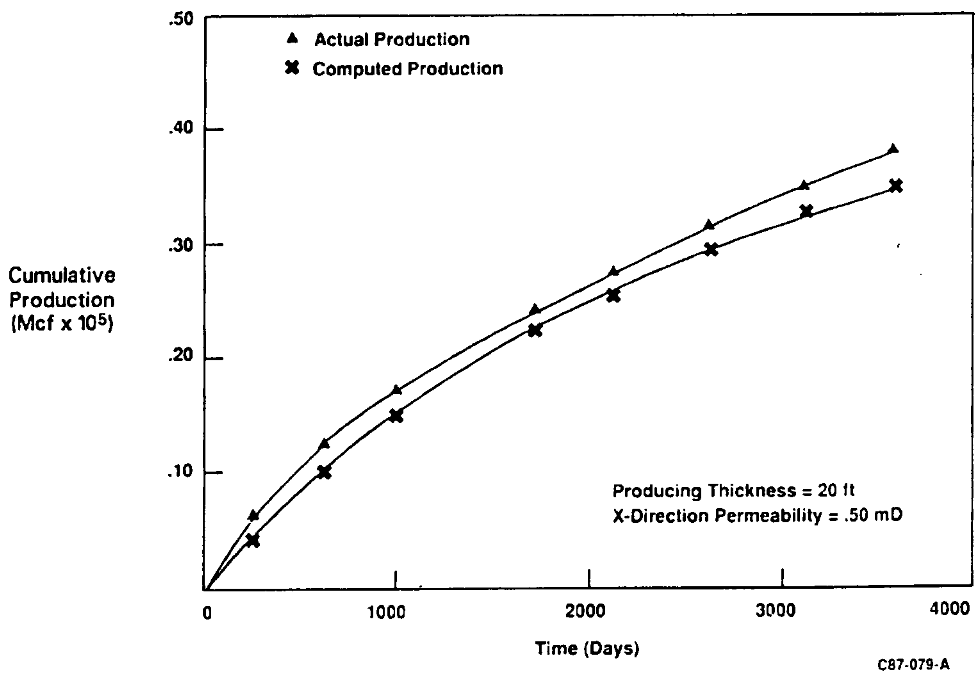

Figure 30. History Match for Well 2595

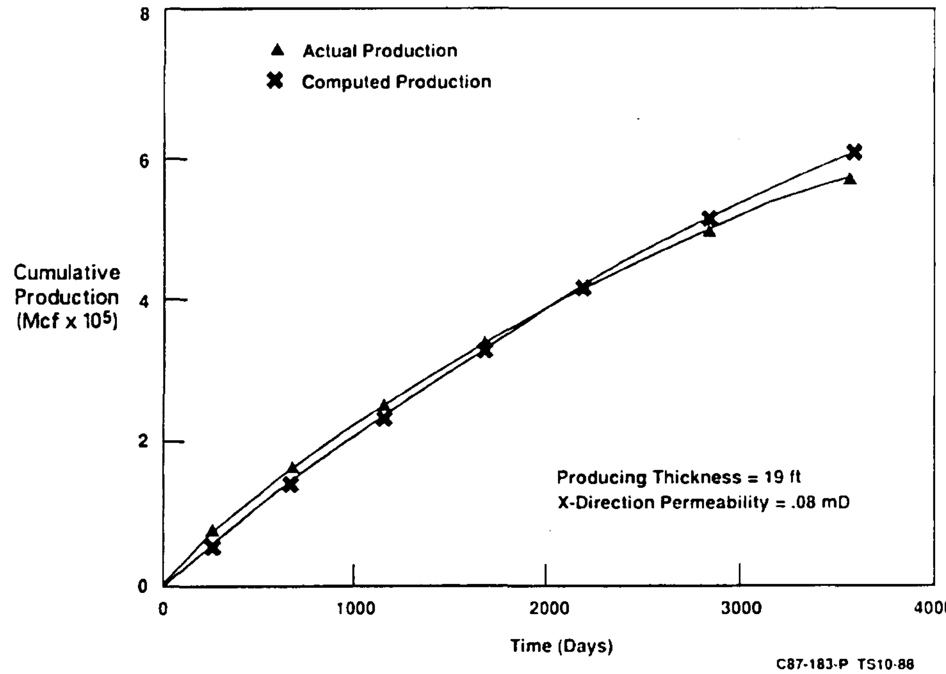

Figure 31. History Match for Well 2593

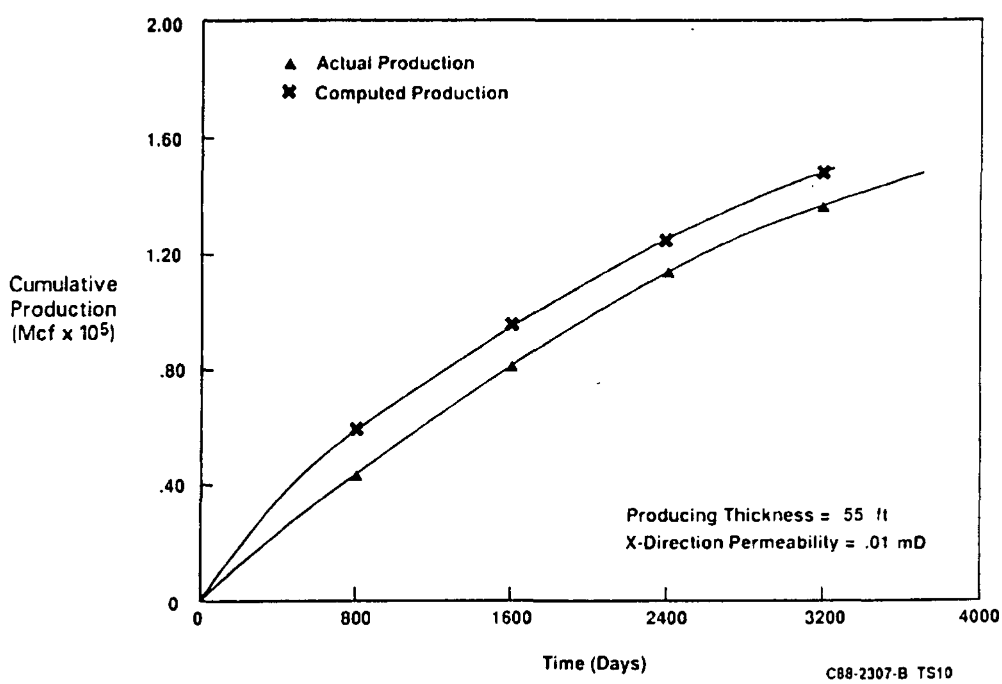

Figure 32. History Match for Well 2606

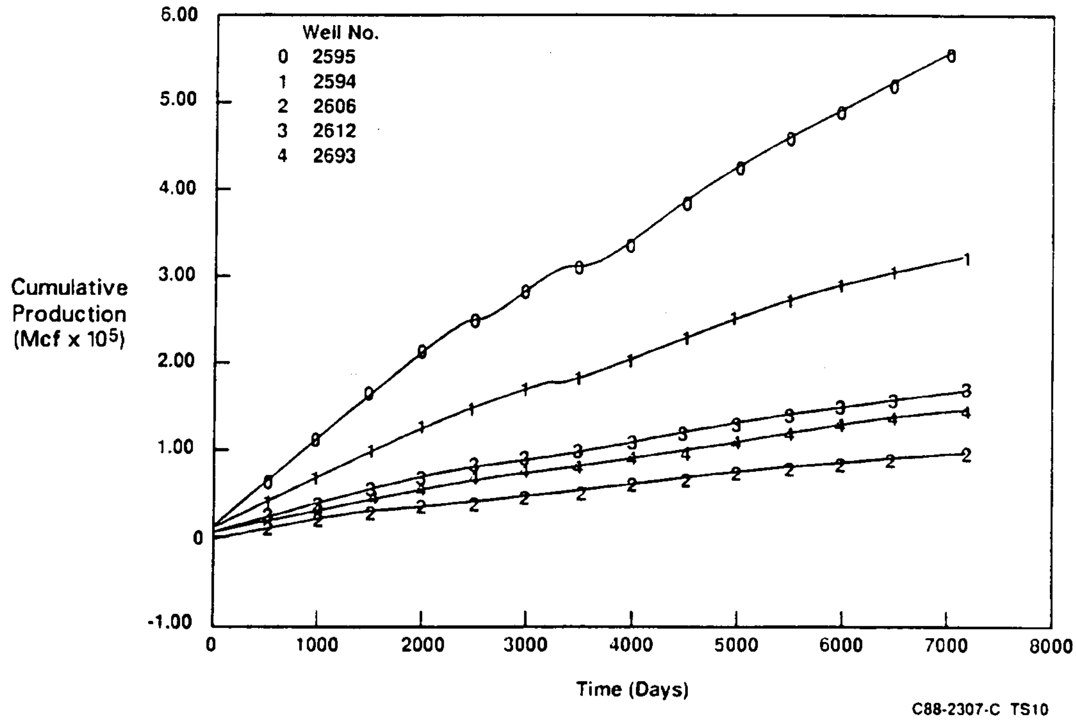

Figure 33. Full-Field History Match With 50 x 50 ft Grid Blocks

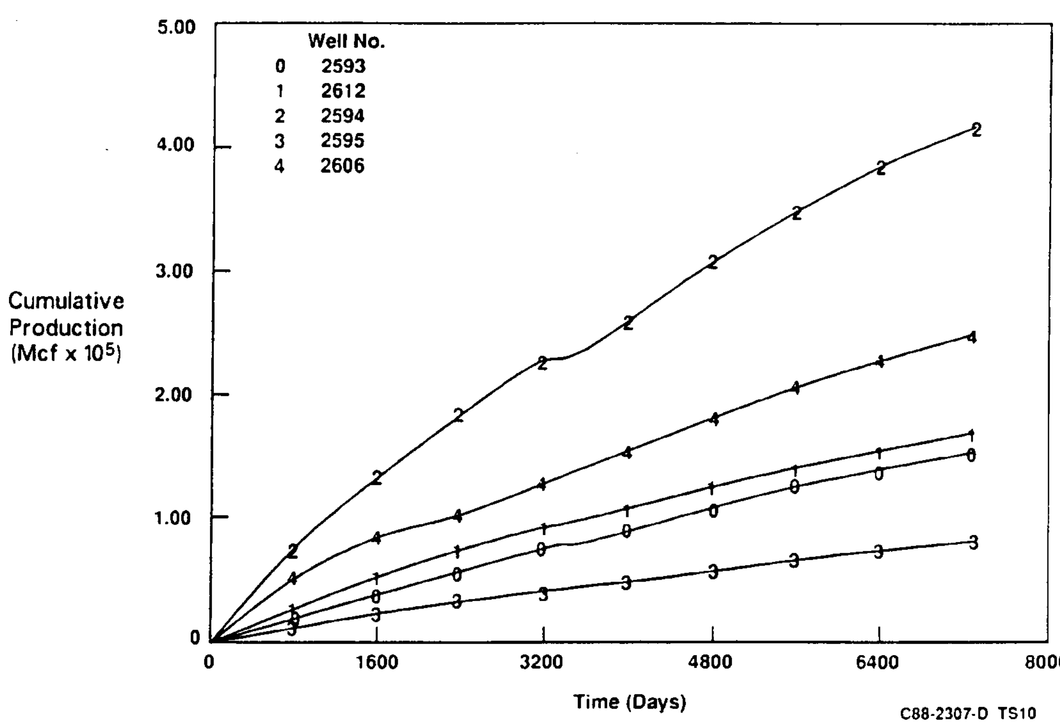

Figure 34. Full-Field History Match With PI Option

4.0 PHASE ONE, FULL-FIELD ANALYSIS

4.1 Gridding and Contouring

The full-field analysis was initiated by creating a full-field modeling, finite-difference grid system of all individually matched wells. The first step was to digitize the wells with respect to a chosen origin. The most recent map of the Clendenin Quadrangle was obtained from the West Virginia Geological Survey. This map provided reliable well locations for the full-field grid. Before digitizing the wells, the bottom east direction axis of the well-grid boundary was rotated 22° north from east. This new axis then provided the correct gridding x-axis. The 22° was derived from Kruuskraa's maximum horizontal stress trajectory for West Virginia (Kruuskraa et al. 1985c). This trajectory represents the preferred principal natural fracture and induced fracture direction. This 22° axis was then used as the orientation for the principal x-direction for natural and induced fractures. Current stress regimes indicated that induced hydraulic fractures would follow the same azimuth as the natural fracture orientation. In other words, the potential of natural fractures to cross or intersect an induced fracture was unlikely, and the two types of fractures could be simulated as a parallel system oriented in the principal permeability direction.

This principal permeability axis was used to create a boundary around the existing wells. A grid was formulated around all 14 wells while a 50 x 50 ft grid block was maintained for each well. The grid array consisted of 80 x 80 ft grid blocks. At that time, DOE/METC's VAX computer facilities were such that simulations with large grid systems were not reasonable because of the large amount of time required. Therefore, only a portion of the 14-well field was identified and gridded for the full-field study to make the simulation possible. Five of the 14 wells in the bottom left portion of the boundary were identified and gridded. This area is shown by the dotted line in Figure 35. Each well was represented by a 50 x 50 ft grid block, while grids gradually increased moving away from each well's coordinates. This was to ensure a low material balance error in the simulation.

The matched permeability and thicknesses for individual wells were then contoured over the entire 14-well field. This was accomplished using the METC GRID® and CONTOUR® programs to determine the permeabilities and thicknesses at the generated grid midpoints for input into SUGAR-MD. The matched thicknesses, the permeability-thickness products, and initial rock pressures are shown in Figures 36, 37, and 38.

4.2 Full-Field History Matching

The shut-in periods and on-line times for each of the five wells were entered into SUGAR-MD. Three wells began producing in March while two began production in May. The history-matched values that were contoured over the field and the shut-in history of the wells were used to simulate all five wells over a 10-year period. Since each well's productivity was represented by a 50 x 50 ft grid block, the initial simulation of the five wells did not match the actual five-well cumulative production. The contoured permeability had to be doubled to match the five-well cumulative history. This was because the hydraulically fractured wells' productivity was not represented accurately with the 50 x 50 ft grid blocks. The simulated wells were underproducing considering the original confirmed thickness and permeability values. The matched individual-well cumulative production is shown in Figure 34.

4.3 Infill Well Simulation

After the full-field match was completed, the 20-year projected production was simulated as a base case to evaluate the impact of infill wells over a 10-year period. One, three, and five wells were installed randomly in the field and simulated from 10 to 20 years. The location of these wells is shown in Figure 39.

In addition, all five infill wells were put on line at the same time as the existing wells. The results indicate an overall 68% increase in production: a 22% increase with one infill well, a 32% increase with three infill wells, and a 42% increase with five infill wells. The productivity of these wells is uncertain, however, because of the 50 x 50 ft grid block and the individual production of the existing wells.

The five infill wells were then installed in an area of high flow capacity as indicated by the permeability and thickness contours. The kh, or the contour for the product of permeability and thickness, was then used to determine the locations of these wells. They were installed in the lower left portion of the field. This preferred area is shown in Figure 39, and the results of this simulation are shown in Figure 40. An overall 88% increase in production was predicted: a 22% increase was predicted for one infill well, a 48% increase for three infill wells, and a 68% increase for five infill wells. When the wells were simulated in the area of high flow capacity, five infill wells drilled after the field had produced for 10 years could produce the same amount as five wells installed at time zero with the random well pattern.

4.4 Economic Analysis

The Devonian Shale Gas Economic Model (DGEM) was used to evaluate the economic potential of installing the infill wells randomly and in the area of high flow capacity with 50 x 50 ft grid blocks representing the wells. A METC CASHFLOW model was also available for the analysis, but because of the code's inability to account for taxes and its lack of stored data and flexibility, the DGEM was chosen.

The Columbia Gas rate-of-return (ROR) was used to calculate the required gas price. Table 6 lists the input data used to generate the gas price for a 20% rate of return.

Table 6. Financial Analysis Data

Operating Cost Overhead (Fraction)	0.2000
G&A Rate on Investment (Fraction)	0.1000
Depreciation Life (Years)	20.0000
Royalty Rate (Fraction)	0.1250
Severance Tax Rate (Fraction)	0.0800
Windfall Profits Tax Rate (Fraction)	0.0000
Income Tax Credit Rate (Fraction)	0.1000
State Income Tax Rate (Fraction)	0.0200
Federal Income Tax Rate (Fraction)	0.4600
Discount Factor	1.2000
Year in Which Sales Begin (Year)	2.0000
Lease Bonus Capital Rate (Fraction)	0.0050
Year After Investment to Begin Depreciation	1.0000
Well Depth (Feet)	5000.
Net Pay Thickness (Feet)	29.0
Well Spacing (Acres/Well)	80.

Capital Costs[1] Per Well

Cost Category	Dollars (1983)
Geological and Geophysical Costs per Well	1,000
Drilling and Completion Costs per Well	112,500
Production and Lease Equipment Costs per Well for a Maximum Gas Production Rate of 90.4 Mcf/day/well	7,500
Stimulation Costs for Borehole Shooting	8,000
Allocated Dry Hole Costs for a 0.000 Dry Hole Rate at 188608.7 per Well for Drilling	0
and 8000.0 per Well for Stimulation	0
Total Investment	129,000

Average Annual Operating Costs per Well

Cost Category (1983)	Dollars
Primary Operating Costs (POC) per Well for an Average Gas Production Rate of 38.1 Mcf/day/well	3,000
Average Annual Operating Cost	3,000

[1] Tangible capital costs include 20% of all drilling and completion costs, and all other capital costs (excluding stimulation). Intangible capital costs include 80% of all drilling and completion costs, all dry hole costs, lease acquisition costs (expended over project life), stimulation costs, and all geological and geophysical costs.

Results indicate that the installation of wells in the area of high flow capacity is the most feasible drilling strategy. For a 20% ROR, the minimum economic gas price was $1.41/Mcf for one well, $2.84/Mcf for three wells, and $3.27/Mcf for the randomly installed wells. An economic analysis was not conducted on production from wells installed in the area of high flow capacity because the 50 x 50 ft wellbore simulation was not reliable. Production values indicate that the wells in the high productivity area would be more economical.

The capital costs and expenses are shown in Table 6. The drilling, completion, and stimulation costs for a vertical well were 30% capitalized and amortized over a 5-year period. Seventy percent of the costs were expended. The dry hole costs were expended; the success ratio used here was 100% to calculate the minimum economic limit. The casing costs were depreciated by a double-declining balance method for 7 years; the total cost was $15,000. The production and exploration equipment costs were depreciated by a double-declining balance method for 7 years; equipment costs were $7,500. Geologic and geophysical costs were expended at $1,000, and the lease bonus costs were capitalized and depreciated by the percentage depletion method and based upon 0.5% of the revenue. Royalty costs were paid out of revenues and merely collected by the owner. The standard royalty rate for the area was 12.5% of the revenues. The primary operating costs, general and administrative costs, and operating overhead costs were expended at $3,000, 10% of the investment, and 20% of the annual and labor costs, respectively.

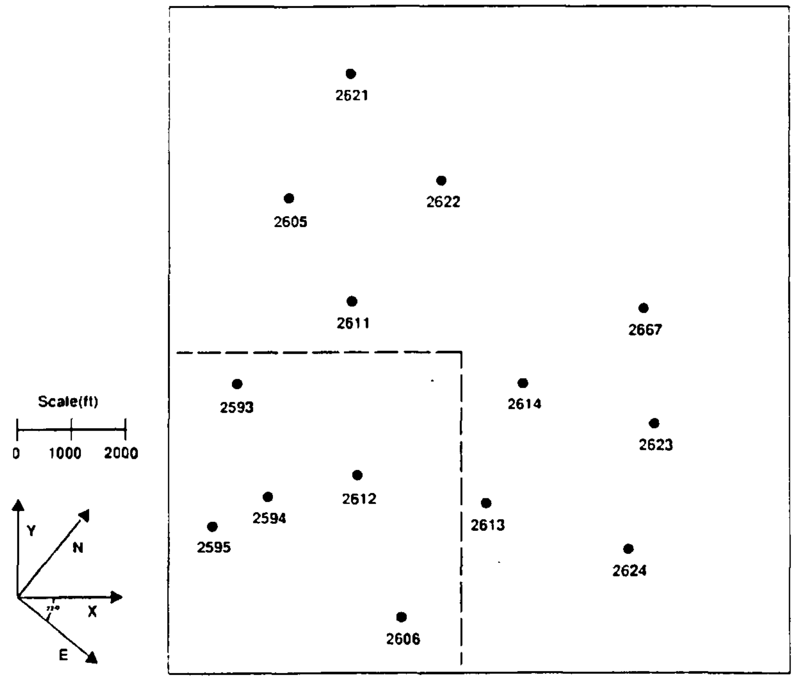

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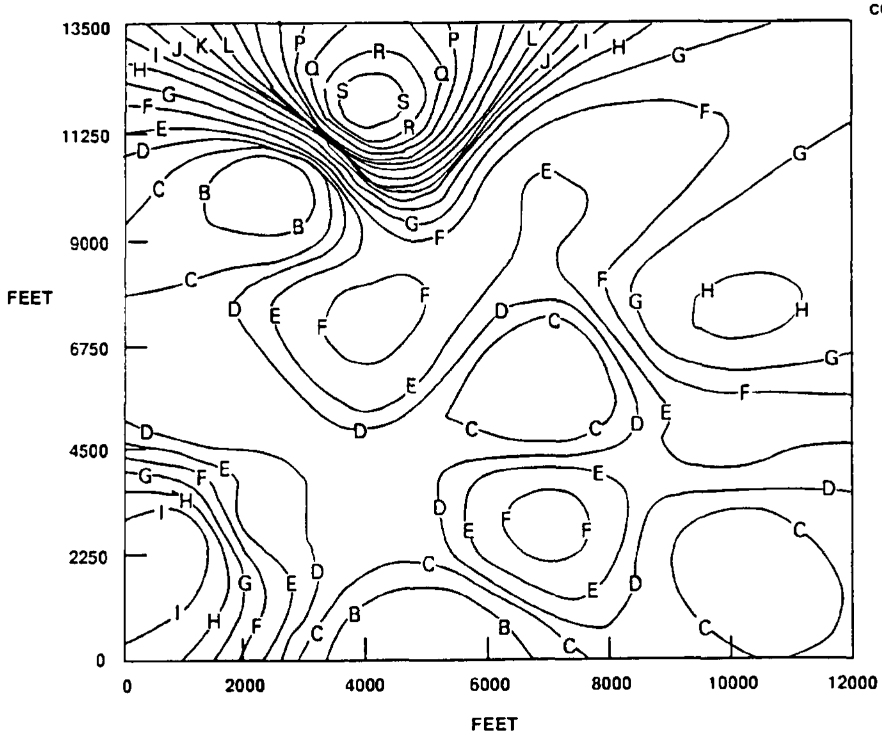
Figure 35. G3DFR Full-Field Grid System



CONTOUR	Z-VALUE/2 (ft)
A	0.4000
B	0.9063
C	1.411
D	1.916
E	2.421
F	2.926
G	3.432
H	3.997
I	4.442
J	4.947
K	6.463
L	5.958
M	5.463
N	6.968
O	7.474
P	7.979
Q	8.484
R	8.989
S	9.496
T	10.00

C87-183-AA TS11

Figure 36. Producing Thickness Contours in Kanawha County

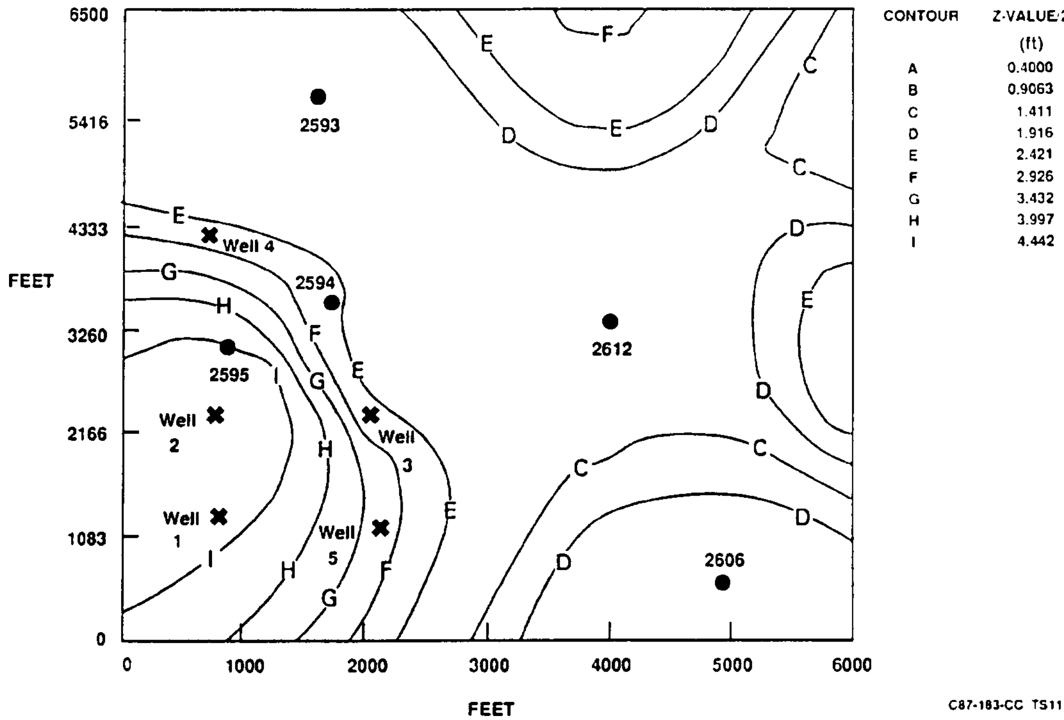


Figure 37. Permeability-Thickness Product Contours in Kanawha County

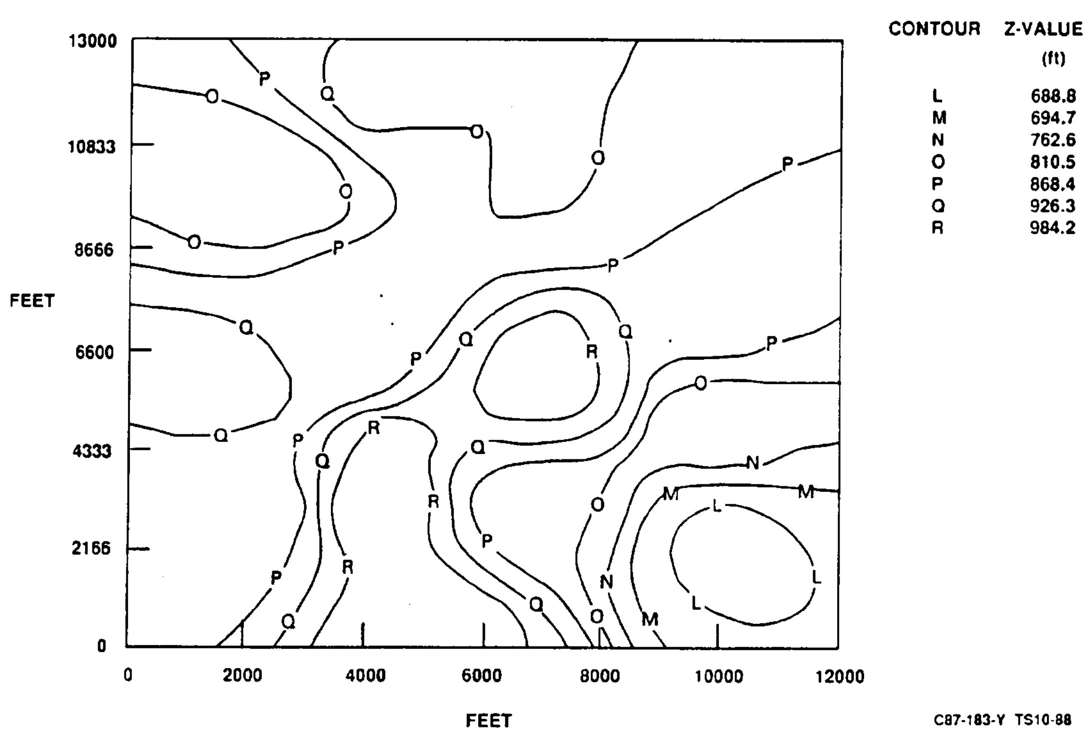


Figure 38. Initial Rock Pressure Contours in Kanawha County

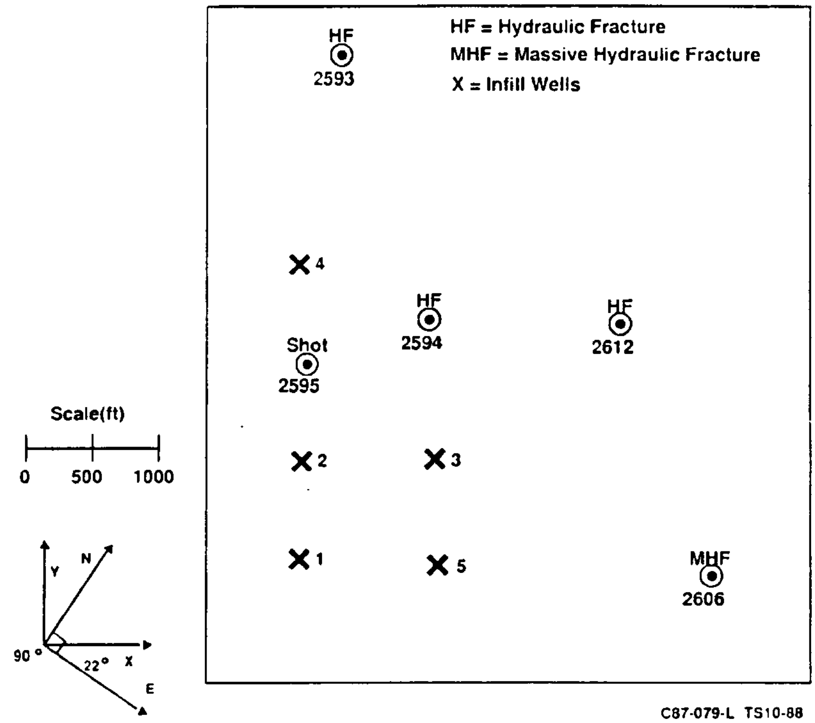


Figure 39. Random or High-Flow Capacity Infill Well Grid

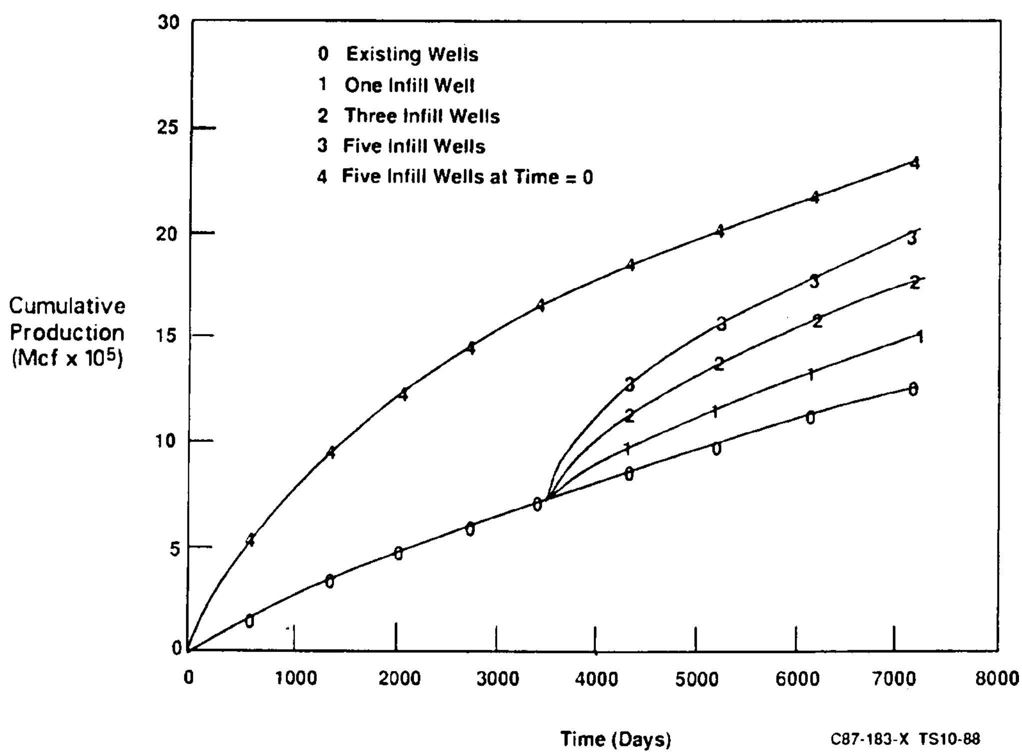


Figure 40. High-Flow Capacity Cumulative Production Results

5.0 PHASE TWO, FULL-FIELD ANALYSIS

The Phase One permeability, thickness, and rock pressure contours were used for Phase Two. Phase Two was carried out as a result of a model evaluation indicating that the PI for both SUGAR-MD and SUGAR-MD and G3DFR was functioning properly. The PI calculations provided a means to assign the correct productivity to each well in the full field according to prior individual stimulation techniques. With 50 x 50 ft grid blocks, the results were not reliable since the productivities of all the wells were identical and probably were similar to large radial fracturing treatments.

5.1 Full-Field History Matching

The full-field existing-well match was repeated with the PI assigned to each well rather than the 50 x 50 ft grid block. The PI value was calculated according to grid-block size, permeability, thickness, and wellbore radius. The fracture wing length corresponded to the cumulative x-direction grid-block length. Induced fracture azimuths were identical to the principal natural fracture orientation as a result of work by Kruuskraa et al. (1985a) and Blanton et al. (1980). Their analyses indicated that the Clendenin Quadrangle fell within an area where natural fracture crossing was not probable, and that natural fractures, induced fractures, and the maximum horizontal stress followed the approximate N 30°E orientation. The five existing wells were then simulated simultaneously for 10 years to complete the full-field history match. The match was completed with one simulation, and the permeability did not have to be changed to match cumulative field production. Also, the individual well matches were correct. This match was then extended an additional 10 years to evaluate the impact of infill wells. The individual full-field existing well productions are shown in Figure 34.

5.2 Infill Well Simulation

As in Phase One, infill wells were placed both randomly and in the high-flow capacity area of the matched full field (Figures 39 and 40). One, three, and five wells were installed and three types of stimulations were analyzed. Shot wells, hydraulic-fracture wells with 150-ft wing lengths, and hydraulic-fracture wells with 300-ft wing lengths were evaluated for the infill wells. The impact of the 4:1 natural-fracture permeability anisotropy was also addressed. When five infill wells were installed in the area of high flow capacity, the 40-acre well spacing and anisotropy effects caused significant interference and a reduction of well productivity. This is shown in Table 7. An evaluation was conducted to determine the impact of two infill wells in this area placed such that anisotropy should not effect their production by maintaining an 80-acre spacing (simulation of only Wells 1 and 3 in Figure 40). Also, three wells were placed in the 160-acre portion in a pattern to avoid anisotropy effects, as shown in Figure 40. Results are shown in Table 8.

Comparing well installation in the random locations versus areas of high flow capacity shows that production potential may be increased substantially

Table 7. Cumulative Production of Simulated Infill Wells With High Flow Capacity

ONE INFILL WELL

Existing Wells (20-Year Production in Mcf)

Well No.	Shot	300-ft Wing Length Hydraulic Fracture	150-ft Wing Length Hydraulic Fracture
2593	157,000	160,000	159,000
2612	173,000	173,000	173,000
2594	412,000	418,000	417,000
2595	81,000	84,000	83,000
2606	251,000	252,000	251,000

Infill Well (10-Year Production in Mcf)

Well No.	Shot	150-ft Wing Length Hydraulic Fracture	300-ft Wing Length Hydraulic Fracture
1	217,000	352,000	387,000

THREE INFILL WELLS

Existing Wells (20-Year Production in Mcf)

Well No.	Shot	150-ft Wing Length Hydraulic Fracture	300-ft Wing Length Hydraulic Fracture
2593	159,000	159,000	159,000
2612	172,000	172,000	172,000
2594	405,000	408,000	411,000
2595	77,000	76,000	79,000
2606	249,000	250,000	250,000

Infill Wells (10-Year Production in Mcf)

Well No.	Shot	150-ft Wing Length Hydraulic Fracture	150-ft Wing Length* Hydraulic Fracture	300-ft Wing Length Hydraulic Fracture
1	175,000	253,000	274,000	283,000
2	127,000	172,000	210,000	158,000
3	194,000	239,000	190,000	261,000

* Well orientation to avoid anisotropy, Wells 2, 1, and 3 (Figure 39).

Table 7. Cumulative Production of Simulated Infill Wells With High Flow Capacity (Continued)

FIVE INFILL WELLS

Existing Wells (20-Year Production in Mcf)

Well No.	300-ft Wing Length Hydraulic Fracture	150-ft Wing Length Hydraulic Fracture	Shot
2593	157,000	156,000	155,000
2612	172,000	172,000	172,000
2594	409,000	405,000	402,000
2595	78,000	75,000	74,000
2606	250,000	250,000	250,000

Infill Wells (10-Year Production in Mcf)

Well No.	Shot	150-ft Wing Length Hydraulic Fracture	300-ft Wing Length Hydraulic Fracture
1	157,000	198,000	215,000
2	114,000	154,000	164,000
3	173,000	208,000	233,000
4	46,000	87,000	113,000
5	143,000	191,000	214,000

Two Infill Wells (Preferred Infill Drilling Pattern in High Flow Capacity Area, Production in Mcf)

Existing Wells	150-ft Wing Length Hydraulic Fracture
2593	159,000
2612	172,000
2594	410,000
2595	77,000
2606	250,000
Infill Wells	
1	332,000
3	335,000

Table 8. Cumulative Production of Simulated Infill Wells With Random Flow Capacity

ONE INFILL WELL

Existing Wells (20-Year Production in Mcf)

Well No.	Shot	150-ft Wing Length Hydraulic Fracture	300-ft Wing Length Hydraulic Fracture
2593	160,000	160,000	157,000
2612	173,000	173,000	173,000
2594	419,000	417,000	413,000
2595	85,000	83,000	81,000
2606	252,000	251,000	251,000

Infill Wells (10-Year Production in Mcf)

Well No.	Shot	150-ft Wing Length Hydraulic Fracture	300-ft Wing Length Hydraulic Fracture
1	218,000	352,000	387,000

THREE INFILL WELLS

Existing Wells (20-Year Production in Mcf)

Well No.	Shot	150-ft Wing Length Hydraulic Fracture	300-ft Wing Length Hydraulic Fracture
2593	155,000	151,000	151,000
2612	172,000	171,000	171,000
2594	412,000	406,000	406,000
2595	82,000	80,000	80,000
2606	252,000	252,000	252,000

Infill Wells (10-Year Production in Mcf)

Well No.	Shot	150-ft Wing Length Hydraulic Fracture	300-ft Wing Length Hydraulic Fracture
1	157,000	369,000	386,000
2	33,000	71,000	100,000
3	44,000	79,000	107,000

Table 8. Cumulative Production of Simulated Infill Wells With Random Flow Capacity (Continued)

FIVE INFILL WELLS

Existing Wells (20-Year Production in Mcf)

Well No.	150-ft Wing Length Hydraulic Fracture	300-ft Wing Length Hydraulic Fracture
2593	146,000	149,000
2612	170,000	171,000
2594	405,000	408,000
2595	79,000	79,000
2606	250,000	251,000

Infill Wells (10-Year Production in Mcf)

Infill Well No.	150-ft Wing Length Hydraulic Fracture	300-ft Wing Length Hydraulic Fracture
1	362,000	380,000
2	63,000	93,000
3	76,000	106,000
4	67,000	102,000
5	94,000	132,000

by using geology to determine well sites. Results indicate that the site with high flow capacity is the preferred area for infill drilling. Although this area is restricted to 160 acres, the installation of two wells in this area would produce more gas than three wells randomly located in the field.

5.3 Economic Analysis

An economic analysis of the Phase Two modeling results was completed with the DGEM code. To evaluate the economic feasibility of infill wells, the results shown in Table 6 were examined.

Again, data shown in Table 6 were used to calculate the economic feasibility of each infill drilling scenario. Columbia Gas, the lease holder of the existing field of wells, uses a desired 20% ROR for a proposed well. This value was held constant in the DGEM data to calculate a required gas price to meet this ROR. In Figures 41 and 42, the required gas price for both random and high-flow-capacity well sites is shown. For each area, gas prices are listed for one, three, and five infill wells with shot, 150-ft wing length, and 300-ft wing length stimulations. As expected, the required gas price is reduced with the more extensive stimulation methods, and a closer well spacing tends to increase the required gas price. In Figure 42, the lowest curve depicts the impact of properly spacing the wells. Two hydraulic fractures with 300-ft wing lengths were simulated in an 80-acre spacing and aligned such that the least amount of interference was likely to occur. Results indicate that a well spacing closer than 80 acres is not feasible for the area. When three wells were simulated, the required gas price increased from $2.00 to $3.00/Mcf. This is because of the interference when well spacing was reduced from 80 to 60 acres.

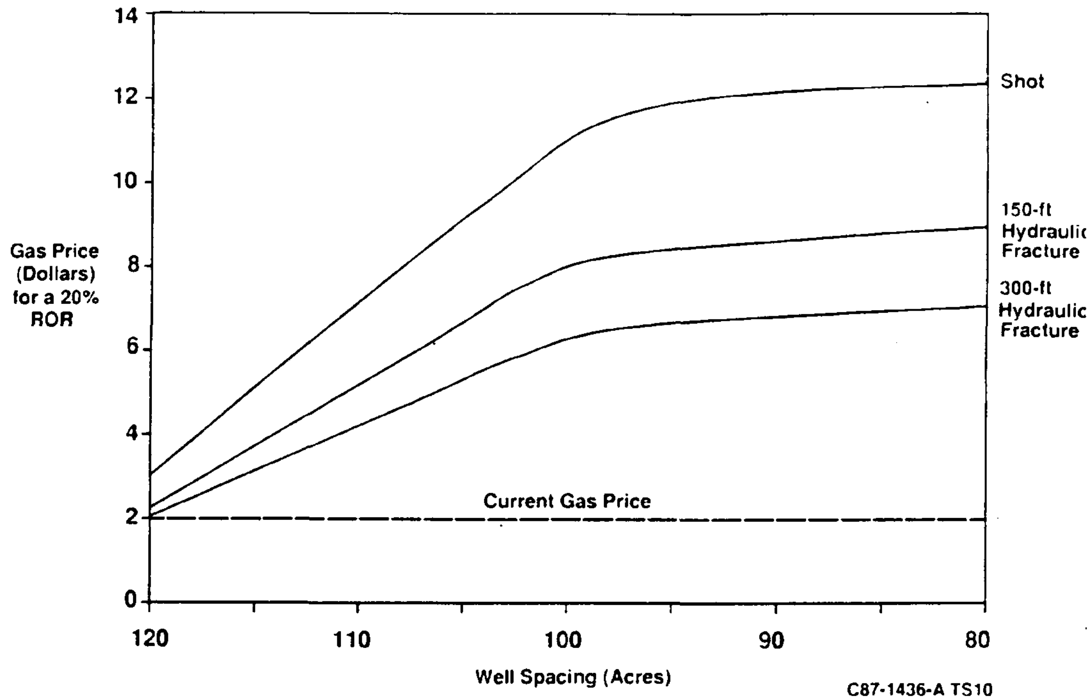


Figure 41. Required Gas Price for a 20-Percent Rate of Return on a Well Site With Random Flow Capacity

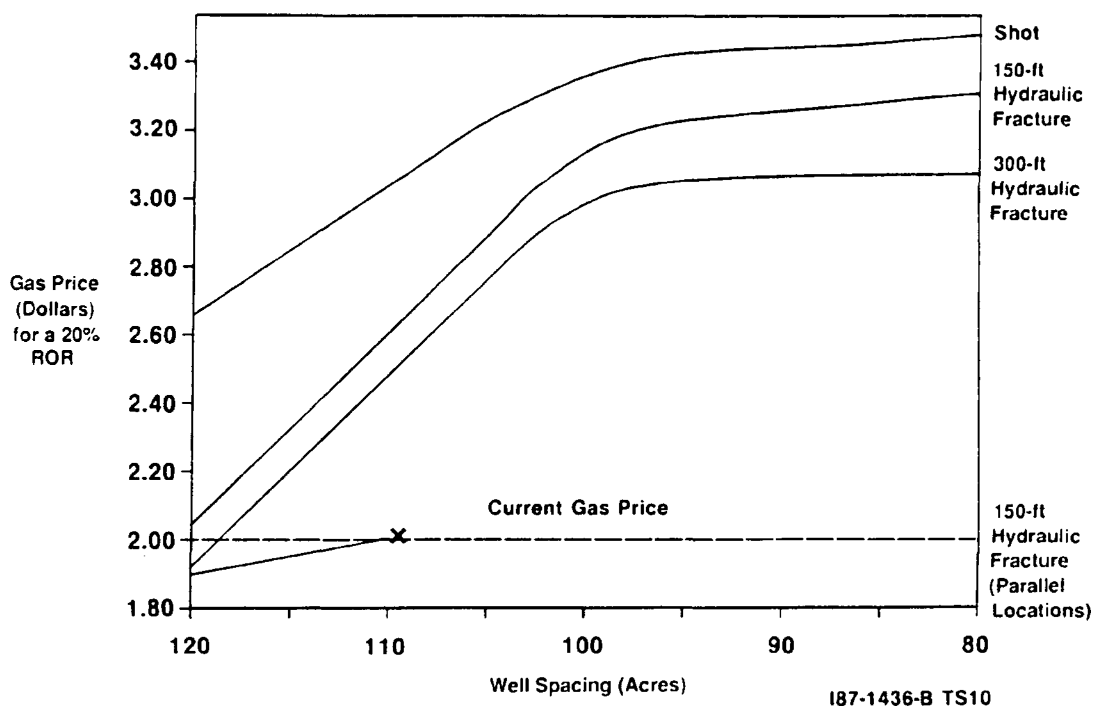


Figure 42. Required Gas Price for a 20-Percent Rate of Return on a Well Site With High Flow Capacity

6.0 DISCUSSION OF RESULTS

Results of the Kanawha County case study indicate that it is imperative to evaluate individual well production when conducting a full-field simulation analysis. The lack of individual well information in previous studies may have caused inaccurate results. In addition, the PI is the preferred option when simulating a field of wells with individual stimulations, and, therefore, producing potentials. The methodology used in Phase One, single-well matching with variable-pressure node and a full-field match with 50 x 50 ft variable-pressure nodes, is not accurate. An invalid prediction of infill well potential occurred because full-field permeability and thickness contours were misrepresented. As depicted in Figures 33 and 34, the full-field cumulative production match using a 50 x 50 ft grid block misrepresented the potential of each well. Hydraulically fractured wells were underproducing while the shot well was overproducing. When the permeability was multiplied by 2.2 to match the full-field cumulative production, the flow capacity of the entire field was increased, not just the capacity in the drainage area of the existing wells. Thus, the characteristics of the formation were adjusted and the stimulation mechanisms or flow enhancements near the wellbores were misrepresented. This posed some problems, including (1) the inaccurate prediction of a drainage pattern because of the lack of hydraulic fracture representation, (2) rapid gas drainage in areas of the field where the flow capacity was not as high as simulated, and (3) overproduction prediction of infill wells when the proper productivity was assigned to those wells. This is verified by the results of the cumulative production match using the full-field PI. To achieve the match, neither permeability nor thickness had to be adjusted. Also, when single well production on a full-field scale was evaluated, each of the wells matched its actual production history. Thus, the full-field representation was accurate, increasing the reliability of the infill drilling analysis.

Results of the infill drilling analysis indicated that well placement in areas of high flow capacity increases gas recovery from the existing field. Tables 7 and 8 indicate that improved stimulation techniques increase the productivity of the wells. However, the Kanawha County stress regime is such that natural fractures are not likely to intersect induced fractures. If intersection were possible, improved stimulation might have made the random wells more productive and economically favorable. Future simulations are planned to evaluate this possibility.

The optimum infill drilling strategy was the selection of two hydraulically fractured wells in the area of high flow capacity. The well pattern is shown in Figure 40, represented by Wells 1 and 3. This scenario was the most productive because of the positive influence of stimulation, the high flow capacity and significant formation thickness, and the lack of well-to-well interference caused by permeability anisotropy and reduced well spacing. These results then indicate that well spacing under 80 acres is not profitable in this area even in the most productive portions of the field. Tables 7 and 8 indicate that some gas is lost from the existing wells when infill wells are added. This is significant in that the infill wells may be productive, but the lost gas caused by interference is counter-productive and is not preferred. These results demonstrate the significance of well spacing and patterns for developing a field with measurable permeability anisotropy.

A few points of interest with regard to reliability of the analysis should be addressed. As previously discussed, the single-well matched producing thicknesses and permeabilities were contoured over the field to predict the impact of infill drilling. These matching parameters were derived from a match of final rock pressures. It is likely that error exists in these pressures, possibly because of human error when the readings were recorded. The probability of this error occurring has not been determined, but it should be acknowledged. The focus is then on finding an explanation that will lend credibility and a satisfactory degree of reliability to the history-matching results.

Previous evaluations have determined that different rock pressure matches for a single well can be achieved with nearly equal values of kh, the product of permeability and thickness. This indicates that if there is an error in the rock pressures, the kh product is probably a reasonable representation of the surrounding productivity of the reservoir. Since this product is used to select productive sites for infill drilling, it is probable that the location has a reasonable degree of reliability. The reliability of the contour remains questionable.

Finally, the hydraulic fracture wing lengths are predicted from high-quality treatment data, yet the geometry may be optimistic or the productivity of the stimulation non-reflective of the treatment because of formation damage. Obviously, there is some reluctance to feel confident in the geometries predicted by the codes. A strategy to reduce this uncertainty is to use data from well test analyses or to history match using fracture length as one of the variables.

This strategy has its limitations. More reliable data are required, such as permeability and post-stimulation pressure build-up or draw-down data. A more effective method should be developed to incorporate the results of a stimulation treatment into the reservoir model so that it can be used as a confident, base-case history-matching parameter.

7.0 CONCLUSIONS AND RECOMMENDATIONS

Results of the infill drilling case study have helped to identify the preferred strategy for increasing gas recovery from Kanawha County, West Virginia. The study determined that well spacing, permeability anisotropy, stimulation techniques, and formation characteristics (permeability and thickness) all have significant impacts on the productivity of an infill drilling venture. Well spacing, anisotropy, and stimulation can have positive effects on field production. However, they can also have detrimental effects by creating interference. This occurs when wells are spaced less than 80 acres apart, are patterned such that hydraulic fractures are tip to tip, or are distributed along the direction of principal permeability. The most productive strategy, then, is to pattern infill wells such that they are distributed perpendicular to the principal permeability direction, and to use a significant hydraulic fracture treatment. Well spacing of less than 80 acres appears to be non-productive. These results support the conclusions derived from the state-wide feasibility study. Infill drilling with 80-acre spacing in Kanawha County, then, remains economically feasible according to current gas prices.

The reliability of modeling can be improved with the proper techniques and input data. Specifically, this study indicates that variable-pressure nodes for individual well matches and then for the full-field simulation cannot be used. If the full-field analysis is completed by representing individual wells with 50 x 50 ft grid blocks from an individual well match, the results are not correct. Well production and field flow capacity are misrepresented. If variable-pressure, 50 x 50 ft grid blocks are to be used in the full-field analysis, then individual well matches should be completed with 50 x 50 ft grid blocks. This maintains consistency from the single to full-field analysis. The most reliable method is the variable-rate node option using the PI. Phases One and Two of this analysis determined that the PI functions properly and that this option provides a consistent transition from individual to full-field analysis. Thus, changes in field permeability are not required to match the full-field cumulative production. Making significant changes in the reservoir permeability to complete a full-field match will result in unreliable predictions when evaluating the impact of infill drilling.

The reliability of a reservoir modeling study is improved as the quality of the data is increased. Unfortunately, large quantities of error-free data in several locations are not available. However, compensations can be made for such errors (e.g., the compensations for rock pressures and wellbore skin factor mentioned earlier). The reliability of the contouring technique used to determine permeability, thickness, and pressure values throughout the reservoir has not been evaluated. This is being studied; however, until this study is completed, the method is more satisfactory than other techniques such as statistical regression. The reliability of the gas desorption isotherm remains questionable. This value was held constant as a base case for all simulations. Currently, only gas content for representative areas is available, and a set of graphic isotherms on how gas desorption takes place as a function of reservoir pressure is not available. Although a parametric study has indicated a significant sensitivity to long-time production history and the desorption isotherm function, modelers are restricted to available data. Obviously, more desorption data are required to improve the results of modeling analysis.

Results of the site specific study in Kanawha County substantiate the conclusions of the hypothetical feasibility study. (See Volume II of this report.) This reflects favorably on the study and lends credibility to the results. However, it should be acknowledged that formation properties do vary in individual reservoirs. These exceptions indicate that the hypothetical study results are not applicable in all cases, but provide a direction for infill drilling ventures in specific geologic partitions, through analysis of formation properties that influence gas production because of reduced well spacing.

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