Improved Reservoir Modeling Using Gridded Seismic Attributes: North Concho Bluff Field, West Texas

Peter Lufholm, Geologist
George Watts, Geophysicist
Larry Lofton, Engineer

OXY USA Inc., Midland Texas

Abstract:

The North Concho Bluff Field produces from the upper Guadalupian tidal-flat sandstone play of the Queen Formation. Recently, the waterflood production from the field had decreased to a point where it was barely generating a positive cash flow. A reservoir simulation model was constructed in an attempt to improve earnings by identifying areas of potential oil bypassed during waterflooding. However, the spatial coverage of modern well log and core data within the field was inadequate in describing the reservoir for the simulator study. A better method of describing the reservoir heterogeneity was needed.

A 3-D seismic volume, having a uniform density distribution of data, was interpreted across the field. The reservoir interval consisting of four clastic cycles, encased by evaporites produces a classic trough-over-peak seismic response. Seismic attribute mapping of a portion of the seismic volume was used to better define the reservoir characteristics within the inter-well region. Final seismic-guided average porosity and average permeability grid files were used as inputs into a single layer reservoir model. History matching using these grids was accomplished with only minor adjustments to the model, as compared to using well data alone. The model identified an additional potential recoverable reserve target in excess of 2 MMBO.

A limited drilling program was initiated to verify the model, resulting in better than predicted production. Using seismic-guided reservoir properties improved the reservoir description for the simulator, allowing for a strategic drilling plan to be developed. The method presented advances the application of seismic-guided reservoir properties from reservoir description to operational reservoir management. Through strategic drilling, the North Concho Bluff Field had gone from a stage of potential divestiture to adding significant cash flow from a 'depleted' reservoir.

Introduction:

The greatest challenge to any reservoir characterization process is describing the reservoir properties within the inter-well region. The study of the North Concho Bluff Field consisted of reservoir characterization utilizing modern well logs integrated with core data and a 3-D seismic volume. The project was completed using commercially available PC based systems for the geophysical interpretation and a proprietary geologic PC based platform described by Srivastava (1994). Comparable geologic platforms are available commercially. A methodology of integrating well log and core derived reservoir properties with the 3-D seismic volume was used to extend these reservoir properties within the inter-well region. The resultant seismic grids provided the needed inter-well control for both the reservoir simulation and numerical modeling. This paper details the methods and results of this study.

The Queen Formation (Figure 1) is a sandstone reservoir that produces oil from the North Concho Bluff Field, near the junction of Upton, Crane, Ector and Midland Counties (Figure 2). The North Concho Bluff Field was discovered in October 1956 and has produced in excess of seven and one half million barrels of oil. Primary production reached a maximum of 600 BOPD in 1959, declining to 200 BOPD by 1962. Water injection began in 1964, increasing production to 1000 BOPD from 1966 to 1973. Field production steadily declined for the next twenty years to 35 BOPD by 1994. By this time the field had been reduced to eight active production wells, two active injection wells, one disposal well, twelve temporally abandoned wells and twenty-six plugged and abandoned wells. Due to the state of the field, a study was undertaken to evaluate the Queen reservoir for any additional opportunities or to determine the best practical method to divest of the property.

Geologic Setting:

Most of the Queen reservoirs are located along the west side of the Central Basin Platform. The Concho Bluff, North Concho Bluff complex, however (Figure 3) is one of a small number of Queen fields located in a tidal-flat sandstone play on the eastern and southern margins of the Central Basin Platform (Holtz, et al., 1995). Mazzullo (1992) has described the depositional setting for the area where the reservoir interval of the Queen Formation was deposited across a broad low relief shelf, with clastic material interfingering with evaporite deposits during a low-stand sea level.

The Mazzullo geologic model, based on texture, stratification, color, and the lack of fossil content from core descriptions, indicates that the reservoir was deposited in the fluvial and sabhka environments of a desert coastal plain (Figure 4). Local salinas developed within topographic lows near the shoreline. Fluvial sandflats were able to migrate freely across the desert sabhka producing the alternating stratigraphy. Fan delta deposition was confined to topographic lows.

North Concho Bluff Field is a combination structural and stratigraphic trap. Structural mapping reveals a series of low relief folds across the study area. The stratigraphic component of the trap is formed by the dissolution of anhydrite and halite cements, and by lateral permeability changes on the western margin of the field. Average depth to the reservoir is 4500 feet. Thick-bedded anhydrite and halite deposits as seen in cores and modern log suites (Figure 5) bracket the reservoir interval. The reservoir interval consists of four cycles of interbedded sandstone, siltstone, mudstone and evaporites (Mazzullo, 1992) totaling approximately forty feet thick (Figure 6).

3-D Seismic Data:

The 3-D seismic volume across the North Concho Bluff Field that covers eight square miles was acquired and processed in 1992. The seismic program was designed to image both shallow (3,200 feet) and deep (13,000 feet) geological objectives. Field acquisition parameters are summarized in Table 1. The data was processed with a routine sequence through two-pass 3-D migration. Data quality at the Queen level was very good, containing frequencies as high as 80 Hertz (Figure 7).

The seismic bin locations are spaced 110 feet north to south by 165 feet east to west, providing a bin density approximately 200 times greater than the well control having porosity and permeability data. With this increased data density, a more complete description of the reservoir continuity in the interwell space could be made.

Seismic-Guided Method:

The seismic-guided method for the estimation of reservoir properties (Schultz, et al., 1994a) is a non-geostatistical, data-driven application suited for 3-D seismic data volumes, where data points (bin locations) are uniform, closely spaced and extensive. The input data are reservoir properties (average porosity (PhiA), and average permeability (kA)) derived from cores and well logs, and seismic attributes (structure, isopach, amplitude, frequency, and phase) derived from the 3-D volumes. The reservoir properties are cross-plotted against each seismic attribute, and a significance measurement is determined for each cross-plot. A quality matrix is developed which relates how well each seismic attribute relates to a given reservoir property. The underlying physical relationships between the seismic attributes and the reservoir properties are important, but not necessary, in using this method. The coefficients of fit, of an over-determined, multiple variable linear regression solution, are applied to a calibration equation which best converts the seismic attribute data to an estimate of the given reservoir property. A residual correction is added to the estimated seismic derived reservoir property to insure a good tie between the seismic data and the well data. Confidence estimates can be made by leaving selected wells out of the procedure and comparing the computed seismic attribute values to the actual well data at the missing well locations (Schultz, et al., 1994b).

Reservoir Properties:

Synthetic seismograms were produced from seven sonic logs to obtain correspondence between the well data and the seismic data. Figure 7 is a representative synthetic seismogram, its sonic log and a typical seismic section from the 3-D volume. The reservoir sandstone (interval velocity $\approx$ 12,000 ft/sec) encased by evaporites (interval velocity $\approx$ 17,000 ft/sec), produces a classic trough-over-peak seismic response. The seismic trough ties to the top of the reservoir and the seismic peak ties to its base.

Reservoir properties were averaged over the gross reservoir interval, to be consistent with the geophysical resolution. The number of modern well log suites was very limited within the field. Most of the basic reservoir data (porosity and permeability) were assembled from core data. Where modern log suites exist, neutron-density cross-plot porosity was computed and averaged over the gross reservoir interval. No core to log porosity correction was made due to the lack of modern log suites in cored wells. The permeability data was arithmetically averaged over the gross interval. Figures 8 and 9 illustrate the average porosity and average permeability distribution based on well log/core data alone.

Seismic Attributes:

Seismic attributes are all measurable quantities extracted from the seismic volume at the reservoir level. The trough and peak representing the top and base of the reservoir (Figure 7) were correlated as time structure horizon files to isolate the reservoir within the seismic volume. An average velocity gradient was developed to produce the depth structure and isopach values.

The absolute value of the relative amplitude associated with both the seismic trough (top of reservoir) and the seismic peak (base of reservoir) were summed to establish a total relative amplitude value (Figure 10) across the reservoir isochron. The Hilbert transform was used to create seismic attribute values of instantaneous amplitude, instantaneous frequency and instantaneous phase. These instantaneous seismic attributes were then summed between the seismic time structure horizons bounding the reservoir to create reservoir amplitude (Figure 11), reservoir frequency (Figure 12) and reservoir phase (Figure 13) files.

Statistical Correlations:

Two reservoir properties: average porosity, and average permeability were used in the data integration study. Six seismic attributes: reservoir structure, reservoir isochron, relative amplitude, summed amplitudes, summed frequencies, and summed phases were sampled from the contoured grid files to the well locations. The reservoir properties at each well location were cross-plotted against each sampled seismic attribute resulting in considerable data scatter.

Each cross-plot was evaluated using a routine correlation coefficient and a significance measure called Kendall's Tau indicator (Schultz, et al., 1994a). The correlation coefficient from a normal regression analysis is a measure of only the linear relationship of the data. The Tau indicator, however, is derived from the slopes of every pair of points within the cross-plot, and applies to both linear and nonlinear relationships. The Tau indicator and correlation coefficient for all cross-plots are summarized in the quality matrix of Table 2. Kendall's Tau is required to be greater than 70% to be considered in the development of a calibration equation (Schlutz, et al. 1994a). The amplitude, frequency and phase all exceed this requirement.

Permeability, although it has a qualifying Tau indicator value in excess of 70%, the associated correlation coefficient is low (<35%). Since permeability normally exhibits a log normal distribution, the seismic attributes were compared to the common logarithm of the permeability to facilitate recognition of any linear correlations on semi-log and log-log planes. A quality matrix was assembled (Table 3) to evaluate the logarithmic distributions. The Tau indicator is particularly strong (>90%) for all cross-plotted distributions. More importantly, the correlation coefficients have been more than doubled for four of the seismic attribute variables evaluated with logarithmic permeability. The logarithmic values are used in the multi-variable non-linear regression analysis, to produce the coefficients needed for a calibration equation.

Seismic-Guided Mapping:

Porosity data have a strong linear statistical correlation (Table 2) with the amplitude, frequency and phase seismic attributes. Using the porosity as the dependent variable and the relative amplitude, summed frequencies, and summed phases as the independent variables, multiple variable linear regression coefficients were generated and an average porosity calibration equation was derived:

PHIA = 0.0785 + (0.00000438 Amplitude) - (0.000769 Frequency) - (0.000877 Phase)

This results in a correlation coefficient of 75%.

Permeability displays a strong nonlinear correlation with some of the seismic attributes. Multiple variable linear regression coefficients were generated using the logarithmic permeability as the dependent variable and the logarithmic summed amplitudes, linear summed frequencies and linear summed phases as independent variables. These coefficients are used to define the average permeability calibration equation:

$$\mathbf{Log\ (AK) = -3.2844 + (1.4253\ Log\ (SumAMPS)) - (0.0184\ Frequency) - (0.00472\ Phase)}$$

This results in a correlation coefficient of 71%. After the logarithmic permeability has been predicted by the seismic attributes, the antilog function can then be applied to attain the average permeability values at each seismic bin location.

The two calibration equations for average porosity and permeability were applied to the seismic attributes at the seismic bin files to produce the seismic predictions of porosity and permeability. Since the correlation coefficients for the calibration equations are less than 100% in both cases, the seismic predictions do not precisely match the well data, therefore a residual correction was computed.

The seismic predictions were sampled to the wells and subtracted from the log and core derived porosity and permeability values to create residual files. These residuals were then gridded and sampled back to the seismic bin locations. The gridded residuals were added to the gridded seismic predicted values, creating the final seismic-guided values. The seismic-guided mapping method therefore has used seismic measurements to shape the inter-well geologic variability (Watts, et al., 1995). Comparison of Figures 14 and 15 with the well data in Figures 8 and 9, respectively, reveals that the basic well data is preserved and a better representation of the variation within the data in the inter-well region is established.

Reservoir Simulation Model:

Reservoir simulation applies the concepts and techniques of mathematical modeling to the analysis of the behavior of petroleum reservoir systems. This study combines reservoir characterization with reservoir simulation to first identify areas of 'banked oil' which were poorly swept by the initial water flood. Numerical modeling was then used to simulate the development of the reservoir into the future, and to improve the production forecasting, production economics and the recoveries of the remaining banked oil.

Close teamwork by both engineers and geoscientists is required to describe as realistic as possible the characteristics of the reservoir. Engineering provided the production history files which includes the production data, flow rate data, mechanical and operational data. The fluid data including: compressibility, relative permeability, and capillary pressure were obtained from studies and special core reports from nearby fields producing stratigraphically equivalent Queen reservoirs.

A single layer model with a 61 x 52 grid was chosen to describe the Queen reservoir in the North Concho Bluff Field. The areal dimensions for each cell in the model was 190 feet by 173 feet. Discrete values of porosity, permeability, structure and net thickness were extracted from the geologic interpretation as definition for each grid cell. The geologic description was based on lateral interpolation of the data between control points at well locations. The distribution of wells having this descriptive data however is not uniform throughout the field. The density of this data is also restricted to the 933 feet well spacing development. Consequently, the majority of reservoir characterization defining the computer model is based on sparse well data interpolated over relatively large areas. This standard method of defining a reservoir for input into a computer model oversimplifies the reservoir description by failing to capture much of the inter-well variance and detail.

The seismic evaluation provided the needed inter-well data to better define the reservoir parameters input into each grid cell of the computer model. Data obtained from a seismic 3-D volume having a uniform spacing of 110 feet by 165 feet provides a better characterization of the reservoir than data obtained from irregularly spaced well data which is never closer than 933 feet. Increasing the control point density minimizes the required lateral interpretation.

The North Concho Bluff Field was simulated using the two different versions of reservoir characterization. One model was constructed from parameters based on well data interpolation only. The other model used the seismic interpolated data that incorporated the well data. Each model was verified through a process of matching the performance history of the field. In other words, while operating the model under similar constraints as recorded in the field development, the initial reservoir parameters were modified in such a manner causing the model to duplicate the historically recorded pressures, gas-oil ratios and water-oil ratios. The degree to which this performance can be matched with only minimal modifications is a verification of the reservoir characterization input into the model. Figure 16 shows that the model using the seismic data provided a much better match of the historical water cut performance than did the model that relied only on the well data for reservoir characterization. The model using only well data required a great deal of modification to even match the performance history as closely as shown. Conversely, the model utilizing seismic data required very little modification to match historical performance.

Based on the superior history matching results, increased confidence was placed on the projections made by the simulator using the seismic guided reservoir grids. The projections made with this model indicate that the field might yield an additional 2 MMBO through a redevelopment program of select infill drilling and improved pattern injection.

Development Testing:

A limited drilling program was developed to confirm the model results. An area in the northeastern portion of the field (Figure 17) was high-graded from the model and was selected for infill drilling. This program consisted of drilling two new producers and converting two existing well bores to injection wells for pressure support. Cost containment during the drilling and completion was essential in keeping the project economic. The two wells (#52 and #53) were drilled, both encountering approximately 25 feet of net pay, and were successfully completed. Initial production from the new wells was slightly higher than the model predictions. Current production for the field is in excess of 200 BOPD, with 85% of the production attributable to the two newly drilled wells. Prior to drilling, the field was producing approximately 35 BOPD. Conversion work on two water injection wells was recently completed and pressure support is being maintained.

Infill Re-development Plan:

The 'depleted' state of the reservoir and the economic risks associated with the field has presented a challenge for re-development of this reservoir without risking significant capital in a blanket re-drill program. The data from the two new wells were reincorporated into the reservoir model, and re-run. A strategic drilling plan was conceived for re-development of the field, in which a portion of the drilling program would be targeted to proving up producible reserves in areas of increasingly higher risk. Subsequent drilling would then complete the infill and continue to extend into other areas of increasing risk. At the end of each drilling program, the data would be reincorporated back into the model, and the model would be re-run to evaluate the next year's drilling program. The re-development plan (Figure 18) is currently scheduled to extend to the year 2000. The final result is that through production forecasting, the current projected program is shown to add significant reserves (Figure 19) to an otherwise 'depleted' reservoir scheduled to be sold or plugged out.

Conclusions:

The seismic-guided estimation of reservoir properties method is a marked change from the traditional approach of seismic data interpretation. Historically, one would begin with a theory and make certain approximations (model) which would eventually lead to a relationship between the measurable seismic quantities (attributes) and a physical rock property. In this case, both the seismic data and the well data are only passively used to establish or verify the physical relationship. The seismic-guided method places a higher emphasis on the data, realizing that there may or may not be any physical relationship between a given seismic attribute to a particular reservoir property. Therefore, every measurable seismic attribute must be evaluated with respect to each relevant reservoir property to fully describe any functional relationship that may exist. The overall objective is to translate as much of the well information as possible to the concentration of 3-D data points via the measurable attributes within the seismic data.

The North Concho Bluff Field has been a perfect application to illustrate the benefits of using the seismic-guided method:

1.) All of the detailed spatial variation in the inter-well region, as expressed by the seismic attribute information, has been successfully converted into porosity and permeability distributions.
2.) Both of the seismic-guided maps, porosity and permeability, accurately tie to the well data.
3.) Extensions of the reservoir, beyond the well control, are delineated on the seismic-guided distributions.
4.) The final seismic interpretation is in the form of porosity and permeability, as opposed to amplitude, frequency, and phase, etc., allowing for the interpretation to be used as input for a numerical reservoir simulator.
5.) History matching, using the seismic-guided grid files, was accomplished much sooner, with less modification to the reservoir characterization model, as compared to using the well data alone.

6.) Drilling based upon reservoir simulation, using the seismic-guided properties, has identified economically recoverable banked-oil in what was originally thought to have been a depleted reservoir.

REFERENCES:

Holtz, M. H., R. P. Major, L.E. Remington, A. S. Anderson, T. L. Ramsey, and J. C. McGee, 1995, New oil and gas recovery technologies targeted at the Upper Guadalupian platform carbonate and sandstone play, Permian Basin: workshop by Bureau of Economic Geology at the University of Texas, Austin, Texas Independent Producers and Royalty Owners Association, and the Petroleum Technology Transfer Council, July 27, 1995.

Mazzullo, J., A. Malicse, D. Newsom, J. Harper, C. McKone, and B. Price, 1992, Facies, Depositional Environments, and Reservoir Properties of the Upper Queen Formation, Concho Bluff and Concho Bluff North Fields, Texas: in Mruk, D. H., and Curran, B. C., eds., Permian Basin Exploration and Production Strategies: Applications of Sequence Stratigraphy and Reservoir Characterization Concepts: WTGS Fall Symposium 92-91, p.67-78.

Schultz, P.S., S. Ronen, M. Hattori and C. Corbit, 1994a, Seismic-guided estimation of log properties, Part 1: A data-driven interpretation methodology: The Leading Edge, May 1994, p. 305-310 and 315.

Schultz, P.S., S. Ronen, M. Hattori and C. Corbit, 1994b, Seismic-guided estimation of log properties, Part 3: A controlled study: The Leading Edge, July 1994, p. 770-776.

Srivastava, G.S., 1992, Interactive software integrates geological and engineering data, Oil and Gas Journal, Sept. 5, Vol. 92, No.36, pp. 85-91.

Watts, G. P., Lyons, T.D., and Taylor, A. R., 1995, 3-D seismic prediction of reservoir properties, West Moose Field, Ector County, Texas: High-Definition Seismic Guidebook-1995, Rocky Mountain Association of Geologists, Denver, CO, pp. 185-195.

Acknowledgments:

The authors owe much to the Western Region, OXY USA Inc. for allowing the use of the North Concho Bluff Field as a case history study, and for graphic-art assistance. We also thank Schlumberger Geco-Prakla for granting permission to illustrate and discuss their data in this paper.

Table 1
Seismic acquisition parameters for data shot across North Concho Bluff Field

SEISMIC DATA ACQUISITION PARAMETERS	
North Concho Bluff Field Ector and Upton Counties, Texas	
RECORDING PARAMETERS	
Recording Equipment:	Input/Output Two System
Channels	480 with Roll Along
Receiver Lines:	8
Groups per Line:	60
Sample Rate:	2 Milliseconds
Record Length:	4 Seconds
RECEIVER LINE AND GROUP PARAMETERS	
Receiver Line Interval:	1,980 ft.
Receiver Group Interval:	220 ft.
Geophones per Group	12 in 100 ft. Linear Array
Geophone Spacing:	9 ft.
ENERGY SOURCE PARAMETERS	
Vibrators:	4
Sweep Length:	8 Seconds
Sweeps per Point:	8
Sweep Frequency:	8-100 Hz, Nonlinear, 6 db/octave
Source Line Interval:	880 ft.
Source Point Interval:	330 ft. Staggered Between Lines
SAMPLING EFFORT	
Bin Spacing:	110 ft N-S by 165 ft E-W
Fold at 3,000 ft. Level:	6
Fold at 11,500 ft. Level:	26
Total Survey Size:	42 sq. mi.
North Concho Bluff Area:	8 sq. mi.

Table 2
Quality Matrix for Linear Relationships Tau Indicator % (Correlation Coefficient%)

	Structure	Isopach	Relative Amplitude	Summed Amplitudes	Frequency	Phase
PHI	11 (22)	54 (3)	98 (68)	98 (64)	80 (37)	82 (69)
K	14 (4)	55 (26)	98 (30)	97 (29)	92 (27)	93 (28)

Table 3
Quality Matrix for Nonlinear Relationships Tau Indicator % (Correlation Coefficient%)

	Relative Amplitude	Summed Amplitudes	Frequency	Phase	Log(Summed Amplitudes)	Log (Frequency)
Log(K)	98 (65)	98 (65)	92(68)	93 (62)	98 (67)	94 (40)

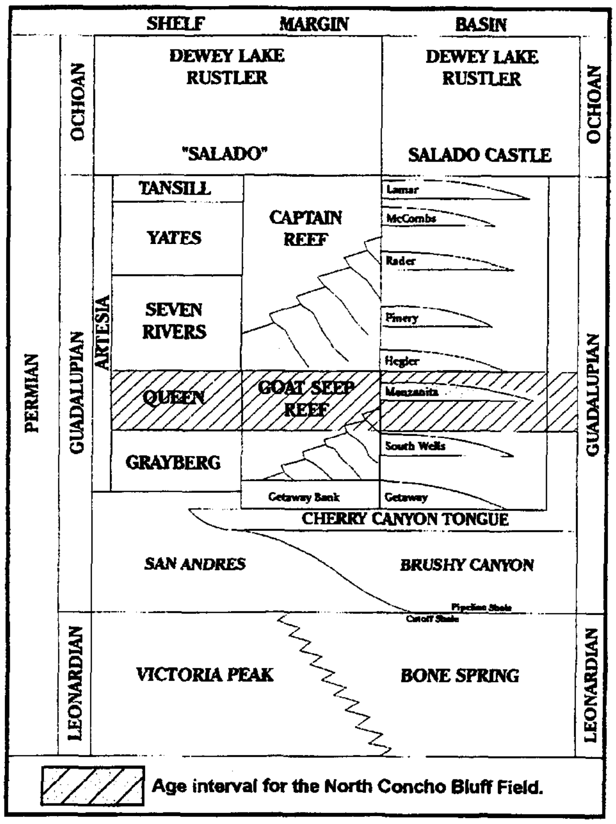

Figure 1 - Stratigraphic column representing Permian aged rocks of the Permian Basin region.

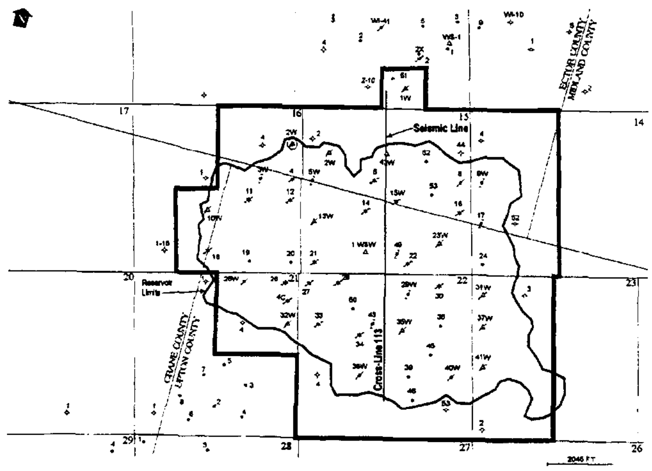

Figure 2 - Location Map: Showing location of 3-D Seismic Line 113 North Concho Bluff Field, Ector and Upton Counties, Texas

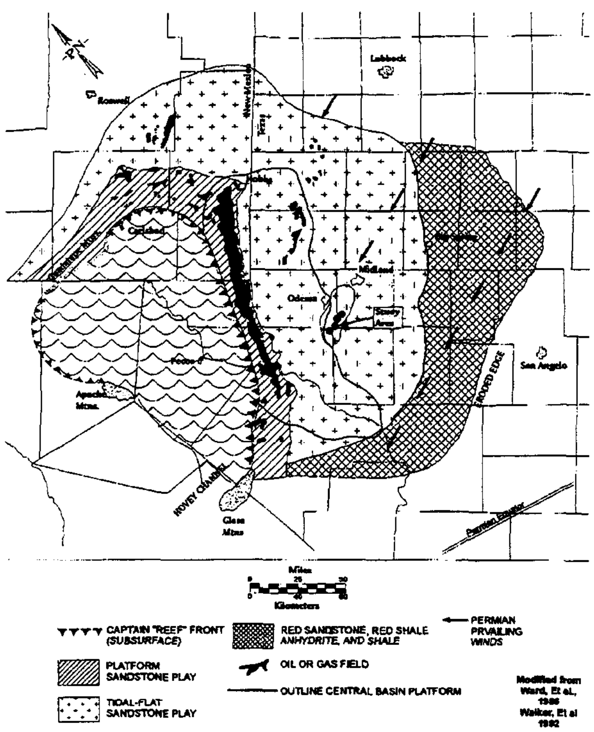

Figure 3 - Generalized Permian Upper Guadalupian series, Yates-Seven Rivers-Queen formations.

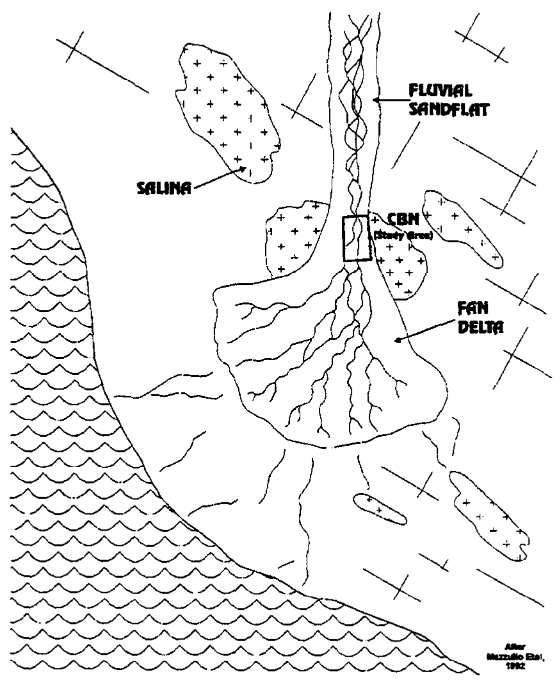

Figure 4 - Depositional model for the Upper Queen in the North Concho Bluff Field

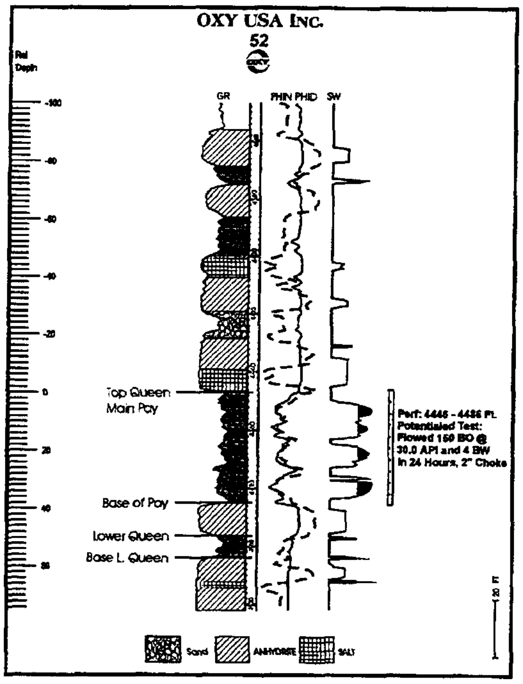

Figure 5 - Generalized Type Log, North Concho Bluff Field

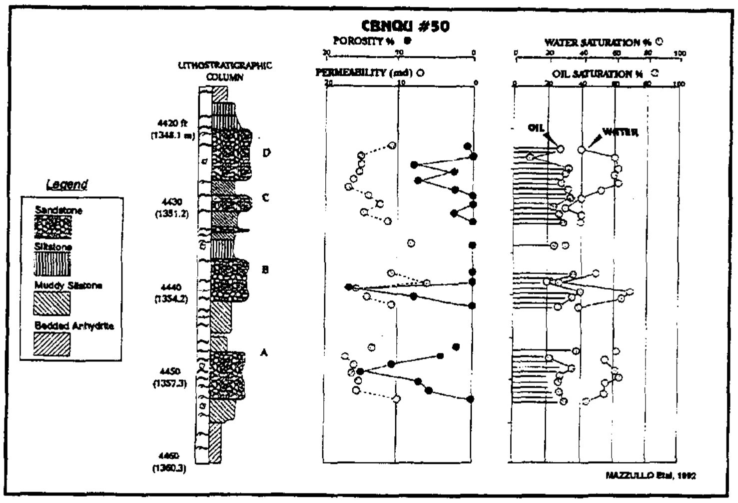

Figure 6 - Petrophysical Properties of the Queen Main Pay Interval

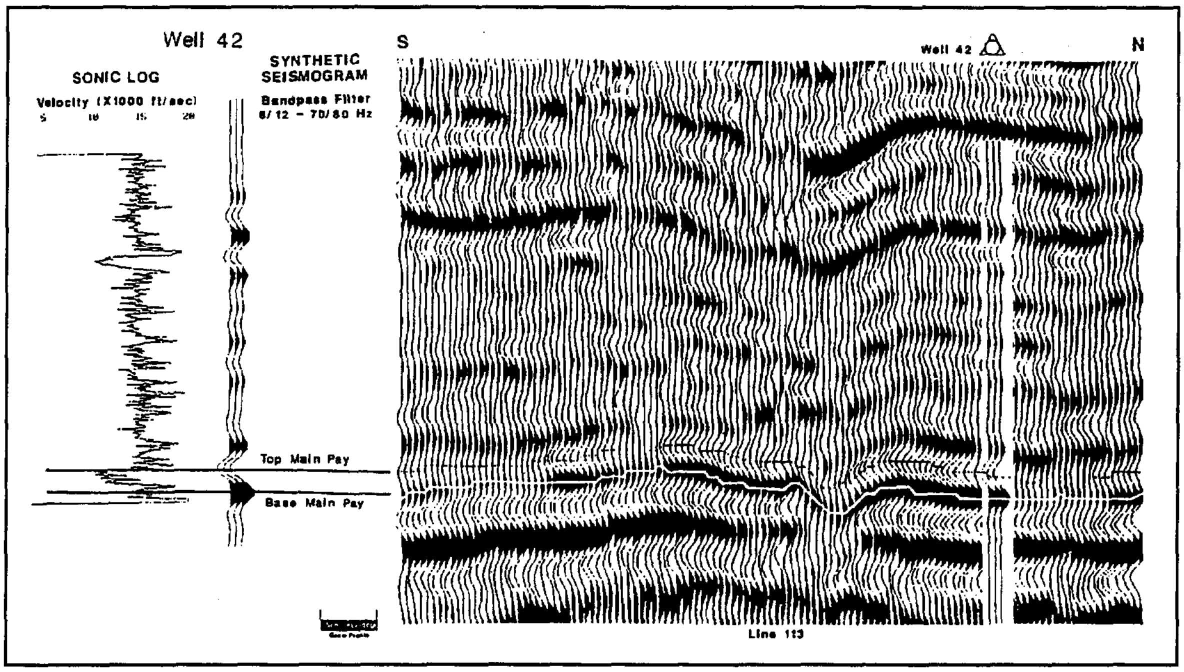

Figure 7 - Correlation between Sonic log, Synthetic Seismogram, and 3-D Seismic Line, North Concho Bluff Field. 3-D seismic line courtesy of Schlumberger Geco-Prakla.

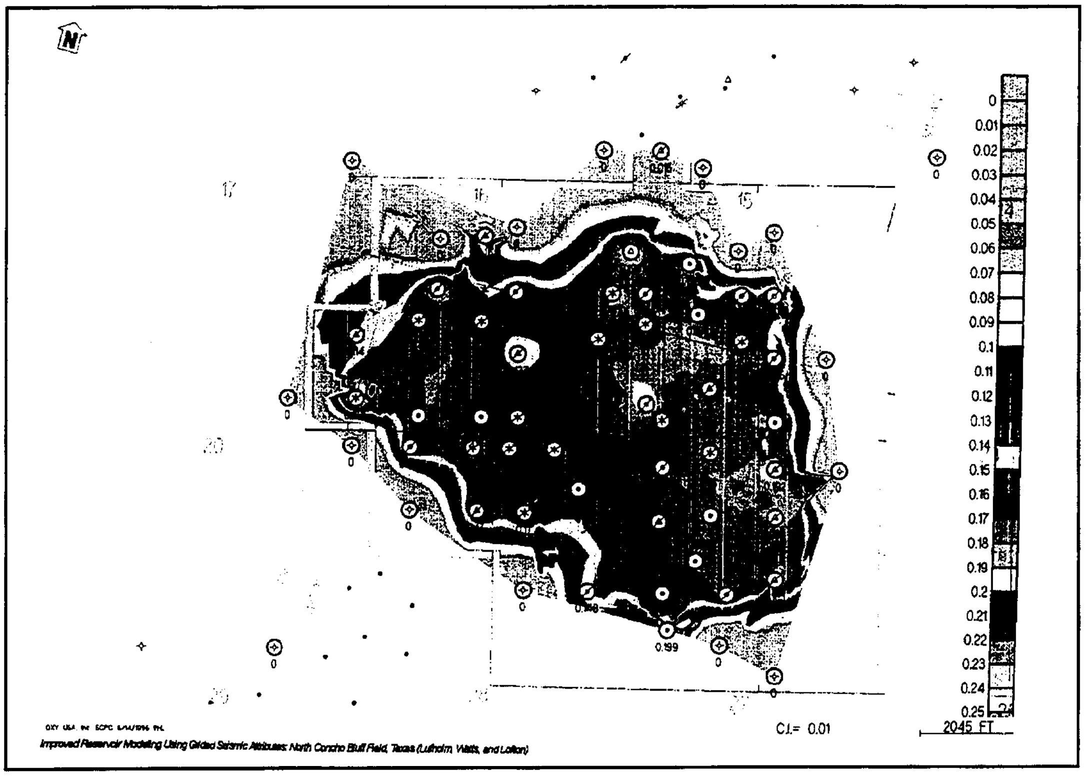

Figure 8 - Average porosity (Phia) for the main Queen pay interval, based on core and well log data, for the North Concho Bluff Field

Figure 9 - Average permeability (Ak) for the main Queen pay interval based on core data, for the North Concho Bluff Field.

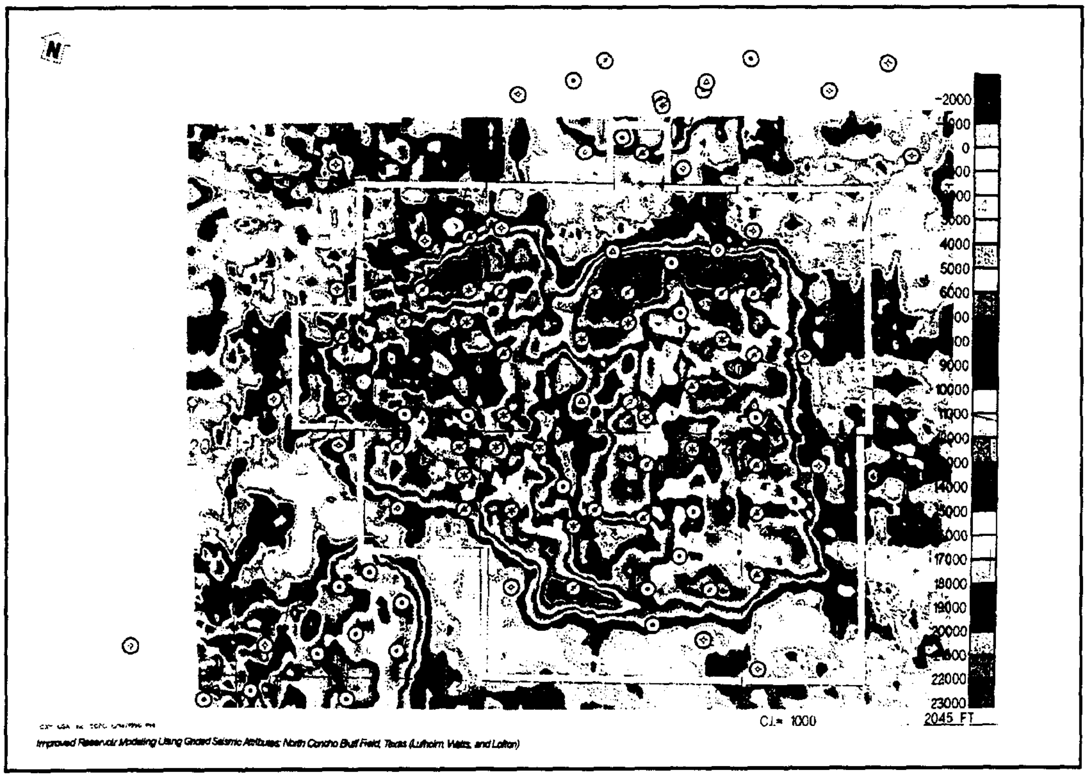

Figure10 - Total relative amplitude across the main Queen pay interval.

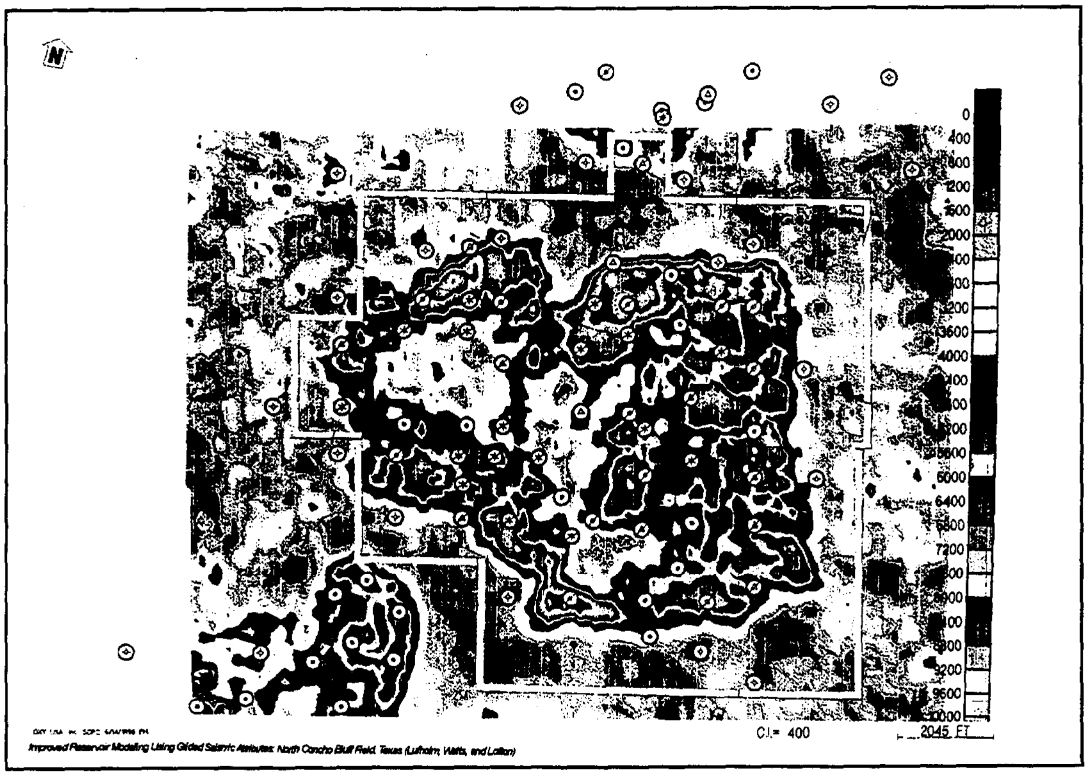

Figure 11 - Instantaneous amplitudes created from the Hilbert Transform and summed across the main Queen pay interval.

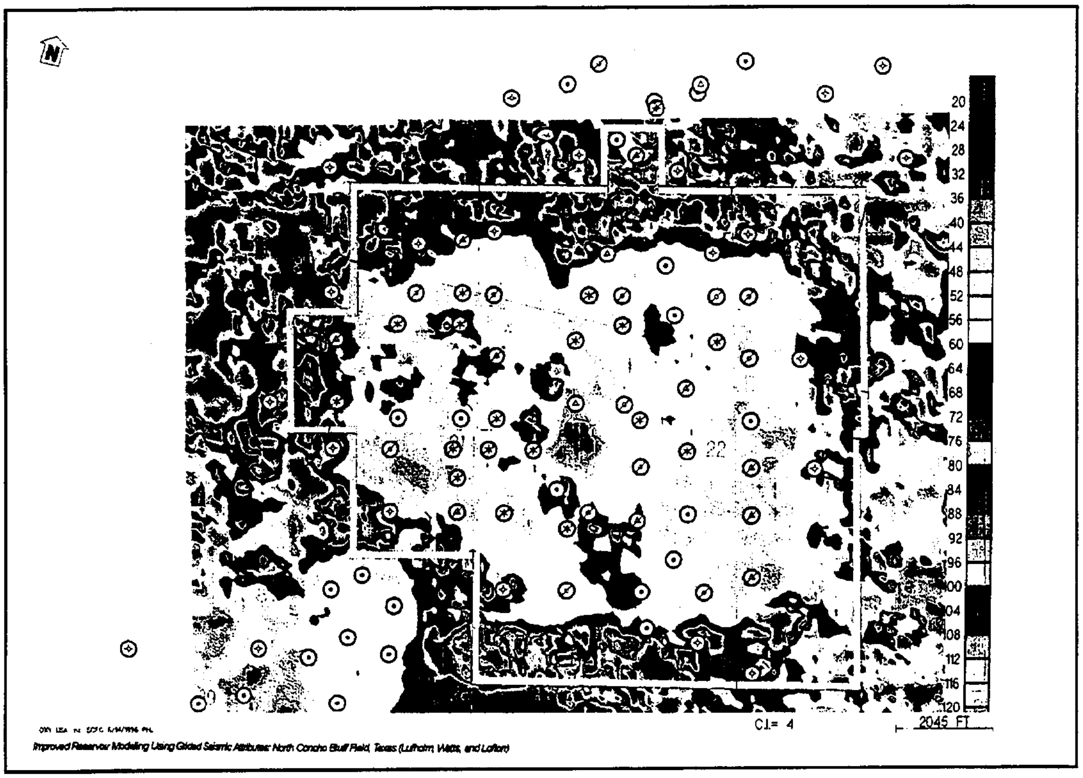

Figure 12 - Instantaneous frequencies created from the Hilbert Transform and summed across the main Queen pay interval.

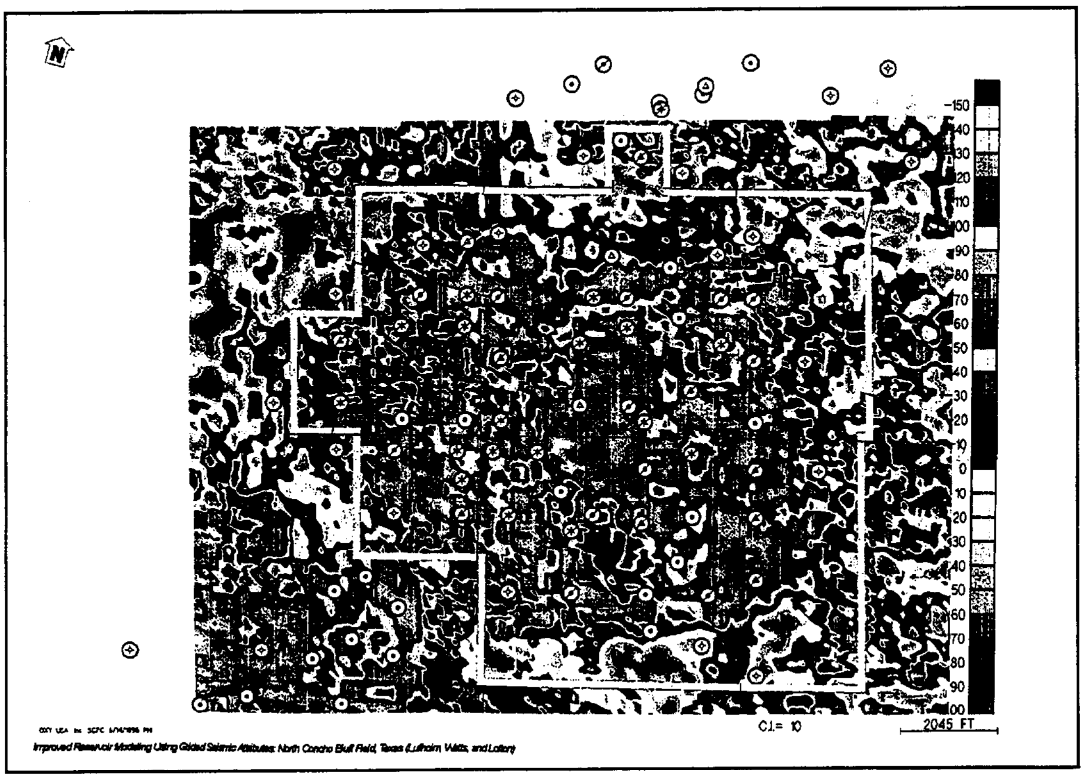

Figure 13 - Instantaneous phase created from the Hilbert Transform and summed across the main Queen pay interval.

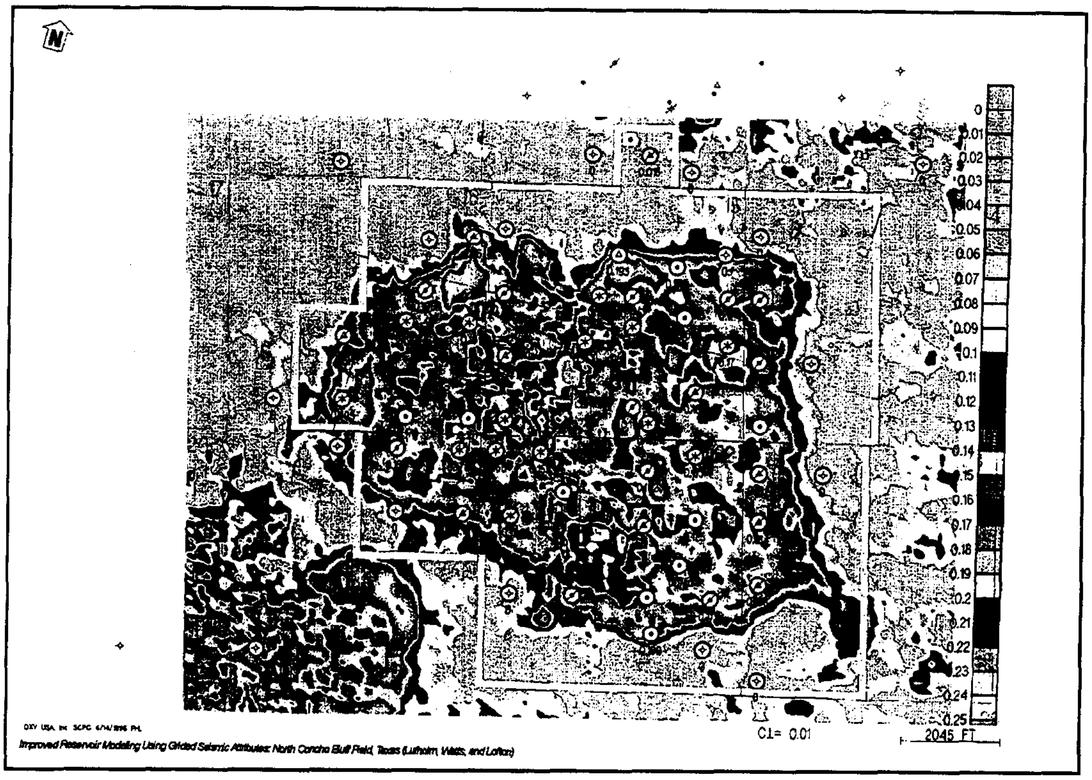

Figure 14 - Seismic guided average porosity across North Concho Bluff Field. Comparison with Figure 8 reveals that the well data has been preserved with a better representation of the inter-well region.

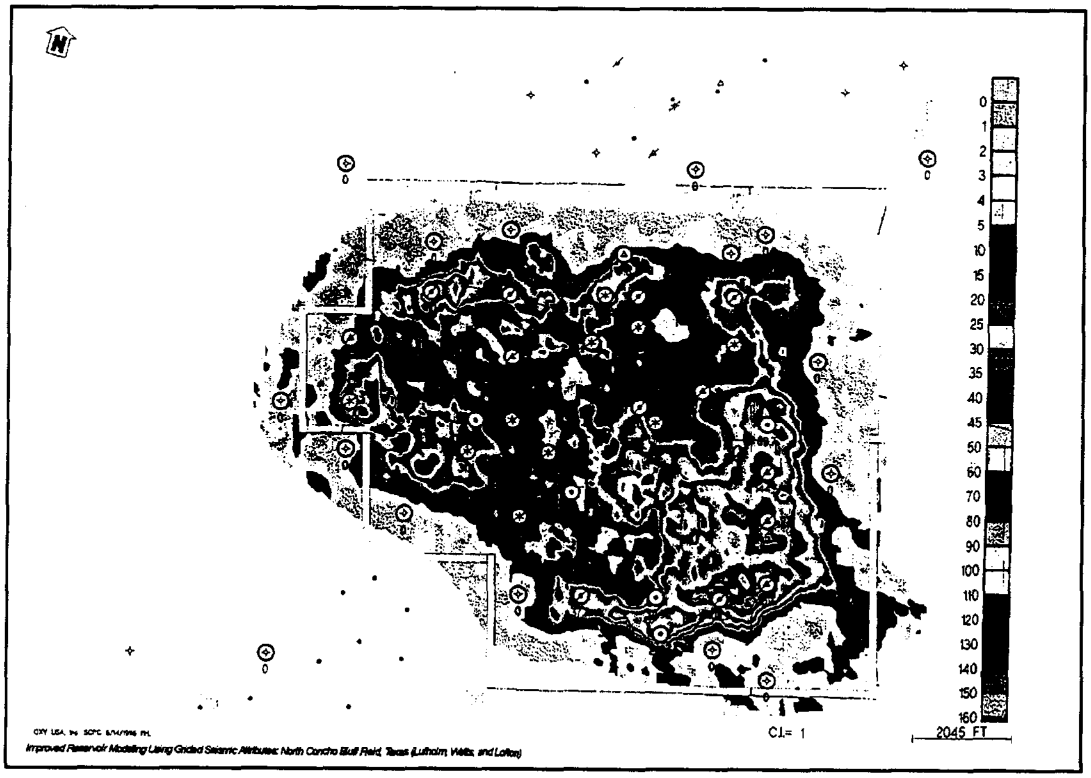

Figure 15 - Seismic guided average permeability across North Concho Bluff Field. Comparison with Figure 9 reveals that the well data has been preserved with a better representation of the inter-well region.

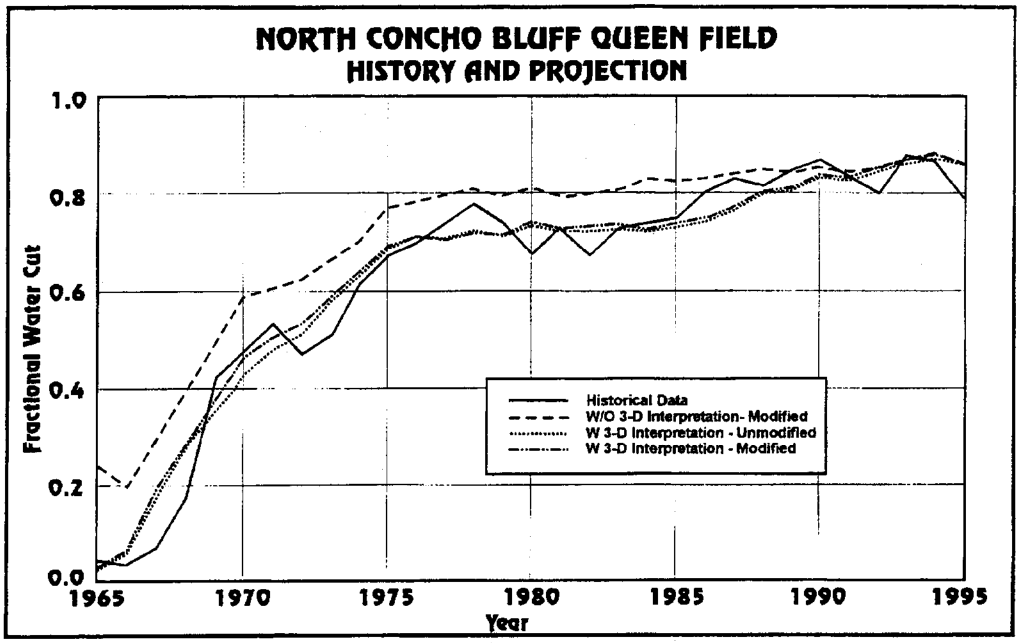

Figure 16 - Results from reservoir simulation using well reservoir properties from well data alone vs. using seismic guided reservoir properties for the North Concho Bluff Field.

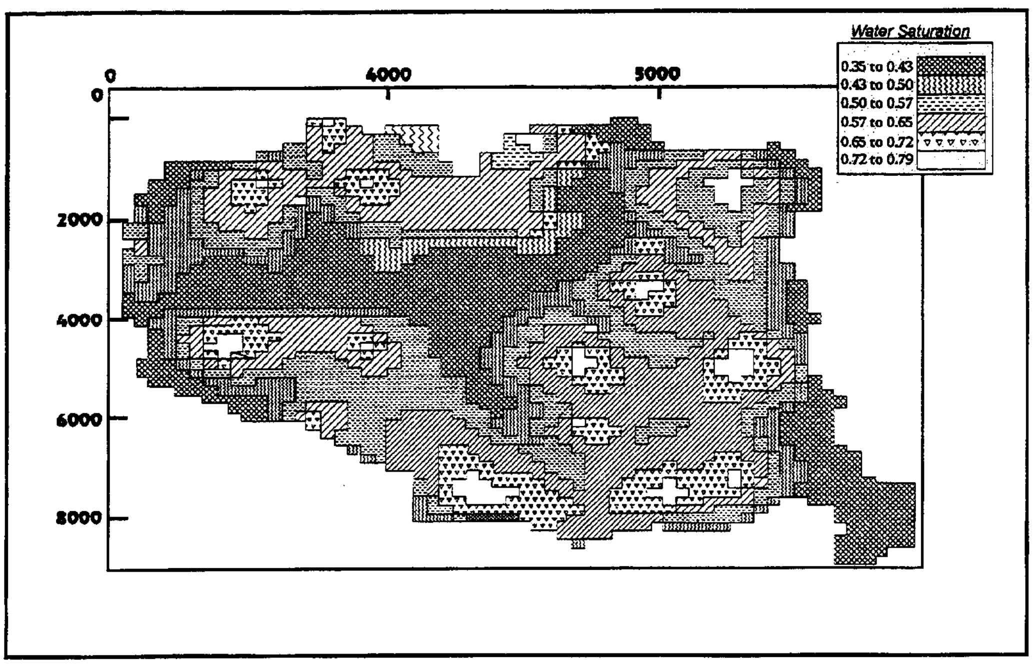

Figure 17 - Water saturation map from simulator of January 1, 1996. Note areas of low water saturations resulting from poor waterflood sweep efficiency.

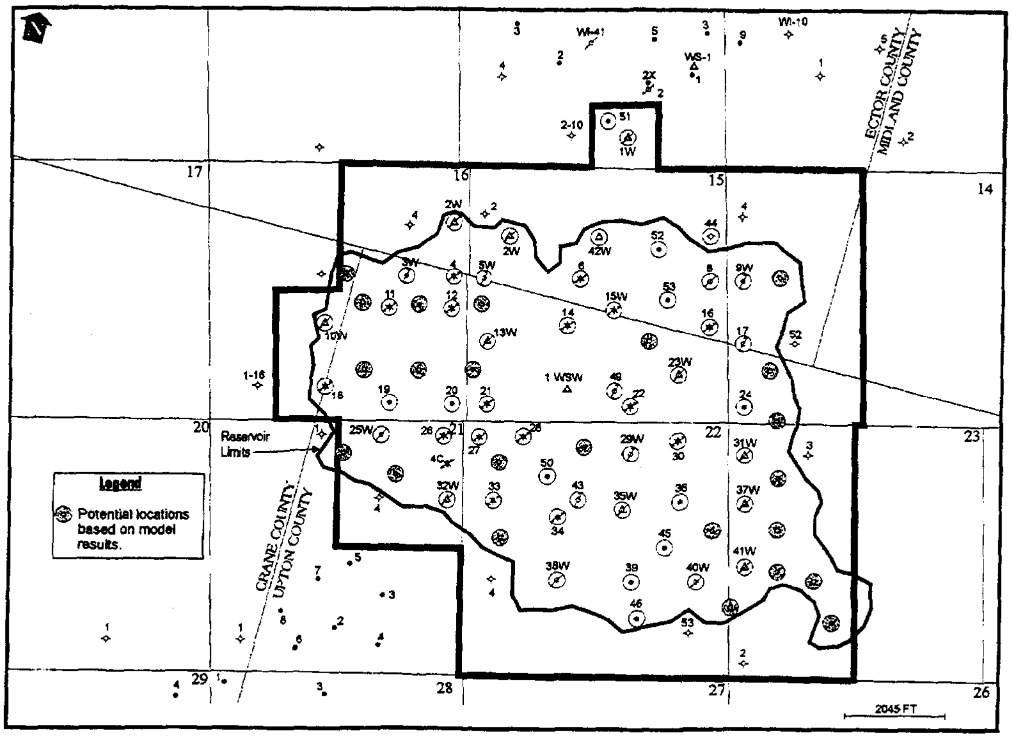

Figure 18 - Re-development plan for the North Concho Bluff Field. Modeled locations for strategic drilling.

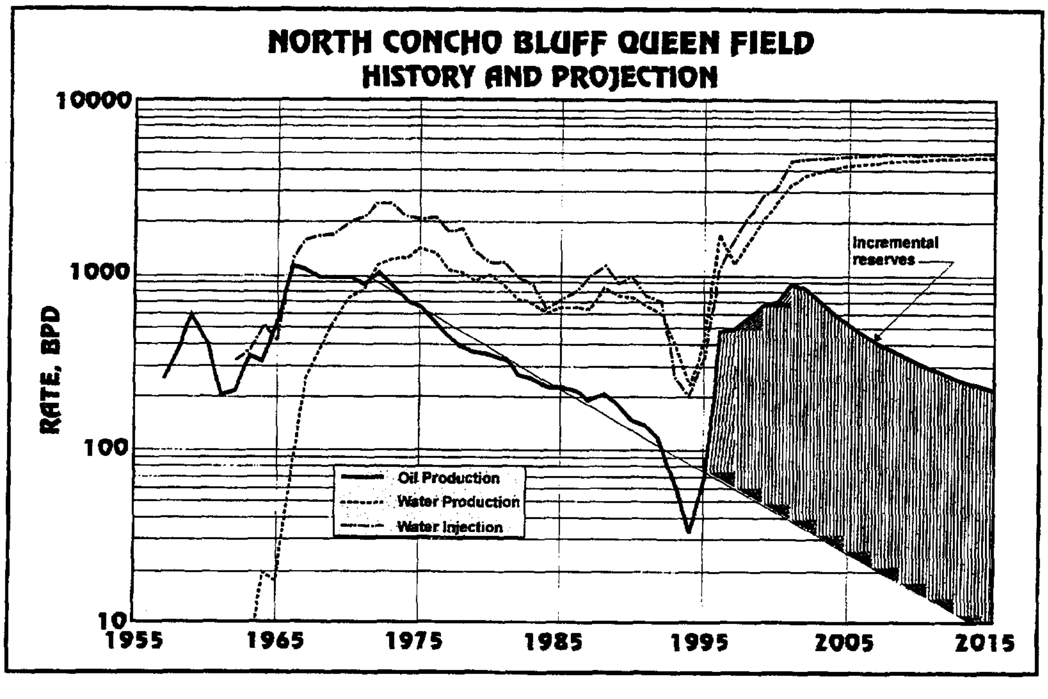

Figure 19 - Historical and projected production rates from numerical modeling. Incremental reserve addition from strategic drilling.