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Study of Gas Migration From Naval Oil Shale Reserve No. 3 to the Rulison Field

Research Report

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TABLE OF CONTENTS

TABLE OF CONTENTS
(Continued)

LIST OF FIGURES

LIST OF FIGURES
(Continued)

LIST OF TABLES

1.0 EXECUTIVE SUMMARY

The U.S. Department of Energy's (DOE's) Morgantown Energy Technology Center (METC) has conducted a reservoir simulation study and an engineering analysis on gas migration for two tight lenticular sandstone units, the Wasatch Formation and the lenticular portion of the Mesaverde Group, in Garfield County, Colorado. The study quantified potential gas loss through migration from the Naval Oil Shale Reserve (NOSR) No. 3 (Figure 1) to nearby producing wells located in the Rulison Field. It also forecasted production for proposed NOSR No. 3 wells located at previously selected sites, offsetting commercial wells outside the reserve. This study also estimated the potential for gas migration from NOSR No. 3 to the Rulison Field for wells completed in the blanket-like Cozzette and Corcoran sandstones near the bottom of the Mesaverde Group.

For the shallow, lenticular sandstone lenses of the Wasatch Formation, 27 wells were used in the study. (See Figure 2.) The analysis used production data (approximately 50 months for each well) to predict the amount of gas which will be produced at 25 years of operating life. Completion records and geophysical logs were used to calculate reservoir gas-in-place for each lens that was perforated. In the engineering analysis, 15 Wasatch wells near the reserve boundary were used to calculate potential gas loss. About one-half of the wells showed more gas to have been actually produced in 4 years than the calculated original gas-in-place within the lenses connected to the wellbore. This led to the conclusion that either natural fracturing in the shale separating the sandstone lenses established strong lens-to-lens communication, or lenses were connected in clusters. In effect, a lens connected to the wellbore appears to also drain remote lenses. The Wasatch wells showing abnormally high production are clustered just south of the DOE's test well 1XM9 (Figure 2), indicating a strong potential for gas loss through migration from the portion of NOSR No. 3 near 1XM9. The amount of gas loss from the reserve determined in the "worst case" scenario is 3,800 millions of cubic feet (MMCF) in 25 years.

The reservoir simulation study used 27 Wasatch wells to characterize the reservoir properties throughout the study area. This was done by varying certain parameters until a close match between actual and simulated production was obtained and then extrapolating the reservoir parameters over the entire study area. Cumulative production at 25 years was predicted for the six proposed offset wells in the Wasatch. The simulation results showed that four of the six proposed NOSR Wasatch wells would be good producers. The average total cumulative production at 25 years for the six wells was approximately 2,550 MMCF.

For the lenticular portion of the Mesaverde Group, 12 wells were used in the analysis. Approximately 50 months of production data, completion records, and geophysical logs were available for each well. In addition to these data, production data for six nearby Superior Oil Company wells producing from the lenticular Mesaverde were available. The Superior wells had 15 to 21 years production data available for analysis and showed that production lives of at least 15 to 21 years could be anticipated. The analysis of the Superior well data also showed that the production rate of Mesaverde wells in the study area follow a hyperbolic decline and are probably draining small discrete sandstone bodies. Hence, these wells suggest that Mesaverde completions in this area are only producing from lenses that are directly connected to the wellbore. Another contribution of the Superior wells was that they served to confirm the validity

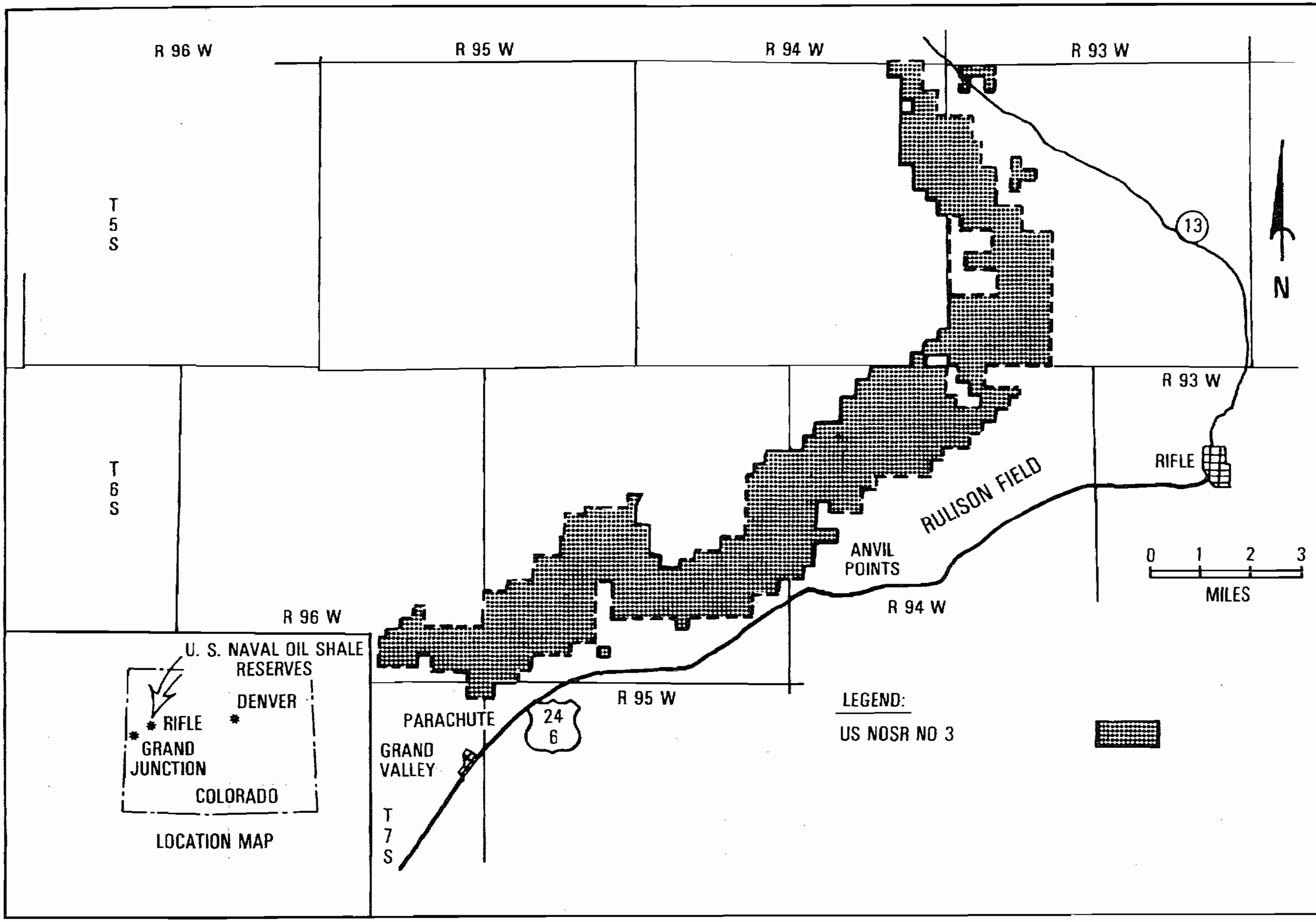

FIGURE 1. GENERAL LOCATION MAP NAVAL OIL SHALE RESERVE NO. 3

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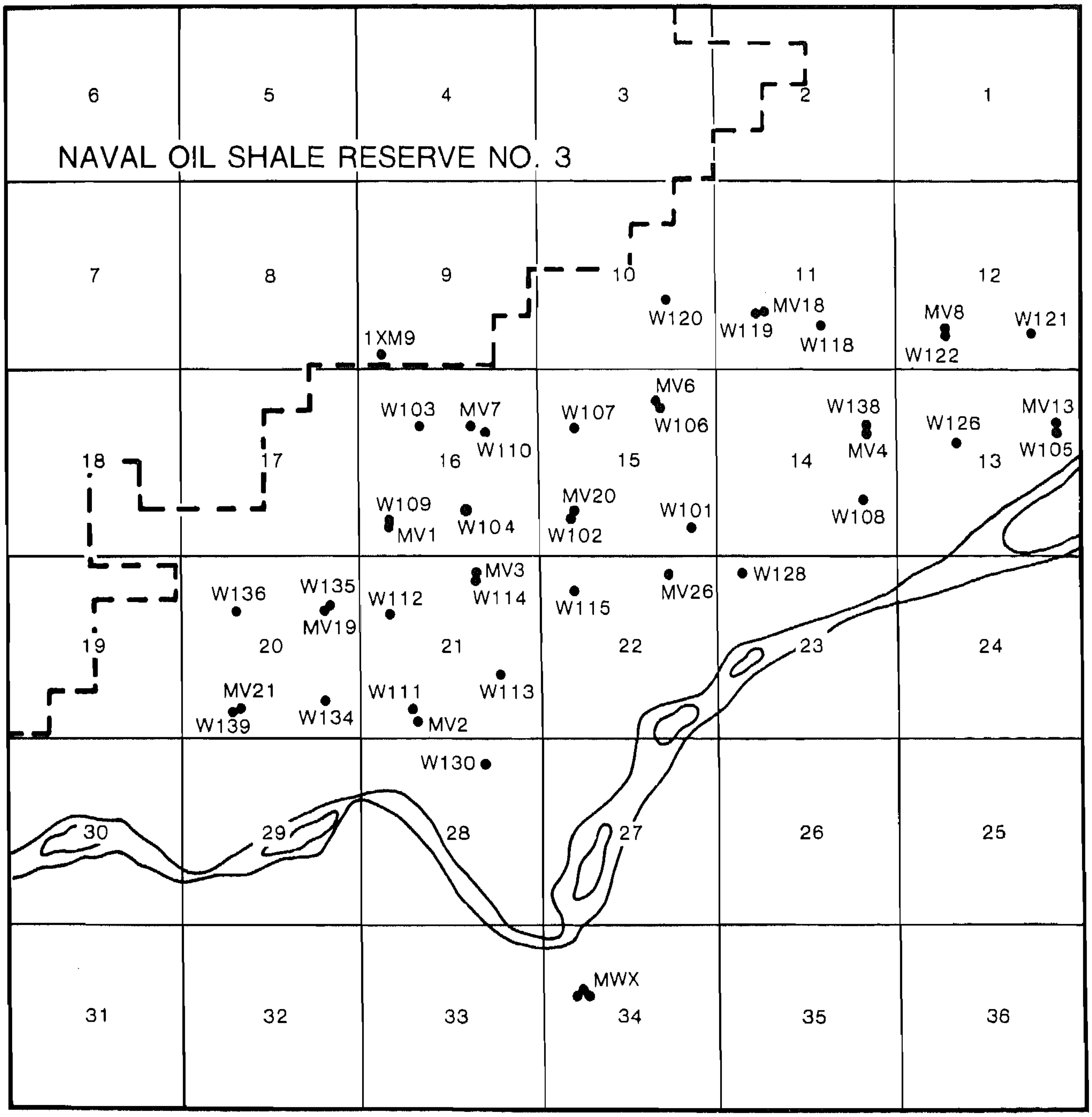

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FIGURE 2. LOCATION MAP OF STUDY AREA TOWNSHIP 6S, RANGE 94W

of the prediction technique used in this study, i.e., basing 25-year production predictions on only 50 months of actual production history.

Six Mesaverde wells near the reserve boundary were used in the engineering calculations for gas loss. The "worst case" scenario showed that only one well was draining gas from across the NOSR No. 3 boundary. The amount of gas migration in 25 years was 56 MMCF. Thus, the potential loss from the lenticular portion of the Mesaverde was shown to be negligible.

Twelve Mesaverde wells were used to characterize the study area for the reservoir simulation study. The predicted 25-year cumulative production for the eight proposed offset wells in the Mesaverde was 9,650 MMCF. Seven of the eight proposed wells were expected to be good producers with a forecasted 25-year cumulative production of approximately 1,000 MMCF or more. The eighth well lies in an area where the predicted production for two of the Wasatch wells was also low, suggesting an area where drilling would not be economically feasible. Although the gas loss through migration to the Mesaverde wells was negligible, the simulation study showed that wells drilled in certain areas of the Mesaverde can be very good producers.

At this time, there are no known wells producing from the blanket Cozzette and Corcoran sands near the NOSR No. 3 boundary. However, data from the DOE Multiwell Experiment (MWX) (a nearby field test site in these formations) was used as input to a reservoir simulator to predict potential gas loss from the reserve if Corcoran/Cozzette wells were located along the study area boundary. This scenario assumed that blanket sandstone reservoir properties measured at MWX were uniform throughout the study area. Since reservoir parameters are known to vary over a given area, this assumption gives results that must be used cautiously. The reservoir simulator showed that significant gas loss through migration to wells located outside the reserve would occur assuming that these wells would be completed on a normal 320-acre spacing. These losses could probably be prevented by locating offset wells on a 320-acre spacing inside NOSR No. 3.

2.0 BACKGROUND

The DOE Office of Naval Petroleum and Oil Shale Reserves (NPOSR) was concerned that a significant gas loss from NOSR No. 3 to nearby producing commercial wells in the Rulison Field could occur through migration across the reserve boundary. The DOE also wanted an estimate of the expected production rate from several proposed offset wells. To answer these questions, the following elements were used in this study: hydraulic fracture treatment and completion records, geophysical logs, a geologic study (Knutson 1985), DOE field test data, approximately 4 years of production data from 39 industry wells in the adjacent Rulison Field, reservoir analysis computer codes, and reservoir engineering calculations.

NOSR No. 3, which is currently undeveloped, borders the Rulison gas field, which is currently under commercial development by Williams Exploration Company (WEC) (which recently acquired Northwest Exploration Company), Superior Oil Company, and others. The gas reservoirs are in Garfield County, Colorado. They specifically consist of two distinct lenticular geologic units, the Wasatch Formation and the upper Mesaverde Group, and two blanket sandstone members of the lower Mesaverde, the Cozzette and Corcoran sandstones. A third member of the lower Mesaverde, the Rollins sandstone, was not included in this study because no data were available on it. Rulison gas wells are typically completed in one of three zones: the Wasatch wells are completed to depths from 1,000 to 3,500 feet, the lenticular portion of the Mesaverde from 5,500 to 8,000 feet, and the blanket portion of the Mesaverde from 8,000 to 9,000 feet.

METC obtained production data from SHELADIA Associates, Inc. of Rockville, Maryland. The data had been compiled for DOE on 28 Wasatch wells and 14 Mesaverde wells that were being produced by WEC near the NOSR No. 3 boundary. Information on 15 of the 28 Wasatch wells and on 6 of the 14 Mesaverde wells that were located very near the NOSR No. 3 boundary was used to calculate the drainage areas of these wells and to quantify potential gas loss from NOSR No. 3. Twenty-seven Wasatch and 12 Mesaverde wells were used to characterize reservoir properties by using a reservoir simulator. The reservoir properties were then used to forecast production for proposed NOSR No. 3 offset wells. MWX provided data for input to a reservoir simulator, which quantified potential gas loss from NOSR No. 3 from the Corcoran and Cozzette blanket sandstones in the Mesaverde Group.

3.0 TECHNICAL BACKGROUND

3.1 LOCATION

NOSR No. 3 lies north of the Colorado River and Interstate Highway 70, between the towns of Parachute and Rifle, in Garfield County, Colorado (Figure 1). The Reserve is somewhat crescent-shaped, bending from a southwest-northeast orientation westward towards a more northerly direction. Grand Junction, Colorado, is about 60 miles to the southwest on I-70. Glenwood Springs is about 30 miles to the east on I-70.

The Reserve consists of 14,130 acres and adjoins NOSR No. 1, which consists of 40,760 acres. The surface topography is rugged, and ranges in elevation from approximately 5,700 feet to over 8,000 feet above sea level.

WEC has been actively developing the Rulison Field, particularly the area in Township 6 South-Range 94 West (T6S-R94W) and somewhat in T6S-R93W and T7S-R94W (Figure 1). Since the NPOSR Office is primarily concerned with the immediate need for offsetting presumed gas migration, the study concentrated on the area designated as T6S-R94W. (See Figure 2.) In this township, the study was particularly focused on Sections 10 to 11, 15 to 16, and 20 to 21.

3.2 FIELD TESTS

The field and laboratory data used in this study were derived from two sites in the Piceance Basin: the No. 1XM9 test well that was recently drilled in NOSR No. 3, and the three test wells at DOE's MWX site. (See Figure 2.) The 1XM9 well was drilled to a total depth of 7,893 feet. It penetrated about 2,500 feet of lenticular reservoir sandstones that alternated with siltstones and shales. The well was also selectively cored over parts of the Mesaverde Group (99 feet of the upper fluvial section and 46 feet of the lower coastal zone). The laboratory analysis of this core provided porosity and permeability data to supplement other calculated values that were derived from log analyses. Along with a suite of field logs, a special televiewer log was run across the Mesaverde, indicating several natural fractures in these reservoir sandstones. The natural fracture data were, in part, replicated by hot-wire gas detector responses recorded during the drilling phase. These drilling, coring, and logging data were later augmented by pre- and post-frac well testing, which consisted of pressure drawdown and buildup cycles. Analyses of these reservoir performance tests provided more data on the production potential of the 1XM9 well.

Even though 1XM9 supplied site-specific reservoir information on the NOSR No. 3 lenticular sandstones, a large portion of the fundamental reservoir, rock, and geologic property inputs that were required by the study came from the MWX site, which is located 3.5 miles south-southeast of 1XM9. The MWX field laboratory has three closely spaced wells forming a triangle that has 140 to 180 feet per side. The wells range in depth from 7,550 to 8,350 feet, and penetrate the entire lenticular portion of the Mesaverde Group, with two of the three wells penetrating the Corcoran and Cozzette blanket sandstones. The goal of this unique field laboratory is to characterize lenticular sandstones and to evaluate stimulation performance in these low permeability reservoirs. In addition to the more than 4,100 feet of core taken at the site, research geophysical log suites and well flow and interference tests have provided an extensive data base of detailed, reservoir characterization and performance characteristics for the Mesaverde. This data base includes the typical lens geometry, permeability and porosity of the reservoir matrix, as well as the reservoir, geologic, and mechanical properties. Because of its proximity to the reserve, data from MWX have been extrapolated to the study area.

3.3 GEOLOGY AND STRUCTURE

The study area is situated in the Rulison Field near the center of the Piceance Basin. The basin is a large structural downwarp with a sedimentary sequence that is more than 20,000 feet thick. The principal gas production in the Rulison Field is from a series of fluvial sandstone lenses of the Tertiary-age Wasatch Formation and Cretaceous-age Williams Fork Formation of the Mesaverde Group. Figure 3 is a schematic northeast-southwest cross section of the geological formations in the Piceance Basin.

The entrapment of gas in both the Wasatch and Mesaverde formations is primarily the result of lithologic discontinuities. Structural closure is not a significant trapping mechanism within the study area. The gas deposit in each formation occurs in an aggregate of hundreds of separate small individual lenses -- discontinuous sandstone bodies that are characterized by very low porosity and extremely low permeability.

Locally, the Wasatch is defined as the rock unit that extends from the Earth's surface down to the top of the Mesaverde. It is of Tertiary age, and both Eocene and Paleocene sediments are probably represented in the defined interval. Lithologically, the Wasatch comprises multiple sandstone lenses in a shale matrix. The sandstones in the Wasatch are usually white, fine- to coarse-grained, conglomeratic, clay-filled, slightly calcareous, and without visual porosity. The shales are very bentonitic and are varicolored red, green, yellow, maroon, and brown.

The Mesaverde Group is defined as the rock unit that extends between the base of the Wasatch Formation down to the top of the continuous Mancos shale. The contact between the Wasatch and Mesaverde is an unconformity with large regional relief but very little local relief. The base of the Mesaverde is a stratigraphic change from continental to marine sediments and is gradational in nature. In the lower portion, marine shales intertongue with the continental shales. The lower portion of the Mesaverde, influenced by marine processes, is more consistent than the upper. Specific rock units have been named in the lower portion and include the Rollins, Cozzette, and Corcoran blanket sandstones.

4.0 FRACTURE SYSTEMS

All of the sandstones of the Mesaverde Group and Wasatch Formation within the study area have very low intergranular (matrix) permeability. Recent MWX studies have shown the effective matrix permeability to be less than 10 microdarcies (Branagan 1985). Special analyses of MWX core indicate a dry permeability of less than 1 microdarcy (Soeder 1984). By comparison, a good conventional sandstone reservoir will have an effective matrix permeability of tens to hundreds of millidarcies, or three to four orders of magnitude higher.

As a result of these very low permeabilities, gas production from these sandstones is highly dependent on enhanced, or secondary, permeability resulting from natural fractures in the sandstones. These naturally occurring fractures, which can increase the effective reservoir permeability to hundreds of microdarcies, are the result of regional and local stress patterns. The orientations of these fracture systems have been identified in both surface (Verbeek and Grout 1983; Lorenz 1985) and subsurface studies (Clark 1983).

4.1 REGIONAL SYSTEM

The regional stress pattern follows the direction of maximum compressive stress. This principal direction has been verified from fracture measurements of oriented core taken at MWX (Figure 4) that showed a preferred orientation of N74°W ±11°. Other fracture trends have been identified from surface joint measurements and from outcrop studies (Knutson 1985; Verbeek and Grout 1984), but these fractures appear to have a limited effect on the deeper formations. In fact, Verbeek and Grout (1984) concluded that surface joint measurements were not good predictors of fractures at depths below 3,300 feet. Thus, the other fracture sets may be significant for shallower Wasatch targets, but will probably not influence production in the deeper Mesaverde. Analysis conducted at METC confirms that there is limited predictive capability using surface joints.

4.2 RESULTS OF MWX FRACTURE STUDIES

The role of natural fractures in production from tight sandstones in the Mesaverde has been recognized for some 20 years (Hollenshead and Pritchard 1960). The MWX study, however, has helped quantify the importance of natural fractures and has provided a better understanding of their occurrence. As a result of the MWX studies, the conceptual model of the tight sandstone reservoirs is a dual-porosity system consisting of a tight matrix that discharges gas to an extensive fracture system. An additional finding of the MWX studies is that the effective permeability of the reservoirs could be anisotropic with a dominant flow direction of N74°W. Original reservoir modeling efforts have used anisotropies ranging from 10 to 200 times that of the orthogonal direction

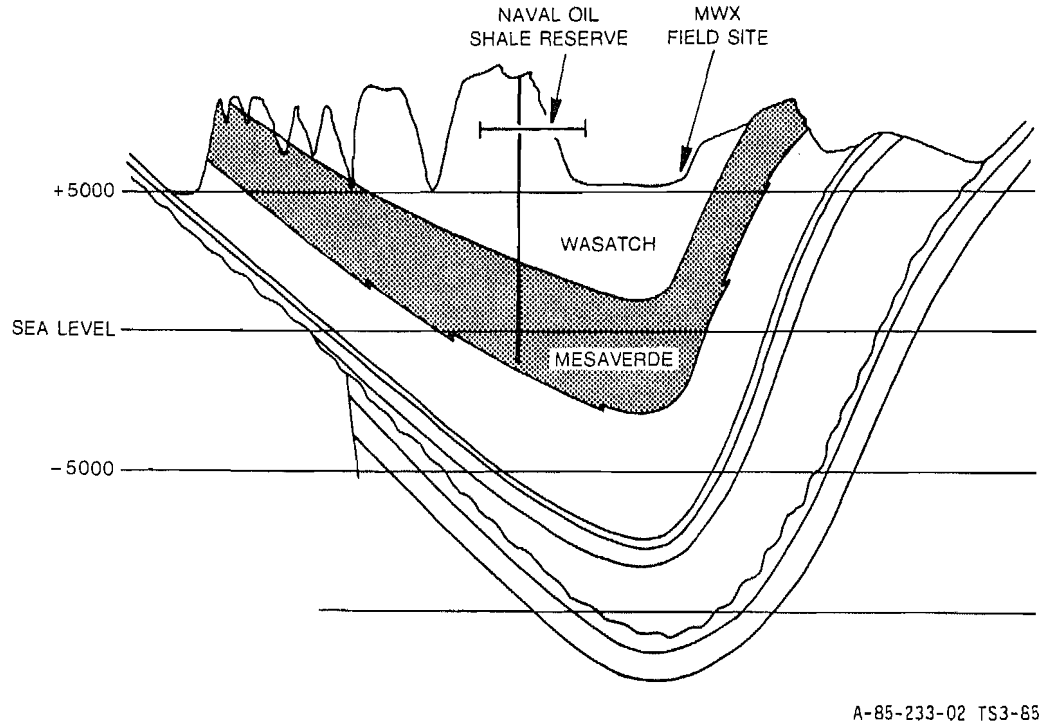


FIGURE 3. SCHEMATIC CROSS SECTION NORTHEAST-SOUTHWEST ACROSS PICEANCE BASIN

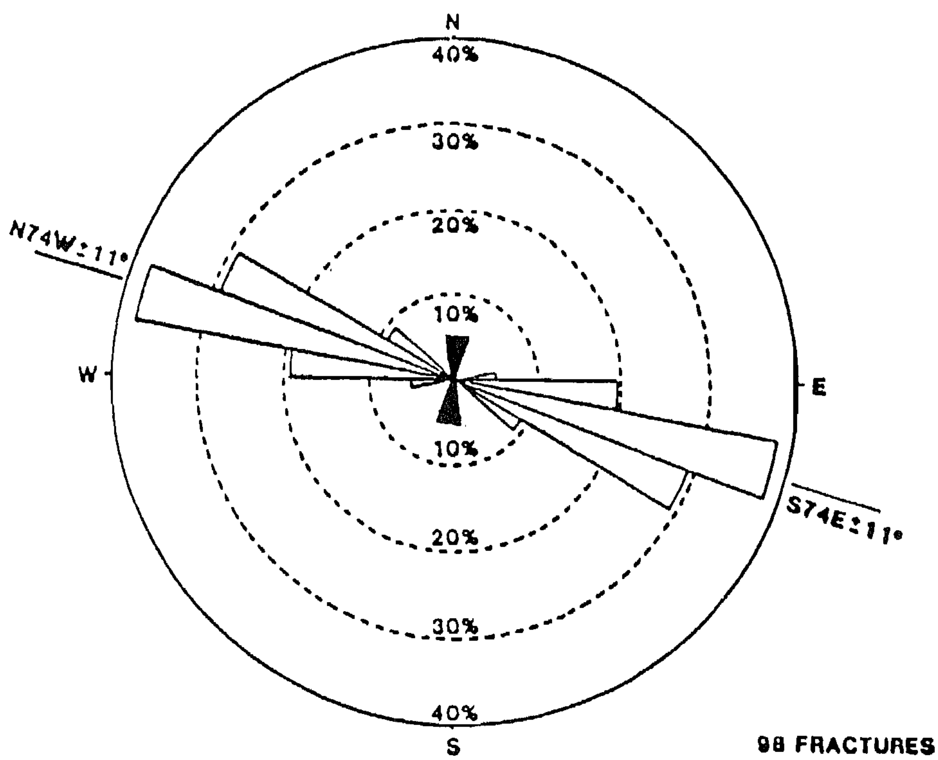


FIGURE 4. ORIENTATION OF NATURAL FRACTURES FROM MWX CORE

(Branagan 1985), however, recent well-to-well interference testing showed no anisotropy at all (Horton 1985).

5.0 GEOLOGIC IMPLICATIONS FOR RESERVOIR PERFORMANCE

For the purpose of estimating reservoir drainage, the implications of the geologic characterization are clear. The sandstone geometries of the Mesaverde Group and Wasatch Formation are, for the most part, bounded lenticular sandstones with little lateral continuity. The blanket sandstones of the marine Iles Formation, the lower part of the Mesaverde Group, are laterally continuous, but exhibit significant lateral variation within the overall blanket deposit. In general, for all of the sandstones of the Mesaverde Group and Wasatch Formation in the study area, owing to the very low matrix permeability, gas migration will probably be controlled by the occurrence and orientation of natural fractures or by effective fractures induced by hydraulic stimulation.

The significance of the high degree of permeability anisotropy is that even blanket sandstones will exhibit an elliptical drainage pattern that is elongated in the preferred drainage direction. Moreover, all other factors being equal, wells located along the preferred drainage direction (N74°W) will have a higher chance for interference than wells located in a line orthogonal to the preferred drainage direction (north-northeast). The west-northwest trending natural fractures will also have a greater effect in overriding the northeast-trending discontinuities in the blanket sandstones.

In nearly all instances, natural fractures are confined to the more brittle sandstones and do not continue through the intervening shale (Knutson; Sattler). This means that the role of natural fractures in connecting nearby sandstone lenses is minimal. Thus, even though natural fractures can exist in zones of high productivity as reported by Peterson (1984), such hot zones do not necessarily suggest that extensive lateral communication is present. In contrast to previous indications, this report identifies a part of the Wasatch where natural fractures are thought to establish communication between lenses.

To illustrate this situation, Figure 5 depicts a hypothetical lens distribution with a marginal preferred northwest orientation. Some lenses communicate by direct lens-to-lens connection (due perhaps to channel migration), but most are discrete reservoirs bounded by the intervening shale. Given an extensive overriding regional fracture system (Figure 6), the lenses could be connected by the fractures and would behave as a blanket sandstone. This could be occurring in part of the Wasatch. However, due to the expected differences in the mechanical properties of the sandstone and the shale, the fracture system will generally be confined to the sandstone lenses, and will result in the system shown in Figure 7. In this last system, the natural fractures will significantly enhance the production of a single lens or lens package. However, even though any well that is drilled into the lenticular sandstones in such an area might be very productive, the probability of well-to-well interference is low. This appears to be the case in the lenticular Mesaverde.

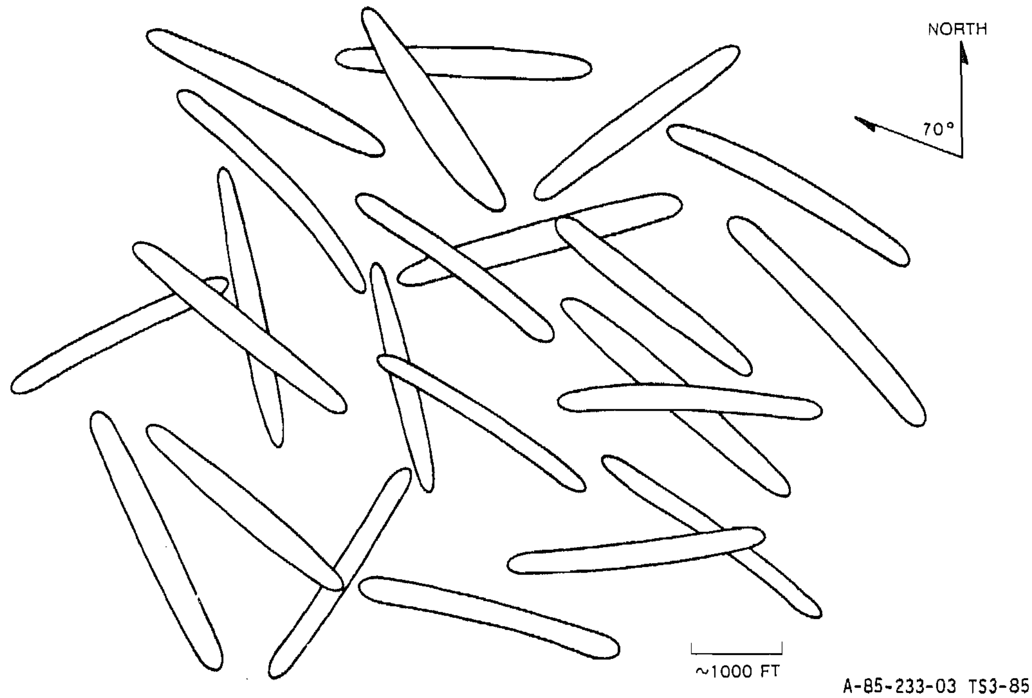


FIGURE 5. DIAGRAM OF LENS TO LENS COMMUNICATION THROUGH SCOURING

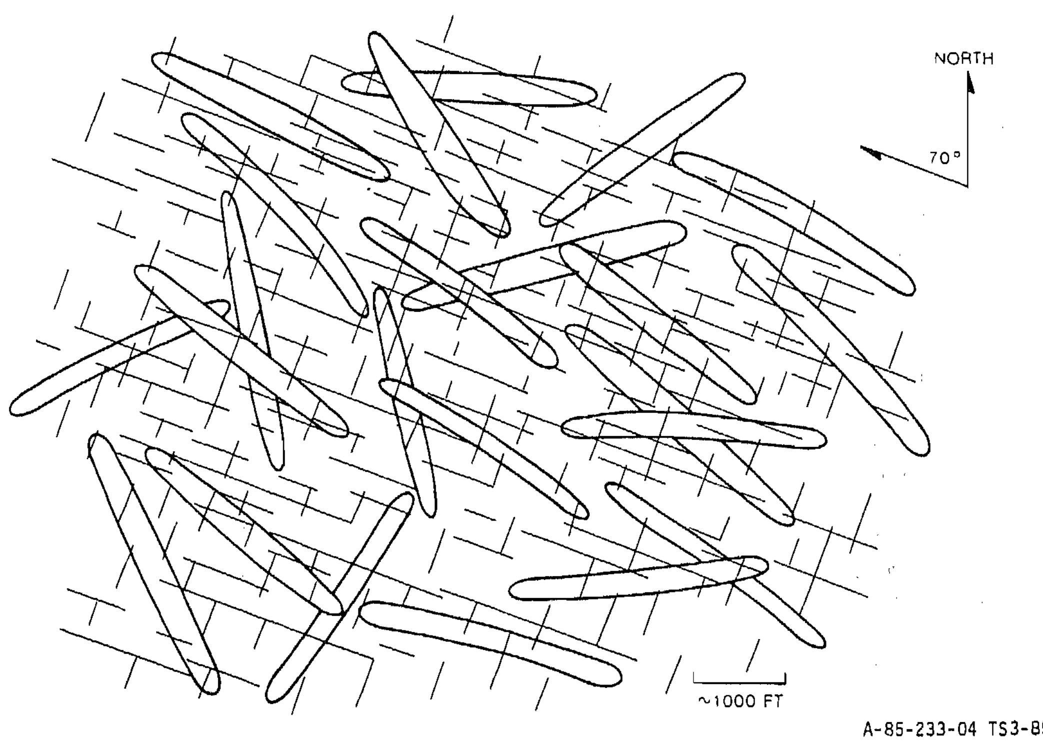


FIGURE 6. DIAGRAM SHOWING COMMUNICATION THROUGH UNCONFINED REGIONAL FRACTURES

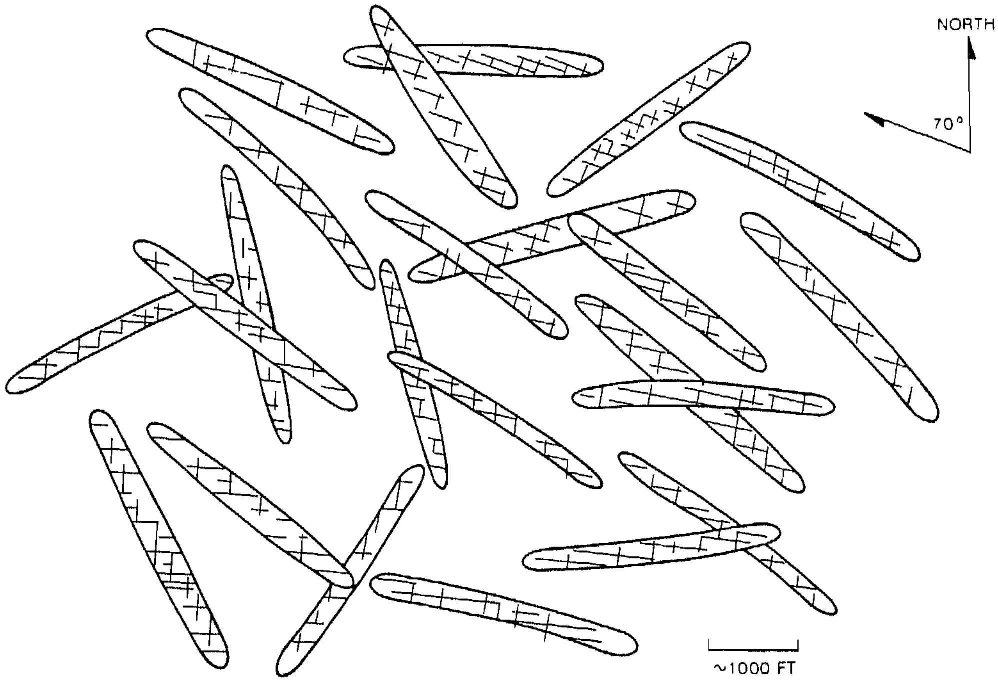


FIGURE 7. DIAGRAM SHOWING ENHANCEMENT DUE TO CONFINED REGIONAL FRACTURES

6.0 RESULTS OF ENGINEERING ANALYSIS

6.1 GAS MIGRATION IN THE BLANKET SANDSTONE PORTION OF THE MESAVERDE

6.1.1 Reservoir Computer 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- or 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 well simulator. For example, it may be used for history matching of well test or production data, studying the effects of dual-porosity (primary/secondary) systems, or forecasting production performance of individual wells. In the rectangular mode, the reservoir may be virtually any shape by use of "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 inputting 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 (Science Applications, Inc. 1983a and 1983b).

6.1.2 Hydraulic Fracture Computer Model Description

OSUFRAC is a general hydraulic fracture model. It predicts the elliptical cross-section width and wing length of a constant height vertical fracture. The induced fracture propagates in a homogeneous elastic medium that is subjected to uniform tectonic stress (stress resulting from changes in the land structure). The one-dimensional fluid flow through the fracture is incompressible (no variation in fluid density) and non-Newtonian (the fluid shear stress is not directly proportional to the fluid deformation). Variable fluid injection rates and proppant transport effects are not included in the fluid mechanics portion of the model.

Finite element formulations are used to predict the hydraulic fracture geometry, stress magnitude at the crack tip, and the fracture fluid leak off to the formation.

Hydraulic fracture fluid properties, static fracture height, total fluid injection rate, treatment time, fracture interval, tectonic stress, and rock properties are required to simulate the fracture geometry. OSUFRAC may be used to design a hydraulic fracture treatment or to determine a post-stimulation fracture geometry. For example, a well's rock and mechanical properties and tectonic stress may be used in the model to select treatment procedures for a desired fracture geometry, or to simulate the geometry of an existing induced fracture from service company treatment reports. Additional information on OSUFRAC is available (Advani and Lee July 1983).

6.1.3 Simulation Results

The reservoir simulator SUGAR-MD was used to predict potential gas migration across the NOSR No. 3/Rulison Field boundary in the deeper blanket sandstones of the Mesaverde. A 33 x 31 finite difference grid covering an area approximately 5.6 miles by 5.6 miles was overlaid on the study area and was oriented with the X-axis in the direction of maximum permeability (~ N70°W). Reservoir properties were taken from the well test analysis that was performed on the blanket sandstones at MWX (Branagan 1985), and were applied uniformly over the study area. In nearly all cases, grid blocks containing wells were kept small (375 feet by 375 feet).

Using the Colorado regulations for spacing (320 acres), 9 wells were located in blocks adjacent to NOSR No. 3. The wells were simulated as flowing for a period of 5 years against a constant wellhead pressure of 550 psi. Within 3 days a noticeable pressure drop was evident in the grid blocks within the reserve adjacent to the Rulison boundary. By the end of the simulation, a reduction in reservoir pressure of nearly 3,000 psi had occurred in the area of NOSR No. 3 adjacent to the boundary, and all parts of the reserve within the study area had experienced a pressure decrease of several hundred psi. This represents a significant drainage volume and a significant potential gas loss from the reserve. It must be recognized that the simulation scenario chosen assumes uniform reservoir properties in the blanket sandstones across the study area. Lorenz (1983) has reported significant lateral variation within the blanket sandstones. However, the preferred orientation of the fracture system (N70°W) will tend to provide fracture conduits across the primary permeability barriers in the blanket sandstones, which are oriented to the northeast.

On the basis of a single point (MWX), it is not possible to evaluate the role of natural fractures in breaching the permeability barriers. Moreover, one commercial well (MV21) completed in the blanket sands was nonproductive and was later plugged back. This may indicate poor completion, or it may attest to the significant degree of lateral variability, or both. However, given the assumption of this simulation that uniform reservoir properties or sufficient fracture enhancement override local variations, there is a potential for significant gas migration across the NOSR No. 3/Rulison boundary, should the Mesaverde blanket sandstones be produced in the Rulison Field.

6.2 GAS MIGRATION IN THE LENTICULAR SANDSTONE PORTION OF THE MESAVERDE

6.2.1 Calculation of Reservoir Size

Six wells located in the Rulison Field near the NOSR No. 3 boundary were studied to estimate the gas loss through migration from NOSR No. 3 as the wells were produced. The wells were MV1, MV3, MV6, MV7, MV18, and MV19 (see Figure 2). MV21, which is also near the boundary, was not used since little production data were available. The first step in the analysis was to determine the size of the reservoir for each well. Gamma ray logs were used to determine gross sandstone thickness for each lens in each well whenever the completion record indicated a perforated interval. A net sandstone thickness was then determined using formation density and/or compensated neutron logs for each previously identified sandstone interval. It was necessary to identify producing sandstones in this manner since the producing reservoir for a well completed in the lenticular portion of the Mesaverde is the sum of several distinct sandstone lenses. Gas in place (GIP) was then calculated for each sandstone lens using the formula:

$$GIP = \frac{h \times w \times l \times \phi \times Sg}{Bg},$$

where

h = lens thickness, feet,

w = lens width, feet,

l = lens length, feet,

ϕ = porosity, fraction,

Sg = 1 - Sw = gas saturation, fraction,

Sw = water saturation, fraction, and

Bg = formation volume factor, R (reservoir) CF/SCF.

A ratio of 1:40:200 (Knutson 1985) was used for the h:w:l ratio. The GIP for each lens was then added to give a GIP for each well. The GIP ranged from 2,430 MMCF for MV19 to 7,900 MMCF for MV3 and is summarized for MV19 in Table 1.

6.2.2 Estimation of Cumulative Production at 25 Years

The next step in the analysis was to predict the cumulative gas production for each well at 25 years. Using available production data, exponential and hyperbolic decline curves were generated for each well. The declines were clearly more hyperbolic in nature than exponential, as illustrated in Figure 8. The hyperbolic declines fit the data reasonably well, as indicated by correlation indices of .90 for MV1, .53 for MV3, .62 for MV6, .39 for MV7, .76 for MV18, and .88 for MV19. A correlation index of 1.0 indicates a perfect fit. A hyperbolic decline was expected since these lenticular reservoirs are known to be naturally fractured (within the lenses); hence, a rapid decrease in production rate during the early years of production (drainage from the natural fractures) followed by an almost constant production rate for the remaining years (drainage from the matrix) was expected. The hyperbolic declines were given by an equation:

$$Q = C_1(C_2 + t)^{-C_3},$$

where

Q = flow rate,

t = time, and

C_1, C_2, and C_3 = constants.

The hyperbolic declines were then used to forecast cumulative production at 25 years. These forecasts ranged from 72 MMCF for MV18 to 1,300 MMCF for MV1. To reduce the uncertainty in forecasting cumulative production at 25 years using only 50 months of actual production data, two independent analyses were performed.

The first independent analysis used production data from six Superior Oil Company wells located near the study area. These wells had production histories ranging from 15 to 21 years and were completed in the lenticular portion of the Mesaverde. Two decline curves were generated for each well, one using the first 48 months of production data and the second using all of the available (15 to 21 years) production data. The forecasted cumulative production figures at 25 years were then compared and the correlation indices were examined. This investigation showed that the forecasted cumulative production values using both long-term and short-term data were in good agreement, and that the hyperbolic decline fit of the data was excellent, as indicated by the correlation indices. This information is summarized in Table 2 and is illustrated for S1GH in Figures 9 and 10. The fact that these wells had 15 to 21 years of production data, and are still producing, also indicated that an expected 25-year life for a lenticular Mesaverde well was reasonable.

TABLE 1. GAS-IN-PLACE AND CUMULATIVE PRODUCTION BY INDIVIDUAL LENSES FOR WELL MV19

GROSS THICKNESS (G.T.) (feet)	NET THICKNESS (feet)	WIDTH 40 x G.T. (feet)	LENGTH 200 x G.T. (feet)	RESERVOIR VOLUME GAS-IN-PLACE (MMCF)	PERCENT CONTRIBUTION OF PRODUCTION	ESTIMATED PRODUCTION AT 25 YEARS (MMCF)
32	5	1,280	6,400	360	14.8	104
26	12	1,040	5,200	570	23.5	165
11	8	440	2,200	70	2.8	20
23	13	920	4,600	485	19.9	140
23	5	920	4,600	185	7.7	55
22	5	880	4,400	170	7.0	50
10	3	400	2,000	20	.8	6
26	12	1,040	5,200	570	23.5	165
TOTAL	155			2,430	100.0	705

Average Depth = 6,745 feet.

Reservoir Temperature = 185°F = 645°R.

Reservoir Pressure = .75 (6,745) = 5,059 psia.

Gas Gravity = .67 => Z = .995, $Bg = \frac{14.7}{520} \left(\frac{.995(645)}{5,059}\right) = .0036$ RCF/SCF.

ϕ = 7 percent, Sw = 55 percent => Sg = 45 percent.

Percent gas produced at 25 years = $\frac{705 \text{ MMCF}}{2,430 \text{ MMCF}} \times 100 = 29$ percent.

TABLE 2. SUPERIOR WELLS DECLINE CURVE ANALYSIS

WELL	DECLINE USING 48 MONTHS OF DATA: CORRELATION INDEX	CUMULATIVE PRODUCTION AT 25 YEARS (MMCF)
S1GH	.78	550
S30-95	.64	170
SJ1F	.37	1,100
S29-95A	.79	790
S3-94	.91	390
S28-95	.69	300

WELL	NO. OF YEARS OF DATA	DECLINE USING ALL PRODUCTION DATA: CORRELATION INDEX	CUMULATIVE PRODUCTION AT 25 YEARS (MMCF)
S1GH	20	.96	640
S30-95	18	.95	100
SJ1F	21	.96	900
S29-95A	16	.83	840
S3-94	15	.85	420
S28-95	19	.99	380

To further reduce the uncertainty of predicting cumulative production to 25 years, a second independent analysis, using both OSUFRAC and SUGAR-MD, was conducted. Using these models allowed the forecasted value to be determined as a function of measured reservoir parameters from MWX and 1XM9. OSUFRAC predicted an induced hydraulic fracture wing length of 309 feet for MV7. This geometry was used as input to SUGAR-MD, along with other significant fixed values: permeability anisotropy ($k_{fx}:k_{fy}$) of 2.747:1, ϕ_m (matrix porosity) = 3.15 percent, k_m (matrix permeability) = .003 millidarcies. Permeability anisotropy was calculated using the fact (established in part by oriented core and well test data from MWX and regional surface geological information) that the sandstone lenses trended east to west, and the natural fractures trended N 70° W, with an estimated anisotropy of 10:1. This gave an effective anisotropy of 2.747:1, where the k_f vector was oriented in the same direction as the trend of the sandstone lenses. ϕ_m and k_m are measured values from cores taken at both MWX and 1XM9. ϕ_m is actually the product of ϕ_m x Sg from core and geophysical log measurements since SUGAR-MD is only a one-phase simulator and a 100 percent saturation must be assumed. Natural fracture permeability k_f and natural fracture porosity ϕ_f were then varied until a good history match of simulated and actual production data was obtained. This history match was determined for both cumulative production data and production rate data for MV7, as shown in Figures 11 and 12. The resulting reservoir model was then run for 25 years and cumulative production at 25 years was calculated. This value was in good agreement with that given by the hyperbolic decline curve for MV7. MV7 was the only Mesaverde well used in this analysis.

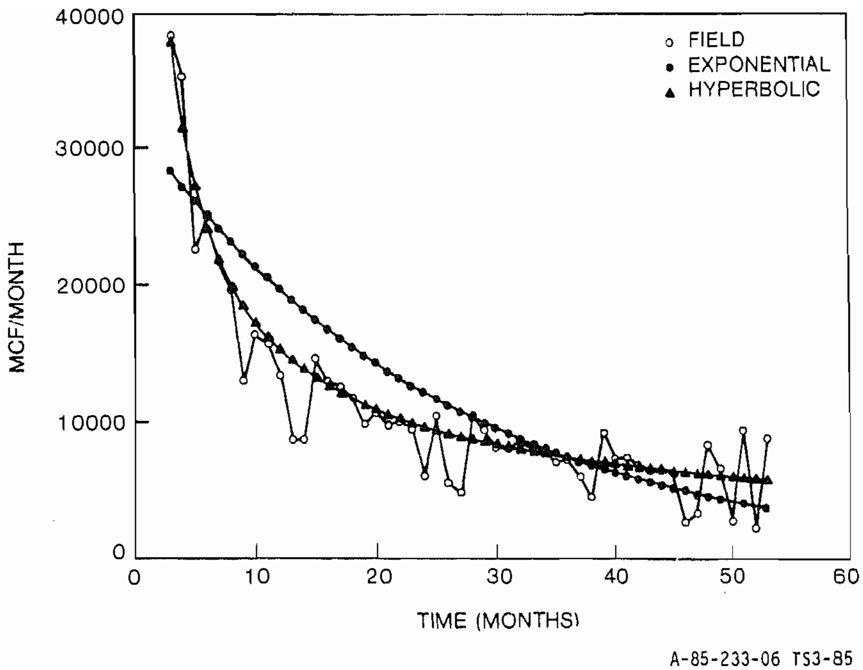


FIGURE 8. TYPICAL MESAVERDE DECLINE CURVE ANALYSIS

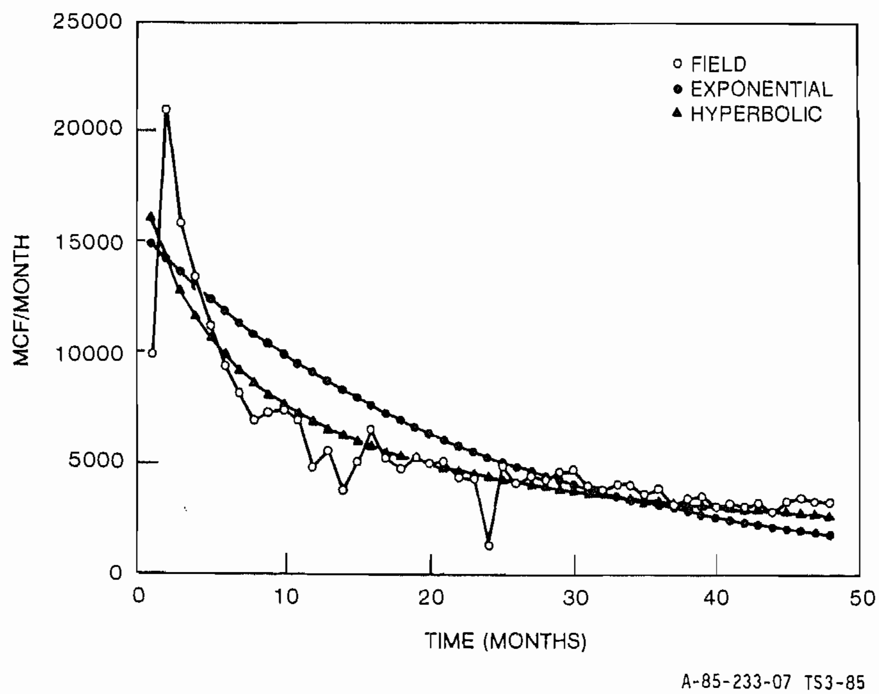


FIGURE 9. DECLINE CURVE ANALYSIS SUPERIOR NO. 1GH (S1GH)

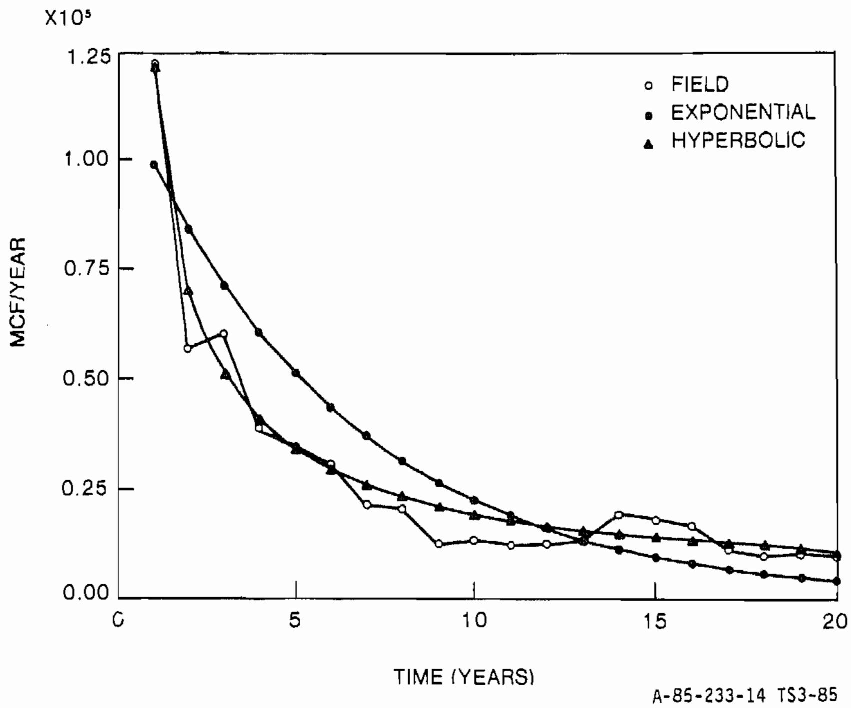


FIGURE 10. DECLINE CURVE PREDICTION SUPERIOR NO. 1GH (S1GH)

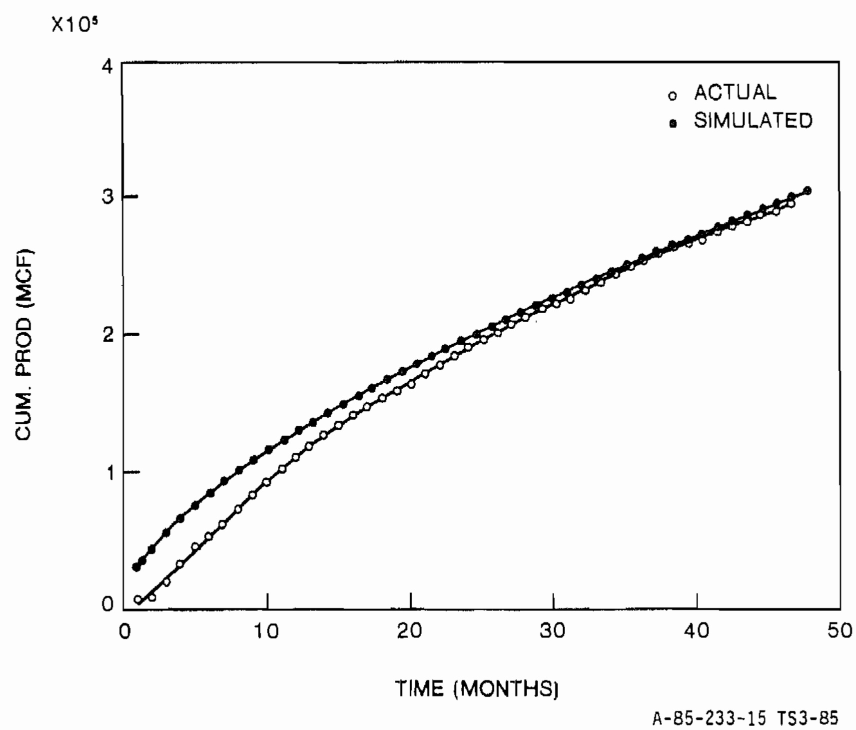


FIGURE 11. MV7 HISTORY MATCH - CUMULATIVE PRODUCTION

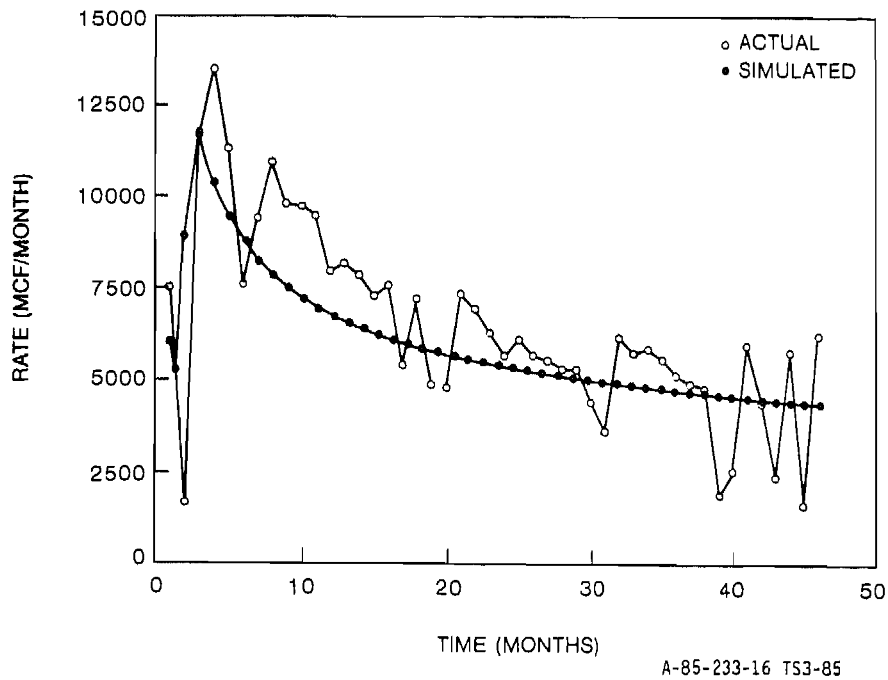


FIGURE 12. MV7 HISTORY MATCH - RATE OF PRODUCTION

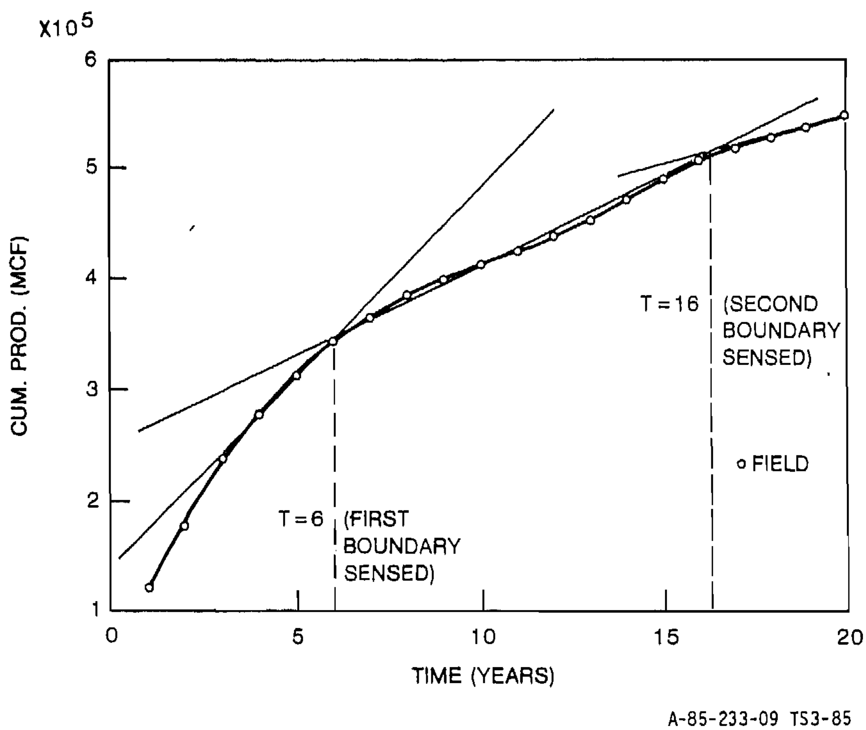


FIGURE 13. CUMULATIVE PRODUCTION ANALYSIS SUPERIOR NO. 1GH (S1GH)

The six Superior wells also offered evidence that lens-to-lens communication generally does not exist for wells completed in the lenticular part of the Mesaverde. The cumulative production versus time plots (an example is given in Figure 13) indicate that a reservoir boundary was reached by a producing well whenever a clear change in slope is detected for lines that go through several consecutive points on the graph. Using this interpretation, some of the Superior wells reached two boundaries. The first boundaries were reached between 4 and 12 years, with second boundary effects seen between 11 and 17.5 years. These observations indicated the Superior wells were probably producing from discrete sandstone units and not from blanket sandstones.

6.2.3 Calculation of Recovery Factor

Recovery factor is the ratio of gas produced to the original gas-in-place and is dependent on reservoir properties such as permeability and pressure. The recovery factors for this study were determined by using a reservoir simulator (SUGAR-MD). The 4-year cumulative gas production of 27 Wasatch and 12 Mesaverde wells were history matched by varying reservoir input parameters until a close agreement between actual production and simulated production was found. The wells were then grouped based on fracture permeability (the dominant input parameter affecting production), and the reservoir properties for wells in each group were averaged. The model was then run for 40 years and a recovery factor was determined. Table 3 shows the recovery factors calculated for the Wasatch and Mesaverde wells.

6.2.4 Areal Extent of Sandstone Lenses and Gas Loss

The next step in the analysis was to estimate the volume of the sandstone lenses that extended across the NOSR No. 3 boundary and the volume of gas loss that was occurring. Distances to the NOSR No. 3 boundary from each existing Mesaverde well were calculated by assuming the sandstone lens orientation to be east-west (Knutson 1985), and also by varying the orientation so the lens intersected the boundary at a sh^rter distance. These distances are given in Table 4. Estimated gas production was determined for each sandstone lens by multiplying the percent contribution of production for the lens by the cumulative production at 25 years as predicted by the decline analysis. These calculations are summarized for MV19 in Table 1.

A drainage length that was necessary to produce this amount of gas was then calculated from the equation:

$$\frac{GP}{RF} = \frac{\bar{I} \times w \times h \times \phi \times Sg}{Bg},$$

where

GP = gas produced, SCF,

RF = recovery factor, fraction, and

$\bar{I}$ = drainage length, feet.

TABLE 3. RECOVERY FACTOR FOR MESAVERDE AND WASATCH WELLS

FORMATION	RECOVERY FACTOR (Percent)	FORMATION	RECOVERY FACTOR (Percent)
Mesaverde		Wasatch	
Group 1	31.5	Group 1	66
MV1 MV2 MV3 MV7 MV19 MV26		W108 W113 W114 W115 W136	
Group 2	7.0	Group 2	65.5
MV4 MV6 MV8 MV13 MV18 MV20		W101 W104 W109 W111 W112 W134	
		Group 3	59.5
		W103 W121 W122 W139	
		Group 4	53
		W102 W107 W118 W119 W138	
		Group 5	48
		W105 W110 W120 W126 W128 W135	

TABLE 4. DISTANCES TO NOSR NO. 3 BOUNDARY FOR THE MESAVERDE WELLS

		DISTANCE WITH VARIATION IN SAND LENS ORIENTATION	
WELL	EAST-WEST DISTANCE (feet)	ORIENTATION VARIATION	DISTANCE (feet)
MV1	8,870	10.4°	3,650
MV3	8,810	18.7°	6,480
MV6	9,980	12.0°	4,810
MV7	5,970	4.4°	4,660
MV18	6,580	12.5°	4,030
MV19	6,810	6.4°	4,190

Three different drainage scenarios of gas migration in the Mesaverde were examined. The first scenario assumed a specified well location within the lenses (the location was chosen so that three-fourths of the lens length extended in the direction of the reserve boundary), and a recovery factor of 25 percent, which was less than the calculated recovery factor (Table 3). This gave a "worst case" scenario (maximum migration potential) for gas migration from NOSR No. 3. The analysis showed that only one well, MV19, was draining gas from across the reserve boundary. MV19 showed a total drainage of 56 MMCF in 25 years. The drainage calculations are summarized for MV19 in Table 5. The second scenario assumed the same well location as the first scenario, however, a recovery factor of 31.5 percent, which was determined by reservoir simulation, was used. This analysis showed that MV19 was only draining 2 MMCF of gas from NOSR No. 3 at 25 years. The third scenario assumed a well location at the center of the lenses. This scenario showed no migration from the Mesaverde using either recovery factor. All three analyses showed that no significant drainage would occur from NOSR No. 3 to producing Mesaverde wells in the Rulison Field. Table 6 shows a summary of the gas loss and area drained for the Mesaverde wells for the three scenarios investigated.

6.3 GAS MIGRATION IN THE WASATCH

6.3.1 Calculation of Reservoir Size

The methodology used to determine reservoir size for the Mesaverde wells was also used to determine reservoir size for 15 Wasatch wells near the NOSR No. 3 boundary: W102, W103, W104, W107, W109, W110, W112, W114, W118, W119, W120, W134, W135, W136, and W139. (See Figure 2.) Well W106 could not be used since little production data were available. The ratio of h:w:l used for the Wasatch wells was 1:15:150 (Knutson 1985). GIP ranged from 41 MMCF for W136 to 331 MMCF for W114, and is summarized for W109 and W120 in Tables 7 and 8.

6.3.2 Estimation of Cumulative Production at 10 and 25 Years

For each of the 15 Wasatch wells, decline curves were generated from approximately 50 months of actual production data, and gas produced at 10 and 25 years was forecast. The declines were again more hyperbolic than exponential and are shown for W109 and W120 in Figures 14 and 15. Gas produced at 10 years ranged from 64 MMCF for W110 to 1,020 MMCF for W114; at 25 years the range was from 98 MMCF for W135 to 1,700 MMCF from W114. The correlation indices for the hyperbolic decline for the Wasatch wells were near 0.6, showing a fair fit to the real production data. Again, there was a problem of predicting production values at 10 and 25 years from only 50 months of actual data. To reduce the uncertainty in these numbers, two investigations were conducted. In the first investigation, four additional wells found near the Rulison Field that were producing from the Wasatch were used. These wells had approximately 10 years of production history and provided a level of confidence in predicting at least 10 years of production life for the Wasatch wells. In the second investigation, OSUFRAC and SUGAR-MD were used to predict cumulative gas produced at 10 and 25 years. Again, using these models provided an independent calculation and also made use of measured reservoir parameters, log data, and hydraulic fracture treatment data. The models were used only on well W120, and the production output from history matching agreed very well with the production numbers from the decline curves. At 10 years, the decline curve for

TABLE 5. POTENTIAL DRAINAGE TO MV19, "WORST CASE" SCENARIO

LENS	DRAINAGE LENGTH (feet)	WIDTH (feet)	3/4 LENS LENGTH (feet)	LENGTH OF LENS (feet) OVER BOUNDARY	POTENTIAL GAS DRAINAGE FROM NOSR NO. 3 AT 25 YEARS (MMCF)
1	7,470	1,280	1,600	1,680	23
2	6,070	1,040	1,300	580	16
3	2,570	440	550	0	0
4	5,370	920	1,150	30	0.7
5	5,370	920	1,150	30	0.3
6	5,130	880	1,100	0	0
7	2,340	400	500	0	0
8	6,070	1,040	1,300	580	16
				TOTAL	56

RF = Recovery Factor = 25 percent.

Anisotropy = 2.747.

$$\frac{GP}{RF} = \frac{\text{Gas Produced}}{\text{Recovery Factor}} = \frac{\bar{l} \times w \times h \times \phi \times Sg}{Bg}$$

Distances From Boundary

6,810 feet E-W.
4,190 feet at 10.4° Orientation.

TABLE 6. CUMULATIVE POTENTIAL GAS DRAINAGE FROM NOSR NO. 3 AT 25 YEARS (MESAVERDE FORMATION)

	AREA DRAINED (Acres)	GAS LOSS (MMCF)
Scenario One "Worst Case"	49	56
Scenario Two	4	2
Scenario Three	0	0

W120 showed a cumulative production of 96 MMCF and SUGAR-MD predicted 100 MMCF, while at 25 years the decline curve predicted a cumulative production of 150 MMCG and SUGAR-MD predicted a value of 190 MMCF. The analysis clearly showed that the 15 Wasatch wells were expected to produce for at least 10 years, and the gas production predicted by the decline curves was reasonable. The upper limit of 25 years for the lifespan of the Wasatch wells was chosen so that a comparison could be made with the Mesaverde wells.

6.3.3 Connectivity of Sandstone Lenses

The Wasatch wells were divided into two groups (A and B) based on approximately 50 months of production data. Each Group A well showed a 4-year cumulative production of less than 100,000 MCF, while each Group B well showed a 4-year cumulative production between 100,000 MCF and 500,000 MCF (see Figure 16). The Group A wells were W102, W107, W110, W118, W119, W120, and W135. This grouping of wells by 4-year cumulative production also partitioned the wells geographically. All the wells in Group A were located in or near Sections 10, 11, and 15 (except W135), and all the wells in Group B were located in Sections 16, 20, and 21 (Figure 16). Further study of cumulative production showed that virtually all of the wells in Group B had actual cumulative gas production at 4 years greater than the calculated GIP, while virtually all the Group A wells had a 4-year cumulative gas production of less than the calculated GIP. There was only one exception in both instances.

It was also observed that gas produced at 25 years, as predicted by the decline analysis, exceeded calculated GIP for all the Wasatch wells except W120 and W135. These analyses clearly showed that some mechanism was providing lens-to-lens communication, especially for Wasatch wells in Sections 15, 16, 20, and 21. This suggested an area probably having a high fracture density in the materials separating the sandstone lenses, or an area of higher sand content where there are lenses that are joined in clusters (lenses in direct sand-to-sand contact). It is hypothesized that this fracturing yields good communication between the lenses, and creates reservoir behavior similar to that of a blanket sandstone. Figure 17 shows an anticlinal structure, with the axis of the system running directly through the cluster of highly productive wells.

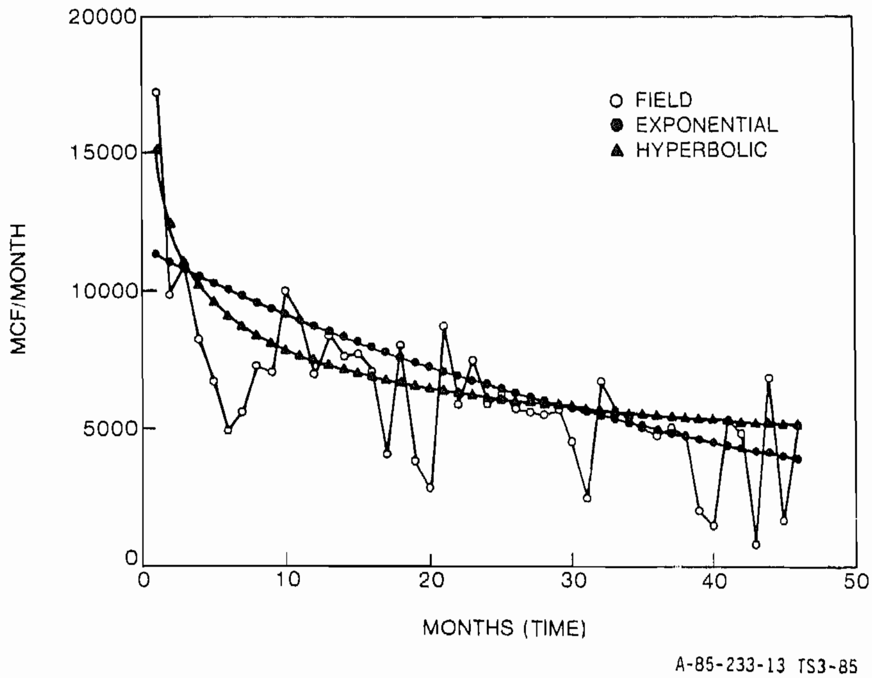


FIGURE 14. DECLINE CURVE ANALYSIS WASATCH NO. 109 (W109)

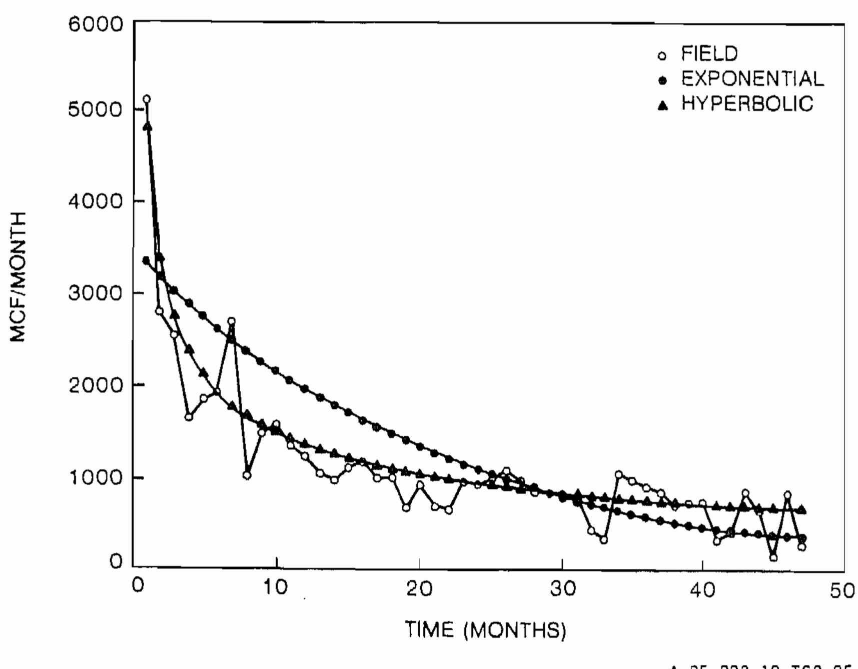


FIGURE 15. DECLINE CURVE ANALYSIS WASATCH NO. 120 (W120)

TABLE 7. GAS-IN-PLACE AND CUMULATIVE PRODUCTION BY INDIVIDUAL LENSES FOR WELL W120

GROSS THICKNESS (G.T.) (feet)	NET THICKNESS (feet)	WIDTH 15 x G.T. (feet)	LENGTH 150 x G.T. (feet)	RESERVOIR VOLUME GAS-IN-PLACE (MMCF)	PERCENT CONTRIBUTION OF PRODUCTION	ESTIMATED PRODUCTION AT 10 YEARS (MMCF)	ESTIMATED PRODUCTION AT 25 YEARS (MMCF)
28	18	420	4,200	103	41.5	39	64
11	4	165	1,650	4	1.4	1	2
21	15	315	3,150	49	19.4	19	30
4	2	60	600	0.2	0.1	0.1	0.1
17	7	255	2,550	15	5.9	6	9
18	5	270	2,700	12	4.8	5	7
12	10	180	1,800	11	4.2	4	7
22	12	330	3,300	43	17.1	16	26
6	5	90	900	1	0.5	0.5	0.8
6	5	90	900	1	0.5	0.5	0.8
16	6	240	2,400	11	4.5	4	7
TOTAL	89			250	100.0	95	154

Average Depth = 3,863.

Reservoir Temperature = 127°F = 587°R.

Reservoir Pressure = .40 (3,863) = 1,545 psia.

Gas Gravity = .61 => Z = .860, $Bg = \frac{14.7}{520} \left(\frac{.860(587)}{1,545}\right) = .0092$ RCF/SCF

ϕ = 7 percent, Sw = 57 percent => Sg = 43 percent.

Percent gas produced at 10 years = $\frac{95 \text{ MMCF}}{250 \text{ MMCF}} \times 100 = 38$ percent.

Percent gas produced at 25 years = $\frac{154 \text{ MMCF}}{250 \text{ MMCF}} \times 100 = 62$ percent.

TABLE 8. GAS-IN-PLACE AND CUMULATIVE PRODUCTION BY INDIVIDUAL LENSES FOR WELL W109

GROSS THICKNESS (G.T.) (feet)	NET THICKNESS (feet)	WIDTH 15 x G.T. (feet)	LENGTH 150 x G.T. (feet)	RESERVOIR VOLUME GAS-IN-PLACE (MMCF)	PERCENT CONTRIBUTION OF PRODUCTION	ESTIMATED PRODUCTION AT 10 YEARS (MMCF)	ESTIMATED PRODUCTION AT 25 YEARS (MMCF)
14	12	210	2,100	13	6.3	39	77
26	22	390	3,900	83	39.9	250	490
7	7	105	1,050	2	1.1	7	13
18	15	220	2,700	27	13.0	82	160
21	17	315	3,150	42	20.1	130	250
10	7	150	1,500	4	1.9	12	23
13	9	195	1,950	8	4.1	26	50
8	8	120	1,200	3	1.4	9	17
18	11	270	2,200	20	9.6	60	120
10	10	150	1,500	6	2.7	17	33
TOTAL	118			208	100.0	632	1,200

Average Depth = 2,474.

Reservoir Temperature = 90°F = 550°R.

Reservoir Pressure = .40 (2,474) = 989 psia.

Gas Gravity = .61 => Z = .77, $Bg = \frac{14.7}{520} \left(\frac{.77(550)}{989}\right) = .012$ RCF/SCF.

ϕ = 7 percent, Sw = 57 percent => Sg = 43 percent.

Percent gas produced at 10 years = $\frac{632 \text{ MMCF}}{208 \text{ MMCF}}$ = 300 percent.

Percent gas produced at 25 years = $\frac{1,200 \text{ MMCF}}{208 \text{ MMCF}}$ = 580 percent.

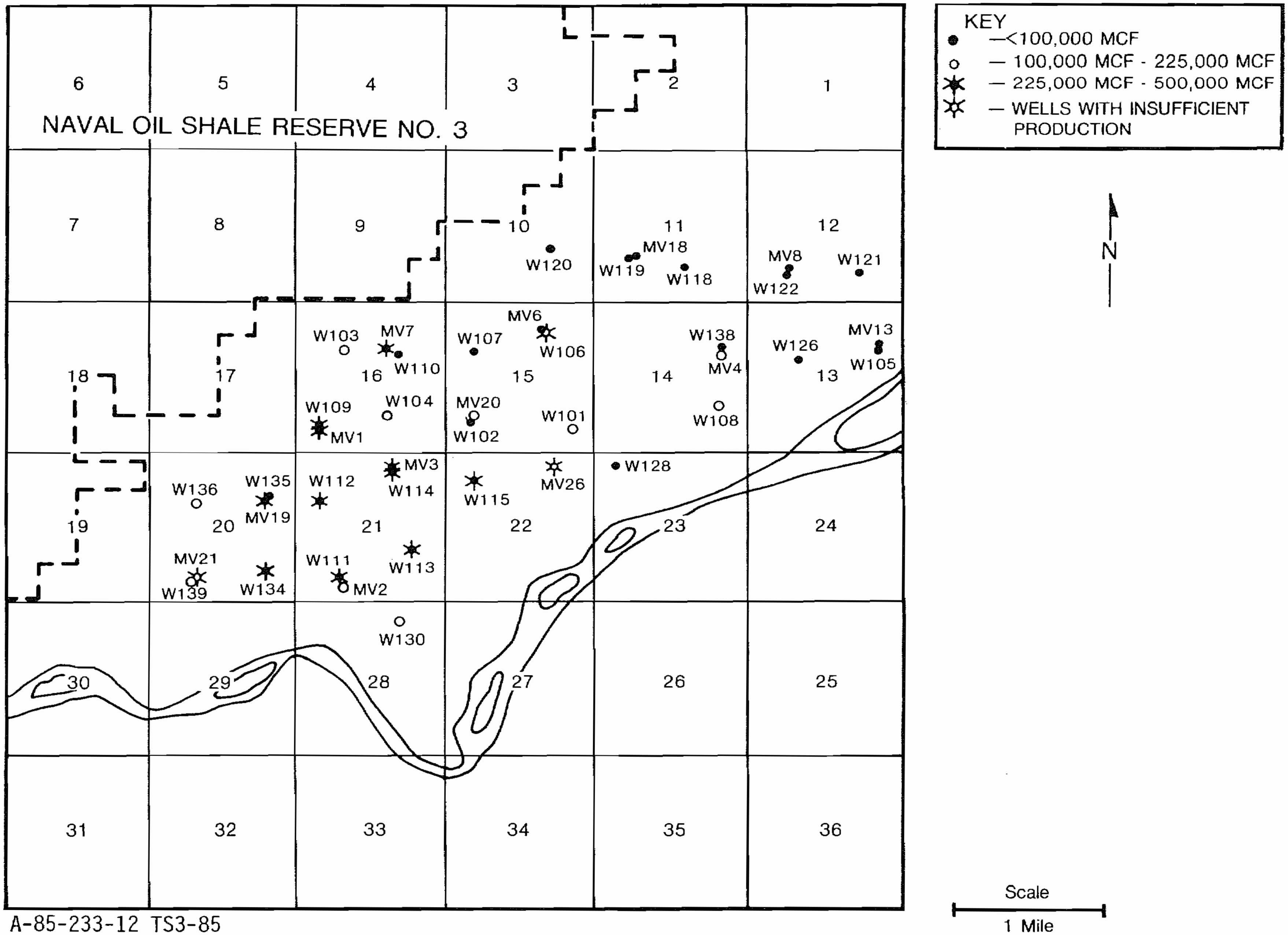


FIGURE 16. FOUR-YEAR CUMULATIVE PRODUCTION FOR WASATCH AND MESAVERDE WELLS

This system offers an explanation for the actual gas produced at 4 years exceeding the GIP. This anticline extends through Sections 4, 5, 6, 7, 8, 9, 17, and 18 in NOSR No. 3, and indicates that these areas have a high potential for gas loss through migration as WEC continues producing their wells in the Rulison Field.

6.3.4 Estimation of Gas Loss Through Migration

The distance from each of the 15 Wasatch wells to the NOSR No. 3 boundary in a N45°W direction (Knutson 1985) was calculated and these distances are summarized in Table 9. No variation in orientation was assumed for the Wasatch since a 10° variation in lens orientation yielded only a very small change in distance.

Gas production for each lens was calculated by multiplying the percent contribution of production for the lens by the cumulative production at 25 years, as predicted by the decline analysis (see Tables 7 and 8). A drainage length was then calculated from the equation

$$\frac{GP}{RF} = \frac{\bar{l} \times w \times h \times \phi \times Sg}{Bg} \quad .$$

Gas migration from the reserve to wells producing in the Wasatch was calculated for three drainage scenarios. The first scenario assumed that the lenses in the Wasatch were connected through lens-to-lens contact. The well was located such that three-fourths of the length of this lens package was extended in the direction of the reserve. The drainage width was assumed to be twice that of the original lens width (to account for variation in lens orientation), and a recovery factor of 50 percent was used. These assumptions gave a "worst case" scenario for gas migration from the Wasatch. Tables 10 and 11 summarize these calculations for W109 and W120 for gas drainage at 25 years. Group A wells showed a total drainage of 150 MMCF at 10 years and 500 MMCF at 25 years. Group B wells showed a total drainage of 1,290 MMCF at 10 years and 3,310 MMCF at 25 years. The total for the Wasatch Formation was 1,440 MMCF at 10 years and 3,810 MMCF at 25 years.

The second scenario also assumed an elongated drainage pattern with two times the original lenses width; however, the well was located in the center of the lens package. This scenario could also represent drainage from lenses that were connected by a natural fracture network. In this network, drainage was occurring in an ellipitical pattern according to anisotropy, which was restricted in the width direction due to the absence of fractures. The recovery factors used for this scenario were those calculated through reservoir simulation (Table 3). The total drainage for Group A wells was only 30 MMCF at 25 years, and the total drainage for Group B wells was 160 MMCF at 10 years and 1,140 MMCF at 25 years.

The last scenario assumed no boundary restrictions in any direction, and that drainage occurred in an elliptical pattern according to the anisotropy. In this case, no drainage occurred. Table 12 shows the gas loss and area drained for the three scenarios examined in the Wasatch. These analyses indicate that the potential gas loss from NOSR No. 3 to wells producing in the Wasatch Formation could be significant.

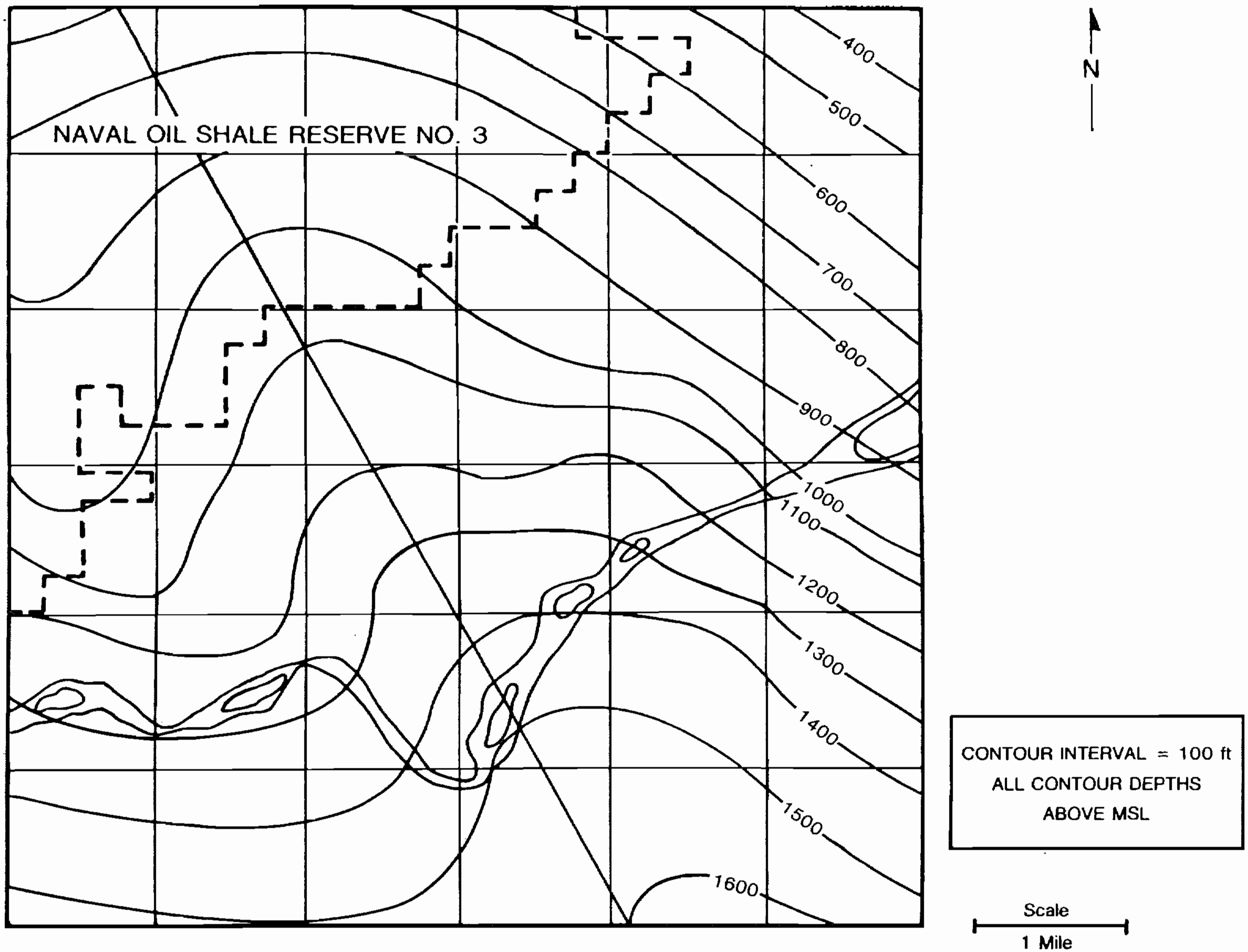


FIGURE 17. STRUCTURE CONTOUR MAP ON TOP OF THE MESAVERDE GROUP

TABLE 9. DISTANCES TO NOSR NO. 3 BOUNDARY FOR THE WASATCH WELLS

WELL	NORTH 45° WEST ORIENTATION DISTANCE (feet)
W102	6,100
W103	2,500
W104	5,800
W107	3,400
W109	5,100
W110	2,600
W112	4,900
W114	6,700
W118	5,800
W119	3,300
W120	1,300
W134	9,700
W135	4,100
W136	6,200
W139	4,700

7.0 MODEL APPLICATION

The study of the 42-well area involved extensive use of a dual-porosity reservoir model (SUGAR-MD) developed specifically for naturally fractured reservoirs. The model simulates a naturally fractured gas reservoir and production performance from the reservoir. It depicts a dual-porosity system in which gas is stored in the rock matrix (less permeable part of the rock). The gas is subsequently released into the natural fracture network, which provides a transport mechanism for the gas when linked to the wellbore. The capability to simulate performance for wells that are completed in lenticular reservoirs (where the sandstone lenses are separated by shale but in hydraulic communication) was added by METC to the original dual-porosity model for this study. Sandstone lenses and shale were placed in the reservoir simulator such that the effective bulk reservoir consisted of 20 percent sandstone (Knutson 1985). For each well, all sandstone lenses were assumed to be the same size as indicated by the well logs. Shale blocks were modeled by assuming them to be zero-porosity blocks, but allowing flow through the shale by means of a fracture system. This allowed the simulation of gas production from lenticular reservoirs where the sandstone lenses are disjointed (separated), and where natural fractures exist in both the gas-bearing sandstone lenses and in the shale separating the lenses. The model was used as a tool to history match actual and simulated production data. History matching consists of adjusting a small set of input parameters (for this study, k_f, ϕ_f, and L_f) until close agreement between actual and simulated data is obtained.

TABLE 10. POTENTIAL DRAINAGE TO W109, "WORST CASE" SCENARIO

LENS	LENGTH (feet)	WIDTH (feet)	3/4 LENGTH (feet)	LENGTH OF LENS (feet) OVER BOUNDARY	POTENTIAL GAS DRAINAGE FROM NOSR NO. 3 AT 25 YEARS (MMCF)
1	12,300	420	9,300	4,200	26
2	22,900	780	17,200	12,100	258
3	7,000	210	5,300	205	0.4
4	15,900	540	11,900	6,800	67
5	18,500	630	13,900	8,800	120
6	8,800	300	6,600	1,500	4
7	11,500	390	8,600	3,500	15
8	7,000	240	5,300	200	0.5
9	15,900	540	11,900	6,800	50
10	8,800	300	6,600	1,500	6
				TOTAL	546

RF = Recovery Factor = 50 percent

Anisotropy = 2.145

$$\frac{GP}{RF} = \frac{\text{Gas Produced}}{\text{Recovery Factor}} = \frac{l \times w \times h \times \phi \times Sg}{Bg}$$

Distance from Boundary
5,100 feet at North 45° West

TABLE 11. POTENTIAL DRAINAGE TO W120, "WORST CASE" SCENARIO

LENS	LENGTH (feet)	WIDTH (feet)	3/4 LENGTH (feet)	LENGTH OF LENS (feet) OVER BOUNDARY	POTENTIAL GAS DRAINAGE FROM NOSR NO. 3 AT 25 YEARS (MMCF)
1	5,200	420	3,900	2,600	32
2	2,000	165	1,500	200	0.2
3	3,900	315	2,900	1,600	12
4	700	60	500	--	--
5	3,200	255	2,400	1,000	3
6	3,300	270	2,500	1,200	3
7	2,200	180	1,700	300	1
8	4,100	330	3,100	1,700	11
9	1,100	90	800	--	--
10	1,100	90	800	--	--
11	2,900	240	2,200	900	2
				TOTAL	64

RF = Recovery Factor = 50 percent

Anisotropy = 2.145

$$\frac{GP}{RF} = \frac{\text{Gas Produced}}{\text{Recovery Factor}} = \frac{1 \times w \times h \times \phi \times Sg}{Bg}$$

$$\frac{\text{Distance from Boundary}}{\text{1,300 feet at North 45° West}}$$

TABLE 12. CUMULATIVE POTENTIAL GAS DRAINAGE FROM NOSR NO. 3 AT 25 YEARS (WASATCH FORMATION)

	SCENARIO 1		SCENARIO 2		SCENARIO 3	
	AREA DRAINED (Acres)	GAS LOSS (MMCF)	AREA DRAINED (Acres)	GAS LOSS (MMCF)	AREA DRAINED (Acres)	GAS LOSS (MMCF)
Group A						
W102	34	25	0	0	0	0
W107	79	135	23	29	0	0
W110	36	42	0	0	0	0
W118	108	118	0	0	0	0
W119	46	116	0	0	0	0
W120	25	64	2	1	0	0
Subtotal	330	500	25	30	0	0
Group B						
W103	76	171	28	61	0	0
W104	410	371	155	157	0	0
W109	220	546	64	156	0	0
W112	290	334	83	114	0	0
W114	506	807	160	272	0	0
W134	409	520	136	182	0	0
W136	220	325	79	130	0	0
W139	190	238	65	68	0	0
Subtotal	2,300	3,310	770	1,140	0	0
Total	2,630	3,810	795	1,170	0	0

7.1 SINGLE WELL ANALYSIS

Several model input parameters (Table 13) were measured in the field or calculated and then fixed for the single well analysis, which used a dual-porosity reservoir simulator, SUGAR-MD. Thirty-nine of the 42 commercial wells were used for this analysis. The significant fixed parameters were k_m, ϕ_m (ϕ_m is actually the product of $\phi_m \times S_g$ since the simulator is single phase), S_w, $k_{fx}:k_{fy}$, and h:w:l. For the 27 Wasatch wells used in the single well analysis (one of the 28 Wasatch wells did not have sufficient data), $k_m = .0101$ md, $\phi_m = 0.0301$, $S_w = .57$, $k_{fx}:k_{fy} = 2.145:1$, and h:w:l = 1:15:150. For the 12 Mesaverde wells used in the analysis (two of the 14 Mesaverde wells did not have sufficient data), $k_m = .003$ md, $\phi_m = .0315$, $S_w = .55$, $k_{fx}:k_{fy} = 2.747:1$, and h:w:l = 1:40:200. Each well's actual cumulative production was closely matched with simulated data by varying k_f, ϕ_f, and L_f. This gave values for k_f, ϕ_f, and L_f at each of the 27 Wasatch well locations and at each of the 12 Mesaverde well locations. These values were then extrapolated throughout the study area using a contouring program. At this point the performance of a well located anywhere in the study area could be predicted.

Three different reservoir characterizations were considered for the simulation study. The first assumed that each well completed in the Mesaverde Group was draining from a sandstone body with a given reservoir volume that was determined from geophysical logs. That is, there was no lens-to-lens communication for the Mesaverde wells, and drainage only occurred from lenses that were in direct contact with the wellbore. The second characterization was made assuming that the sandstone lenses in the Wasatch Formation were in direct sand-to-sand contact with other lenses. That is, if a wellbore was in contact with a sandstone lens as indicated by the logs, the drainage was actually from a cluster of lenses and not just from the lenses that were penetrated by the wellbore. This scenario (Case 1) was considered possible since actual 4-year cumulative production exceeded calculated GIP (as described in the engineering analysis section) for several Wasatch wells. The third characterization assumed that the sandstone lenses in the Wasatch Formation were in hydraulic communication through a natural fracture network that existed in both the sandstone lenses and the shale separating the lenses. That is, if a wellbore penetrated a lens, gas drainage also occurred from remote lenses through a natural fracture network. This scenario (Case 2) is another possible way to explain the fact that calculated GIP was exceeded by actual 4-year cumulative production for several Wasatch wells.

7.2 TWO-DIMENSIONAL AREAL INVESTIGATION

For the first simulation study, contour maps were generated for k_{fx}, ϕ_f, L_f, l, and h for the study area using data determined from the single well analysis for the 12 commercial Mesaverde wells. Figure 18 shows the contours for k_{fx} and the proposed well sites for the eight offset Mesaverde wells (PMV1 through PMV8). The values were then used in SUGAR-MD to predict the 25-year production performance of the eight proposed offset Mesaverde wells, under the assumption that the wells were draining only from lenses that were penetrated by the wellbore. Table 14 gives a summary of the key model input parameters and results of the 25-year simulation. Initial open flow at 1XM9 (PMV1 on Figure 18) (3.5 millions of cubic feet per day [MMCFD] during post-frac cleanup) indicated this well would be a very good producer. The analysis described above predicted an initial open flow of 2.5 MMCFD. For the eight proposed Mesaverde offset wells, the simulator showed .63 to 1.5 percent of the gas in the natural fracture system with approximately 20 percent of the total GIP recovered at 25 years.

For the second simulation study (Case 1), contour maps were generated for k_{fx}, ϕ_f, L_f, l, and h, using data determined from the single well analysis for the 27 commercial Wasatch wells. The extrapolated values of k_{fx}, ϕ_f, L_f, l, and h were then used with the reservoir simulator to predict the 25-year production performance for the six proposed offset Wasatch wells (PW1 through PW6 on Figure 19). Key input parameters and predicted 25-year cumulative production are shown in Table 15. Figure 19 shows the contours for k_{fx}. This production scenario assumed that the Wasatch wells were draining from clusters of lenses, and not just from individual lenses that were penetrated by the wellbores. Case 1 showed 2.0 to 5.4 percent of the gas in the natural fracture system, with approximately 60 percent of the total GIP recovered at 25 years.

TABLE 13. DATA USED IN CALCULATIONS

PARAMETER	WASATCH		MESAVERDE	
	VALUE	SOURCE	VALUE	SOURCE
Matrix Porosity (ϕ_m)	7 Percent	1XM9 Cores and Logs	7 Percent	1XM9 and MWX Cores and Logs
Water Saturation (S_w)	57 Percent	1XM9 Logs	55 Percent	1XM9 and MWX Logs
Ratio (h:w:l)	1:15:150	Outcrop Studies	1:40:200	Outcrop Studies
Depth	1,000-3,500 Feet	Well Logs	5,500-8,000 Feet	Well Logs
Reservoir Temperature	50° + 2°/100 Feet	MWX Logs	50° + 2°/100 Feet	MWX Logs
Reservoir Pressure	0.40 psi x Depth	MWX Data	0.75 psi x Depth	MWX Data
Net Sand Thickness	Mean = 76 Feet	Well Logs	Mean = 102 Feet	Well Logs
Gas Gravity	0.61	Assumed	0.67	MWX
Anisotropy ($k_{fx}:k_{fy}$)	2.145	MWX Fracture Data and Lens Orientation	2.747	MWX Fracture Data and Lens Orientation
Recovery Factor	50 Percent	Reservoir Model	25 Percent	Reservoir Model
Matrix Permeability (k_m)	5-100 μd	1XM9 Core	0.1-5.0 μd	1XM9 and MWX Core

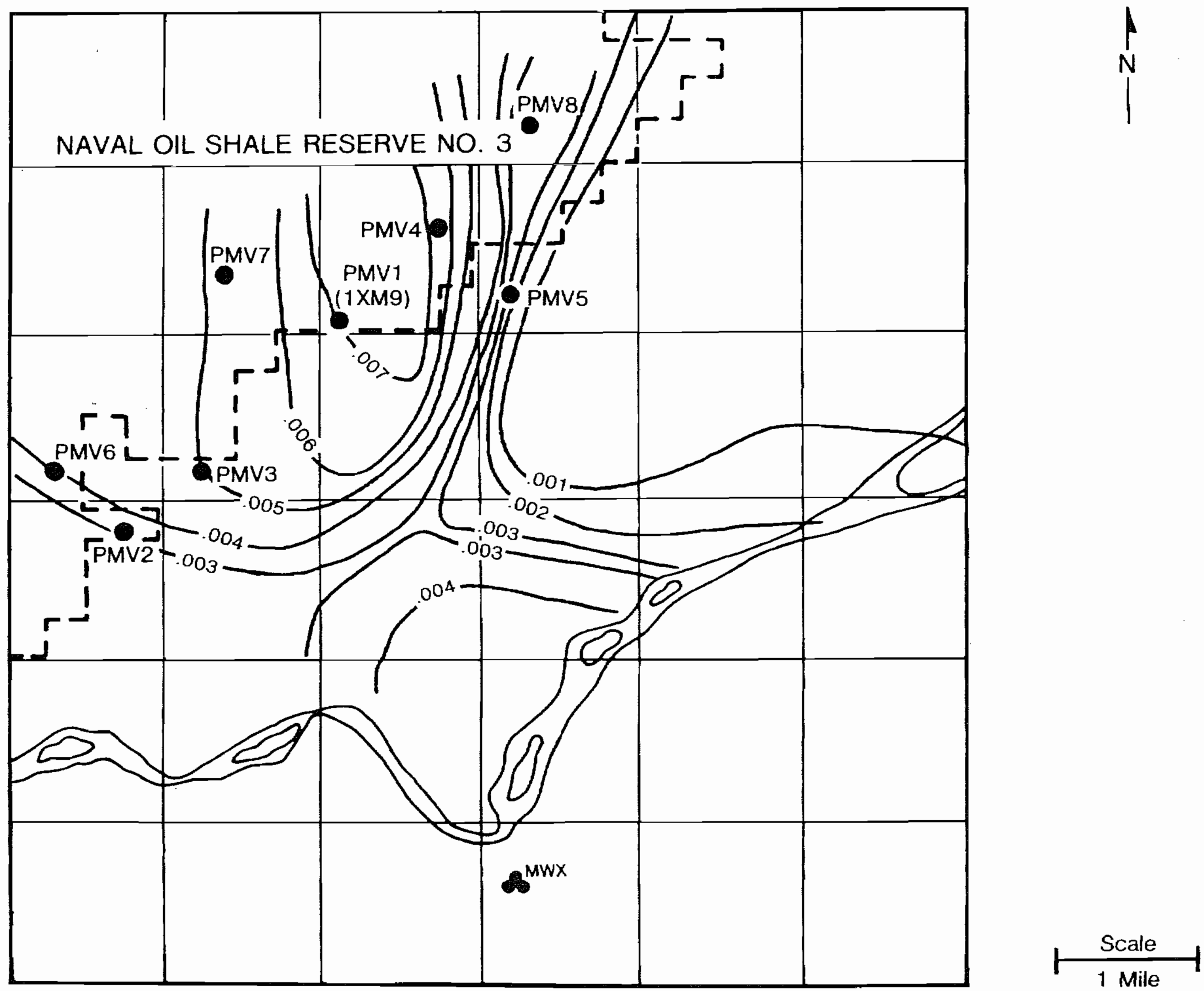


FIGURE 18. CONTOUR MAP OF FRACTURE PERMEABILITY (MD) FOR MESAVERDE WELLS

TABLE 14. HISTORY MATCHING PARAMETERS AND PREDICTED 25-YEAR CUMULATIVE PRODUCTION FOR PROPOSED MESAVERDE WELLS

WELL NO.	k_{fx} (md)	L_f (feet)	ϕ_f (fraction)	25-YEAR CUMULATIVE PRODUCTION (MMCF)
PMV1 (1XM9)	.0067	360	.00048	1,380
PMV2	.0033	1,360	.00025	960
PMV3	.0045	1,300	.00023	1,300
PMV4	.0057	660	.00035	1,740
PMV5	.0012	380	.00022	530
PMV6	.0041	1,320	.00023	1,220
PMV7	.0048	890	.00028	1,520
PMV8	.0029	360	.00020	1,000
			TOTAL	9,650

The third simulation study (Case 2) was done for the Wasatch Formation and assumed that the lenses throughout the study area were in hydraulic communication through natural fractures in both the sandstone lenses and the shale separating the lenses. The dual-porosity simulator had to be modified for this production scenario so that it could simulate gas production from disjointed sandstone lenses that were connected by natural fractures. A 20-percent sandstone, 80-percent shale volume was assumed for this study. Values for k_{fx}, ϕ_f, L_f, l, and h were again determined for all points in the reservoir. Figure 20 shows the contours for k_{fx}. Table 16 gives the key input parameters and the predicted 25-year cumulative production for the six proposed Wasatch wells. Case 2 showed 3.2 to 10.2 percent of the gas in the natural fracture system, with approximately 55 percent of the total GIP recovered at 25 years.

A drill stem test (before hydraulic stimulation) was conducted on Wasatch Well W101 on May 1, 1979. The calculated effective permeability to gas was .13 md. The single well analysis of W101 in this study gave an effective permeability of .12 md for Case 1 and .10 md for Case 2. This close agreement of data determined from history matching with data measured in the field added confidence to the fact that the technique used in this study was reliable.

The 25-year cumulative production figures were different for the Case 1 and Case 2 production scenarios. The six proposed Wasatch wells showed a total 25-year production of 2,620 MMCF for Case 1, and 2,480 MMCF for Case 2. Hence, the analysis showed that lenticular reservoirs that have sandstone lenses that exist in clusters are better areas for gas production than those where the lenses are disjointed and in hydraulic communication through natural fractures

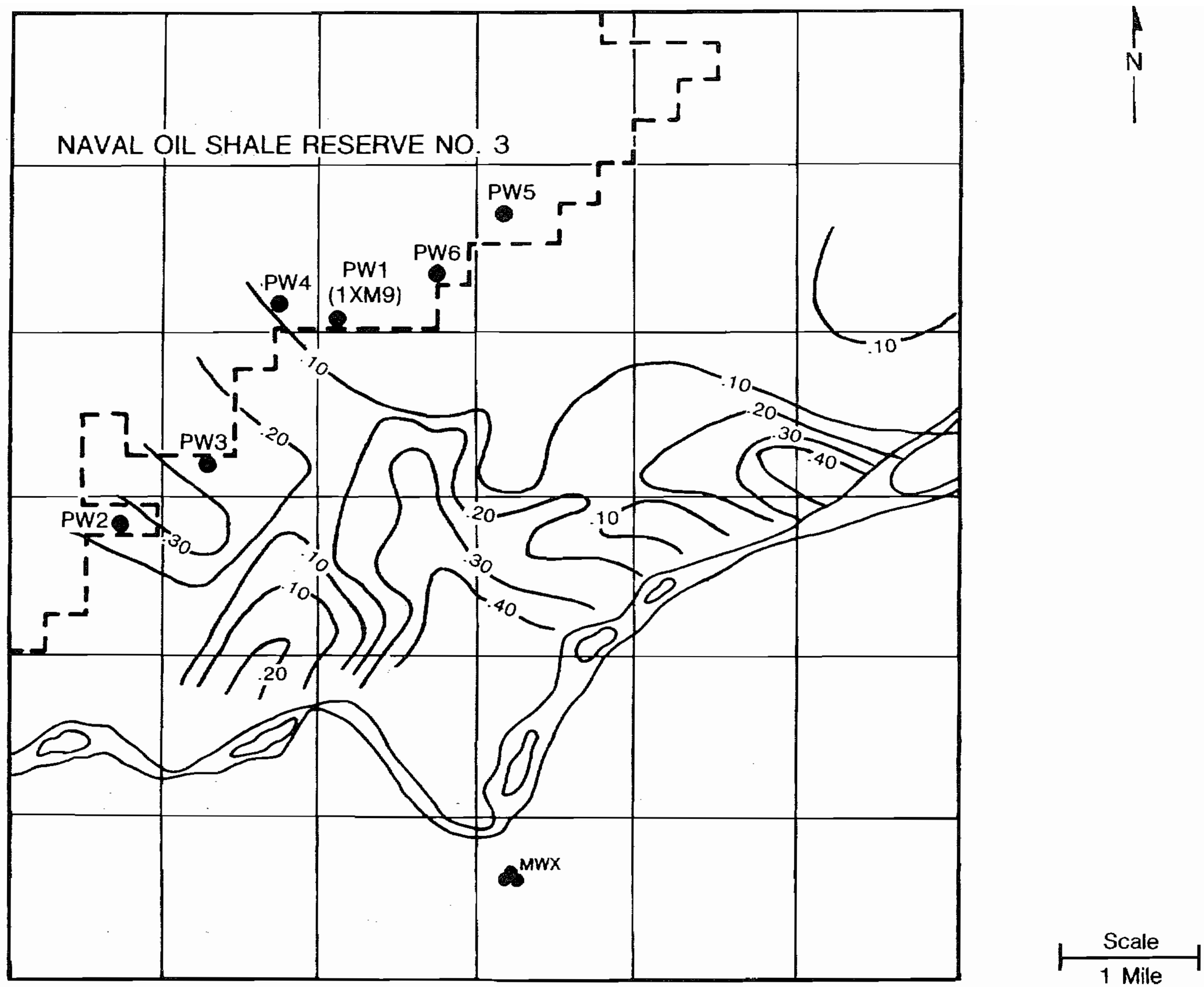


FIGURE 19. CONTOUR MAP OF FRACTURE PERMEABILITY (MD) FOR WASATCH WELLS (CASE 1)

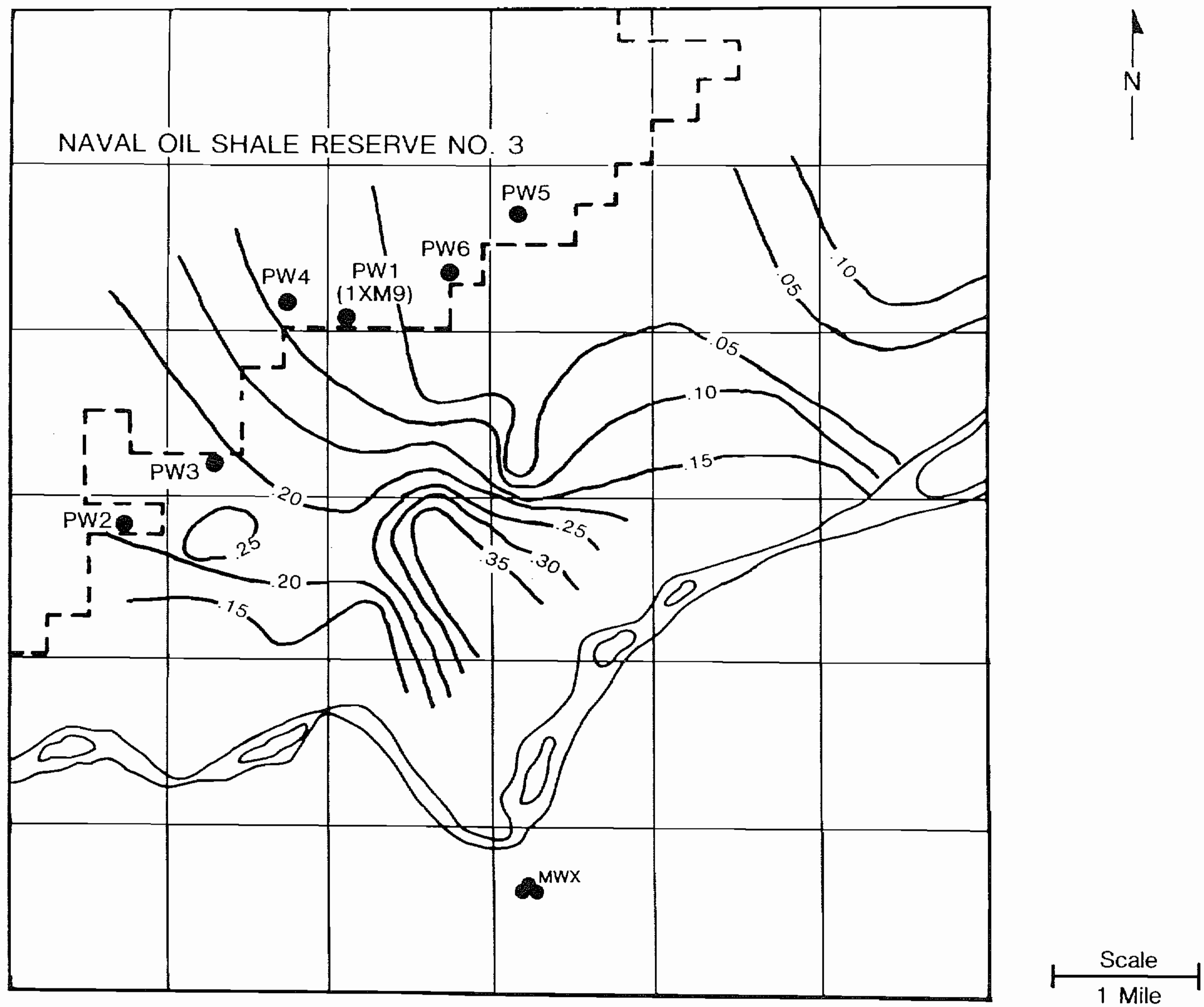


FIGURE 20. CONTOUR MAP OF FRACTURE PERMEABILITY (MD) FOR WASATCH WELLS (CASE 2)

TABLE 15. HISTORY MATCHING PARAMETERS AND PREDICTED 25-YEAR CUMULATIVE PRODUCTION FOR PROPOSED WASATCH WELLS (CASE 1)

WELL NO.	k_{fx} (md)	L_f (feet)	ϕ_f (fraction)	25-YEAR CUMULATIVE PRODUCTION (MMCF)
PW1	.083	250	.0017	550
PW2	.250	300	.0010	480
PW3	.260	340	.0010	620
PW4	.103	250	.0012	580
PW5	.012	260	.0006	140
PW6	.055	220	.0011	250
			TOTAL	2,620

TABLE 16. HISTORY MATCHING PARAMETERS AND PREDICTED 25-YEAR CUMULATIVE PRODUCTION FOR PROPOSED WASATCH WELLS (CASE 2)

WELL NO.	k_{fx} (md)	L_f (feet)	ϕ_f (fraction)	25-YEAR CUMULATIVE PRODUCTION (MMCF)
PW1	.072	250	.0006	520
PW2	.217	230	.0006	490
PW3	.223	220	.0006	610
PW4	.093	210	.0002	540
PW5	.011	170	.0006	110
PW6	.034	220	.0007	210
			TOTAL	2,480

in the shale. Although Case 1 showed a greater gas production at 25 years, the area drained was much greater for Case 2. Offset wells would be more effective for Case 2, since a well only has to lie in the drainage area; whereas, for Case 1 the well must penetrate the sandstone lens cluster.

7.3 FULL FIELD STUDY

To add confidence to the predictions of gas loss through migration calculated in the engineering analysis and to study the effect of well-to-well interference, a full field simulation was conducted on the Wasatch Formation. A 50 x 50 grid system, 29,500 feet x 28,500 feet, was laid out over the study area with the x-direction oriented N 45° W. This was the preferred lens orientation identified for the Wasatch in the geologic study. A mathematical computer code was developed to randomly assign sandstone and shale blocks, using a Monte Carlo routine, such that the percent sandstone (sandstone volume/ total volume) equals the percent entered by the user. Twenty percent was used for this study. The program also allows the user to specify grid blocks as sandstone prior to running the program. In this study, each grid block that represented a well was specified as sandstone. The shale blocks were modeled as zero matrix porosity blocks that were in communication with other blocks through the natural fracture network. This model represented the Case 2 scenario discussed in previous sections.

Reservoir properties obtained from records and single well history matching, P, h, k_{fx}, and ϕ_f, were contoured over the study area. Twenty-four of the 28 Wasatch wells were used; 4 were considered to have been completed too deep to be in the same interval for well-to-well interference. Each well was brought on line in the model as it was in the field. The reservoir model was run for a total of 25 years. The 6 proposed offset wells were then placed in the grid system. These wells were brought on line in January 1986. The first well to come on line in the Rulison Field was in September 1980. The difference in production between the 24 wells in the first run and the 30 wells in the second run (minus the production from the 6 proposed wells) was considered to be the gas loss through migration. Although this number is not totally correct, it is a good estimate of the gas loss.

The gas loss through migration to the Wasatch wells that was predicted by the simulator in the full field simulation was 1,780 MMCF in 25 years. In comparison, the calculated gas loss in the engineering analysis for the second scenario was 1,170 MMCF in 25 years (Table 12). The total production for the 6 proposed offset wells was 3,040 MMCF, compared to 2,620 and 2,480 MMCF as calculated by the simulator in the single well analyses. Table 17 shows the cumulative production for these 6 wells.

7.4 SENSITIVITY ANALYSIS

A sensitivity analysis was conducted to determine which parameters were controlling production and to what degree these parameters were affecting production. The 12 Mesaverde wells were divided into two groups and the 27 Wasatch wells were divided into five groups, based on fracture permeability. Reservoir properties for all wells in each group were averaged to determine input values for the base case for each group. Reservoir parameters were then varied to determine their effect on production. The varied parameters were k_f, L_f, P_i, and ϕ_m.

TABLE 17. CUMULATIVE PRODUCTION OF PROPOSED OFFSET WASATCH WELLS PREDICTED BY THE FULL-FIELD SIMULATION

WELL NO.		25-YEAR CUMULATIVE PRODUCTION (MMCF)
PW1		520
PW2		870
PW3		410
PW4		770
PW5		130
PW6		340
	TOTAL	3,040

The sensitivity analysis showed k_f to be the dominant parameter in predicting the production performance of wells used in this study. The sensitivity to k_f was shown in all three reservoir characterizations that were investigated in this study:

- No lens-to-lens communication exists and drainage only occurs from lenses that are in direct contact with the wellbore (Mesaverde wells).
- Drainage occurs from lens clusters and not just from lenses that are penetrated by the wellbore (Case 1, Wasatch wells).
- Drainage occurs from remote lenses through a natural fracture network (Case 2, Wasatch wells).

Figures 21, 22, and 23 show the predicted 25-year cumulative production profiles for these three characterizations. This relationship between k_f and production performance can be seen by comparing Figures 18, 19, and 20 (contour maps of k_{fx}) with the predicted 25-year cumulative production profiles (Figures 21, 22, and 23, respectively).

Of the other parameters that were varied, P_i and L_f also had a big effect on production. When the fracture length was varied from 760 feet to 1,520 feet for the Mesaverde wells, cumulative production at 40 years increased from 1,600 MMCF to 2,200 MMCF. When the fracture length was varied from 236 feet to 472 feet for the group one Wasatch wells, cumulative production at 40 years increased from 1,400 MMCF to 1,500 MMCF. Fracture porosity had a slight effect on production. Matrix permeability had almost no effect at all.

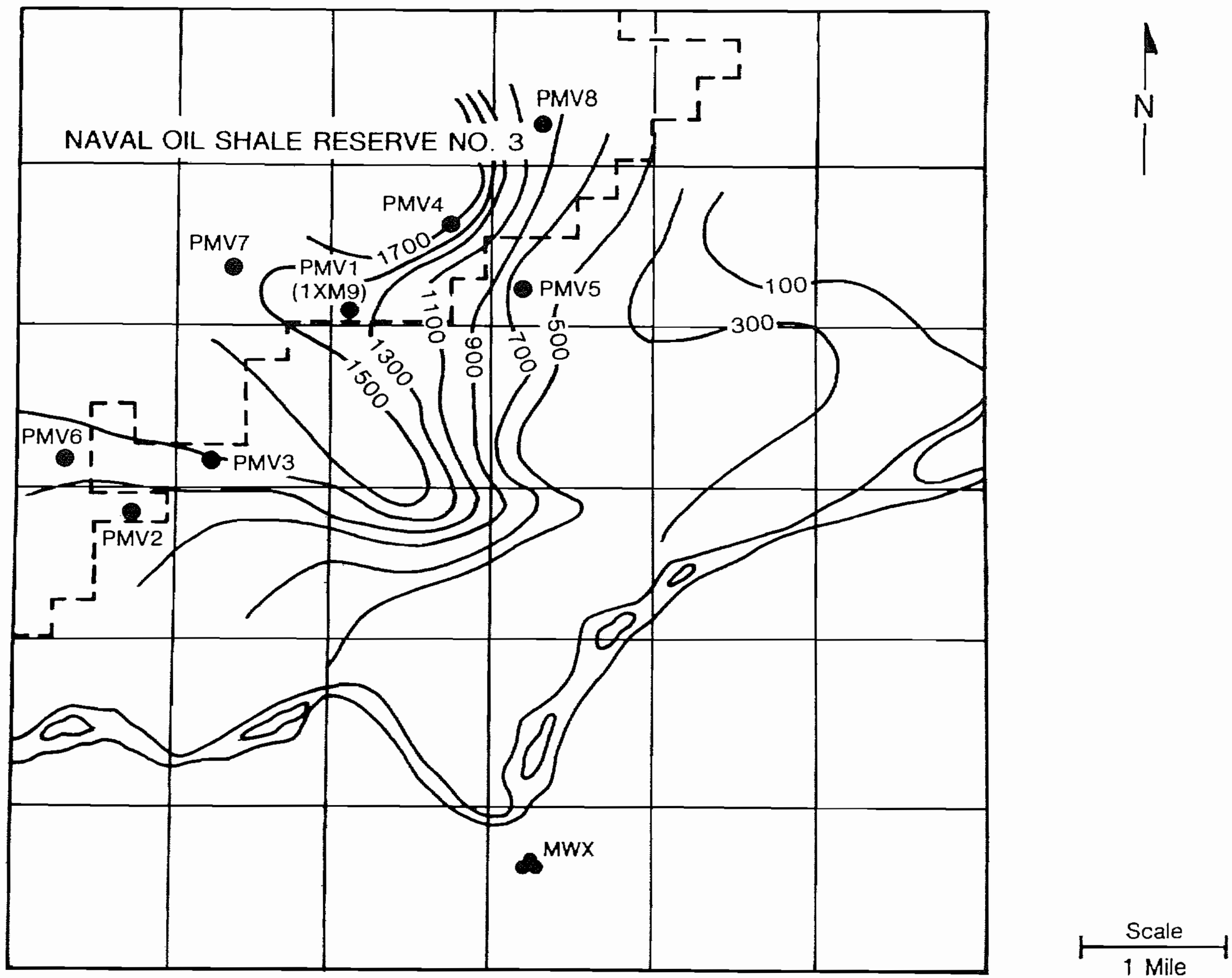


FIGURE 21. CONTOUR MAP OF 25-YEAR CUMULATIVE PRODUCTION (MMCF) FOR MESAVERDE WELLS

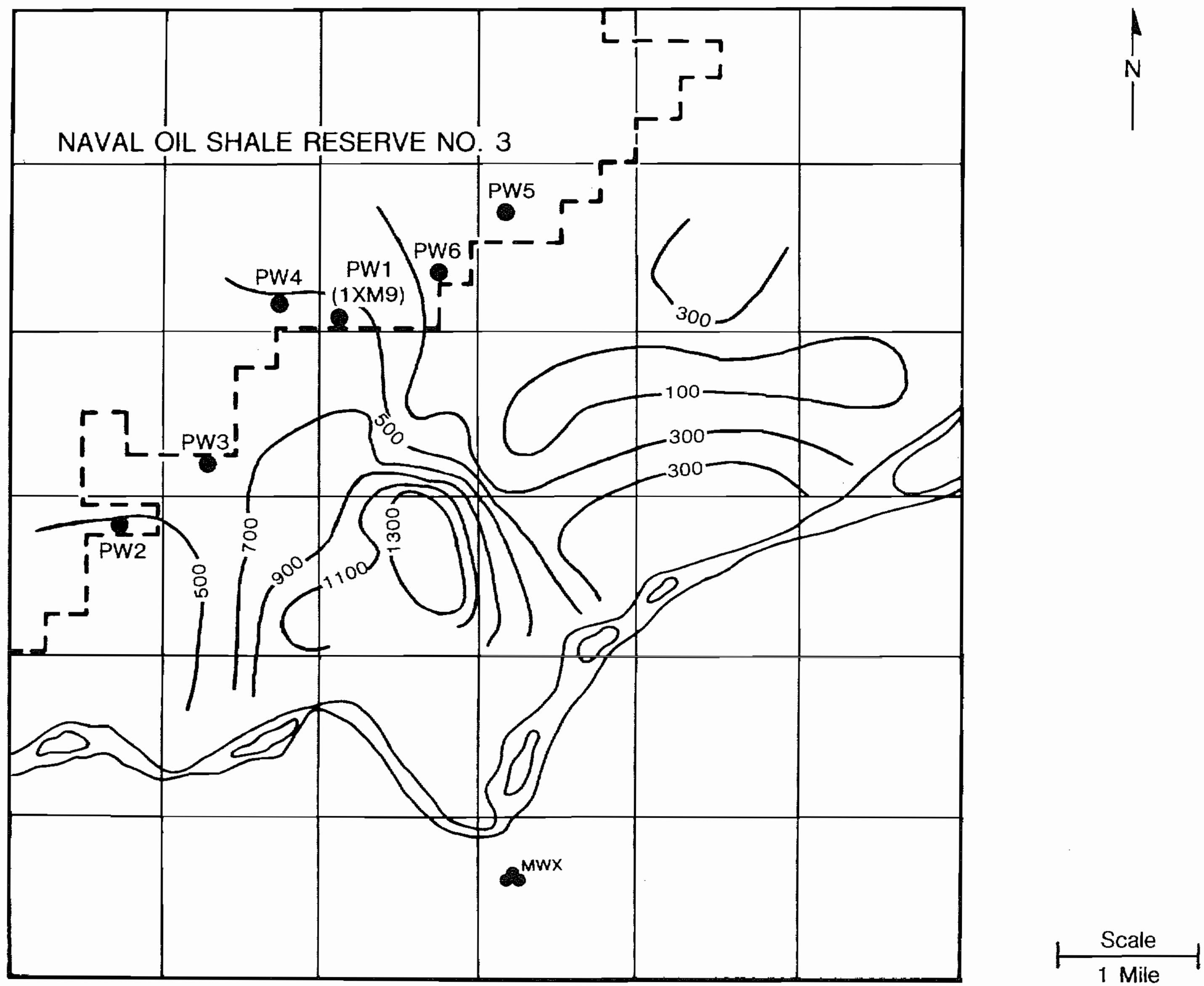


FIGURE 22. CONTOUR MAP OF 25-YEAR CUMULATIVE PRODUCTION (MMCF) FOR WASATCH WELLS (CASE 1)

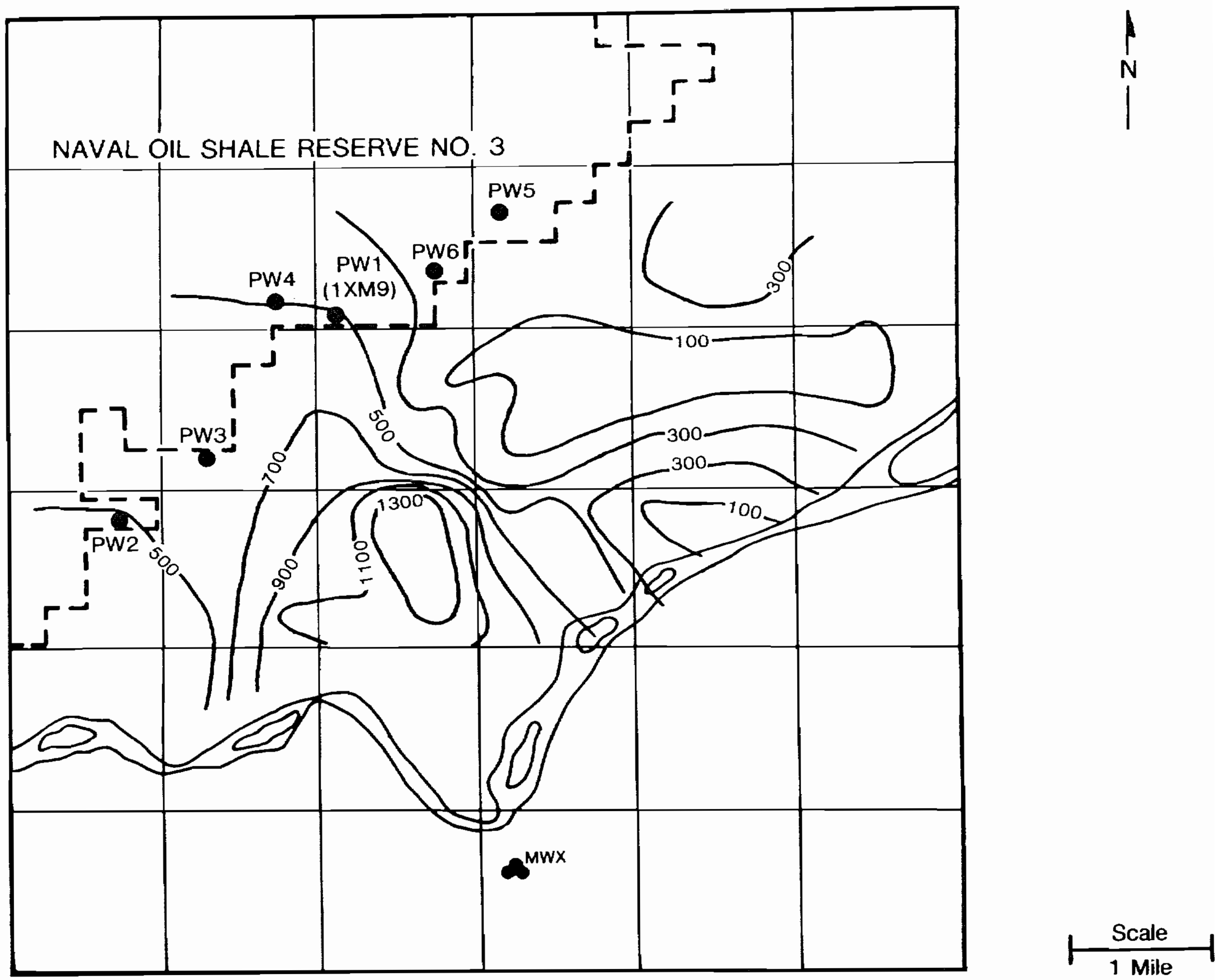


FIGURE 23. CONTOUR MAP OF 25-YEAR CUMULATIVE PRODUCTION (MMCF) FOR WASATCH WELLS (CASE 2)

8.0 CONCLUSIONS

The following conclusions are supported by the analyses presented in this report:

- Mesaverde Group lenticular sandstones appear to exist as discrete reservoirs; thus, gas migration from NOSR No. 3 to the Rulison Field is insignificant for the lenticular portion of the Mesaverde Group, and offset wells are not justified to prevent gas drainage from the reserve.
- In the Wasatch Formation, zones of potentially high productivity exist where gas migration from NOSR No. 3 to the Rulison Field appears to be substantial.
- Offset wells should be used only in areas where reservoir properties suggest good production, and where the reservoir lenses are probably in lateral communication with each other.
- Blanket sand reservoir models (dual-porosity type) can be easily modified so that they are applicable to lenticular reservoirs.
- Production (and production forecasting) can vary significantly in lenticular reservoirs as a function of the natural fracture network and the distribution and geometry of the sandstone lenses.
- The most important reservoir parameter affecting gas production in both the Wasatch Formation and the lenticular portion of the Mesaverde Group is natural fracture permeability.
- Although the engineering analysis showed that migration in the Mesaverde formation was negligible, reservoir simulation showed that seven of the eight proposed NOSR Mesaverde wells will be good producers.
- Reservoir simulation showed that four of the six proposed NOSR Wasatch wells will be good producers.

9.0 APPENDIX: DEPOSITIONAL MODELS

The Mesaverde Group at the NOSR No. 3/Rulison Field study area consists of five distinct depositional environments (Figure 24), each resulting in a specific stratigraphic sequence. In ascending order from oldest to youngest, these environments are shoreline/marine, lower delta plain (paludal), upper delta plain (coastal), fluvial, and paralic (backshore bays and estuaries). Lorenz (1983a) has provided an excellent discussion of these environments, which were recognized at the MWX site as well as at nearby Rifle Gap, where a large outcrop of the entire Mesaverde is exposed along a highway.

9.1 MESAVERDE DEEP

9.1.1 Shoreline/Marine

The shoreline/marine environment resulted in the deposition of the Iles Formation of the Mesaverde Group. This formation consists of three distinct shoreline sandstones (the Corcoran, Cozzette, and Rollins), which intertongue with the dark marine shales of the Mancos Formation. The depositional model for the sand units is a wave-dominated coastline (Lorenz 1983b). Sediment carried to the basin by the rivers was reworked and dispersed parallel to the shoreline by wave action. This resulted in a generally uniform shoreline with a blanket morphology. This depositional model is illustrated in Figure 25.

9.1.2 Orientation and Evidence

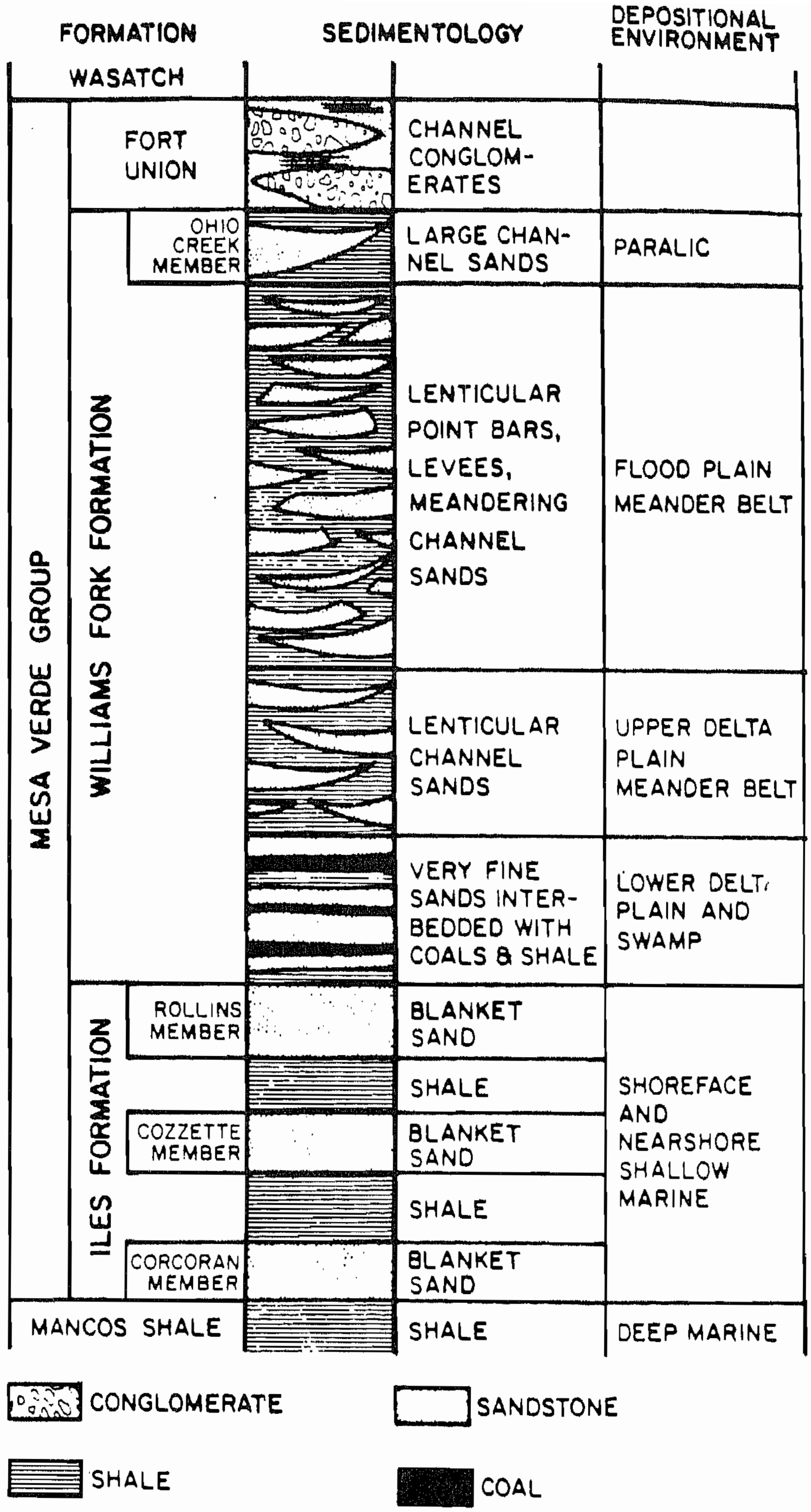
The ancient shoreline had a northeast-southwest orientation or strike (McGookey and others 1972). The resulting sandstones extended hundreds of miles in this direction. The lateral extent of the overall blanket morphology in the northwest-southeast direction (i.e., perpendicular to the shoreline trend) has been shown from outcrop studies to be tens of miles (Warner 1964). However, lateral variability in these shoreline sandstones is significant (Lorenz 1983). Shale breaks are abundant at the base of the sandstones, and the imbricated nature of successive sandstones further restricts the continuity perpendicular to the shoreline. Thus, while the blanket morphology is extensive, internal discontinuities disrupt this morphology.

9.2 MESAVERDE MIDDLE

9.2.1 Lower Delta Plain

The lower delta plain deposits, which overlie the blanket sandstones, consist of fine grain sandstones and siltstones interbedded with coals and shales. These units make up the basal portion of the Williams Fork Formation of the Mesaverde Group. The lower delta plain environment was a swampy, low energy environment with little reworking of the sediments. The sandstone units are deposited within the channels of the distributary system, and as thin sheet sandstones in the marshes between the channels. In addition, the coalescing of sand grains at the mouths of the distributary channels, aided by some reworking, results in thin shoreline sandstones of limited lateral extent.

Distributary channels are significantly smaller than the main channel that feeds them. These channels undergo little lateral migration. Thus, the geometry of distributary channel sandstones is typically linear with a



(After Soeder 1984)

FIGURE 24. STRATIGRAPHIC COLUMN OF ROCK UNITS PRESENT AT MWX SITE

lenticular cross section, and their lateral continuity with nearby sandstones is restricted by the surrounding shales that are deposited in the marshes.

The thin sheet sandstones that are deposited in the marshes between the distributary channels result when high water spills over the channel levees and carries sandy material into the marsh (overbank deposits), or when the levee is breached by the high water and the sandy material spills into the marsh (crevasse splay deposits). Both mechanisms result in thin sandstone units that have a lobate geometry and a lenticular cross section. Like the distributary channel sandstones, lateral continuity between nearby sheet sandstones is restricted by the surrounding coals and shales of the marsh environment.

The distribution and orientation of the lenticular sandstones of the lower delta plains are difficult to predict. The main river valley was perpendicular to the shoreline, which was oriented approximately N60°E. This translates to a downslope direction of N30°W, which approximates the median orientation for the channel sandstone lenses. However, the branching nature of a distributary system (Figure 26) results in a wide spread around this median (which could encompass 90 degrees).

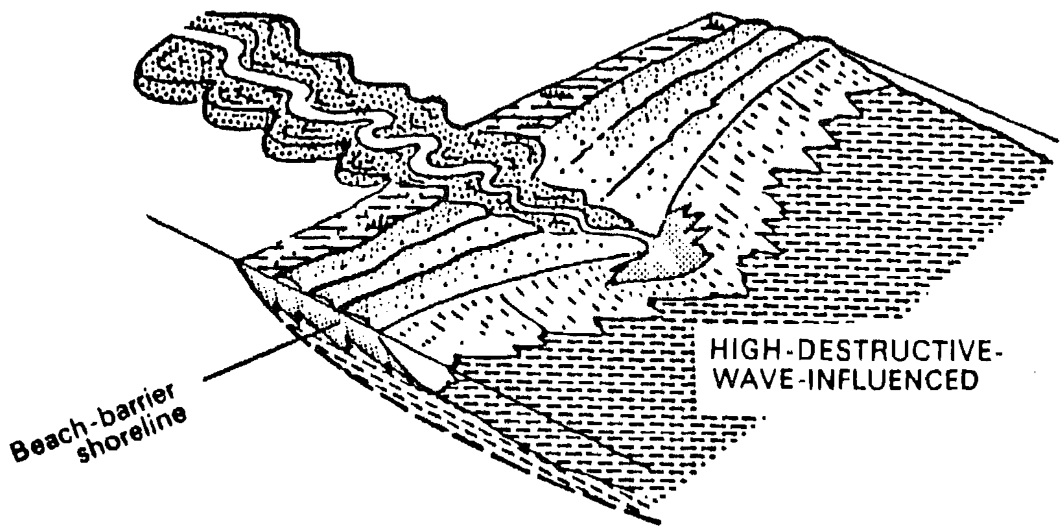
9.2.2 Upper Delta Plain

The upper delta plain environment consists of fine grain sandstones that are deposited in distributary channels, and as overbank and crevasse splay deposits. This environment is similar to the lower delta plain environment with respect to the mechanisms of deposition. However, the upper delta plain is above the zone of marine influence and has a slightly higher energy level. The resulting units include lenticular sandstones interspersed with finer grain siltstones and shales. A few coals are also present, accumulating in the swamps between the channels. The thin blanket sandstones, which can occur in the lower delta plain environment, are absent from the upper delta plain environment due to the absence of marine reworking.

The higher energy level of the upper delta plain can be seen in the higher sand content. At the MWX site, this interval had a sand content of 42 percent as opposed to the 26 percent estimated for the paludal (lower delta plain) zone (Lorenz 1983a). Also, since less branching of the distributary system has occurred in the upper delta plain, the distributary channels are fewer in number but larger than those on the lower delta plain. The lenses are also larger and exhibit a smaller spread around the median orientation that is represented by the downslope direction (N30°W).

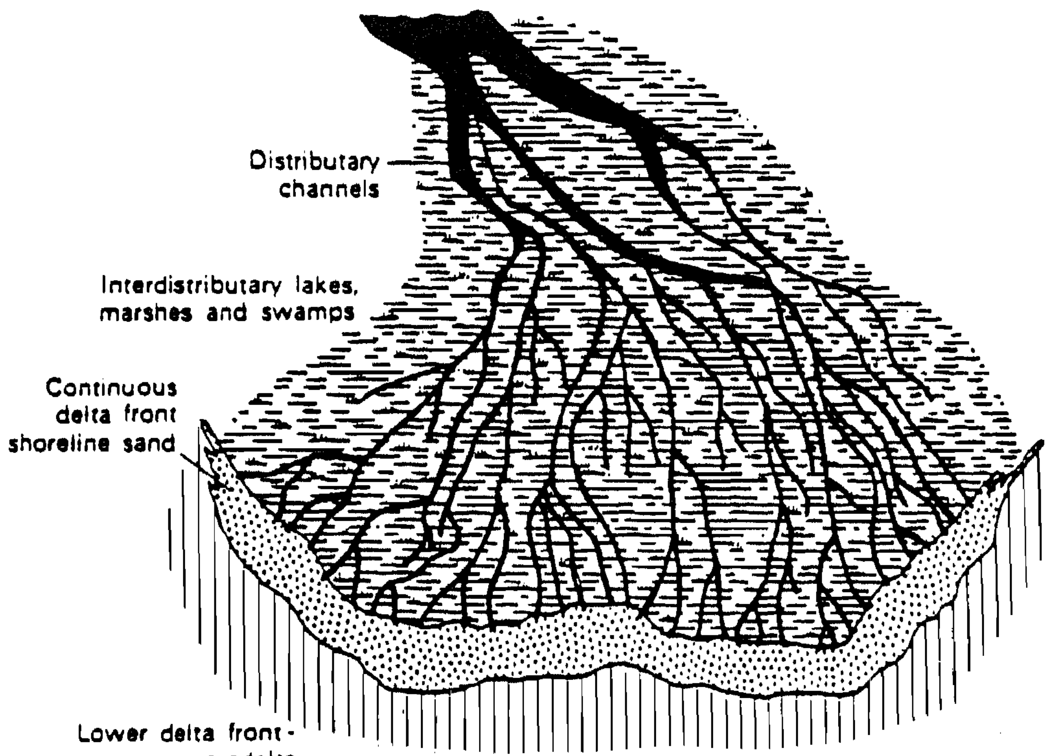
9.2.3 Fluvial

The fluvial environment (flood plain meander belt of Figure 24) consists of the scouring and deposition that occurs within a migrating river channel and in the low energy flood plains that flank the main channel. The zones associated with a fluvial environment are illustrated in Figure 27. The primary sand deposition occurs in the point bars on the inside curve of a river bend, and as the bed load of abandoned channels. Finer grain sands and silts are also deposited on the flood plain as overbank and crevasse deposits that are similar to those described in the delta plain environment. The geometry of the sandstone units produced in these three zones are, respectively, crescent shaped, linear, and lobate. All of these sandstones have a lenticular cross section.



(After Fisher and others 1969)

FIGURE 25. DEPOSITIONAL MODEL OF WAVE DOMINATED SHORELINE



(After Fisher and others 1969)

FIGURE 26. SPREAD OF DISTRIBUTARY CHANNELS ON DELTA PLAIN

Because of the high degree of lateral channel migration, extensive reworking and redeposition occurs in the fluvial environment. Individual point bars consist of imbricated sands that are deposited parallel to the local direction of streamflow (Figure 28). The sandstone lenses occur within a zone of finer grain siltstones and shales as the river channel meanders through the earlier flood plain deposits. Thus, the lateral continuity between sandstones is generally confined to the active meander belt (Figure 29). Within this meander belt, lateral continuity can be significant due to scouring and redeposition. As the individual sandstones interconnect, the resulting geometry for the composite sandstone body is elongate-tabular in the regional direction of stream flow, and tabular in the cross section.

Internal barriers such as shale breaks and channel fill deposits can limit the lateral continuity of these composite sandstones. In addition, in situ breakdown of feldspar grains can increase the clay content of the sandstones, reducing the permeability and further limiting the effective lateral continuity.

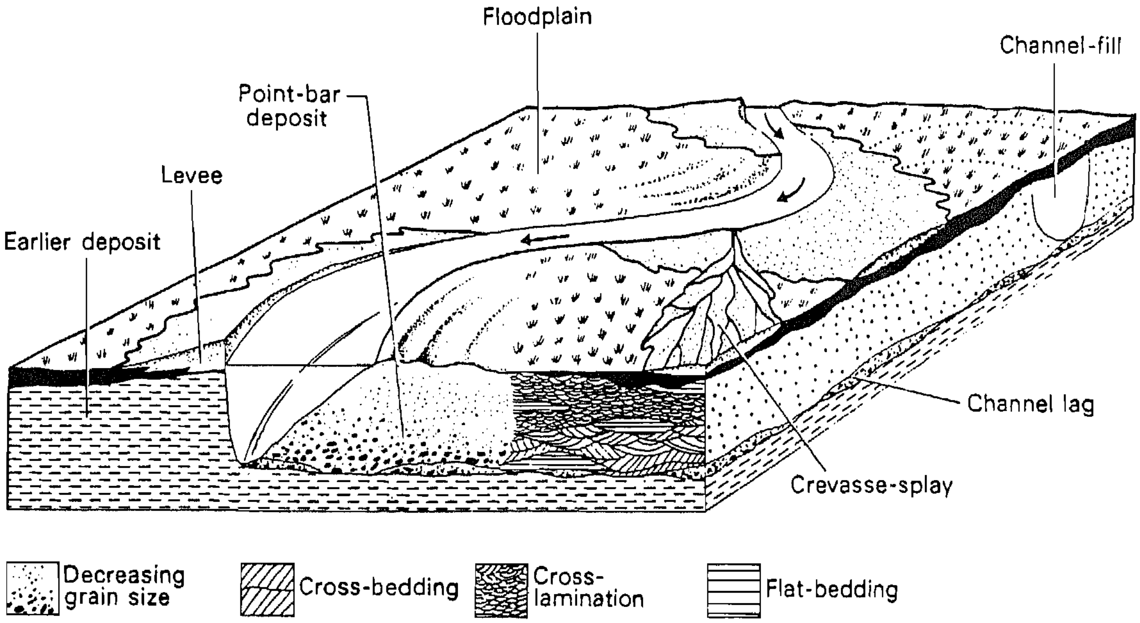
The sand content of the fluvial deposits is high (42 percent at the MWX site) and is reflected in numerous thin sandstone lenses and thick composite sandstones. Using outcrop studies and other estimates, Lorenz (1983a) reported widths for composite sandstones of 1,100 to 2,100 feet. Widths for individual point bars were observed to be 500 to 1,000 feet in outcrops. These values were substantiated by calculations based on stream channel morphology.

Based on the statistical outcrop studies of Hodges and others (1981), Knutson (1985) estimated a median height/width/length ratio of 1:40:200 for the fluvial section of the Williams Fork Formation. Using an average sandstone thickness of 22 feet for the fluvial section, an average sandstone lens size of 22 feet by 880 feet by 4,400 feet is predicted. This composite estimate agrees well with Knutson's earlier work, which focused on the linear channel sandstone and point bar deposits of the Mesaverde and Wasatch strata of the northern Piceance Basin (Knutson 1976).

In general, the orientation of sandstone lenses that are deposited in a fluvial environment would be in the downslope direction. For the fluvial section of the Williams Fork Formation, this downslope direction changed from east-southeast to north-northeast as the shoreline orientation shifted with time. Thus, the expected median orientation of the sandstone lenses in the fluvial section is east-west in the lower interval and becomes northeast-southwest toward the top of the fluvial section. However, due to the high degree of lateral channel migration in the fluvial environment, the orientation of individual lenses would be widely scattered around the expected median.

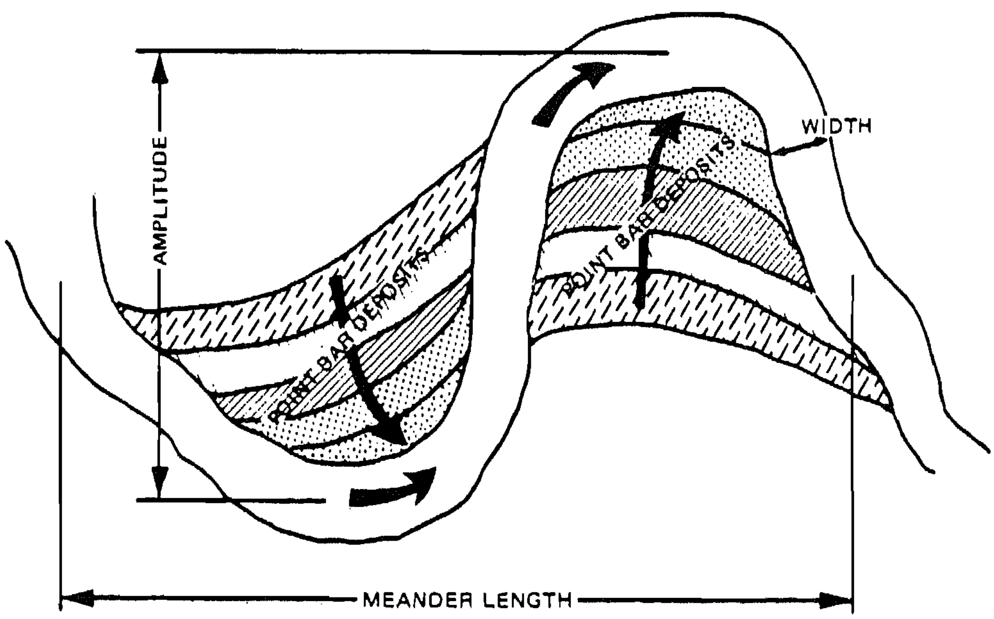
9.3 MESAVERDE UPPER

The uppermost member of the Williams Fork Formation, the Ohio Creek member, has a record of the final encroachment of the inland sea during the Lewis transgression (see Figure 24). The sea flooded the distributary channels and marshes and deposited laterally-extensive sandstones that were well-sorted and medium-grain. These sandstones are thinner than the blanket sandstones of the shoreline/marine environment and have been described as tabular and blanket deposits by different investigators (Lorenz 1983b, Peterson 1984).



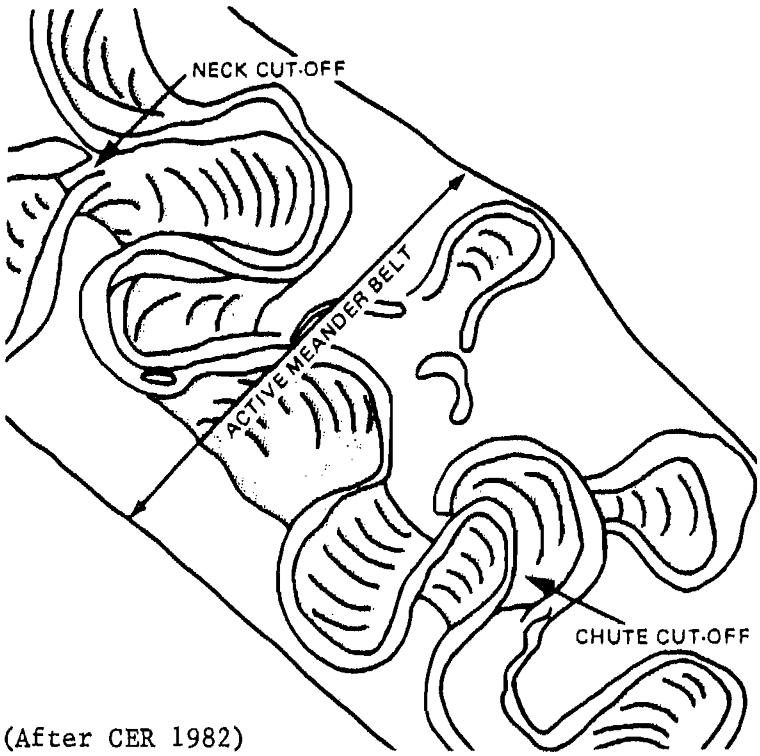
(After Allen 1964)

FIGURE 27. DEPOSITIONAL MODEL OF MEANDERING STREAM



(After CER 1982)

FIGURE 28. ORIENTATION AND IMBRICATION OF POINT BAR DEPOSITS RELATIVE TO STREAM FLOW DIRECTION



(After CER 1982)

FIGURE 29. LOCATION OF POINT BAR AND CHANNEL DEPOSITS WITHIN MEANDER BELT

The sandstone outcrops are continuous for up to 4,700 feet (Lorenz 1983a) and are relatively free from internal discontinuities. The sandstones are not shoreline sandstones; rather, they were deposited in the nearshore, nonmarine environment of a flooded bay or estuary (Lorenz and Rutledge 1985). This is shown by the wide occurrence of brackish water fossils, which indicate the mixing of fresh and marine waters, and extensively burrowed logs, which would not be expected in the reworked shoreline sandstones.

The sand content of the Ohio creek member is 40 percent (Lorenz 1983a). The shoreline orientation is estimated as northeasterly. However, the orientation of the tabular sandstone units depends on their specific environment. Estuary deposits would be oriented roughly perpendicular to the shoreline. Bay deposits, on the other hand, could be elongated in a direction parallel to the shoreline. Both units may, in fact, occur and may coalesce into a composite sandstone with no preferred orientation.

9.4 WASATCH

The Wasatch Formation, which lies above an erosional surface at the top of the Ohio Creek member, is divided into three members: the Atwell Gulch member, the Molina member, and the Shire member. The probable depositional environment for the Wasatch Formation is a fluvial system with associated lake deposits. The sediment source was nearby and to the southeast. Thus, the fluvial system was sediment-laden and may have been a braided stream marked by numerous dissected bars. The direction of drainage of north by northwest would be the preferred lens orientation, but significant scatter would be expected.

The sand content of the Wasatch Formation varies from less than 10 percent for the Shire member to approximately 20 percent for the Molina member (Knutson 1985). The sandstones within the Wasatch Formation are lenticular, and are scattered in the Atwell Gulch and Shire members. Massive conglomeratic sandstones are found at the base of the Wasatch in the Atwell Gulch member, and probably originated as the underlying Mesaverde was eroded. The Molina member is reported to be relatively sandy (Donnell 1961 and 1969), with a persistent basal sandstone that may have been deposited as a composite tabular sandstone during channel migration in a period of tectonic stability.

Knutson (1976) made outcrop measurements on sandstone lenses in the lower Wasatch. His findings indicate a height/width/length ratio of 1:15:150 for the lower Wasatch Formation. For an average thickness of 17 feet in the Atwell Gulch and Molina members, this would suggest an average lens size of 17 feet by 250 feet by 2,500 feet. Assuming a similar ratio for the Shire member and using an average thickness of 12 feet, a typical lens in the Shire member at the top of the Wasatch Formation would measure 12 feet by 180 feet by 1,800 feet.

Communication between lenses in the Wasatch Formation is not expected. The low sand content indicates a dominance of fine grain sediments, which would restrict lens-to-lens contact and communication through scouring. Some extremely thick lenses have been identified in the Wasatch Formation (Knutson 1985), however, and may represent local areas of high sand sedimentation. In addition, the presence of natural fractures in the interlaying shales could result in hydraulic communication between the actual reservoirs.

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