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Characterization and Simulation
of Minneola Field, Clark County, Kansas

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Executive Summary

This project was initiated to evaluate the waterflood potential of the Morrow Sandstone in the Minneola Unit, T30S-R25W, Clark County, Kansas. The evaluation comprised the following tasks:

- a) Subsurface geology was mapped to identify flow units and develop a 3-D reservoir model.
- b) Field production/injection data were analyzed and a production/injection history compiled for a majority of wells. Due to commingled production data, individual well production history could not be created for 3 pairs of wells. Available DST data were analyzed to calculate the initial reservoir pressure.
- c) Core analysis was performed on core from Patton #1-3 and Statton #2-12 to obtain reservoir properties including porosity, permeability, “irreducible” water saturation, capillary pressure relations, and wireline-log Archie cementation exponent. Data from previous Morrow Sandstone studies were utilized for compressibility and relative permeability relations.
- d) Available well logs were analyzed using the Super-Pickett technique to quantify porosity and water saturation (S_w) for flow-units.
- e) Lacking complete relative permeability data, effective permeabilities at end-point saturations were integrated with data from a rock catalog to develop relative permeability and capillary pressure curves for a suite of porosity-permeability pairs.
- f) Based on the above data, an input file was generated to create a 3D-reservoir model in a PC-based reservoir simulator. Simulation studies were carried out to history match individual well production and map residual oil reserves in Minneola field, as of October 2000.
- g) Based on the remaining reserve map, various reservoir management plans for tertiary recovery were simulated to predict their production performance.

The following summarize the interpretation of the results of the reservoir simulation studies.

1. Of the 3 sandstone flow units in the Minneola field, simulator-predicted residual oil reserves in layers #1 and #3 are low and only layer #2 exhibits good remaining oil saturations.
2. Average reservoir pressure is depleted due to prolonged primary production without pressure support.
3. Various field management strategies were simulated to predict oil recovery from three designated areas A, B, and C:

Area A – Using Fager #2-3 as an injector to sweep toward the Patton #2-3 proved to be ineffective due to the presence of a permeability barrier between the two wells. This permeability barrier was necessitated to history match production in the surrounding wells during simulation studies.

Area B – Using the Tedford #B1-10 as an injector to sweep the residual oil into the Tedford #4-10, is constrained by the low permeability of the Tedford #B1-10 drainage area. Simulation of the production performance of a new infill well, AreaBWell, indicates that a cumulative oil recovery of 10,000 bbls (produced at a BHP = 14.7 psi) can be attained after 2 years.

Area C – Low average reservoir pressure severely limits the potential for gas recovery in this area. An infill well, AreaCWell, is predicted to require more than 2 years to recover 10MMscf of gas when produced at a BHP of 14.7 psi.

4. Simulation studies show that oil production will be enhanced in the remaining few producing wells, within the unitized area, if water injection is stopped in the Patton #1-3 and Goeller #1-4 wells. It is interpreted that the present injected water is reducing the relative permeability of the remaining oil. Current injection volumes are insufficient to fill-up the reservoir and thereby initiate an effective sweep.

Setting and History

The Minneola Unit, part of the Norcan East Field, is located in Clark County, Kansas, approximately one mile north and two miles west of Minneola, Kansas. Initial development in this area began with the drilling of Norton #1-8 in Section 8, T30S, R25W. Completed in September 1980, this well initially flowed 157 bopd and 120 mcf. Murfin Drilling Co. began active drilling in 1983. Effective July 1993, Murfin Drilling purchased all of Swift Energy's (successor to Ladd Petroleum) interest in the general area.

The Minneola Unit produces from the Morrow sandstone. Based on available production and pressure data and simulation studies the primary drive mechanism in the reservoir is solution-gas. Initial oil production varied from 38 to 164 bopd with a majority of the wells producing both oil and gas. By 1993, the wells in the unitized area were approaching their economic limit under primary production, with field production having dropped to 26 bopd. In 1994, 13 tracts, operated by Murfin Drilling Co., were unitized to initiate a water-flooding program. The unitized area covers about 1040 acres and includes the W/2 of the NE/4; the S/2 of section 3; the S/2 of section 4; and the N/2 of section 10; all in T30S-R25W, Clark County, Kansas. Included in the unitized area were 12 producing wells and 2 water injection wells.

Subsurface Geology

Figure 1 highlights the area unitized in the Minneola field for waterflooding and also the study area for this project. Table 1 lists the available wireline logs. Wireline logs, DST, IP, and core data were used to define the lateral and vertical architecture of the reservoir. The geologic model characterized the reservoir as comprising three major flow units representing distinct sandstone beds, labeled from shallowest to deepest; sand #1, #2, and #3. Figures 2, 3, and 4 show the subsea structural elevation of each sand unit and the location of wells perforating each sandstone unit. Abbreviated well names were used in the simulation model. Abbreviated and full well names are presented in Table 2. Net pay for each sandstone unit varies across the Minneola unit (Figures 5, 6, and 7).

Production and DST data analysis

Available production data was analyzed and a production history was created at the well level for a majority of the wells in the study area. Appendix A (Figures A1 to A19) shows the production history of the wells in the study area. Reservoir simulation requires a production history for each well that is to be history matched. Production data, for three pairs of wells (1. Tedford #1-10 and Tedford #4-10, 2. Patton #1-3 and #2-3, and 3. Statton #1-12 and 2-12) were commingled, and therefore individual production data for these wells were not available. For the Tedford #1-10 and Tedford #4-10, on the basis of initial production records and operator experience, all the produced oil and water was attributed to Tedford #4-10. Gas production was attributed to Tedford #1-10. Similarly, all of the commingled production from the Patton lease was allocated to Patton #2-3 because Patton #1-3 had a very short producing life. For the Statton lease, lacking a basis to allocate lease production between the two contributing wells, a pseudo-well, identified as CstonM, was created and located adjacent to the Statton #2-12. The commingled Statton lease production was allocated to the CstonM well. Also, in the simulation-input file this well was opened to production from all the three sands in the reservoir. Figure A20 shows the production decline in Minneola field.

Reported oil production is strongly influenced by the periodicity of transporting and recording crude volumes from the stock tanks. The irregular frequency of collecting and reporting introduces irregularity into the production data that are not generally representative of actual well production. To better represent actual well production, monthly production rates for each well were calculated by averaging the raw production data over a period of 6 months. Thus, production history was created from a 6-monthly average of the sales volumes of oil and gas.

DST data were available for six wells. Reservoir pressure data from these DST measurements reveals the decline in reservoir pressure under primary production (Figure 8). Production from the first well in the Minneola field started in June 1982. Extrapolation of a best-fit line through the available pressure data indicates that the initial reservoir pressure in June 1982 was approximately 1,880 psi.

Core Petrophysical Analysis

Two cores were available from the Morrow Sandstone in the Minneola Unit, and they were from Patton # 1-3 and the Statton #2-12 wells. Full-diameter core analysis data, previously measured by commercial laboratories, was available for the 4 wells (Statton #2-12, Patton #1-3, Widner #1-17, and Fager #1-16) that were located in and around the study area. To understand the relationship between rock lithofacies and petrophysical properties and to obtain data for advanced reservoir properties, thirty-six (36) core plugs were obtained from whole cores from the Patton #1-3 and the Statton #2-12. Advanced core studies conducted on these plugs included determination of the following petrophysical properties: porosity, routine and *in situ* Klinkenberg permeability, "irreducible" brine saturation, capillary pressure curves, and *in situ* formation resistivity factor and cementation exponent. Relative permeability and pore volume compressibility properties were obtained from previous Morrow Sandstone analysis. Measured properties were analyzed and integrated to develop generalized reservoir property models - used to describe and quantify the reservoir simulation model. Experimental methods used in core petrophysical properties measurements are described in Appendix B. Table B1 (Appendix B) summarizes core analysis results from the previously measured full-diameter analyses and from the advanced properties measurements performed for this study. Basic reservoir properties are discussed below, referenced figures are presented in Appendix B.

Grain Density and Porosity

Although the available cores do not represent a systematic foot-by-foot sampling of the reservoir interval, the sampling is sufficiently continuous that it represents an appropriate statistical sample. Measurements on available cores indicated that the average grain density is 2.65 ± 0.02 (at 1 standard deviation) g/cc. This density is consistent with the quartzarenite (modified Folk classification) composition exhibiting >90% quartz matrix. The sandstone is generally very fine grained with sub-rounded to rounded grains. Cementation is primarily quartz overgrowth with lesser carbonate cement and minor clay. Abundant glauconite in the core taken from Texas Oil & Gas McConnell B (Sec. 6 T30S R24W) imparts a greenish color to the sandstone and makes the sandstone sensitive to both acid treatment and injected water salinity. The 2.65 gm/cc grain density indicates that density logs interpreted on the standard 2.65 gm/cc matrix density, with proper environmental corrections, should provide accurate porosity values.

In situ porosities (ϕ_{insitu}) were calculated from routine helium porosity (ϕ_{ambient}) values using a correlation for Morrow sandstones measured in a previous study:

$$\phi_{\text{insitu}} = (0.67 * \phi_{\text{ambient}} + 84.7) / 100 * \phi_{\text{ambient}}$$

This correlation predicts an average *in situ* porosity that is approximately 96% of routine core analysis porosity.

In situ porosity over the entire interval, based on all core analyses, averages 16.5 ± 3.8 (1 s.d.) %. Figure B1 illustrates that porosity within the reservoir interval generally ranges

from 12% to 24%. Previous analysis of Morrow cores (Byrnes 2001) has shown that pore volume compressibility at reservoir condition averages $6 \pm 2 \times 10^{-6}$ psi⁻¹ for Morrow sandstone for average porosity around $16 \pm 4\%$.

Permeability

In situ versus Routine – Permeability in the reservoir differs from routine air permeability values measured by conventional core analysis due to both confining stress effects and gas slippage, that is, Klinkenberg effects. Utilizing a generalized correlation for Klinkenberg correction and the air permeabilities measured under *in situ* confining stress, routine air permeability values ($k_{routine}$) were converted to *in situ* Klinkenberg or liquid-equivalent values (k_{insitu}) using the correlation:

$$\log_{10} k_{insitu} = 1.054 \log_{10} k_{routine} - 0.204$$

Full-diameter versus Plug - Full-diameter and corresponding plug permeabilities are similar (Figure B2) indicating that at this scale matrix properties dominate fluid flow, and that shale bedding architecture, cross-bedding, and fractures do not exert a significant influence.

Permeability and Porosity

To predict permeability distribution, within the sand bodies in the study area, a relationship between measured permeabilities and porosity and argillaceousness (shalyness) was developed. The general relationship between permeability and porosity for the Minneola Unit Morrow is similar to the relationship exhibited by other Morrow sandstones (Figure B3). *In situ* Klinkenberg permeability is cross-plotted against *in situ* porosity by well for the Minneola Unit in Figure B4. Because details of lithofacies are not available for many wells in the field a simpler predictive relationship for permeability was developed. A measure for shalyness was obtained from estimation of the shalyness of each core sample using a shalyness index ranging from 0-4. To tie observed shalyness to logs the wireline-log gamma ray for each depth corresponding to each sample interval was recorded and correlated with the measured shalyness index. The high degree of correlation indicated that a gamma-ray index (GRI), representing the Gamma-Ray API values from logs, were representative of the shalyness of the core samples and could therefore be used to replace the shalyness index in permeability prediction. Permeability increases with both increasing porosity and decreasing shalyness. Also evident is that the cleaner sandstones do not exhibit the highest porosity values. This may be due to greater quartz cementation or better sorting and packing. For prediction of reservoir permeability three class of shalyness were defined; $GRI \leq 30$ API units, $30 < GRI < 39$ API units, and $GRI \geq 40$ API units. For each sand interval at a well, the average GRI over the flow unit interval was calculated from the wireline log. The interval was assigned to one of the three classes based on the average interval GRI and the respective permeability was calculated using the appropriate equation for that class as determined by linear regression analysis for each class (Figures 9 and B5).

Both Patton #1-3 and Statton #2-12 show a fining-upward sequence that also correlates with increasing GRI upward. Since permeability decreases with increasing shalyness, the lower intervals in these wells exhibit higher permeability. The division of the Minneola reservoir into 3 layers is consistent with subdivision of the fining upward sequence.

Capillary Pressure

Air-Mercury Capillary Pressure – Five selected cores, representing a range in porosity and permeability for the different lithofacies, were analyzed for complete capillary pressure properties using mercury intrusion analysis to 10,000 psi. Tables and figures for each sample are presented in Appendix B (Tables B2 through B6, Figures B6 through B10).

The capillary pressure curves show a relationship of increasing threshold entry pressure with decreasing permeability that is consistent with a decrease in pore throat size as the permeability decreases. Similar to other Morrow sandstones, the “irreducible” wetting phase saturations were found to increase with decreasing permeability. This trend is better illustrated by the air-brine capillary pressure data discussed below. The more permeable cores exhibit transition zones of only several feet while the least permeable cores exhibit transition zones of 20-30 feet. Based on the saturation versus height profiles, the more permeable reservoir intervals were at or near “irreducible” saturation on discovery. For the less permeable rock, water saturations were considerably greater and reflected the high amount of bound water due to shalyness. For all cores, the wetting phase saturation at approximately 75 feet above free water level is within 5-10% of the “irreducible” saturation that can be achieved by these reservoirs in Kansas, given available structural closures in the state. Comparison between curves indicates that entry pressure, “irreducible” wetting phase saturation, and the capillary curve curvature (reflecting an increase in the heterogeneity of the pore throat sizes) increases with decreasing permeability.

Single-Point Air-Brine Capillary Pressure - Representative core plugs from the Patton #1-3 and Statton #2-12 were tested to determine water saturations near the estimated maximum oil column height for the Minneola Unit to determine original oil saturation. Brine saturated core samples were desaturated using a semi-permeable porous plate capillary pressure cell. Saturations achieved at an air-brine capillary pressure of 46.1 psi approach “irreducible” saturations achieved in the reservoir at an oil column height of approximately 75 feet above free water level. Data are summarized in Table B1.

Figure B11 illustrates that “irreducible” brine saturation (S_{wi}) is strongly correlated with permeability (K) for “clean” and “shaly” lithologies and S_{wi} decreases with increasing K_{insitu} . The relationship between S_{wi} and K_{insitu} is different for shaly (argillaceous to very argillaceous) sandstones than that exhibited by clean to slightly argillaceous sandstones. Shaly sandstones exhibit a significantly greater increase in S_{wi} with decreasing permeability than clean sandstones. This is consistent with increasing surface area and an increase in micropores with increasing clay and shale content. Clean sandstones exhibit little increase in S_{wi} with decreasing K_{insitu} , consistent with only modest increase in surface area and

microporosity with quartz or carbonate cementation. "Irreducible" saturation can be predicted using the following equations:

$$\text{Shaly - Very Shaly: } S_{wi} = -28.89 \log_{10} K_{insitu} + 78.6$$

$$\text{Clean-Slightly Shaly: } S_{wi} = -14.55 \log_{10} K_{insitu} + 46.8$$

The standard error of prediction for these equations is $5 \pm 1\%$. It is important to note that the higher "irreducible" saturations of the lower porosity and permeability sandstone samples diminishes their relative contribution to the total storage and flow capacity of the reservoir compared to the higher porosity and permeability samples.

The predicted irreducible water saturations are consistent (Figure B11) with water saturations measured in the reservoir from wireline logs as discussed in the Pickett Plot Analysis section.

Generalized Capillary Pressure Curves – To provide capillary pressure curves for the reservoir simulation it was necessary to develop generalized curves that represent specific permeabilities, such as the permeability value attributed to a sand body in a well. Equations of generalized capillary pressure curves were constructed based on the relationships evident from the entry pressures in the air-mercury capillary pressure curves and the capillary pressure curve shapes, and from the saturations evident in the air-brine capillary pressure analysis. The relationships between increasing entry pressure, "irreducible" wetting phase saturation, and the capillary-curve curvature (reflecting increasing pore throat size heterogeneity) with decreasing permeability were utilized to develop equations that would predict the capillary pressure curve using permeability as the independent variable.

Entry pressure, or the first pressure at which wetting phase desaturation begins, exhibits a strong correlation with permeability and can be predicted using:

$$P_{cow_{entry}} = 1.311 \log_{10} ki + 3.364$$

where $P_{cow_{entry}}$ is the oil-water entry pressure and ki is the insitu permeability.

To model the changing capillary curve shape with decreasing permeability, an empirical function was developed to predicted curve shape and "irreducible" saturation from ki :

$$P_{cow} = P_{cow_{entry}} + \exp(P_{ca} + P_{cb} S_w^2)$$

where:

S_w = water saturation (%)

$$P_{ca} = 1.363 \log_{10} ki + 9.64$$

$$P_{cb} = -0.29 \log_{10} ki^3 + 0.85 \log_{10} ki^2 - 0.644 \log_{10} ki - 0.52$$

where P_{ca} and P_{cb} are empirical terms calculated for use in the capillary pressure curve equation. Using the above equations, capillary pressure curves were constructed for a given permeability.

Archie Cementation Exponent - Water saturations were derived from wireline logs using the standard Archie equation for water saturation calculations. Previous analysis of Morrow sandstones has shown that the Archie cementation exponent, m , and intercept, a , differ from the conventional values of 2 and 1, respectively, for different lithofacies. To evaluate the correct values for the Archie cementation exponent and intercept, these parameters were measured on many of the core plugs obtained. Values measured are summarized in Table B1 and the formation resistivity factor versus porosity cross-plot is shown in Figure B12.

Figure B12 shows that the Archie cementation exponent averages $m = 1.78 \pm 0.09$ with $a = 1$. Linear regression analysis of the trend indicates that $m = 1.74$ for $a = 1.08$.

Relative Permeability

Previous study of Morrow cores provided oil-water (imbibition) relative permeability curves for six cores from the Stewart field, which are summarized in Table B7 and Figure B13. These cores exhibit S_{wi} versus k_i trends that are similar to those obtained from Morrow core plugs from the Minneola field. Effective water permeabilities at residual oil saturation $k_{ew, Sorw}$ range from 0.06 to 0.325 and averages close to 0.19.

To model the relative permeability curves the following Corey-type equations were used:

$$k_{ro} = \alpha_1 (1 - S_{wD})^m$$

$$k_{rw} = \alpha_2 S_{wD}^n$$

$$S_{wD} = (S_w - S_{wi}) / (1 - S_{or} - S_{wi})$$

Where S_w = water saturation fraction, S_{wi} = “irreducible” water saturation fraction, S_{or} = residual oil saturation to waterflood, α_1 = effective permeability to oil at S_{wi} , α_2 = the effective permeability to water at residual oil saturation, m = oil relative permeability exponent, n = water relative permeability exponent (these last two variables are not related to the Archie cementation and saturation exponents m and n).

For the Stewart field Morrow, relative permeability exponents appear to exhibit trends that change with absolute permeability but cannot be defined with confidence. Based on the distribution of these values, median values were adopted. The above generalized Corey-type equations were used to develop oil-water and gas-oil relative permeability curves for rocks with differing permeability. For each permeability value, the S_{wi} input into the relative permeability equation was predicted using the synthetic capillary pressure curve equations described above. Initial values for m , n , and S_{orw} were 2.8, 3.1, and 37% respectively. Available data indicates that Morrow S_{orw} averages 37% and is not correlated with permeability. Based on this analysis, S_{orw} was assumed to be a constant 37% for all permeabilities. Calculated relative permeability and capillary pressure curves for rocks with 3 md, 10 md, 30 md, 100 md, and 300 md are shown in

Tables B8 through B12 with accompanying figures. Wells in Minneola field do not have a history of water production during the primary phase. Thus, it was assumed that the initial S_w , obtained from wireline logs, at each producing horizon at each well was the irreducible water saturation S_{wi} . Each sand body at each well was initially assigned a relative permeability-capillary pressure set, from amongst the 5 sets (mentioned above), such that the S_{wi} value used in the calculation of relative permeability corresponded closely with the log-derived S_w . The initial log-derived S_w values, obtained at wells in the study area, were grouped in 5 sets, and a relative permeability-capillary pressure table was assigned to each set. Greater subdivision was not considered necessary since the five relative permeability curve sets covered the range in S_w (or S_{wi} in this case) and differed in saturation by less than 15% (saturation percent). During history matching the Corey exponent m and n were adjusted for some well locations to provide gas, oil, and water flow rates consistent with observed production. This is discussed in the Reservoir Simulation section.

Super-Pickett analysis of wireline logs

Resistivity and porosity logs were available for a majority of the wells in the Minneola Unit, and were analyzed using Super-Pickett cross-plots (Figures C1 to C64 in Appendix C). Values of the Archie cementation exponent, m , (= 1.74) and intercept, a (=1.08) were obtained from petrophysical analysis of available cores. As noted, the observed values for the Minneola Unit Morrow cores are consistent with those obtained from channel sands in the Morrow in other fields.

Average grain density, needed for density log interpretation, was measured to be 2.647 g/cc with a standard deviation of 0.012 g/cc. Porosity maps for the three sandstone units, based on density log interpretation using the observed grain density, are presented in Figures 10, 11, and 12. Initial water saturation ($S_w = S_{wi}$) maps were constructed, based on the Super-Pickett analysis at wells located in and around the study area (Table 3). Permeability for each sandstone unit at each well was assigned utilizing the log-derived porosities and the permeability-porosity correlations (Figure 9). The log-linear correlations, shown in Figure 9, project permeabilities greater than 1 darcy for high porosities. The maximum permeability observed in Morrow core-plugs from the Minneola Unit is approximately 250 md. To avoid assigning permeabilities significantly greater than the measured maximum, permeabilities that were predicted to be greater than 500 md (using the permeability-porosity correlations) were assigned a permeability of 500 md (i.e., the maximum permeability in the geomodel was set at 500 md). The initial permeability maps of the three sandstone units are presented in Figures 13 to 15.

Reservoir Simulation

The CMG simulator, a PC-based reservoir simulator, was used to simulate the Minneola field. The model comprised 3-layers using 74 by 32 grid cells in each layer. Each grid cell was sized 250 ft by 250 ft. Thickness of each gridcell was uniquely assigned based on the isopach maps of each sandstone unit (Figures 5 to 7).

Values of the major reservoir parameters that were part of the simulation-input file are summarized in Table D1. During the primary production phase, there is no record of water production from any of the wells in Minneola field. It was therefore assumed that the water saturation calculated from wireline logs was near “irreducible” water saturation (S_{wi}), i.e., relative permeability to water (k_{rw}) = 0. During the initialization process, the simulator calculated the reservoir pressure distribution using the hydrostatic equation and the water saturation (S_w) distribution in each layer was generated from the capillary pressure curves. For each sandstone unit, a capillary pressure curve was assigned to represent the drainage area of the well such that the S_{wi} from the capillary curve corresponded with the S_w derived from the wireline log. The simulator was set to a grid-center basis such that the block saturation was read from the saturation that exists at the center of the grid cell.

For wells that were drilled before 1984 and produced both oil and gas, gas production data were not available during the initial months – ranging between 9 to 28 months (Table D2). A gas-gathering network was laid in place in the Minneola field during 1984, and therefore any previous gas production was perhaps flared and not metered. Without recorded gas production, the gas production history for the initial months was estimated by multiplying the first known GOR with the oil production. No data were available to obtain/calculate either the bubble point pressure (P_b) or the solution GOR for the Minneola Unit. During the course of the simulation studies, it was found that the reservoir pressure decline could be modeled when the reservoir was assumed to have an existing gas cap at the onset of production, i.e., setting the bubble point pressure (P_b) at 2000 psi while the initial reservoir pressure (P_i , from DST studies) was input as 1880 psi. Using standard correlations and assuming the above P_b and P_i , the solution GOR was approximated at 650 scf/STB.

Horizontal permeability was assumed to be isotropic. Measured core data indicate vertical permeability averages 10% of the horizontal permeability where shale laminae exist. In the simulation model, vertical permeability in each grid cell was initially estimated as 10% of the horizontal permeability.

The reservoir simulation study was divided into 2 phases. In the 1st phase, a history match was carried out on the primary production of each well. This process recreated the initial saturation distribution of oil and gas within the productive sandstone units of the reservoir. During the 2nd phase, both the primary and secondary production were history matched, and this process helped to delineate the permeability variation, both laterally and vertically, within the reservoir sandstone units especially within the unitized area – under water injection.

Interpretation of wireline logs resulted only in the estimation of the initial S_w . Initial distributions of the oil and gas saturations were obtained through the process of history matching the cumulative oil and gas production during the primary phase of the field. Though a regular record of the reservoir pressure during its primary production phase was not available, an engineering study conducted before the onset of the waterflood noted that the reservoir pressure had declined to about 100 psi. Adjustments made to the initial oil and gas saturations, within the drainage areas of the wells in the study area, resulted in improving the match between the estimated oil and gas production and the simulation output. It also resulted in simulation prediction of a rapid decline in reservoir pressure.

The results of the history matches of the production performance at each well are presented in Appendix D. For history matching, oil production rate, at each well, was included in the input file. The simulator was set to produce the given oil rate, known from the production history, and in the process, calculate the associated gas and water production without letting the bottom hole pressure drop below 14.7 psi. Figures D1 to D19 are the best matches between the known/estimated historic production and that obtained from simulation. As a result of the simulation studies, a map showing the residual oil reserves in the field, as of October 2000, was generated. Based on this map, different infill recovery plans were simulated to predict their performance - in terms of incremental recovery.

The 2nd phase of the simulation studies extended the history matches obtained in the 1st phase. During this phase, effort was made to: 1) match the water breakthrough at the producing wells within the unitized area under the waterflood, and 2) to match the cumulative water production at these wells. Adjustment of the horizontal and the vertical permeability distributions within the drainage areas of the individual wells play a critical role in improving the matches with water breakthrough and production. Current fluid level data were available for most of the wells within the unitized area. The bottom hole pressure, as of late 2000, calculated by the simulator at wells within the unitized area is compared with the closest recorded fluid level data in the Figures D1 to D19. The complexity in the permeability distribution within the producing sandstone units is evidenced from the approximate matches achievable for water breakthrough and production in some of the wells.

As stated previously, gas production data were not available for many of the wells during the initial months of production. Produced GOR in solution-gas driven reservoirs is not constant. To reconstruct the gas production history, a constant GOR, equal to the first recorded GOR at the well, was multiplied with the recorded/estimated oil production. While comparing simulator predicted gas production with the estimated gas production at the well level, the existence of significant uncertainty in gas production values needs to be kept in mind.

Upon completing the history match for individual production of all productive wells, the residual oil and gas saturations, as predicted from the simulation output, were mapped across the study area. Figures D20 to D22 show the distribution of simulator-predicted

remaining oil saturation-feet (*Sorw*-ft) in each of the three sandstone units in the Minneola Unit for October, 2000. Figures D23 to 25 show the residual gas saturation-feet (*Sgrw*-ft) in the three layers for October, 2000. It is apparent that in sandstone units #1 and #3 there are very little recoverable reserves remaining. Figure D21 shows the three localized areas, marked by circles A, B, and C. Region C in Figure D24 also has high residual gas saturations.

Several drilling plans were simulated to predict recovery performance for different infill well locations to exploit pockets of remaining reserves. The results of the various simulations are presented by area.

Area A – This area was identified as one of the candidate areas for incremental recovery.

Analysis Limitations – As noted earlier, the production data from Patton #2-3 and #1-3 were commingled and there were no production test data available to allocate the commingled production between these wells. Also, the shut-in date of Patton #1-3 was not available. Based on the available information from the field, it was assumed that all the commingled production came from Patton #2-3 because the Patton #1-3 did not produce for a long time. History matching of Patton #2-3 was therefore made on this assumption. No wireline-log data were available over the perforated interval in Fager #2-3. Initial petrophysical properties attributed to the drainage area of this well were based on properties from neighboring wells. Due to lack of the gas production data for the 1st 21 months, an estimated cumulative gas production (Figure D6) has been attributed to Fager #2-3.

Performance Prediction - Fager #2-3 is one of the few wells in the study area with no reported water production to date. For the simulator model to match the production performance of this well, a zone of low permeability (10 md, Figure D26) was introduced between Fager #2-3 and Patton #2-3 (named as ComPat in the simulator model). It is evident from Figure D31 that the injector Patton #1-3 (IPat) is structurally lower than both Fager #1-3 and Patton #2-3 (ComPat). Currently Patton #2-3 is closed. The effectiveness of using Fager #2-3, one of the best producers in the field, as an injector (thus injecting water high on the structure) to recover the remaining oil in region A at Patton #2-3 (called as PatPrd) was simulated.

Figure D27 displays the fluid production at PatPrd when water is injected in the Fager #2-3 beginning in November, 2000, with injection constrained to a maximum BHP of 3000 psi, and resulting daily injection rate around 550 bbl/day. The model also includes the effects of continual water injection in Patton #1-3. The production profiles are compared with those obtained at PatPrd when water is injected only in the Fager #2-3. When water is injected in the Fager #2-3 and Patton #1-3, cumulative oil recovered at PatPrd is 3,015 bbl (end of 2003) and 6,120 bbl (June, 2005) with cumulative produced water of 295,927 bbl (end of 2003) and 737,901 bbl (June, 2005). When water is injected only into the Fager #2-3, cumulative oil recovered at PatPrd is 1,124 bbl (end of 2003) and 3,196 bbl (June, 2005) with cumulative produced water of 198,885 bbl (end of 2003) and 488,212 bbl (June, 2005). The results suggest that the region of low permeability

between Fager #2-3 and Patton #2-3 prevents effective sweep of the remaining oil in area A when the Fager #2-3 is used as an injector. Based on these results, the continued production of the Fager #2-3 is an effective management strategy. Figure D28 shows the production at Hindman #1-3 (i.e., HindNew) due to water injection at Fager #2-3 and Patton #1-3.

Note (Figures D27 and D28):

“FgrInj PatInj” – water injected in Fager #2-3 and Patton #1-3

“FgrInj NoPatInj” – water injected only in Fager #2-3

Area B – It is apparent from Figures D21 and D24 that the residual oil and gas potential in this area is higher than most other areas in the field. Various recovery options were simulated to predict the production performance of each.

Analysis Limitations – Area B is bounded by Tedford #B1-10 in the southwest, Tedford #1 in the northwest, Tedford #4-10 in the north, and Tedford #2-10 in the northeast. No wells exist on the eastern or southeastern borders of the area because the sandstone unit #2 pinches out in these directions. The simulation predicts that the highest residual oil saturations (as of October 2000) occur on eastern and southeastern borders of area B. The higher remaining saturations in these border areas may be due to boundary edge effects and therefore may not reflect actual saturations. Tedford #4-10 is one of the few wells in the field that continues to produce. However, as noted, available production data for this well is commingled with Tedford #1-10. It has been the operator’s experience that Tedford #1-10 has produced significant quantities of gas. For history matching, all produced oil and water production was attributed to the Tedford #4-10 and all the produced gas was assigned to the Tedford #1-10. The uncertainty introduced by this assumption is further compounded by the absence of gas production data for the Tedford #2-10 during the critical first 28 months.

Performance Prediction - One of the options simulated consisted of water injection at Tedford #B1-10 to direct the remaining oil to the Tedford #4-10. In the simulation model, water was injected in the Tedford #B1-10 at a constant BHP of 3000 psi and Tedford #4-10 was produced at a BHP of 14.7 psi. Figure D29 summarizes oil and water production at the Tedford #4-10 as a result of five different reservoir management scenarios:

1. “Basecase” profiles show cumulative oil and water production at the Tedford #4-10 (producing well) if water injection continued as usual in the Patton #1-3 and the Goeller #1-4.
2. “TedBInj” profiles show the effect of injecting water in the Tedford #B1-10 (with BHP = 3000 psi) in addition to continued water injection in the Patton #1-3 and Goeller #1-4 wells.
3. “NoInjGller” profiles show predicted production if water injection were shut off in the Goeller #1-4 but injection continuing in the Tedford #B1-10 (at BHP = 3000 psi) and Patton #1-3 wells.
4. “NoOldInj” profiles show the effect of stopping water injection in the Patton #1-3 and Goeller #1-4 wells.

5. “NoWtrInj” profiles show the estimated production when no water is injected in the field.

It is apparent from Figure D29 that oil production is maximized and water production is minimized when water injection is stopped in the unitized area. Low permeability within the drainage area of the Tedford #B1-10 severely restricts water injectivity and thereby limits the effectiveness of using this well as an injector.

The effects of stopping water injection, in the unitized area, on the oil production from the few producing wells are summarized in Figure D30. In the simulations abbreviations for the Tedford #4-10, Harris #1-3, Hindman #1-3, and Norton #1-4 are the NewTed, NewHarris, NewHind, and NewNrtn, respectively. In each of these wells, oil production increases when the water injection is stopped in the Patton #1-3 and the Goeller #1-4 wells. Increased oil production may be attributed to enhanced oil relative permeability due to decreased water production.

Simulation studies were also carried out to predict the performance of an infill well in Area B. In Figure D31, the location of a postulated infill well, AreaBWell, is shown with a red circle. Figure D32 shows oil, gas and water production from this infill well for production conditions where BHP is 14.7 psi and where water injection continues in the Patton #1-3 and Goeller #1-4 wells.

Area C – Residual reserve maps, Figures D21 and D24, show that the oil and gas saturation-feet in this area is higher than other areas in the eastern part of the Minneola field. Thus, the incremental production potential of this area was simulated.

Analysis Limitations – Figure D33 shows the distribution of reservoir pressure for October, 2000. This map indicates that the reservoir pressure in the vicinity of Area C has declined to less than 100 psi. Bottom hole pressures in the Schlichting #1-2, Rooney #1, and CStonM (located at Statton #2-12) are 85, 61, and 50 psi, respectively. This low reservoir pressure severely limits the potential for incremental gas recovery from Area C. As noted, only commingled production data were available for the Statton #2-12 and no production test data are available to allocate the lease production between the wells. For history matching, all the commingled production from the Statton lease was allocated to a hypothetical well, CStonM, located adjacent to the Statton #2-12, which produced from all three sandstone units. Another source of uncertainty to the gas saturation in Area C is the lack of gas production data during the first 5 months of production from Rooney #1.

Performance Prediction – A simulation was conducted to predict production from an infill well, AreaCWell (location circled in red in Figure D31). Figure D34 shows predicted oil and gas production from this infill well when it is produced at a BHP = 14.7 psi.

Conclusions

The following summarize interpretation of the results of the various simulations.

1. Of the 3 sandstone flow units in the Minneola field, simulator-predicted residual oil reserves in layers #1 and #3 are low and only layer #2 exhibits good remaining oil saturations.
2. Average reservoir pressure is depleted due to prolonged primary production without pressure support.
3. Various field management strategies were simulated to predict oil recovery from three designated areas A, B, and C:

Area A – Using Fager #2-3 as an injector to sweep toward the Patton #2-3 proved to be ineffective due to the presence of a permeability barrier between the two wells. (The inclusion of this permeability barrier was necessitated during history matching of production and pressure data at the surrounding wells.)

Area B – Using the Tedford #B1-10 as an injector to sweep the residual oil into the Tedford #4-10, is constrained by the low permeability in the drainage area of the Tedford #B1-10. Simulation of the production performance of a new infill well, AreaBWell, indicates that more than 2 years will be required for a cumulative oil recovery of 10,000 bbls (at a producing BHP = 14.7 psi).

Area C – Low average reservoir pressure severely limits the potential for gas recovery. An infill well, AreaCWell, is predicted to require more than 2 years to recover 10MMscf of gas when produced at BHP of 14.7 psi.

4. Simulation studies show that oil production will be enhanced in the remaining few producing wells, within the unitized area, if water injection is stopped in the Patton #1-3 and Goeller #1-4 wells. It is interpreted that the present injected water is reducing the relative permeability of the remaining oil. Also, the current injection volumes are insufficient to fill-up the reservoir and thereby initiate an effective sweep.

REFERENCE:

A.P. Byrnes, L.A. Buatois, M.G. Mangano, T.R. Carr, 2001, "Integration Of Lithofacies And Petrophysics In Marine And Estuarine Morrow Sandstone, Southwest Kansas: A Midcontinent Rock Catalog Example", Oklahoma Geological Survey Circular 104, p. 59-65.

Table 1

Section	Well name	Operator	Status	API	Location	Digitized logs available
1	Lampe #1	Spines Exploration	D&A	15-025-20586	C NE SW	
	McGee #1	Coastal O &G	D&A	15-025-20571	NW NE SE	
	McGee #1-1	Murfin	Gas	15-025-20886	SE SE SE	GR, ILD, N-Dphi
2	Rooney #B1-2	Murfin	D&A	15-025-20917	S2 SW NW	GR, ILD, N-Dphi
	Rooney #2-2	Murfin	D&A	15-025-20674	C SW NE	
	Rooney #1-2	Murfin	D&A	15-025-20546	NE SE NE	
	Hall #2-2	Murfin	D&A	15-025-20838	NW NE SW	GR, ILD, N-Dphi
	Hall #1-2	Murfin	O&G	15-025-20785	SW NW SW	
	Hall #B1-2	Murfin	D&A	15-025-20919	W2 SW SW	
	Schlichting #1-2	Ladd	Gas	15-025-20703	S2 SW SE	GR, ILD, N-Dphi
3	Lena Boucher #1-3	Santa Fe	D&A	15-025-20695	SE SE NW	GR, ILD, Sonic
	Fager #2-3 (Attokan)	Ladd	O&G	15-025-20671	S/2 SW NE	GR, ILD, N-Dphi
	Fager #1-3	Murfin	D&A	15-025-20696	SW SE NE	GR, ILD, N-Dphi, Sonic
	Hindman #1 (#1-3)	Ladd	O&G	15-025-20635	SE NE SW	GR, ILD, N-Dphi, PE, Rhob
	Patton #2-3 (C)	Murfin	O&G	15-025-20685	C NW SE	GR, ILD, N-Dphi
	Patton #2-3	Ladd	D&A	15-025-20859	SE NE SE	GR, ILD, N-Dphi
	Harris #1-3	Ladd	Oil	15-025-20616	NW SW SW	GR, ILD, N-Dphi, PE, Rhob
	Patton #1-3 (C)	Murfin	Oil/Inj	15-025-20668	N/2 SW SE	GR, ILD, N-Dphi, PE, Rhob
	Patton #1	Ladd	O&G	15-025-20594	C SE SE	GR, ILD, N-Dphi, Sonic
4	Harris #2-3	Ladd	Oil	15-025-20708	SE SE SW	
	Norton #1-4	Murfin	O&G	15-025-20890	N2 SE SW	GR, ILD
	Goeller #1-4	Murfin	O&G	15-025-20858	NE SW SE	GR, ILD, N-Dphi
	Norton #E-1	TXO Prod	D&A (W supply)	15-025-20837	S2 SE SW	GR, ILD, N-Dphi
9	Goeller #1-4 (Attokan)	Murfin (Ladd/Swift)	Oil/Inj	15-025-20615	SW SE SE	GR, ILD, N-Dphi, PE, Rhob
	Alley #1-9	Murfin	D&A	15-025-20911	NW NE NW	GR, ILD, N-Dphi
	Norton #B-1	TXO Prod	D&A	15-025-20672	NW NE NE	GR, ILD, N-Dphi, PE, Rhob
	Alley #1-9 (#1)	Ladd	D&A	15-025-20641	W/2 SW NW	
10	Alley #1	Trans Pacific	D&A	15-025-21011	SW SE NW	
	Tedford #1	Ladd	O&G	15-025-20416	NW NW NW	GR, ILD, N-Dphi
	Tedford #4-10 (C)	Murfin	O&G	15-025-20720	NE NE NW	GR, ILD, N-Dphi
	Tedford #2-10	Ladd	O&G	15-025-20669	C NW NE	GR, ILD, N-Dphi
	Tedford #1-10 (C)	Murfin	Gas	15-025-20621	NE NE NE	GR, ILD, N-Dphi, PE, Rhob
	Tedford #B1-10	Murfin	Oil	15-025-20905	NE SW NW	GR, ILD, N-Dphi
	Tedford #3-10	Murfin	D&A	15-025-20788	NE SE NE	GR, ILD, N-Dphi
11	Tedford #2-10	Murfin	D&A	15-025-20686	S/2 SE NW	GR, ILD, N-Dphi, PE, Rhob
	Latzke #1	Ladd	O&G	15-025-20611	S/2 N/2 NW	GR, ILD, N-Dphi
	Rooney #1-11	Ladd	D&A	15-025-20702	S/2 NW NE	GR, ILD, N-Dphi, PE, Rhob
12	Rooney #1	Jones Vern	O&G	15-025-20965	NE NE	GR, ILD, N-Dphi
	Statton #2-12 (C)	Murfin	O&G	15-025-20991	NW NW NW	GR, ILD, N-Dphi, PE, Rhob
	Statton #1-12 (C)	Murfin	Gas	15-025-20881	NE NE NW	GR, ILD, N-Dphi
12	Statton CPC #98-2	Cimarron Pet	D&A	15-025-00081	SE SE NW	

Codes: GR gamma ray log
ILD deep resistivity log
N-Dphi neutron and density porosity logs

PE photoelectric log
Rhob litho-density log

Table 2

Well name	Operator	API	Start date	Perforated sand(s)	Abbreviation
Latzke #1	Ladd	15-025-20611	Jun-82	SS#2 & 3	Latz1L
Patton #1	Ladd	15-025-20594	Aug-82	SS#2	Pat1L
Harris #1-3	Ladd	15-025-20616	Nov-82	SS#2 & 3	Haris13L
Hindman #1 (#1-3)	Ladd	15-025-20635	Dec-82	SS#2	Hndmn13L
Goeller #1-4 (Attokan)	Murfin (Ladd/Swift)	15-025-20615	Dec-82	SS#2	IGller
Fager #2-3 (Attokan)	Ladd	15-025-20671	Mar-83	SS#2	Fgr23L
Patton #1-3 (C)	Murfin	15-025-20668	Mar-83	SS#3	IPat
Tedford #1	Ladd	15-025-20416	Mar-83	SS#2	TedF1L
Patton #2-3 (C)	Murfin	15-025-20685	May-83	SS#2	ComPat
Harris #2-3	Ladd	15-025-20708	Jul-83	SS#1	Haris23L
Tedford #2-10	Ladd	15-025-20669	Aug-83	SS#2 & 3	TedF210L
Schlicting #1-2	Ladd	15-025-20703	Jan-84	SS#2	Sctling12L
Tedford #4-10 (C)	Murfin	15-025-20720	Feb-84	SS#2	CTedF410M
Tedford #1-10 (C)	Murfin	15-025-20621	Feb-84	SS#1	CTedF110M
Hall #1-2	Murfin	15-025-20785	Jun-84	SS#2	Hall12M
Goeller #1-4	Murfin	15-025-20858	Jan-85	SS#2	Gller14M
Norton #1-4	Murfin	15-025-20890	Apr-85	SS#2	Nrtn14M
Tedford #B1-10	Murfin	15-025-20905	Aug-85	SS#2	TedfB110M
Statton #1-12 (C)	Murfin	15-025-20881	Dec-85	SS#1	CStonM
Rooney #1	Jones Vern	15-025-20965	Jan-87	SS#2	Rney1JV
Statton #2-12 (C)	Murfin	15-025-20991	Jun-87	SS#1 & 2(part)	CStonM

Note: Commingled production from Statton #1-12 and #2-12 was attributed to 1 well, CStonM, that was located at the same position as Statton #2-12

Table 3													
Well name	API	SD #1 Phi	SD #1 Sw	SD#1 GR	SD#1 Perm md	SD #2 Phi	SD #2 Sw	SD#2 GR	SD#2 Perm md	SD#3Phi	SD#3Sw	SD#3GR	SD#3 Perm md
McGee #1-1	15-025-20886	0.217	0.316	35	112.7								
Rooney #B1-2	15-025-20917	0.2	0.39	63	22.1	0.165	0.62	78	8.4				
Hall #2-2	15-025-20838					0.126	0.624	41	2.8				
Hall #1-2	15-025-20785	0.108	0.45	57	1.7	0.199	0.341	30	224.2				
Hall #B1-2	15-025-20919	0.191	0.275	57	17.2	0.16	0.533	59	7.3				
Schlichting #1-2	15-025-20703					0.242	0.215	30	952.9				
Lena Boucher #1-3	15-025-20695	0.127	0.492	62	2.9								
Fager #2-3 (Attokan)	15-025-20671	0.254	0.156	22	1427.0								
Fager #1-3	15-025-20696	0.274	0.289	53	173.3								
Hindman #1 (#1-3)	15-025-20635					0.23	0.196	25	636.3				
Patton #2-3 (C)	15-025-20685					0.256	0.205	28	1526.3	0.238	0.321	50	63.7
Patton #2-3	15-025-20859	0.185	0.282	47	14.6	0.15	0.378	33	13.6				
Harris #1-3	15-025-20616	0.108	0.418	72	1.7	0.203	0.308	31	72.4	0.249	0.392	47	86.5
Patton #1-3 (C)	15-025-20668					0.128	0.54	42	3.0	0.194	0.456	37	54.5
Patton #1	15-025-20594	0.098	0.424	82	1.3	0.16	0.516	46	7.3				
Harris #2-3	15-025-20708												
Norton #1-4	15-025-20890												
Goeller #1-4	15-025-20858					0.229	0.317	31	164.7				
Norton #E-1	15-025-20837					0.166	0.592	41	8.6				
Goeller #1-4 (Attokan)	15-025-20615					0.179	0.302	33	33.9				
Alley #1-9	15-025-20911					0.191	0.444	87	17.2				
Norton #B-1	15-025-20672					0.202	0.246	54	23.4				
Tedford #1	15-025-20416	0.067	0.572	62	0.5	0.171	0.369	62	9.9				
Tedford #4-10 (C)	15-025-20720					0.202	0.233	47	23.4				
Tedford #2-10	15-025-20669					0.123	0.87	58	2.6	0.104	0.766	68	1.5
Tedford #1-10 (C)	15-025-20621	0.19	0.557	35	48.0								
Tedford #B1-10	15-025-20905					0.226	0.455	49	45.6				
Tedford #3-10	15-025-20788					0.186	0.402	71	15.0	0.216	0.712	46	34.6
Tedford #2-10	15-025-20686	0.178	0.26	63	12.0	0.188	0.55	41	15.9				
Latzke #1	15-025-20611					0.231	0.574	52	52.4	0.232	0.463	36	181.0
Rooney #1-11	15-025-20702	0.097	0.33	57	1.3	0.174	0.375	60	10.7				
Rooney #1	15-025-20965	0.125	0.582	80	2.8	0.252	0.254	30	1334.1	0.216	0.336	56	34.6
Statton #2-12 (C)	15-025-20991	0.215	0.459	51	33.6	0.262	0.279	35	466.9	0.218	0.325	39	116.3
Statton #1-12 (C)	15-025-20881	0.233	0.235	53	55.4								

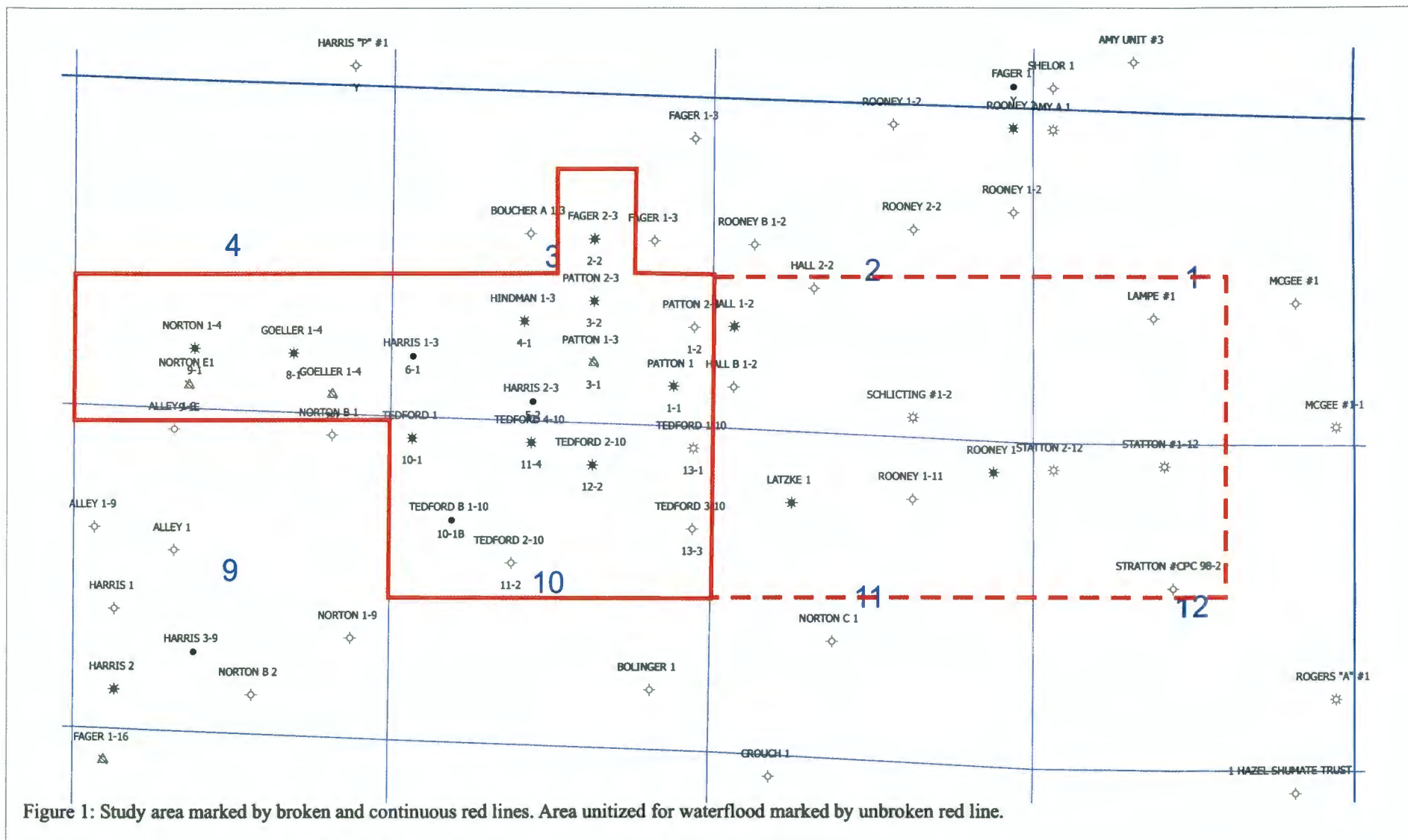


Figure 1: Study area marked by broken and continuous red lines. Area unitized for waterflood marked by unbroken red line.

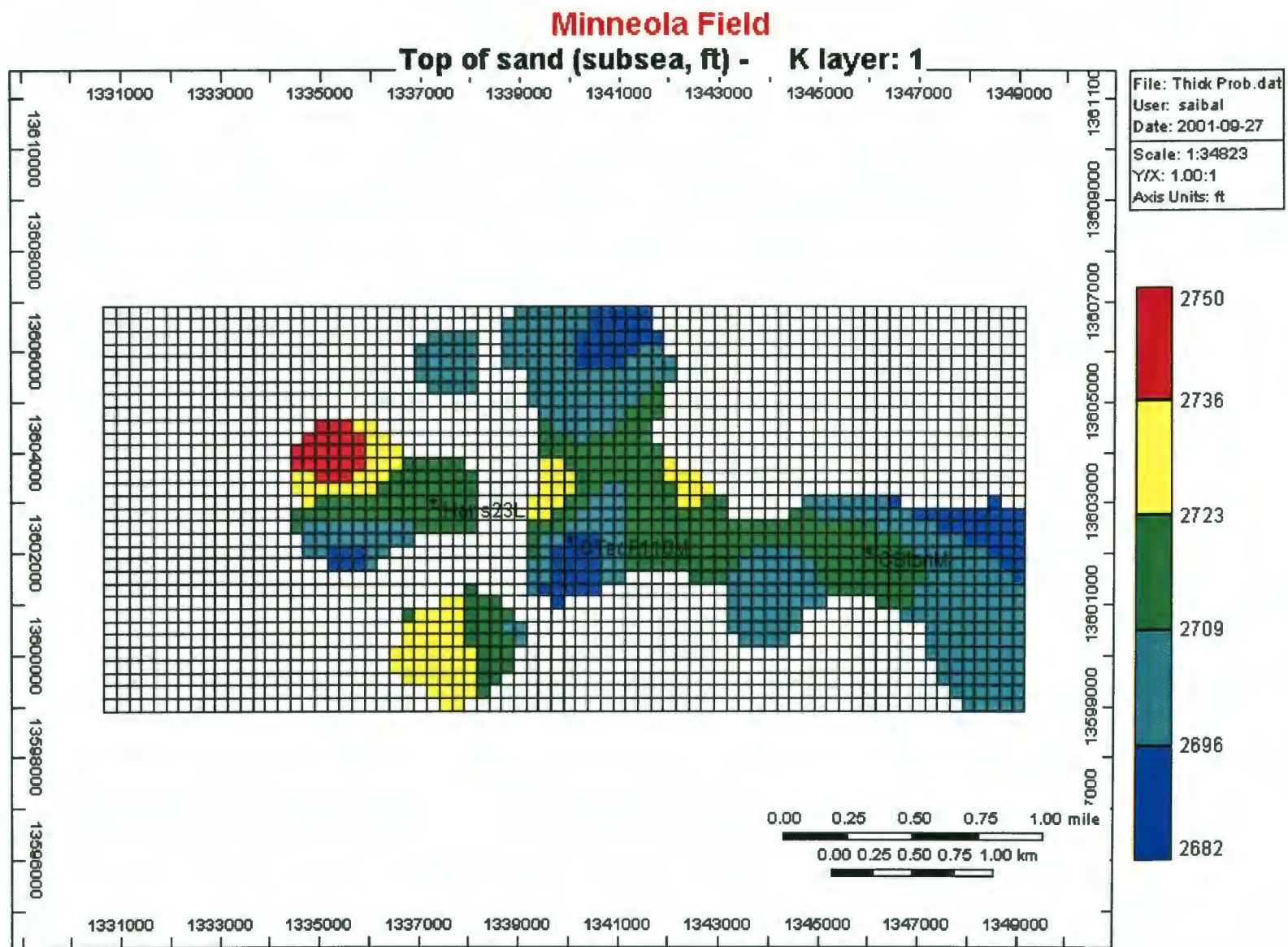


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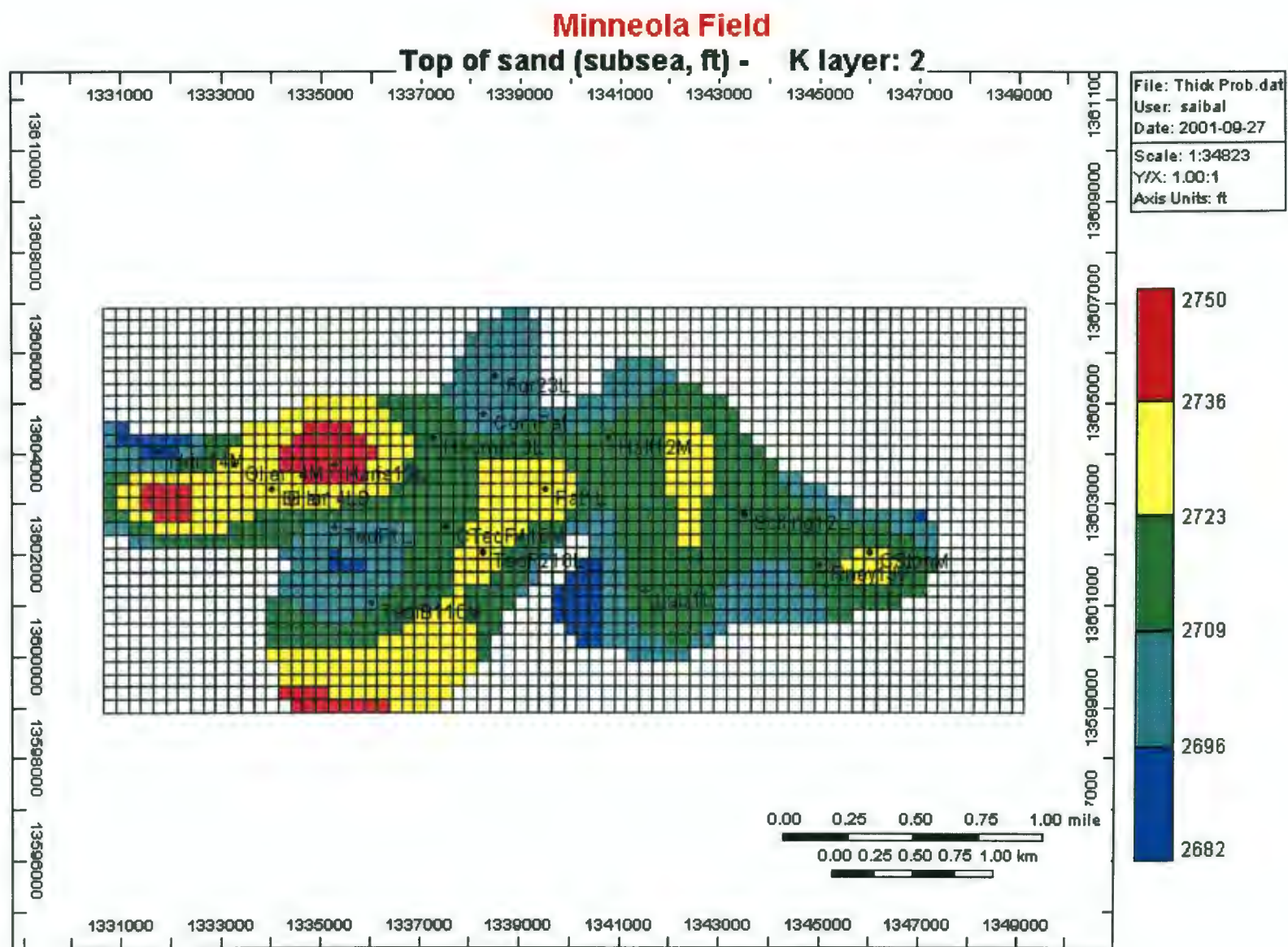


Figure 3

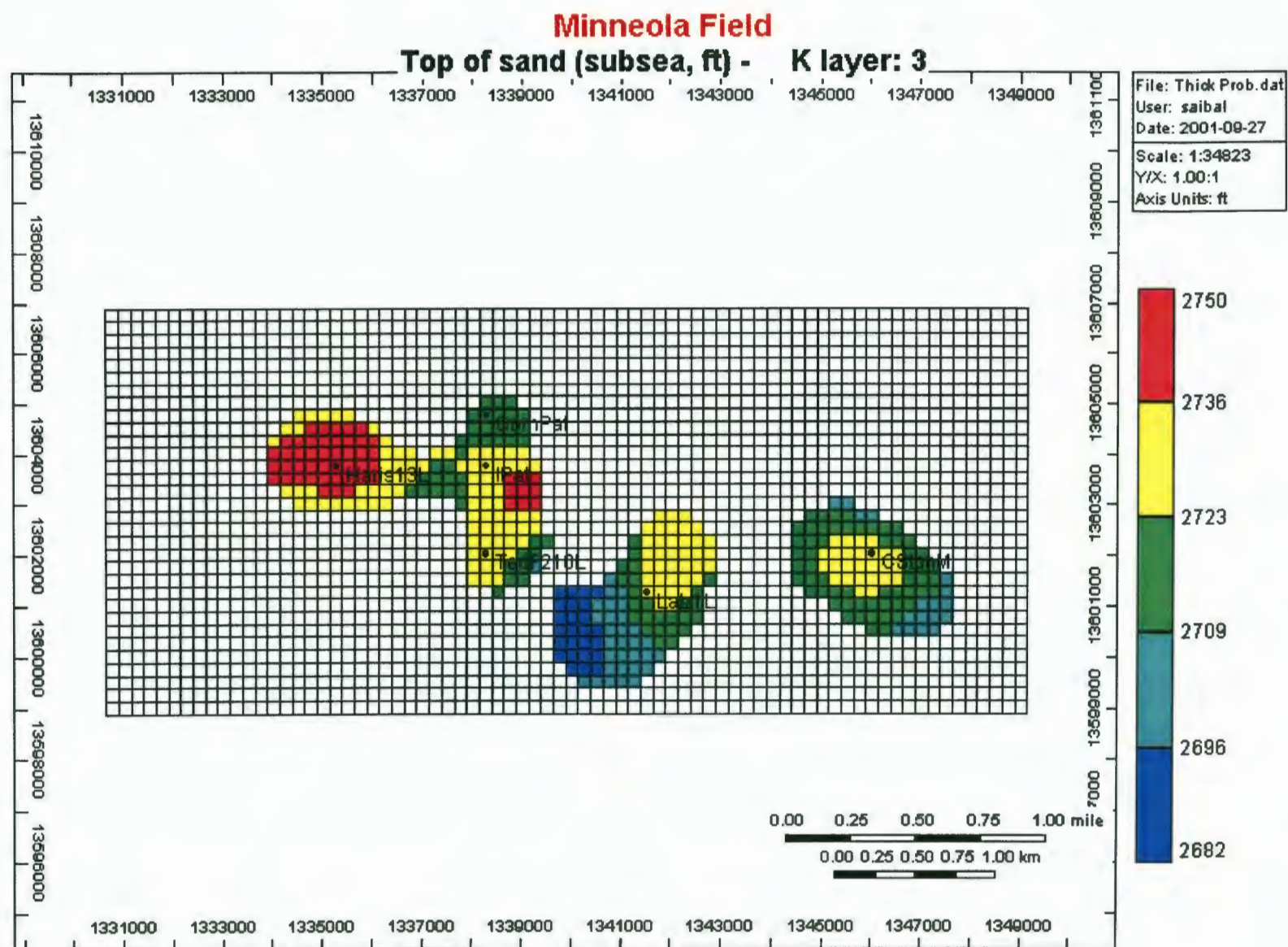


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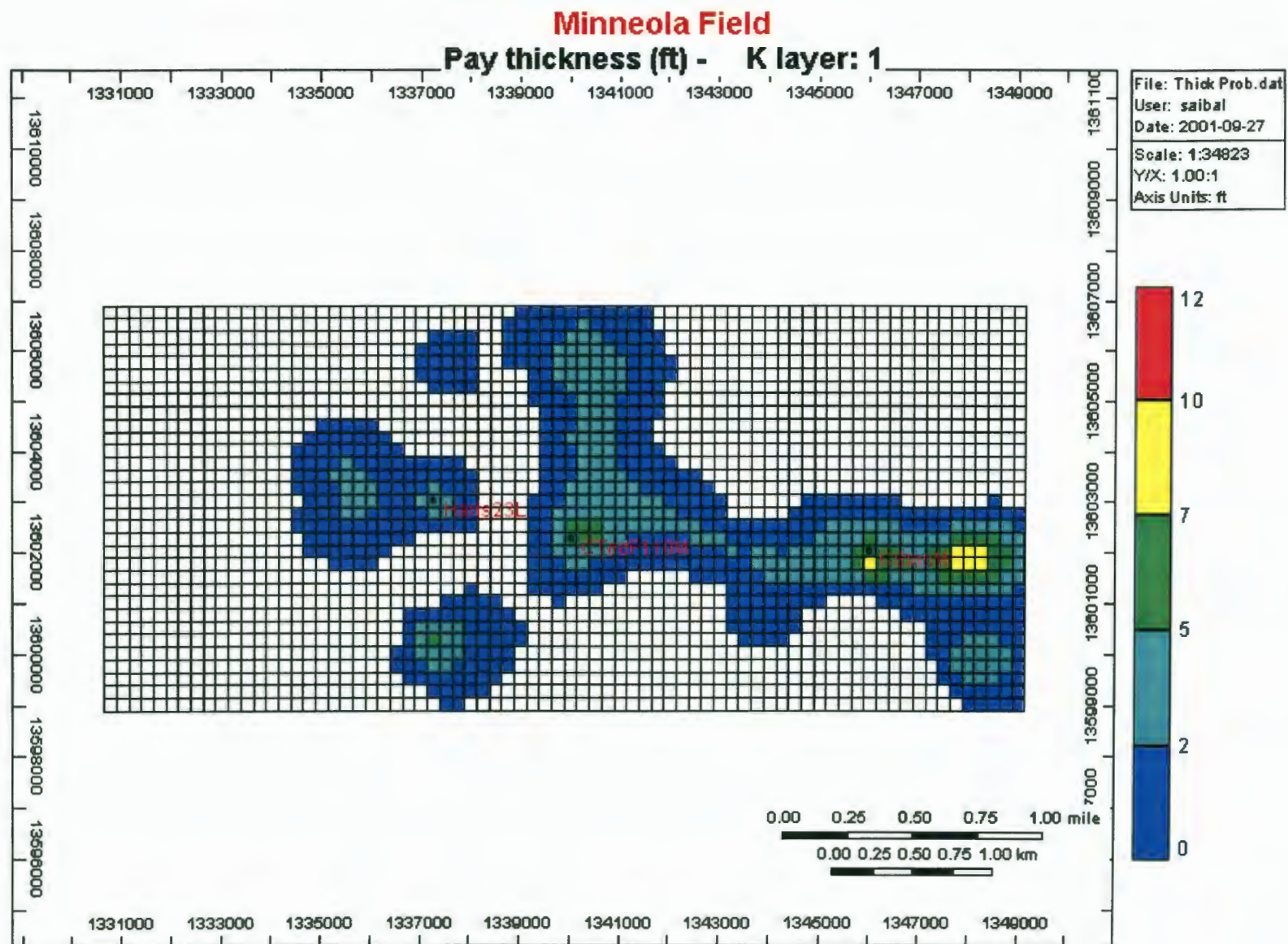


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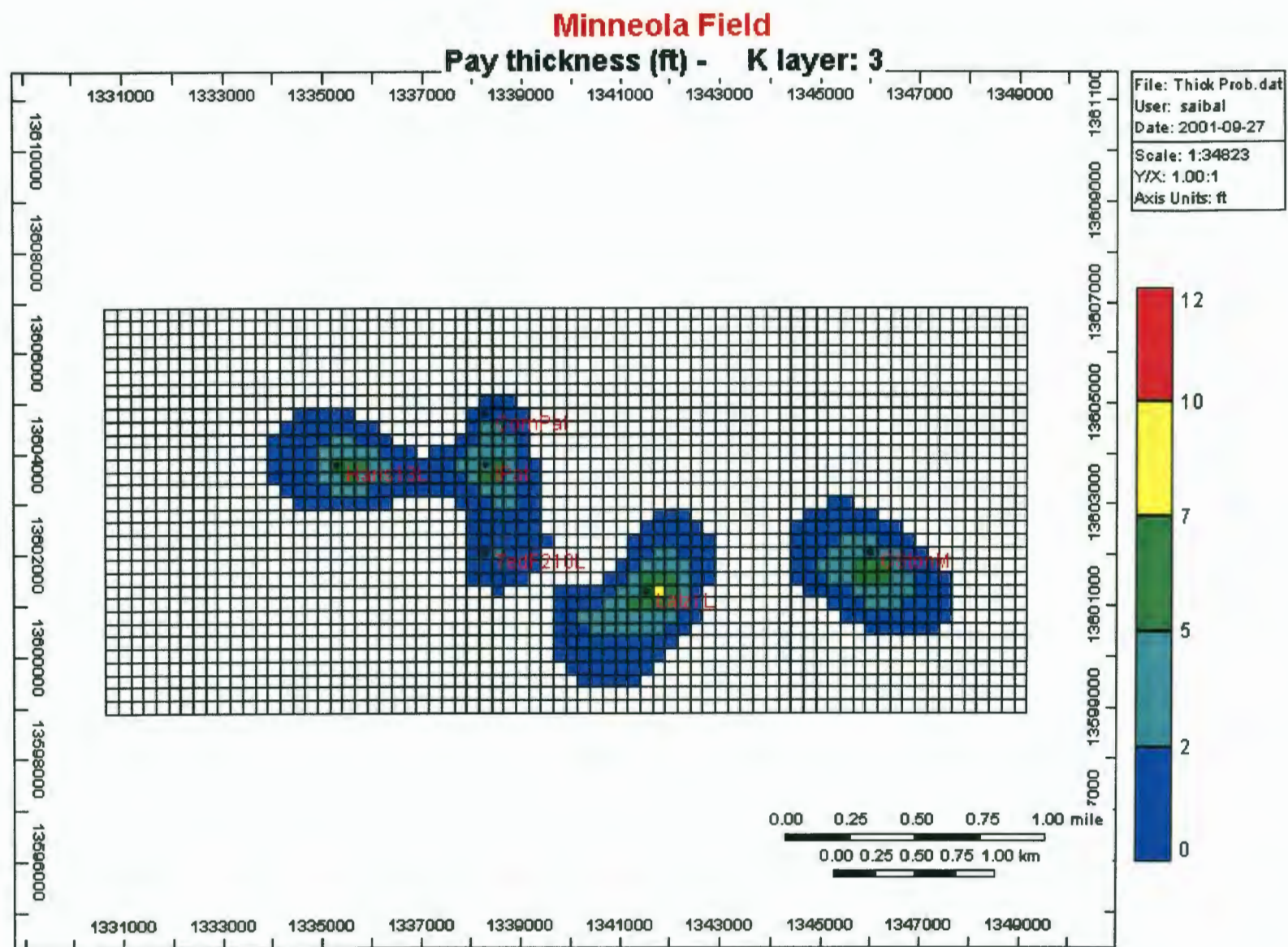
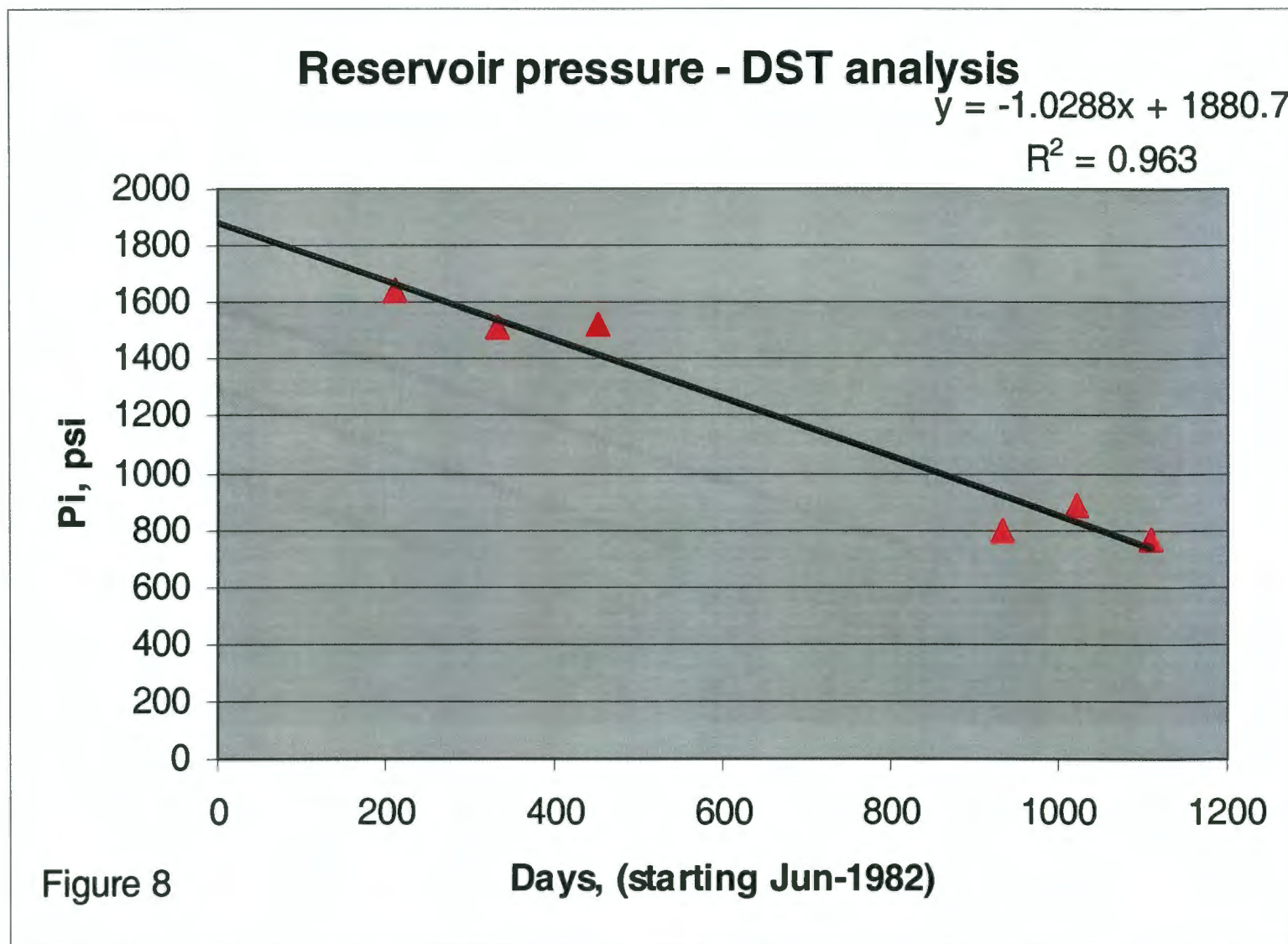


Figure 7



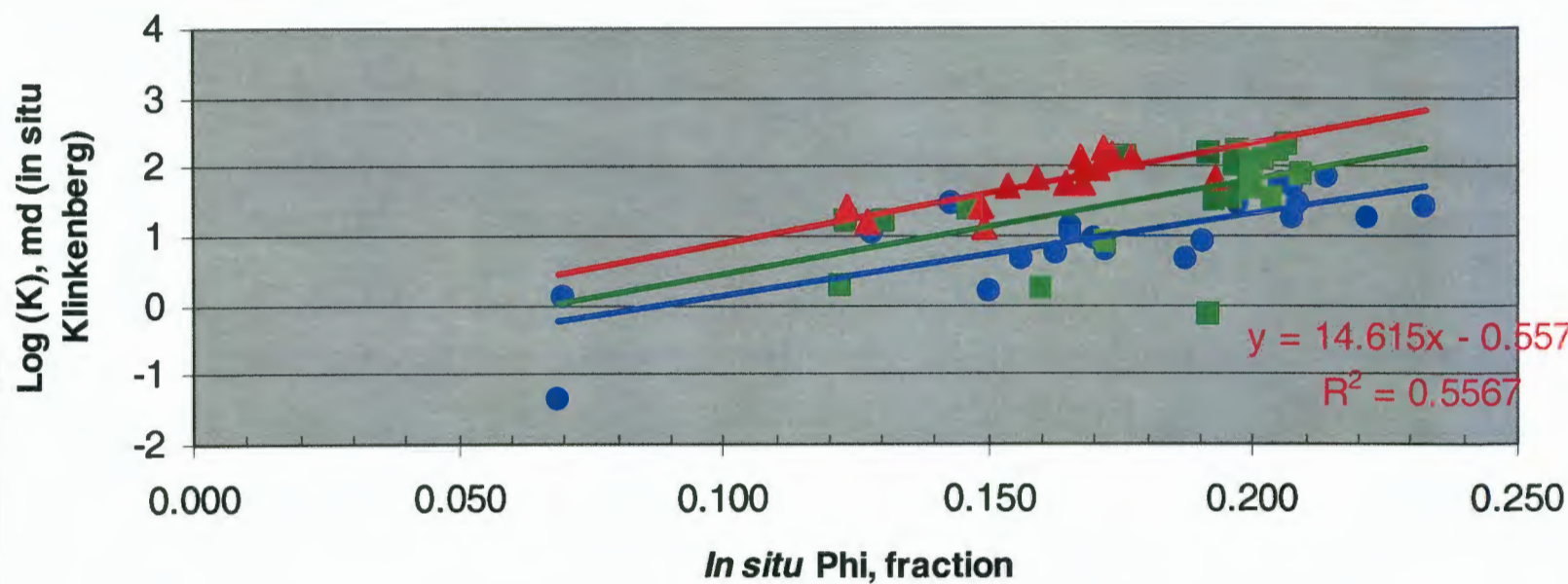
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$$R^2 = 0.2929$$

Log (K) vs. Phi

$$y = 12.075x - 1.0697$$

$$R^2 = 0.5796$$



$$y = 14.615x - 0.5578$$

$$R^2 = 0.5567$$

Figure 9

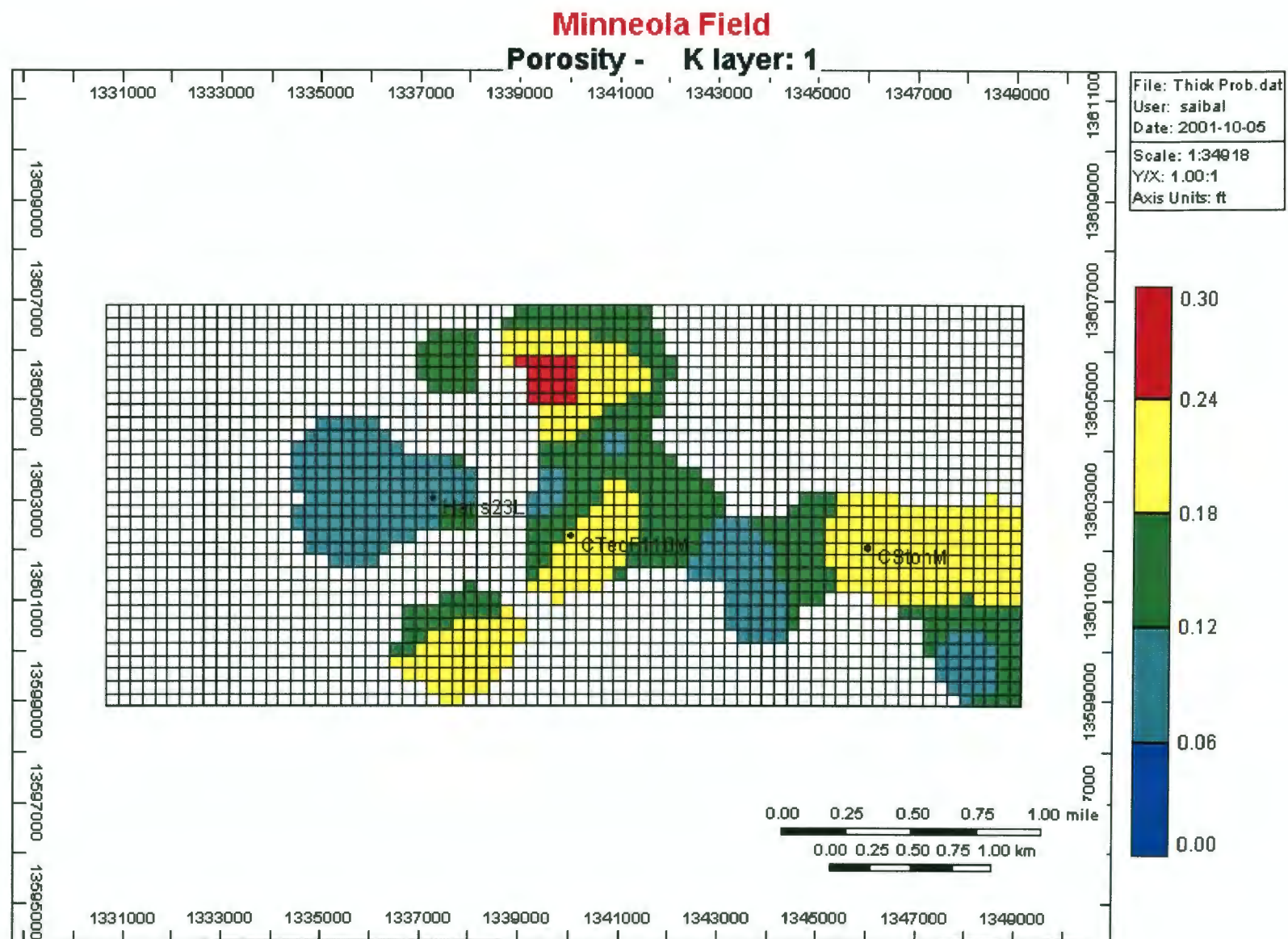


Figure 10

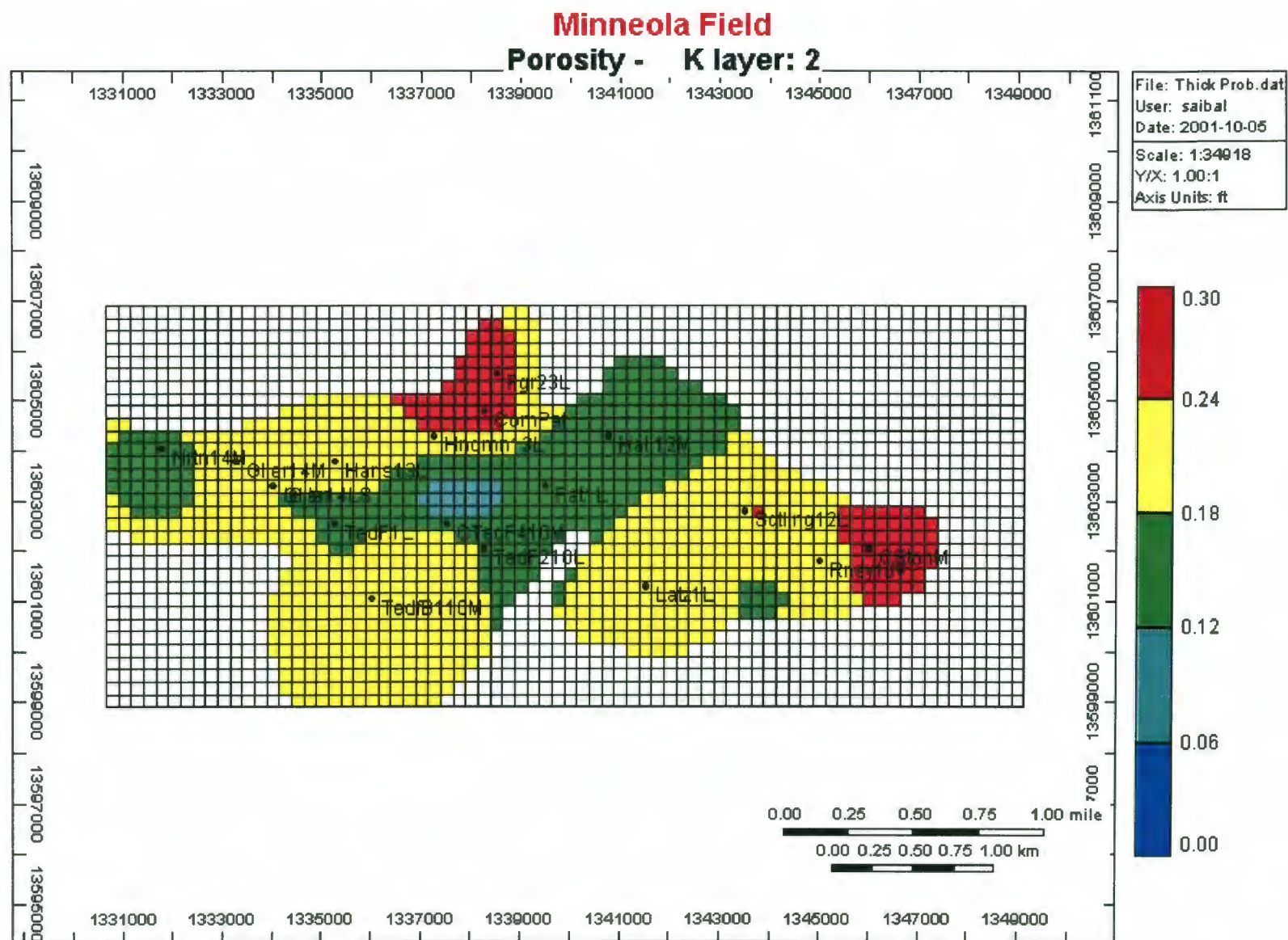


Figure 11

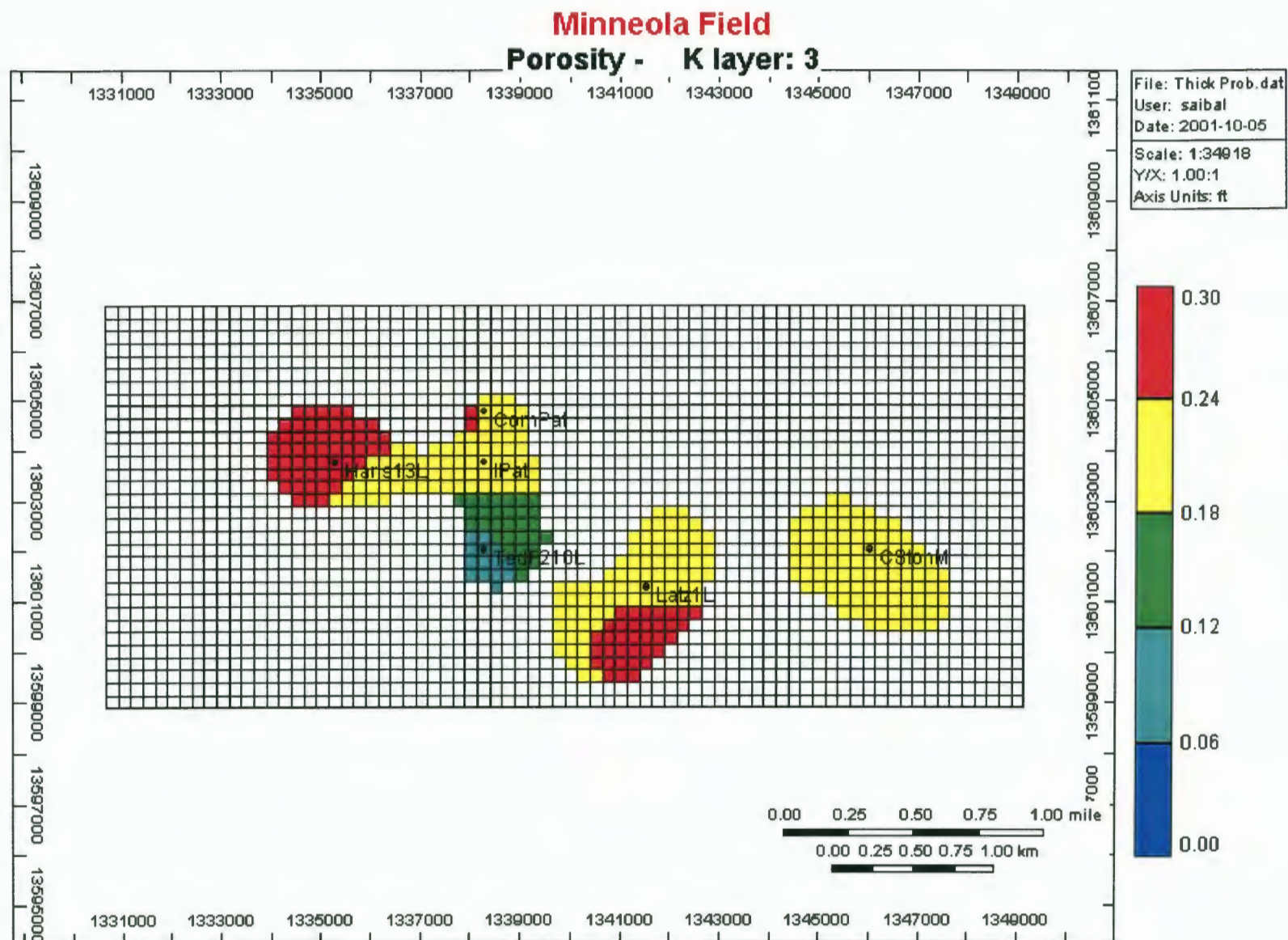


Figure 12

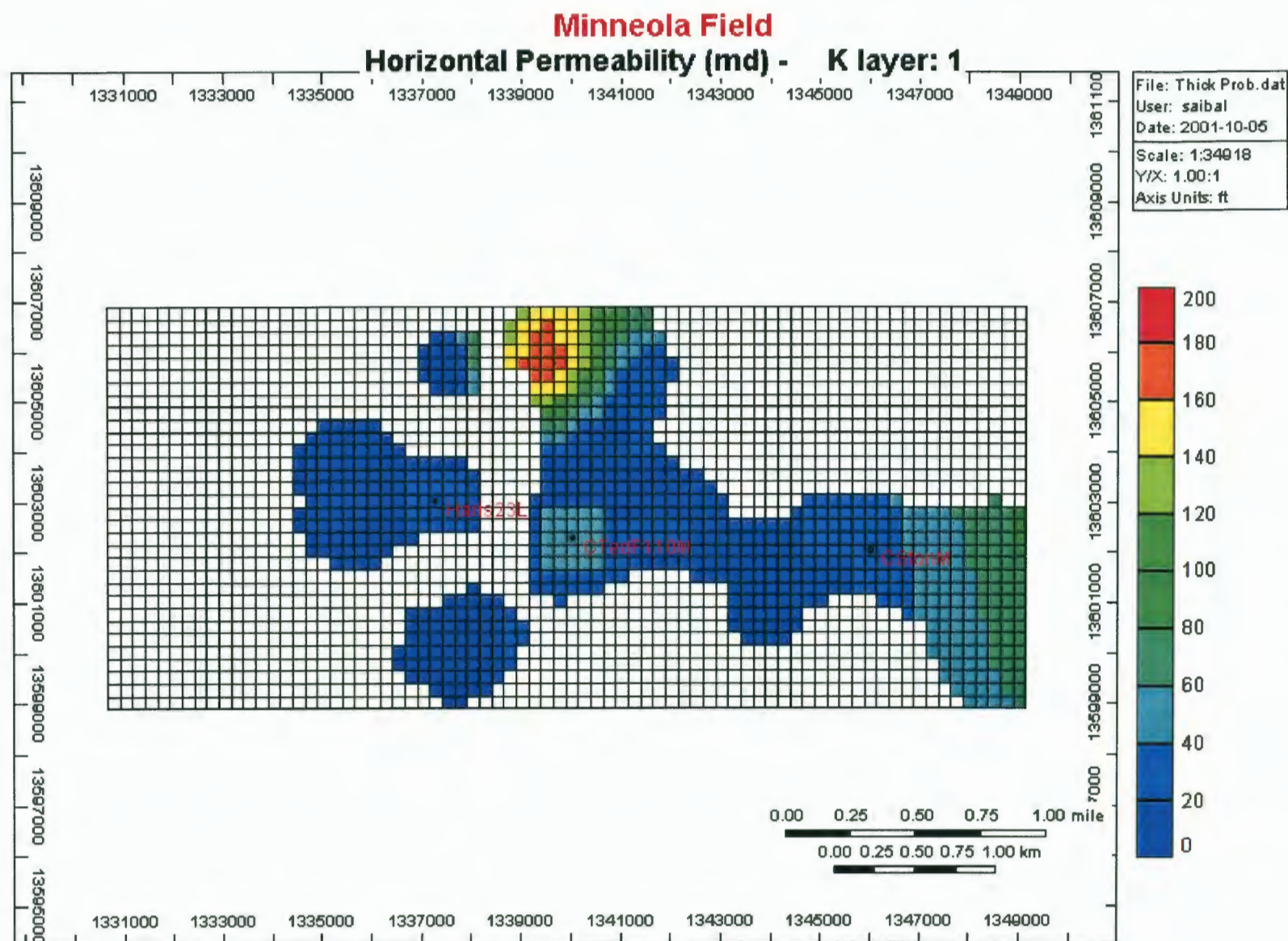


Figure 13

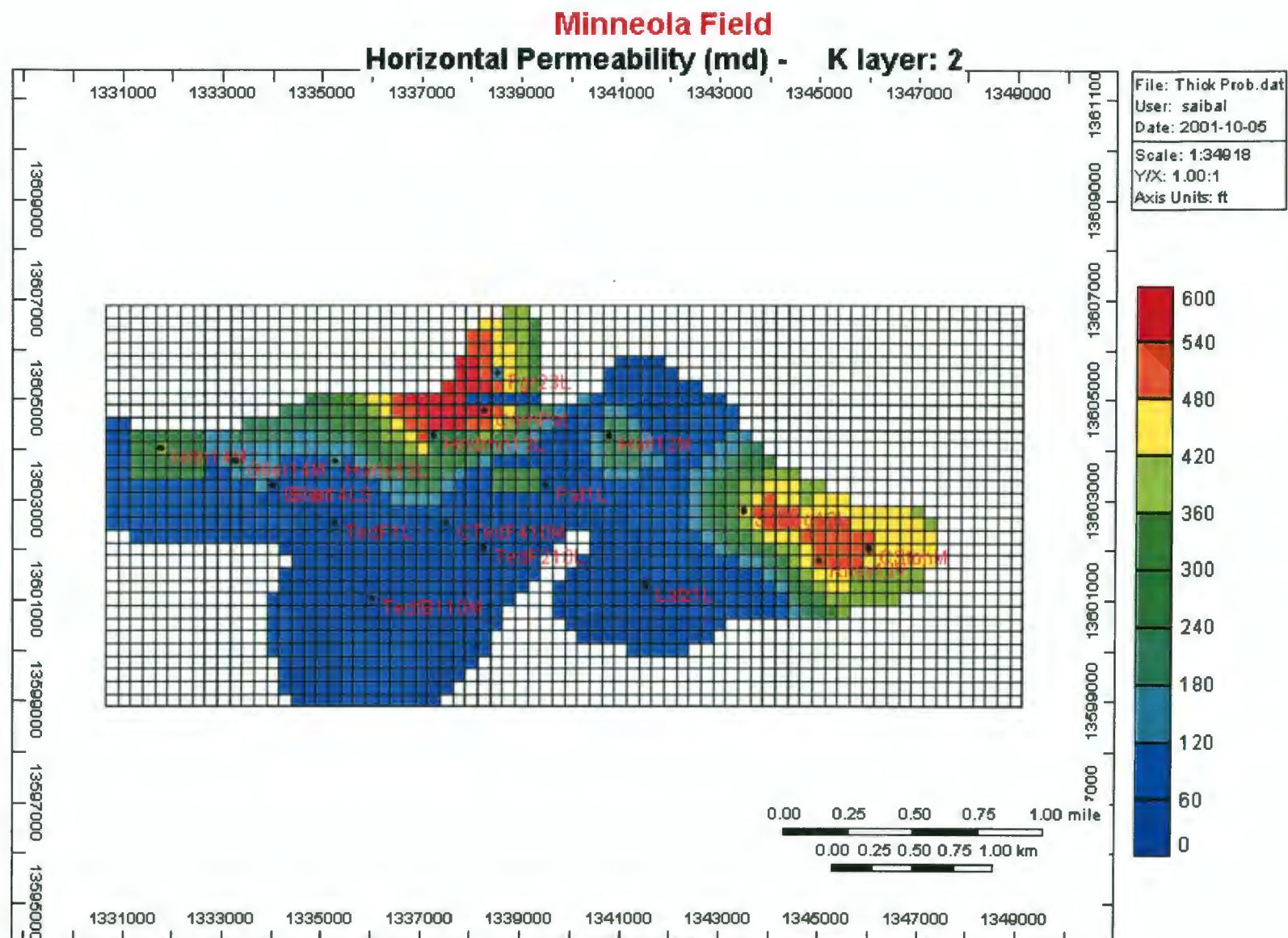


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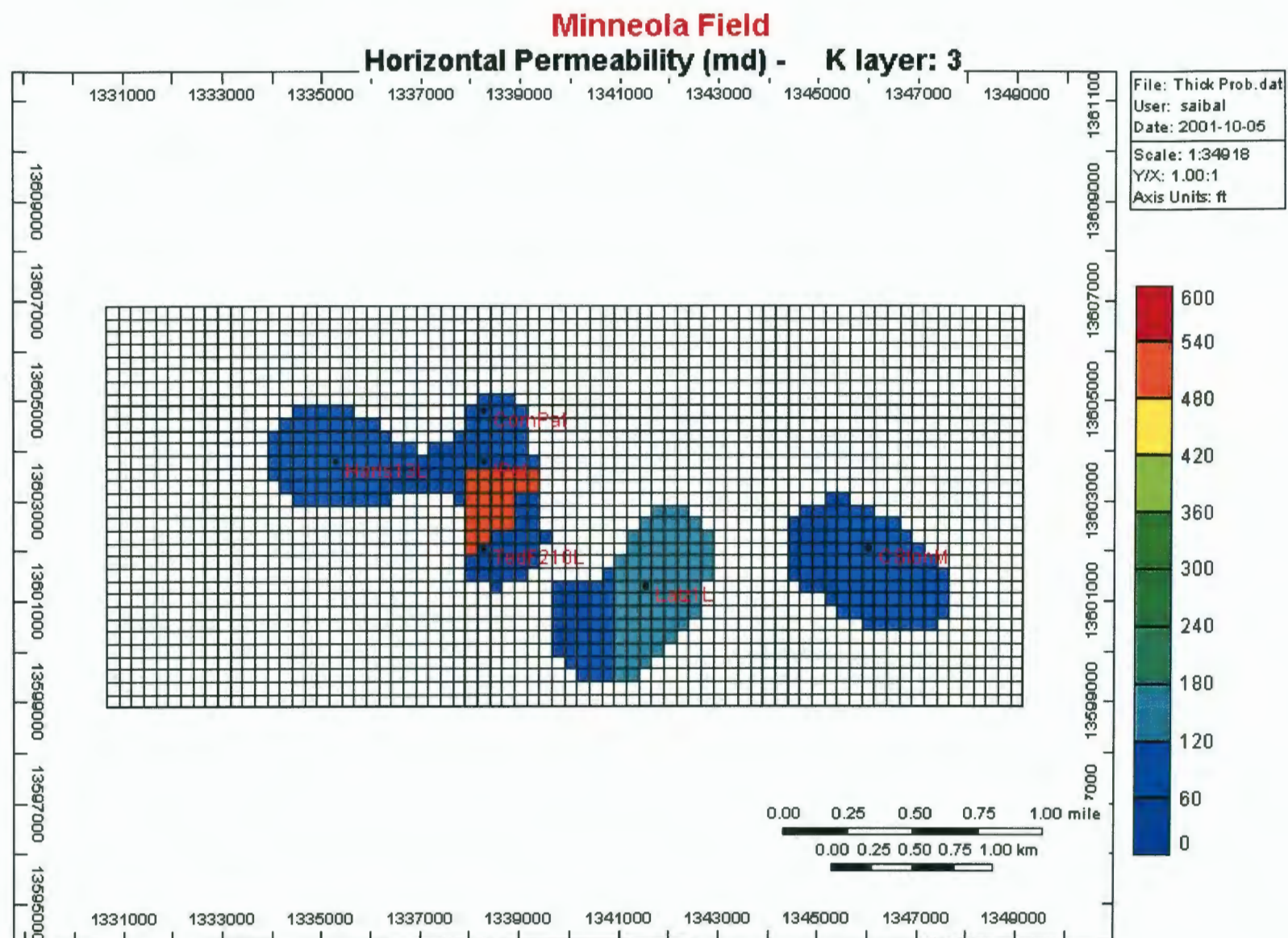


Figure 15

APPENDIX A

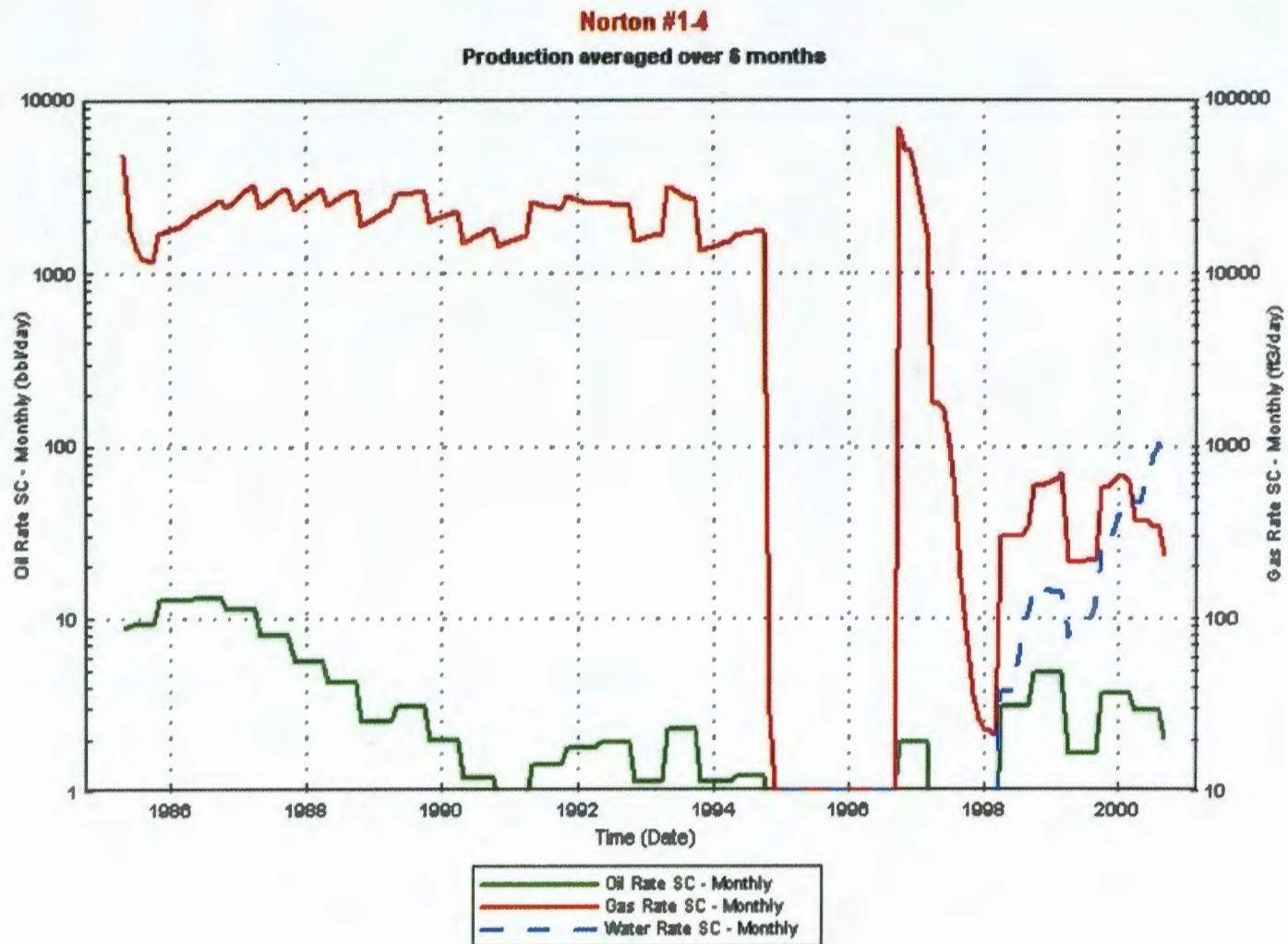


Figure A1

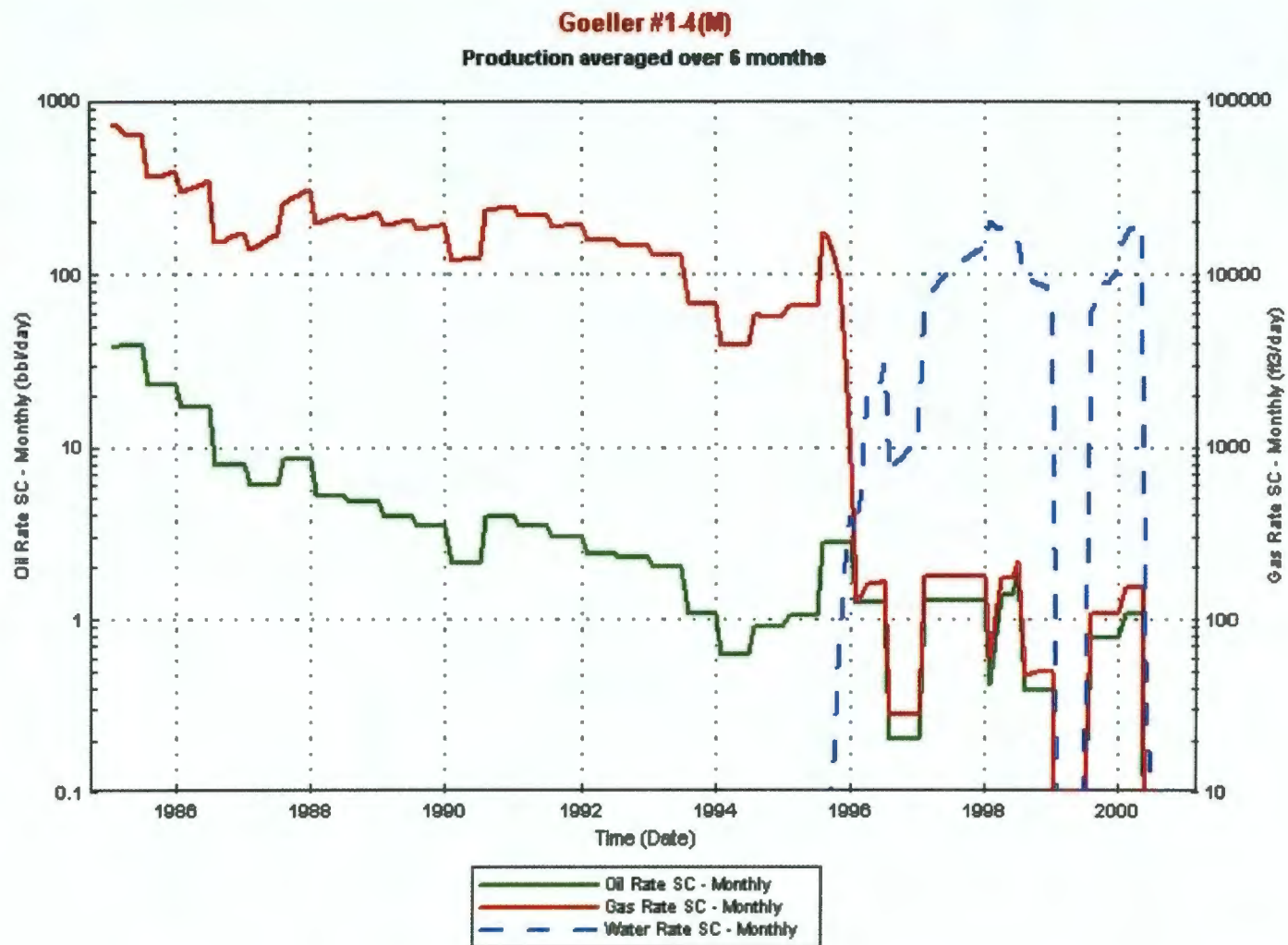


Figure A2

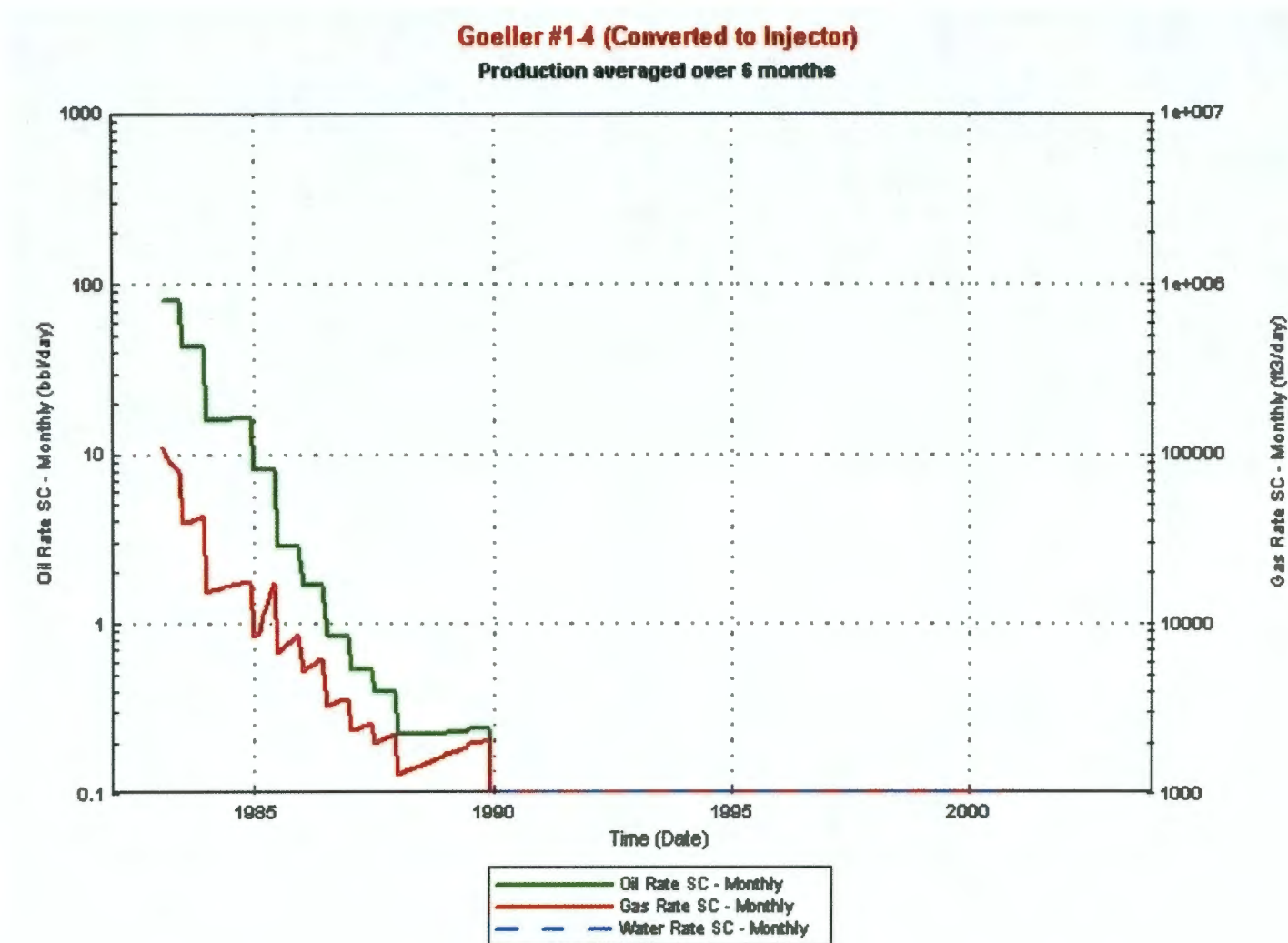


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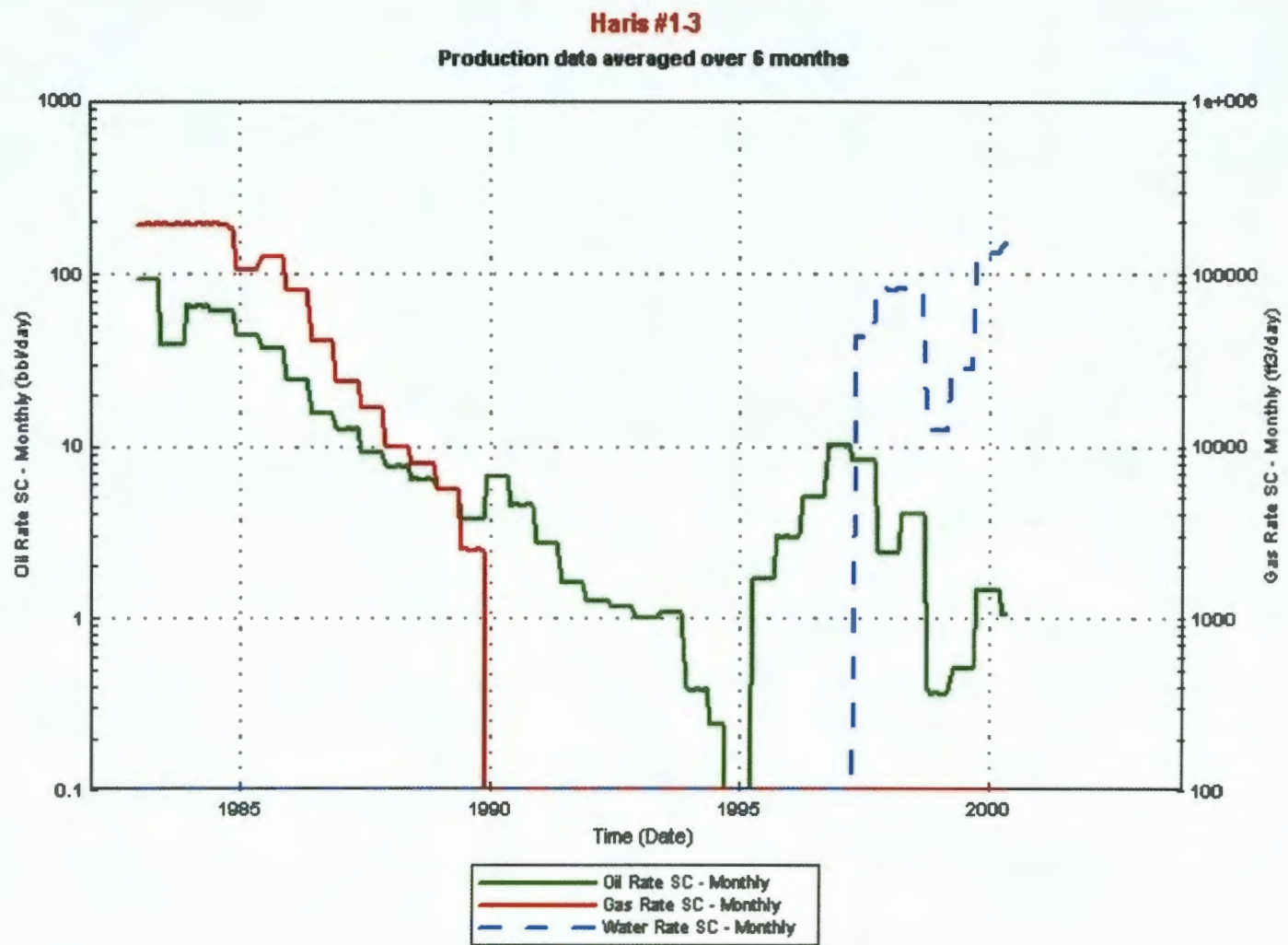


Figure A4

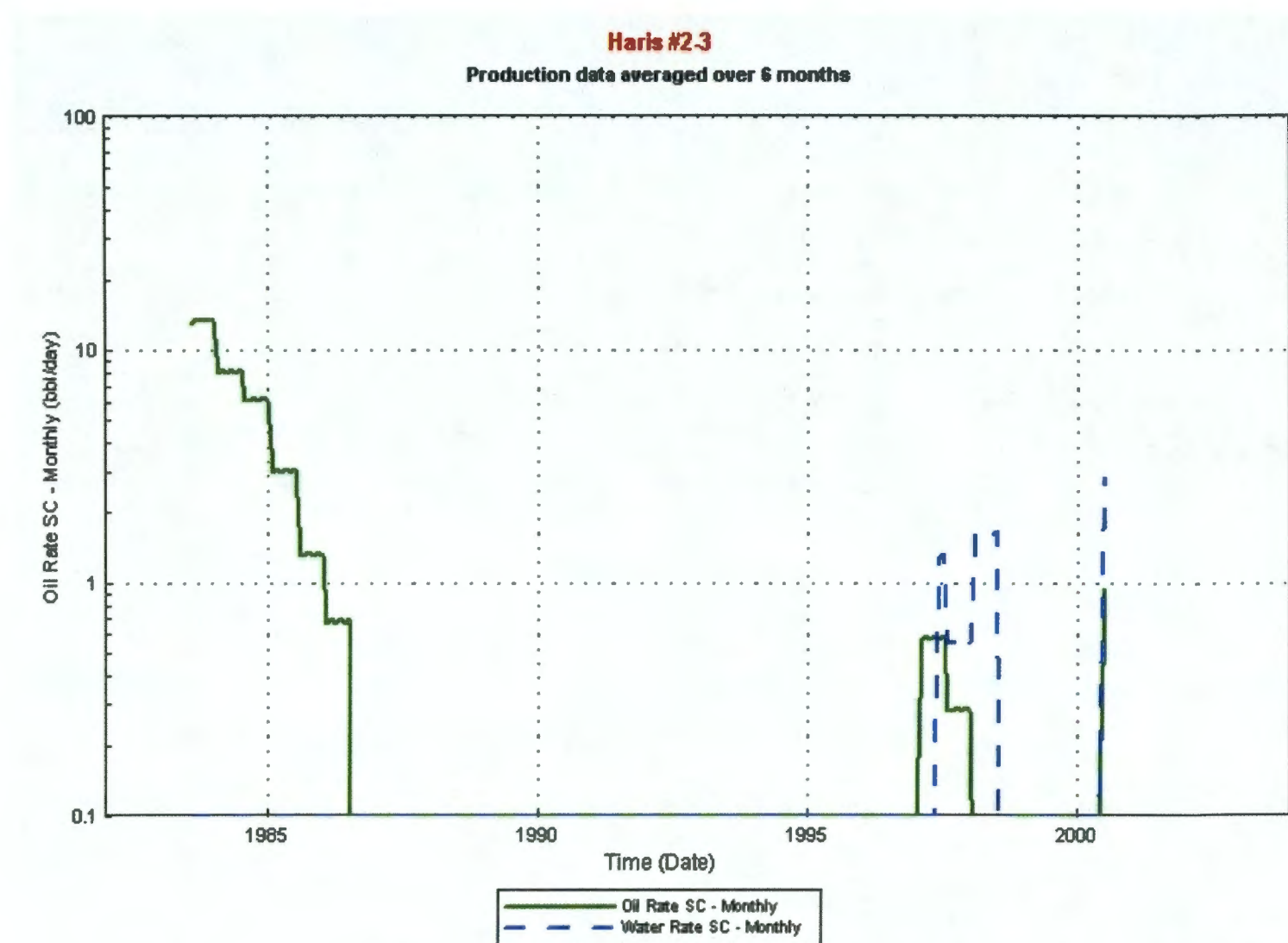


Figure A5

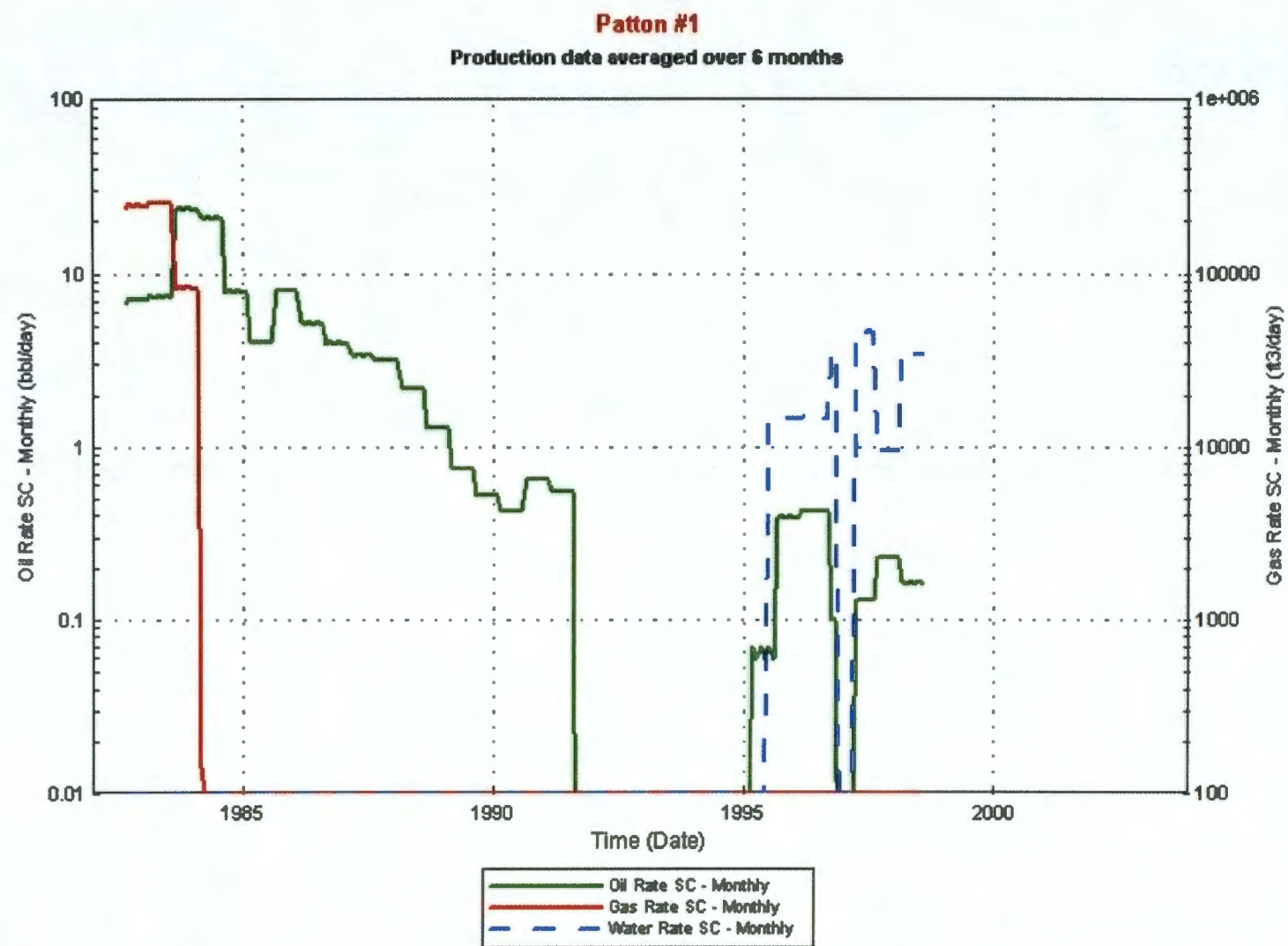


Figure A6

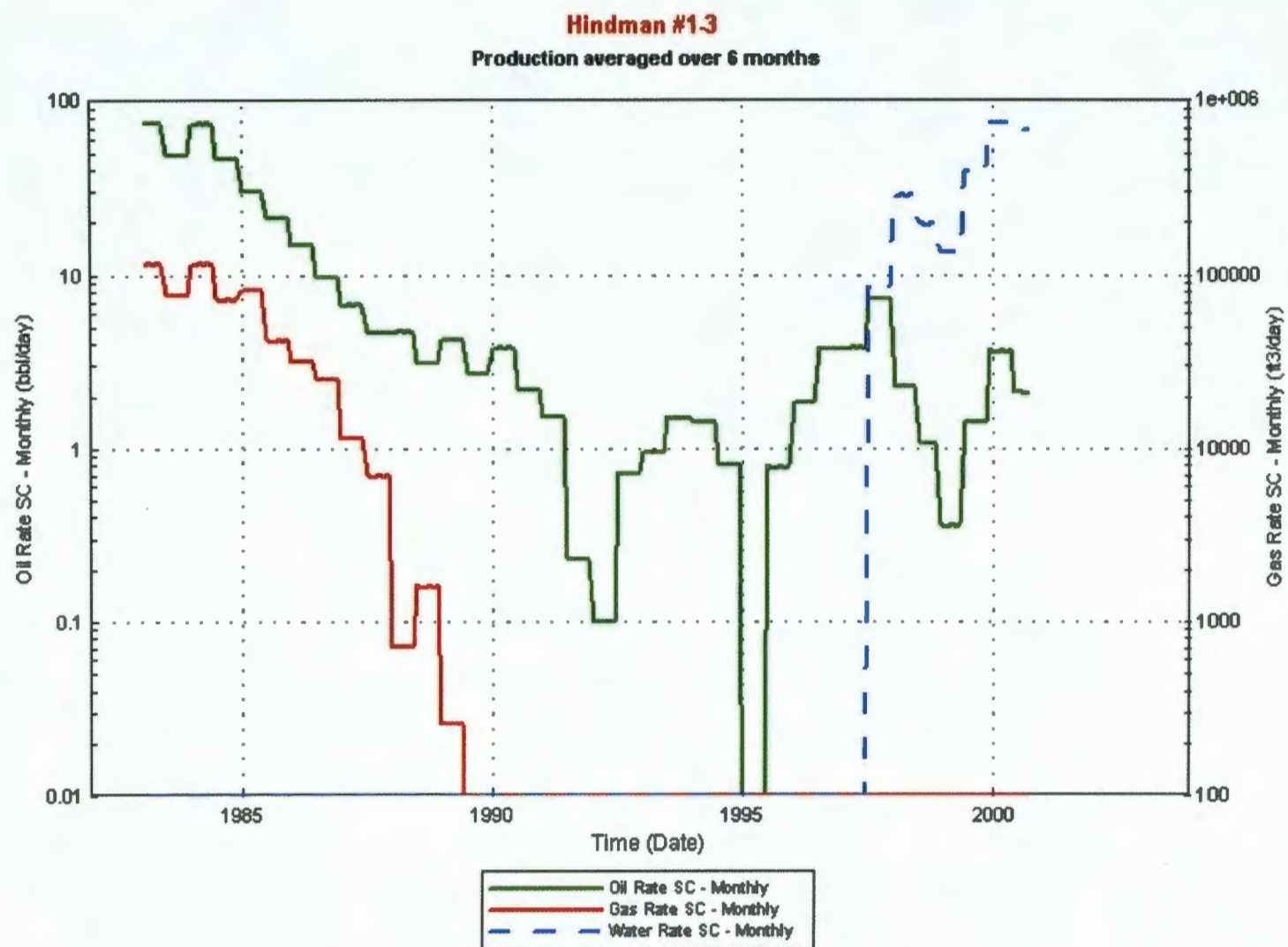


Figure A7

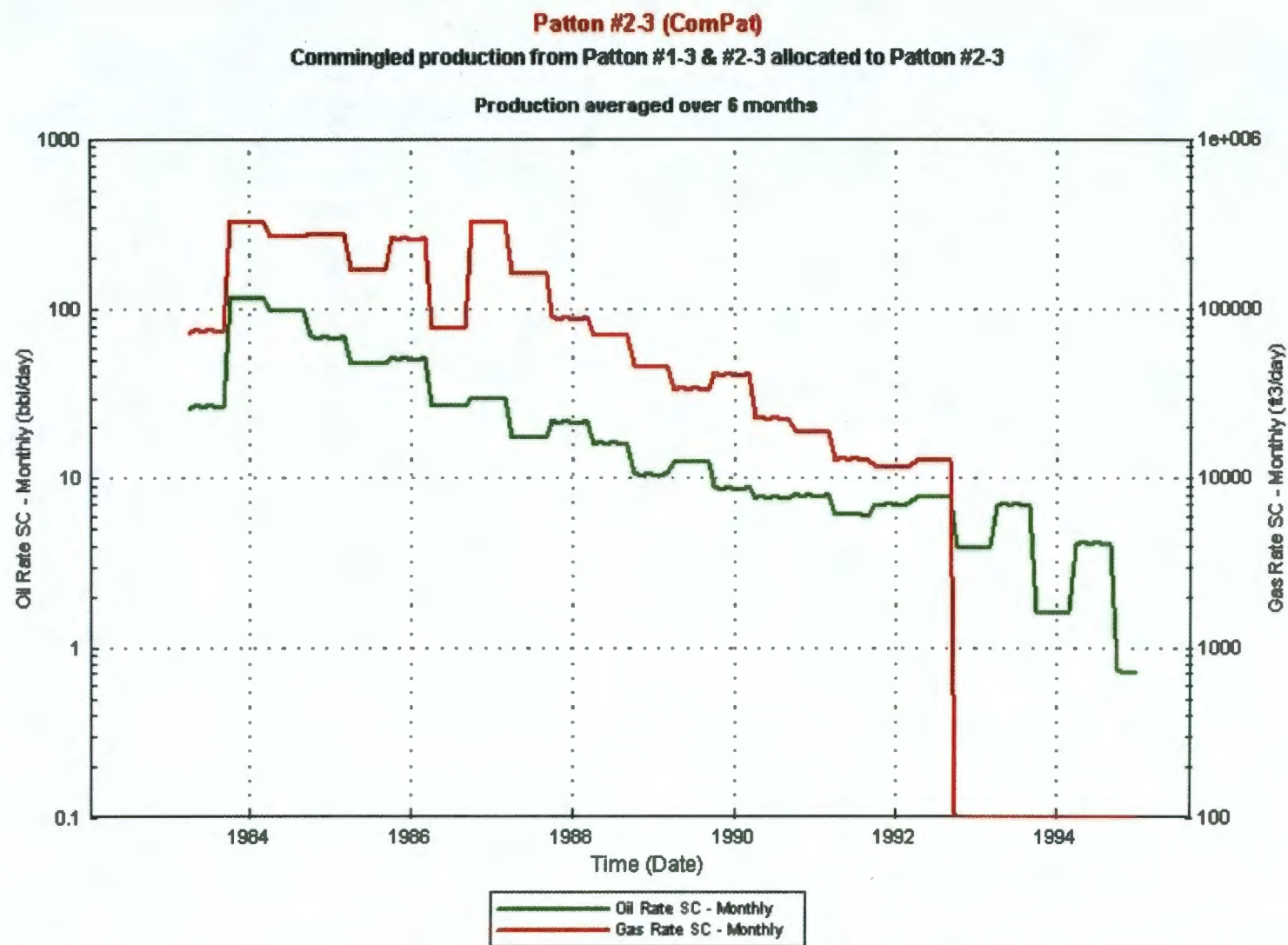


Figure A8

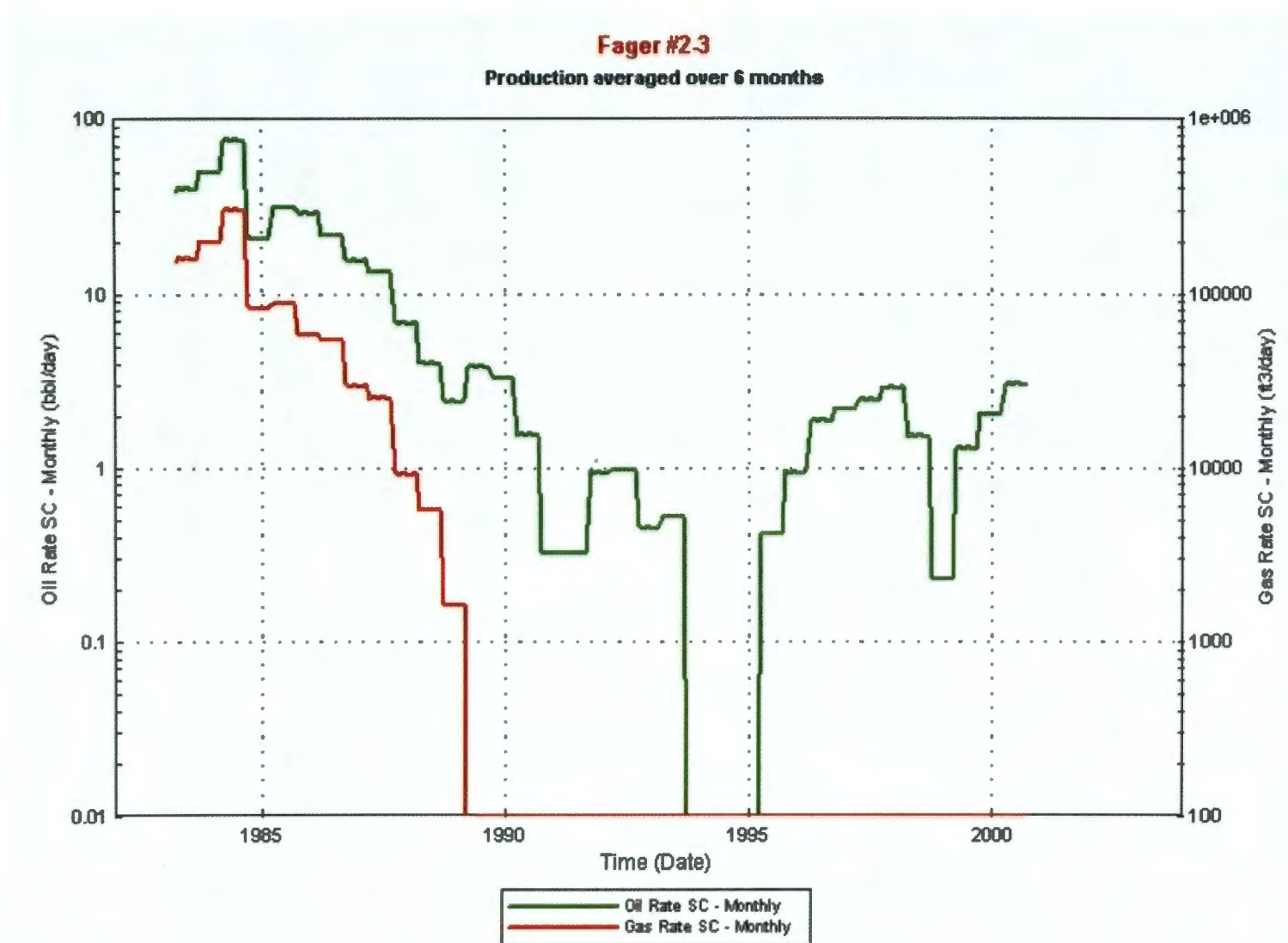


Figure A9

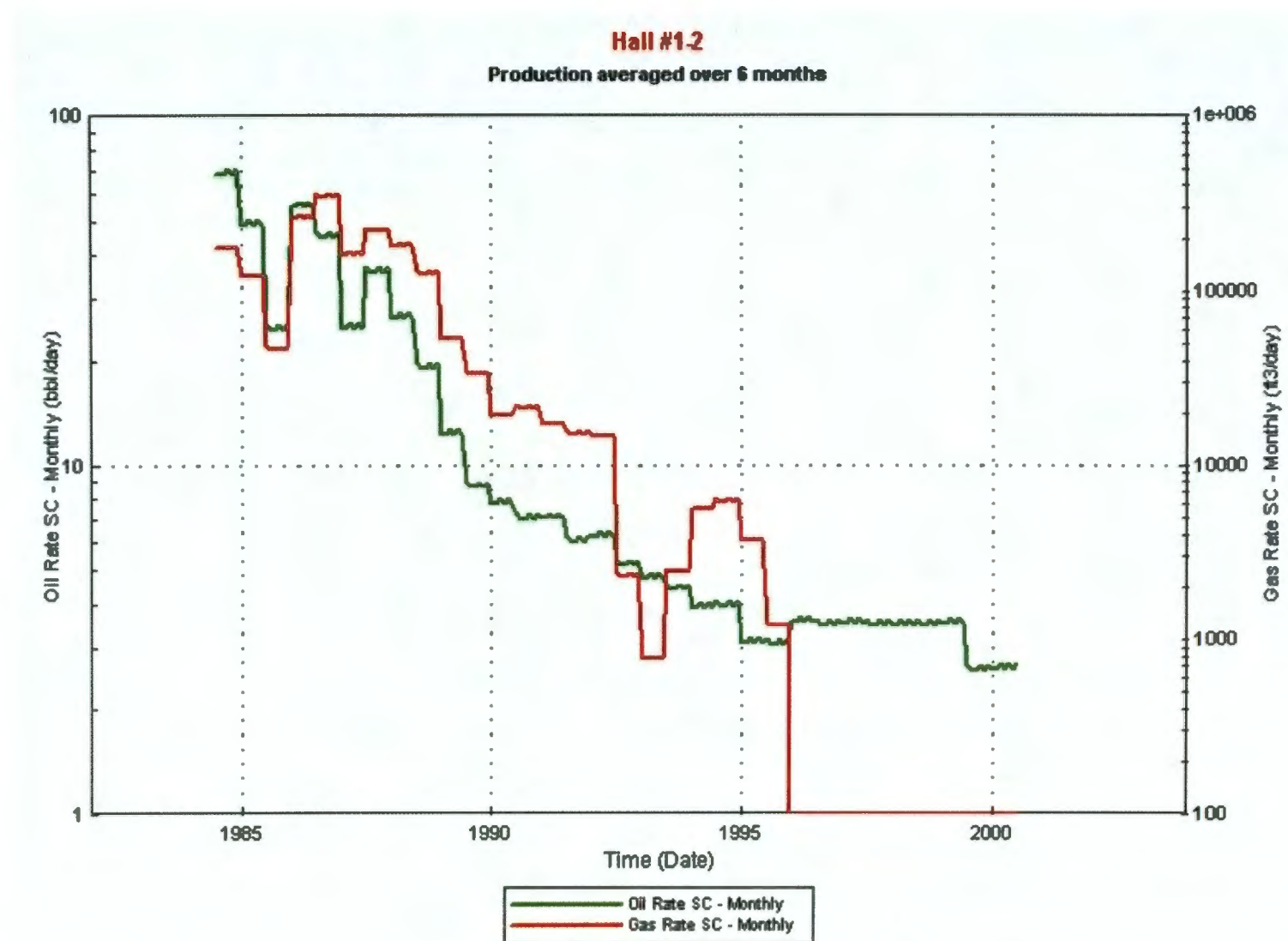


Figure A10

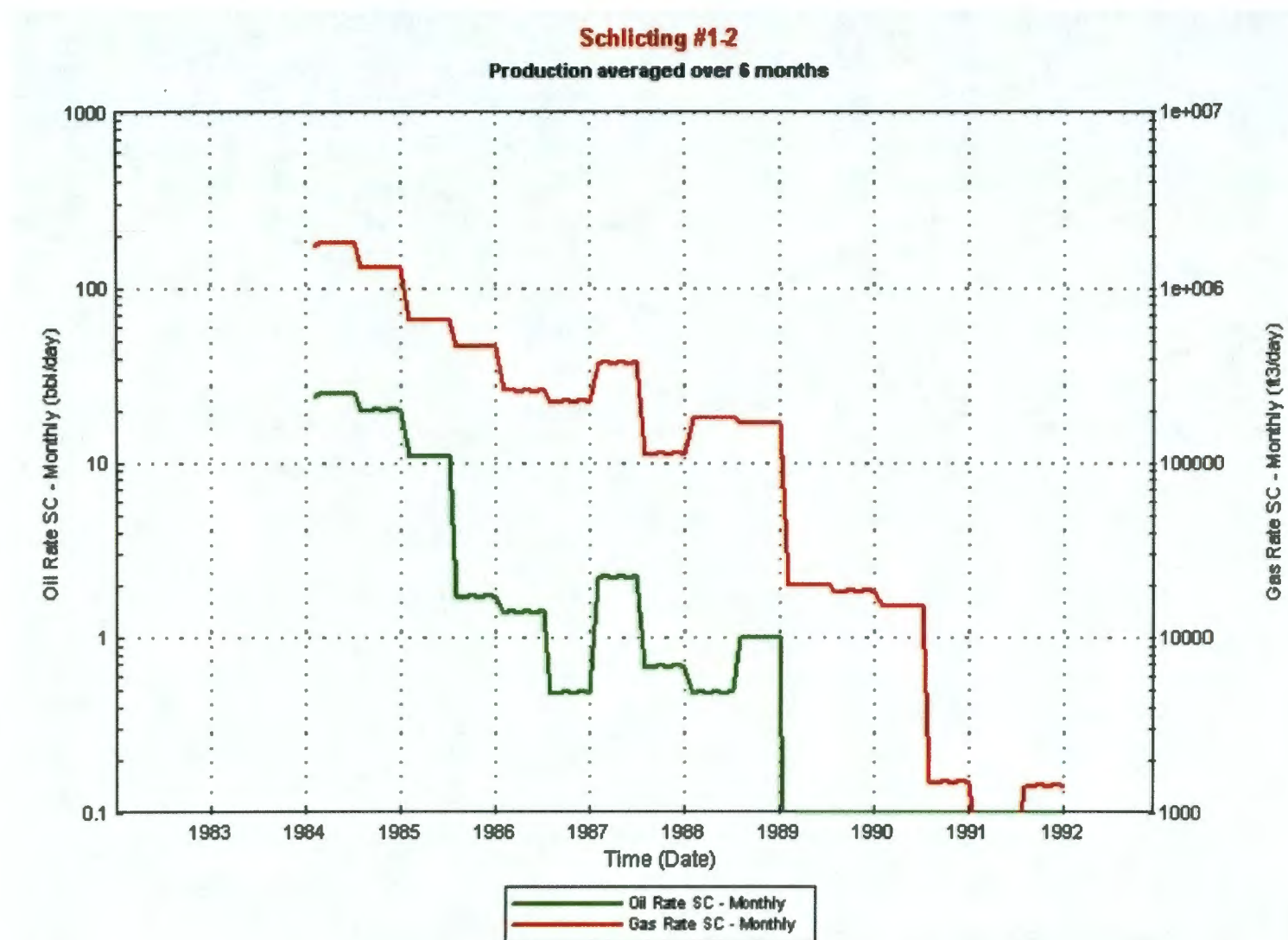


Figure A11

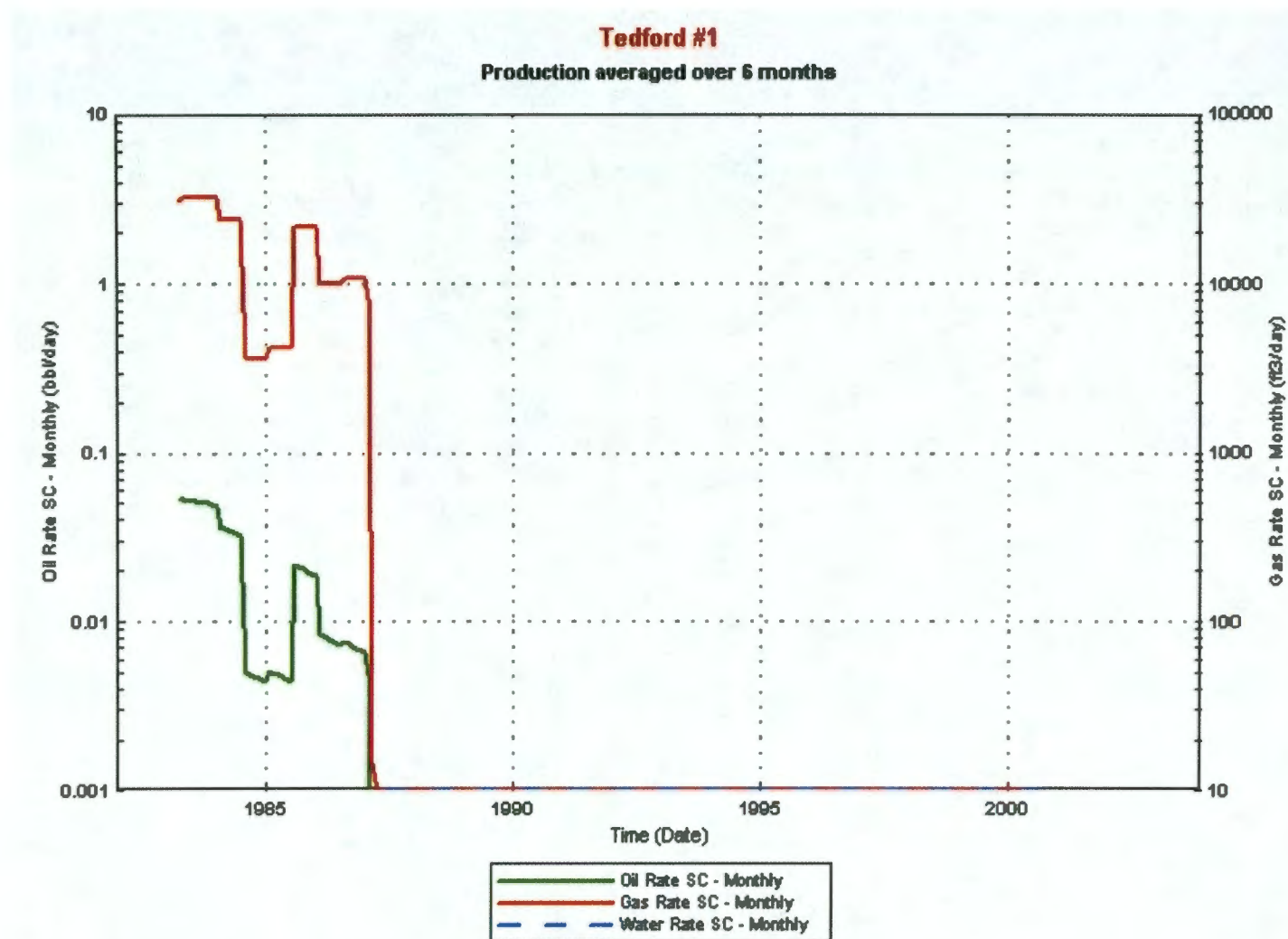


Figure A12

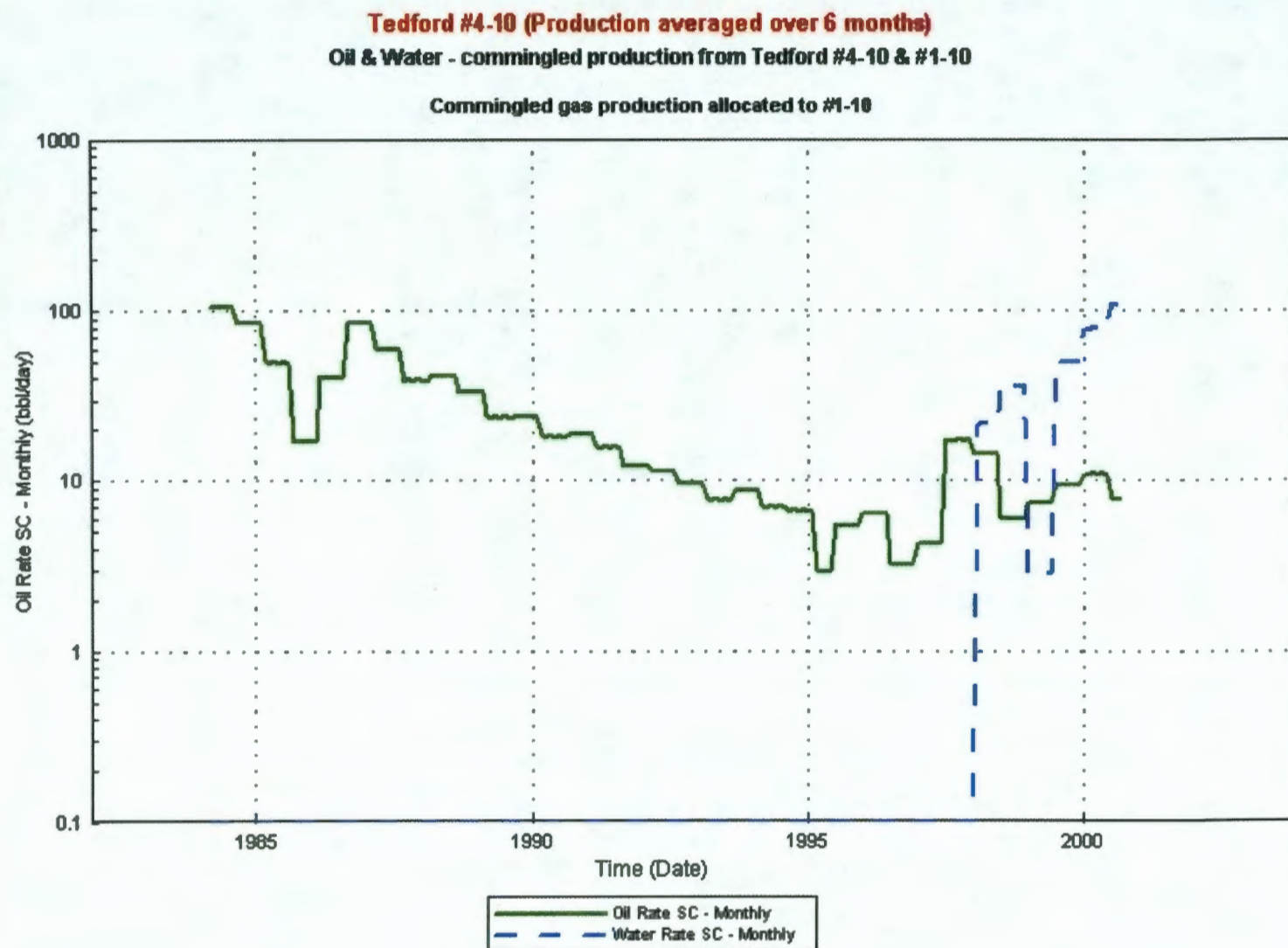


Figure A13

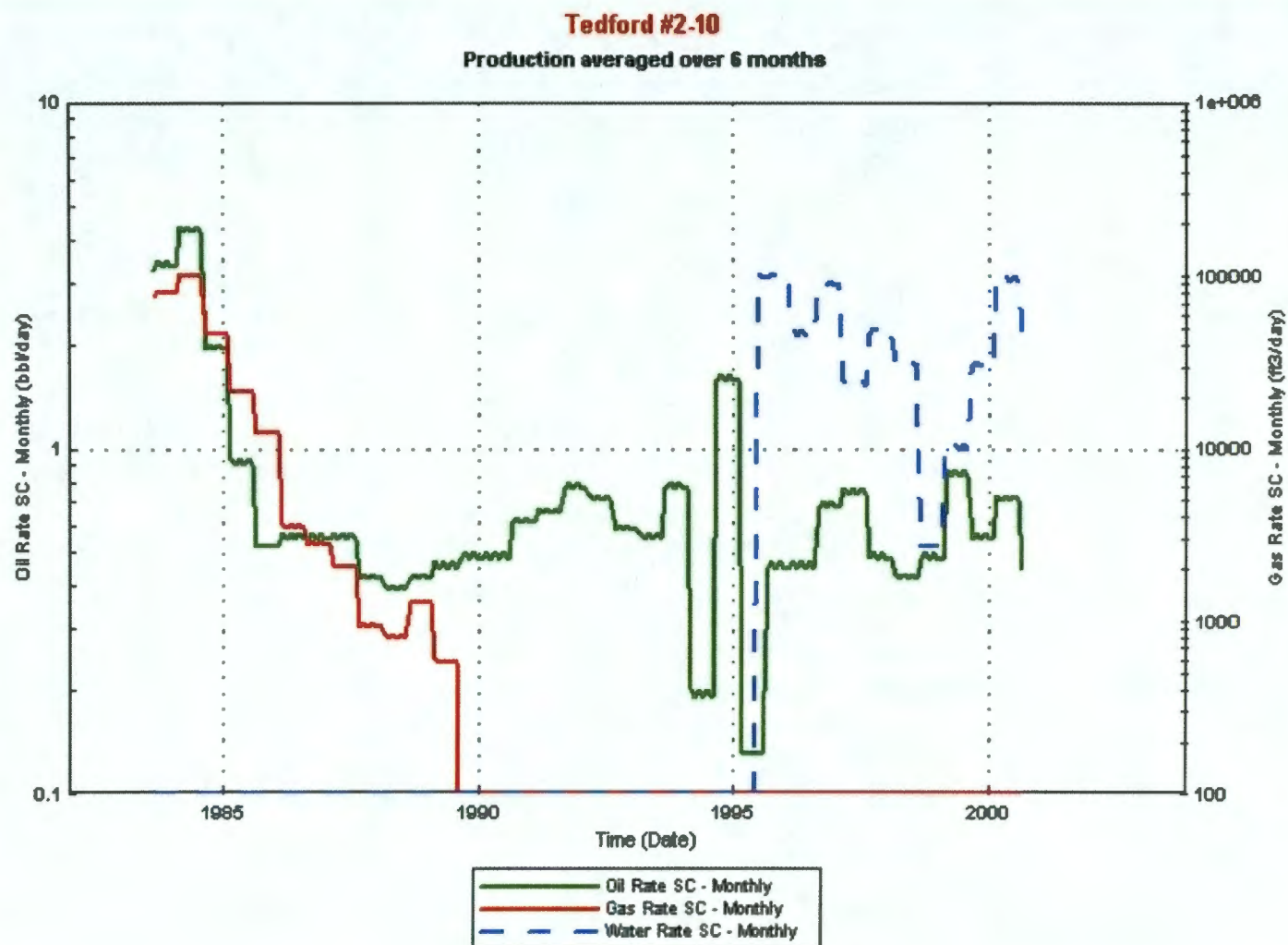


Figure A14

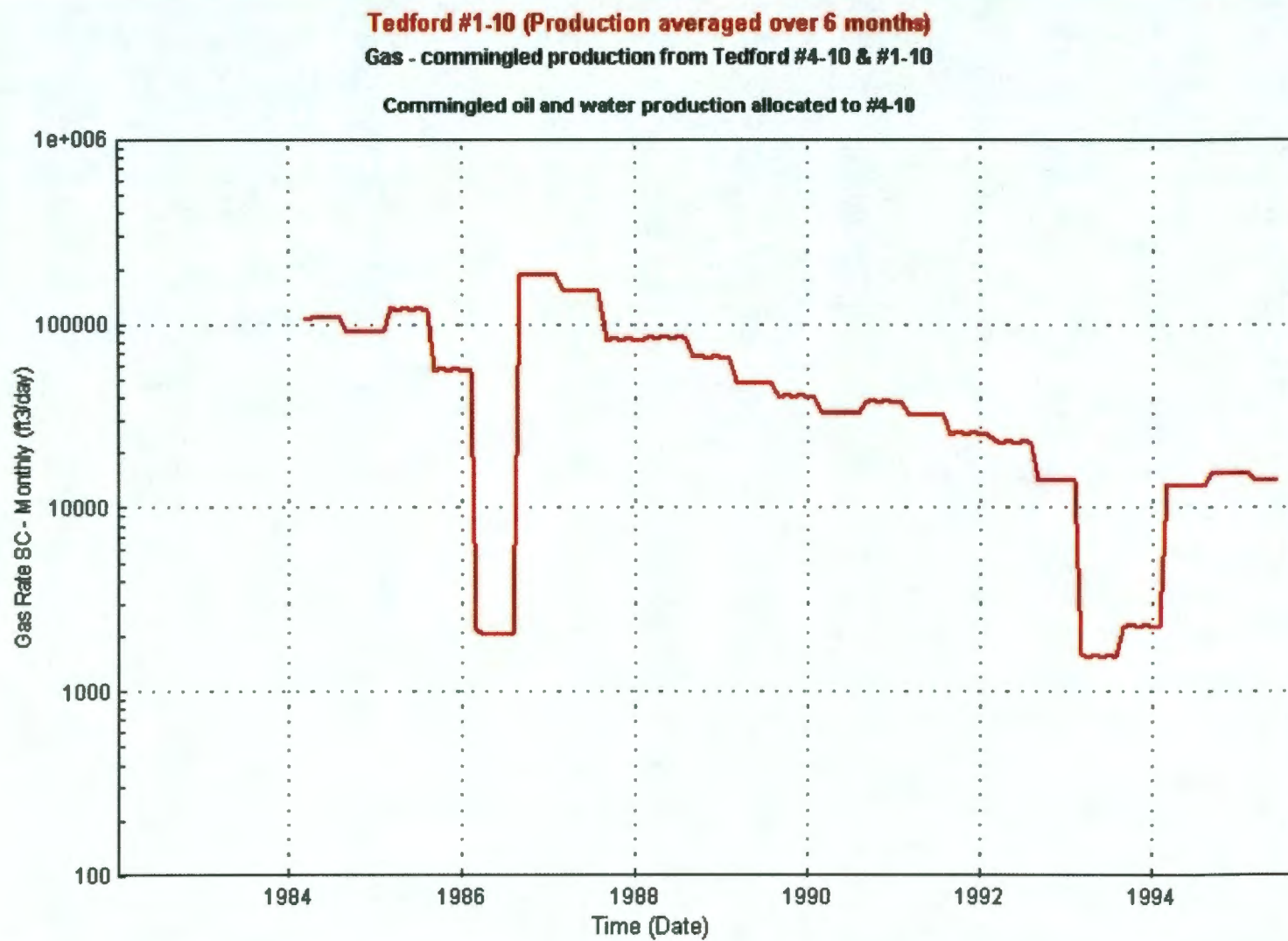


Figure A15

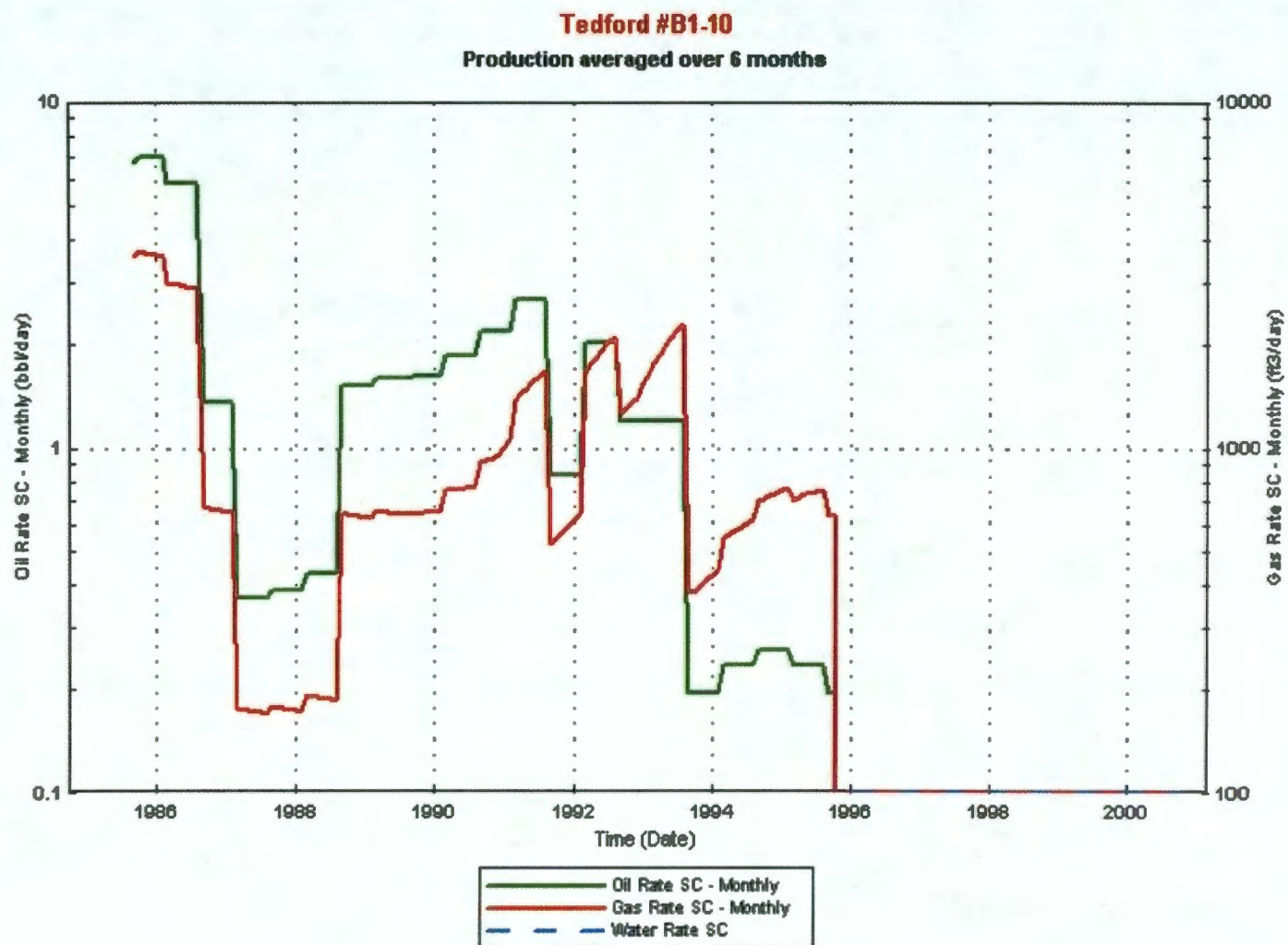


Figure A16

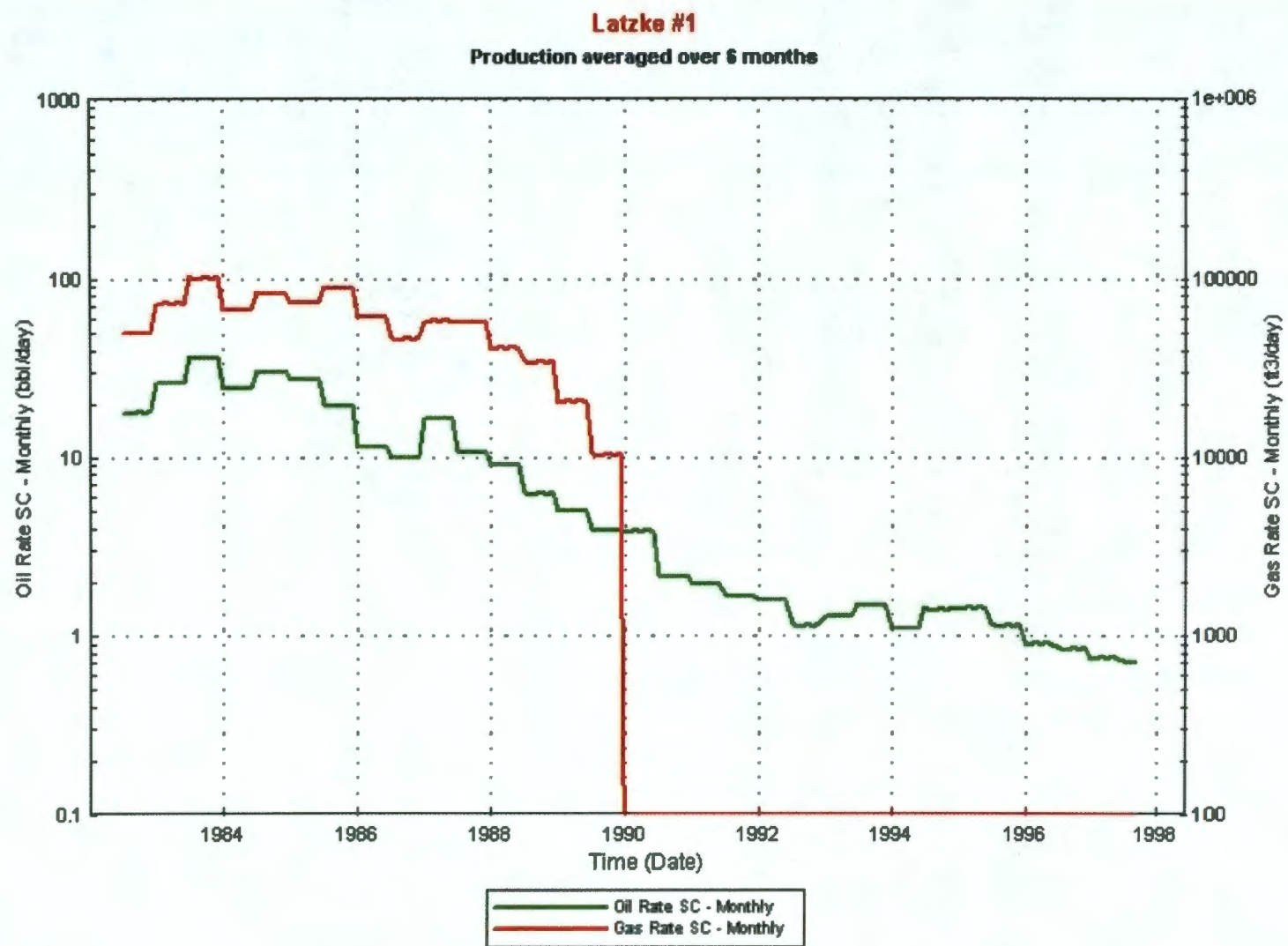


Figure A17

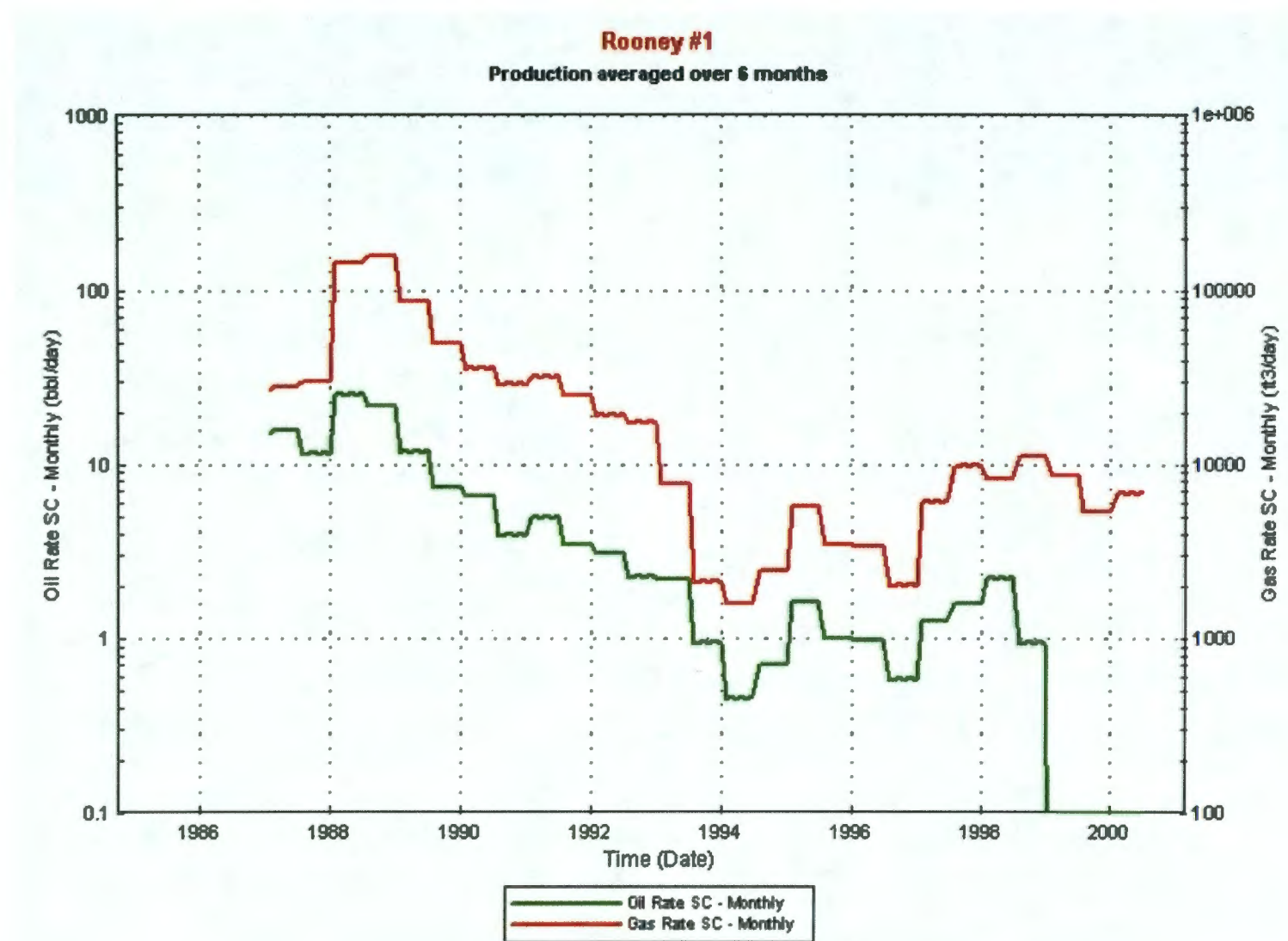


Figure A18

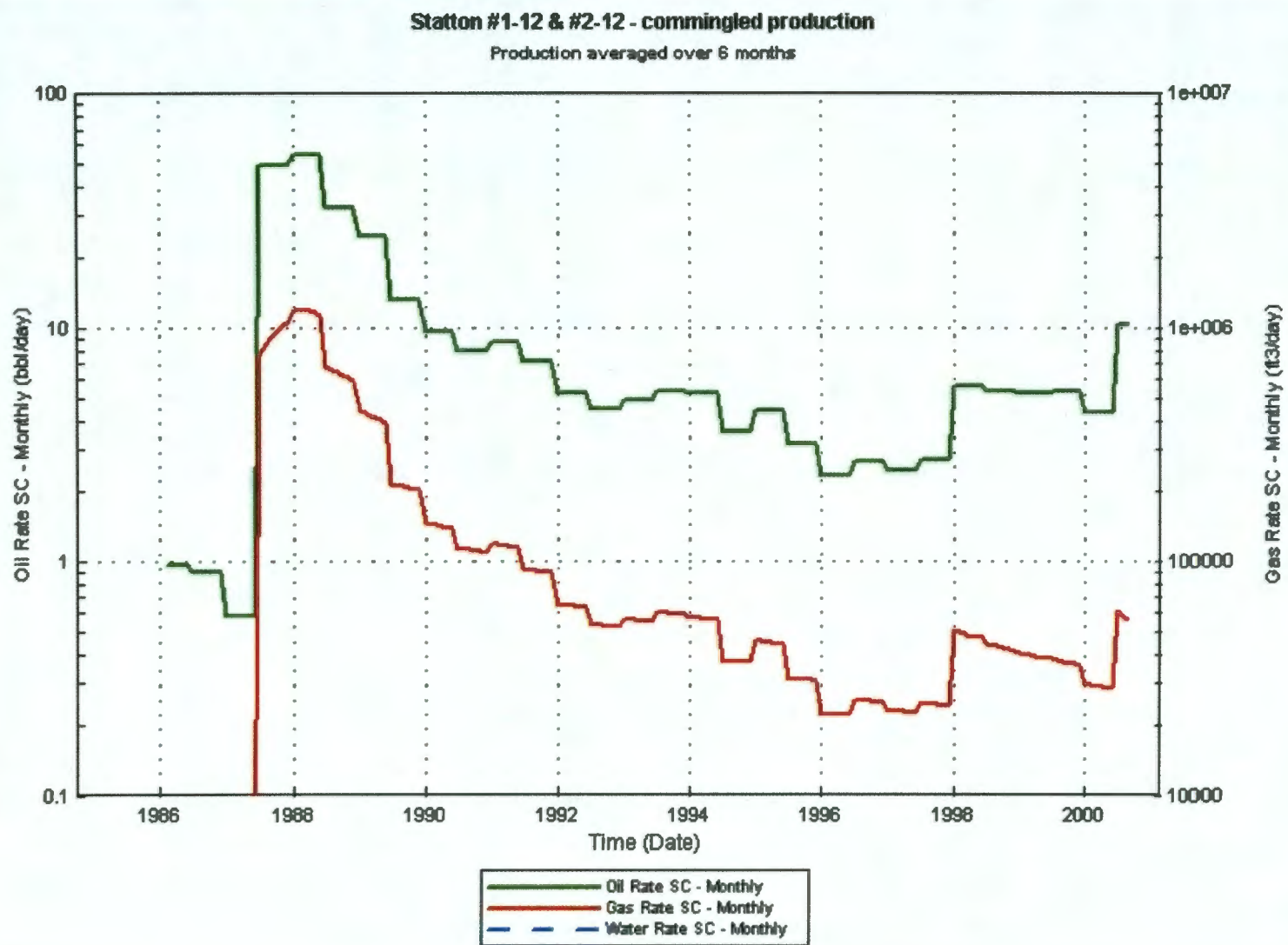


Figure A19

MINNEOLA FIELD SIMULATION AREA

Field Production decline

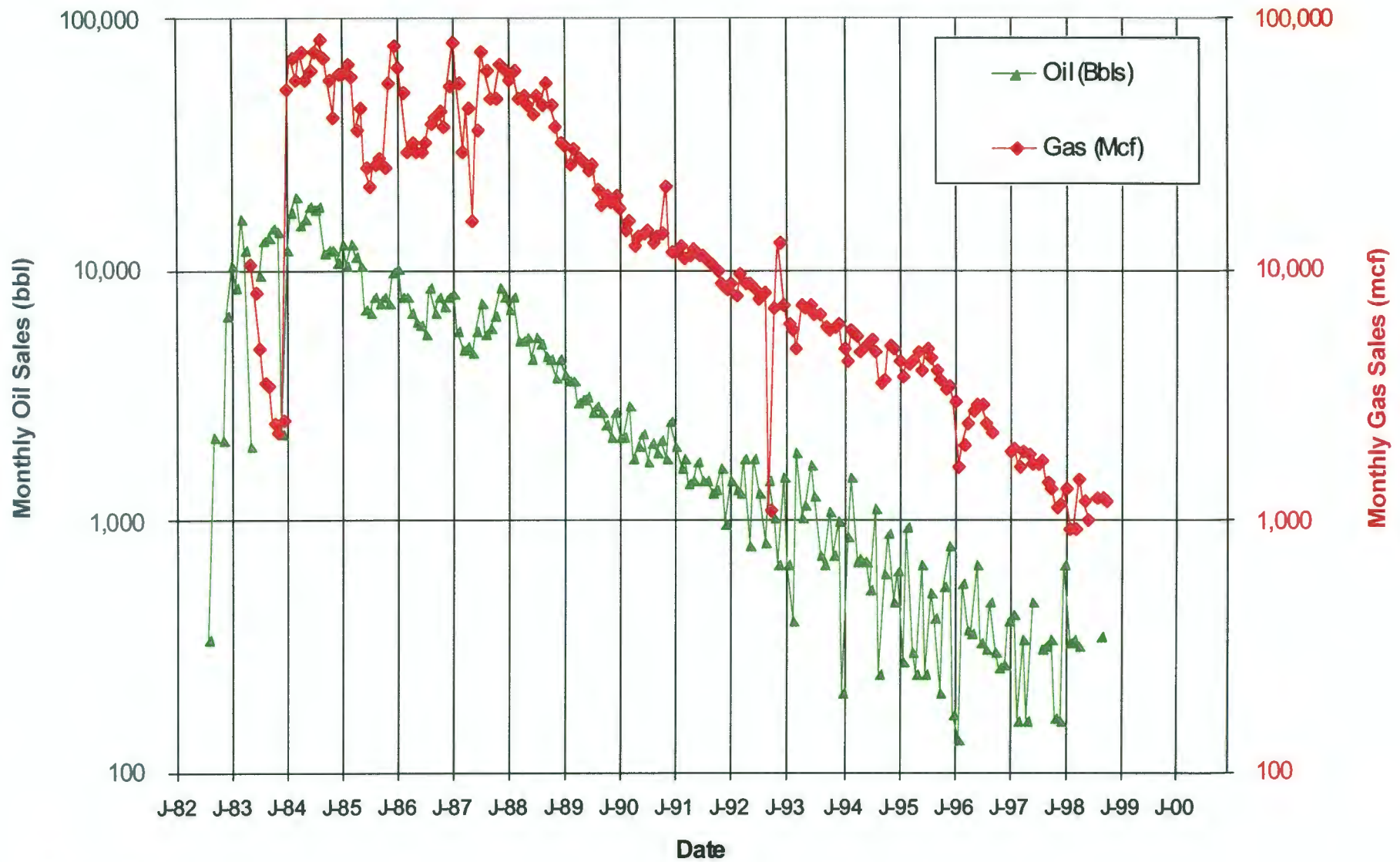


Figure A20

APPENDIX B

Appendix B – Core Petrophysical Analysis

Experimental Methods

Sample Preparation - Core plugs measuring approximately 1-inch in diameter and 2-inches long were obtained from whole core using a diamond core drill bit and tap water as coolant. The samples were Soxhlet extracted with a toluene/methyl alcohol azeotrope to remove any oil and salt precipitate in the pore space. The core plugs were dried at 70 °C to a constant weight within ± 0.003 gm. The samples were not humidity oven dried since porosities measured in this fashion do not reflect log-measured porosities and are also not suitable for correlation with electrical resistivity measurements.

Porosity - Ambient Helium porosity was re-determined using a Boyle's Law technique. Dry sample weights were measured to ± 0.001 gm and bulk volume was determined to an accuracy of ± 0.02 cc by mercury immersion. Ambient Helium porosity was measured to an accuracy and precision of better than ± 0.1 porosity percent. Porosity data are summarized in Table 1.

Routine Air and *In situ* Klinkenberg Permeability - To measure Routine Air and *in situ* Klinkenberg gas permeabilities, each core was placed in a Hassler type confining pressure cell and subjected to hydrostatic confining stress of 500 psi, to simulate routine core analysis laboratory confining stress conditions and 2,650 psi to approximately simulate *in situ* stresses. Routine air permeabilities were measured at less than 50 psi differential pressure using a mass flow transducer for flow measurement. Klinkenberg permeabilities, which correspond to non-reactive liquid permeabilities or high pressure gas permeabilities, were determined by measurement of gas permeability at confining stress and correction for Klinkenberg conditions based on the mean pore pressure. Routine air and *in situ* permeability data are presented in Table 1.

Electrical Resistivity - After porosity and permeability measurements the core plugs were evacuated overnight and pressure saturated at 1,000 psi with a deaerated 200,000 ppm NaCl brine. Subsequent to vacuum/pressure saturation with a 200,000 ppm NaCl brine (0.049 ohm-mt @ 20 °C), the cores were allowed to equilibrate with the brine for a period of ten (10) days. After this the 'routine' formation resistivity factor at 500 psi confining stress was measured every day on each plug until values were constant within 2% over three measurements. Once a plug had reached equilibration with the brine, it was placed in a Hassler-type core holder and subjected to hydrostatic confining stress of 2,650 psi. Electrical resistivity was measured using a two-electrode configuration. Resistivity was recorded only after the core had achieved equilibrium with the confining stress as determined by no change in the pore volume over a period of ten (10) minutes. Data are summarized in Table 1.

Single-Point Air-Brine Capillary Pressure - On completion of electrical resistivity measurements, the saturated core plugs were placed in a porous-plate capillary pressure cell and desaturated at 46.1 psia air-brine capillary pressure, equivalent to an oil column height of approximately 75 feet above free water level. Saturation was determined gravimetrically.

Air-Mercury Capillary Pressure Analysis - Subsequent to other advanced properties measurements selected core plugs, representing the range of lithofacies and porosity/permeability were vacuum pressure saturated with methyl alcohol and flow through cleaned to remove any salt. The samples were dried and the helium porosity redetermined as described above. Each sample was transferred to the capillary pressure instrument and evacuated to a pressure of less than 0.01 torr for a period of 15 minutes. The sample was subjected to increasing mercury injection pressures ranging from 2 to 10,000 psia. At each pressure, equilibrium was assumed to have been established when the volume of mercury injected was less than 0.1% of the pore volume for a two-minute period. Injected mercury volumes were corrected for system and mercury compressibility effects. Results are presented in tables and figures for each sample. Accuracy and precision vary with sample pore volume and outer pore sizes and surface roughness. Pump injection volumes are readable to 0.001cc. Based upon pore volumes of 1 to 2cc, estimated precision for the measurement is 1% for pore sizes less than 107um.

Appendix B

Table B1 - Summary of Core Petrophysical Properties

Well Name	Core Depth (ft)	Log Depth (ft)	Gamma Ray Index (API)	Argil. Index	Routine Helium Porosity (%)	Corresponding Full-Diameter Porosity (%)	Calculated <i>In situ</i> Porosity (%)	Plug Routine Air Permeability (md)	Full-Diameter Maximum Air Permeability (md)	Full-Diameter K90 Air Permeability (md)	Meas./Calc. <i>In situ</i> Klinkenberg Permeability (md)	Grain Density (g/cc)	Water Saturation at H=-75 ft (pc=32 psig) (%)	Archie Cementation Exponent (a=1)	Formation Resistivity Factor	Sample Type
Patton 1-3	5317.2	5321.7	46	4	7.7	7.8	6.9	0.0796			0.0253	2.66	86.5			
Patton 1-3	5318.1	5322.6	45	0	13.8	13.7	12.9	22.7			17.2	2.64	23.8	1.79	39.0	
Patton 1-3	5318.9	5323.4	40	1	15.4	13.7	14.6	30.5			23.7	2.63	22.2	1.81	32.4	hg
Patton 1-3	5319.4	5323.9	38	0	13.9	13.1	13.1	22.0			17.4	2.63				
Patton 1-3	5319.4	5323.9	38	0	13.2	13.1	12.3	21.9			17.3	2.63				vert
Patton 1-3	5320.1	5324.6	38	3	19.6	16.7	19.2	1.17			0.645	2.66	57.7			
Patton 1-3	5320.1	5324.6	38	2	17.8	16.7	17.2	11.9			8.91	2.65	45.6	1.89	27.7	hg
Patton 1-3	5320.6	5325.1	44	2	16.4	16.7	15.6	4.00			2.73	2.67				
Patton 1-3	5320.6	5325.1	44	2	15.8	16.7	15.0	2.47			1.65	2.67				hg
Patton 1-3	5321.8	5326.3	73	1	17.7	15.1	17.0	120			97.3	2.65				hg
Patton 1-3	5321.8	5326.3	73	1	17.4	15.1	16.8	119			94.8	2.66				
Patton 1-3	5324.2	5328.7	22	1	17.3	16.6	16.7	163			137	2.64	11.1			
Patton 1-3	5325	5329.5	14	1	17.9	17.1	17.3	192			157	2.65	14.9			vert
Patton 1-3	5325.7	5330.2	15	1	18.2	17.1	17.7	172			140	2.64	16.0	1.75	20.7	
Patton 1-3	5326.3	5330.8	16	1	17.7	17.4	17.1	229			192	2.64	13.1	1.72	21.0	
Patton 1-3	5327.3	5331.8	38	4	15.7	15.6	14.9	18.2			12.8	2.65	37.2	1.76	28.6	
Patton 1-3	5328.1	5332.6	16	1	13.2	13.6	12.3	35.6			28.0	2.66	24.3	1.79	42.8	
Statton 2-12	5315.7	5308.7	46	2	17.8		17.2	8.84			6.44	2.65	53.1	1.78	23.0	
Statton 2-12	5316.2	5309.2	46	0	17.2		16.5	15.9			12.1	2.66	39.0			vert
Statton 2-12	5317.2	5310.2	45	2	17.0		16.3	7.84			5.26	2.66	57.2	1.72	22.7	
Statton 2-12	5318.7	5311.7	43	2	19.2		18.7	6.63			4.70	2.66	62.2			hg
Statton 2-12	5319.9	5312.9	48	2	22.3		22.2	25.0			22.1	2.64				
Statton 2-12	5319.9	5312.9	48	2	21.0		20.8	23.8			17.8	2.65				
Statton 2-12	5320.2	5313.2	48	0	20.8		20.5	73.0			58.9	2.65	26.6			
Statton 2-12	5320.7	5313.7	49	3	19.5		19.1	11.4			8.47	2.65	51.9	1.85	21.3	
Statton 2-12	5322.4	5315.4	34	2	20.0		19.6	44.4			34.1	2.64	32.1	1.83	19.9	
Statton 2-12	5323.1	5316.1	30	1	20.7		20.4	44.0			34.1	2.64	34.0	1.86	19.4	
Statton 2-12	5323.5	5316.5	29	0	19.7		19.2	88.7			71.3	2.65	16.9			vert
Statton 2-12	5323.9	5316.9	30	1	20.0		19.7	133			107	2.64	23.6	1.76	17.6	
Statton 2-12	5324.7	5317.7	30	0	20.8		20.5	200			178	2.62				hg
Statton 2-12	5324.7	5317.7	30	0	20.9		20.6	247			201	2.63				
Statton 2-12	5325.3	5318.3	33	1	20.5		20.2	149			118	2.65	21.3	1.74	16.1	
Statton 2-12	5325.4	5318.4	34	1	21.2		20.9	98.8			77.1	2.64	23.1	1.80	16.8	
Statton 2-12	5326	5319	35	1	20.3		20.0	72.1			56.3	2.65	20.4			vert
Statton 2-12	5326.2	5319.2	35	0	18.0		17.4	163			133	2.65	6.3	1.71	19.9	
Statton 2-12	5326.21	5319.21	35	0	18.2		17.6	170			136	2.65	21.9	1.71	19.6	

Continued

Appendix B

Table B1 - Summary of Core Petrophysical Properties (continued)

Well Name	Core Depth (ft)	Log Depth (ft)	Gamma Ray Index (API)	Argil. Index	Routine Helium Porosity (%)	Corresponding Full-Diameter Porosity (%)	Calculated <i>In situ</i> Porosity (%)	Plug Routine Air Permeability (md)	Full-Diameter Maximum Air Permeability (md)	Full-Diameter K90 Air Permeability (md)	Meas./Calc. <i>In situ</i> Klinkenberg Permeability (md)	Grain Density (g/cc)	Water Saturation at H=-75 ft (pc=32 psig) (%)	Archie Cementation Exponent (a=1)	Formation Resistivity Factor	Sample Type
Commercial Laboratory Routine Analyses																
Statton 2-12	5315	5308		2	17.6		17.0	12.9			9.26	2.65				
Statton 2-12	5316	5309		2	17.2		16.5	17.8			13.0	2.66				
Statton 2-12	5317	5310		2	21.6		21.4	91.3			72.8	2.66				
Statton 2-12	5318	5311		2	21.1		20.8	38.3			29.2	2.66				
Statton 2-12	5319	5312		2	23.2		23.2	34.5			26.1	2.66				
Statton 2-12	5320	5313		2	21.0		20.7	63.9			50.0	2.66				
Statton 2-12	5321	5314		3	20.1		19.7	37.5			28.5	2.66				
Statton 2-12	5322	5315		2	19.7		19.3	41.9			32.0	2.66				
Statton 2-12	5323	5316		1	20.3		19.9	63.4			49.6	2.65				
Statton 2-12	5324	5317		0	20.1		19.7	199			166	2.65				
Statton 2-12	5325	5318		1	20.3		19.9	143			117	2.65				
Statton 2-12	5326	5319		0	19.6		19.2	188			156	2.65				
Patton 1-3	5317	5321.5			7.8		7.0		2	1.8	1.30	2.65				
Patton 1-3	5318	5322.5			13.7		12.8		15	10.4	10.9	2.62				
Patton 1-3	5319	5323.5			13.1		12.2		2.8	2.7	1.85	2.62				
Patton 1-3	5320	5324.5			16.7		16.0		2.7	2.2	1.78	2.67				
Patton 1-3	5321	5325.5			15.1		14.3		38	37.7	28.9	2.73				
Patton 1-3	5322	5326.5			17.4		16.7		70.3	51	55.3	2.65				
Patton 1-3	5323	5327.5			16.1		15.4		67.4	25.5	52.9	2.61				
Patton 1-3	5324	5328.5			16.6		15.9		88.9	81.3	70.8	2.60				
Patton 1-3	5325	5329.5			17.1		16.4		70.8	26.4	55.7	2.63				
Patton 1-3	5326	5330.5			17.4		16.7		1.4	0.4	0.89	2.62				
Patton 1-3	5327	5331.5			15.6		14.8		35.4	32	26.8	2.64				
Patton 1-3	5328	5332.5			13.6		12.7		22.9	6.6	17.0	2.66				
Widner 1-17	5328				5.8		5.1		0.09	0.09	0.05	2.68				
Widner 1-17	5329				8.8		8.0		5.8	2.2	4.0	2.67				
Widner 1-17	5330				10.7		9.8		2.4	1.7	1.6	2.67				
Widner 1-17	5331				10.6		9.7		1.8	1.3	1.2	2.66				
Widner 1-17	5332				13		12.1		1	0.87	0.6	2.67				
Widner 1-17	5333				13.6		12.7		22	22	16	2.71				
Fager 1-16	5322				16.9		16.2		43		33					
Fager 1-16	5324				17.95		17.3		103		83					
Fager 1-16	5326				15.8		15.0		133		108					
Fager 1-16	5328				16.5		15.8		78		62					

Appendix B - Table B2
Mercury Injection Capillary Pressure Analysis
Murfin Patton #1-3 5319.4 ft

In situ Klinkenberg Permeability = 17.4md
In situ Porosity = 13.1%

Mercury Injection Capillary Pressure (psia)	Approx. Pore Entry Diameter (um)	Cumulative Wetting Phase Saturation (% pore vol)	Pore Size Distribution Frequency	Cumulative Surface Area (m2/g)	Approx. Gas-Water Height Above Free Water Level (ft)	Approx. Oil-Water Height Above Free Water Level (ft)	Honarpour <i>et al.</i> Imbibition Carbonate		Corey Calculated		
							Oil Relative Permeability (%)	Water Relative Permeability (%)	Oil or Gas Relative Permeability (%)	Water Relative Permeability (%)	Log Oil/Brine Kro/Krw Ratio
2.0	107	100.0	0.0	0.000	0.1	0.1	0.0	100.0	0.0	100.0	-5.0
2.5	86	100.0	0.0	0.000	0.6	0.9	0.0	100.0	0.0	100.0	-5.0
3.3	65	100.0	0.0	0.000	1.0	1.5	0.0	100.0	0.0	100.0	-5.0
4.3	50	100.0	0.0	0.000	1.3	1.9	0.0	100.0	0.0	100.0	-5.0
5.5	39	100.0	0.0	0.000	1.6	2.5	0.0	100.0	0.0	100.0	-5.0
7.2	30	100.0	0.0	0.000	2.2	3.2	0.0	100.0	0.0	100.0	-5.0
9.3	23	100.0	0.0	0.000	2.8	4.2	0.0	100.0	0.0	100.0	-5.0
12.0	18	100.0	0.0	0.000	3.6	5.4	0.0	100.0	0.0	100.0	-5.0
15.5	14	100.0	0.0	0.000	4.6	7.0	0.0	100.0	0.0	100.0	-5.0
20	11	99.5	0.5	0.000	6.0	9.0	0.0	100.0	0.0	97.7	-5.0
25	8.6	98.5	0.9	0.000	7.5	11.3	0.0	100.0	0.0	94.0	-5.0
35	6.1	46.2	50.4	0.020	10	16	20.0	6.0	8.9	4.3	0.3
45	4.8	32.8	15.4	0.028	13	20	44.5	2.5	25.0	0.7	1.5
55	3.9	29.3	3.5	0.031	16	25	51.1	1.9	30.6	0.4	1.9
75	2.9	24.5	4.8	0.035	22	34	61.1	1.2	39.8	0.2	2.3
95	2.3	22.6	1.9	0.037	28	43	65.3	1.0	44.0	0.1	2.6
120	1.8	19.9	2.7	0.040	36	54	71.5	0.7	50.5	0.1	2.9
150	1.4	19.0	0.9	0.038	45	68	73.6	0.6	52.8	0.0	3.0
200	1.1	17.2	1.8	0.042	60	90	78.0	0.5	57.8	0.0	3.3
260	0.82	15.6	1.6	0.047	78	117	82.0	0.3	62.5	0.0	3.6
350	0.61	13.6	2.0	0.055	105	158	87.1	0.2	68.6	0.0	4.0
430	0.50	12.1	1.5	0.062	128	194	90.9	0.2	73.3	0.0	4.4
550	0.39	11.1	1.0	0.069	164	248	93.6	0.1	76.8	0.0	4.7
725	0.30	9.8	1.3	0.080	217	327	97.0	0.1	81.4	0.0	5.1
925	0.23	7.9	1.9	0.099	276	417	102.2	0.0	88.5	0.0	6.0
1200	0.18	7.1	0.8	0.111	358	541	104.5	0.0	91.6	0.0	6.6
1550	0.14	6.2	0.9	0.126	463	699	106.9	0.0	95.1	0.0	7.6
2000	0.11	5.3	0.9	0.146	597	902	109.3	0.0	98.6	0.0	9.9
2600	0.08	5.0	0.3	0.155	777	1173	110.3	0.0	100.0	0.0	15.0
3350	0.06	4.2	0.8	0.184	1001	1511	100.0	0.0	100.0	0.0	15.0
4300	0.05	3.7	0.6	0.213	1284	1939	100.0	0.0	100.0	0.0	15.0
5550	0.04	2.9	0.8	0.261	1658	2503	100.0	0.0	100.0	0.0	15.0
7200	0.03	2.4	0.5	0.301	2151	3247	100.0	0.0	100.0	0.0	15.0
9300	0.02	1.9	0.5	0.358	2778	4194	100.0	0.0	100.0	0.0	15.0

All Hg calculations assume air-mercury T=484 dyne/cm, contact angle=140deg.

Oil/Gas-Brine Pc assumes insitu o/g-brine Tcos0=	47.00	21.00	dynes/cm
Oil/gas-Brine height assumes o/g density gradient =	0.0476	0.3464	psi/ft
Oil/gas-Brine height assumes brine density gradient =	0.4720	0.4720	psi/ft
Swi assumed for relative permeability =	5.0	5.0	%
Sorw assumed for relative permeability =	30	30	%
<i>In situ</i> Gas/Oil & Brine Density (g/cc)=	0.110/0.80	1.09	g/cc

Appendix B - Table B3
Mercury Injection Capillary Pressure Analysis
Murfin Statton #2-12 5319.9 ft

In situ Klinkenberg Permeability = 22.1 md
In situ Porosity = 21.6%

Mercury Injection Capillary Pressure (psia)	Approx. Pore Entry Diameter (um)	Cumulative Wetting Phase Saturation (% pore vol)	Pore Size Distribution Frequency	Cumulative Surface Area (m ² /g)	Approx. Gas-Water Height Above Free Water Level (ft)	Approx. Oil-Water Height Above Free Water Level (ft)	Honarpour <i>et al.</i> Imbibition Carbonate		Corey Calculated		
							Oil Relative Permeability (%)	Water Relative Permeability (%)	Oil or Gas Relative Permeability (%)	Water Relative Permeability (%)	Log Oil/Brine Kro/Krw Ratio
2.0	107	100.0	0.0	0.000	0.1	0.1	0.0	100.0	0.0	100.0	-5.0
2.5	86	100.0	0.0	0.000	0.6	0.9	0.0	100.0	0.0	100.0	-5.0
3.3	65	100.0	0.0	0.000	0.7	1.1	0.0	100.0	0.0	100.0	-5.0
4.3	50	100.0	0.0	0.000	1.0	1.5	0.0	100.0	0.0	100.0	-5.0
5.5	39	100.0	0.0	0.000	1.3	1.9	0.0	100.0	0.0	100.0	-5.0
7.2	30	100.0	0.0	0.000	1.6	2.5	0.0	100.0	0.0	100.0	-5.0
9.3	23	100.0	0.0	0.000	2.2	3.2	0.0	100.0	0.0	100.0	-5.0
12.0	18	100.0	0.0	0.000	2.8	4.2	0.0	100.0	0.0	100.0	-5.0
15.5	14	99.9	0.1	0.000	3.6	5.4	0.0	100.0	0.0	100.0	-5.0
20	11	99.7	0.2	0.000	4.6	7.0	0.0	100.0	0.0	99.7	-5.0
25	8.6	97.2	2.5	0.001	6.0	9.0	0.0	100.0	0.0	98.7	-5.0
35	6.1	83.4	13.8	0.010	7.5	11.3	0.0	100.0	0.0	88.5	-6.0
45	4.8	67.4	16.0	0.022	10	16	0.0	100.0	0.1	45.3	-2.6
55	3.9	60.5	6.8	0.029	13	20	1.5	11.9	1.6	17.5	-1.1
75	2.9	54.5	6.1	0.037	16	25	6.7	9.3	3.3	10.8	-0.5
95	2.3	51.3	3.2	0.042	22	34	12.7	7.2	5.9	6.6	-0.1
120	1.8	48.4	2.9	0.048	28	43	16.3	6.3	7.7	5.0	0.2
150	1.4	46.5	1.8	0.047	36	54	20.0	5.5	9.7	3.8	0.4
200	1.1	44.3	2.2	0.054	45	68	22.5	5.0	11.2	3.2	0.6
260	0.82	42.5	1.8	0.062	60	90	25.6	4.4	13.2	2.5	0.7
350	0.61	39.1	3.4	0.083	78	117	28.3	4.0	14.9	2.0	0.9
430	0.50	35.7	3.4	0.109	105	158	33.7	3.3	18.8	1.4	1.1
550	0.39	31.6	4.1	0.148	128	194	39.6	2.6	23.4	0.9	1.4
725	0.30	26.0	5.5	0.218	164	248	47.2	1.9	30.1	0.5	1.8
925	0.23	21.1	5.0	0.298	217	327	58.4	1.1	41.0	0.2	2.4
1200	0.18	17.0	4.1	0.383	276	417	69.3	0.6	53.2	0.0	3.1
1550	0.14	12.6	4.3	0.500	358	541	79.1	0.3	65.2	0.0	3.8
2000	0.11	10.0	2.7	0.593	463	699	90.0	0.1	79.9	0.0	5.0
2600	0.08	7.6	2.4	0.700	597	902	97.1	0.0	90.1	0.0	6.3
3350	0.06	5.4	2.2	0.830	777	1173	103.6	0.0	100.0	0.0	15.0
4300	0.05	3.5	1.9	0.970	1001	1511	100.0	0.0	100.0	0.0	15.0
5550	0.04	2.3	1.2	1.083	1284	1939	100.0	0.0	100.0	0.0	15.0
7200	0.03	1.2	1.1	1.225	1658	2503	100.0	0.0	100.0	0.0	15.0
9300	0.02	0.5	0.7	1.333	2151	3247	100.0	0.0	100.0	0.0	15.0
					2778	4194	100.0	0.0	100.0	0.0	15.0

All Hg calculations assume air-mercury T=484 dyne/cm, contact angle=140deg.

Oil/Gas-Brine Pc assumes insitu o/g-brine Tcos0=	47.00	21.00	dynes/cm
Oil/gas-Brine height assumes o/g density gradient =	0.0476	0.3464	psi/ft
Oil/gas-Brine height assumes brine density gradient =	0.4720	0.4720	psi/ft
Swi assumed for relative permeability =	7.6	7.6	%
Sorw assumed for relative permeability =	30	30	%
<i>In situ</i> Gas/Oil & Brine Density (g/cc)=	0.110/0.80	1.09	g/cc

Appendix B - Table B4
Mercury Injection Capillary Pressure Analysis
Murfin Patton #1-3 5320.6 ft

In situ Klinkenberg Permeability = 2.73md
In situ Porosity = 15.9%

Mercury Injection Capillary Pressure (psia)	Approx. Pore Entry Diameter (um)	Cumulative Wetting Phase Saturation (% pore vol)	Pore Size Distribution Frequency	Cumulative Surface Area (m2/g)	Approx. Gas-Water Height Above Free Water Level (ft)	Approx. Oil-Water Height Above Free Water Level (ft)	Honarpour <i>et al.</i> Imbibition Carbonate		Corey Calculated		
							Oil Relative Permeability (%)	Water Relative Permeability (%)	Oil or Gas Relative Permeability (%)	Water Relative Permeability (%)	Log Oil/Brine Kro/Krw Ratio
2.0	107	100.0	0.0	0.000	0.1	0.1	0.0	100.0	0.0	100.0	-5.0
2.5	86	100.0	0.0	0.000	0.8	0.9	0.0	100.0	0.0	100.0	-5.0
3.3	65	100.0	0.0	0.000	0.7	1.1	0.0	100.0	0.0	100.0	-5.0
4.3	50	100.0	0.0	0.000	1.0	1.5	0.0	100.0	0.0	100.0	-5.0
5.5	39	100.0	0.0	0.000	1.3	1.9	0.0	100.0	0.0	100.0	-5.0
7.2	30	100.0	0.0	0.000	1.6	2.5	0.0	100.0	0.0	100.0	-5.0
9.3	23	100.0	0.0	0.000	2.2	3.2	0.0	100.0	0.0	100.0	-5.0
12.0	18	100.0	0.0	0.000	2.8	4.2	0.0	100.0	0.0	100.0	-5.0
15.5	14	100.0	0.0	0.000	3.6	5.4	0.0	100.0	0.0	100.0	-5.0
20	11	100.0	0.0	0.000	4.6	7.0	0.0	100.0	0.0	100.0	-5.0
25	8.6	100.0	0.0	0.000	6.0	9.0	0.0	100.0	0.0	100.0	-5.0
35	6.1	99.7	0.3	0.000	7.5	11.3	0.0	100.0	0.0	100.0	-5.0
45	4.8	98.3	1.4	0.001	10	16	0.0	100.0	0.0	98.5	-5.0
55	3.9	88.3	10.0	0.008	13	20	0.0	100.0	0.0	91.0	-6.5
75	2.9	84.1	4.2	0.012	16	25	0.0	100.0	0.1	49.8	-2.9
95	2.3	62.5	21.6	0.039	22	34	0.0	100.0	0.2	37.7	-2.2
120	1.8	54.8	7.7	0.051	28	43	5.0	5.4	6.8	5.7	0.1
150	1.4	51.1	3.7	0.046	36	54	12.3	3.3	14.4	2.2	0.8
200	1.1	48.0	3.2	0.055	45	68	16.6	2.5	19.7	1.2	1.2
260	0.82	45.4	2.6	0.064	60	90	20.7	1.9	25.3	0.7	1.5
350	0.61	43.2	2.2	0.074	78	117	24.2	1.4	30.8	0.4	1.9
430	0.50	41.6	1.6	0.082	105	158	27.4	1.1	36.0	0.3	2.1
550	0.39	39.9	1.7	0.095	128	194	29.8	0.9	40.1	0.2	2.4
725	0.30	37.8	2.2	0.115	164	248	32.6	0.7	45.0	0.1	2.8
925	0.23	36.0	1.8	0.137	217	327	36.2	0.5	51.8	0.1	3.0
1200	0.18	33.9	2.1	0.169	276	417	39.2	0.4	57.9	0.0	3.3
1550	0.14	31.6	2.4	0.217	358	541	43.0	0.2	65.8	0.0	3.8
2000	0.11	29.2	2.3	0.278	463	699	47.4	0.1	75.8	0.0	4.6
2600	0.08	26.6	2.6	0.367	597	902	52.0	0.0	86.6	0.0	5.7
3350	0.06	23.8	2.9	0.494	777	1173	57.3	0.0	100.0	0.0	15.0
4300	0.05	20.7	3.1	0.667	1001	1511	100.0	0.0	100.0	0.0	15.0
5550	0.04	17.4	3.3	0.908	1284	1939	100.0	0.0	100.0	0.0	15.0
7200	0.03	14.0	3.4	1.225	1658	2503	100.0	0.0	100.0	0.0	15.0
9300	0.02	10.5	3.5	1.658	2151	3247	100.0	0.0	100.0	0.1	15.0
					2778	4194	100.0	0.0	100.0	0.2	15.0

All Hg calculations assume air-mercury T=484 dyne/cm, contact angle=140deg.

Oil/Gas-Brine Pc assumes insitu σ /g-brine Tcos0=	47.00	21.00	dynes/cm
Oil/gas-Brine height assumes σ /g density gradient =	0.0476	0.3464	psi/ft
Oil/gas-Brine height assumes brine density gradient =	0.4720	0.4720	psi/ft
Swi assumed for relative permeability =	26.6	26.6	%
Sorw assumed for relative permeability =	30	30	%
<i>In situ</i> Gas/Oil & Brine Density (g/cc)=	0.110/0.80	1.09	g/cc

Appendix B - Table B5
Mercury Injection Capillary Pressure Analysis
Murfin Patton #1-3 5321.8 ft

In situ Klinkenberg Permeability = 97.3md
In situ Porosity = 17.1%

Mercury Injection Capillary Pressure (psia)	Approx. Pore Entry Diameter (um)	Cumulative Wetting Phase Saturation (% pore vol)	Pore Size Distribution Frequency	Cumulative Surface Area (m2/g)	Approx. Gas-Water Height Above Free Water Level (ft)	Approx. Oil-Water Height Above Free Water Level (ft)	Honarpour <i>et al.</i> Imbibition Carbonate		Corey Calculated		
							Oil Relative Permeability (%)	Water Relative Permeability (%)	Oil or Gas Relative Permeability (%)	Water Relative Permeability (%)	Log Oil/Brine Kro/Krw Ratio
		100.0	0.0	0.000	0.1	0.1	0.0	100.0	0.0	100.0	-5.0
2.0	107	100.0	0.0	0.000	0.6	0.9	0.0	100.0	0.0	100.0	-5.0
2.5	86	100.0	0.0	0.000	0.7	1.1	0.0	100.0	0.0	100.0	-5.0
3.3	65	100.0	0.0	0.000	1.0	1.5	0.0	100.0	0.0	100.0	-5.0
4.3	50	100.0	0.0	0.000	1.3	1.9	0.0	100.0	0.0	100.0	-5.0
5.5	39	100.0	0.0	0.000	1.6	2.5	0.0	100.0	0.0	100.0	-5.0
7.2	30	99.5	0.5	0.000	2.2	3.2	0.0	100.0	0.0	97.8	-5.0
9.3	23	98.9	0.6	0.000	2.8	4.2	0.0	100.0	0.0	95.3	-5.0
12.0	18	96.3	2.6	0.001	3.6	5.4	0.0	100.0	0.0	85.0	-5.5
15.5	14	82.8	13.5	0.004	4.6	7.0	0.0	100.0	0.1	44.2	-2.6
20	11	46.9	35.9	0.014	6.0	9.0	22.0	5.3	10.4	3.5	0.5
25	8.6	38.6	8.3	0.017	7.5	11.3	34.5	3.3	18.8	1.4	1.1
35	6.1	32.1	6.5	0.020	10	16	46.1	2.1	27.9	0.6	1.7
45	4.8	29.8	2.2	0.021	13	20	50.5	1.7	31.8	0.4	1.9
55	3.9	28.5	1.3	0.022	16	25	53.1	1.6	34.3	0.3	2.1
75	2.9	26.2	2.3	0.025	22	34	57.9	1.2	38.9	0.2	2.3
95	2.3	24.7	1.5	0.027	28	43	61.2	1.1	42.2	0.1	2.5
120	1.8	23.1	1.6	0.030	36	54	64.6	0.9	45.9	0.1	2.7
150	1.4	22.2	0.9	0.029	45	68	66.7	0.8	48.1	0.1	2.8
200	1.1	21.1	1.1	0.032	60	90	69.1	0.7	50.8	0.1	2.9
260	0.82	20.0	1.1	0.036	78	117	71.6	0.6	53.6	0.0	3.1
350	0.61	18.9	1.2	0.042	105	156	74.4	0.5	56.9	0.0	3.3
430	0.50	17.4	1.5	0.051	128	194	77.9	0.4	61.1	0.0	3.5
550	0.39	16.7	0.7	0.056	164	248	79.6	0.3	63.1	0.0	3.7
725	0.30	15.2	1.5	0.071	217	327	83.2	0.2	67.7	0.0	4.0
925	0.23	13.5	1.8	0.095	276	417	87.8	0.2	73.6	0.0	4.4
1200	0.18	11.7	1.8	0.125	358	541	92.4	0.1	79.9	0.0	5.0
1550	0.14	9.8	1.6	0.166	463	699	97.3	0.0	86.7	0.0	5.8
2000	0.11	7.9	1.9	0.221	597	902	102.6	0.0	94.4	0.0	7.4
2600	0.08	6.6	1.3	0.270	777	1173	106.4	0.0	100.0	0.0	15.0
3350	0.06	5.0	1.6	0.345	1001	1511	100.0	0.0	100.0	0.0	15.0
4300	0.05	3.7	1.3	0.427	1284	1939	100.0	0.0	100.0	0.0	15.0
5550	0.04	2.3	1.4	0.535	1658	2503	100.0	0.0	100.0	0.0	15.0
7200	0.03	1.6	0.7	0.609	2151	3247	100.0	0.0	100.0	0.0	15.0
9300	0.02	0.9	0.7	0.696	2778	4194	100.0	0.0	100.0	0.0	15.0

All Hg calculations assume air-mercury T=484 dyne/cm, contact angle=140deg.

Oil/Gas-Brine Pc assumes insitu o/g-brine Tcos0=	47.00	21.00	dynes/cm
Oil/gas-Brine height assumes o/g density gradient =	0.0476	0.3464	psi/ft
Oil/gas-Brine height assumes brine density gradient =	0.4720	0.4720	psi/ft
Swi assumed for relative permeability =	6.6	6.6	%
Sorw assumed for relative permeability =	30	30	%
<i>In situ</i> Gas/Oil & Brine Density (g/cc)=	0.110/0.80	1.09	g/cc

Appendix B - Table B6
Mercury Injection Capillary Pressure Analysis
Murfin Statton 2-12 5324.7 ft

In situ Klinkenberg Permeability = 178md
In situ Porosity = 20.1%

Mercury Injection Capillary Pressure (psia)	Approx. Pore Entry Diameter (um)	Cumulative Wetting Phase Saturation (% pore vol)	Pore Size Distribution Frequency	Cumulative Surface Area (m ² /g)	Approx. Gas-Water Height Above Free Water Level (ft)	Approx. Oil-Water Height Above Free Water Level (ft)	Honarpour <i>et al.</i> Imbibition Carbonate		Corey Calculated		
							Oil Relative Permeability (%)	Water Relative Permeability (%)	Oil or Gas Relative Permeability (%)	Water Relative Permeability (%)	Log Oil/Brine Kro/Krw Ratio
2.0	107	100.0	0.0	0.000	0.1	0.1	0.0	100.0	0.0	100.0	-5.0
2.5	86	100.0	0.0	0.000	0.6	0.9	0.0	100.0	0.0	100.0	-5.0
3.3	65	100.0	0.0	0.000	0.7	1.1	0.0	100.0	0.0	100.0	-5.0
4.3	50	99.8	0.2	0.000	1.0	1.5	0.0	100.0	0.0	100.0	-5.0
5.5	39	99.8	0.0	0.000	1.3	1.9	0.0	100.0	0.0	99.3	-5.0
7.2	30	99.7	0.1	0.000	1.6	2.5	0.0	100.0	0.0	99.3	-5.0
9.3	23	99.7	0.0	0.000	2.2	3.2	0.0	100.0	0.0	98.8	-5.0
12.0	18	99.3	0.4	0.000	2.8	4.2	0.0	100.0	0.0	98.8	-5.0
15.5	14	58.1	41.2	0.012	3.6	5.4	0.0	100.0	0.0	97.2	-5.0
20	11	30.2	28.0	0.022	4.6	7.0	0.5	9.9	3.3	10.9	-0.5
25	8.6	23.6	6.6	0.025	6.0	9.0	21.7	2.5	25.3	0.7	1.6
35	6.1	19.2	4.5	0.028	7.5	11.3	30.8	1.5	36.3	0.3	2.2
45	4.8	16.8	2.4	0.030	10	16	37.9	0.9	45.6	0.1	2.7
55	3.9	15.7	1.1	0.031	13	20	42.0	0.7	51.2	0.1	3.0
75	2.9	13.5	2.2	0.034	16	25	43.9	0.6	53.9	0.0	3.1
95	2.3	12.4	1.1	0.035	22	34	47.8	0.4	59.7	0.0	3.4
120	1.8	10.9	1.5	0.039	28	43	49.9	0.4	62.8	0.0	3.6
150	1.4	10.0	0.9	0.038	36	54	52.8	0.3	67.1	0.0	3.9
200	1.1	9.0	1.0	0.042	45	68	54.6	0.2	70.0	0.0	4.1
260	0.82	8.1	0.8	0.046	60	90	56.7	0.2	73.2	0.0	4.4
350	0.61	7.0	1.1	0.053	78	117	58.4	0.1	76.0	0.0	4.6
430	0.50	6.2	0.8	0.059	105	158	60.8	0.1	79.8	0.0	4.9
550	0.39	5.4	0.8	0.067	128	194	62.4	0.1	82.5	0.0	5.2
725	0.30	4.4	1.0	0.080	164	248	64.2	0.0	85.4	0.0	5.6
925	0.23	3.7	0.7	0.092	217	327	66.2	0.0	88.9	0.0	6.1
1200	0.18	3.2	0.6	0.104	276	417	67.9	0.0	91.7	0.0	6.6
1550	0.14	2.5	0.6	0.121	358	541	69.1	0.0	93.9	0.0	7.2
2000	0.11	2.2	0.3	0.132	463	699	70.5	0.0	96.3	0.0	8.1
2600	0.08	1.6	0.6	0.162	597	902	71.2	0.0	97.5	0.0	8.8
3350	0.06	1.3	0.3	0.179	777	1173	72.6	0.0	100.0	0.0	15.0
4300	0.05	0.8	0.5	0.217	1001	1511	100.0	0.0	100.0	0.0	15.0
5550	0.04	0.5	0.3	0.246	1284	1939	100.0	0.0	100.0	0.0	15.0
7200	0.03	0.4	0.1	0.266	1658	2503	100.0	0.0	100.0	0.0	15.0
9300	0.02	0.1	0.3	0.309	2151	3247	100.0	0.0	100.0	0.0	15.0
					2778	4194	100.0	0.0	100.0	0.0	15.0

All Hg calculations assume air-mercury T=484 dyne/cm, contact angle=140deg.

Oil/Gas-Brine Pc assumes insitu o/g-brine Tcos0=	47.00	21.00	dynes/cm
Oil/gas-Brine height assumes o/g density gradient =	0.0476	0.3464	psi/ft
Oil/gas-Brine height assumes brine density gradient =	0.4720	0.4720	psi/ft
Swi assumed for relative permeability =	1.6	1.6	%
Sorw assumed for relative permeability =	30	30	%
<i>In situ</i> Gas/Oil & Brine Density (g/cc)=	0.110/0.80	1.09	g/cc

Appendix B - Table B7

Summary of Relative Permeability Data for Stewart Field Morrow Sandstones

Well	Depth (ft)	Porosity (%)	Air permeability (md)	keo,Swi (md)	Ratio keo/kair	krw,Sor (fraction)	Swi (%)	Sor,w (%)	~krw exponent n	~kro exponent m
Meyer 10-1	4779.2	17.9	304	196	0.64474	0.144	15.7	40.3	3.2	2.2
Meyer 10-1	4788.5	16.1	135	105	0.77778	0.235	20.2	36	3.5	2.9
Meyer 10-1	4793.4	15.4	134	90	0.67164	0.117	16.7	41.7	6.1	2.3
Meyer 10-1	4803.5	11.2	54	32	0.59259	0.325	25.4	32.7	3.2	3.6
Scott 4-8	4787.4	15.2	66.9	37	0.55306	0.067	34.9	38.7	1.4	3.9
Scott 4-8	4786	13.8	71.5	29	0.40559	0.06	30.3	48.7	0.5	8

well	Meyer 10-1	Meyer 10-1	Meyer 10-1	Meyer 10-1	Scott 4-8	Scott 4-8
depth	4779.2	4788.5	4793.4	4803.5	4787.4	4786
porosity	17.9	16.1	15.4	11.2	15.2	13.8
kair (md)	304	135	134	54	66.9	71.5
kinsitu klink	257	113	112	44	55	59
ko,Swi(md)	196	105	90	32	37	29
krw,Sor	0.144	0.235	0.117	0.325	0.067	0.060
Swi (%)	15.7	20.2	16.7	25.4	34.9	30.3
Sor,w (%)	40.3	36	41.7	32.7	38.7	48.7

Sw	Krw	Kro	Sw	Krw	Kro	Sw	Krw	Kro	Sw	Krw	Kro	Sw	Krw	Kro	Sw	Krw	Kro
15.7	0.0001	1	20.2	0.0001	1	16.7	0.0001	1	25.4	0.0001	1	34.9	0.0001	1	30.3	0.0001	1
38.0	0.017	0.219	33.9	0.006	0.791	43.3	0.0063	0.099	43.5	0.0092	0.121	42.7	0.017	0.191	31.0	0.013	0.599
39.2	0.023	0.151	45.5	0.014	0.095	45.5	0.011	0.086	44.8	0.016	0.105	45.5	0.021	0.106	32.9	0.025	0.294
45.2	0.051	0.066	50.1	0.056	0.073	48.3	0.014	0.022	48.9	0.053	0.069	50.3	0.032	0.032	34.0	0.031	0.206
51.8	0.077	0.02	52.3	0.075	0.019	51.9	0.044	0.0068	53.7	0.099	0.026	52.9	0.036	0.013	35.6	0.038	0.104
53.7	0.083	0.011	53.2	0.086	0.011	58.3	0.117	0.0001	55.8	0.11	0.014	56.6	0.053	0.002	36.9	0.044	0.067
59.7	0.144	0.0001	64.0	0.235	0.0001				67.3	0.325	0.0001	57.5	0.058	0.001	37.7	0.047	0.054
												59.3	0.064	0.0001	41.6	0.05	0.019
												61.3	0.067	0.0001	49.1	0.058	0.001
															51.3	0.06	0.0001

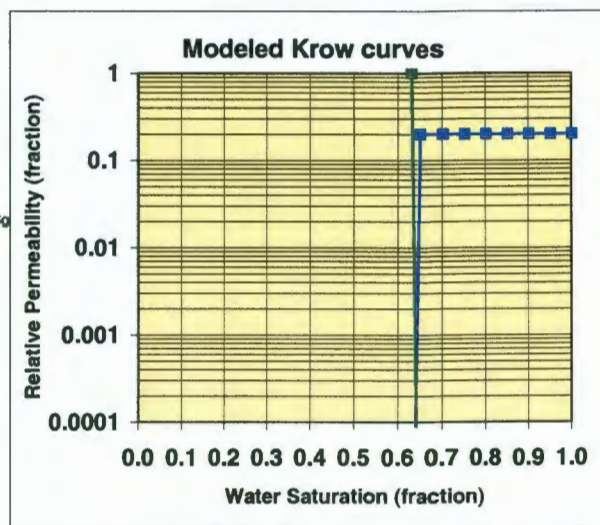
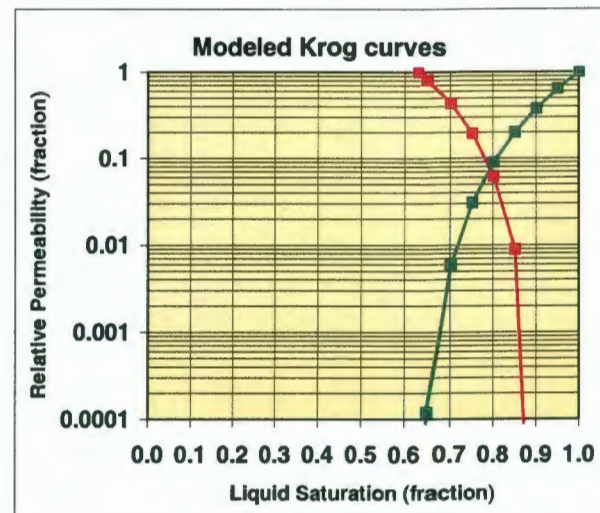
Appendix B

Table B8 - Calculated Relative Permeability & Capillary Pressure - 3 md Morrow Sandstone

[illegible][illegible]

K=	3.0 md				
Krwmax=	0.2	Kromax=	1	Pcentry=	2.738
Krw -m=	2.8	Swl=	0.63	Pca=	8.990
Kro -n=	3.1	Sorw=	1.07	Pcb=	-0.997
water grad	0.468	W sp grav=	1.36	input value	
oil grad	0.305	Oil sp grav=	0.704	calc value	
Krgmax=	1	Kromax=	1		
Krg -m=	2.8	Sgc for kro=	0.00	Sgc for krg=	0.1
Kro -n=	3.1	Sorg for kro=	0.63	Sorg for krg=	0.63
IFTal/IFTow=	1	Sora for kro=	0		

Note: krg calculated using SwDkrg to allow Sgc>0 while still allowing kro approach 1 below So

[illegible][illegible]

Appendix B

Table B9 - Calculated Relative Permeability & Capillary Pressure - 10 md Morrow Sandstone

SW	KRW	KROW	PCOW
0.49704	0.000000	1.000000	7.48442
0.50000	0.000005	0.932587	7.37912
0.55000	0.015194	0.207035	5.91147
0.60000	0.097742	0.009898	4.88864
0.65000	0.200000	0.000000	4.16334
0.70000	0.200000	0.000000	3.64119
0.75000	0.200000	0.000000	3.26022
0.80000	0.200000	0.000000	2.97894
0.85000	0.200000	0.000000	2.76901
0.90000	0.200000	0.000000	2.61083
0.95000	0.200000	0.000000	2.49058
1.00000	0.200000	0.000000	2.39842
1.00000	0.200000	0.000000	2.39842
1.00000	0.200000	0.000000	2.39842
1.00000	0.200000	0.000000	2.39842
1.00000	0.200000	0.000000	2.39842
1.00000	0.200000	0.000000	2.39842
1.00000	0.200000	0.000000	2.39842
1.00000	0.200000	0.000000	2.39842
1.00000	0.200000	0.000000	2.39842
1.00000	0.200000	0.000000	2.39842
1.00000	0.200000	0.000000	2.39842

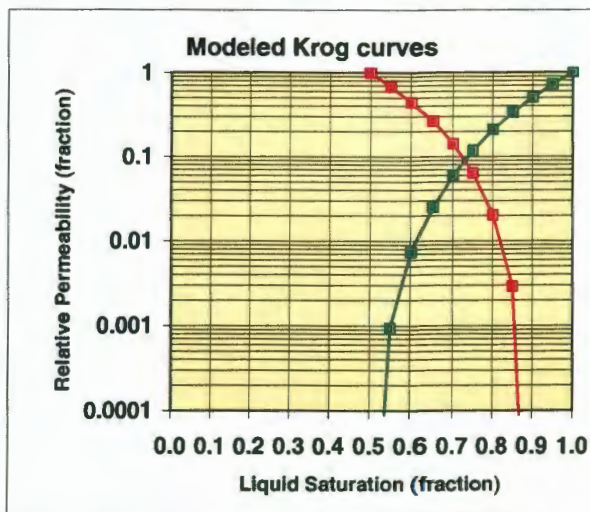
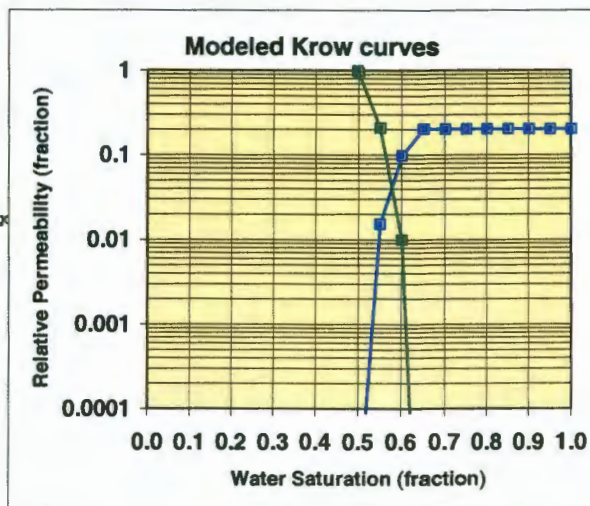
SwD
0.00000
0.02226
0.39832
0.77437
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000

K=	10.0	md		
Krwmax=	0.2	Kromax=	1	Pcentry= 2.053
Krw -m=	2.8	Swl=	0.50	Pcb= 8.277
Kro - n=	3.1	Sorw=	0.37	Pcb= -0.934
water grad	0.468	W sp grav=	1.08	Input value
oil grad	0.305	Oil sp grav=	0.704	calc value
Krgmax=	1	Kromax=	1	
Krg -m=	2.8	Sgc for kro=	0.00	Sgc for krg= 0.1
Kro - n=	3.1	Sorg for kro=	0.50	Sorg for krg= 0.50
IFTgo/FTow=	1	Sorg for kro=	0	

Note: krg calculated using SwDkrg to allow Sgc>0 while still allowing kro approach 1 below Sgc

SL	KRG	KROG	PCOG
0.49704	1.00000	0.000000	3000.00000
0.50000	0.97957	0.000000	1922.82758
0.55000	0.67400	0.00093	191.90065
0.60000	0.43773	0.00732	59.51631
0.65000	0.26272	0.02497	24.84174
0.70000	0.14065	0.06001	12.47427
0.75000	0.06285	0.11877	7.27676
0.80000	0.02020	0.20775	4.84872
0.85000	0.00290	0.33358	3.62563
0.90000	0.00000	0.50299	2.97327
0.95000	0.00000	0.72282	2.60922
1.00000	0.00000	1.00000	2.39842
1.00000	0.00000	1.00000	2.39842
1.00000	0.00000	1.00000	2.39842
1.00000	0.00000	1.00000	2.39842
1.00000	0.00000	1.00000	2.39842
1.00000	0.00000	1.00000	2.39842
1.00000	0.00000	1.00000	2.39842
1.00000	0.00000	1.00000	2.39842
1.00000	0.00000	1.00000	2.39842
1.00000	0.00000	1.00000	2.39842
1.00000	0.00000	1.00000	2.39842
1.00000	0.00000	1.00000	2.39842

SwD	SwDkrg	Sg	So for Pcoog
1.000	1.000	0.503	0.00000
0.994	0.993	0.500	0.00589
0.895	0.869	0.450	0.10530
0.795	0.744	0.400	0.20471
0.696	0.620	0.350	0.30412
0.596	0.496	0.300	0.40353
0.497	0.372	0.250	0.50294
0.398	0.248	0.200	0.60235
0.298	0.124	0.150	0.70177
0.199	0.000	0.100	0.80118
0.099	0.000	0.050	0.90059
0.000	0.000	0.000	1.00000
0.000	0.000	0.000	1.00000
0.000	0.000	0.000	1.00000
0.000	0.000	0.000	1.00000
0.000	0.000	0.000	1.00000
0.000	0.000	0.000	1.00000
0.000	0.000	0.000	1.00000
0.000	0.000	0.000	1.00000
0.000	0.000	0.000	1.00000
0.000	0.000	0.000	1.00000
0.000	0.000	0.000	1.00000



Appendix B

Table B10 - Calculated Relative Permeability & Capillary Pressure - 30 md Morrow Sandstone

SW	KRW	KROW	PCOW
0.35917	0.000000	1.000000	12.00895
0.40000	0.001000	0.602562	9.33460
0.45000	0.009387	0.281832	7.07129
0.50000	0.032049	0.102771	5.53009
0.55000	0.075039	0.022815	4.45661
0.60000	0.143969	0.001091	3.69442
0.65000	0.200000	0.000000	3.14422
0.70000	0.200000	0.000000	2.74129
0.75000	0.200000	0.000000	2.44242
0.80000	0.200000	0.000000	2.21821
0.85000	0.200000	0.000000	2.04828
0.90000	0.200000	0.000000	1.91830
0.95000	0.200000	0.000000	1.81805
1.00000	0.200000	0.000000	1.74012
1.00000	0.200000	0.000000	1.74012
1.00000	0.200000	0.000000	1.74012
1.00000	0.200000	0.000000	1.74012
1.00000	0.200000	0.000000	1.74012
1.00000	0.200000	0.000000	1.74012
1.00000	0.200000	0.000000	1.74012
1.00000	0.200000	0.000000	1.74012

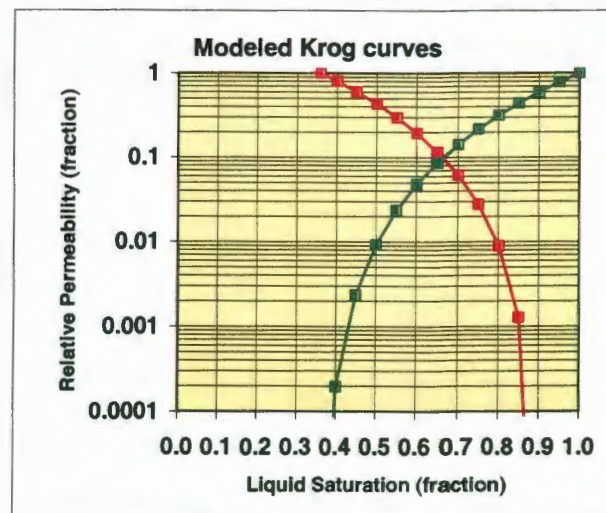
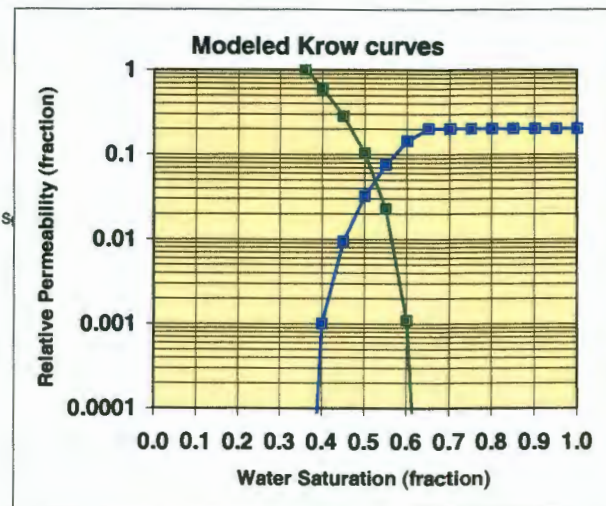
SwD
0.00000
0.15076
0.33537
0.51999
0.70461
0.88923
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000

K=	30.0	md
Krwmax=	0.2	Kromax= 1
Krw -m=	2.8	Swi= 0.36
Kro - n=	3.1	Sorw= 0.37
water grad	0.468	W sp grav= 1.08
oil grad	0.305	Oil sp grav= 0.704
Krgmax=	1	Kromax= 1
Krg -m=	2.8	Sgc for kro= 0.00
Kro - n=	3.1	Sorg for kro= 0.36
IFTgo/IFTow=	1	Sorg for krg= 0

Note: krg calculated using SwDkrg to allow Sgc>0 while still allowing kro approach 1 below S_{wi}

SL	KRG	KROG	PCOG
0.35917	1.00000	0.00000	#####
0.40000	0.80269	0.00020	224.63709
0.45000	0.59762	0.00234	76.43938
0.50000	0.42973	0.00912	34.75293
0.55000	0.29568	0.02339	18.37847
0.60000	0.19203	0.04813	10.80658
0.65000	0.11526	0.08637	6.93165
0.70000	0.06170	0.14124	4.80348
0.75000	0.02757	0.21590	3.57133
0.80000	0.00886	0.31357	2.82786
0.85000	0.00127	0.43750	2.36401
0.90000	0.00000	0.59100	2.06647
0.95000	0.00000	0.77738	1.87107
1.00000	0.00000	1.00000	1.74012
1.00000	0.00000	1.00000	1.74012
1.00000	0.00000	1.00000	1.74012
1.00000	0.00000	1.00000	1.74012
1.00000	0.00000	1.00000	1.74012
1.00000	0.00000	1.00000	1.74012
1.00000	0.00000	1.00000	1.74012
1.00000	0.00000	1.00000	1.74012

SwD	SwDkrg	Sg	So for Pcoo
1.000	1.000	0.641	0.00000
0.936	0.925	0.600	0.06371
0.858	0.832	0.550	0.14174
0.780	0.740	0.500	0.21976
0.702	0.647	0.450	0.29778
0.624	0.555	0.400	0.37581
0.546	0.462	0.350	0.45383
0.468	0.370	0.300	0.53186
0.390	0.277	0.250	0.60988
0.312	0.185	0.200	0.68790
0.234	0.092	0.150	0.76593
0.156	0.000	0.100	0.84395
0.078	0.000	0.050	0.92198
0.000	0.000	0.000	1.00000
0.000	0.000	0.000	1.00000
0.000	0.000	0.000	1.00000
0.000	0.000	0.000	1.00000
0.000	0.000	0.000	1.00000
0.000	0.000	0.000	1.00000
0.000	0.000	0.000	1.00000
0.000	0.000	0.000	1.00000



Appendix B

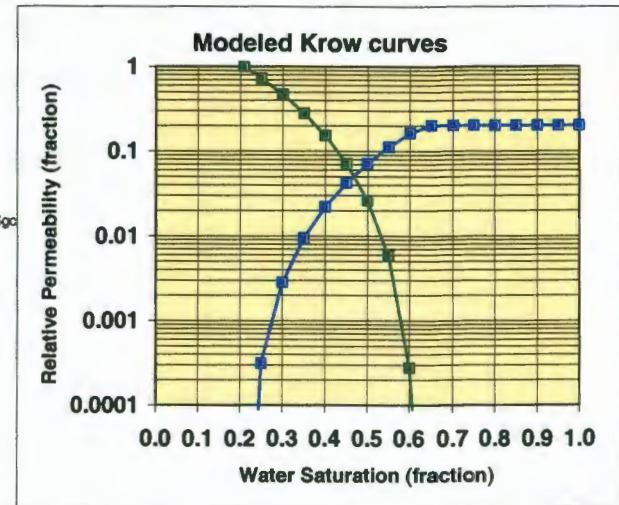
Table B11 - Calculated Relative Permeability & Capillary Pressure - 100 md Morrow Sandstone

SW	KRW	KROW	PCOW
0.20808	0.000000	1.000000	9.03340
0.25000	0.000311	0.722983	5.96985
0.30000	0.002805	0.466853	3.90638
0.35000	0.009465	0.280528	2.73628
0.40000	0.022035	0.152455	2.03967
0.45000	0.042137	0.071307	1.60873
0.50000	0.071306	0.026002	1.33370
0.55000	0.111013	0.005773	1.15354
0.60000	0.162682	0.000276	1.03291
0.65000	0.200000	0.000000	0.95057
0.70000	0.200000	0.000000	0.89343
0.75000	0.200000	0.000000	0.85318
0.80000	0.200000	0.000000	0.82447
0.85000	0.200000	0.000000	0.80373
0.90000	0.200000	0.000000	0.78860
0.95000	0.200000	0.000000	0.77745
1.00000	0.200000	0.000000	0.76916
1.00000	0.200000	0.000000	0.76916
1.00000	0.200000	0.000000	0.76916
1.00000	0.200000	0.000000	0.76916
1.00000	0.200000	0.000000	0.76916

SwD
0.00000
0.09936
0.21786
0.33637
0.45487
0.57338
0.69188
0.81039
0.92890
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000
1.00000

K=	100.0	md			
Krwmax=	0.2	Kromax=	1	Pcentry=	0.742
Krw -m=	2.8	Swi=	0.21	Pcb=	6.914
Kro - n=	3.1	Sorw=	0.37	Pcb=	-1.052
water grad	0.468	W sp grav=	1.08	input value	
oil grad	0.305	Oil sp grav=	0.704	calc value	
Krgmax=	1	Kromax=	1		
Krg -m=	2.8	Sgc for kro=	0.00	Sgc for krg=	0.1
Kro - n=	3.1	Sorg for kro=	0.21	Sorg for krg=	0.21
IFTgo/IFTow=	1	Sorg for kro=	0		

Note: krg calculated using SwDkrg to allow Sgc>0 while still allowing kro approach 1 below Sgc



SL	KRG	KROG	PCOG
0.20808	1.00000	0.000000	#####
0.25000	0.83946	0.00011	90.18557
0.30000	0.67091	0.00126	28.67755
0.35000	0.52585	0.00485	12.45321
0.40000	0.40268	0.01235	6.41165
0.45000	0.29980	0.02532	3.74472
0.50000	0.21558	0.04533	2.43559
0.55000	0.14833	0.07400	1.74347
0.60000	0.09633	0.11298	1.35664
0.65000	0.05782	0.16393	1.13082
0.70000	0.03095	0.22854	0.99426
0.75000	0.01383	0.30852	0.90922
0.80000	0.00444	0.40560	0.85492
0.85000	0.00064	0.52153	0.81950
0.90000	0.00000	0.65805	0.79597
0.95000	0.00000	0.81695	0.78006
1.00000	0.00000	1.00000	0.76916
1.00000	0.00000	1.00000	0.76916
1.00000	0.00000	1.00000	0.76916
1.00000	0.00000	1.00000	0.76916
1.00000	0.00000	1.00000	0.76916

SwD	SwDkrg	Sg	So for Pcoog
1.000	1.000	0.792	0.00000
0.947	0.939	0.750	0.05293
0.884	0.867	0.700	0.11607
0.821	0.795	0.650	0.17921
0.758	0.723	0.600	0.24235
0.695	0.650	0.550	0.30549
0.631	0.578	0.500	0.36862
0.568	0.506	0.450	0.43176
0.505	0.434	0.400	0.49490
0.442	0.361	0.350	0.55804
0.379	0.289	0.300	0.62117
0.316	0.217	0.250	0.68431
0.253	0.145	0.200	0.74745
0.189	0.072	0.150	0.81059
0.126	0.000	0.100	0.87372
0.063	0.000	0.050	0.93686
0.000	0.000	0.000	1.00000
0.000	0.000	0.000	1.00000
0.000	0.000	0.000	1.00000
0.000	0.000	0.000	1.00000
0.000	0.000	0.000	1.00000
0.000	0.000	0.000	1.00000

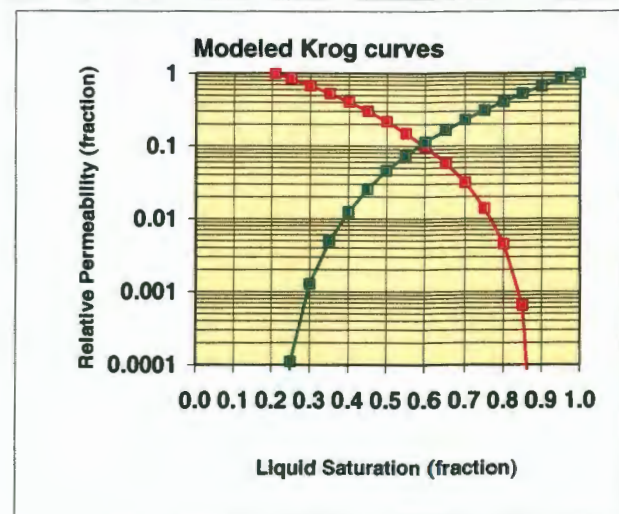
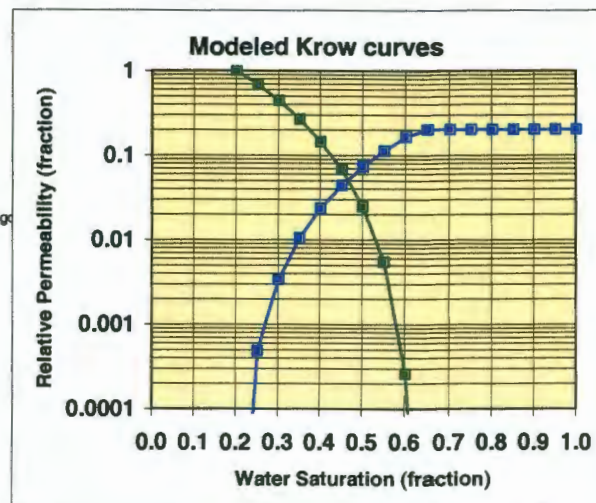


Table B12 - Calculated Relative Permeability & Capillary Pressure - 300 md Morrow Sandstone

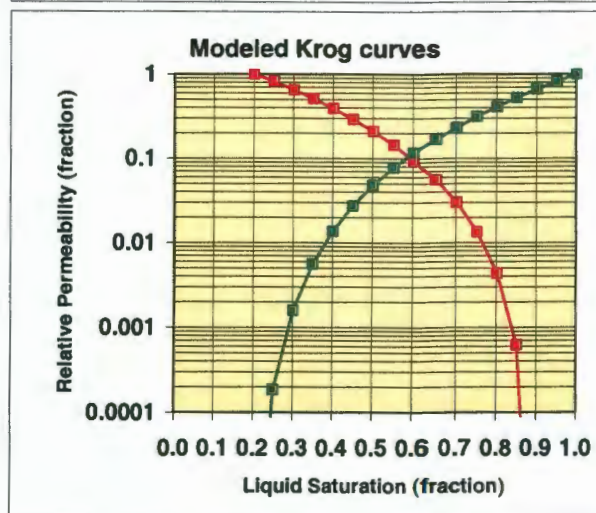
[illegible][illegible]

K=	300.0	md		
Krwm=	0.2	Kromax=	1	Pcentry= 0.116
Krw -m=	2.6	Swl=	0.20	Pca= 6.264
Kro - n=	3.1	Sow=	0.37	Pcb= -1.627
water grad	0.468	W ap grav=	1.08	input value
oil grad	0.305	Oil sp grav=	0.704	calc value
Krgmax=	1	Kromax=	1	
Krg -m=	2.6	Sgc for kro=	0.00	Sgc for krg= 0.116
Kro - n=	3.1	Sorg for kro=	0.20	Sorg for krg= 0.20
IFTgolFTow=	1	Sorg for kro=	0	

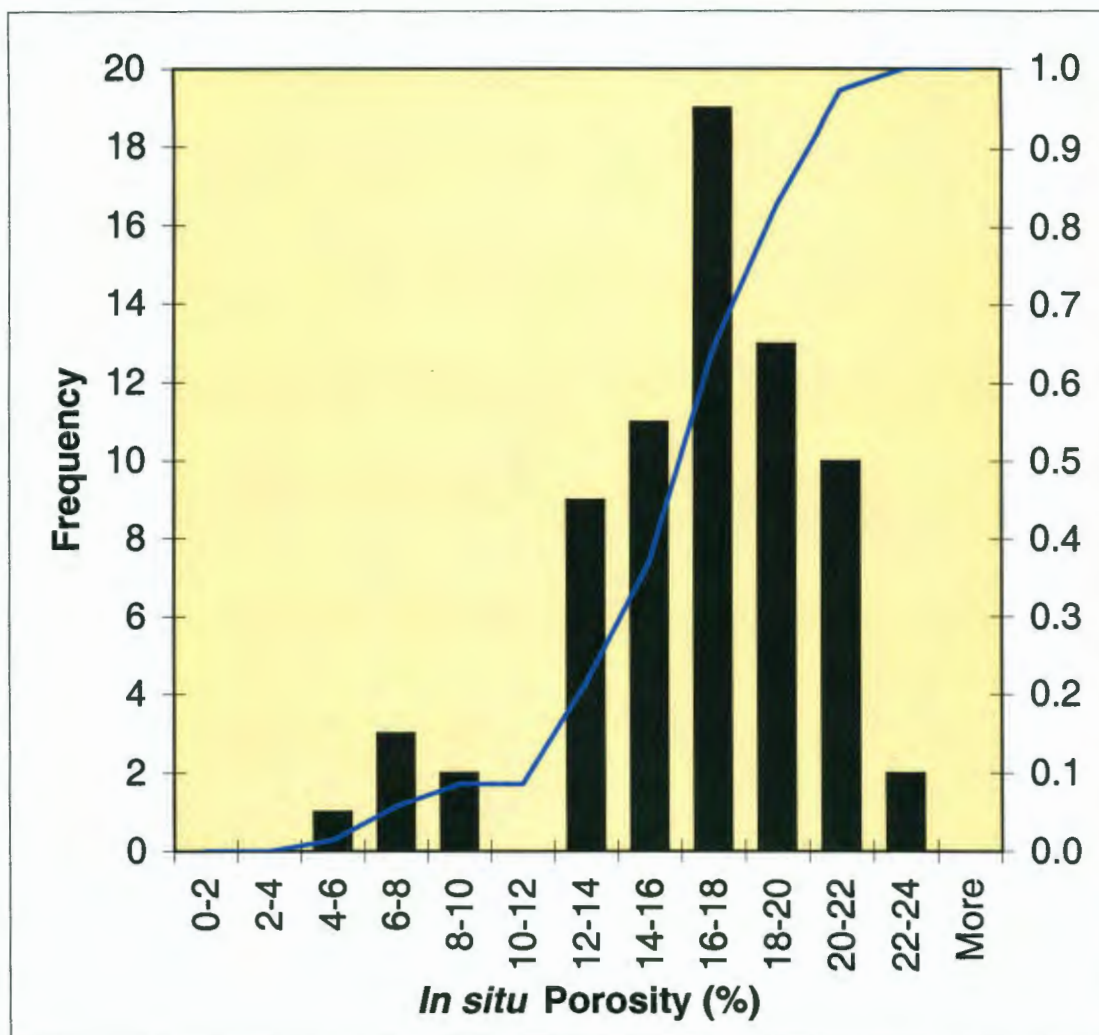
Note: krg calculated using SwDkrg to allow Sgc>0 while still allowing kro approach 1 below Sgc



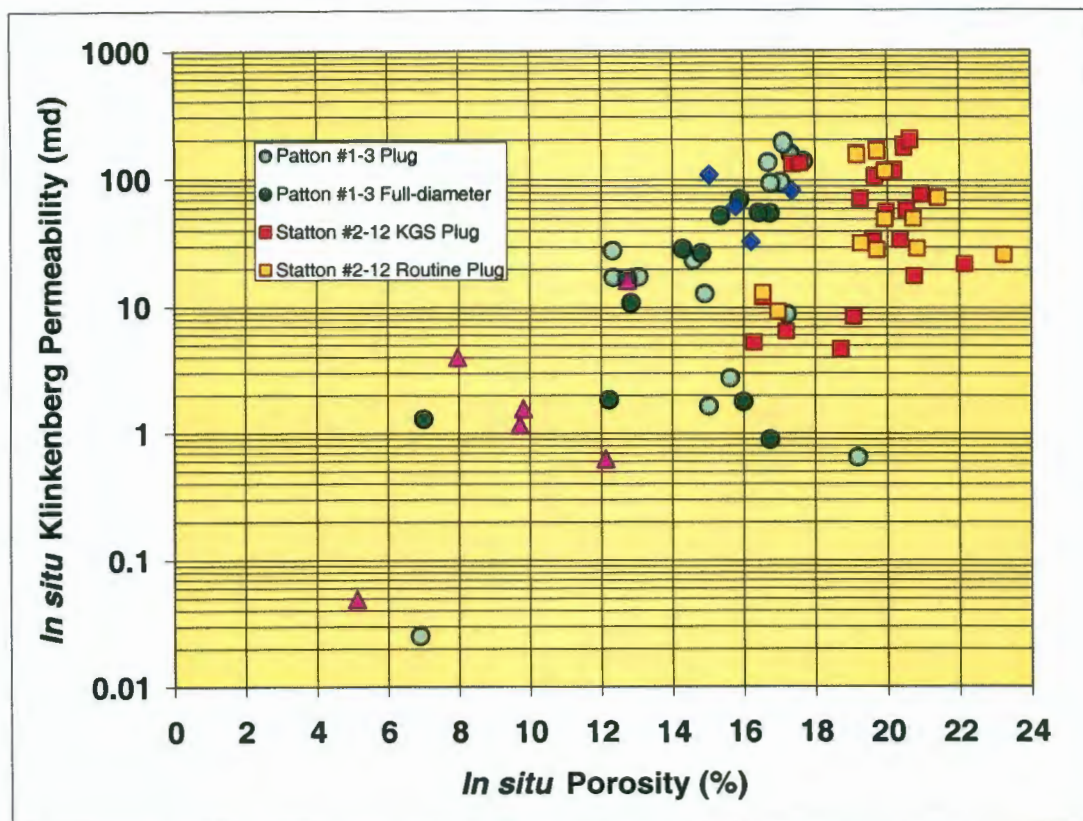
SL	KRG	KROG	PCOG
0.20000	1.00000	0.00000	525.26639
0.25000	0.81261	0.00019	9.10117
0.30000	0.64945	0.00159	1.78250
0.35000	0.50903	0.00558	0.57372
0.40000	0.39890	0.01360	0.27021
0.45000	0.29022	0.02717	0.17533
0.50000	0.20869	0.04781	0.14119
0.55000	0.14359	0.07710	0.12761
0.60000	0.09325	0.11663	0.12178
0.65000	0.05597	0.16803	0.11912
0.70000	0.02996	0.23293	0.11785
0.75000	0.01339	0.31300	0.11722
0.80000	0.00430	0.40991	0.11689
0.85000	0.00062	0.52535	0.11672
0.90000	0.00000	0.66104	0.11662
0.95000	0.00000	0.81867	0.11657
1.00000	0.00000	1.00000	0.11654
1.00000	0.00000	1.00000	0.11654
1.00000	0.00000	1.00000	0.11654
1.00000	0.00000	1.00000	0.11654
1.00000	0.00000	1.00000	0.11654

[illegible]

Appendix B - Figure B1 Minneola Unit Morrow Porosity Distribution from Core

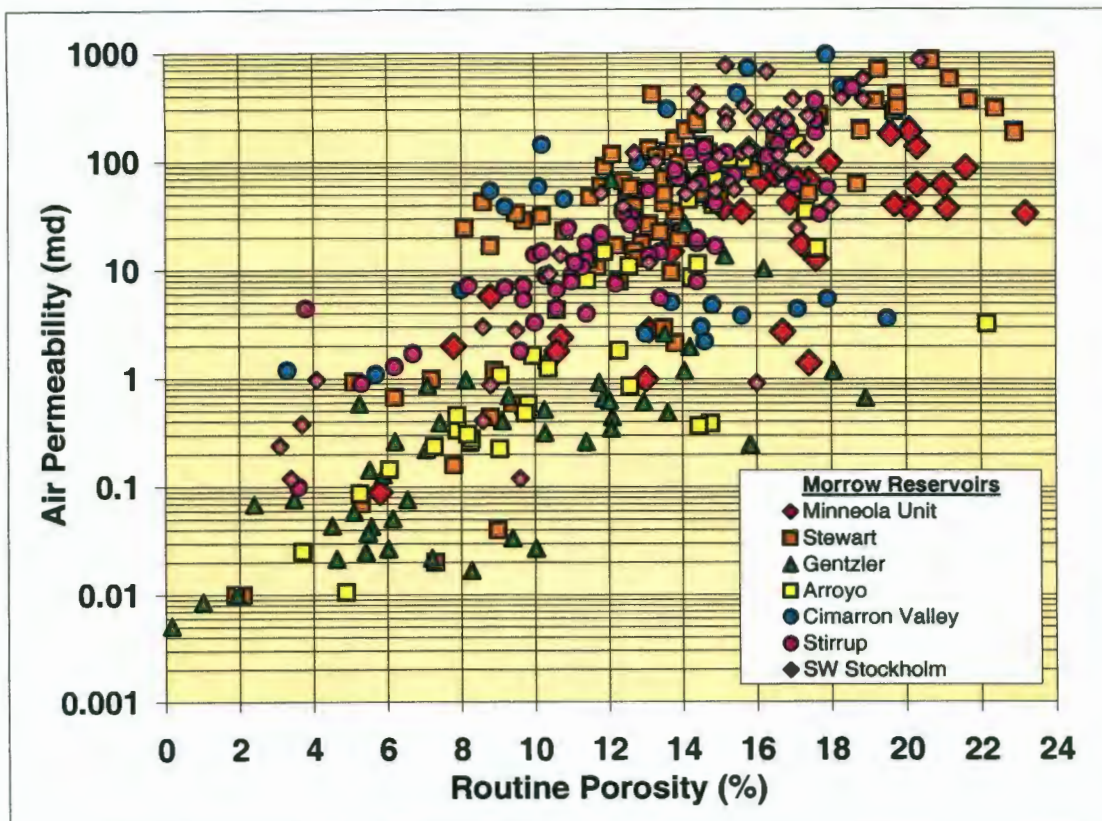


Appendix B - Figure B2 Minneola Unit Permeability vs. Porosity by Core Dimension

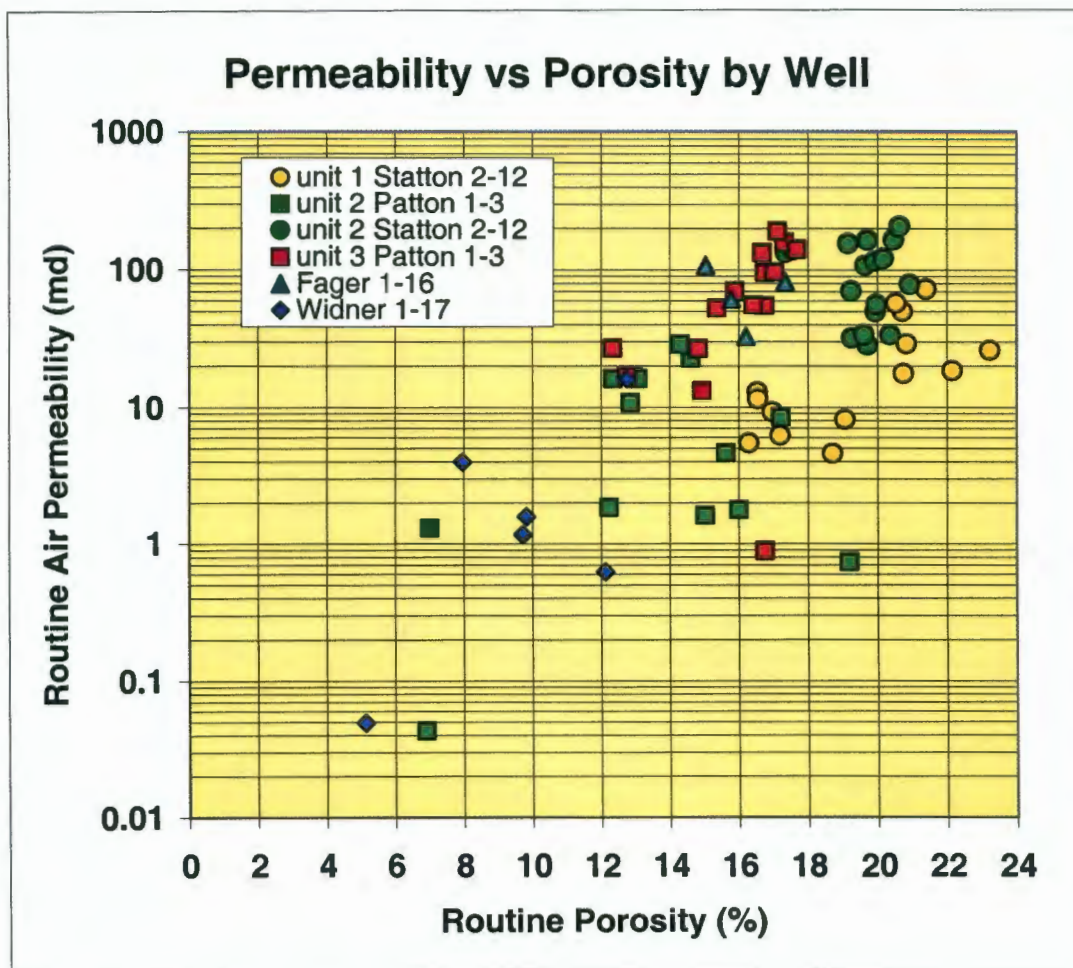


Appendix B

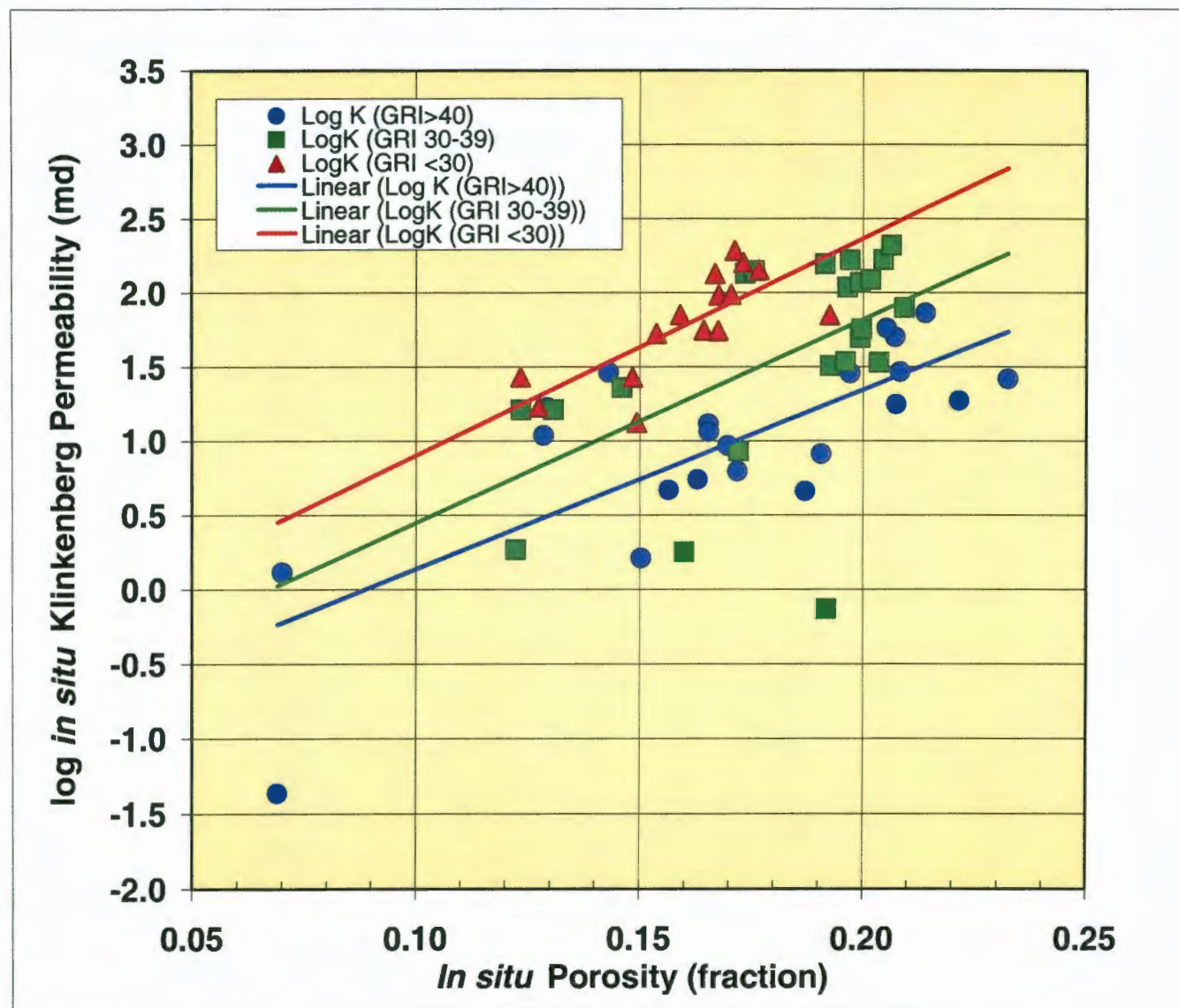
Figure B3 - Permeability vs Porosity for Morrow Sandstones by Field



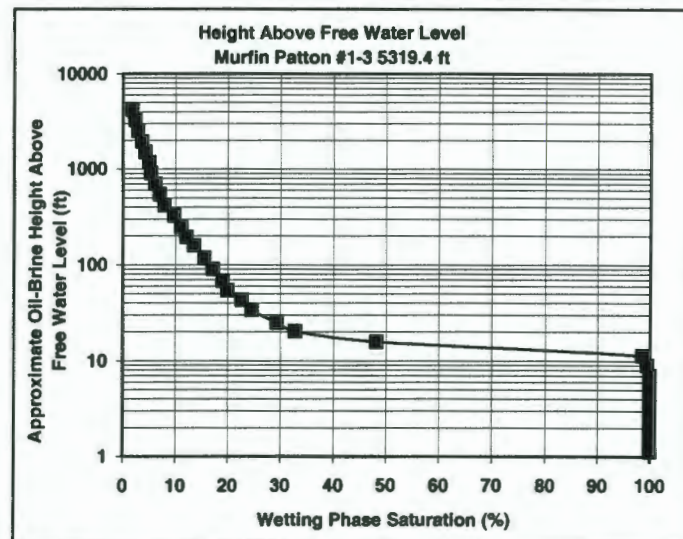
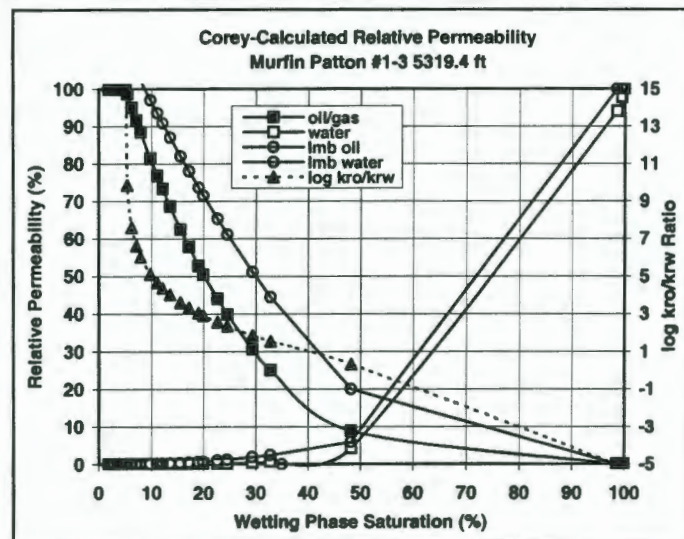
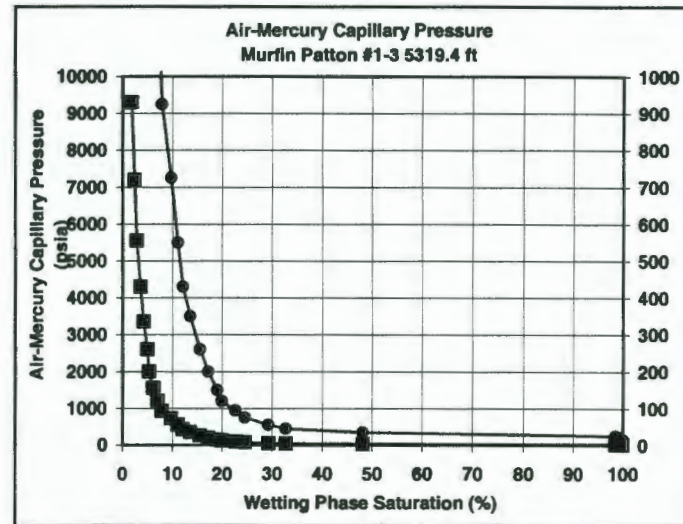
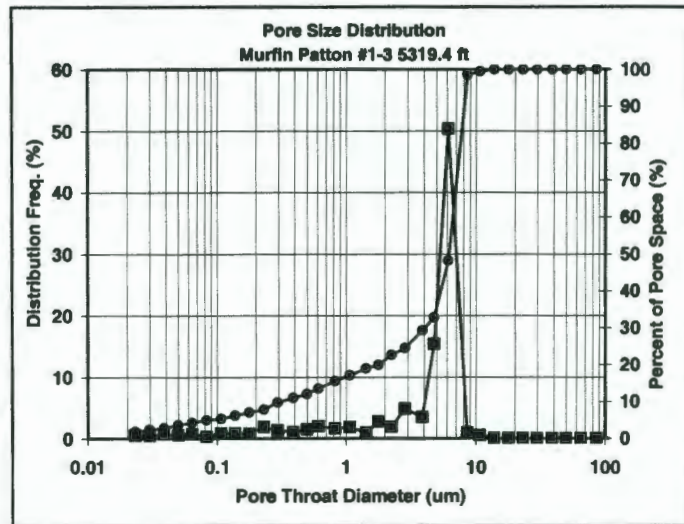
Appendix B - Figure B4 Minneola Unit Permeability vs. Porosity by Well



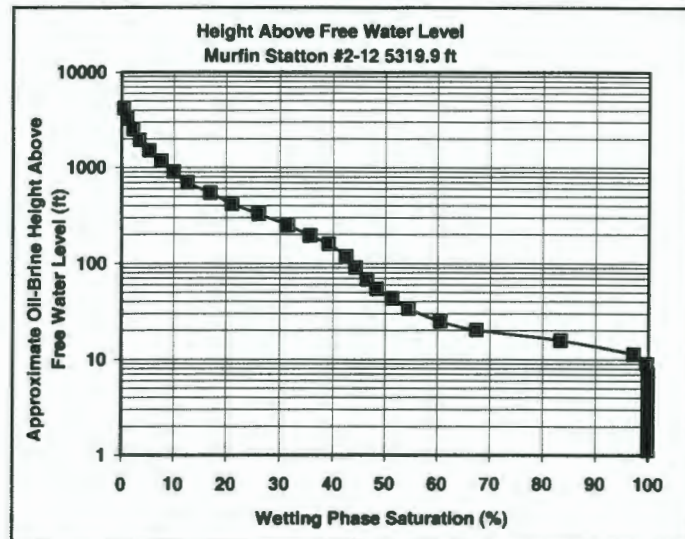
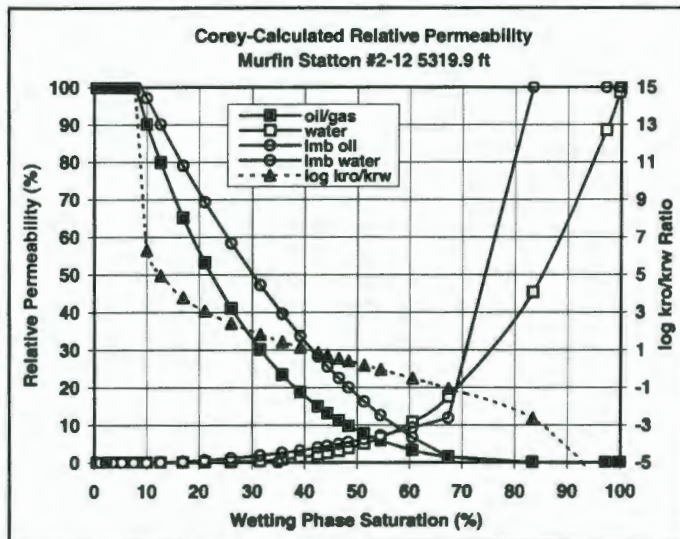
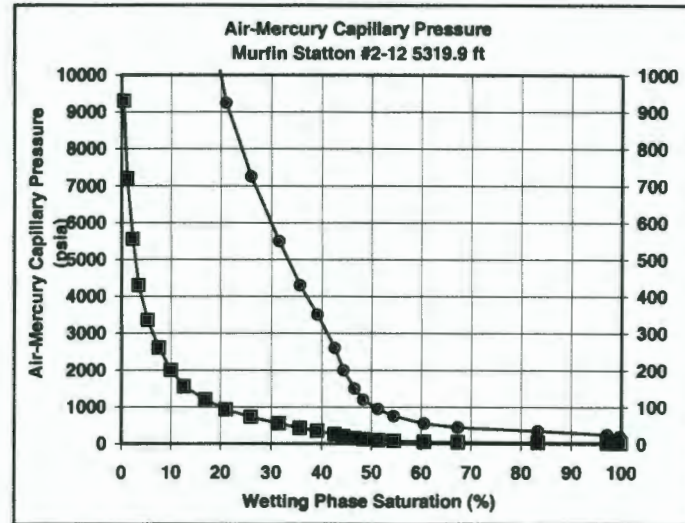
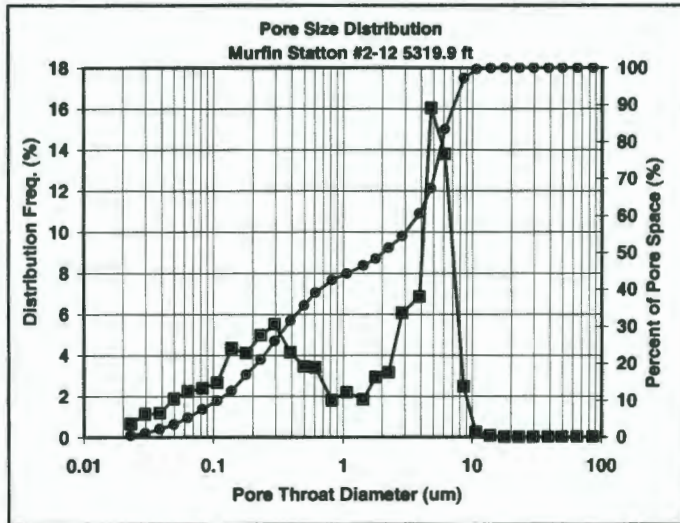
Appendix B - Figure B5 - Permeability vs Porosity Trends for Three Shalyness Lithofacies Classes



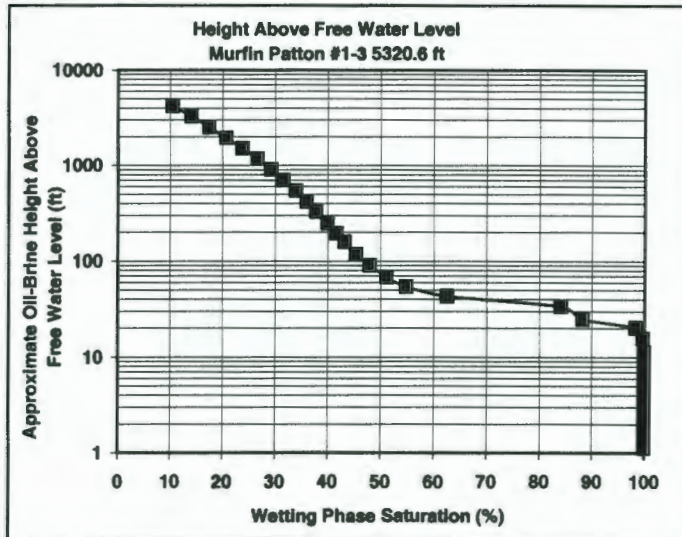
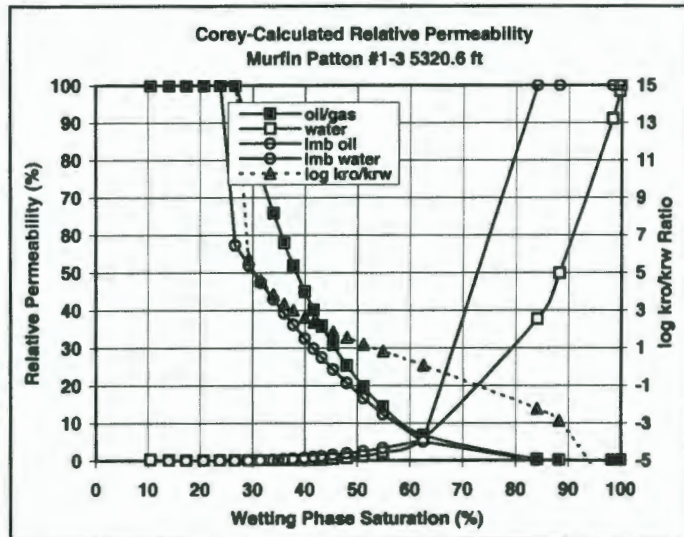
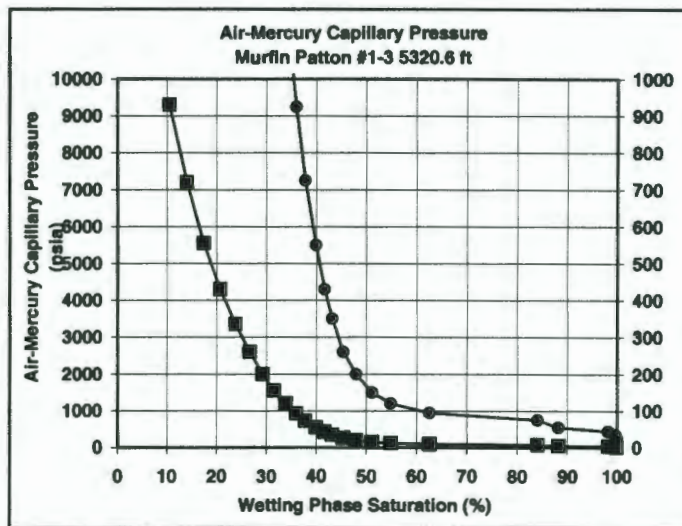
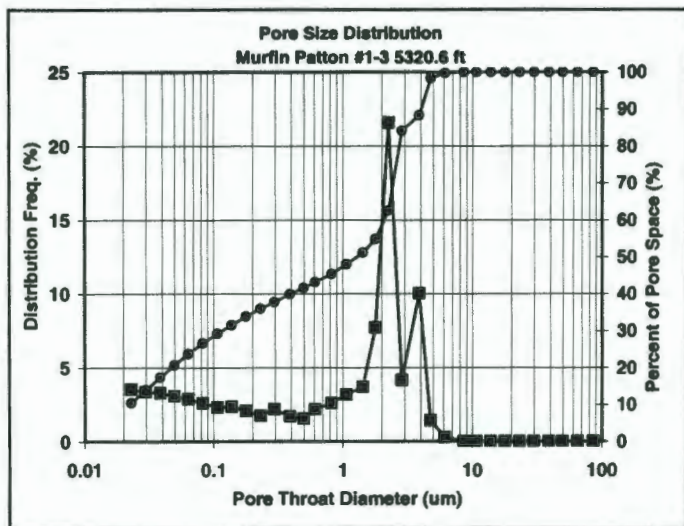
Appendix B - Figure B6
Mercury Injection Capillary Pressure Analysis
Murfin Patton #1-3 5319.4 ft



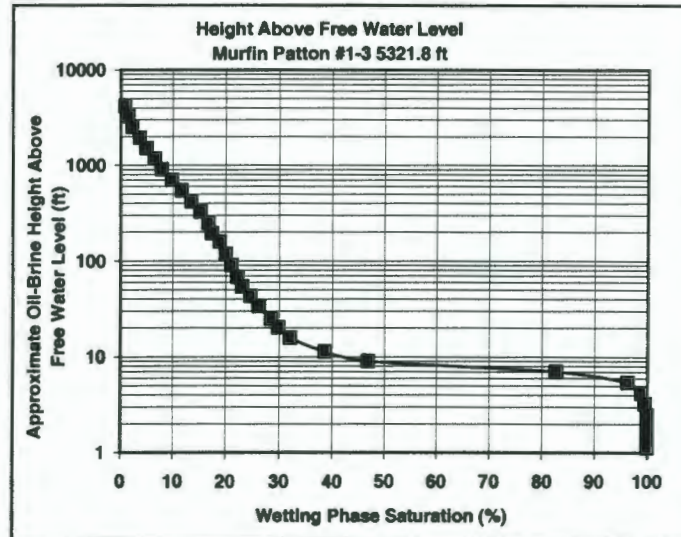
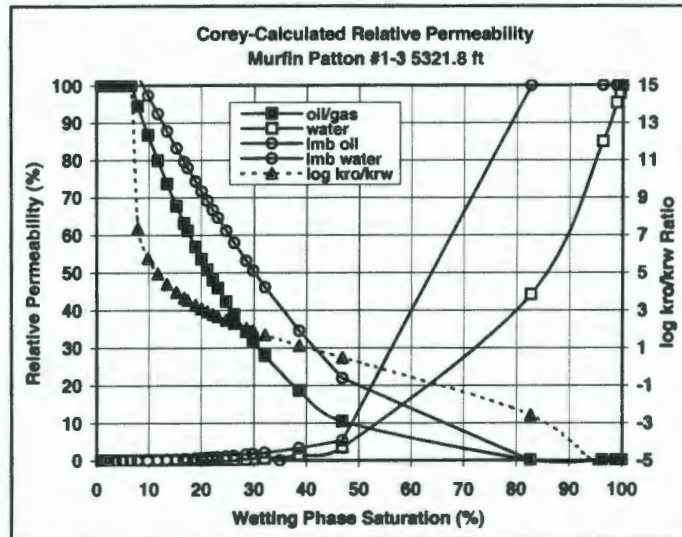
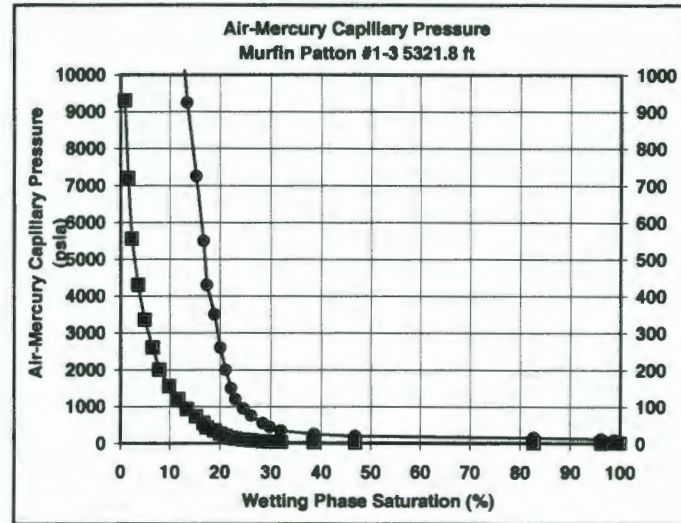
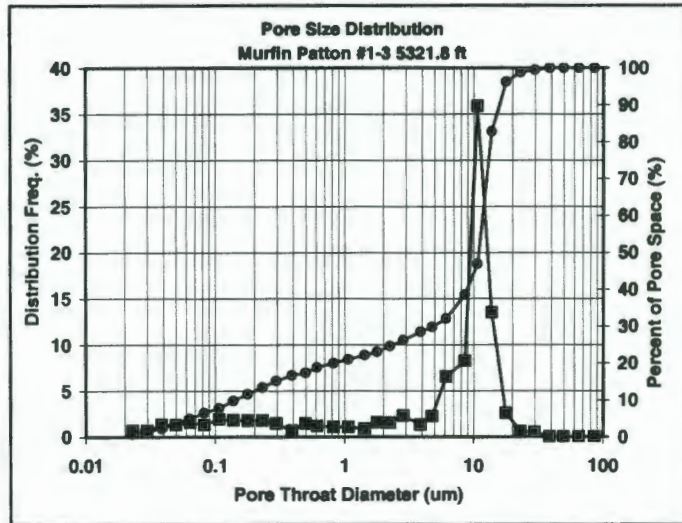
Appendix B - Figure B7
Mercury Injection Capillary Pressure Analysis
Murfin Statton #2-12 5319.9 ft



Appendix B - Figure B8
Mercury Injection Capillary Pressure Analysis
Murfin Patton #1-3 5320.6 ft



Appendix B - Figure B9
Mercury Injection Capillary Pressure Analysis
Murfin Patton #1-3 5321.8 ft



Appendix B - Figure B10
Mercury Injection Capillary Pressure Analysis
Murfin Staton #2-12 5324.7 ft

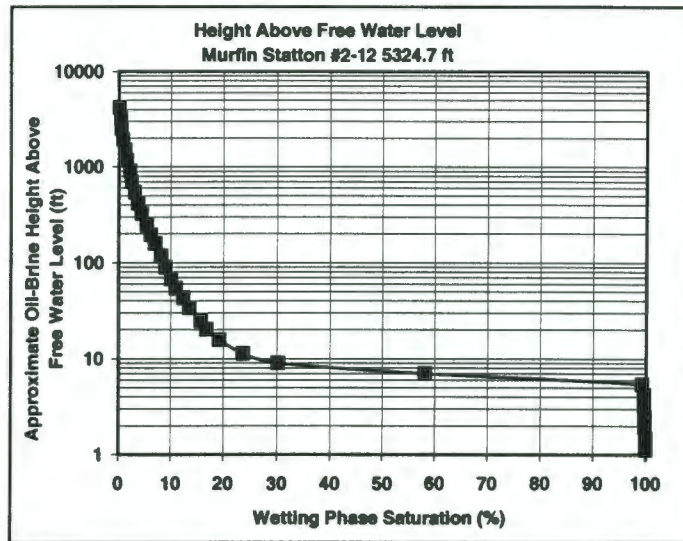
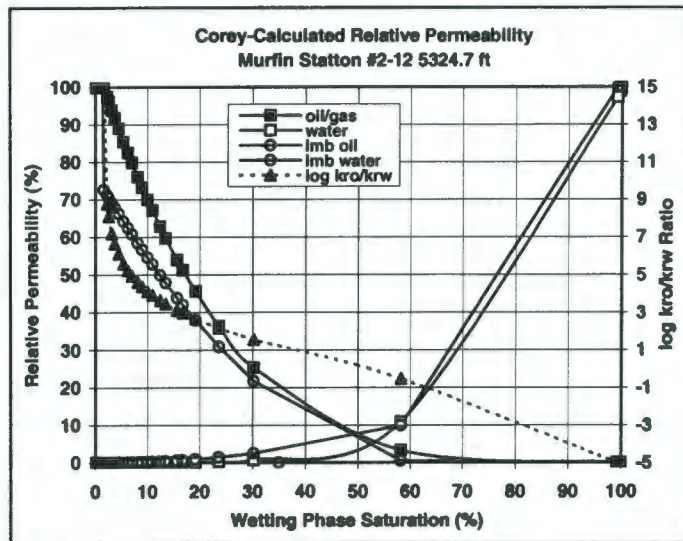
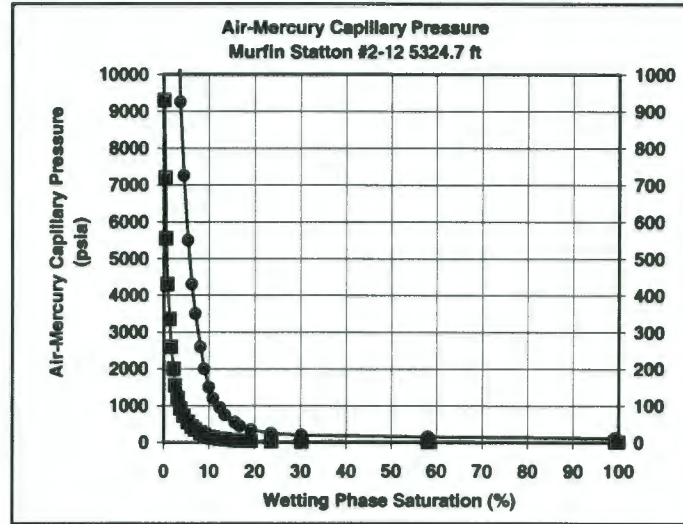
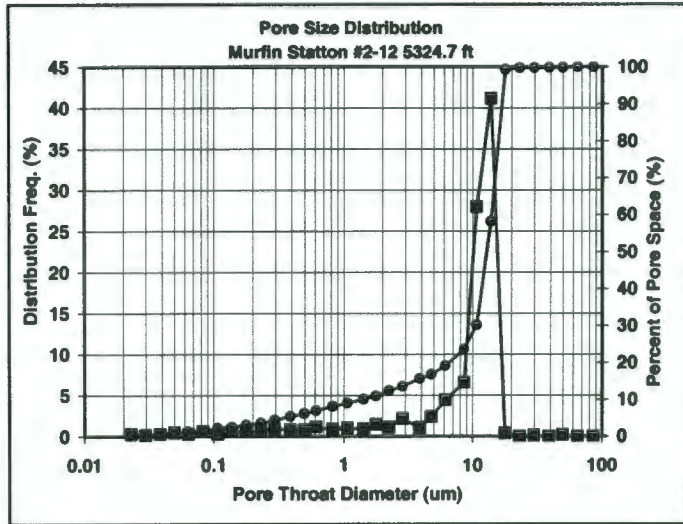
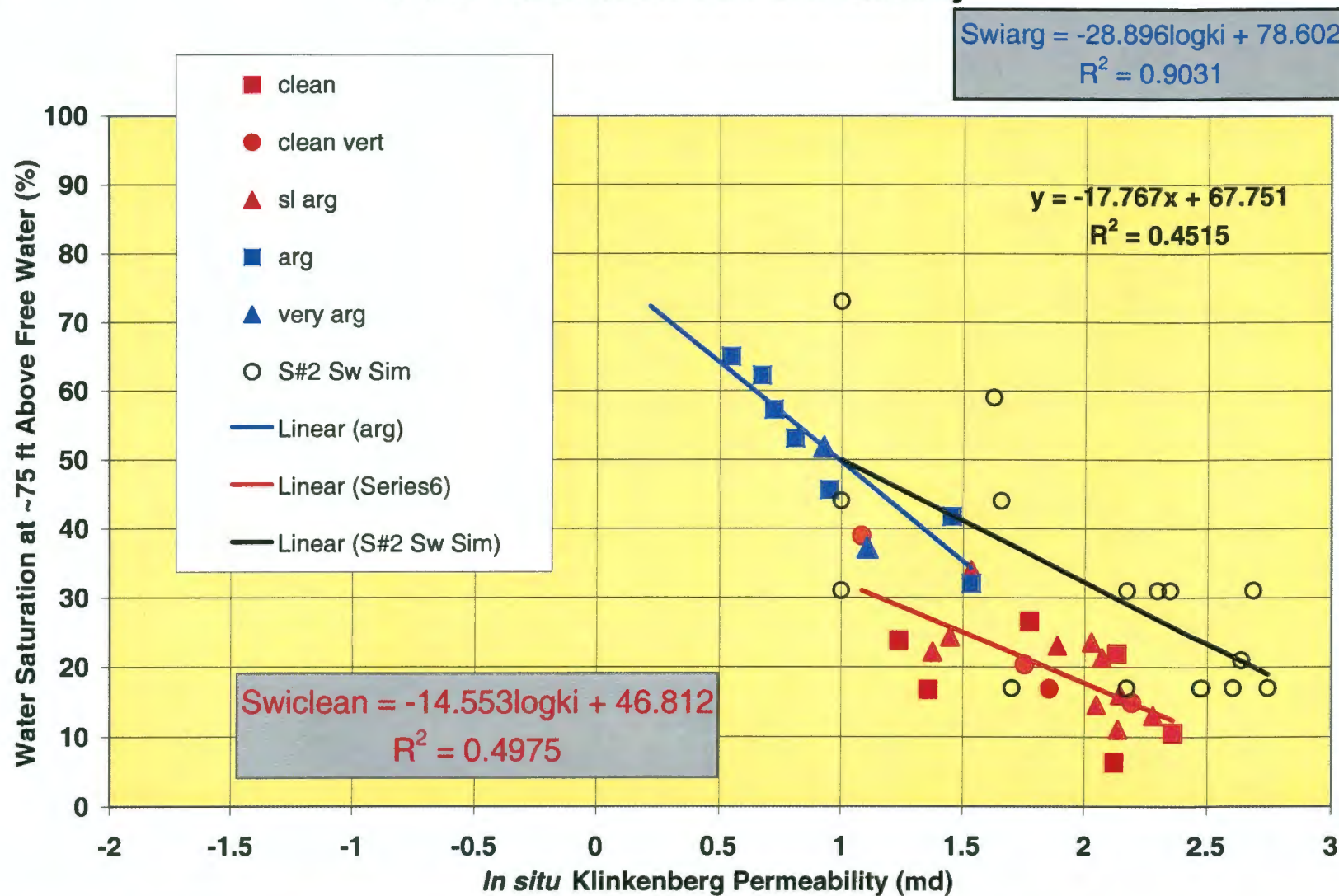


Figure B11

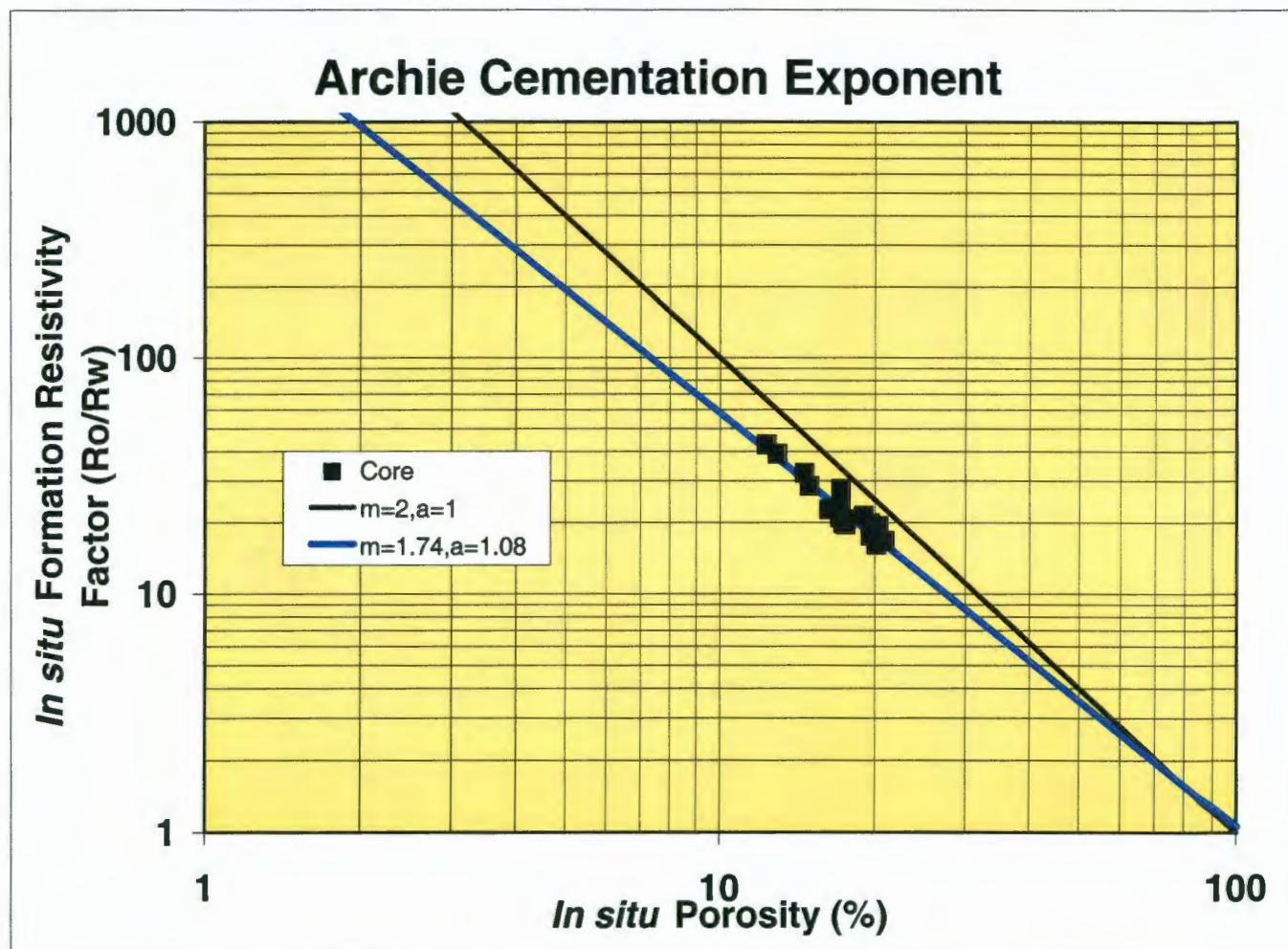
Water Saturation vs Permeability



○ The Sw and K for these points correspond to that used in sand #2 to obtain production matches in the

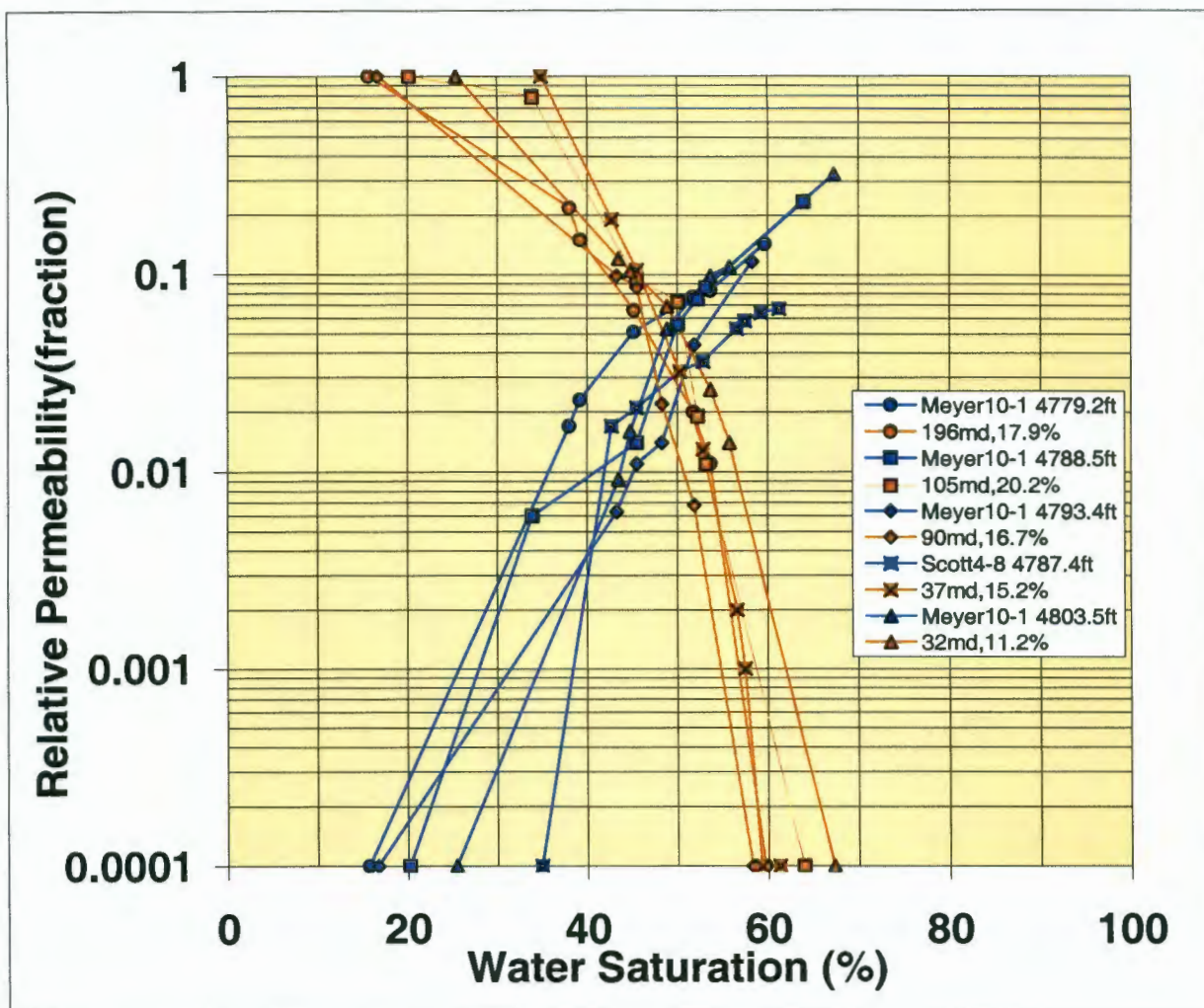
Appendix B

Figure B12 - Archie Cementation Exponent For Minneola Unit Morrow Sandstone



Appendix B

Figure B13 - Stewart Field Morrow Relative Permeabilities



APPENDIX C

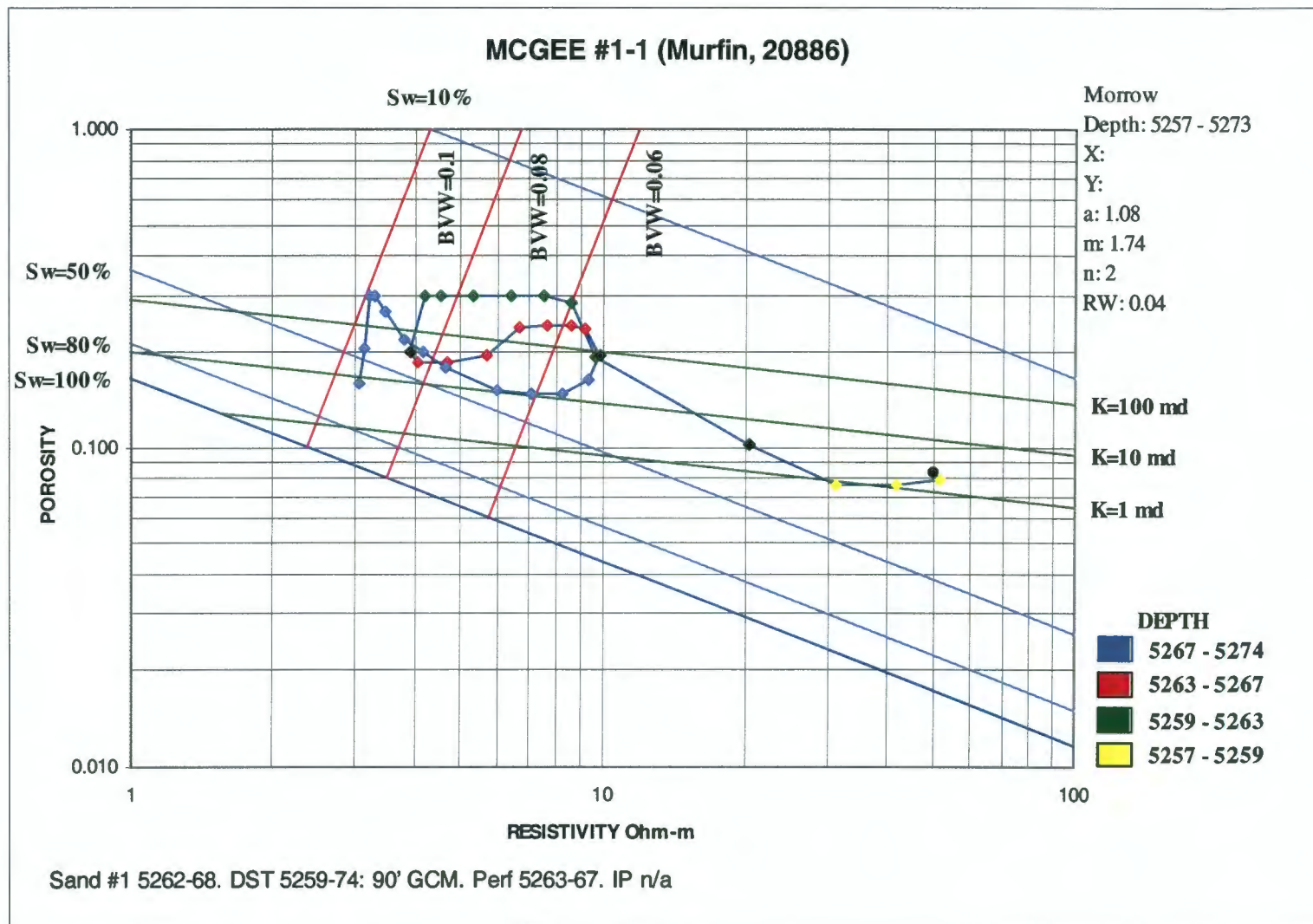


Figure C1

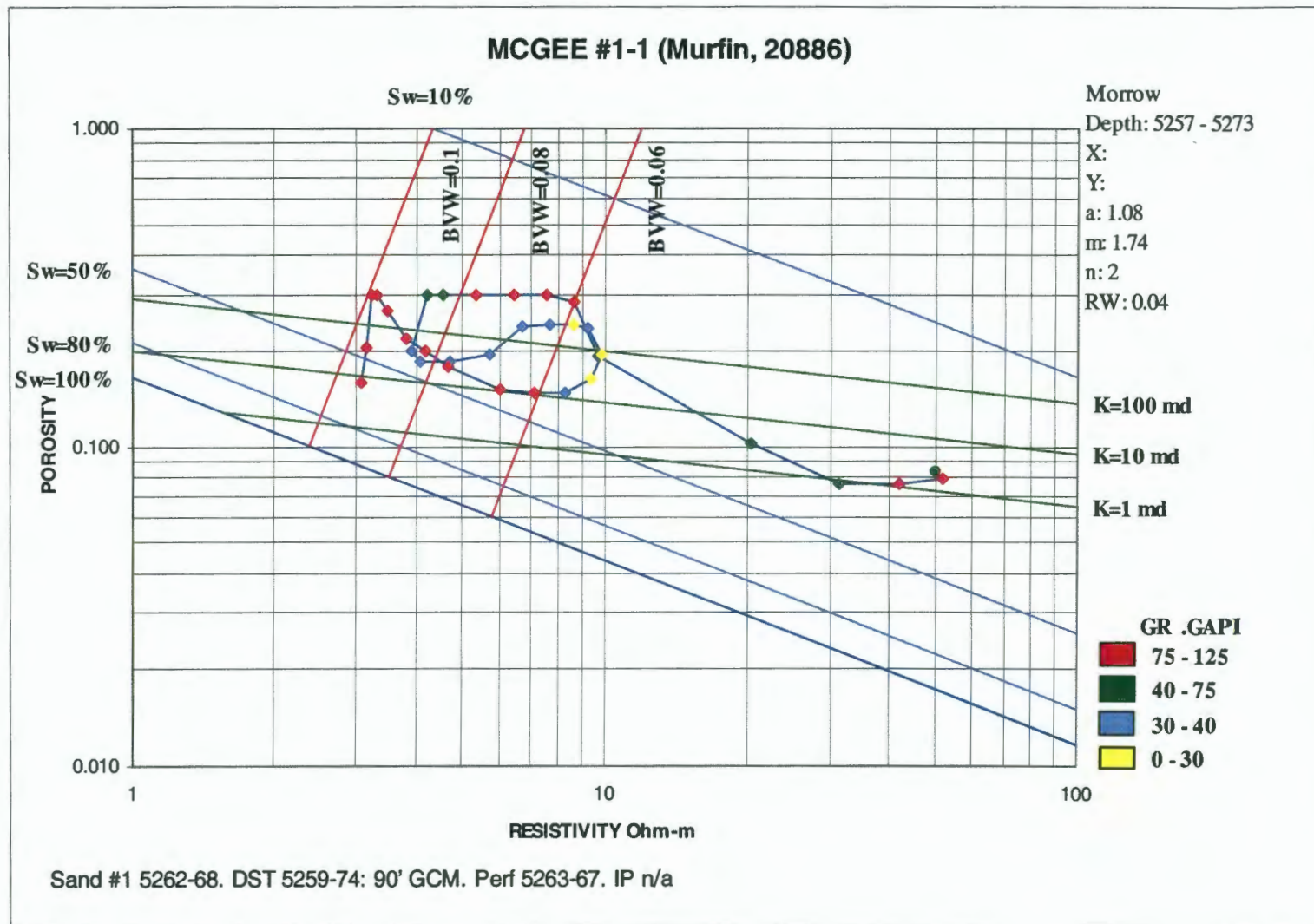


Figure C2

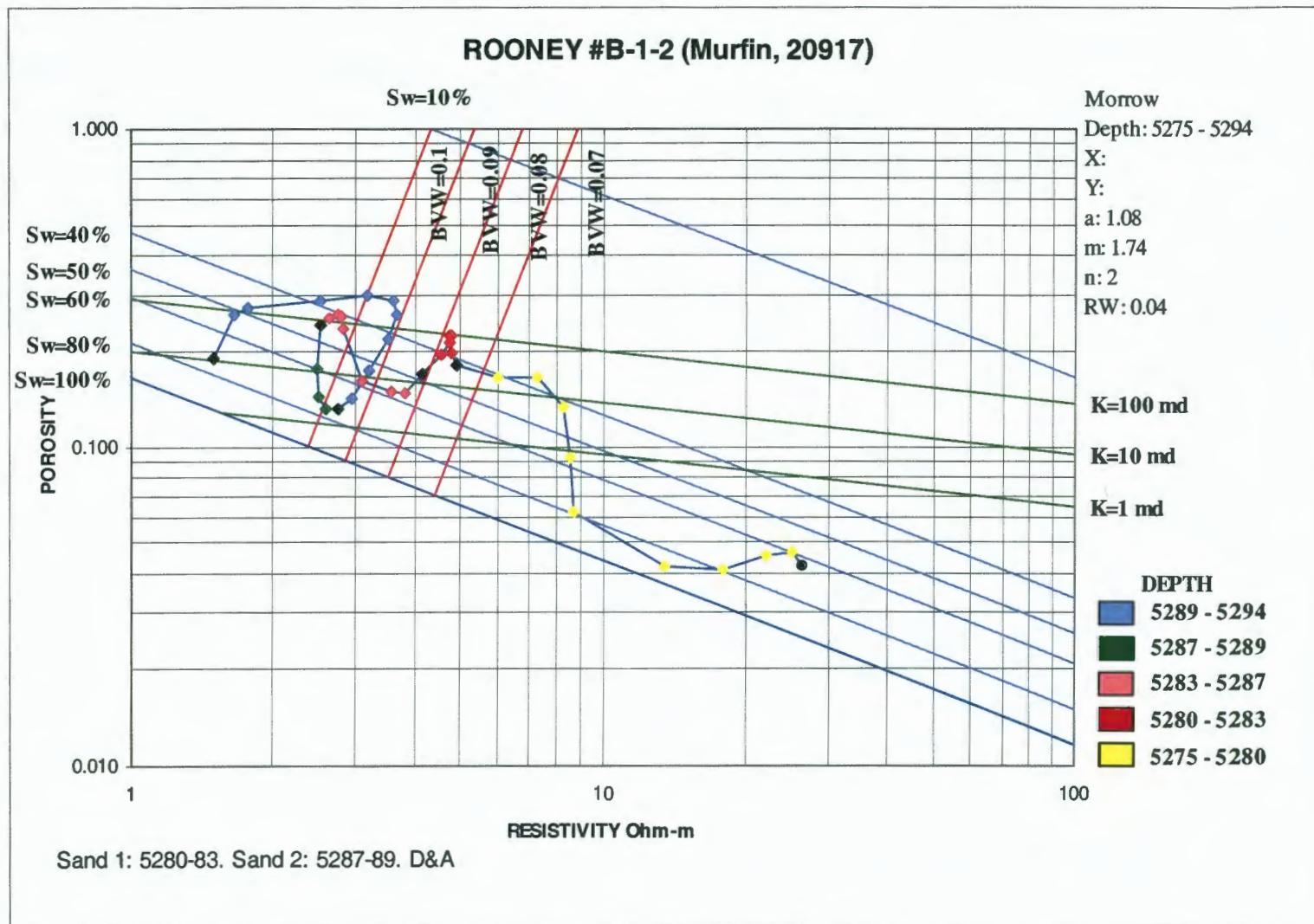


Figure C3

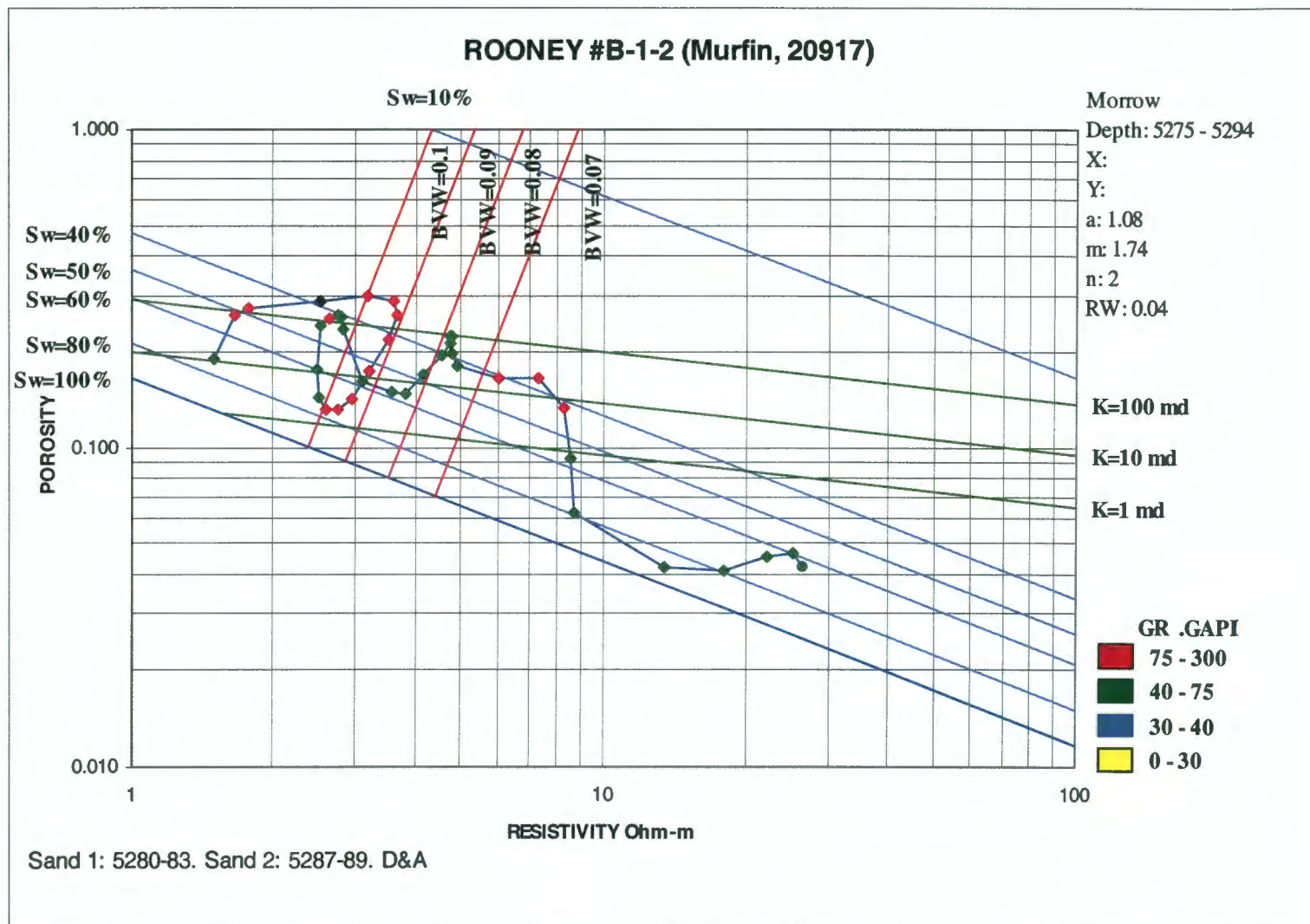


Figure C4

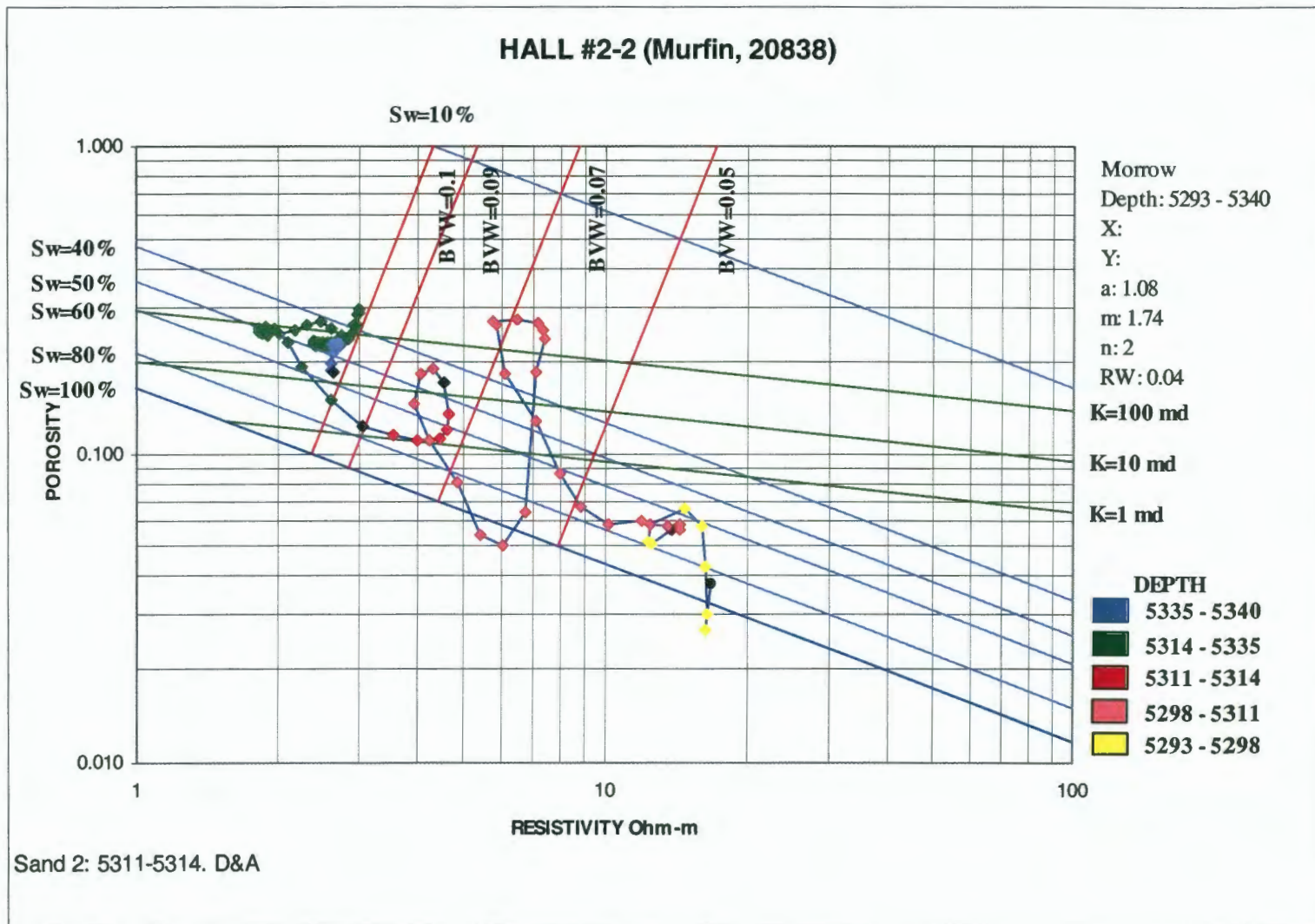


Figure C5

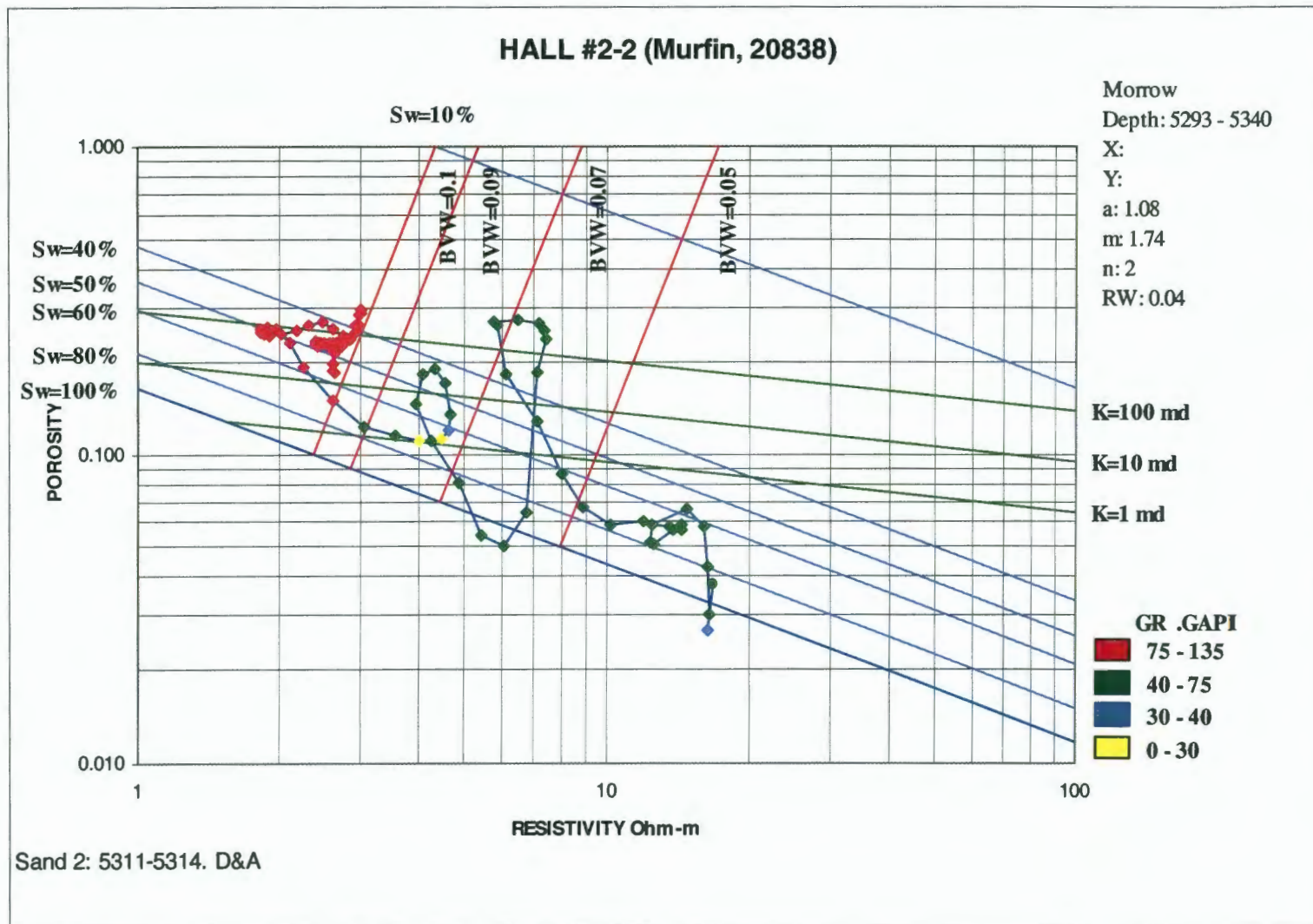


Figure C6

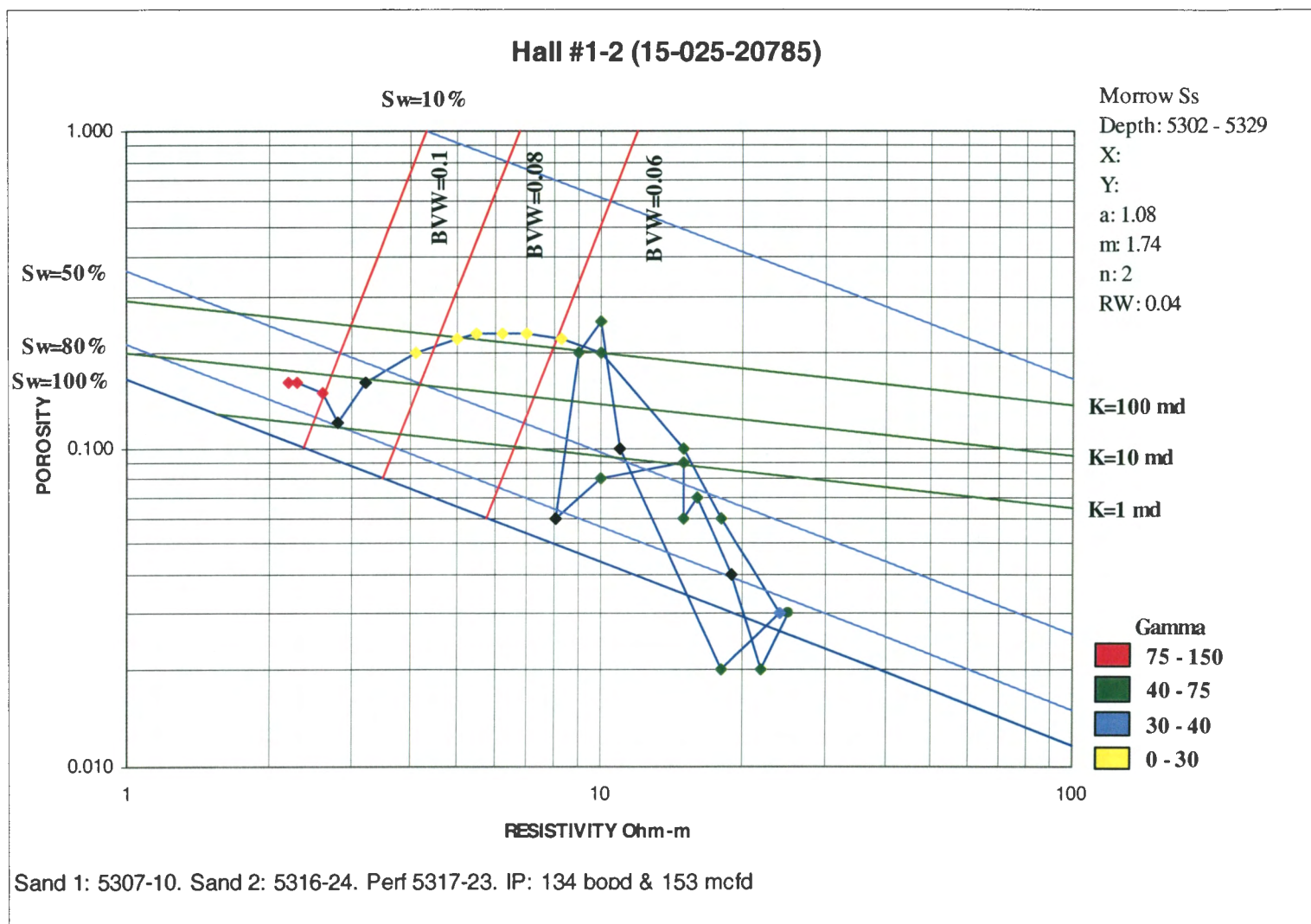


Figure C8

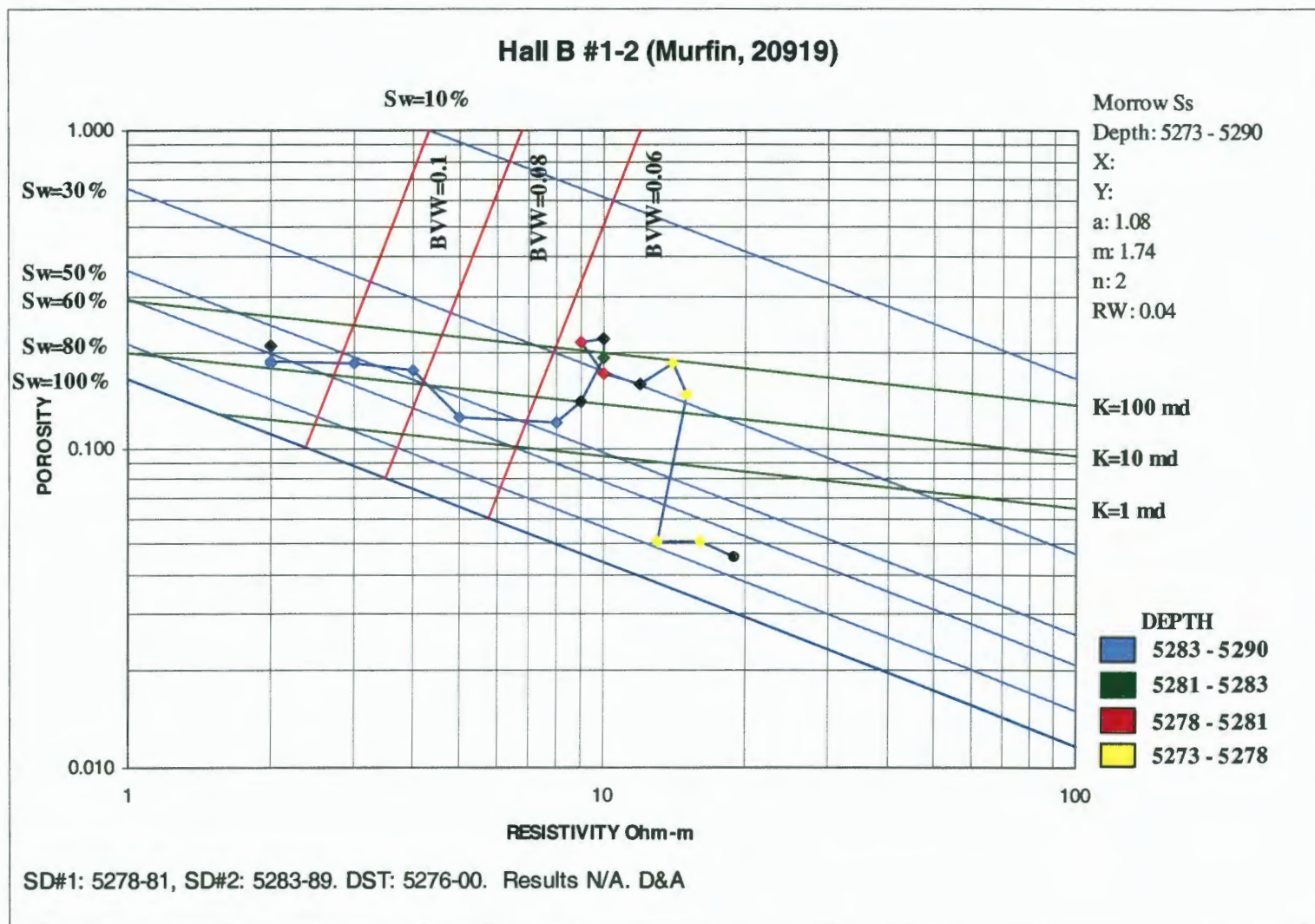


Figure C9

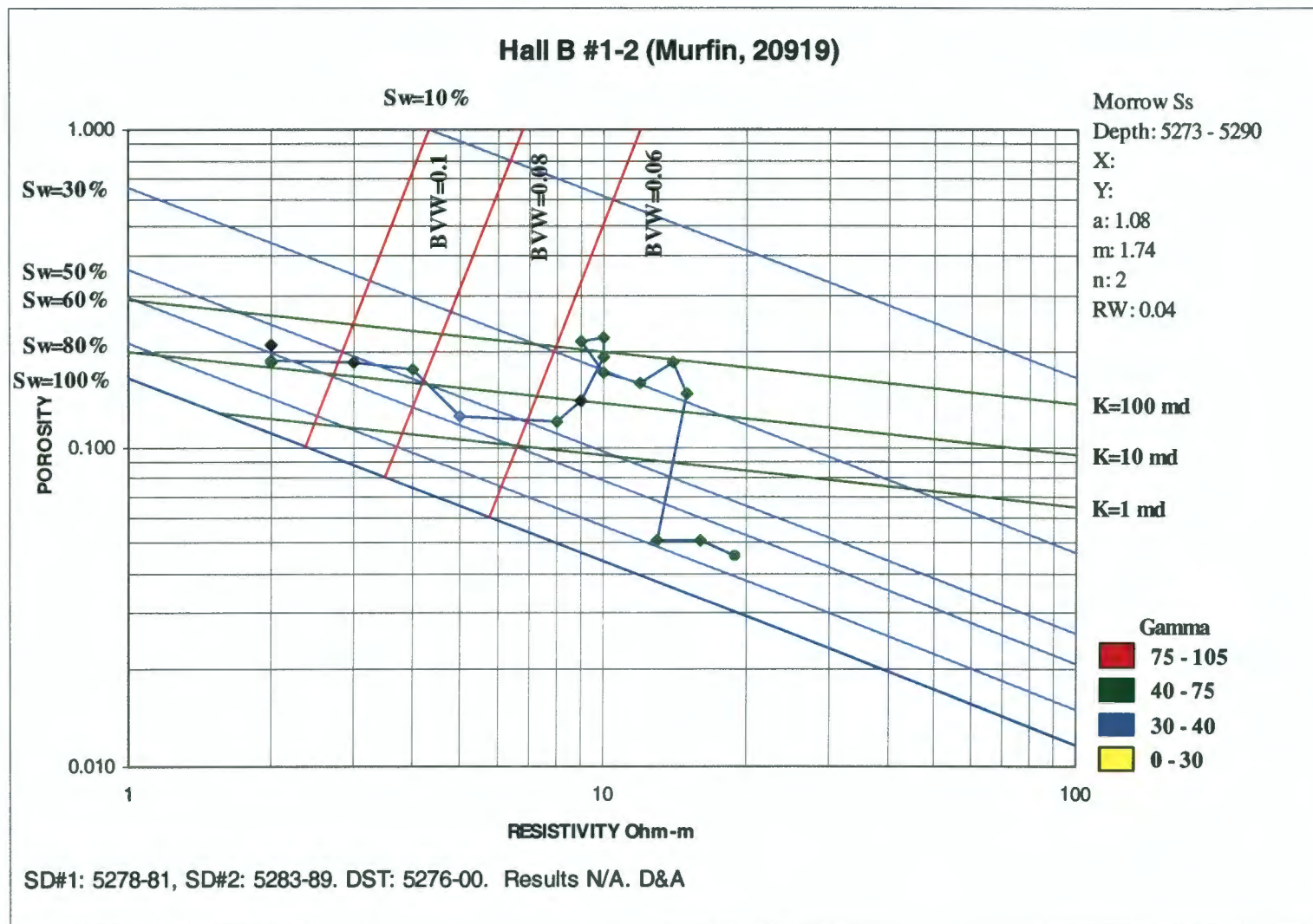


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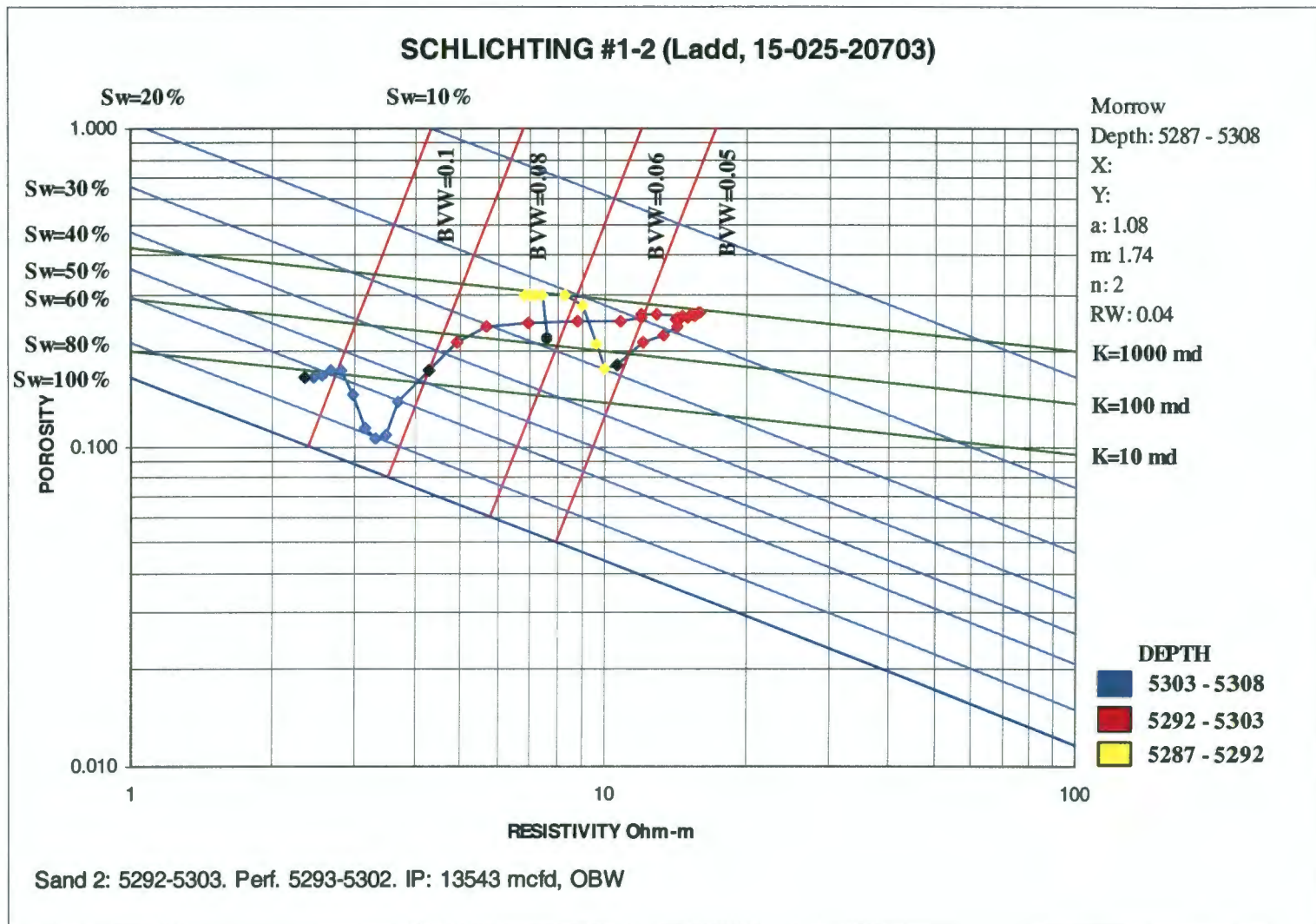


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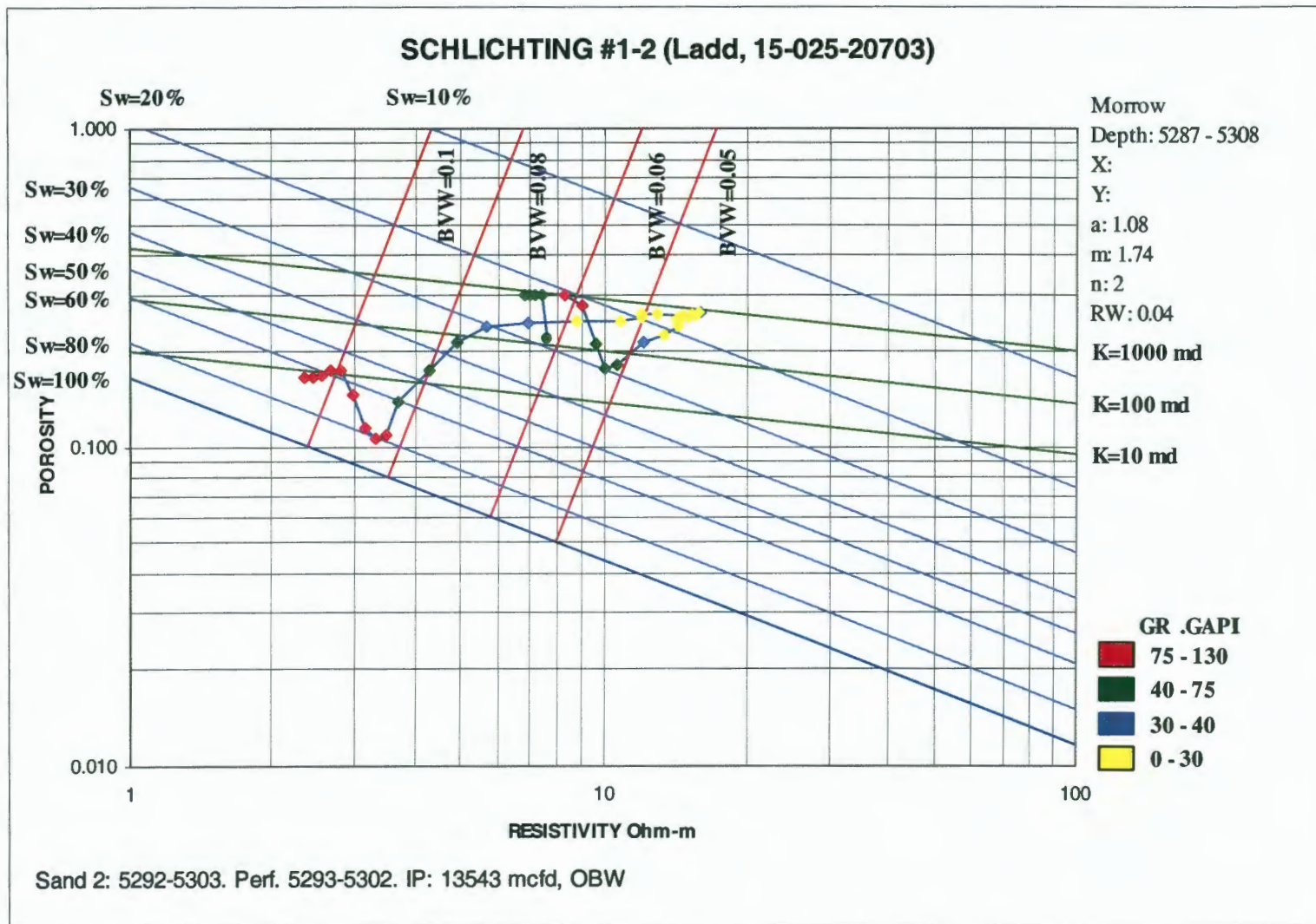


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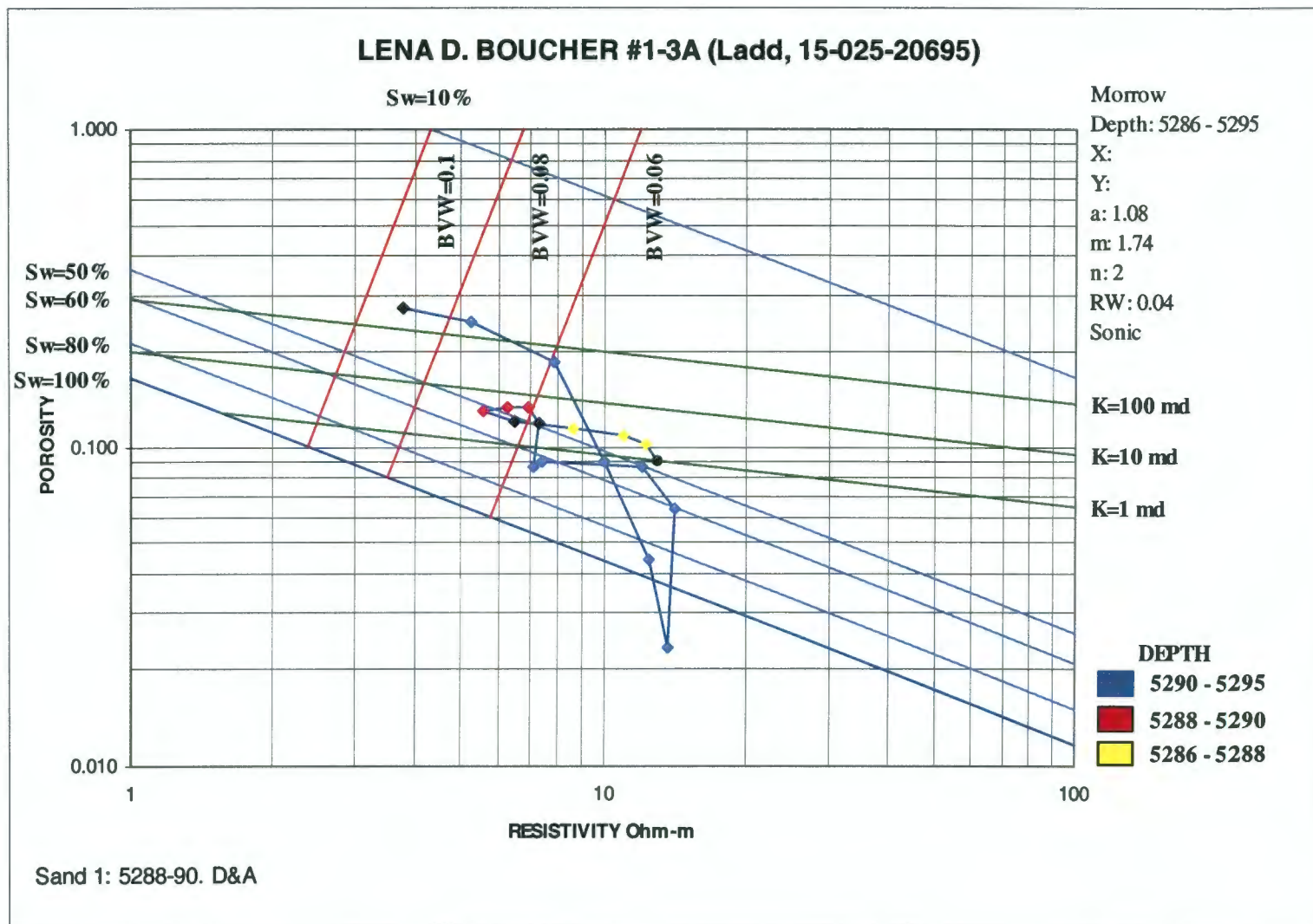


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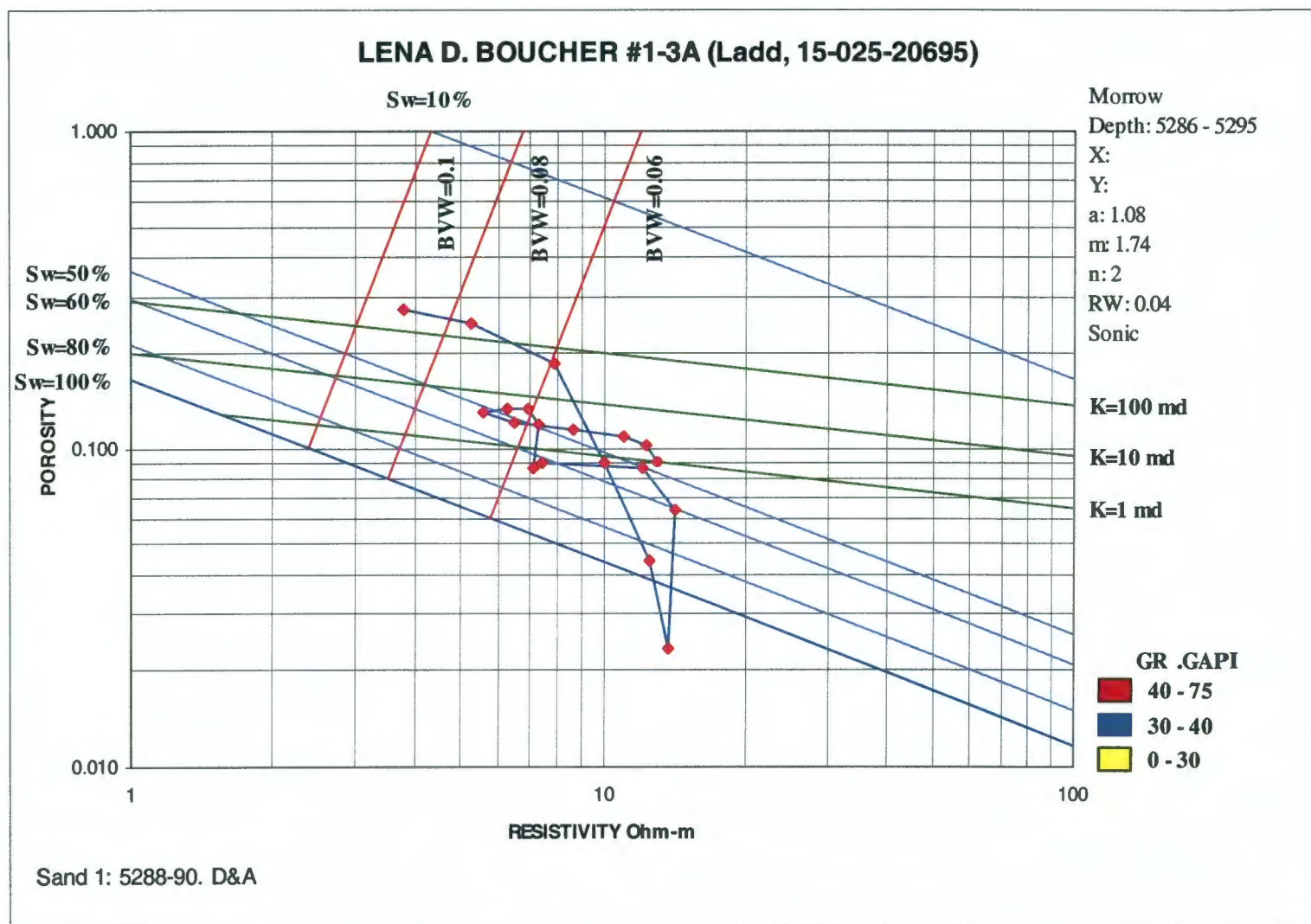


Figure C14

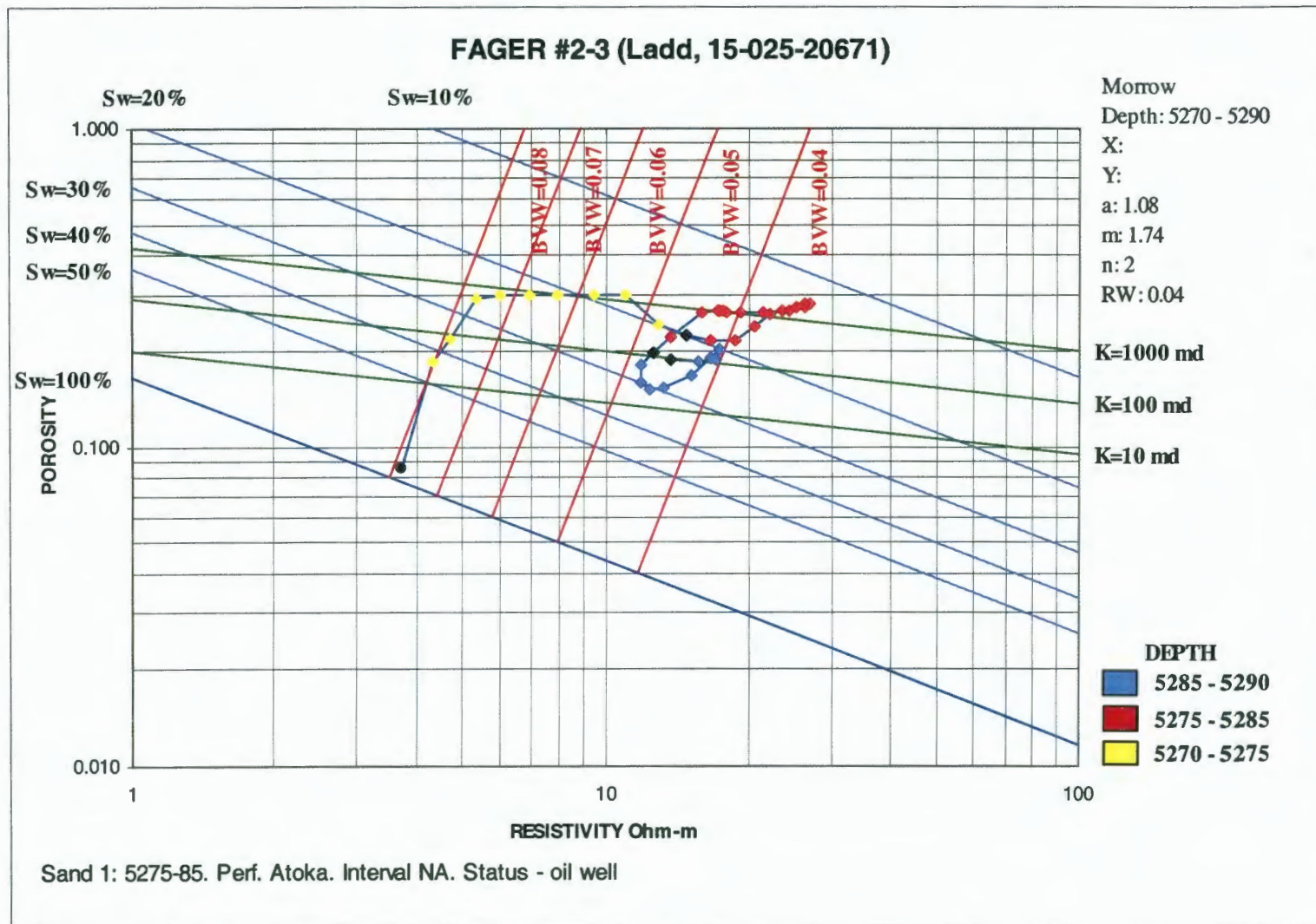


Figure C15

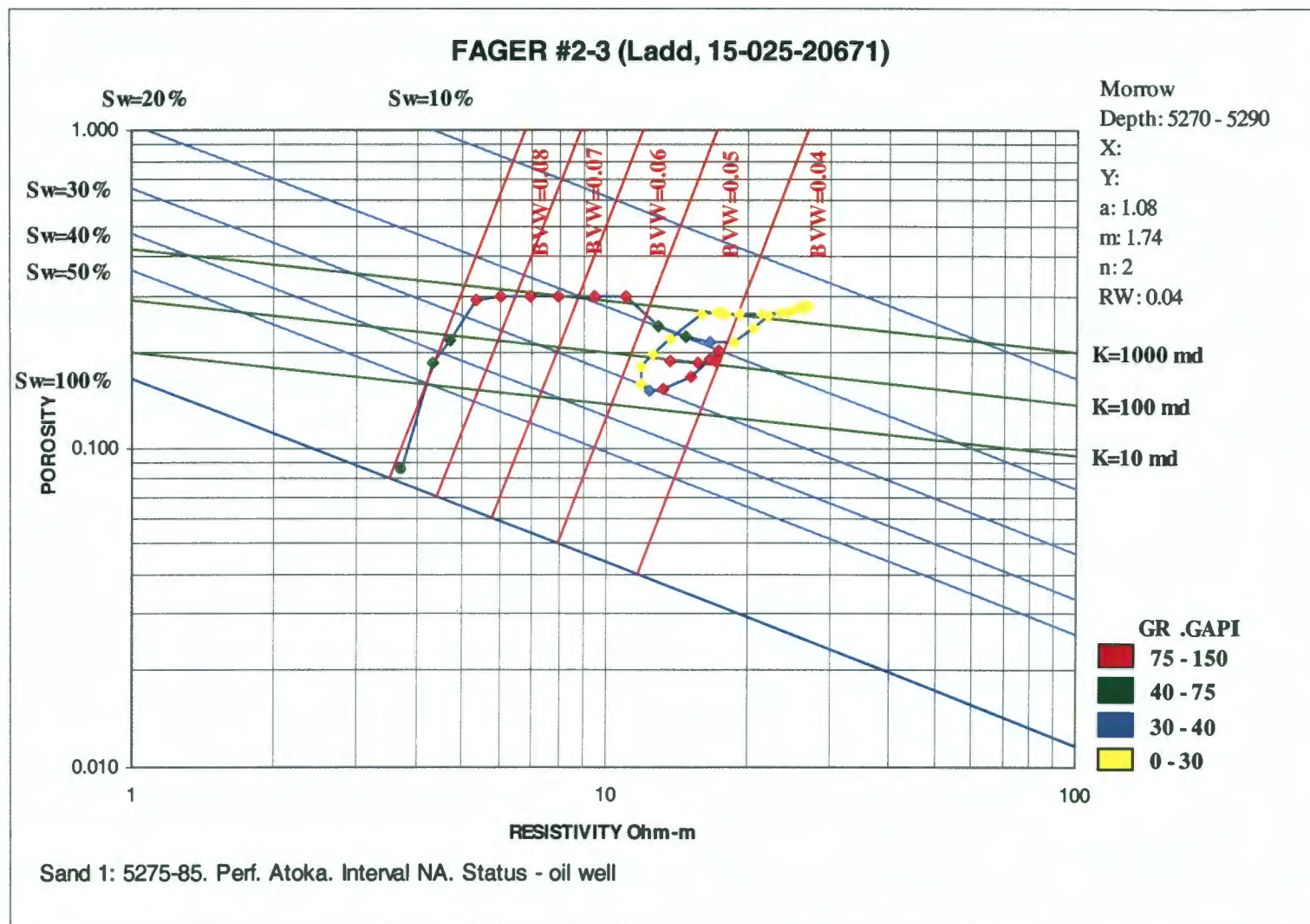


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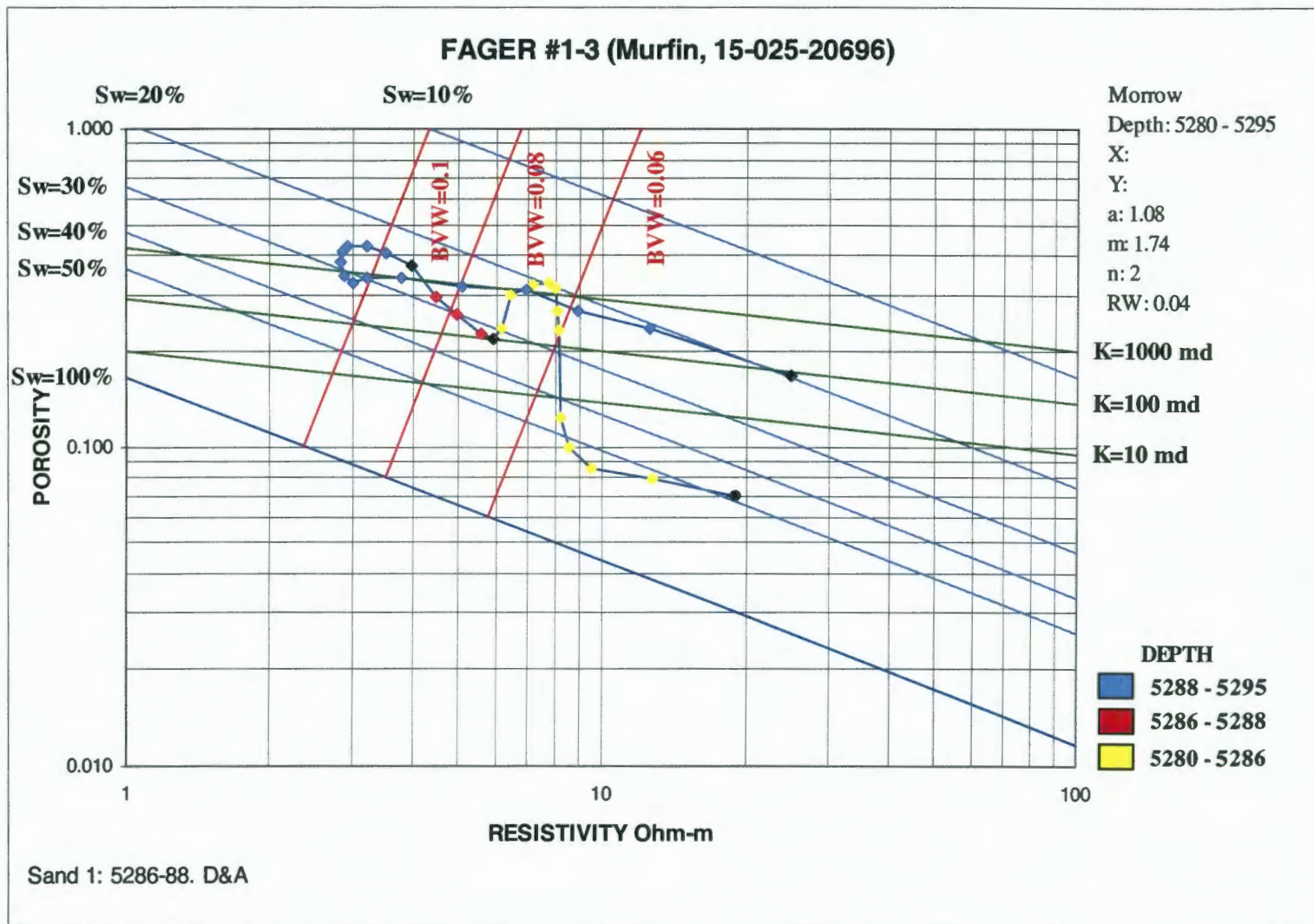


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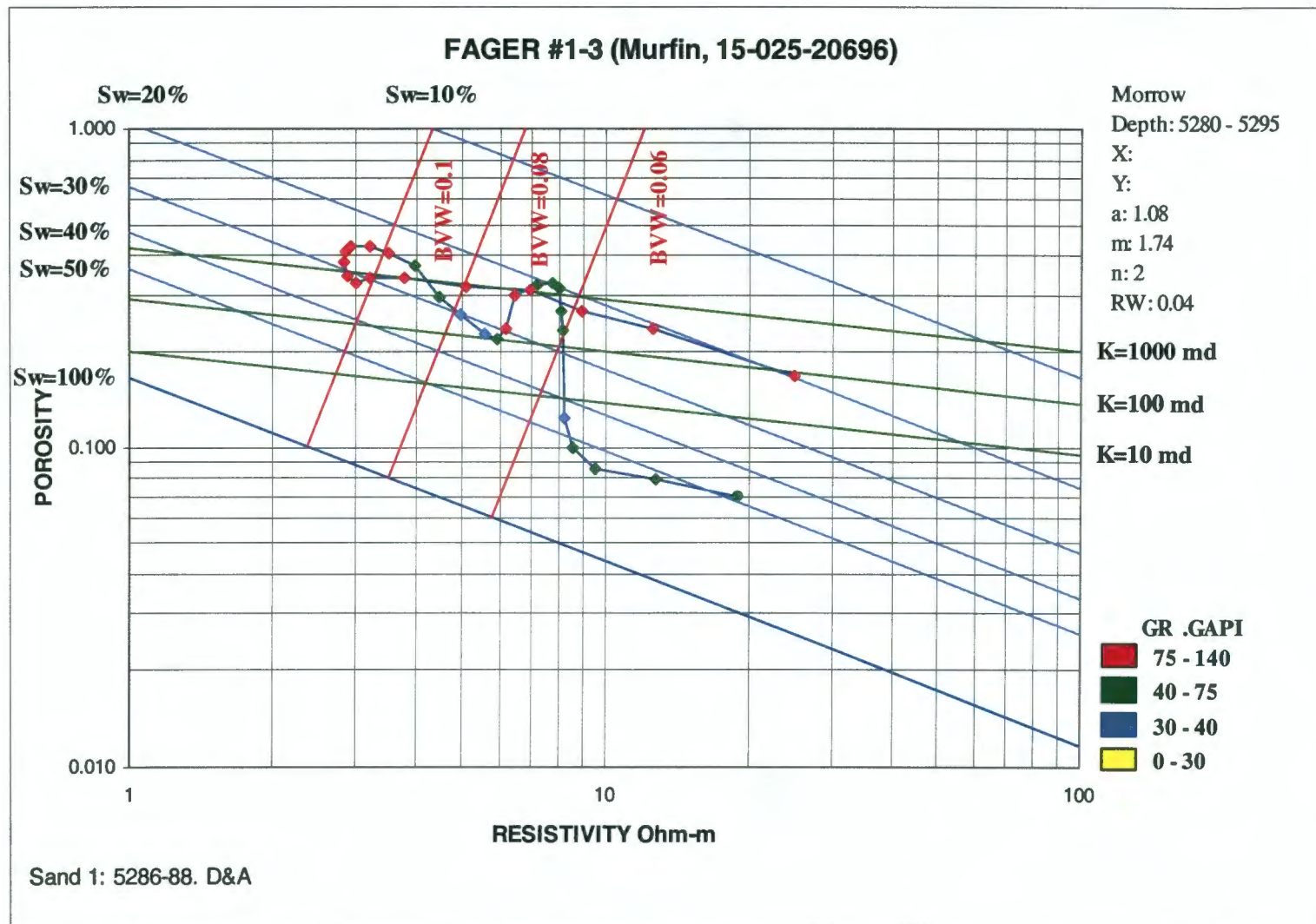


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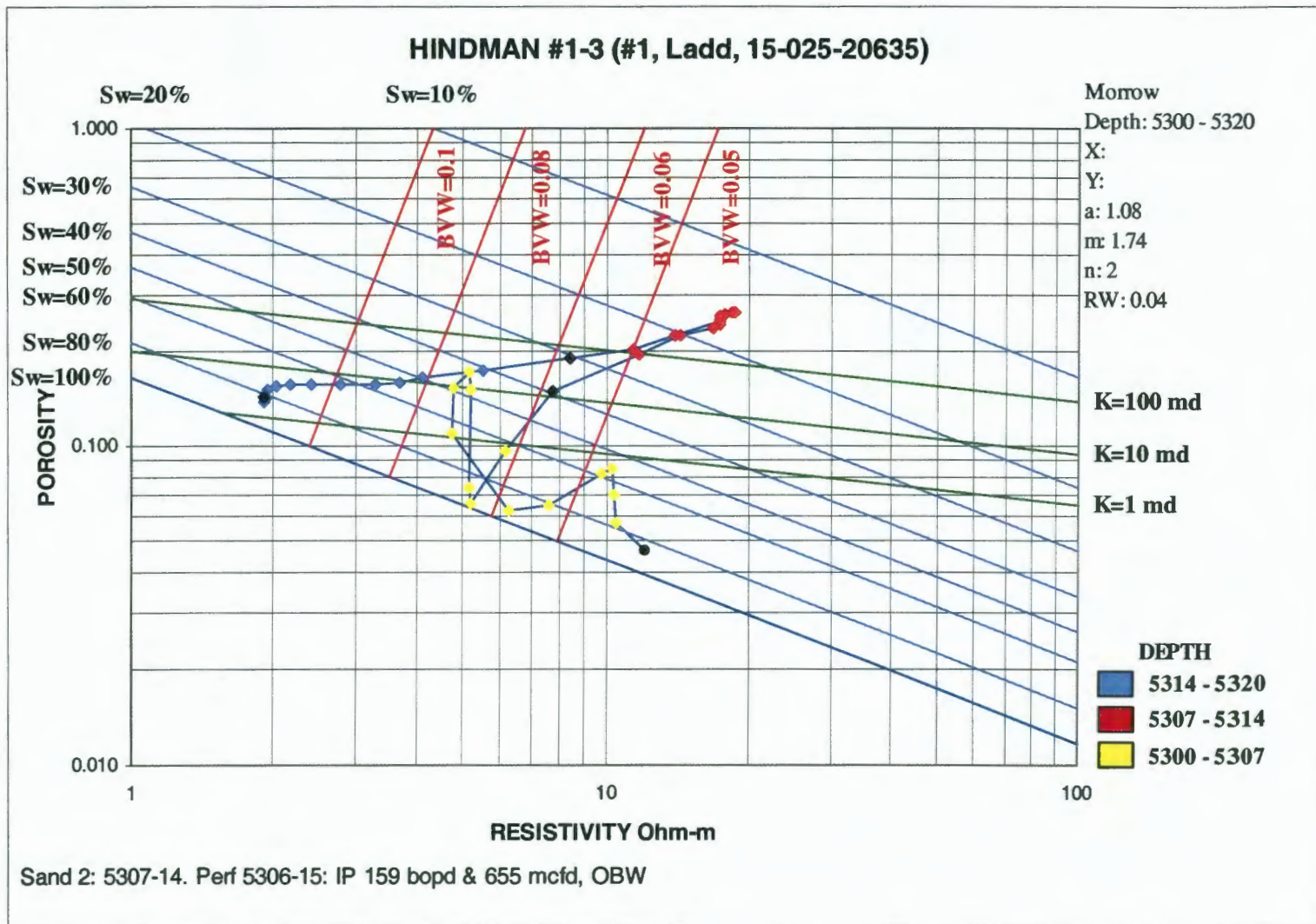


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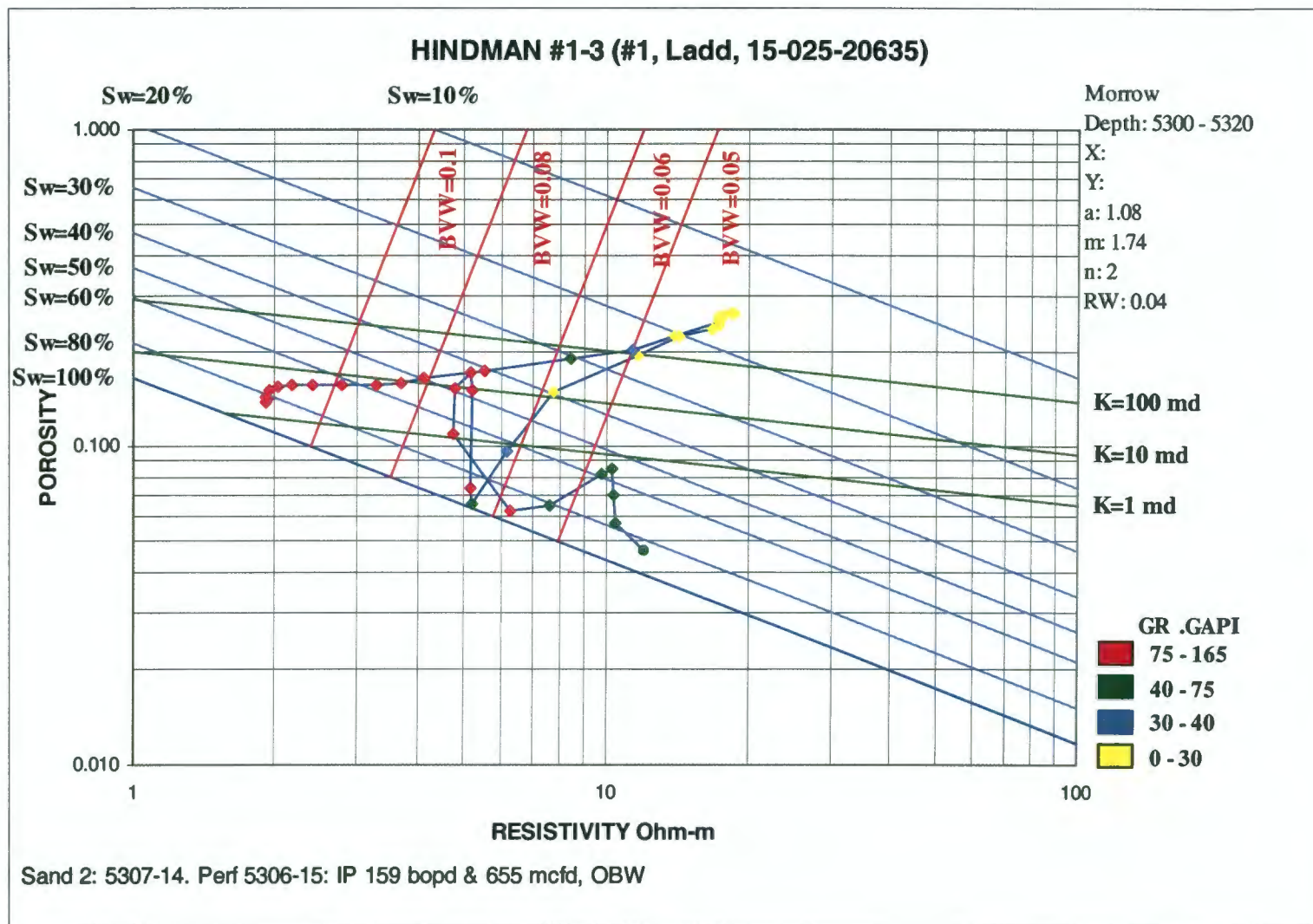


Figure C20

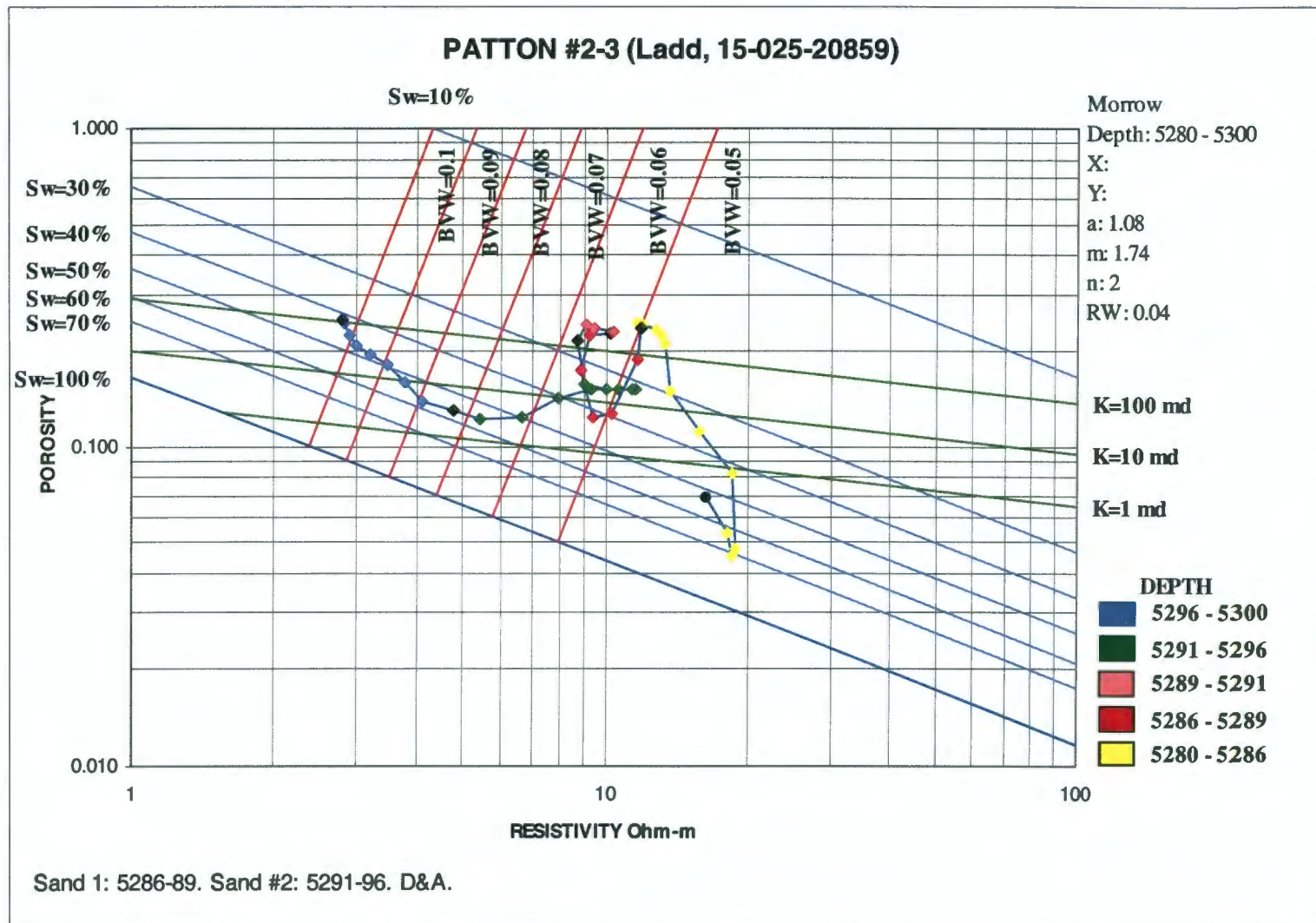


Figure C21

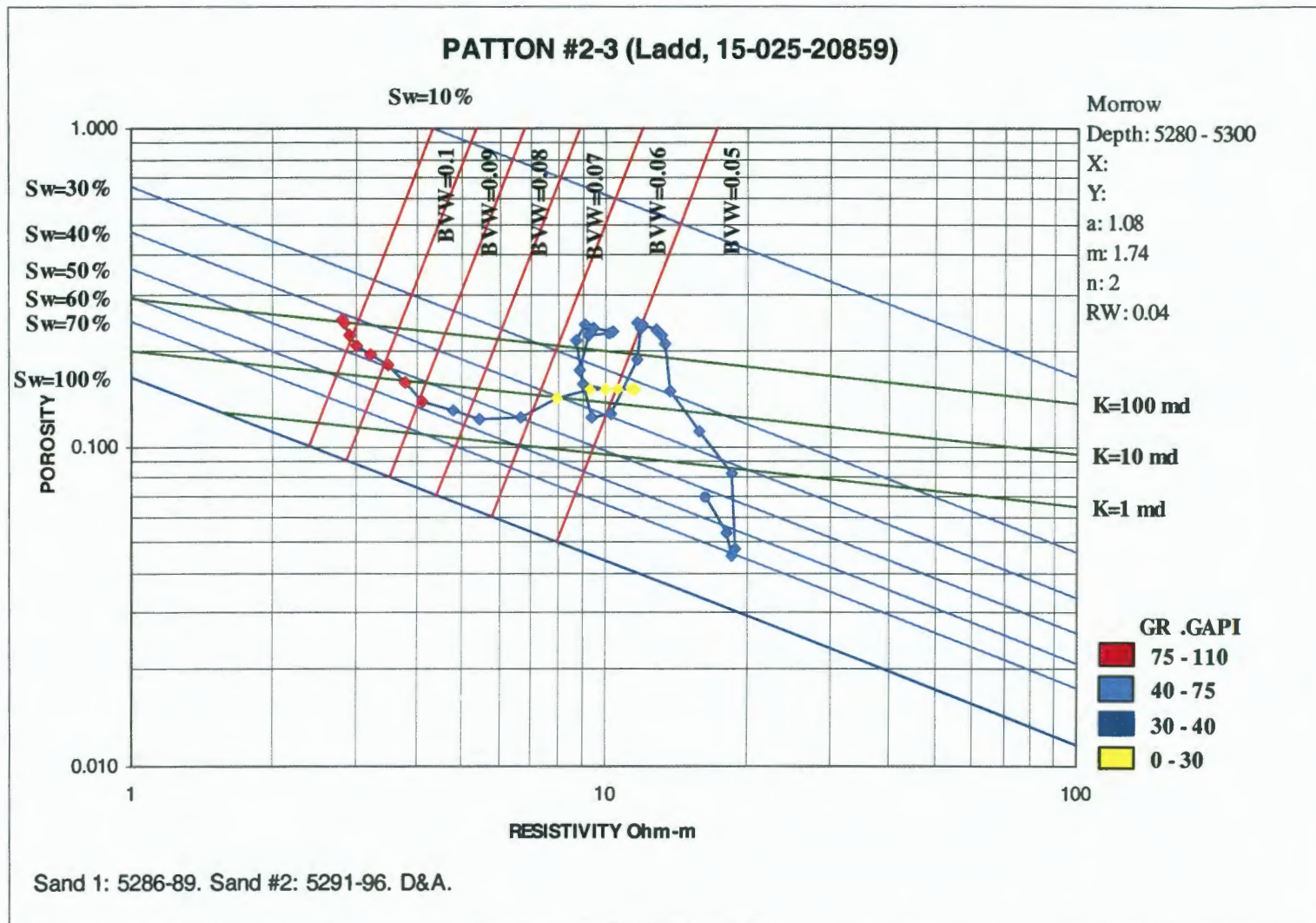


Figure C22

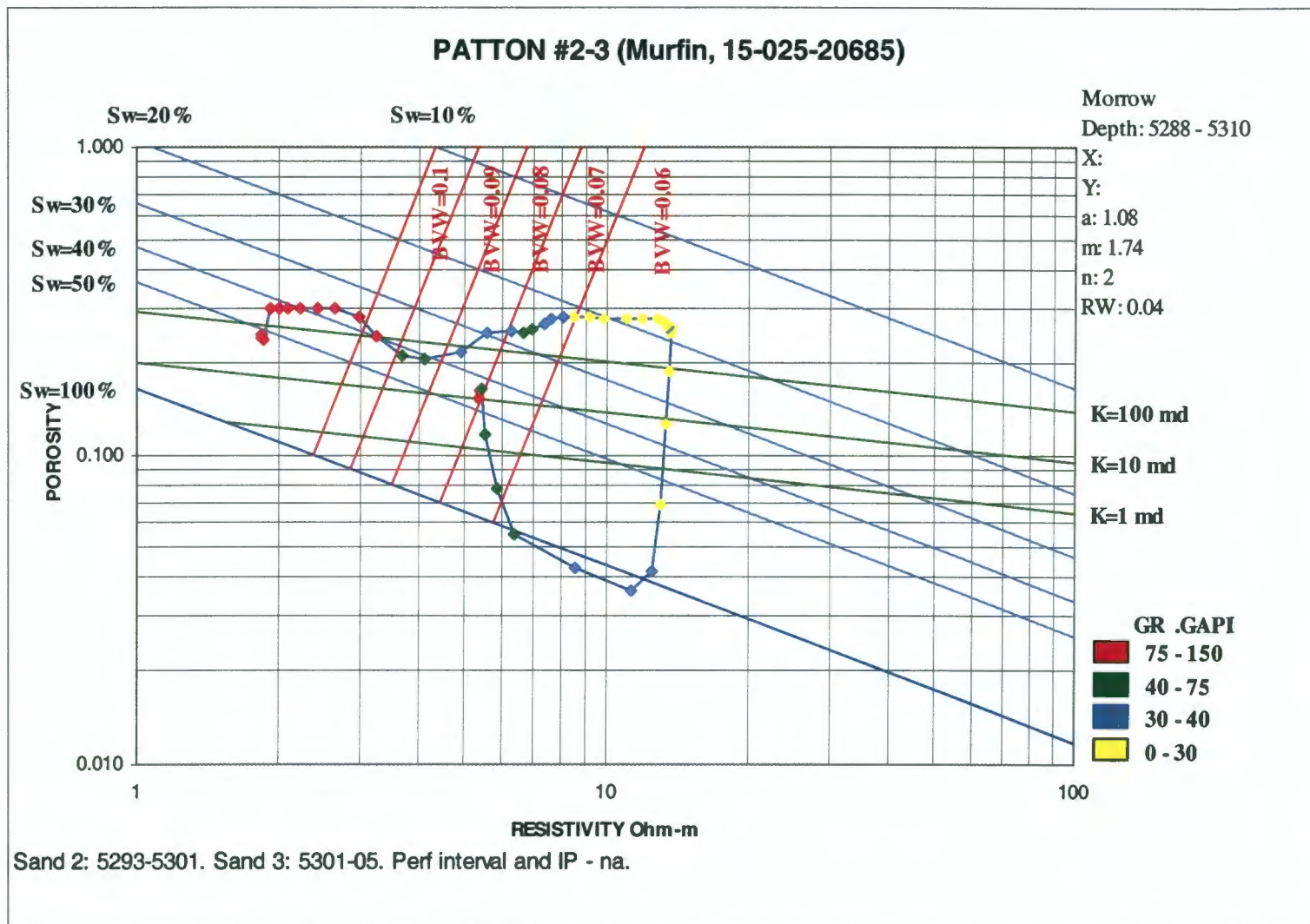


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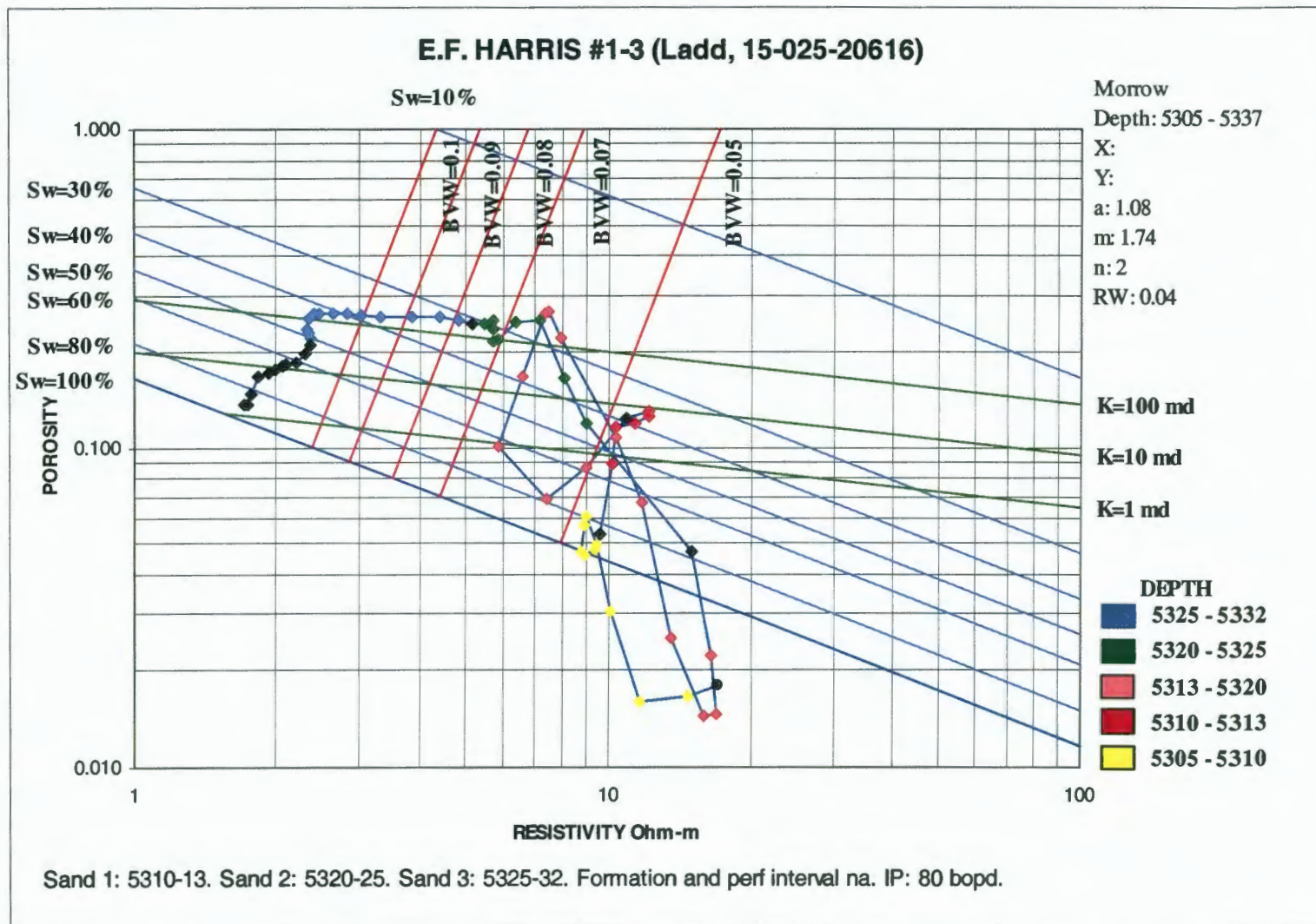


Figure C25

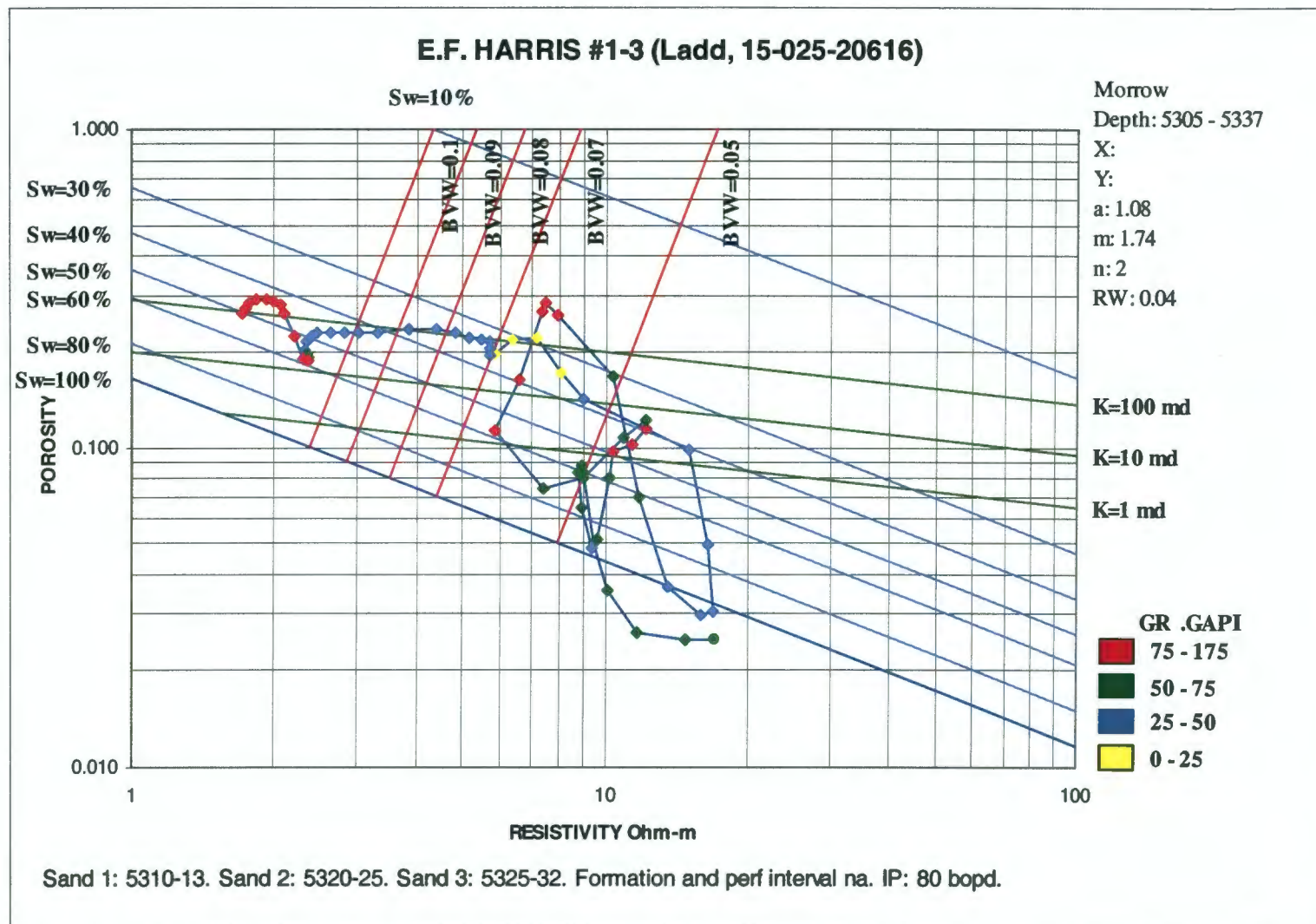


Figure C26

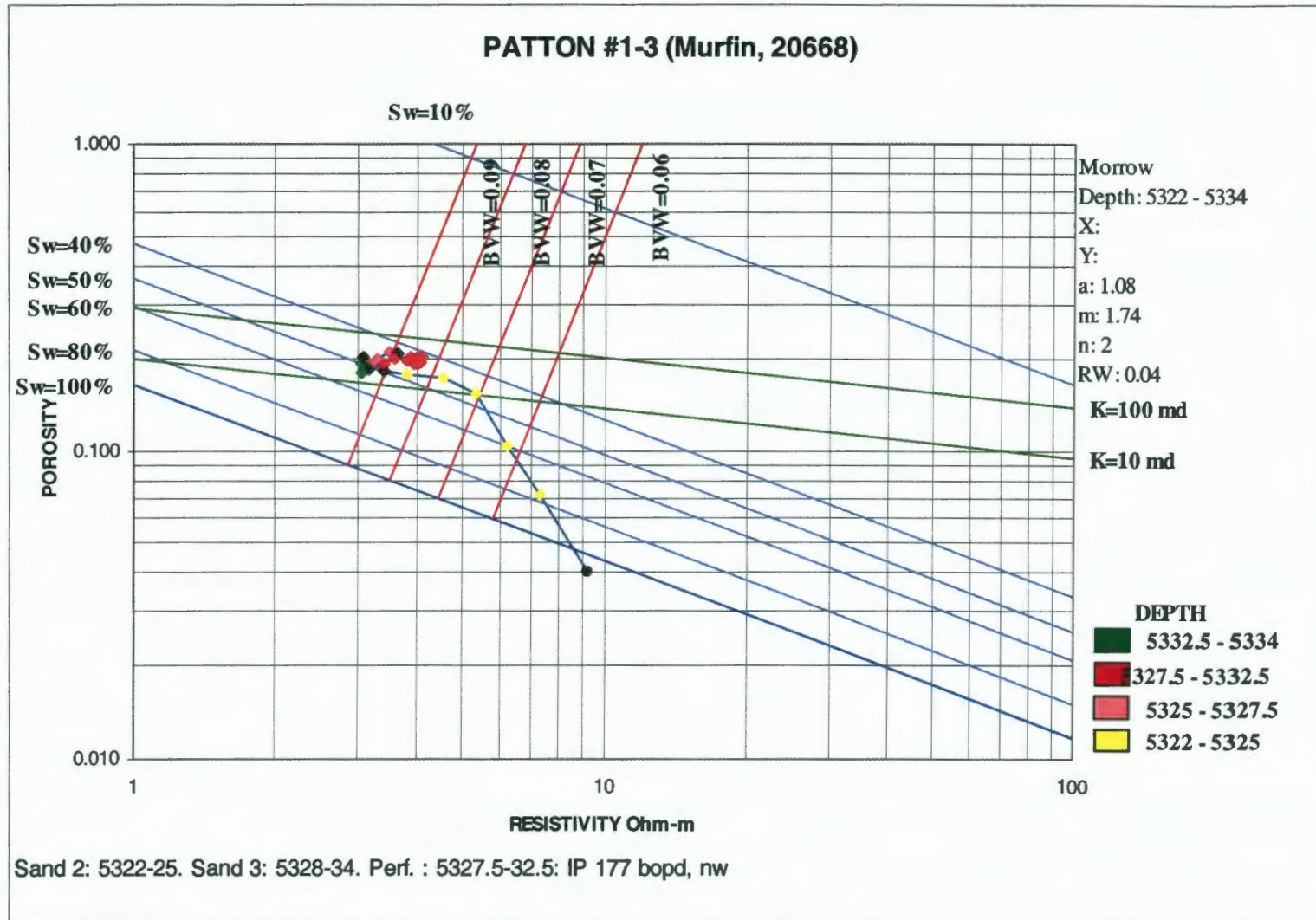


Figure C27

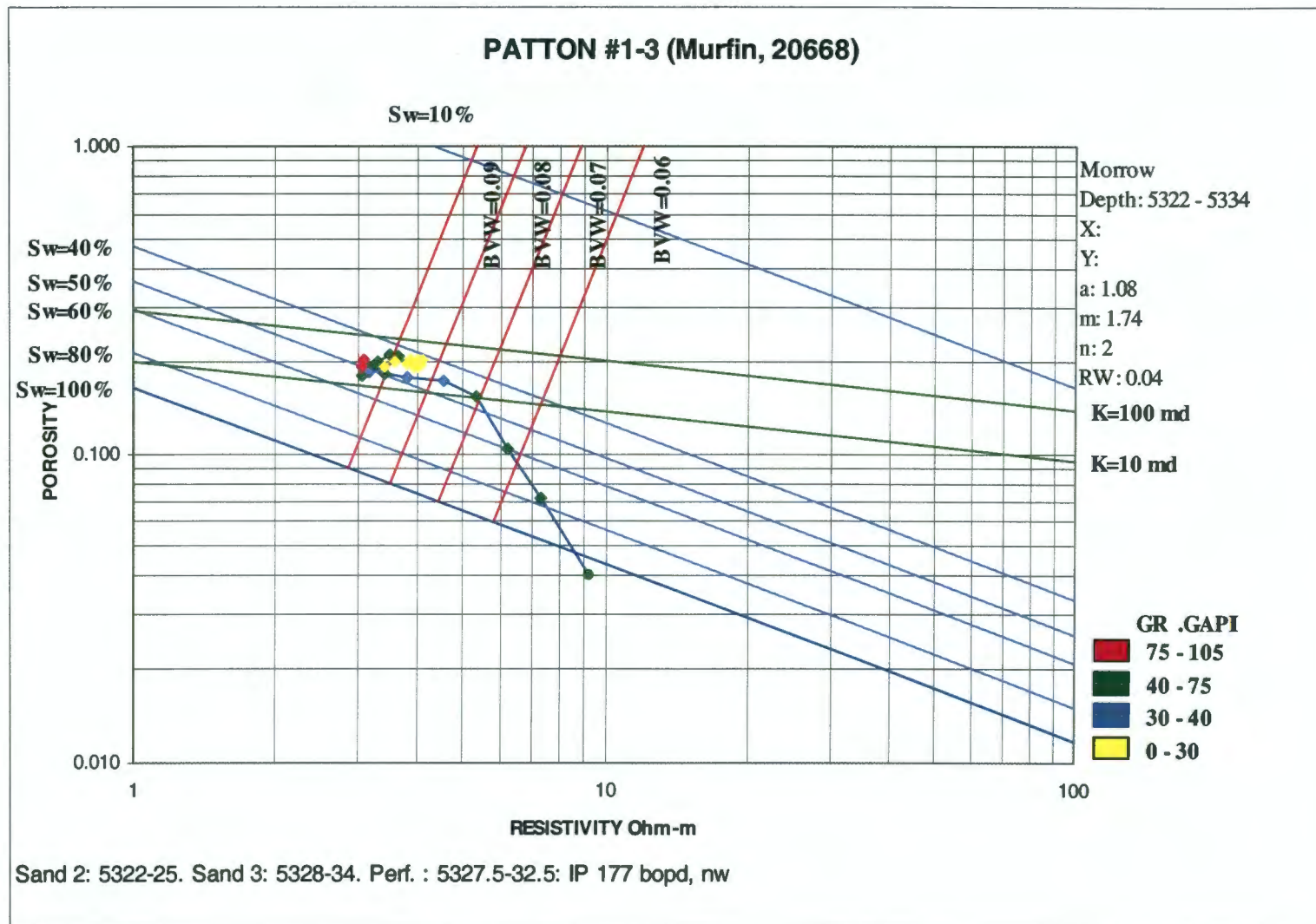


Figure C28

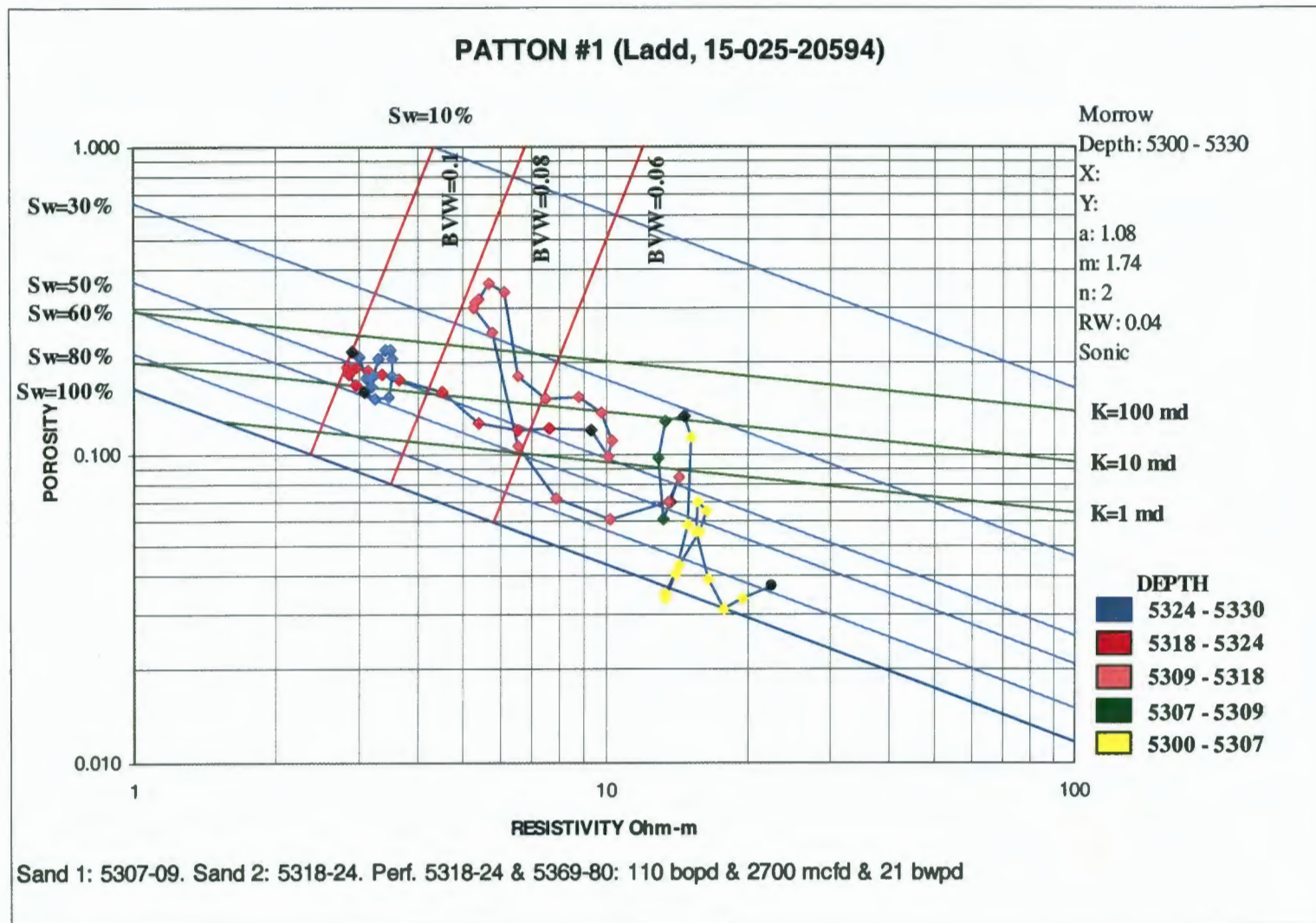


Figure C29

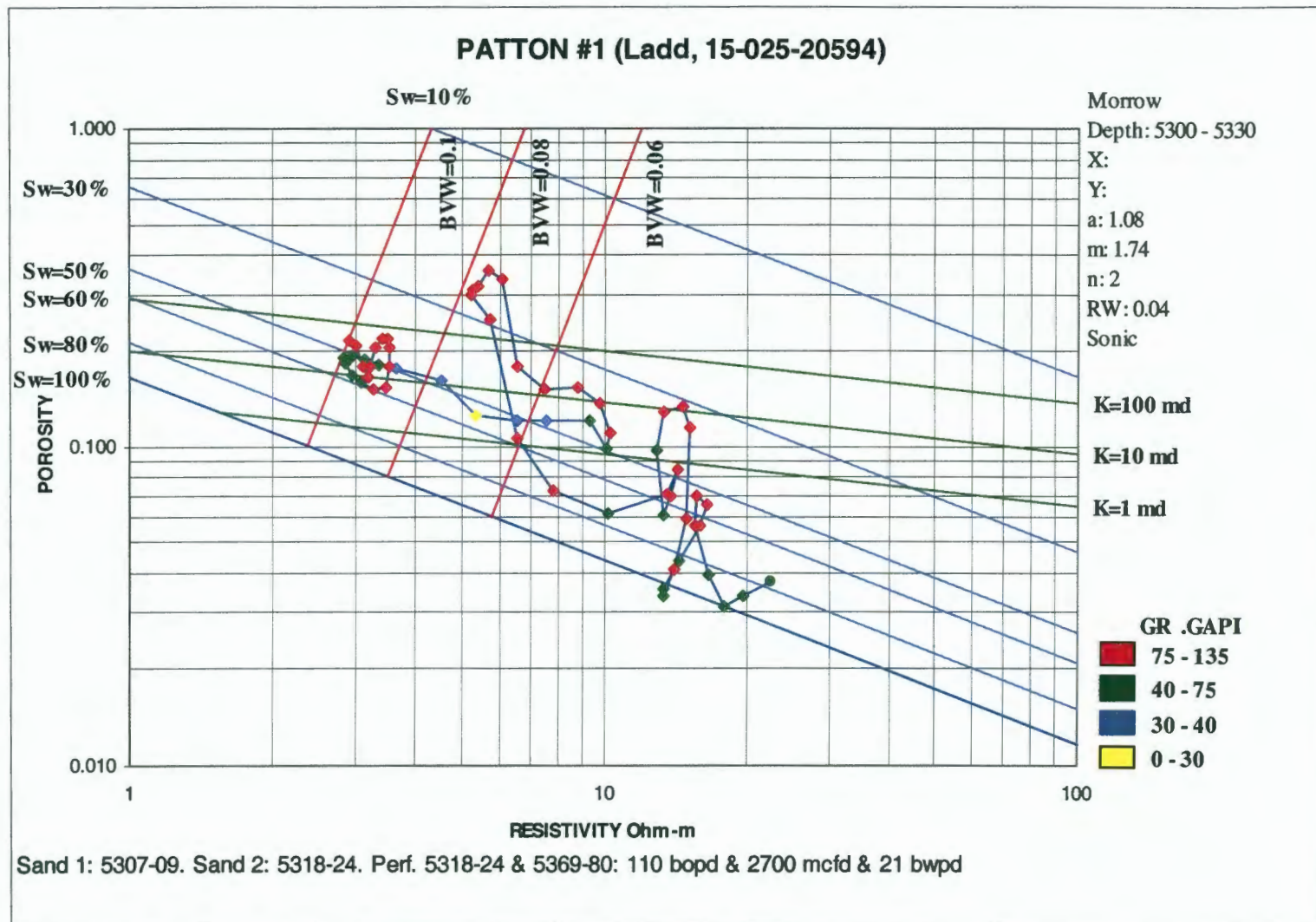


Figure C30

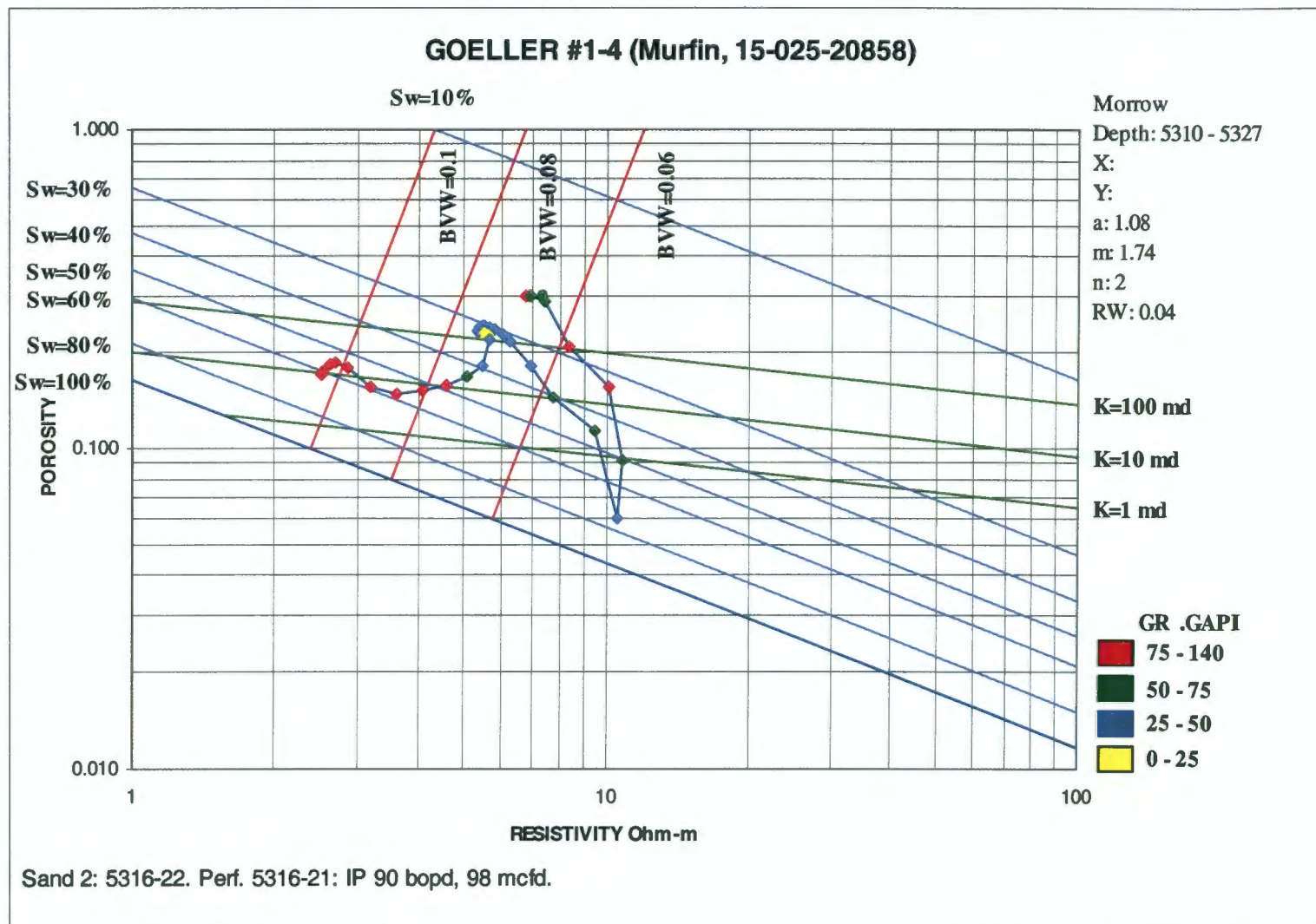


Figure C32

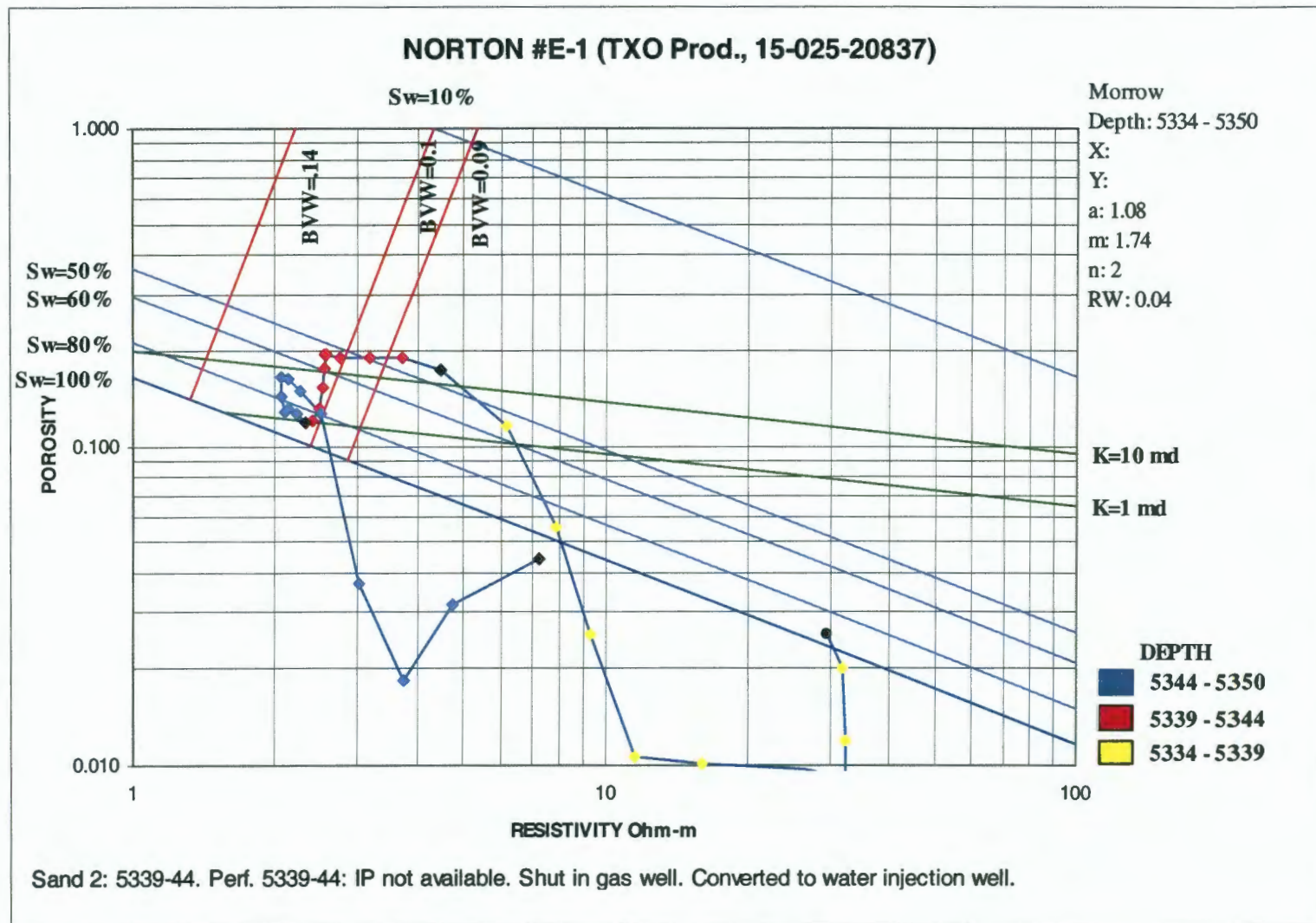


Figure C33

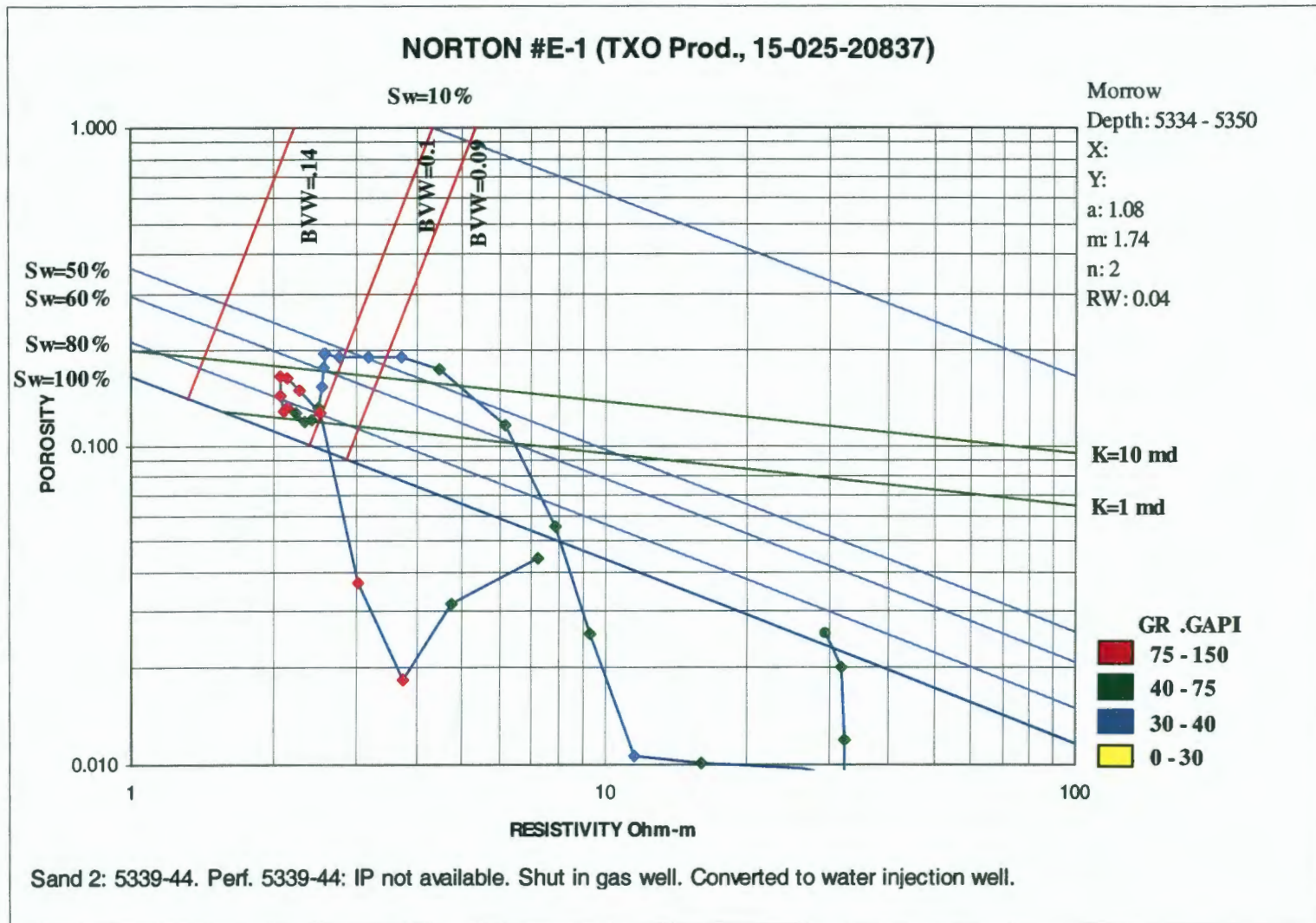


Figure C34

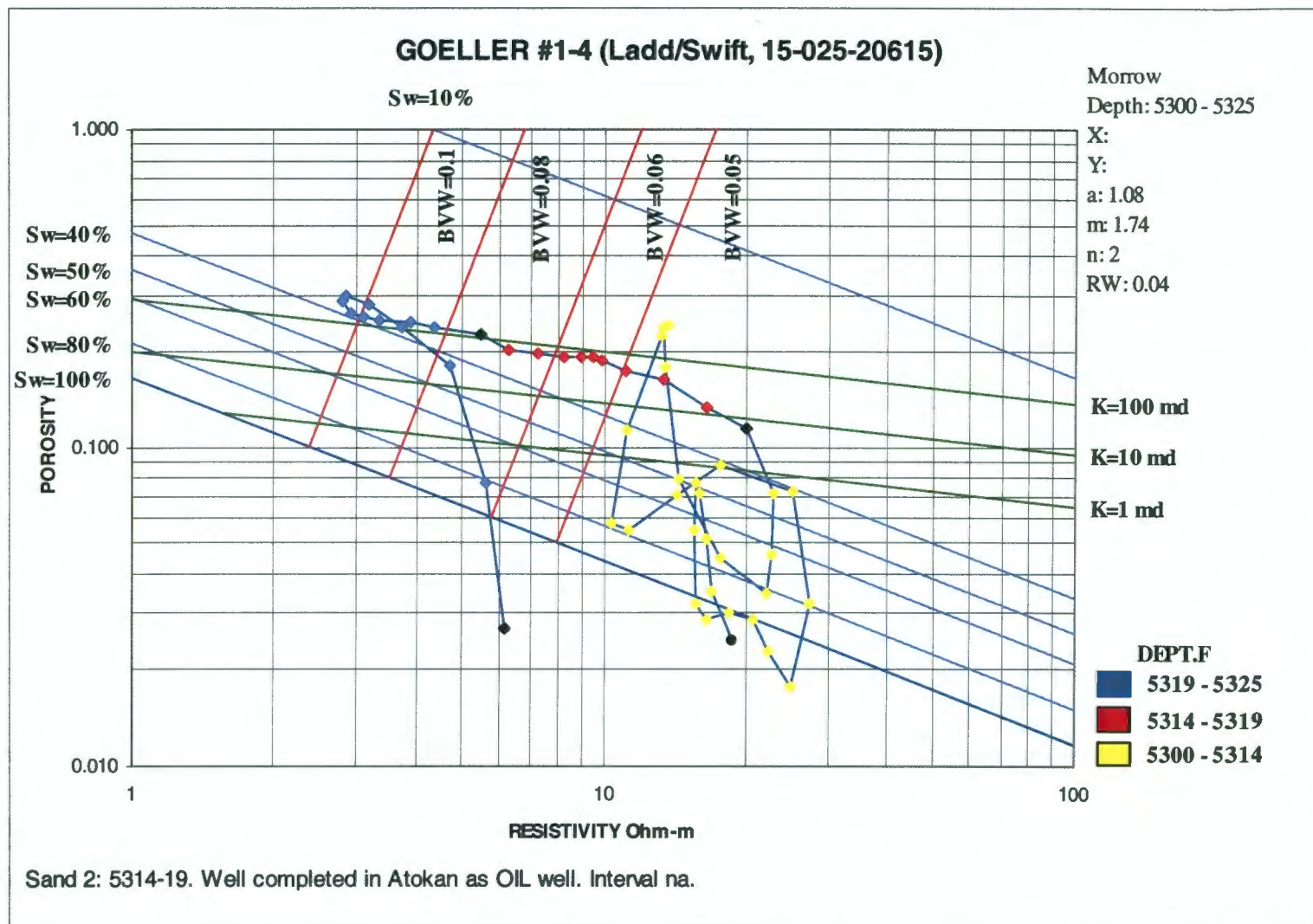


Figure C35

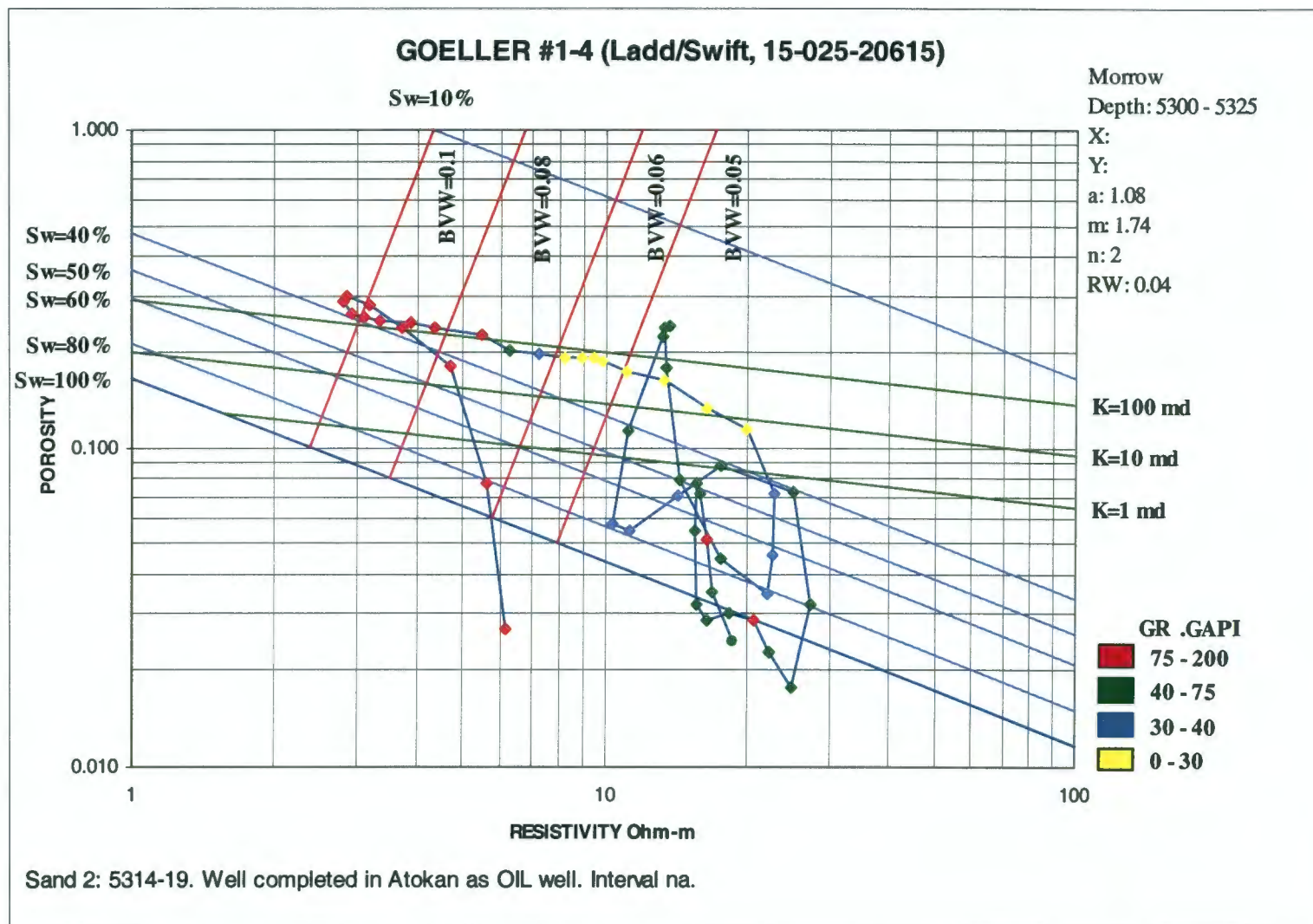


Figure C36

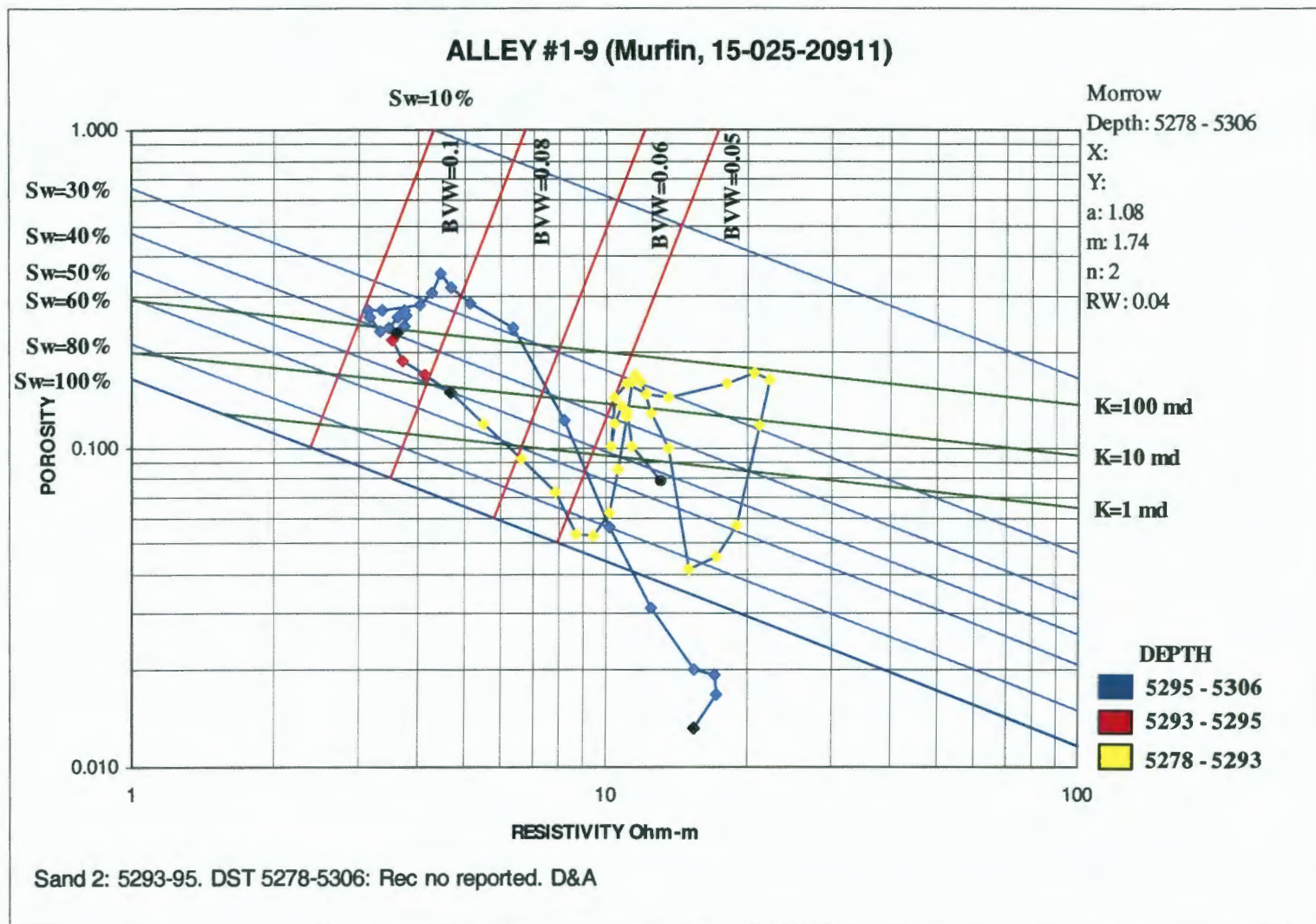


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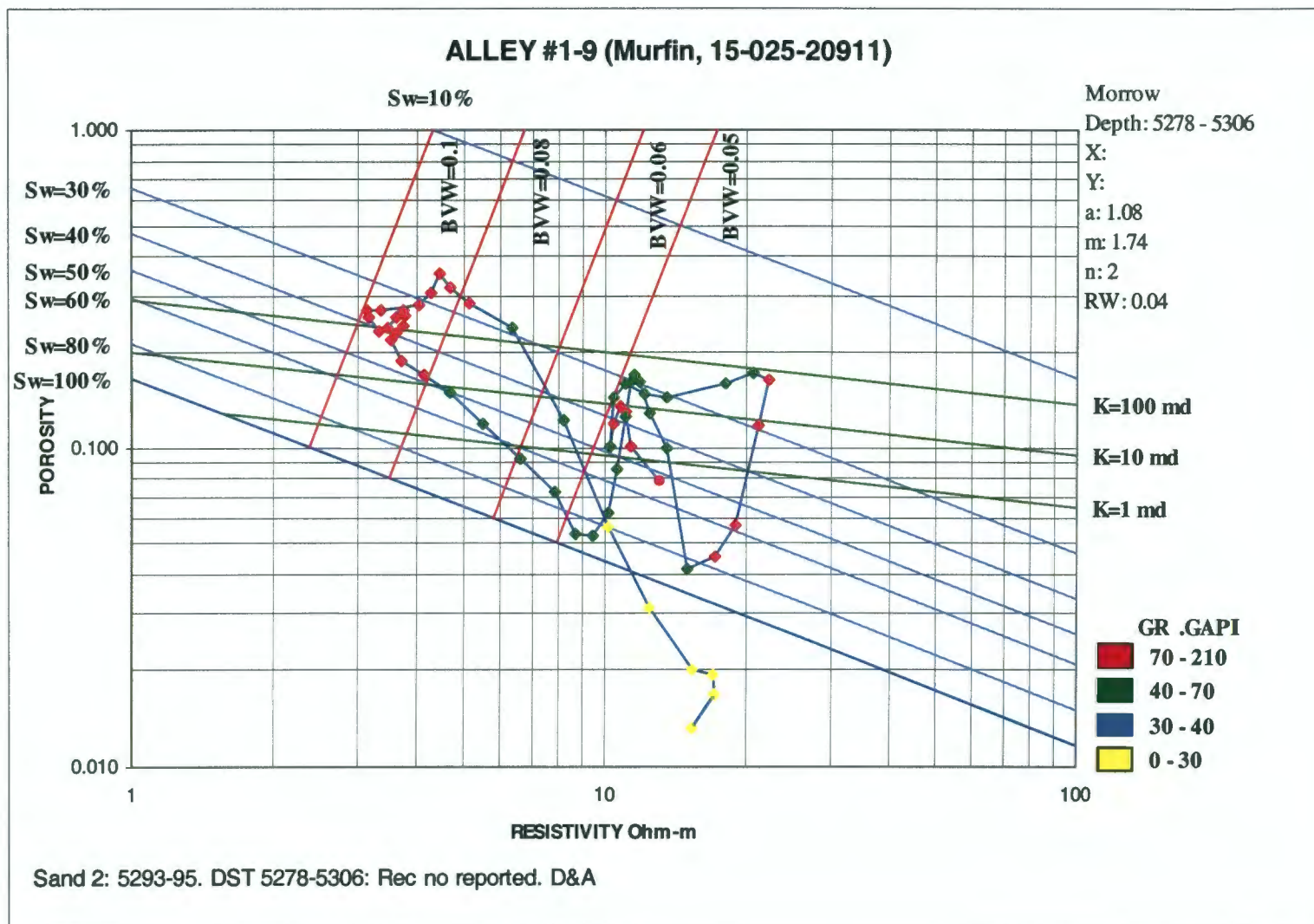


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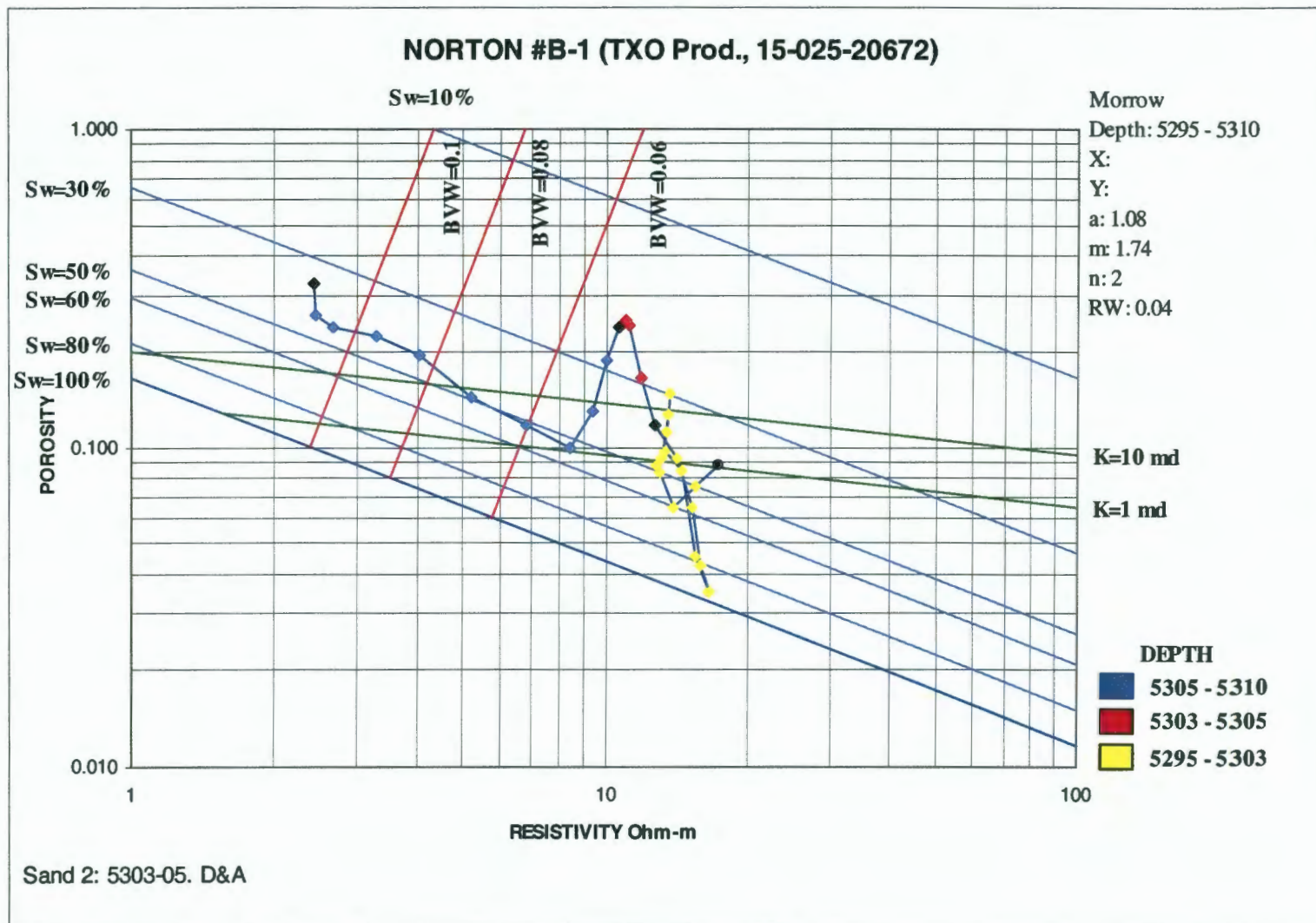


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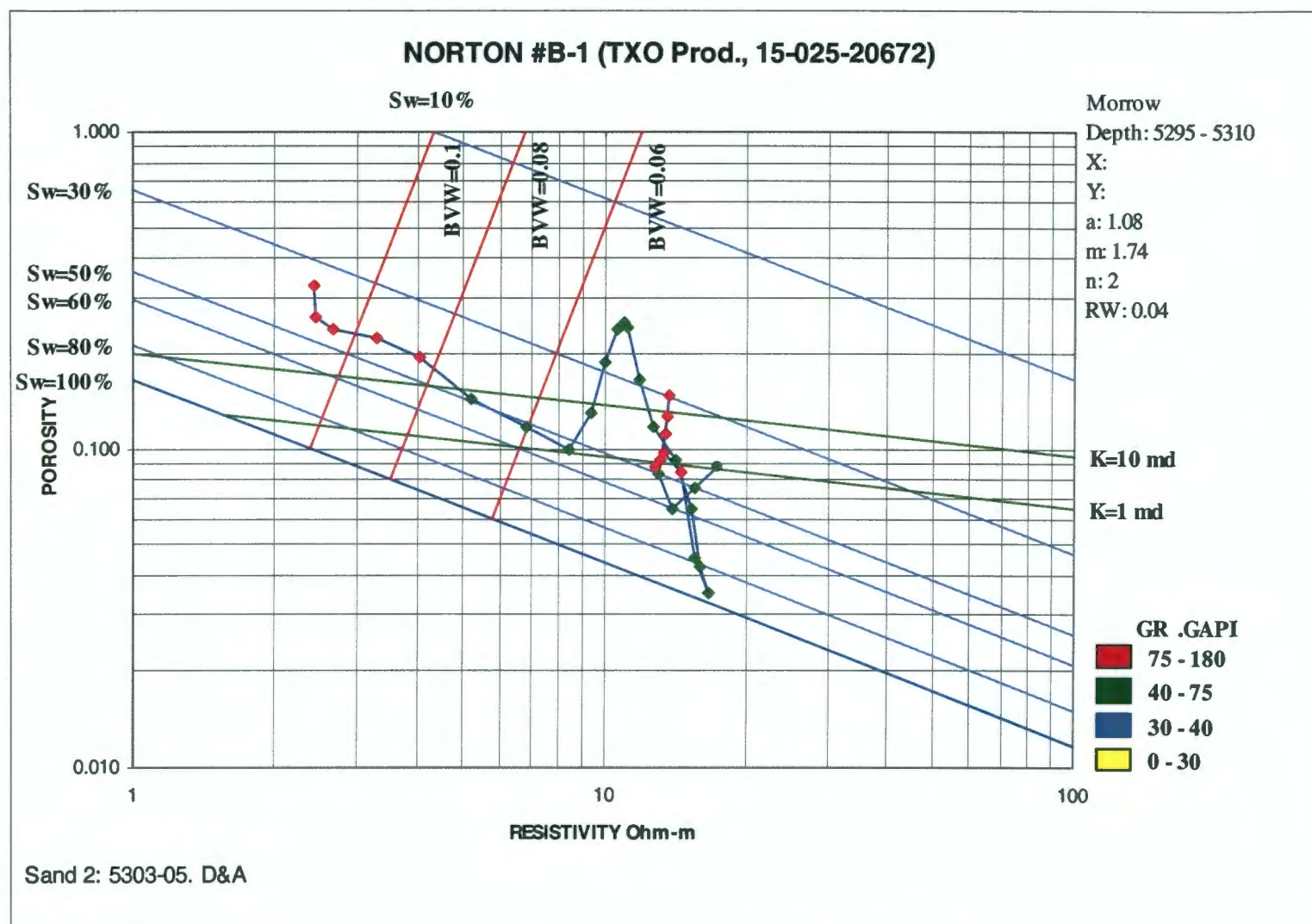


Figure C40

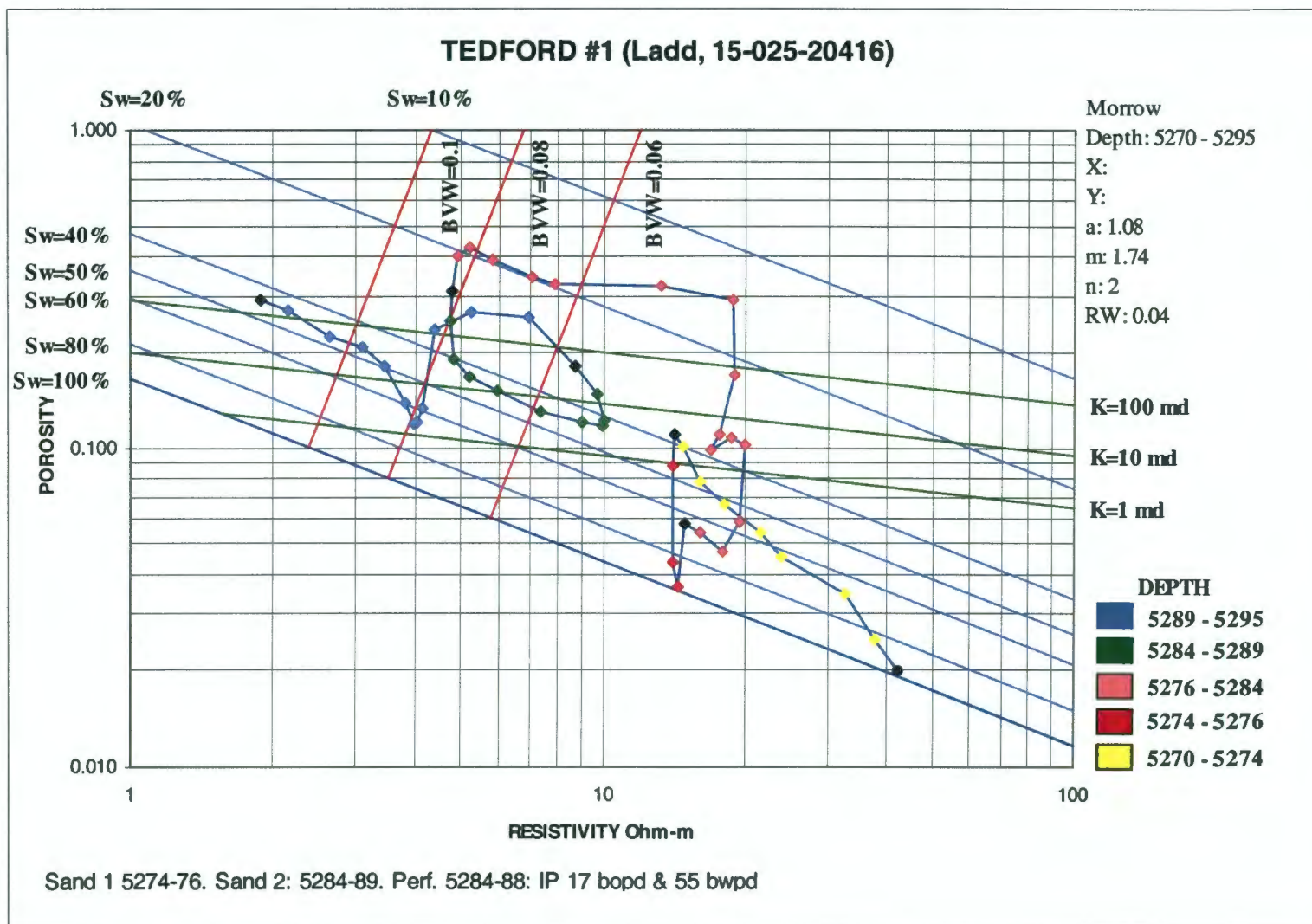


Figure C41

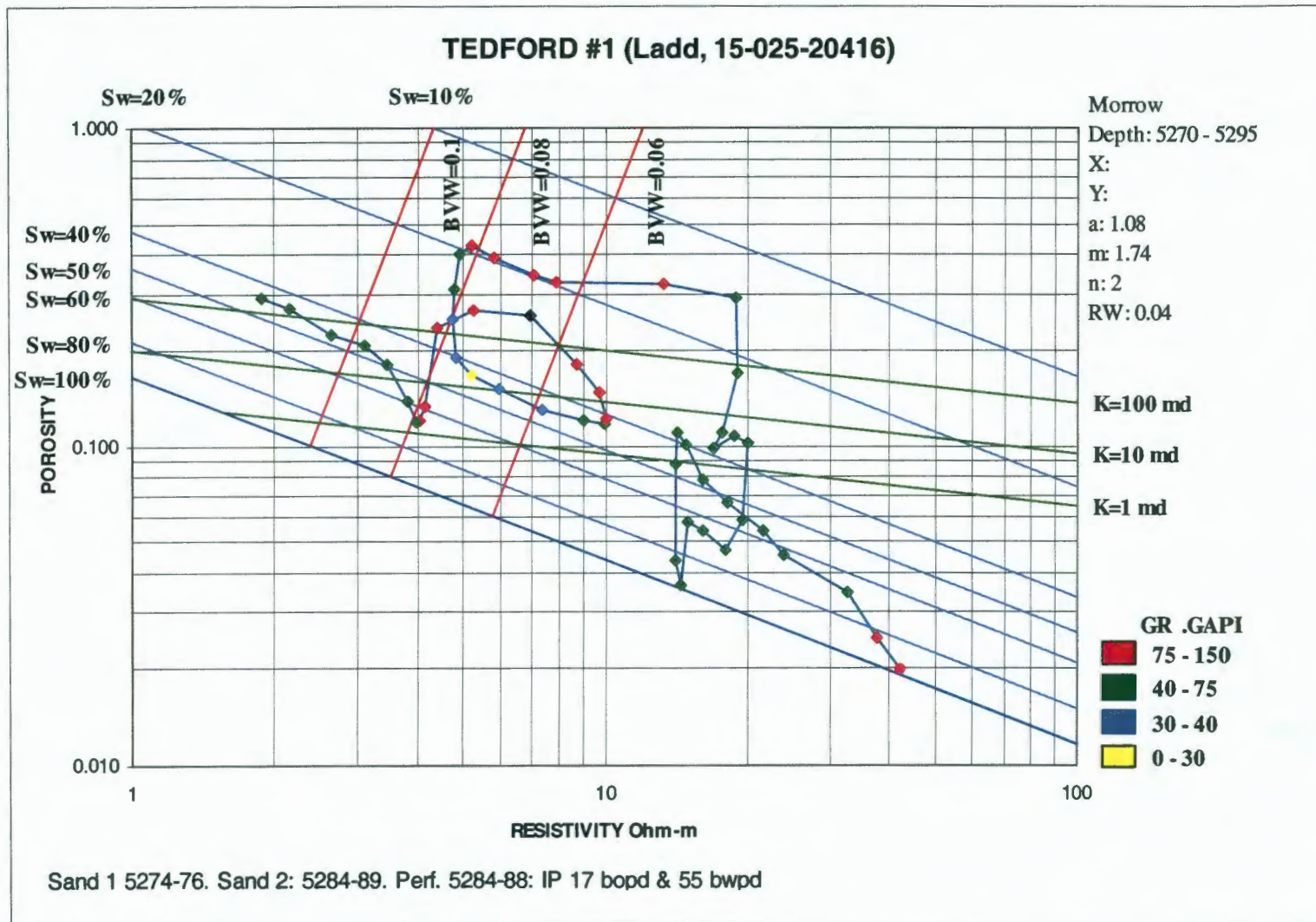


Figure C42

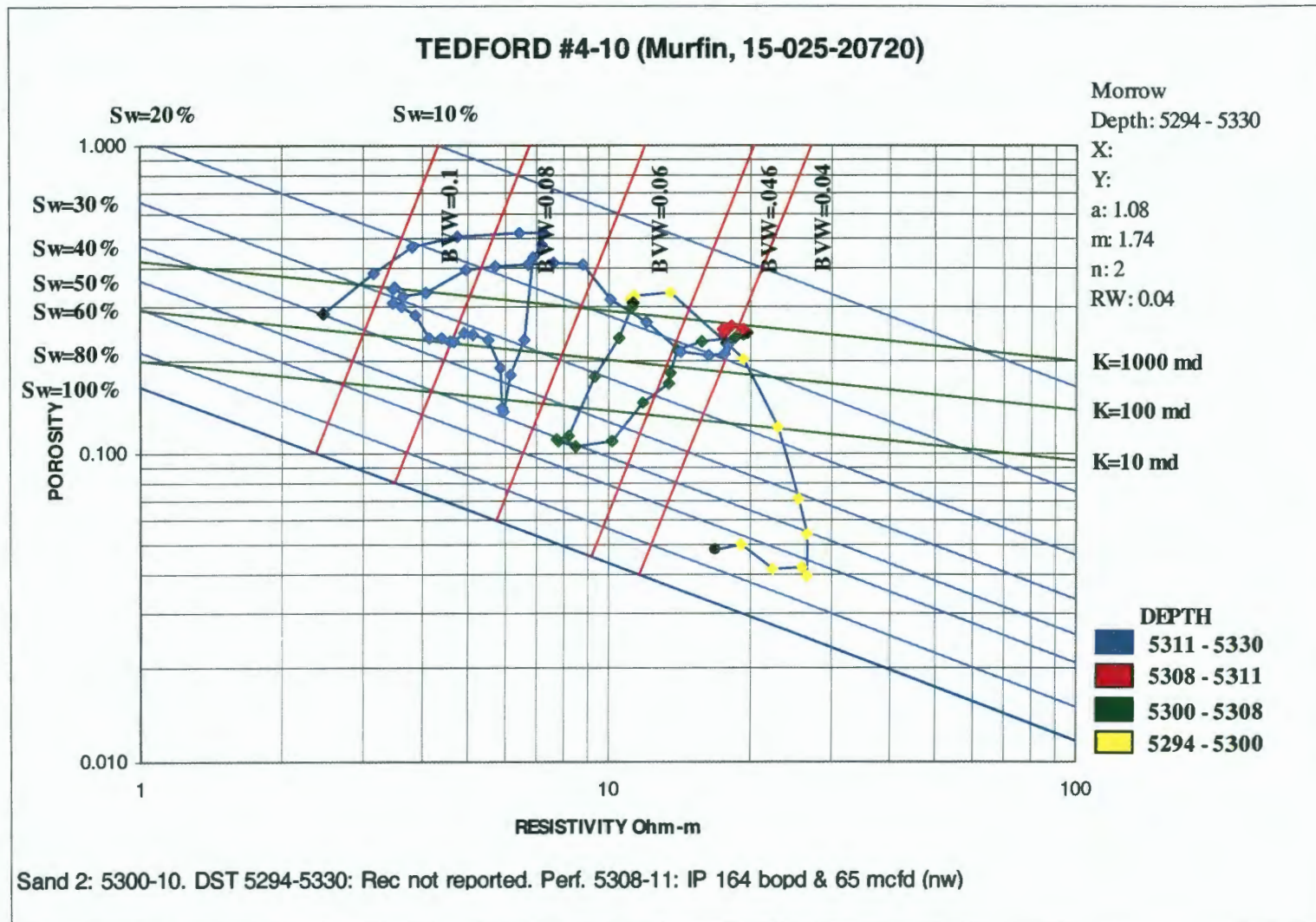


Figure C43

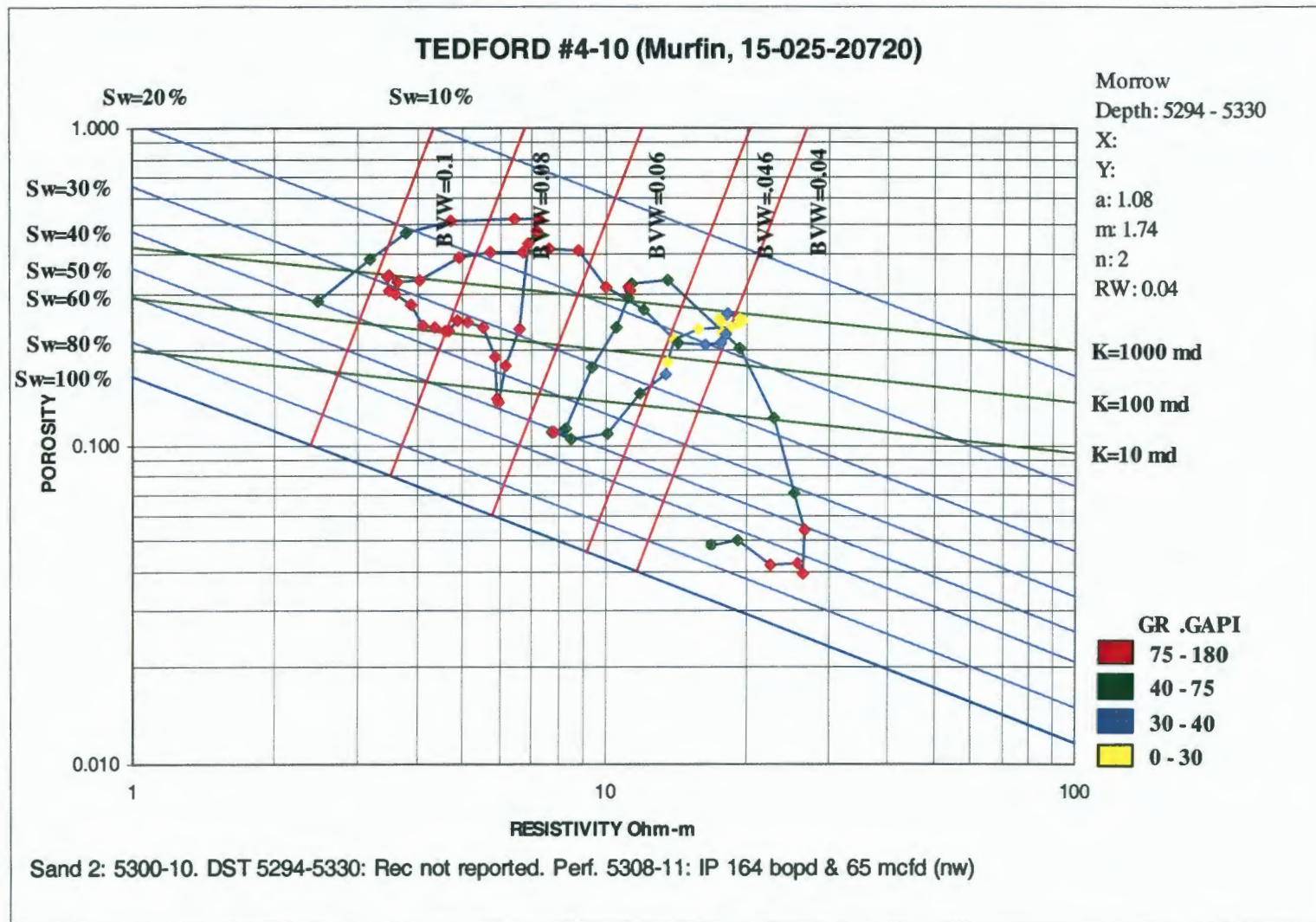


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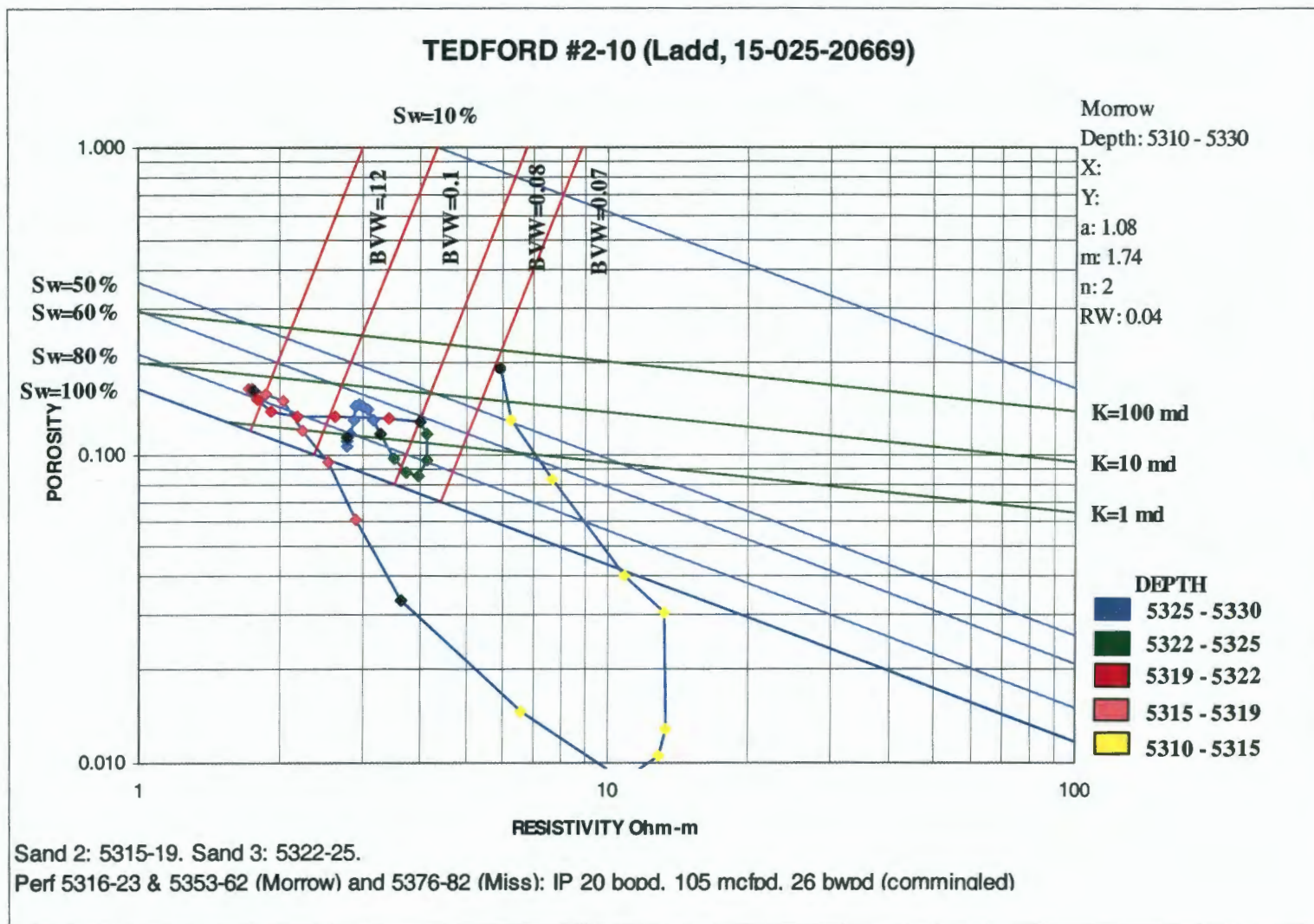


Figure C45

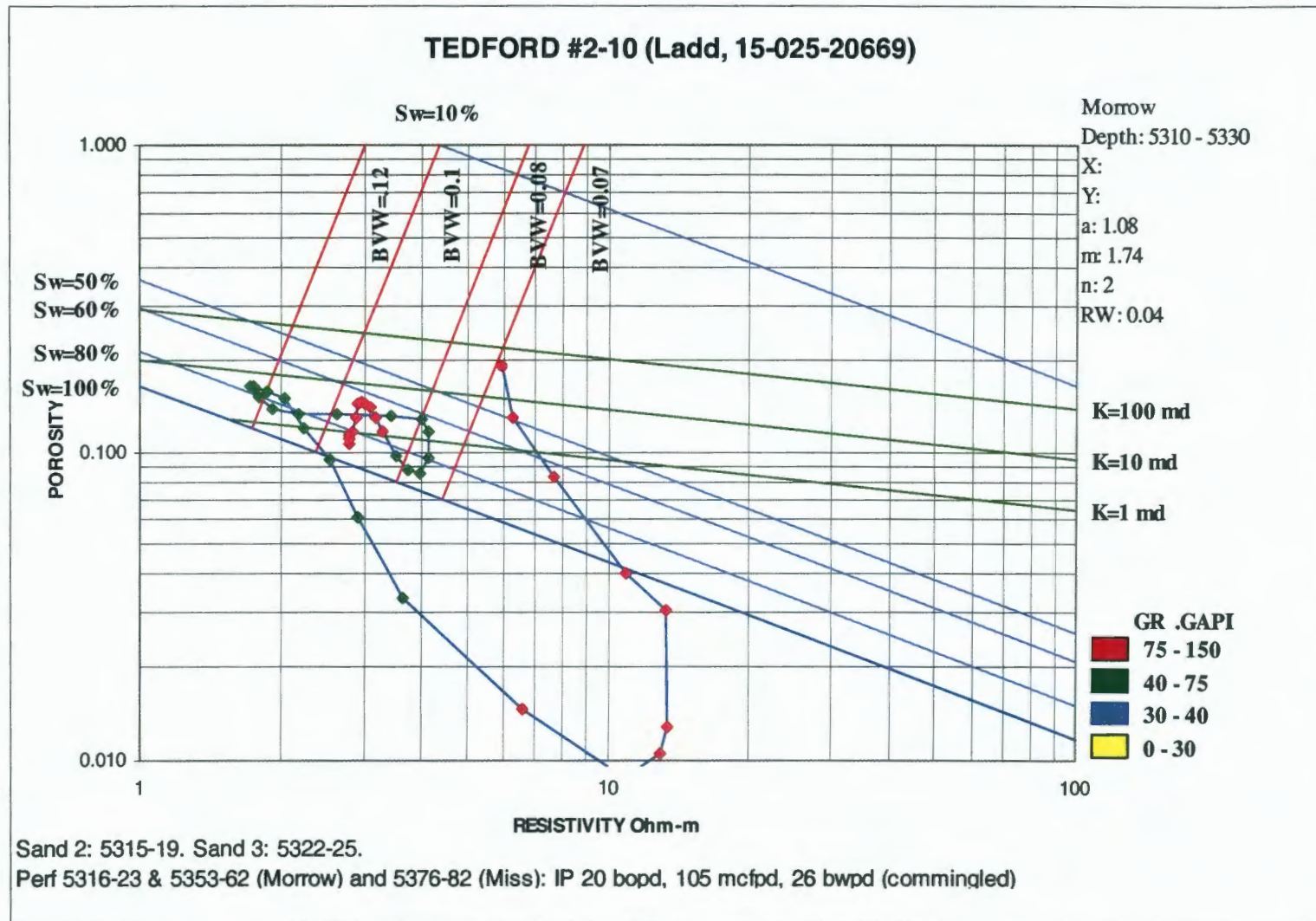


Figure C46

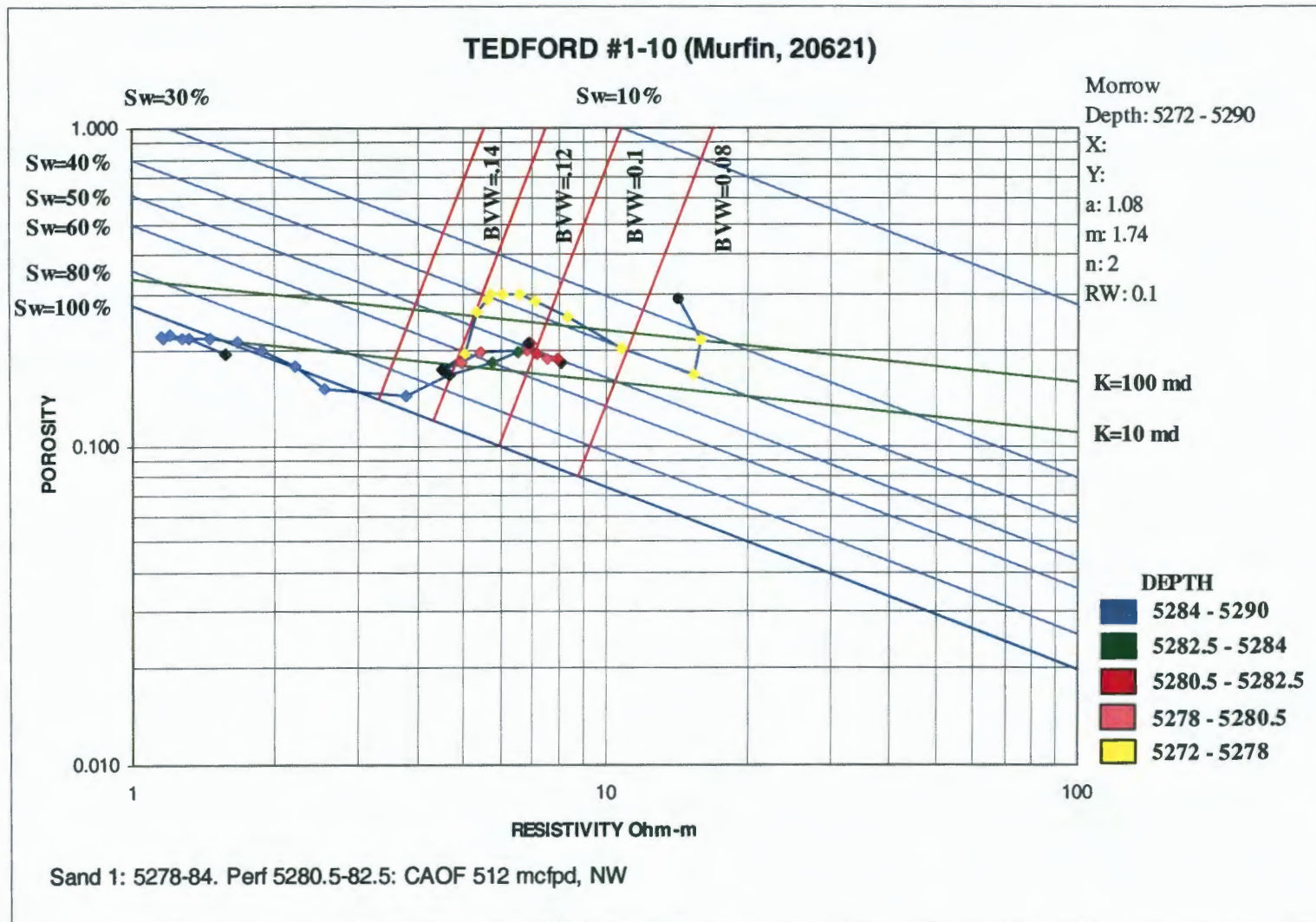


Figure C47

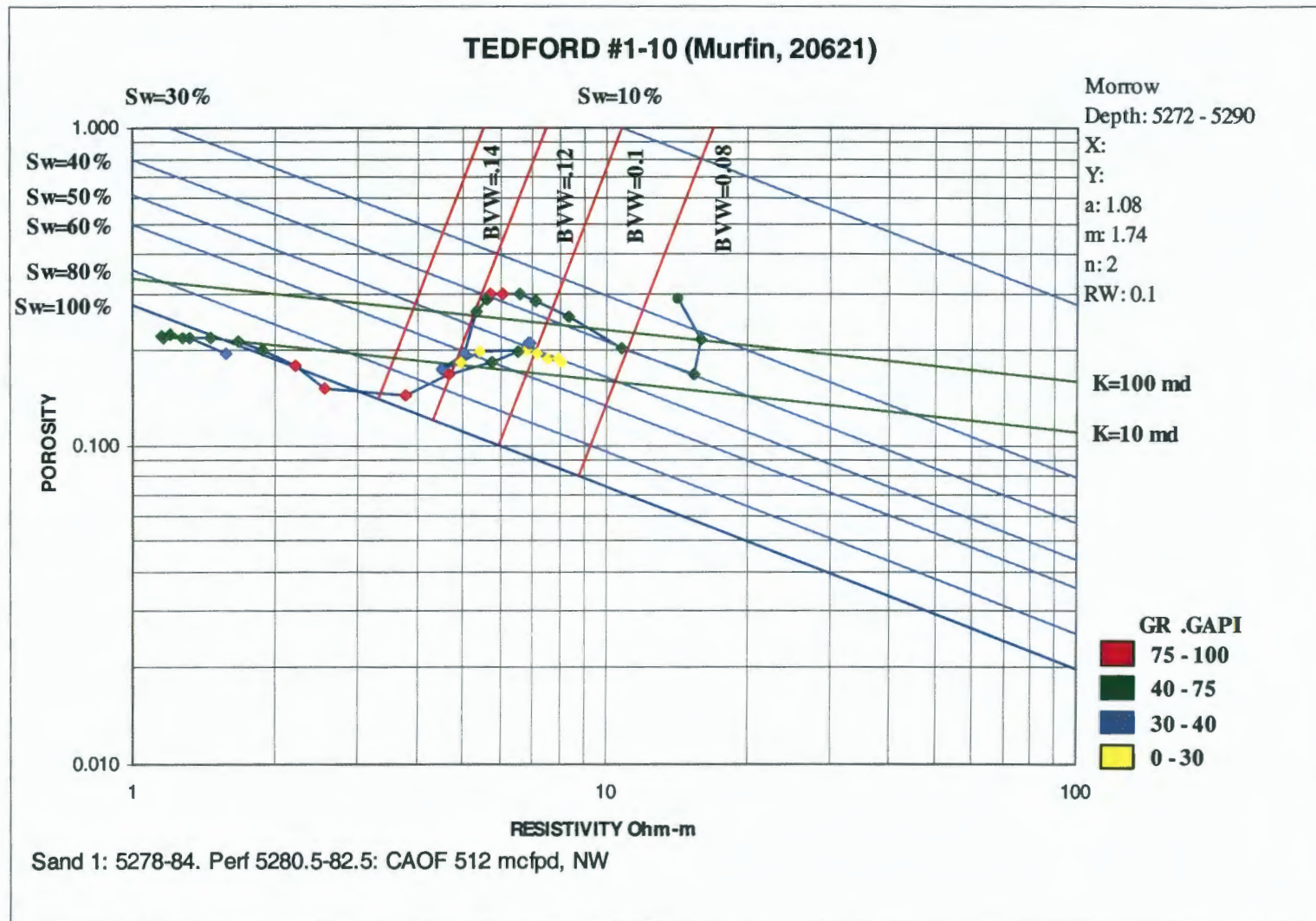


Figure C48

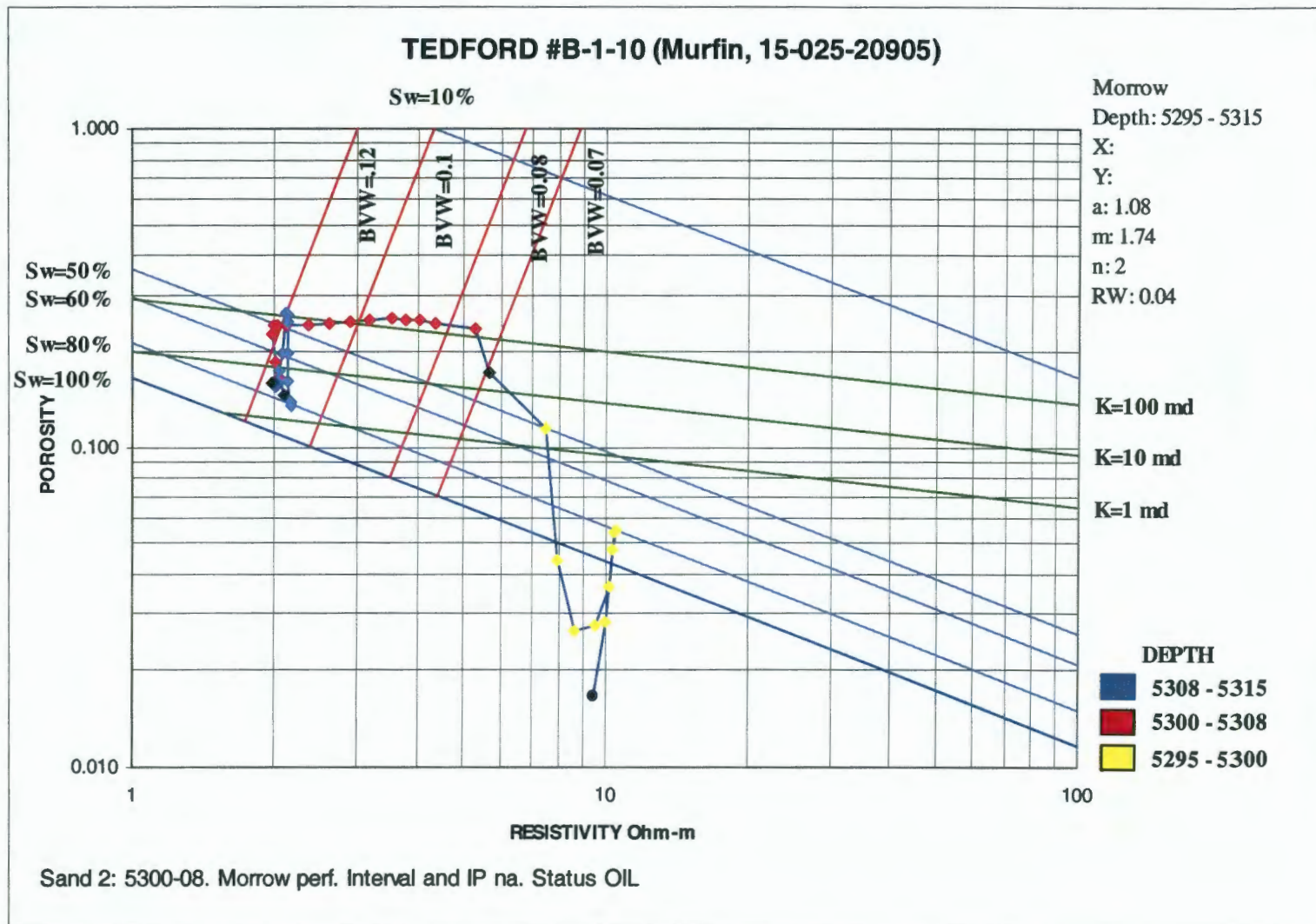


Figure C49

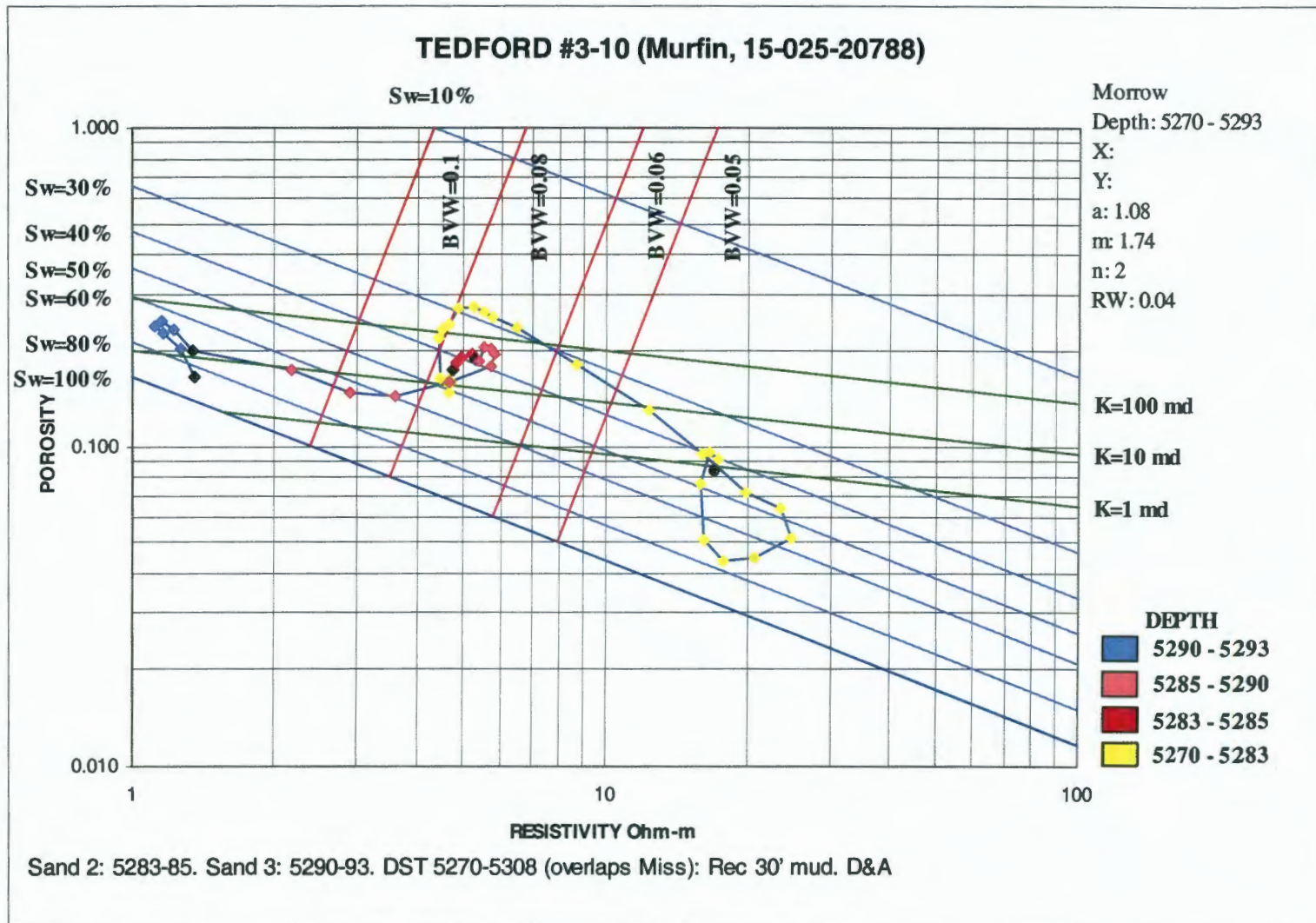


Figure C51

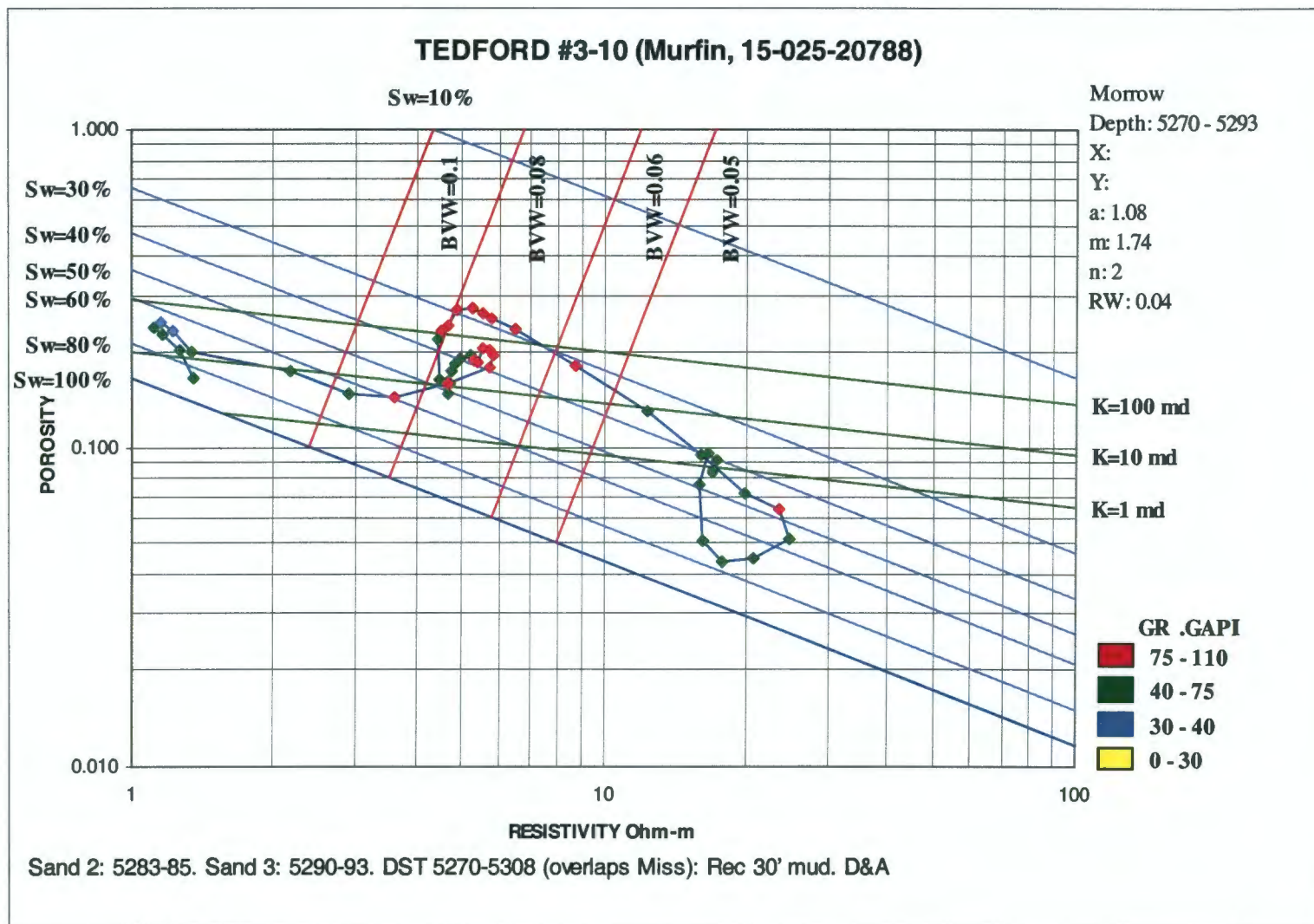


Figure C52

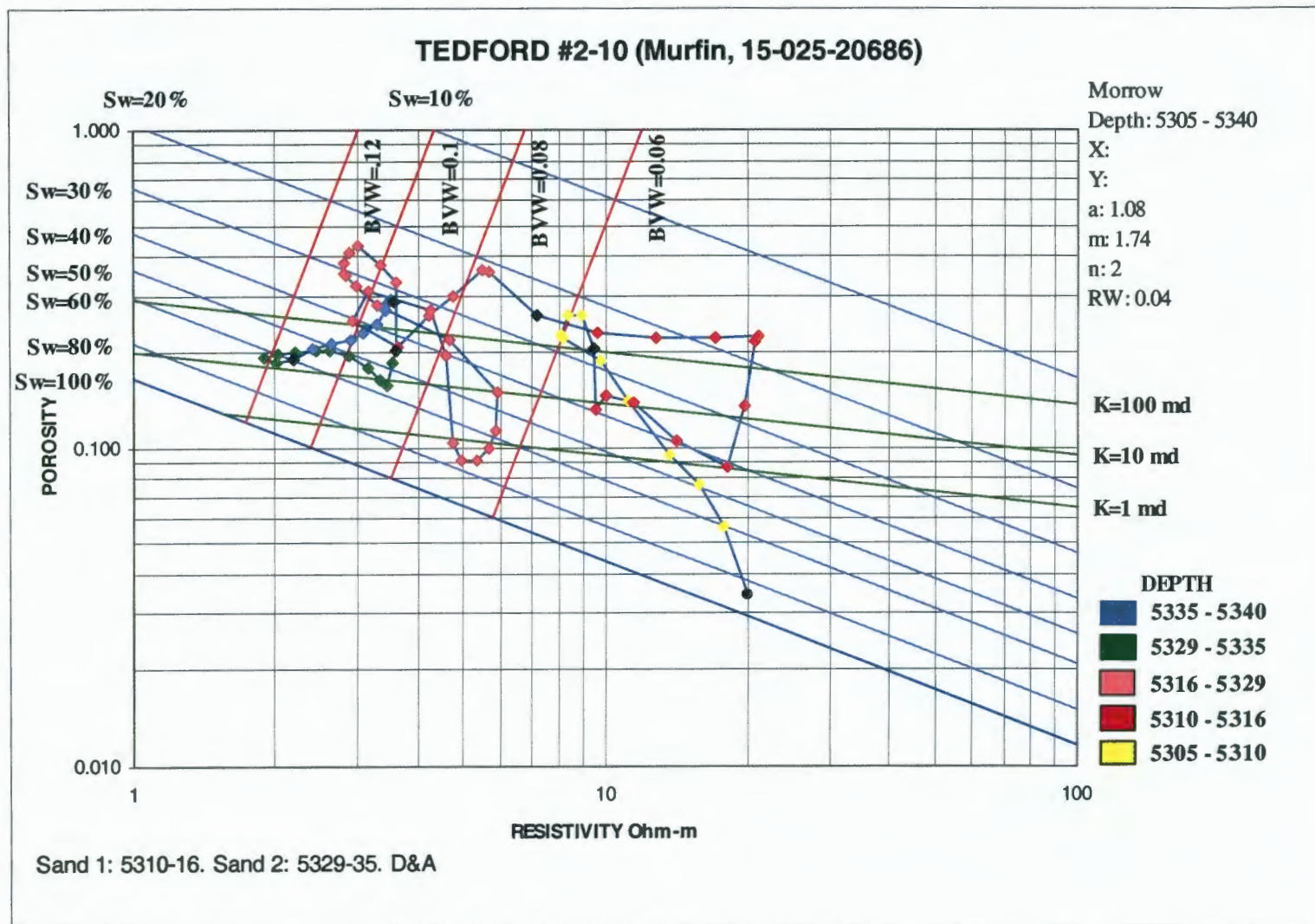


Figure C53

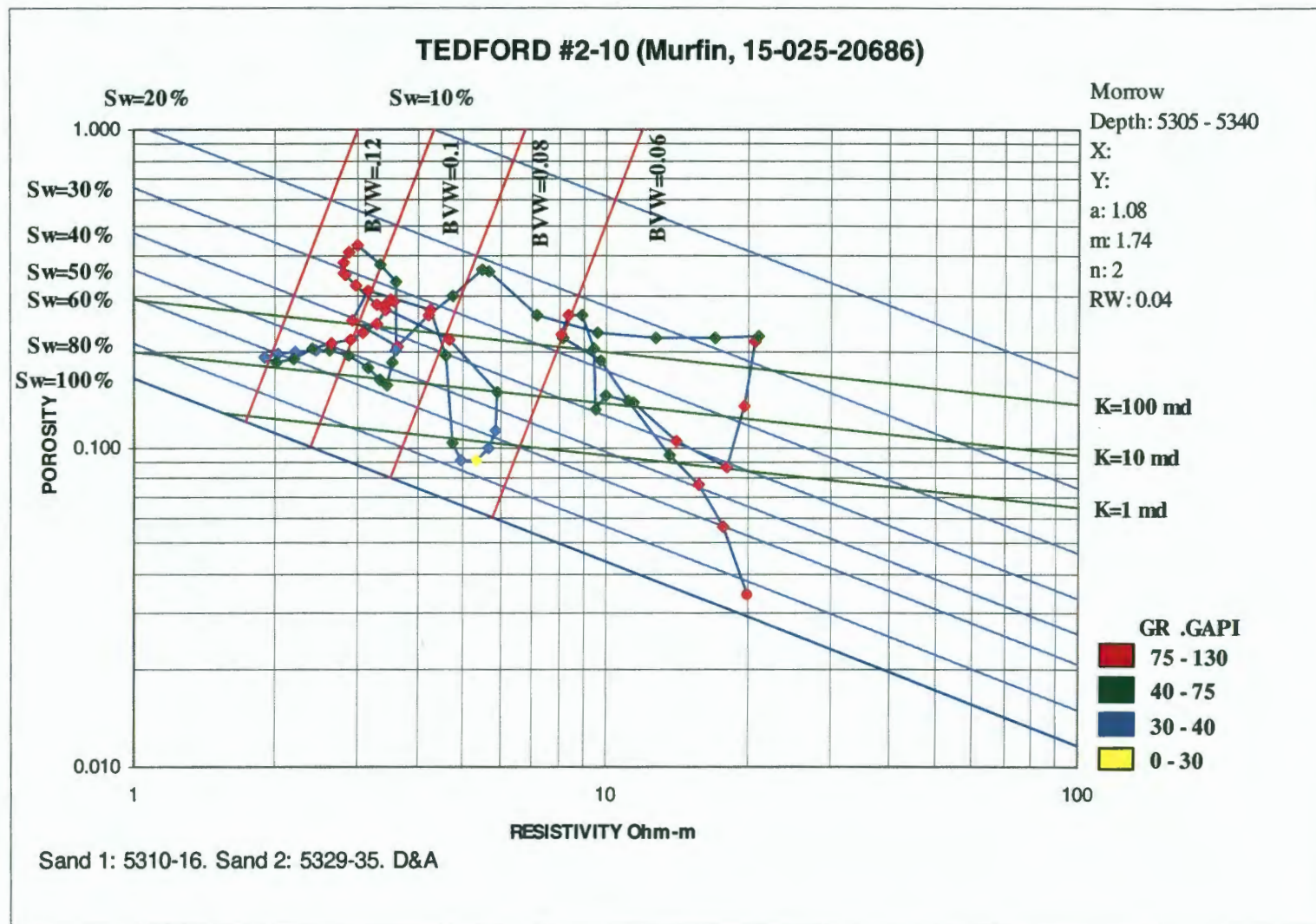


Figure C54

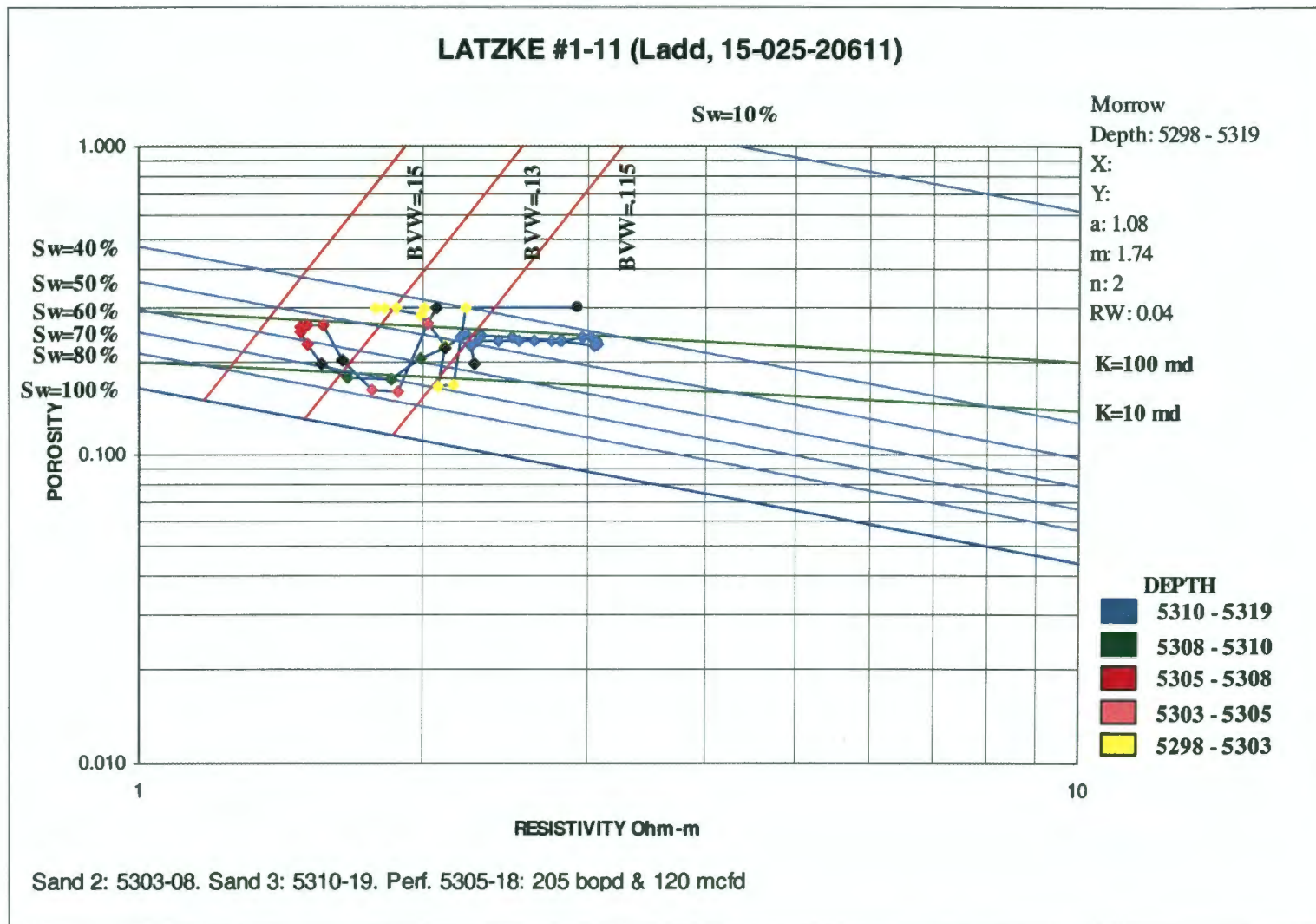


Figure C55

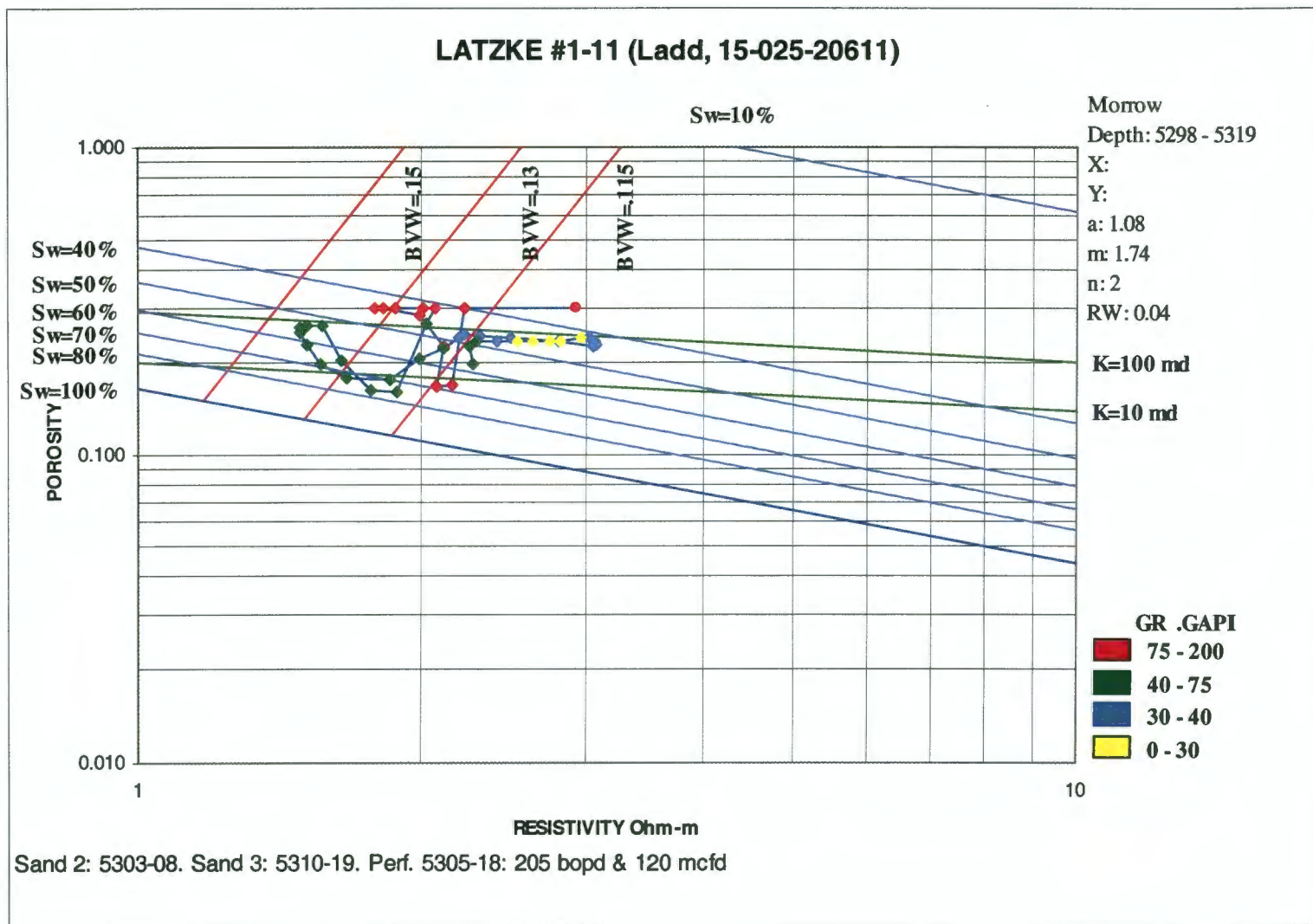


Figure C56

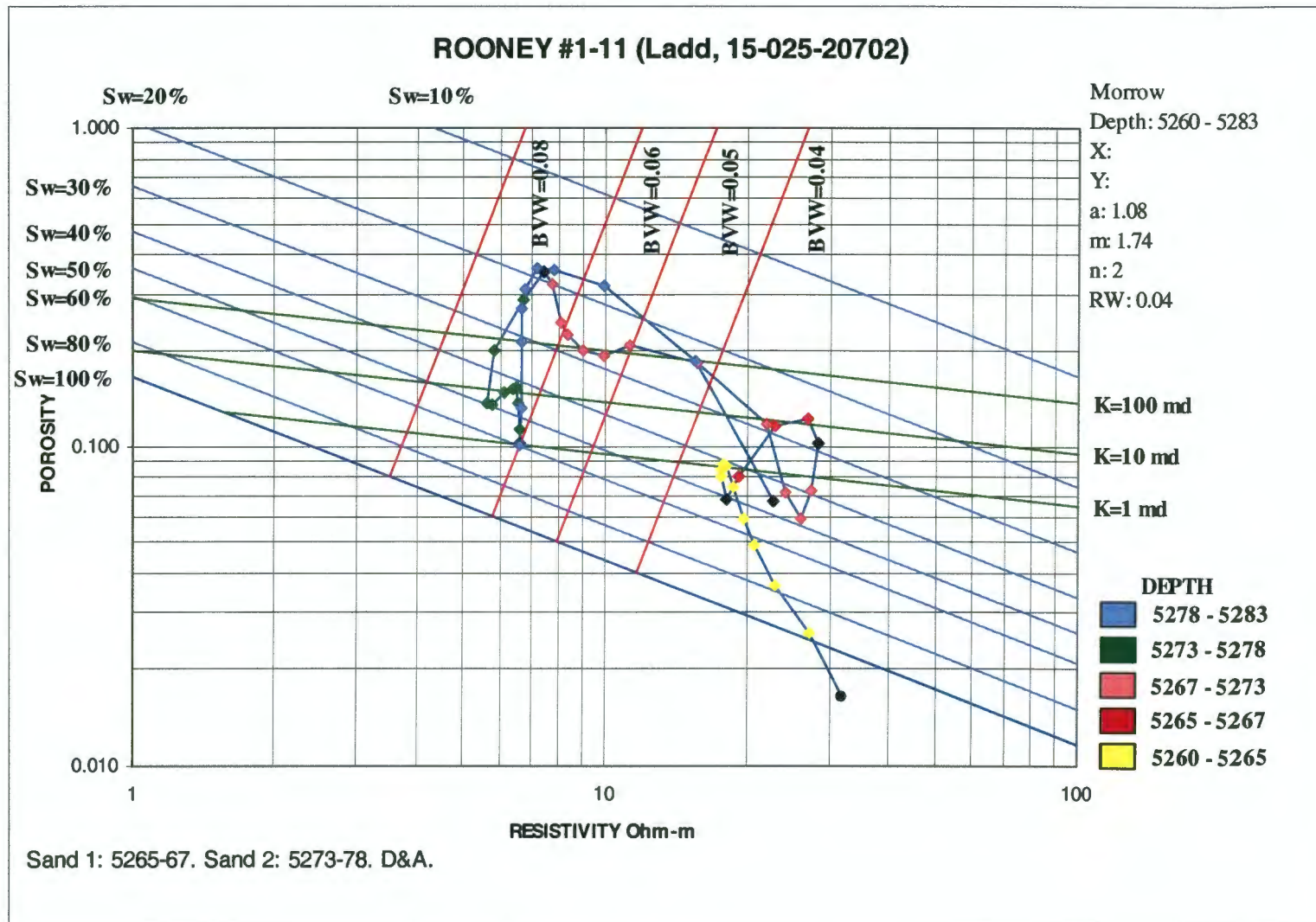


Figure C57

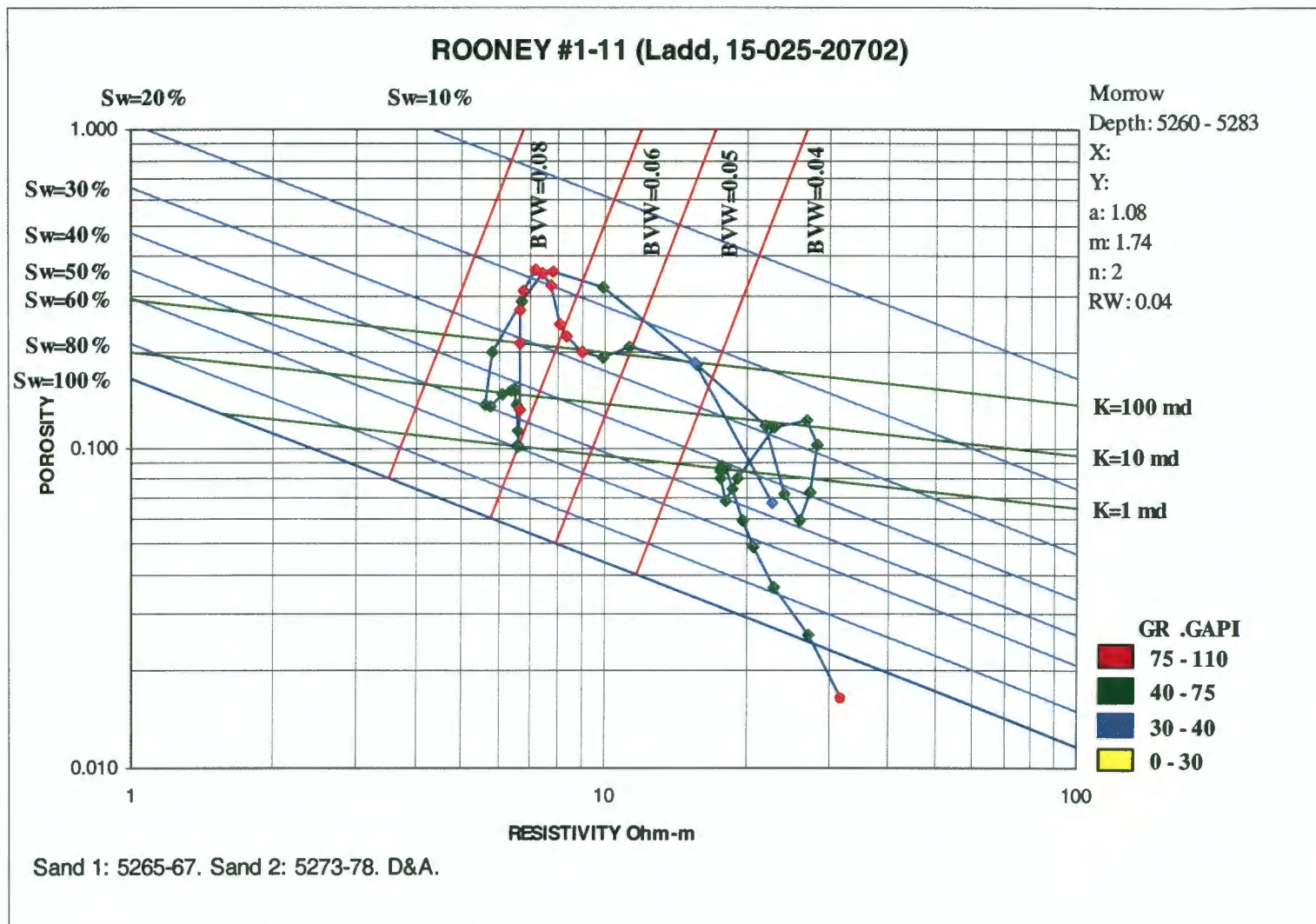


Figure C58

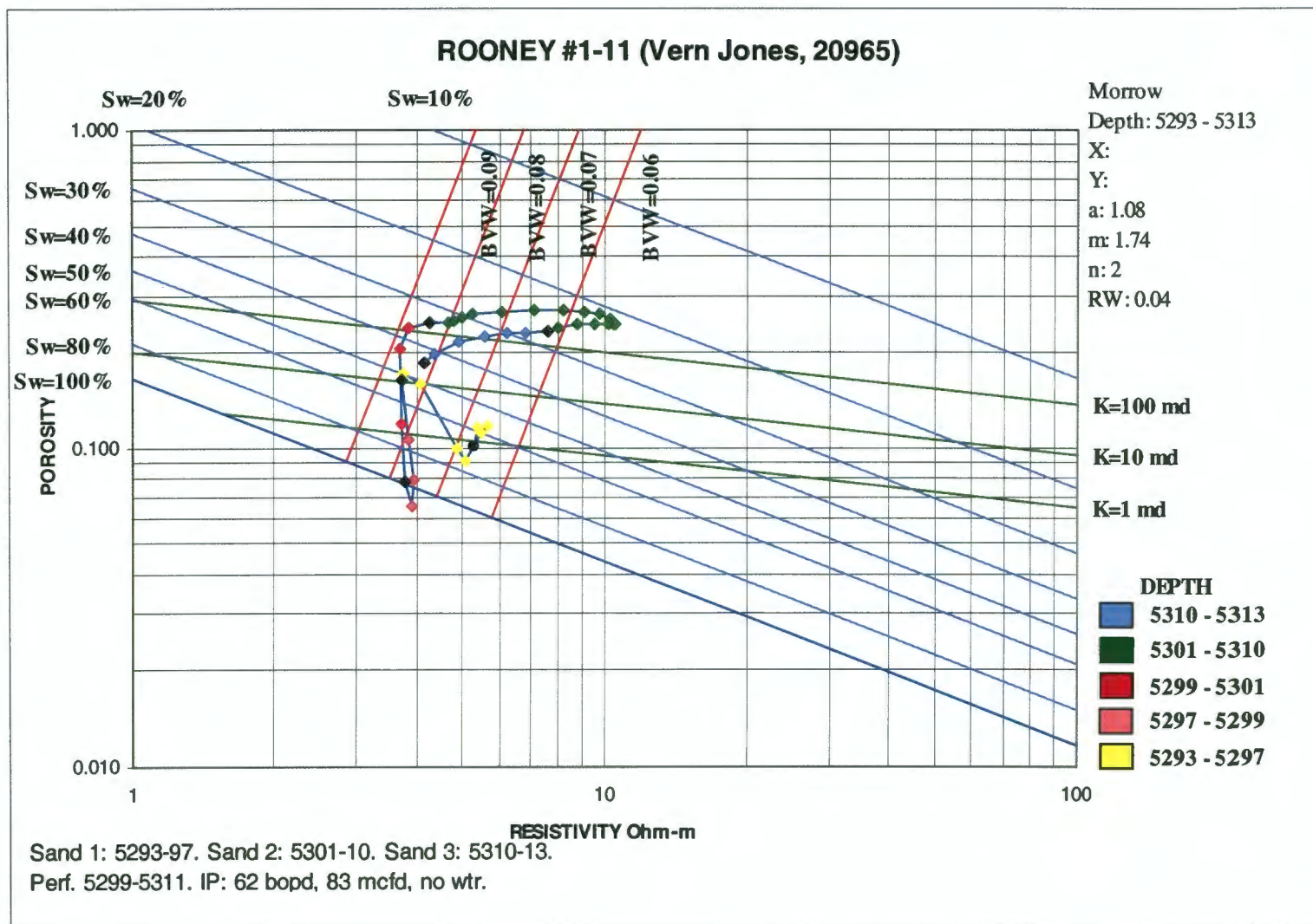


Figure C59

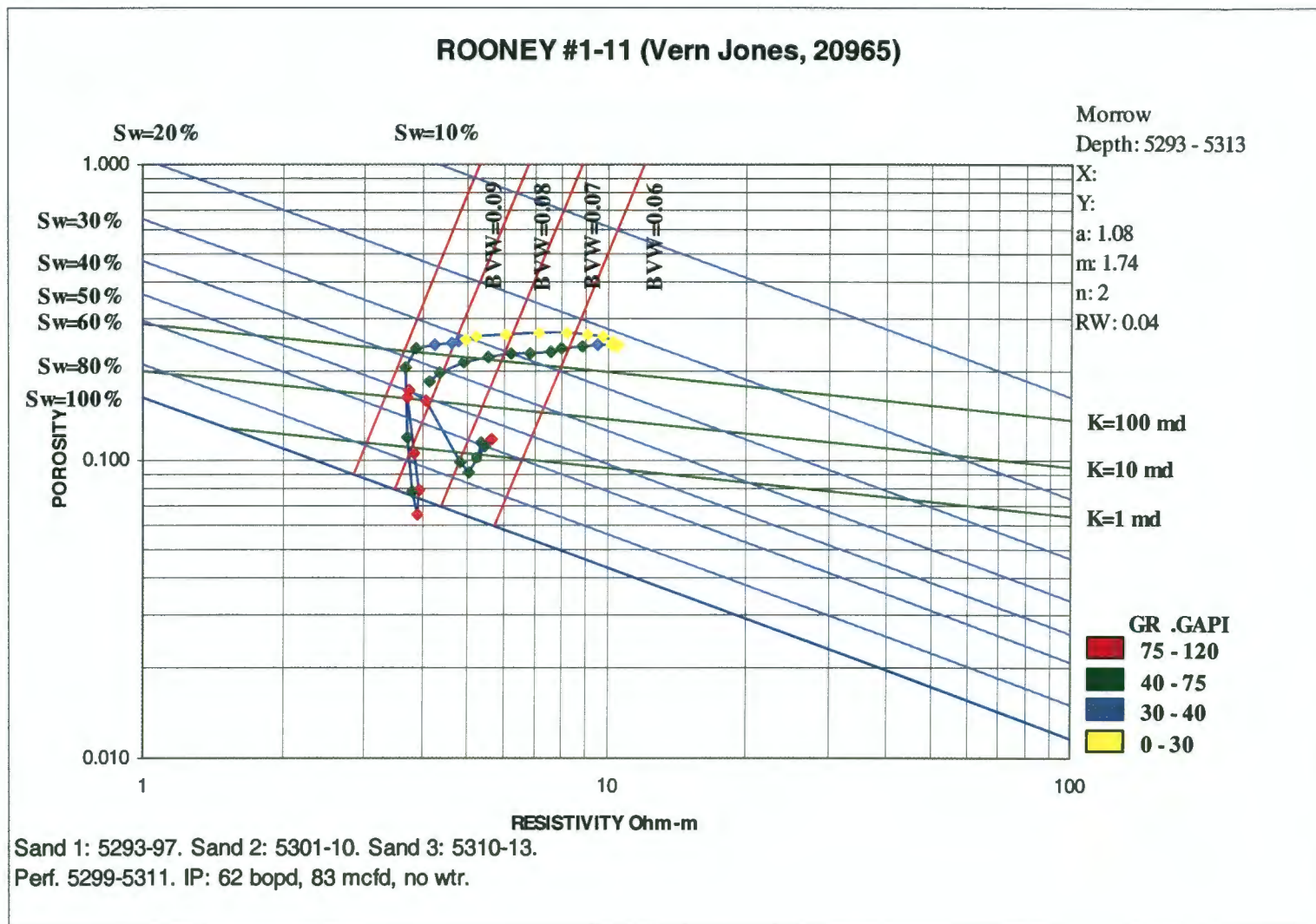


Figure C60

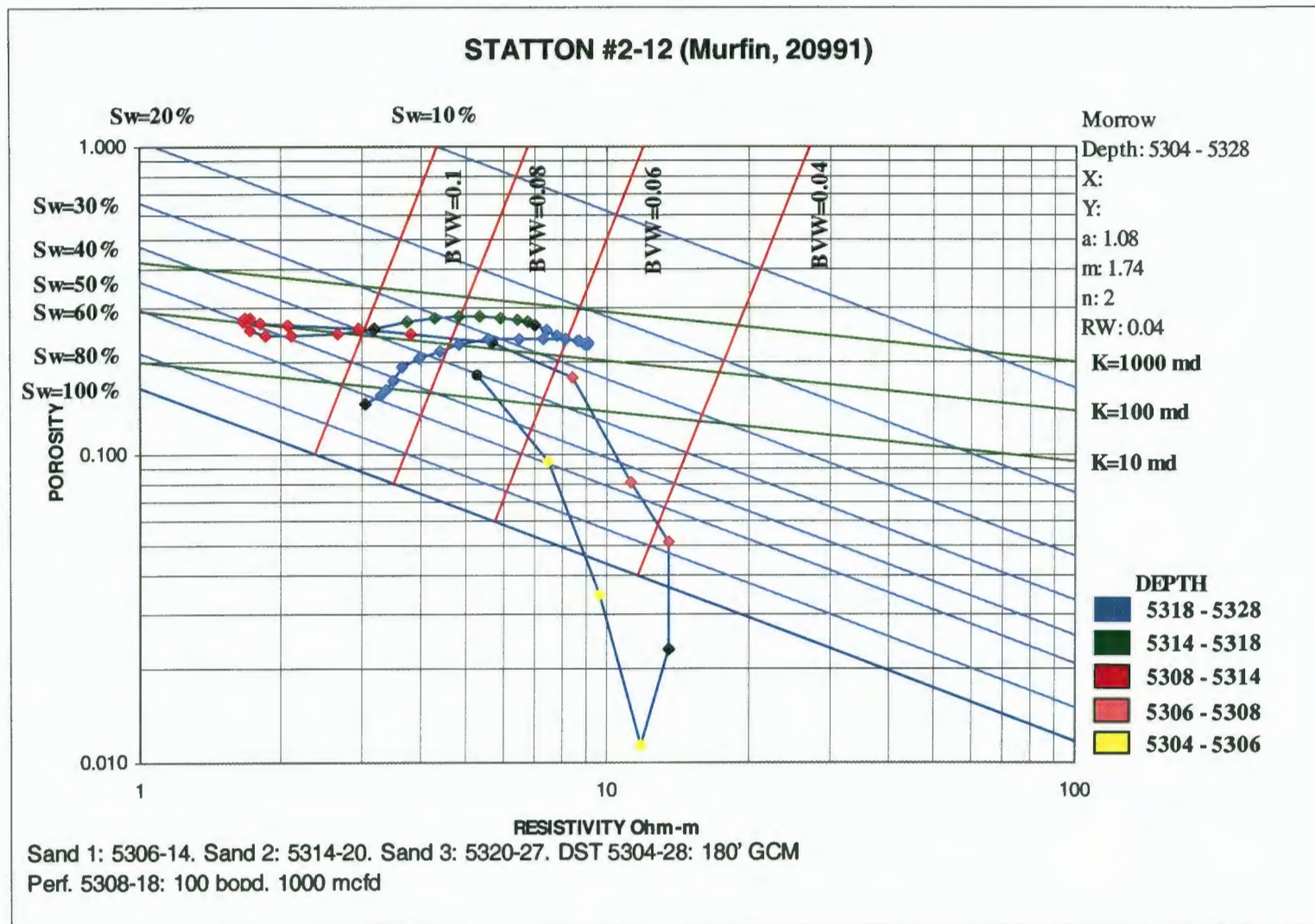


Figure C61

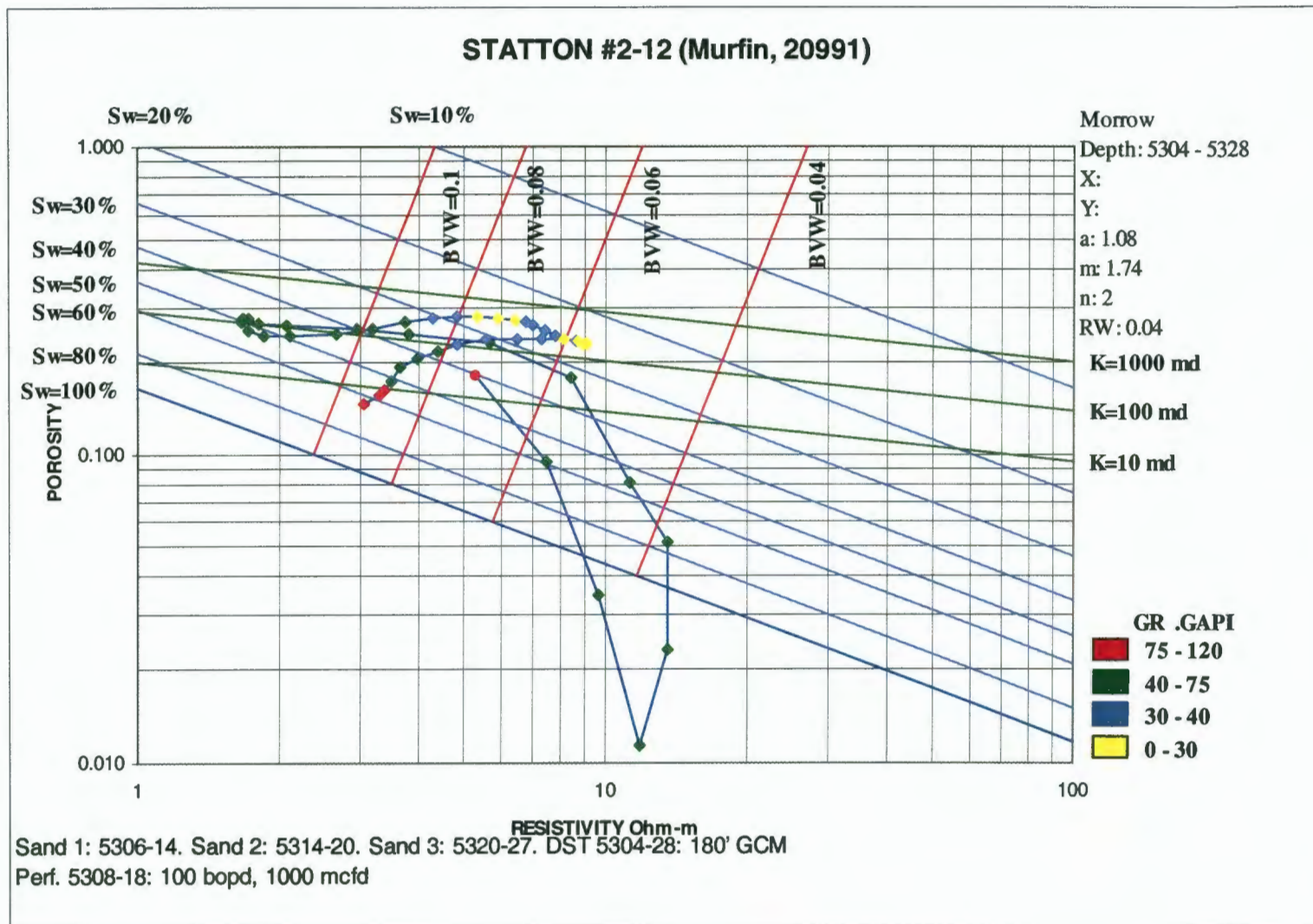


Figure C62

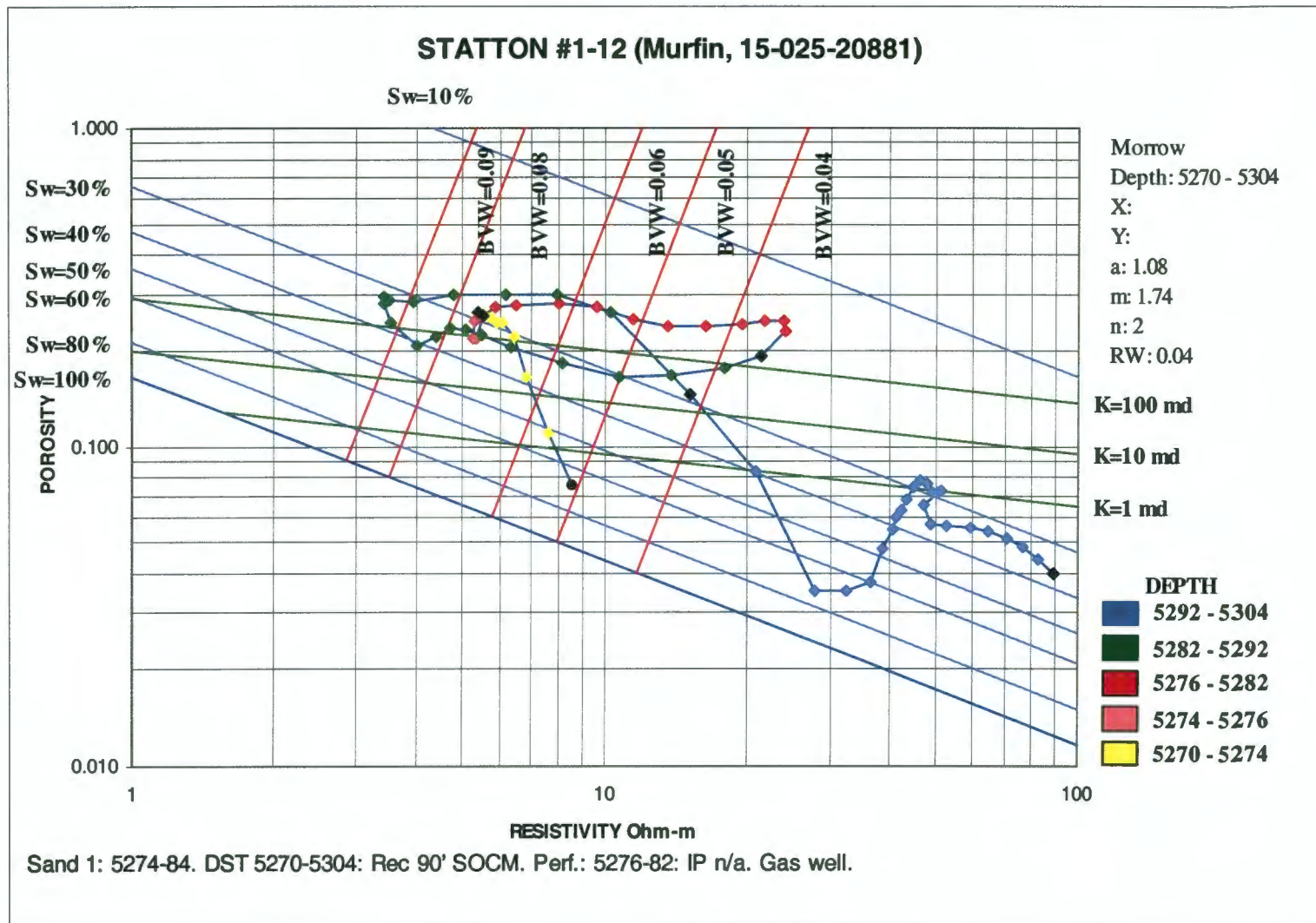


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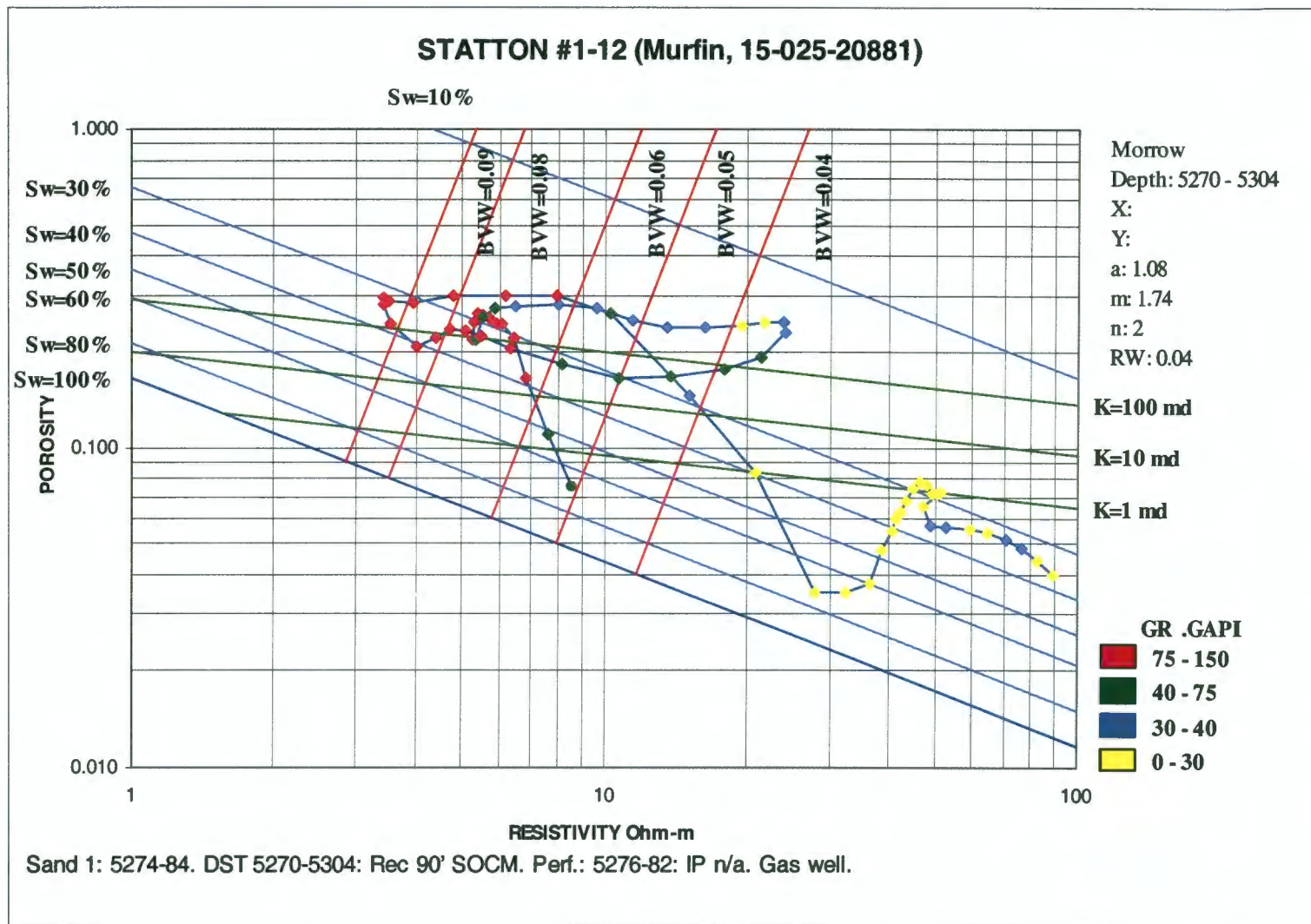


Figure C64

APPENDIX D

Table D1

Projected reservoir pressure @ June 1982	1880 psi
Rock compressibility – at 1880 psi	
Layer 1	$4.951 \times 10^{-6} \text{ psi}^{-1}$
Layer 2	$3.174 \times 10^{-6} \text{ psi}^{-1}$
Layer 3	$1.972 \times 10^{-6} \text{ psi}^{-1}$
Reservoir temperature (average)	124°F
Water salinity	2.5%
Water compressibility (124°F and 2000 psi)	$2.8 \times 10^{-6} \text{ psi}^{-1}$
Viscosity of water at 2000 psi	0.702 cp
Pressure dependence of water viscosity	0.000108 cp/psi
Water density (reservoir conditions)	67.52 lb/ft ³
Water formation volume factor	1.01 @ 124°F & 2000 psi
Maximum reservoir pressure	2000 psi
Oil density (reservoir temperature & pressure)	43.99 lb/ft ³
Gas gravity (@ 60°F, 30" Hg, dry)	0.765 (Air = 1.0)
Oil phase viscosity pressure dependence	0.00004 cp/psi
Undersaturated oil compressibility	$17 \times 10^{-6} \text{ psi}^{-1}$
WOC	3000 ft (subsea)

Table D2			
Well name	API	Start date	Production history record
Latzke #1	15-025-20611	Jun-82	O&G - no gas production record - 1st 27 months
Patton #1	15-025-20594	Aug-82	O&G - no gas production record - 1st 9 months
Harris #1-3	15-025-20616	Nov-82	O&G - no gas production record - 1st 22 months
Hindman #1 (#1-3)	15-025-20635	Dec-82	O&G - no gas production record - 1st 21 months
Goeller #1-4 (Attokan)	15-025-20615	Dec-82	O&G - no gas production record - 1st 26 months
Fager #2-3 (Attokan)	15-025-20671	Mar-83	O&G - no gas production record - 1st 21 months
Patton #1-3 (C)	15-025-20668	Mar-83	O&G - no gas production record 1st 10 months. Production commingled with #2-3
Tedford #1	15-025-20416	Mar-83	Gas well - oil recorded for 1 month
Patton #2-3 (C)	15-025-20685	May-83	O&G - no gas production record 1st 10 months. Production commingled with #1-
Harris #2-3	15-025-20708	Jul-83	Oil well - no gas
Tedford #2-10	15-025-20669	Aug-83	O&G - no gas production record - 1st 28 months
Schlichting #1-2	15-025-20703	Jan-84	Gas well - with oil. O&G record from start
Tedford #4-10 (C)	15-025-20720	Feb-84	O&G - no gas production record - 1st 5 months. Production commingled with #1-1
Tedford #1-10 (C)	15-025-20621	Feb-84	O&G - no gas production record - 1st 5 months. Production commingled with #1-1
Hall #1-2	15-025-20785	Jun-84	O&G - no gas production record - 1st 2 months
Goeller #1-4	15-025-20858	Jan-85	O&G - no gas production record - 1st 2 months
Norton #1-4	15-025-20890	Apr-85	O&G - no gas production record - 1st 1 months
Tedford #B1-10	15-025-20905	Aug-85	Oil well - no gas
Statton #1-12 (C)	15-025-20881	Dec-85	O&G - commingled with #1-12
Rooney #1	15-025-20965	Jan-87	O&G - no gas production record - 1st 5 months
Statton #2-12 (C)	15-025-20991	Jun-87	Significant oil contributor - commingled with #1-12

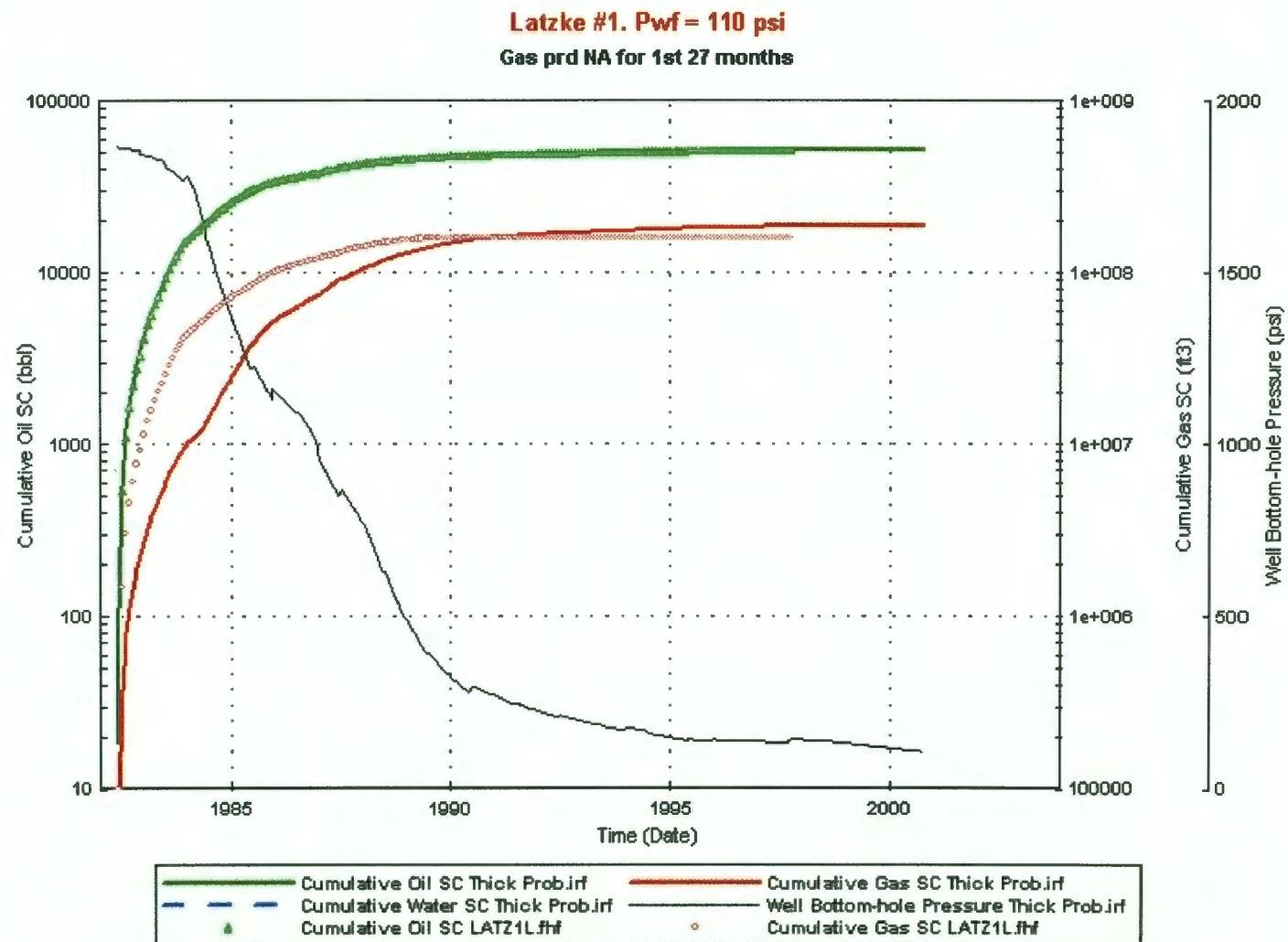


Figure D1

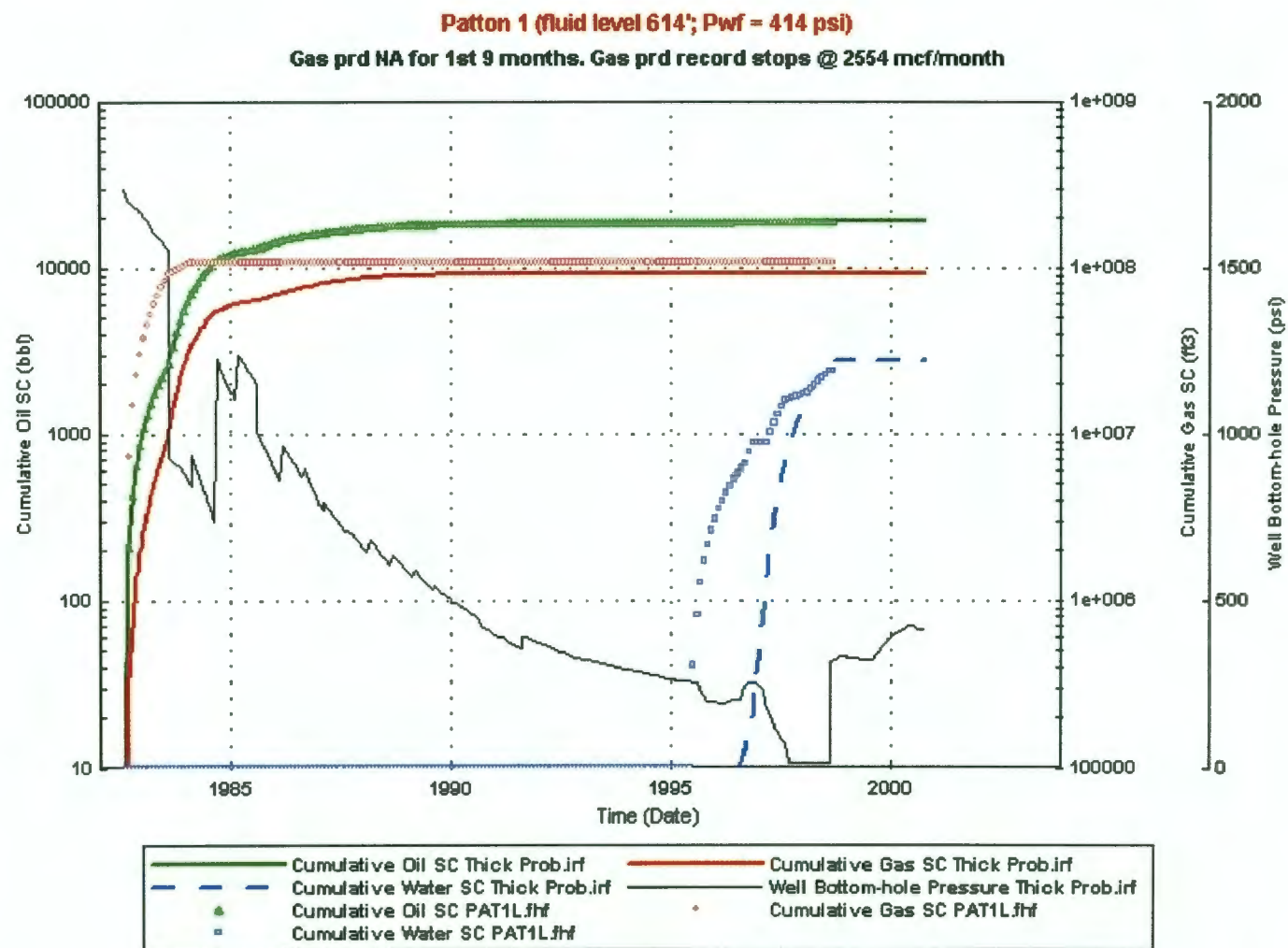


Figure D2

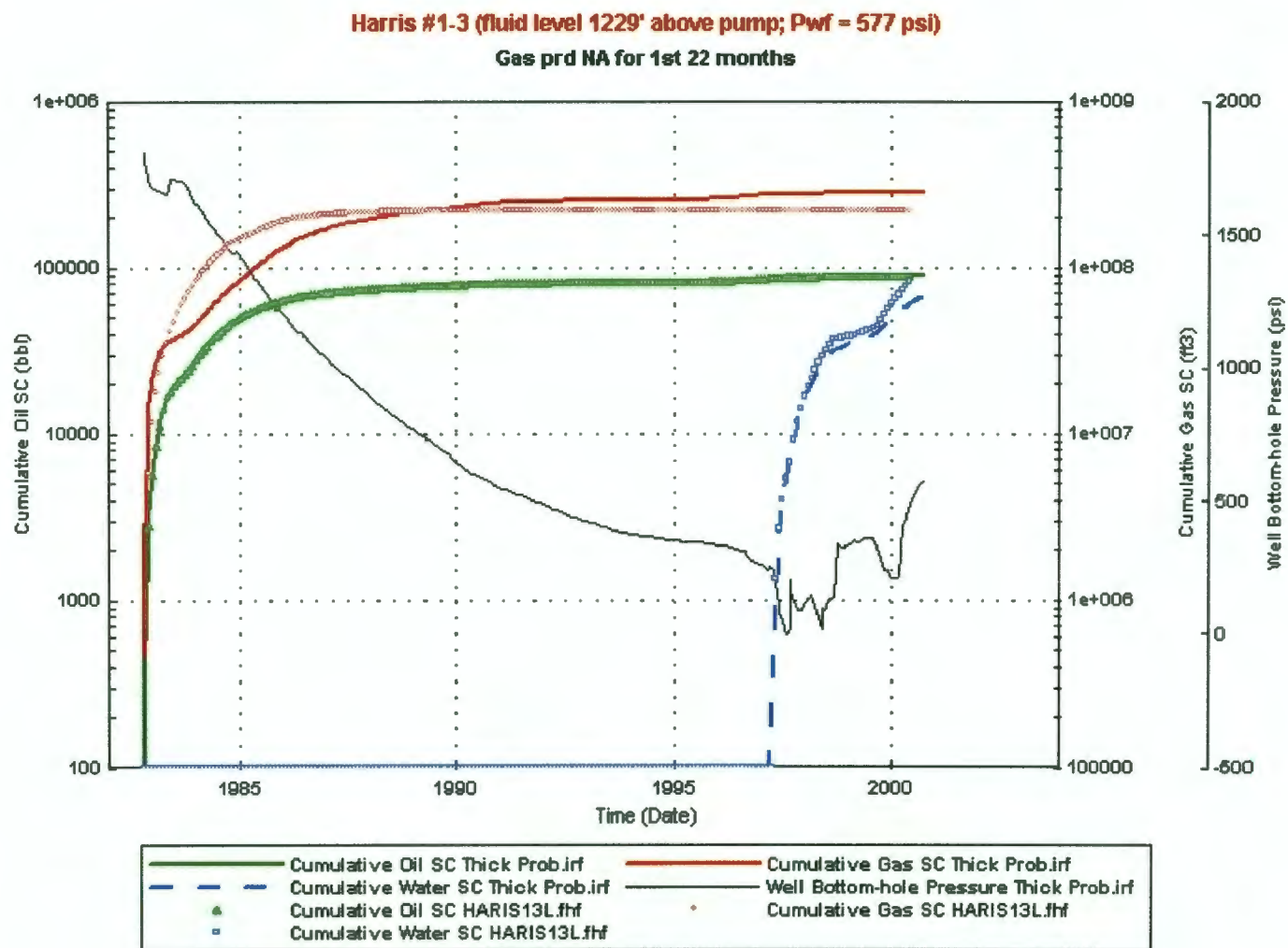


Figure D3

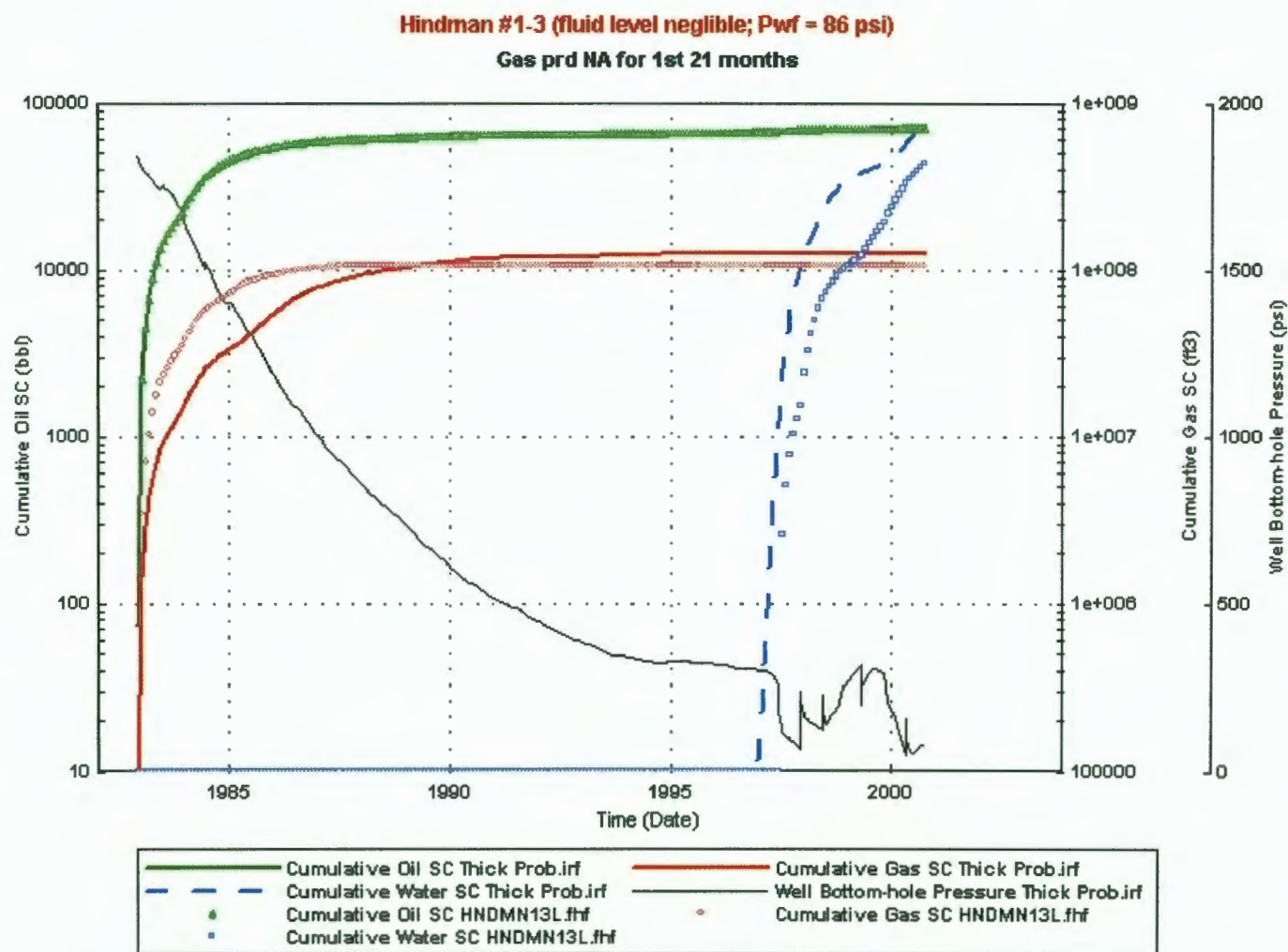


Figure D4

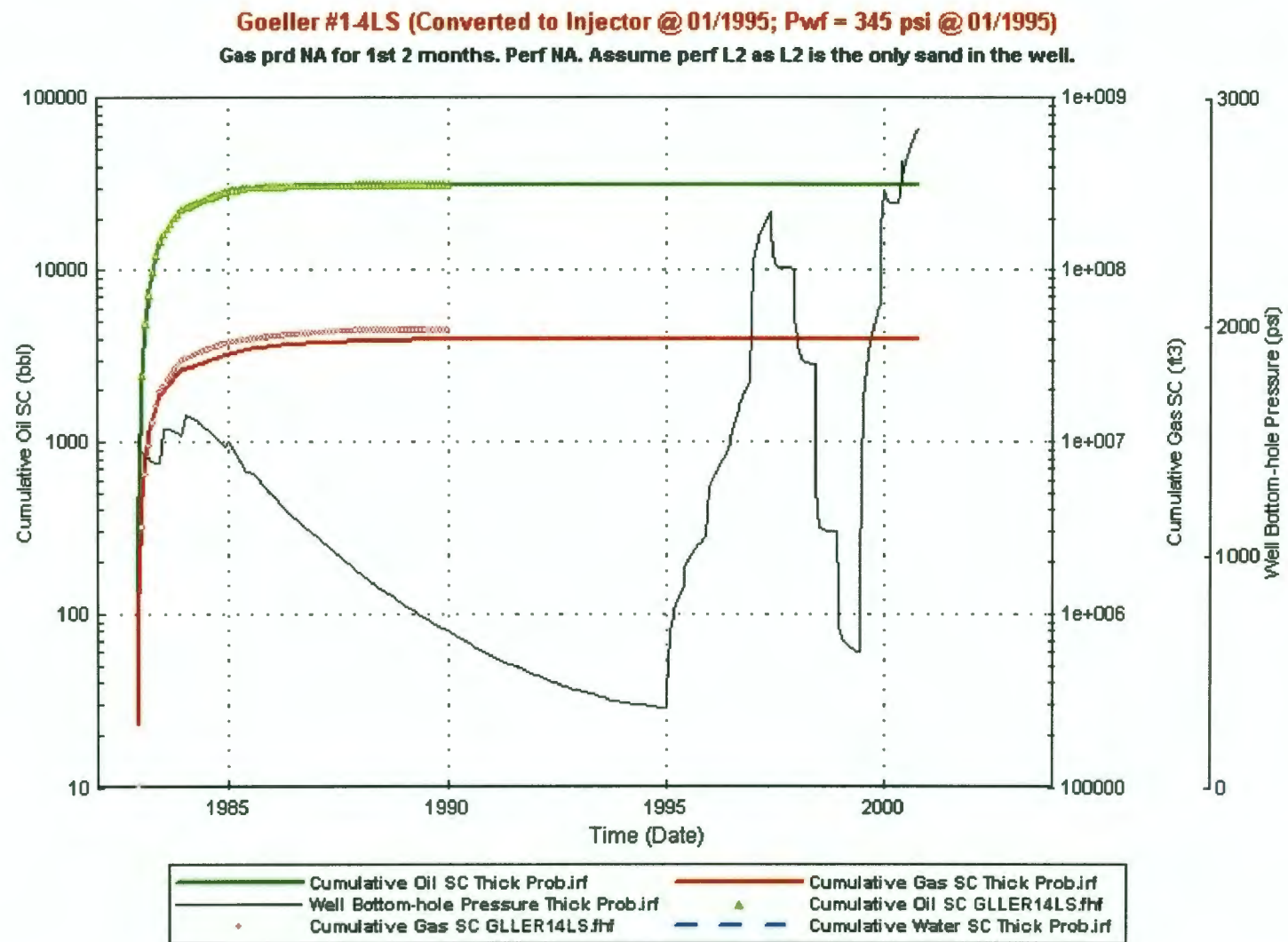


Figure D5

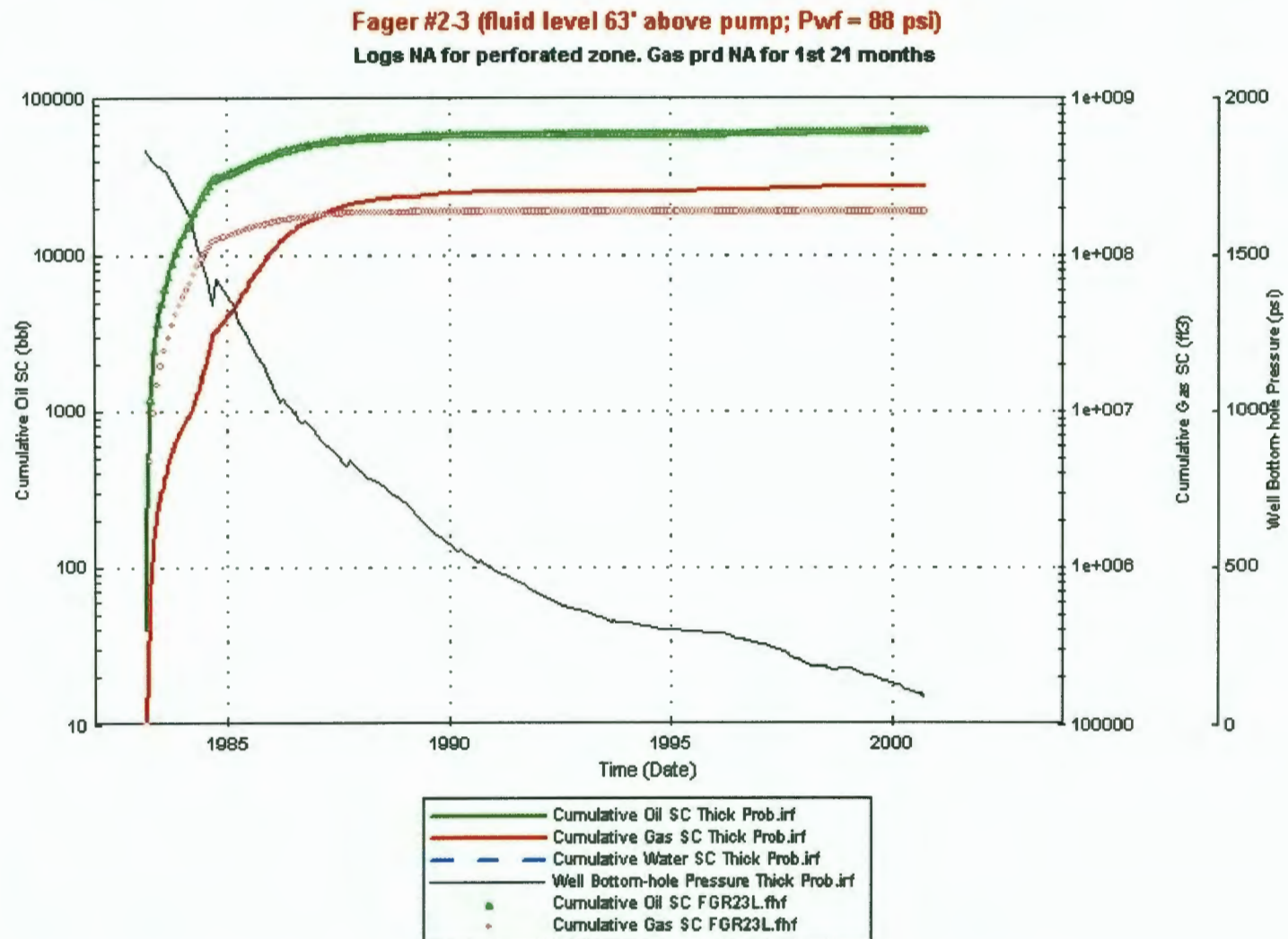


Figure D6

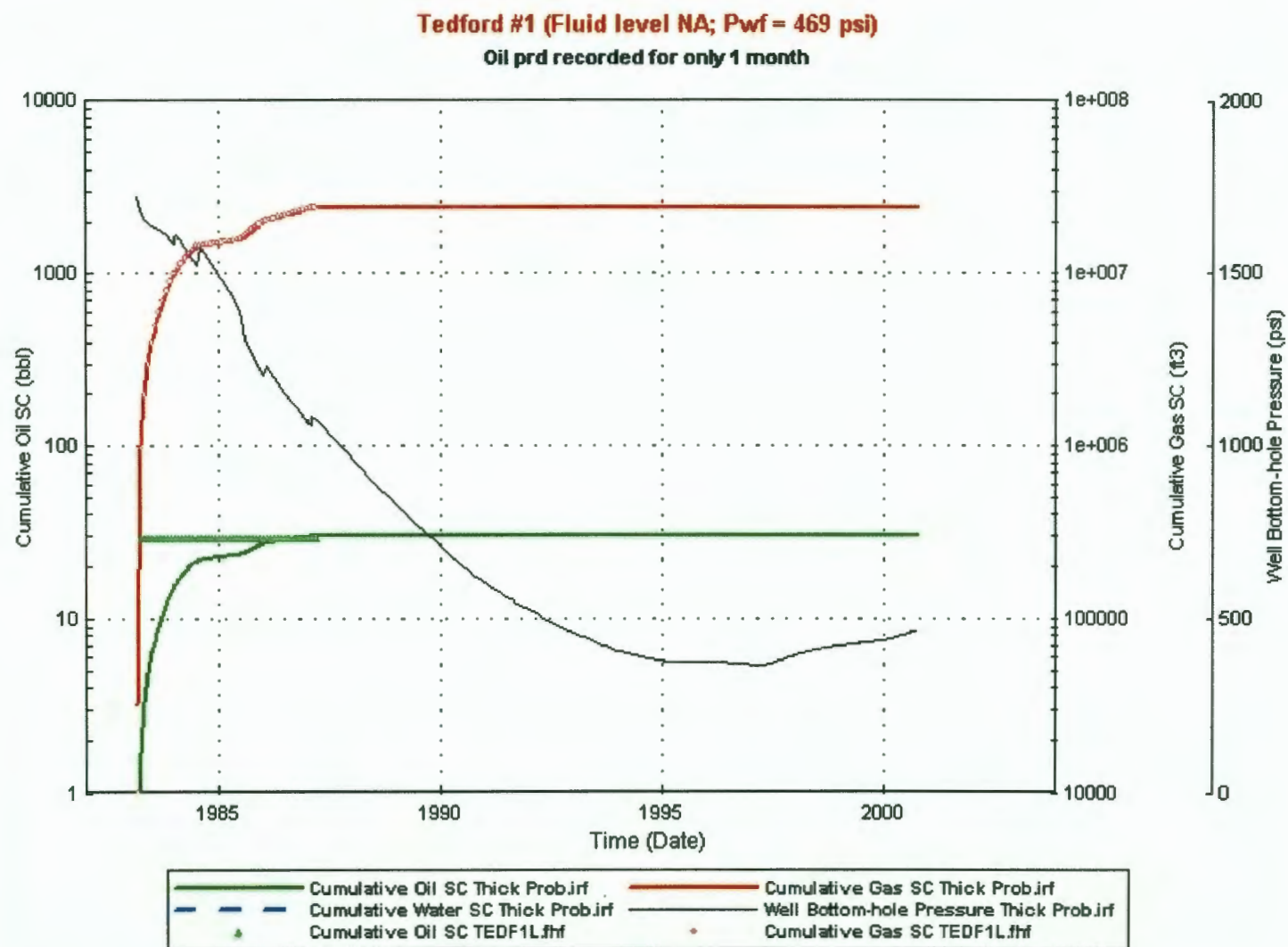


Figure D7

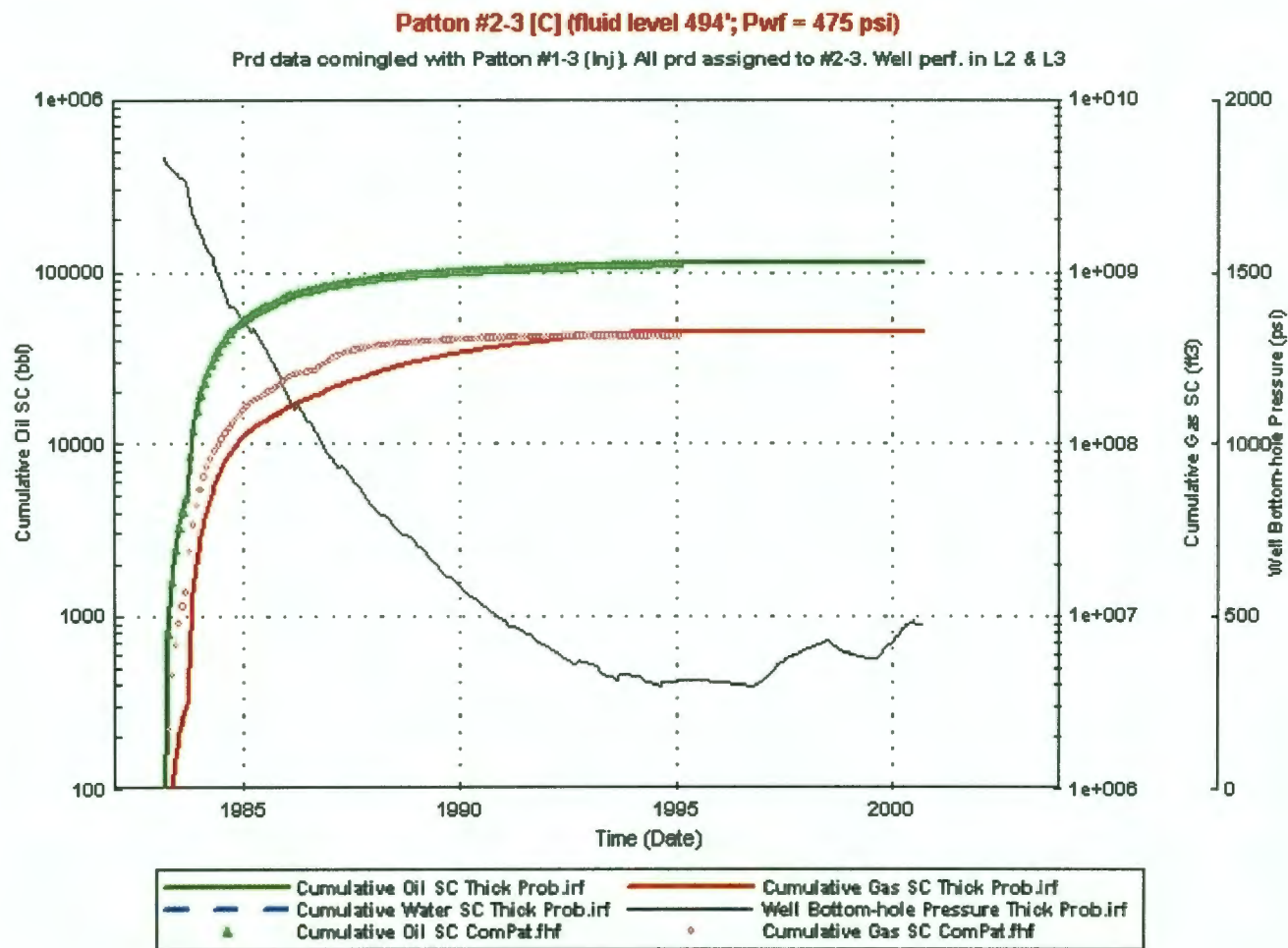


Figure D8

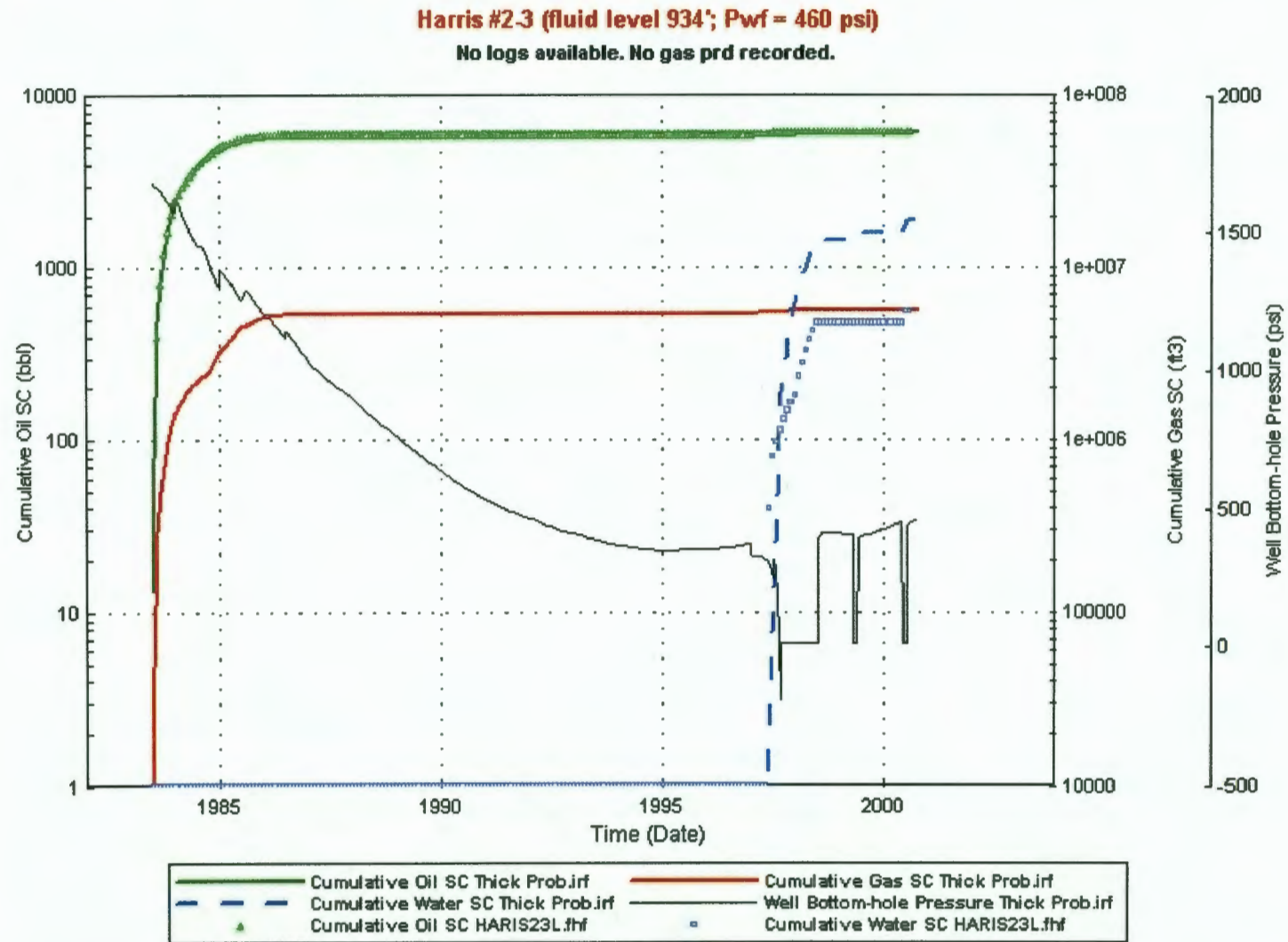


Figure D9

Tedford #2-10 (Fluid level 33' @ 10/2000; Pwf = 14.7 psi @ 08/2000 - when well shut-in)
Gas prd NA for 1st 28 months. Perf also in lower zone 5353-62 (Miss) - contribution NA.

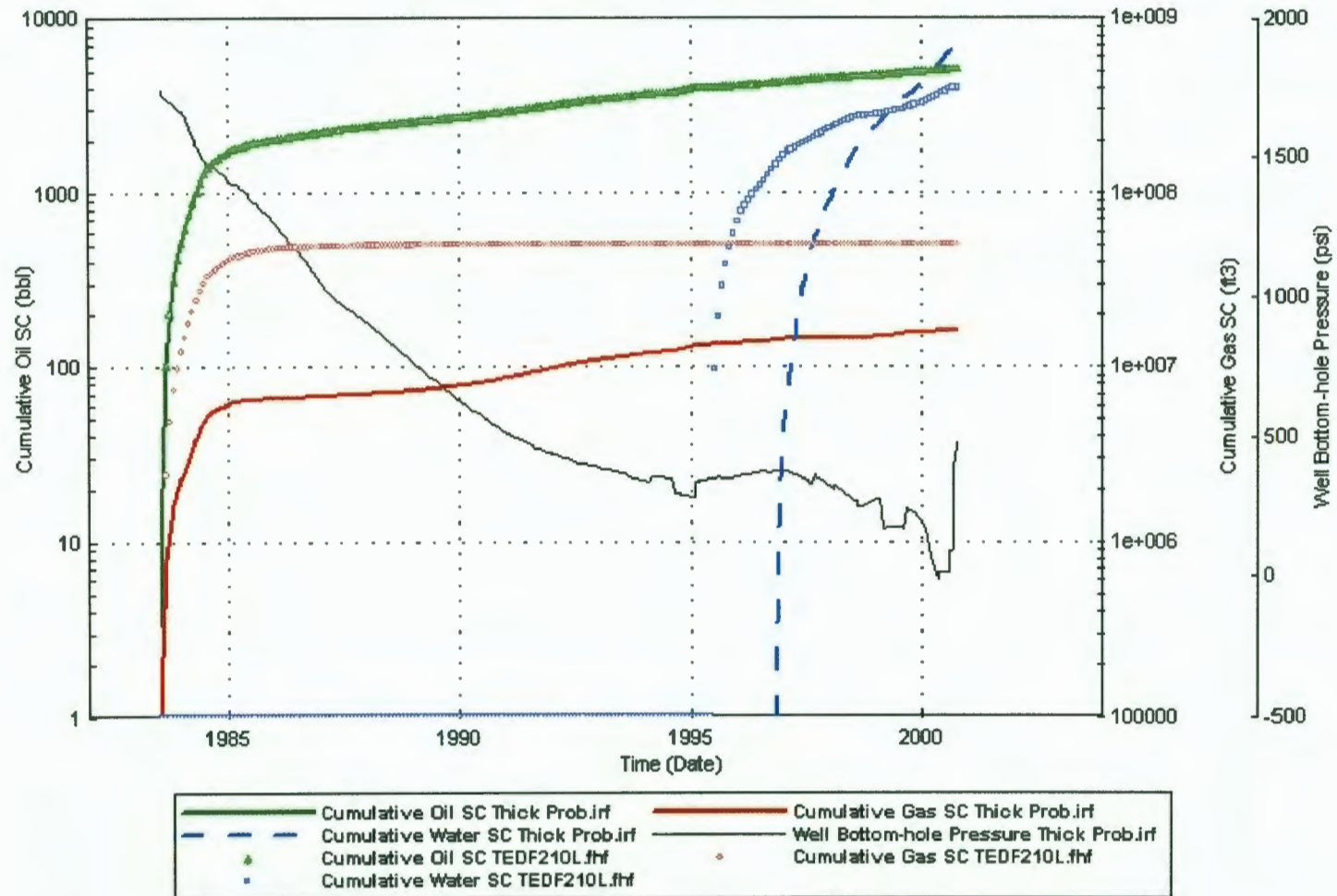


Figure D10

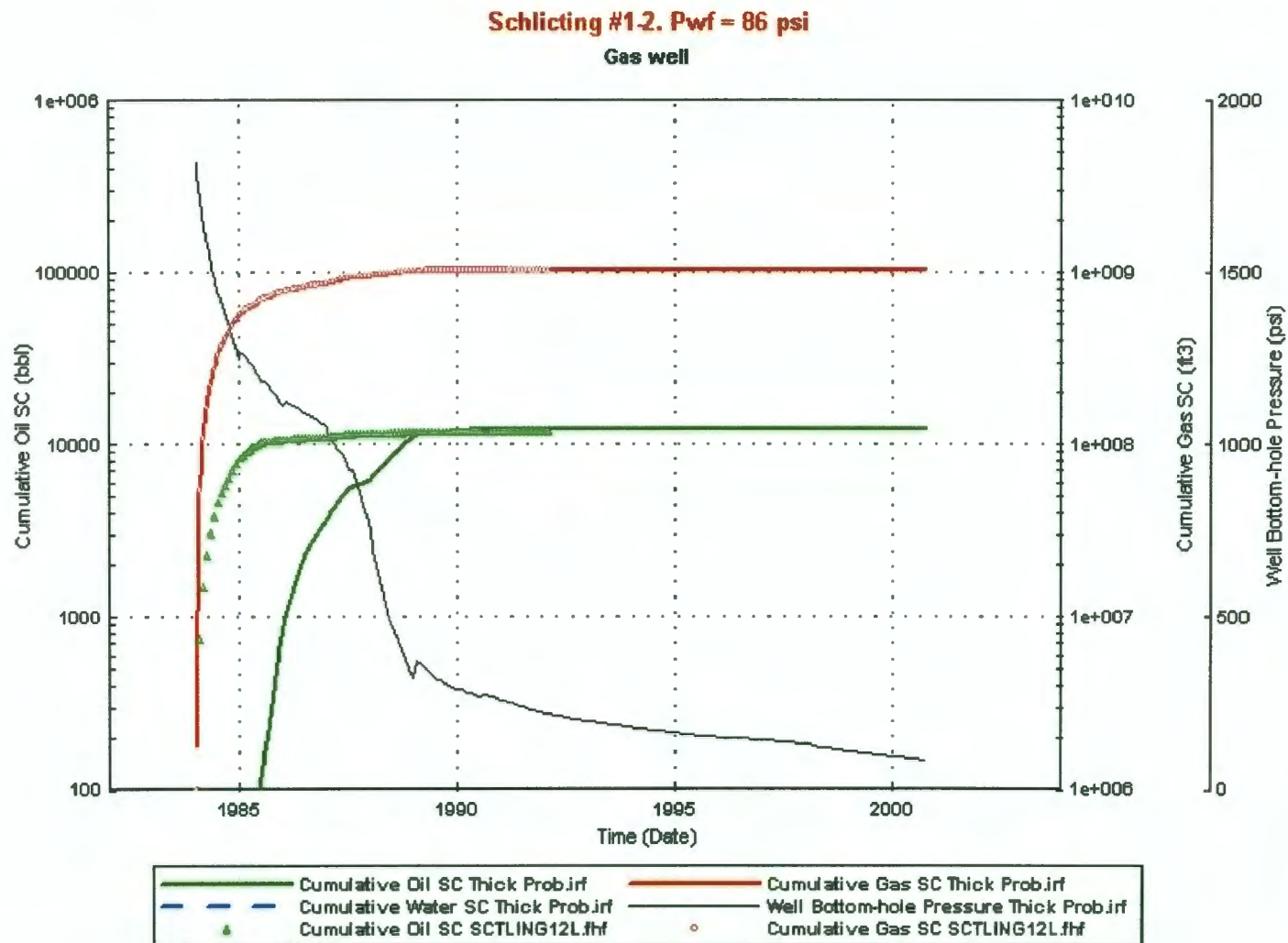


Figure D11

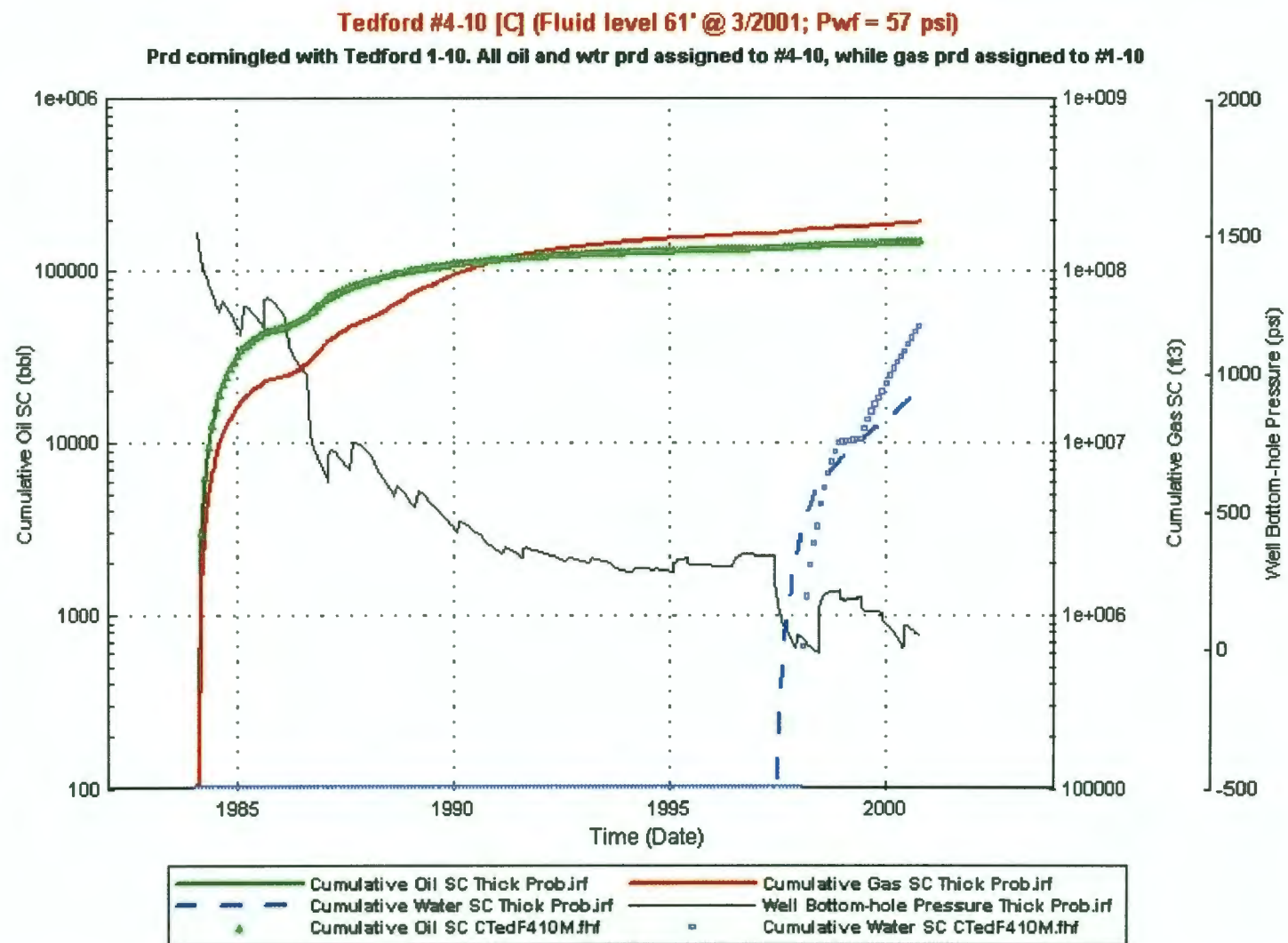


Figure D12

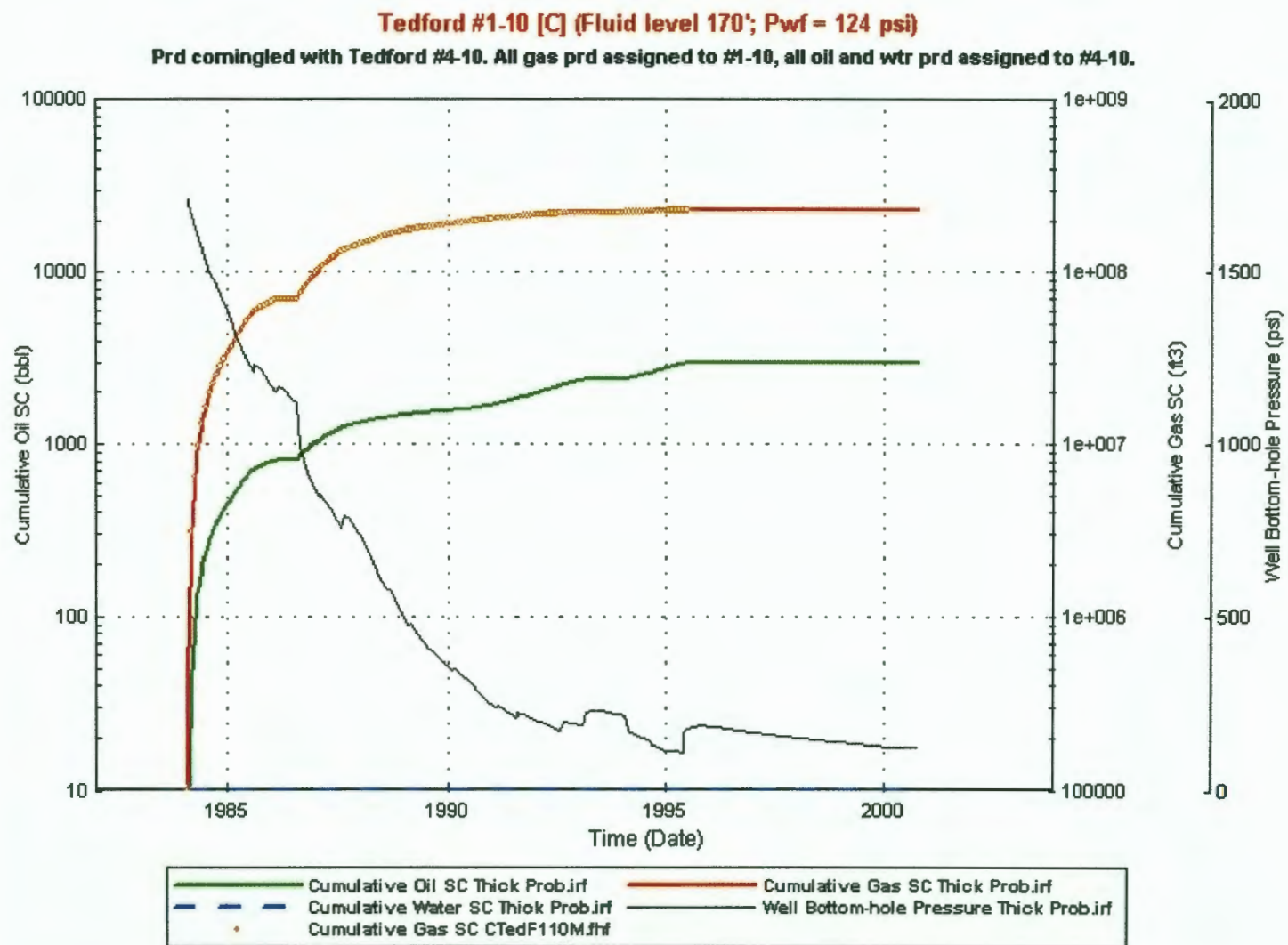


Figure D13

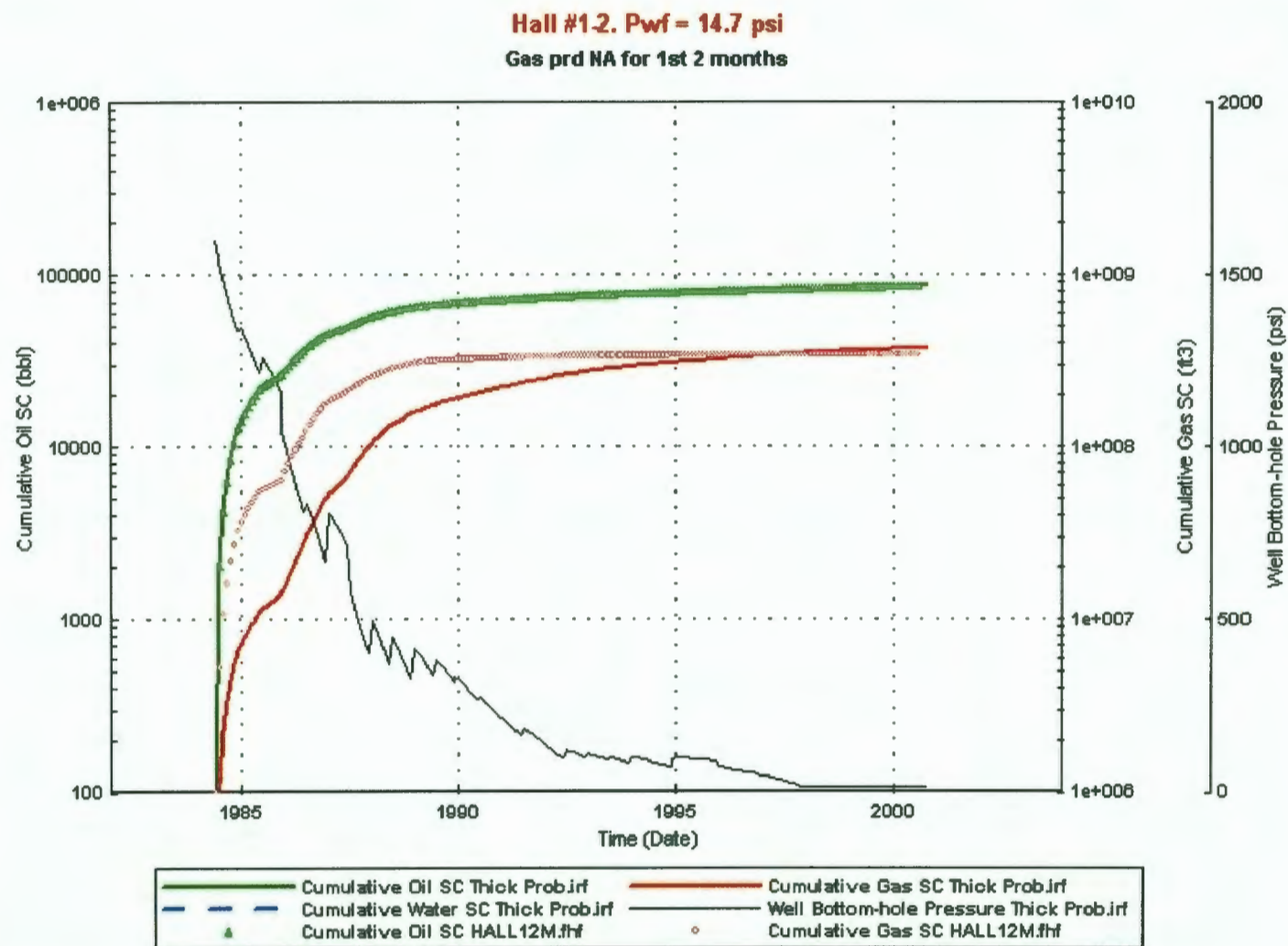


Figure D14

Goeller #1-4M (fuid level 09/2000 was 808'; Pwf = 211 psi @ 05/2000)
Gas prd NA for 1st 2 months

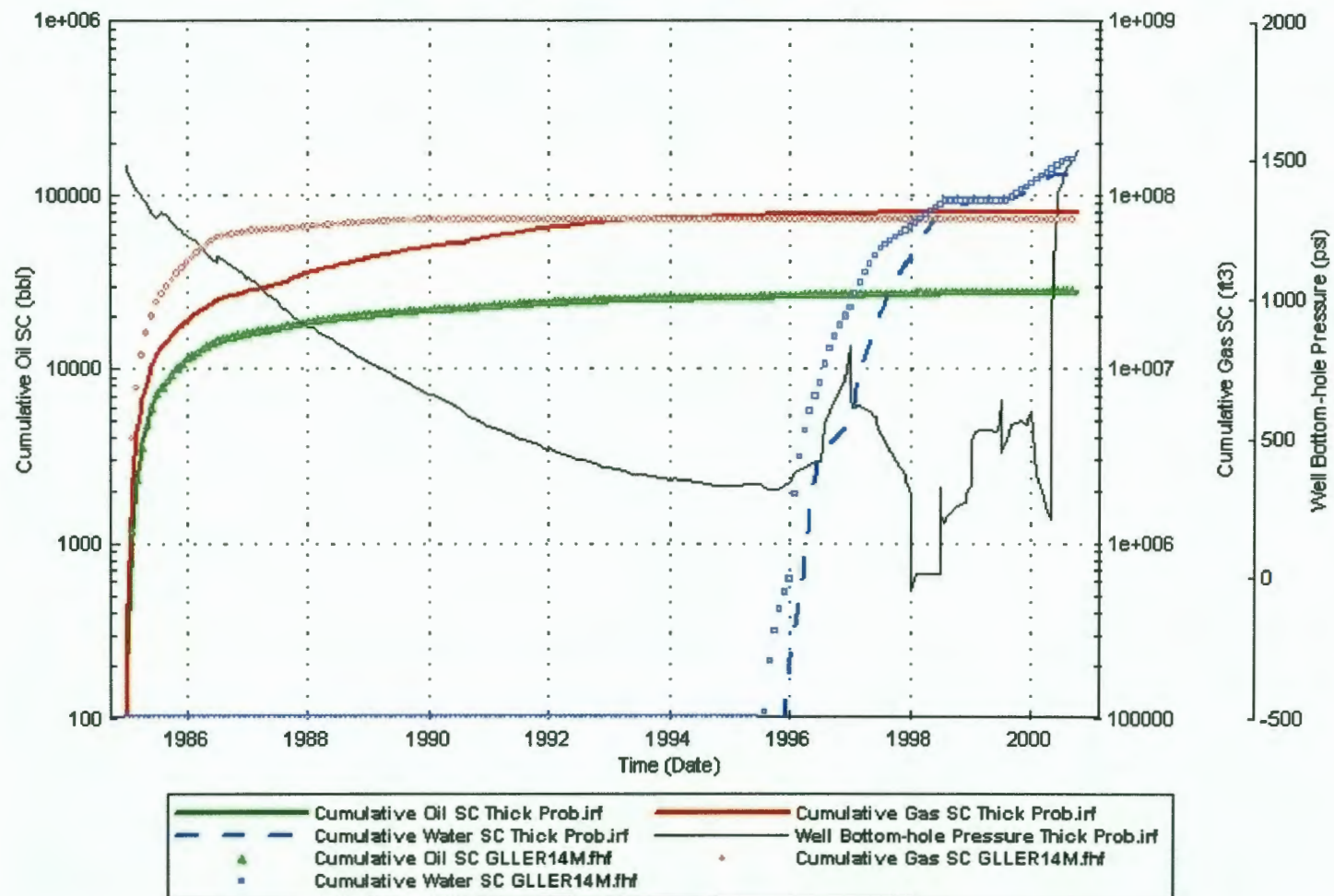


Figure D15

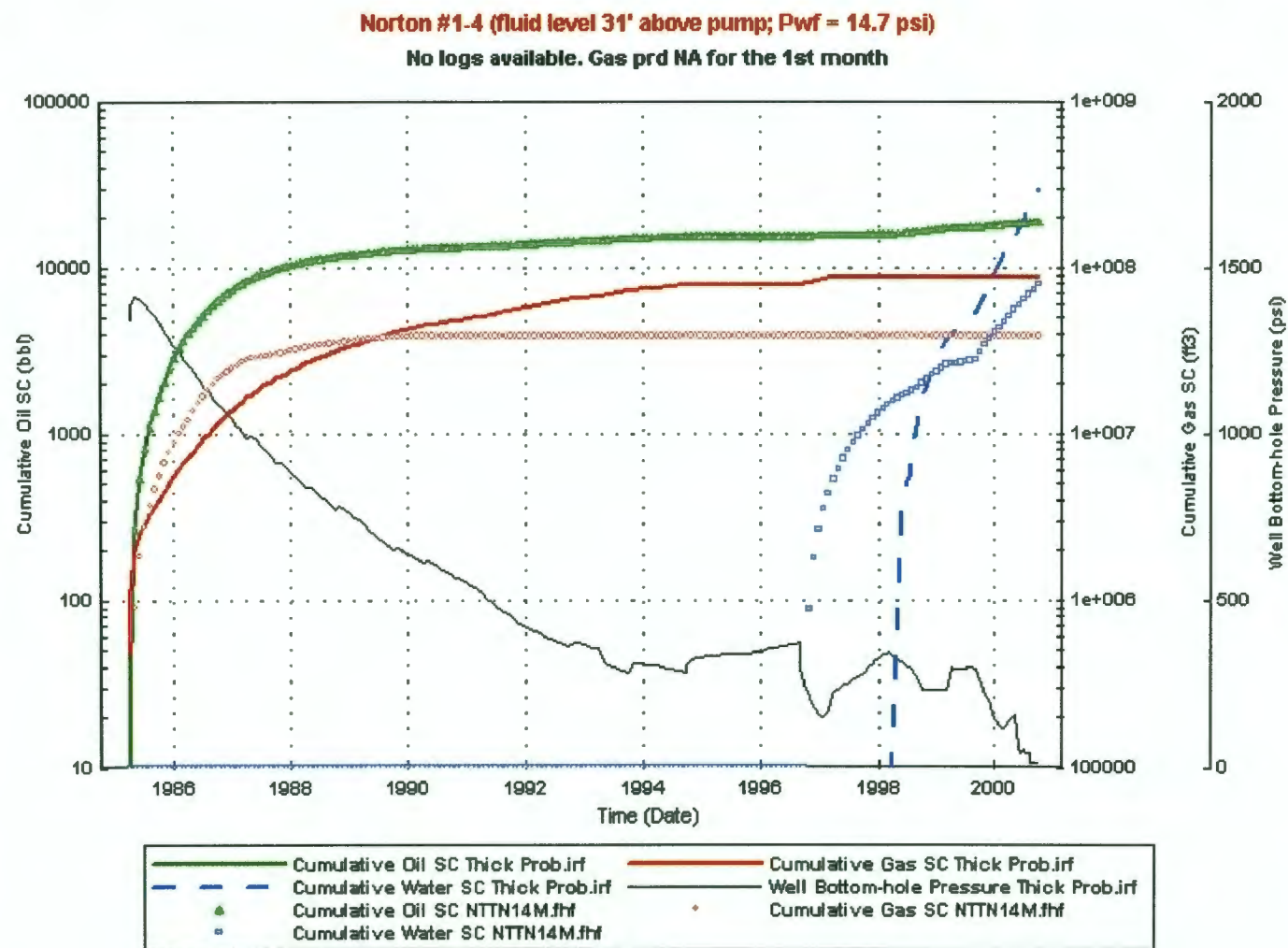


Figure D16

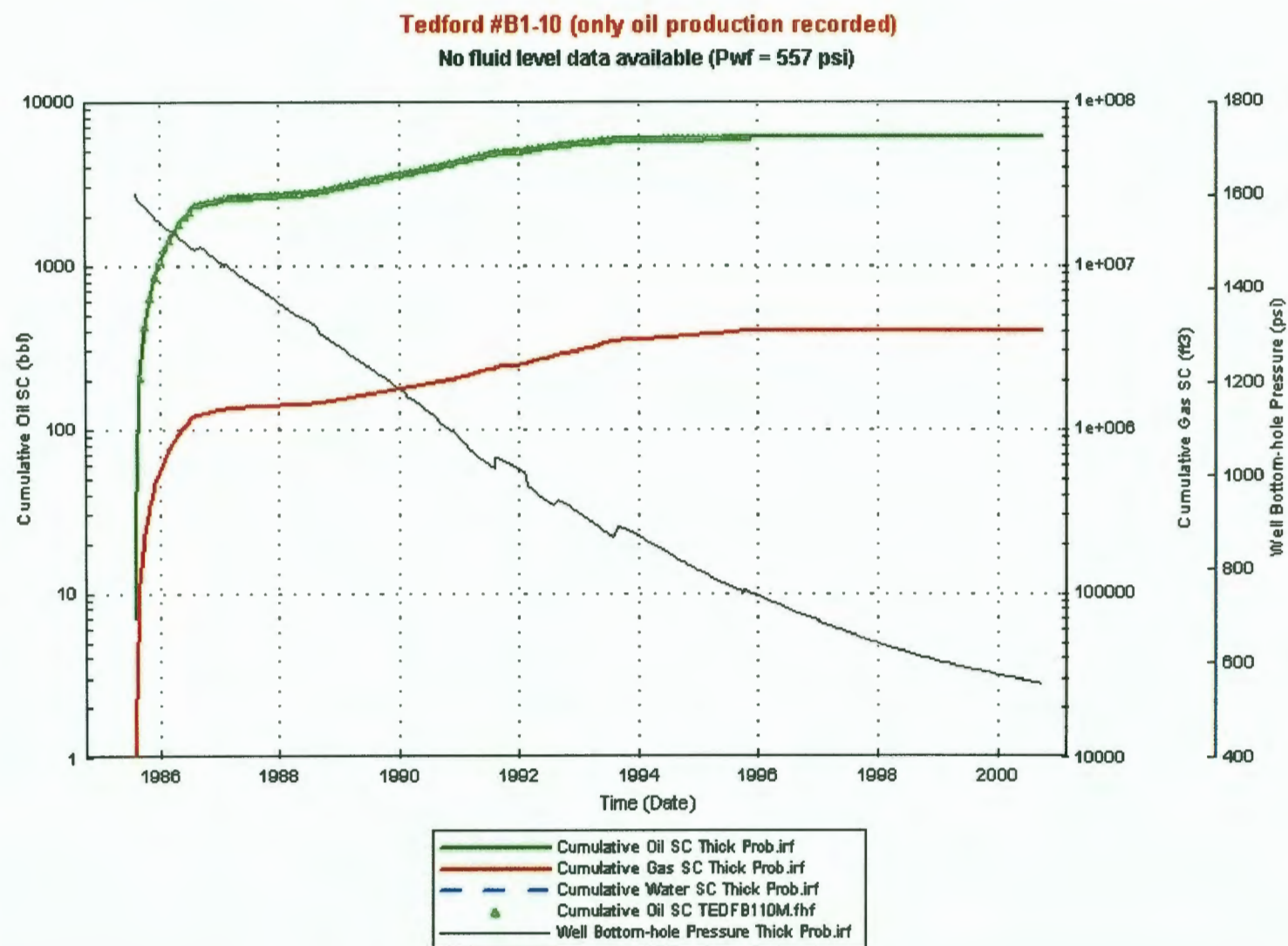


Figure D17

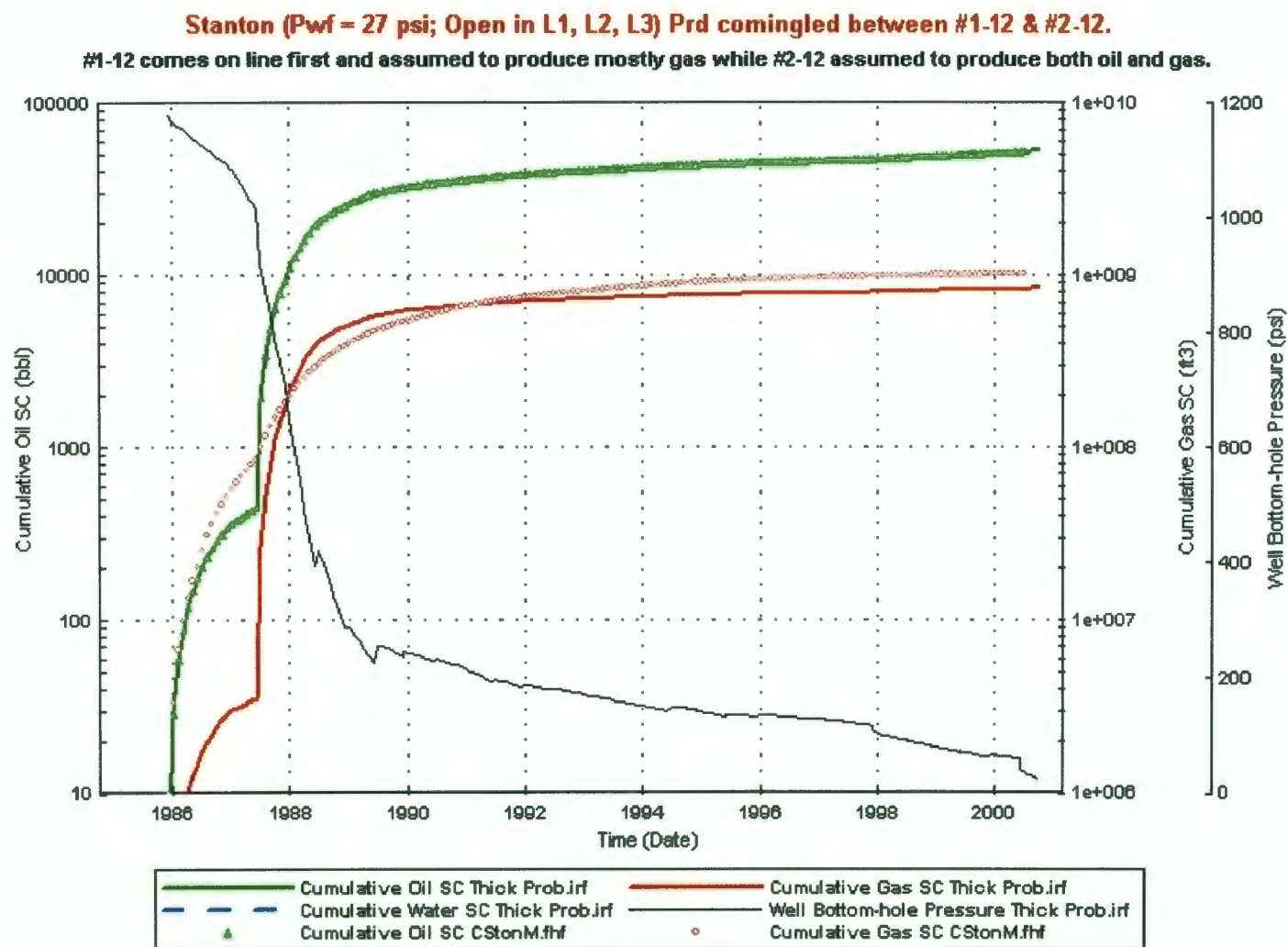


Figure D18

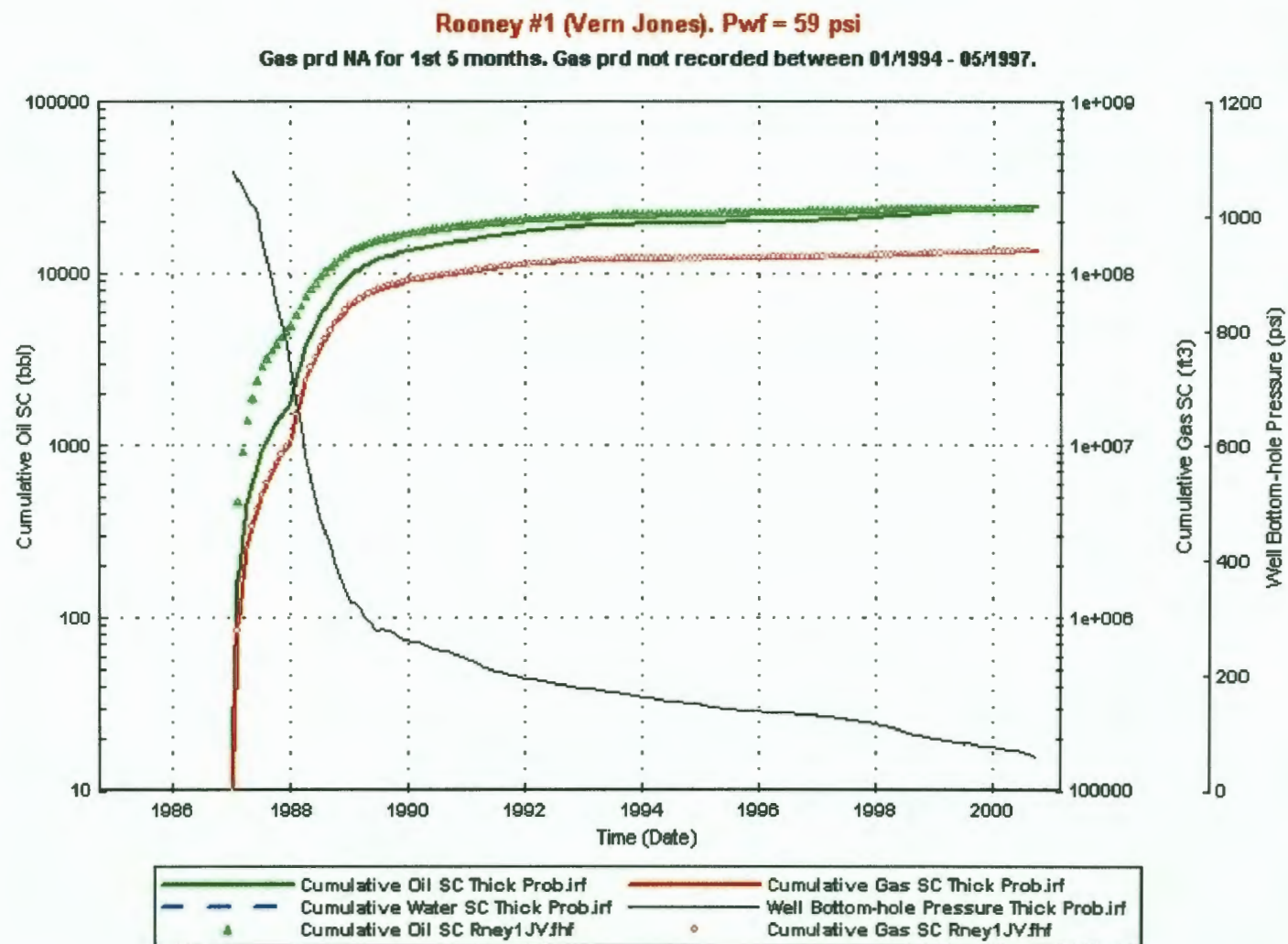


Figure D19

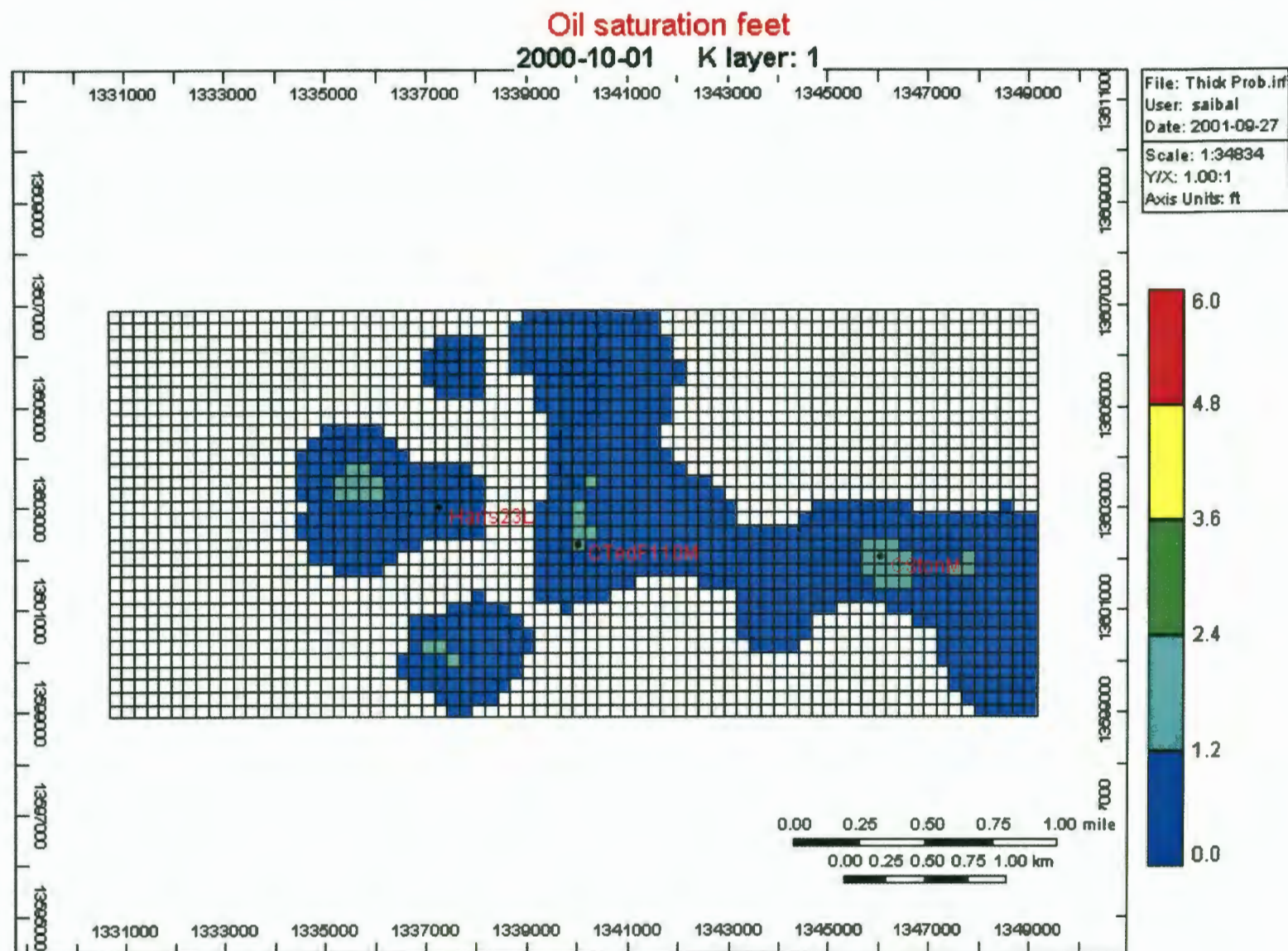


Figure D20

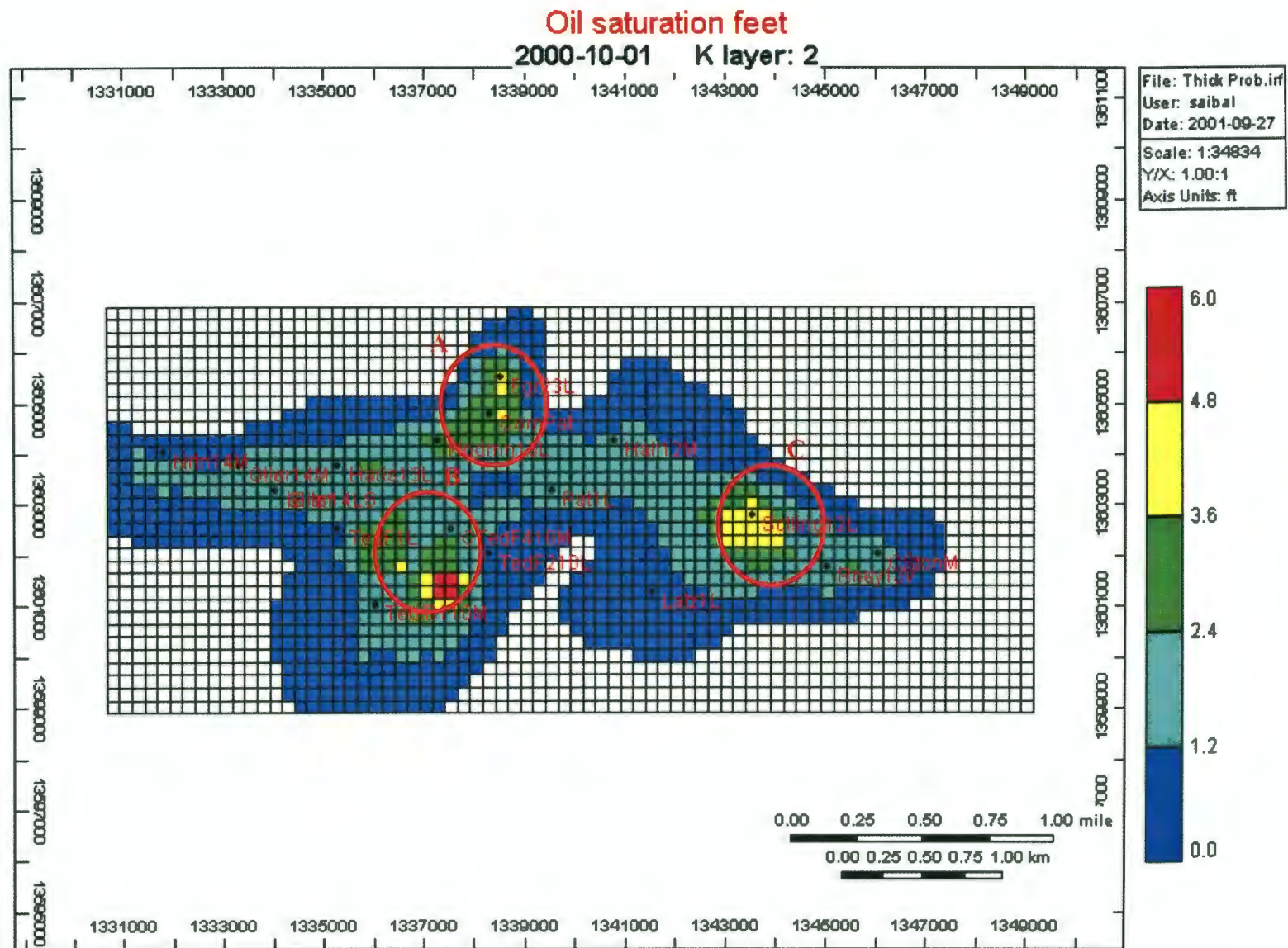


Figure D21

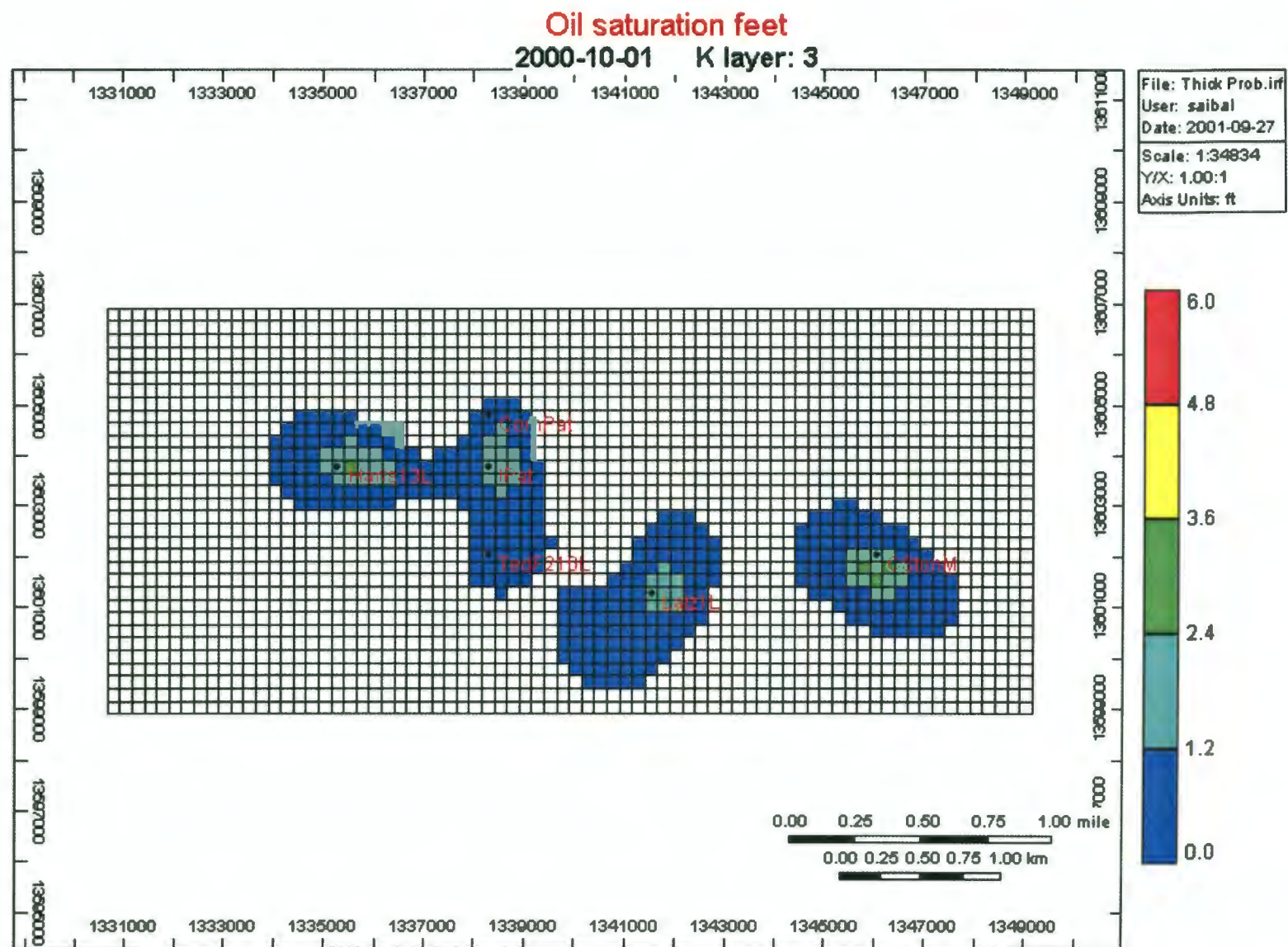


Figure D22

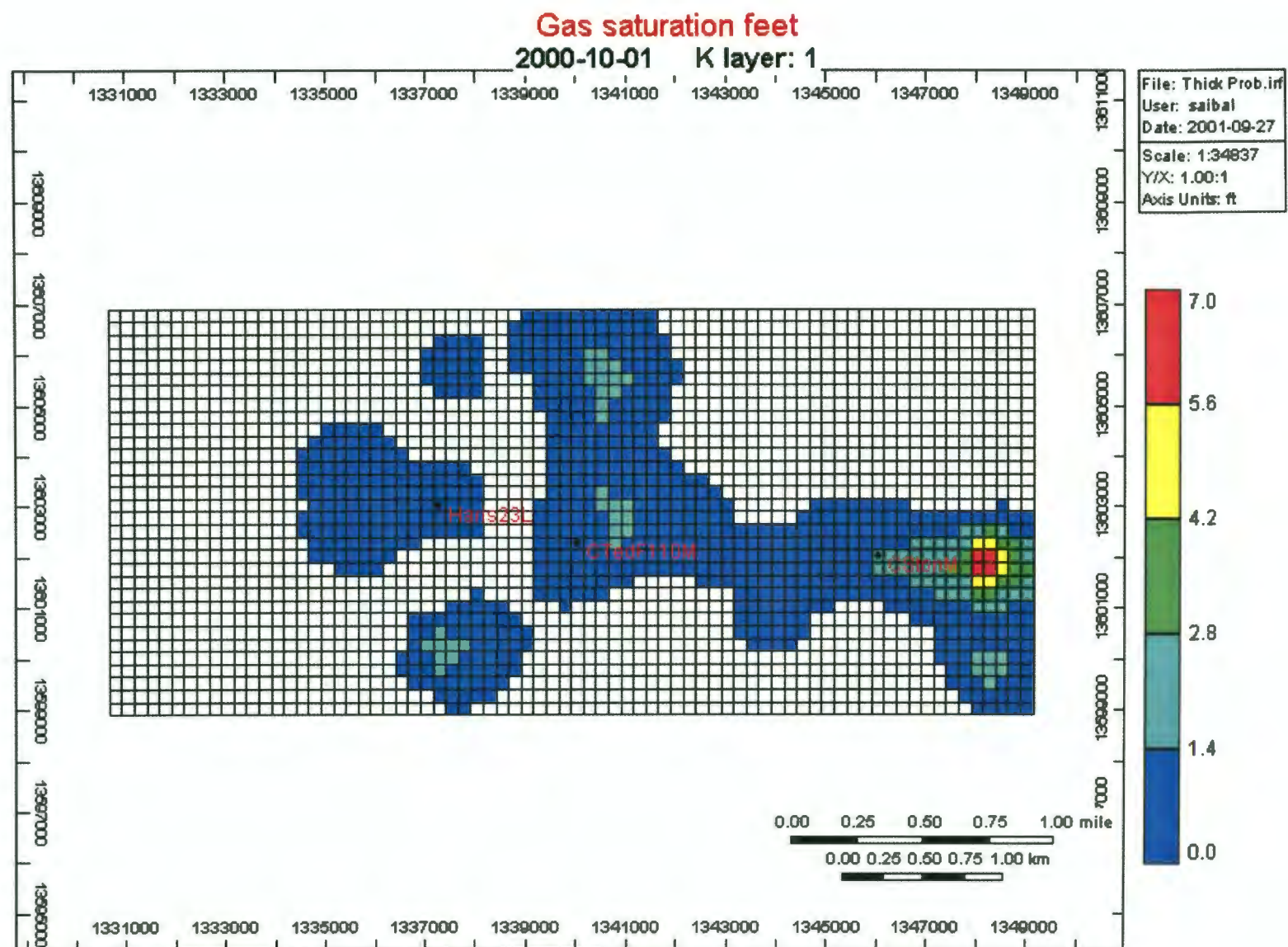


Figure D23

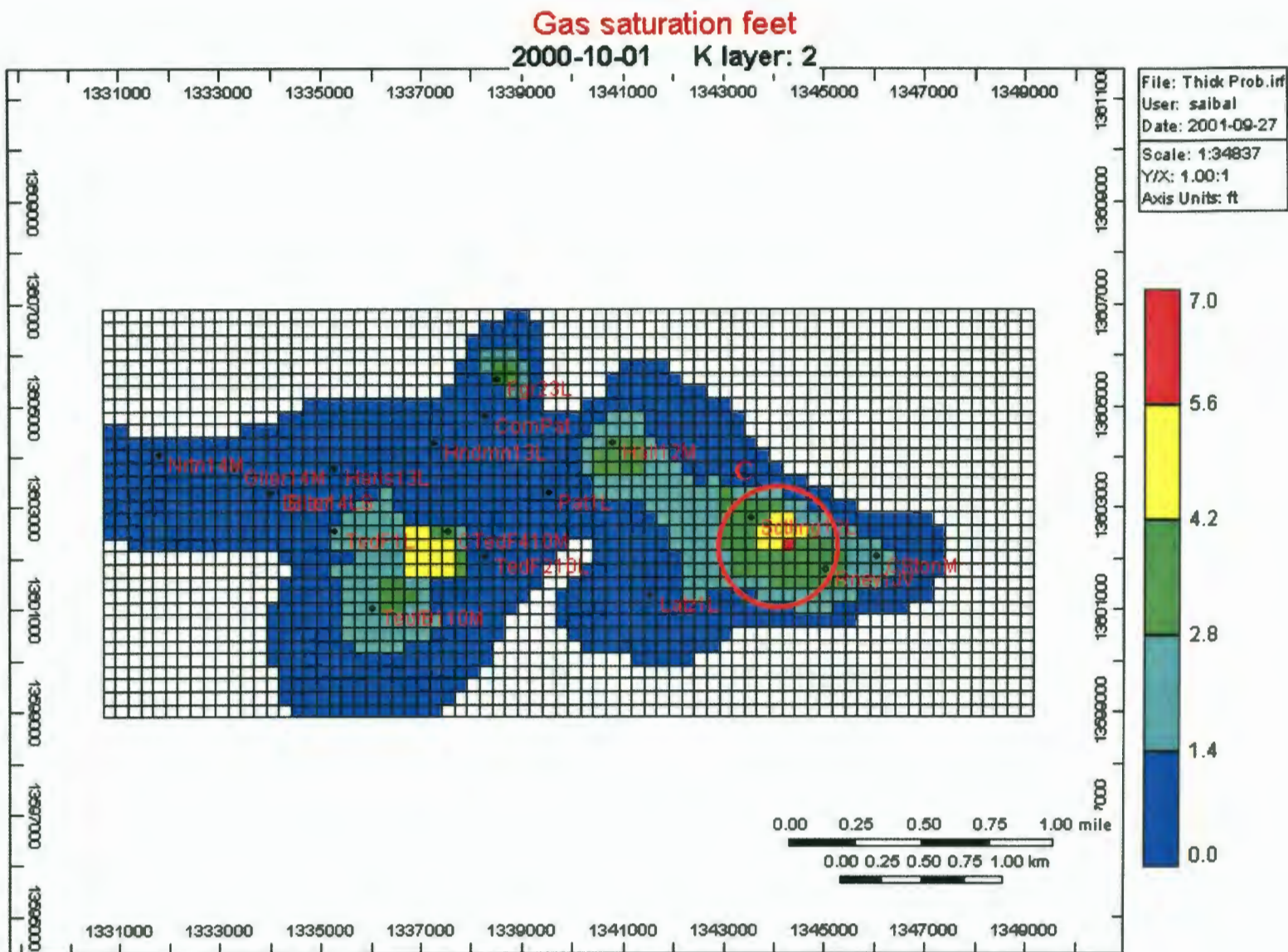


Figure D24

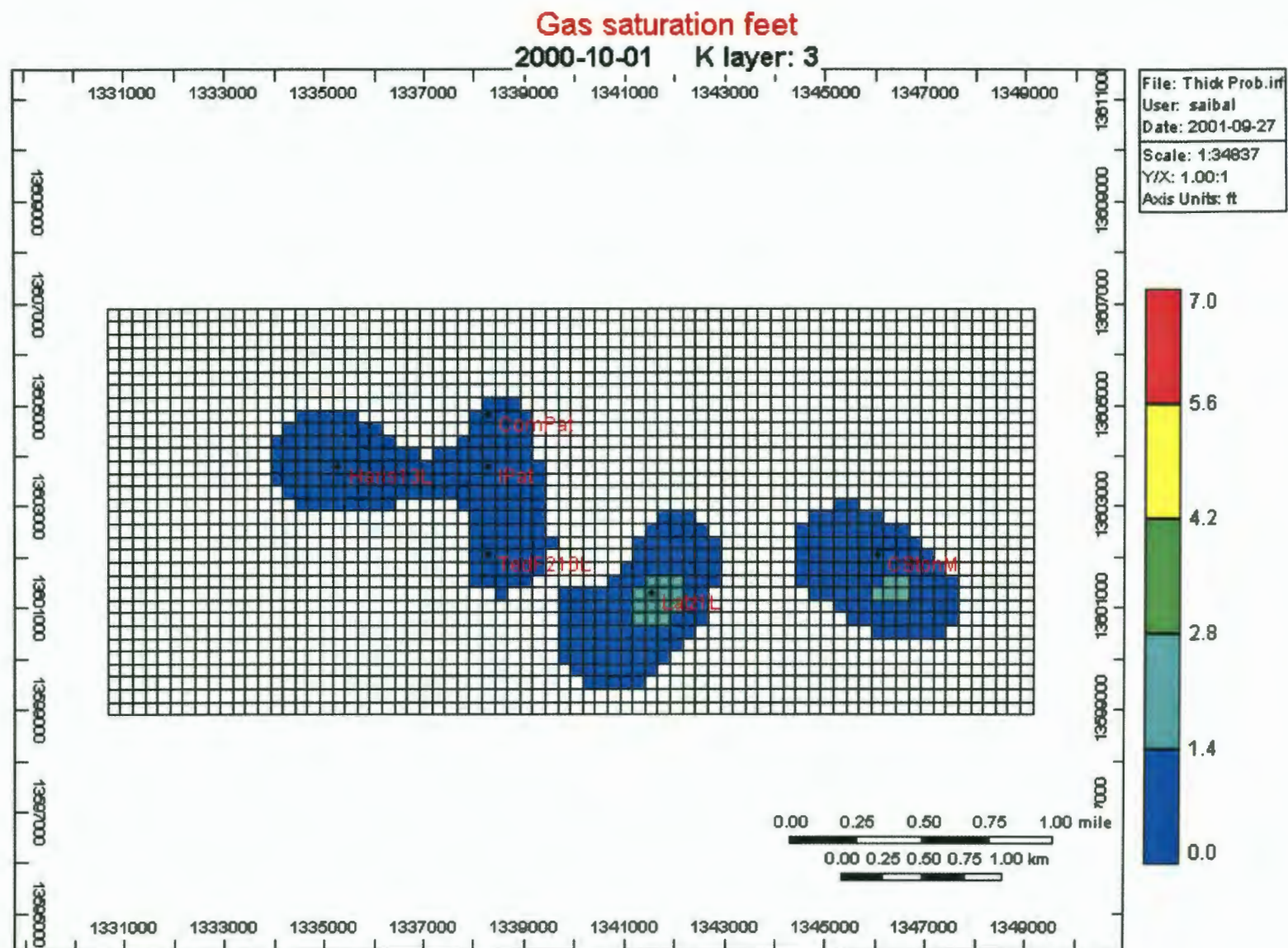


Figure D25

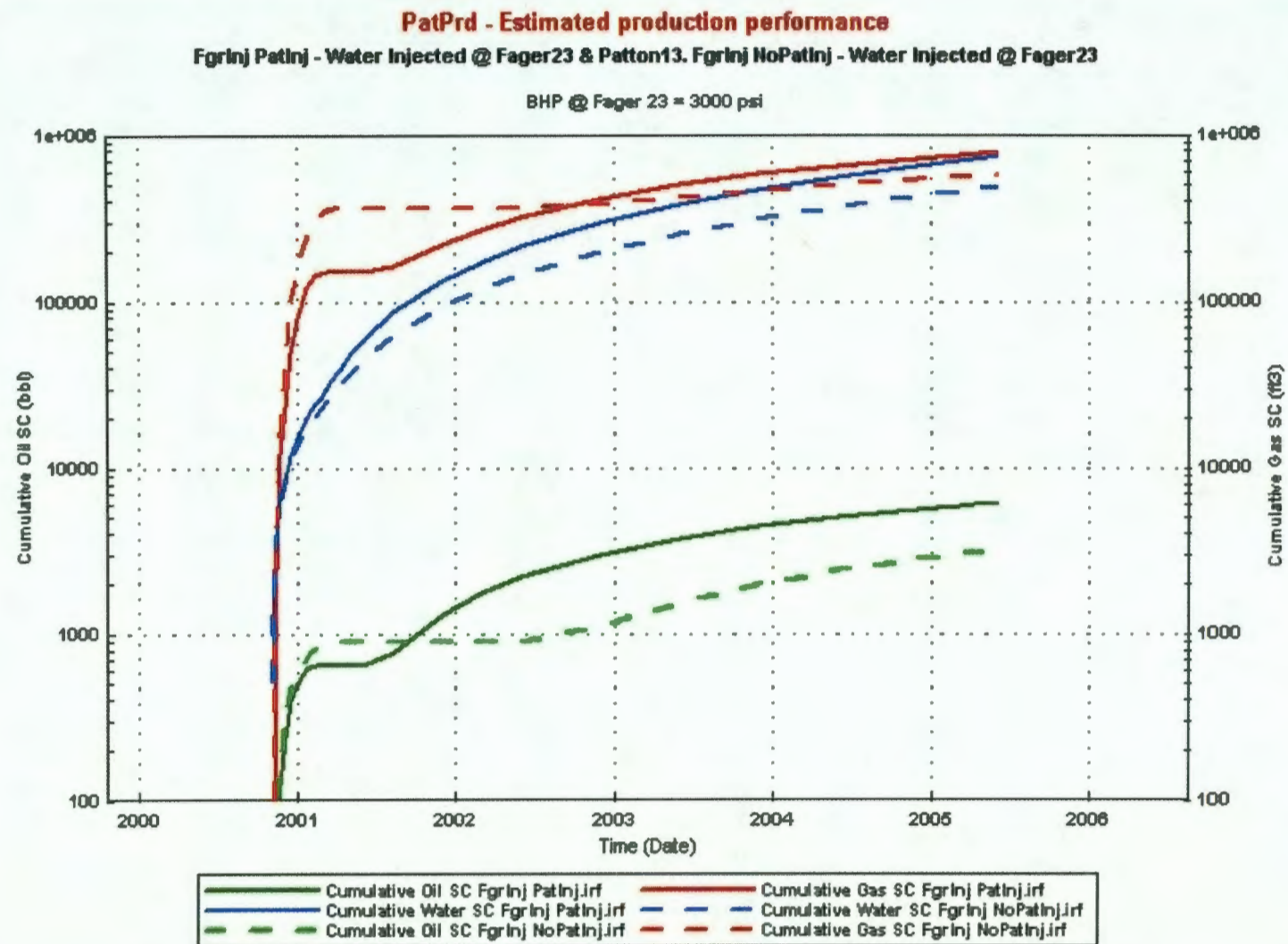


Figure D27

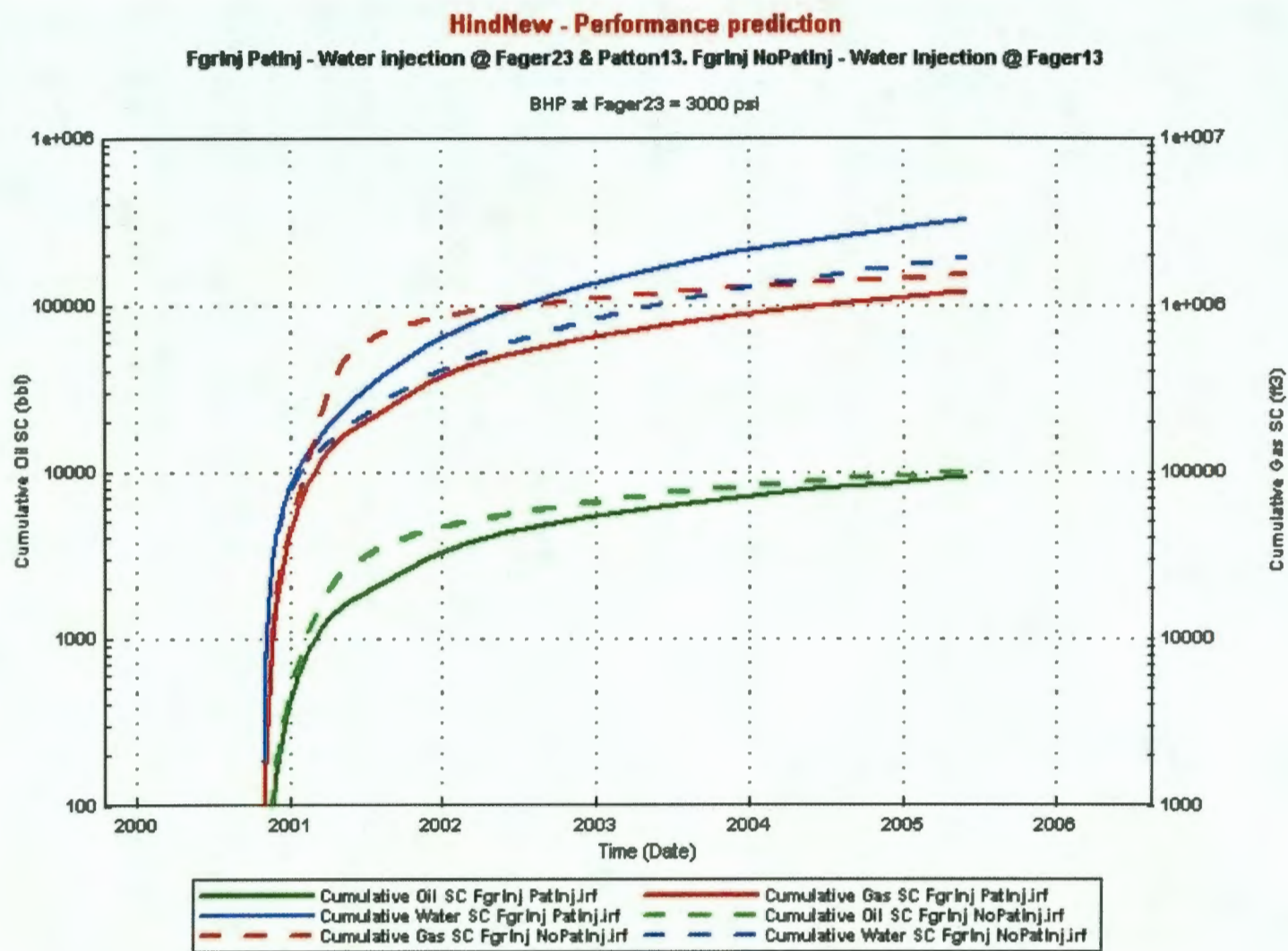


Figure D28

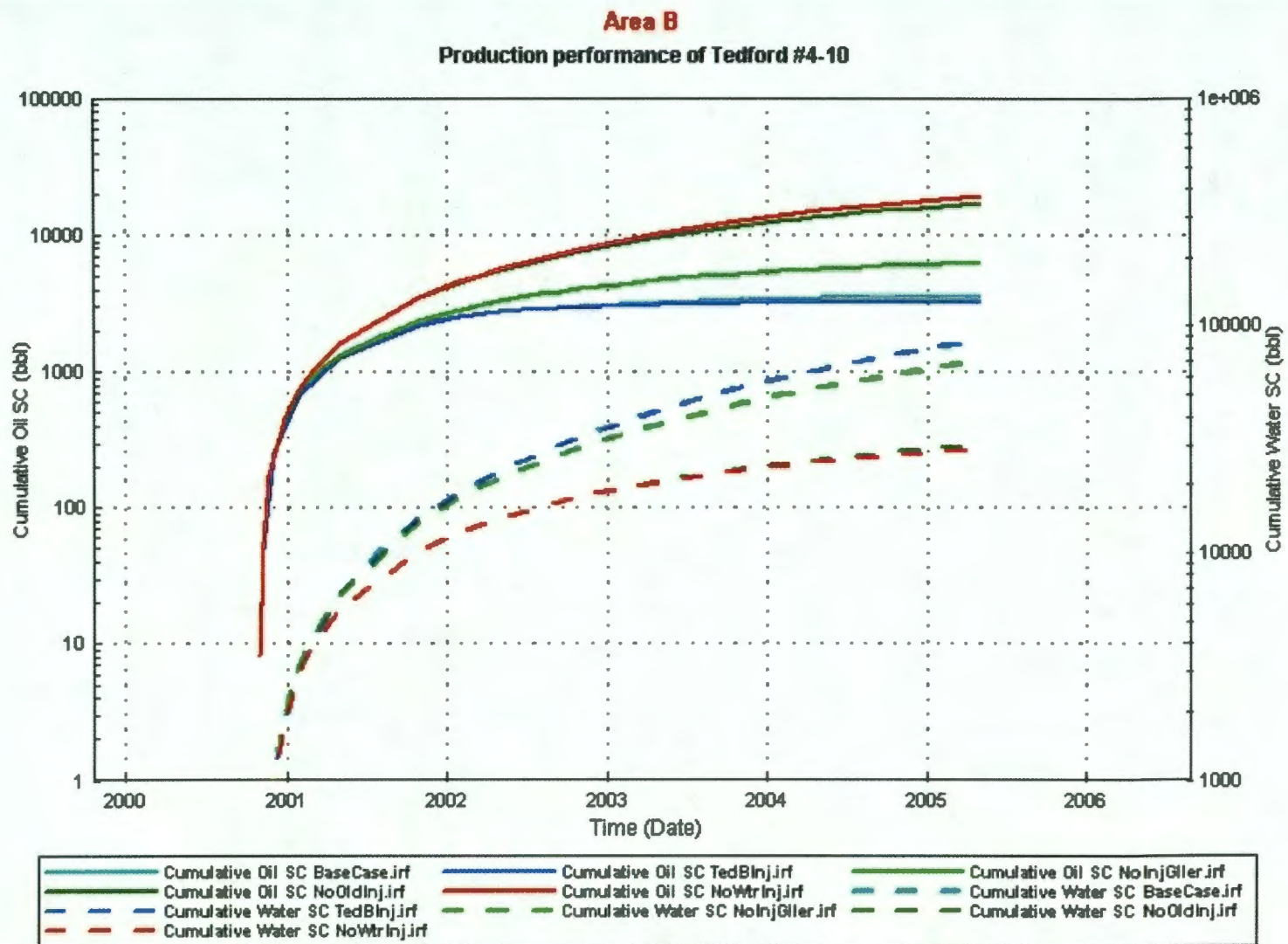


Figure D29

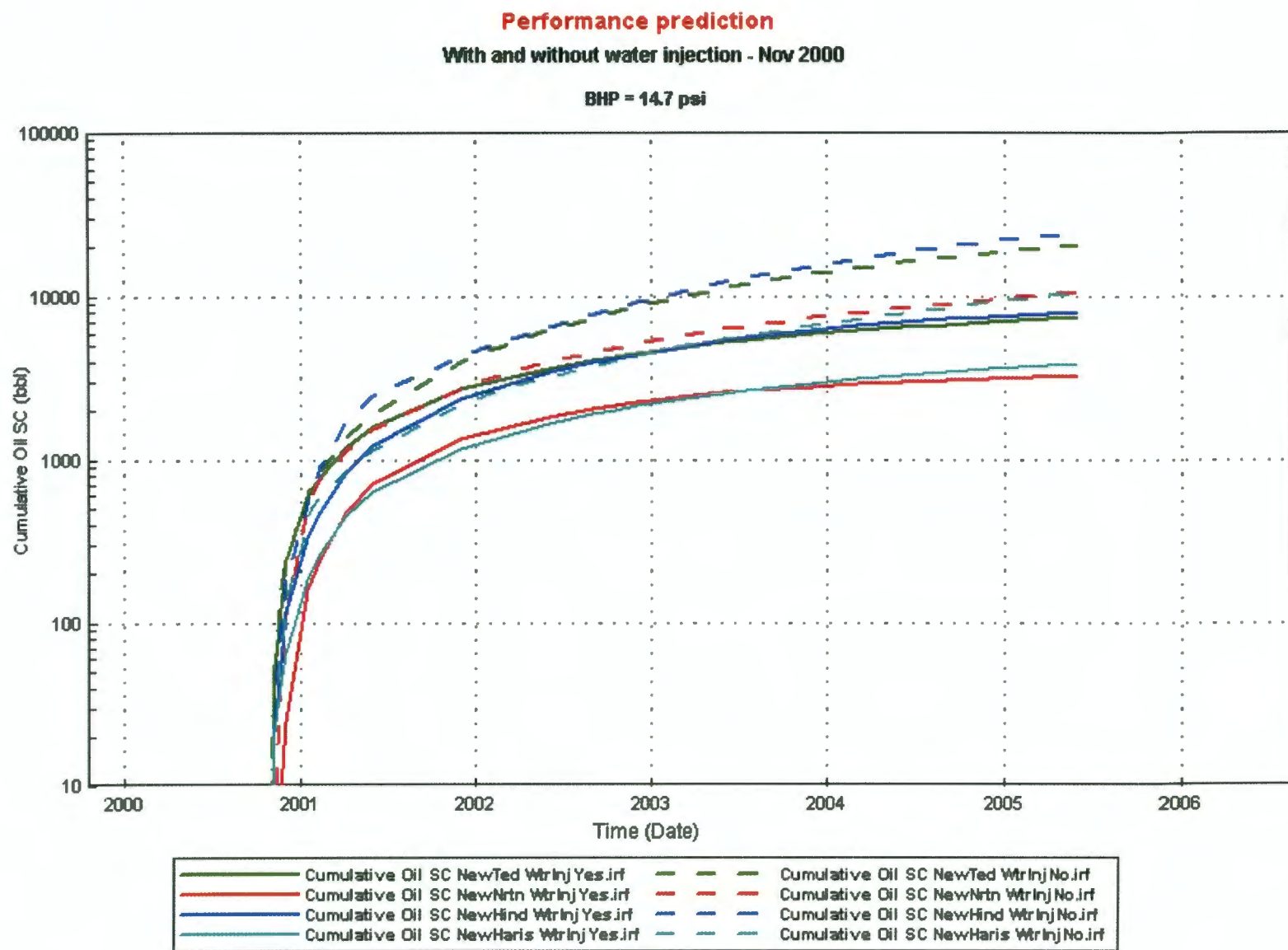


Figure D30

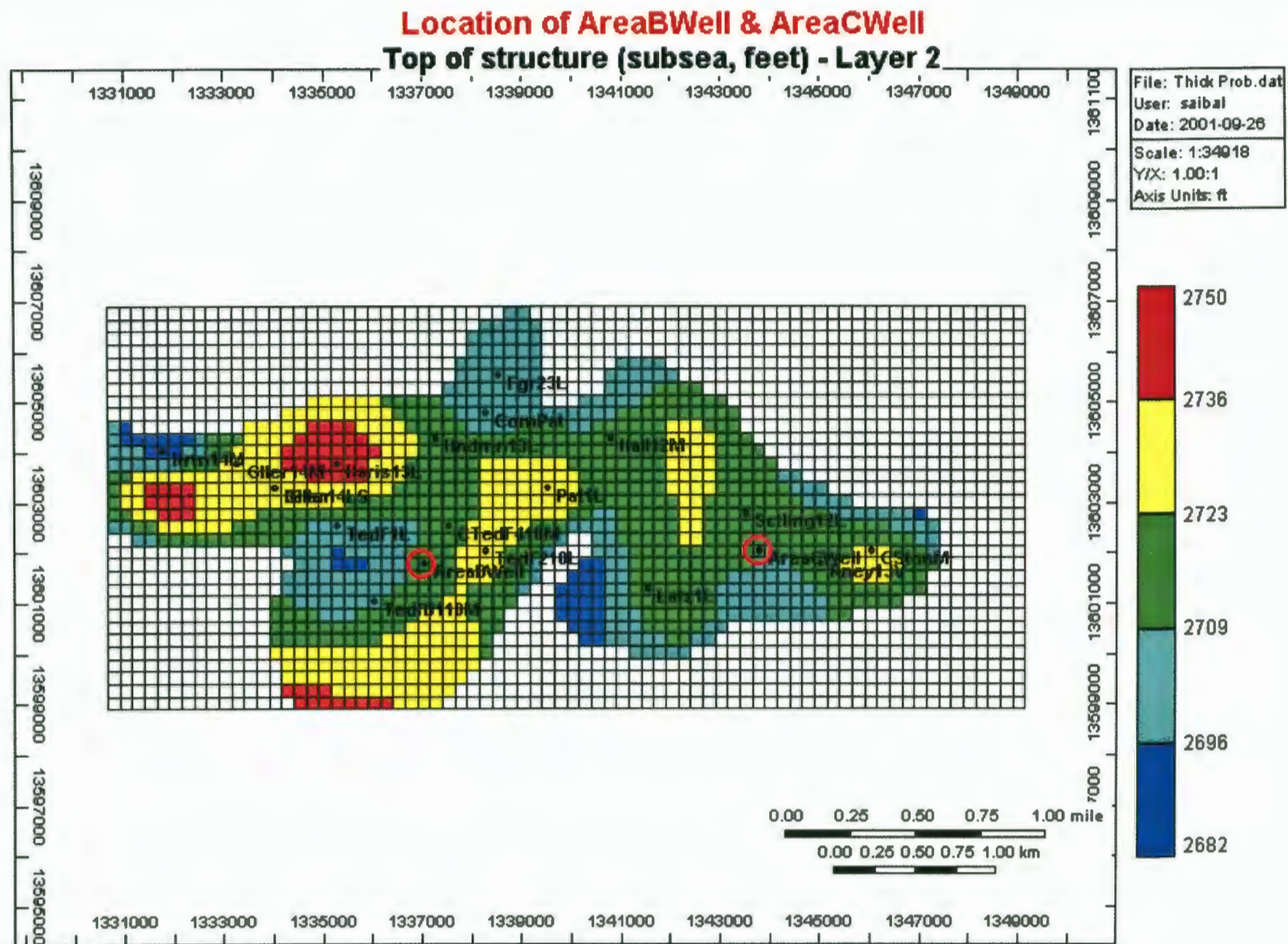


Figure D31

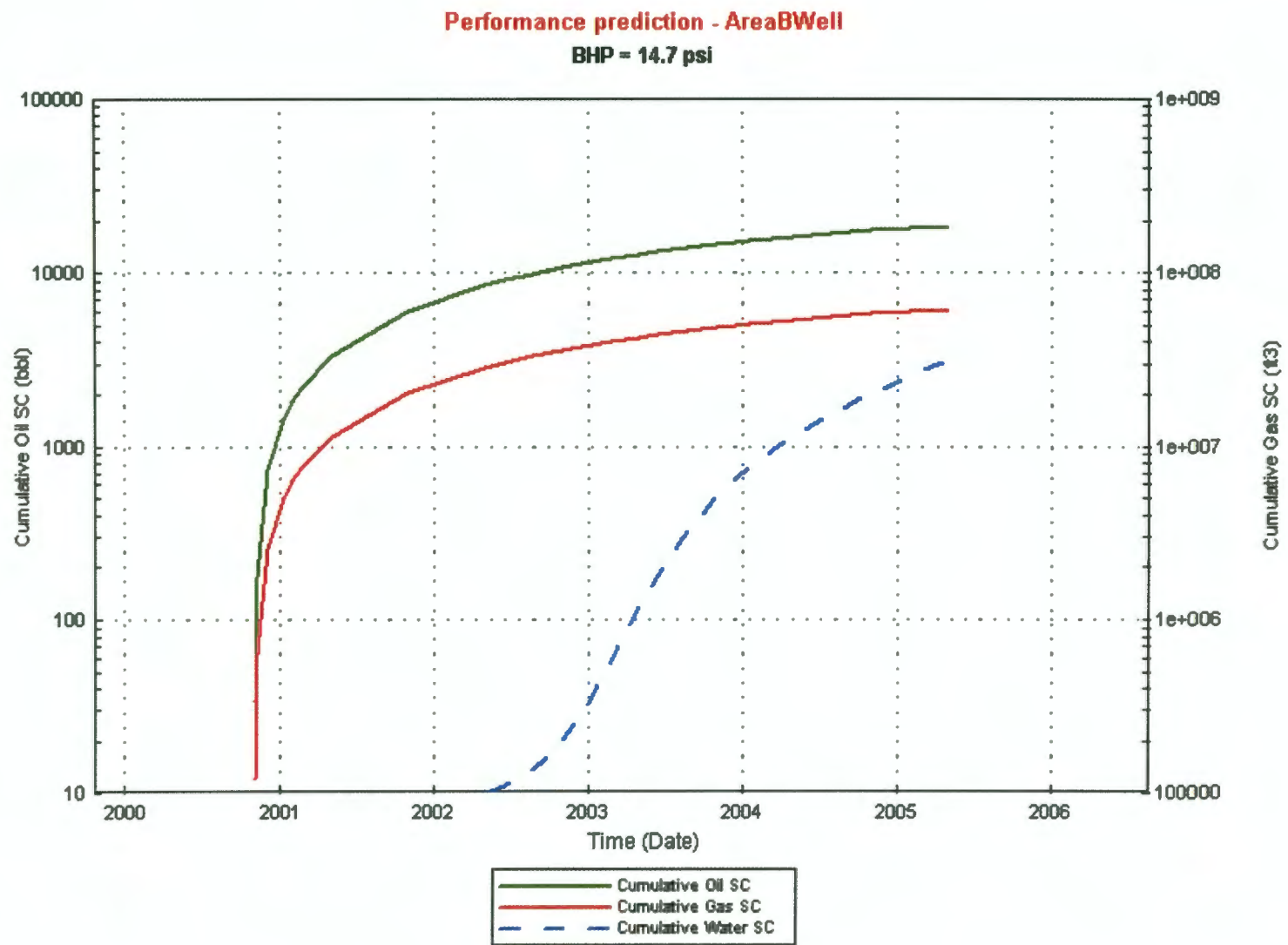


Figure D32

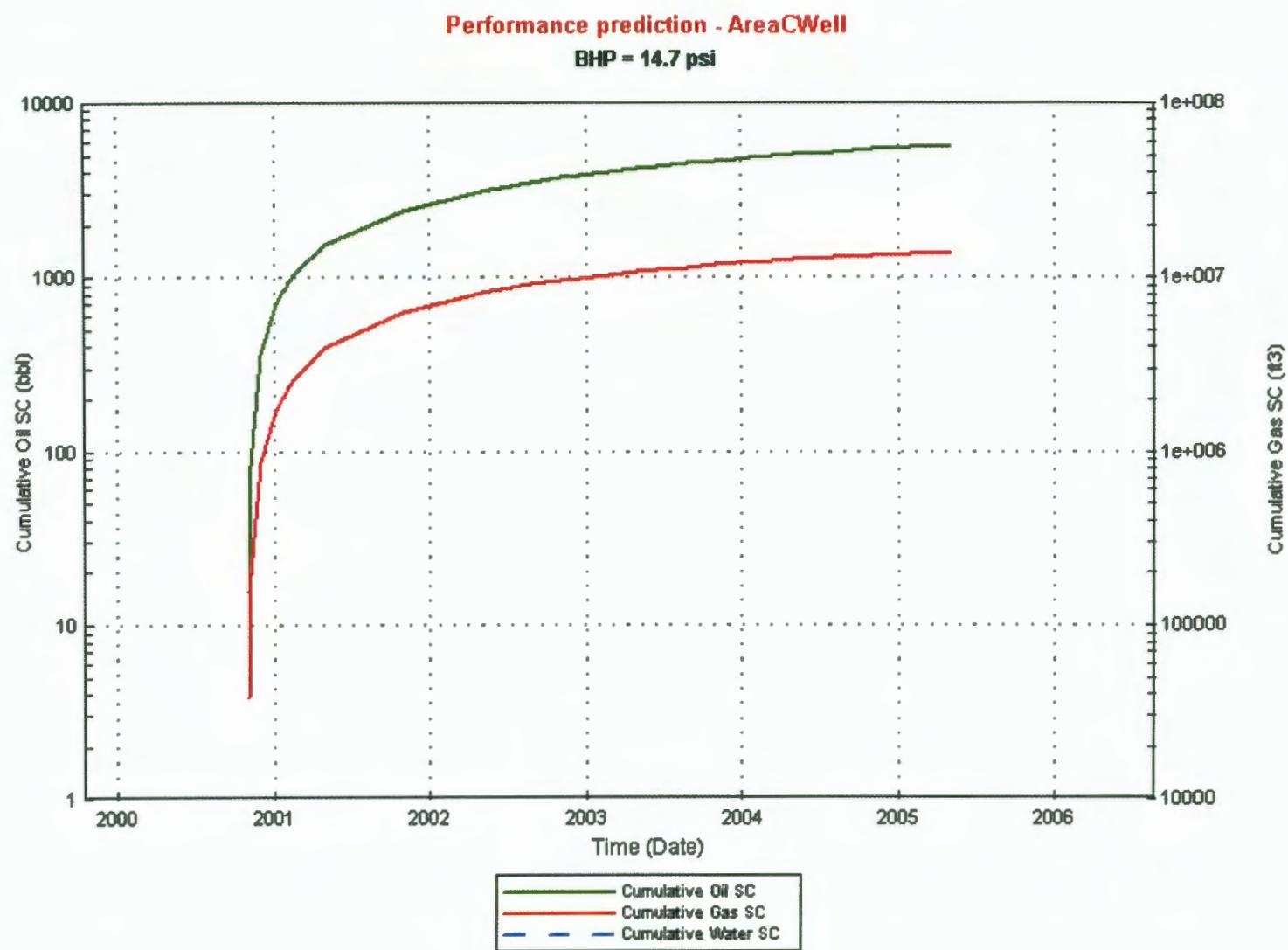


Figure D34