Optimizing Fracture Treatments in a Mississippian "Chat" Reservoir, South-Central Kansas

Final Technical Report

Reporting Period Start Date: June 17, 2002
Reporting Period End Date: June 16, 2005

Principal Authors:
K. David Newell, Saibal Bhattacharya, Alan Byrnes, W. Lynn Watney, and Willard Guy

Date Report Issued:
October 2005

DOE Award #DE-FG26-02NT15268

Woolsey Petroleum Corp.
125 North Market, Suite 1000
Wichita KS 67202-1775

And

Kansas Geological Survey
The University of Kansas
1930 Constant Avenue
Lawrence, KS 66047-3726

Disclaimer

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

ABSTRACT

This project is a collaboration of Woolsey Petroleum Corporation (a small independent operator) and the Kansas Geological Survey. The project will investigate geologic and engineering factors critical for designing hydraulic fracture treatments in Mississippian "chat" reservoirs. Mississippian reservoirs, including the chat, account for 159 million m3 (1 billion barrels) of the cumulative oil produced in Kansas. Mississippian reservoirs presently represent ~40% of the state's 5.6*106m3 (35 million barrels) annual production.

Although geographically widespread, the "chat" is a heterogeneous reservoir composed of chert, cherty dolomite, and argillaceous limestone. Fractured chert with micro-moldic porosity is the best reservoir in this 18- to 30-m-thick (60- to 100-ft) unit.

The chat will be cored in an infill well in the Medicine Lodge North field (417,638 m3 [2,626,858 bbls] oil; 217,811,000 m3 [7,692,010 mcf] gas cumulative production; discovered 1954). The core and modern wireline logs will provide geological and petrophysical data for designing a fracture treatment. Optimum hydraulic fracturing design is poorly defined in the chat, with poor correlation of treatment size to production increase. To establish new geologic and petrophysical guidelines for these treatments, data from core petrophysics, wireline logs, and oil-field maps will be input to a fracture-treatment simulation program. Parameters will be established for optimal size of the treatment and geologic characteristics of the predicted fracturing. The fracturing will be performed and subsequent wellsite tests will ascertain the results for comparison to predictions. A reservoir simulation program will then predict the rate and volumetric increase in production. Comparison of the predicted increase in production with that of reality, and the hypothetical fracturing behavior of the reservoir with that of its actual behavior, will serve as tests of the geologic and petrophysical characterization of the oil field. After this feedback, a second well will be cored and logged, and procedure will be repeated to test characteristics determined to be critical for designing cost-effective fracture treatments.

Most oil and gas production in Kansas, and that of the Micdontinent oil industry, is dominated by small companies. The overwhelming majority of these independent operators employ less than 20 people. These companies have limited scientific and engineering expertise and they are increasingly needing guidelines and technical examples that will help them to not be easteful of their limited financial resources and petroleum reserves. To aid these operators, the technology transfer capagilities of the Kansas Geological Survey will disseminate the results of this study to the local, regional, and national oil industry. Internet access, seminars, presentations, and publications by Woolsey Petroleum Company and Kansas Geological Survey geologists and engineers are anticipated.

TABLE OF CONTENTS

LIST OF GRAPHICAL MATERIALS

Figure 10. An overlay of V_{shale} (fraction)(contour lines) on the reservoir pressure map (shaded contours)

Figure 11. Isopach of low V_{shale} footage at each well (contour lines) compared to reservoir pressure (shaded contours)

Figure 12. Average fractional porosity calculated for reservoir interval at each well (contour lines) compared to reservoir pressure (shaded contours)

Figure 13. Average S_w calculated at each well (contour lines) compared to reservoir pressure (shaded contours)

INTRODUCTION

Geologic and engineering factors critical for designing hydraulic fracture treatments in a Mississippian "chat" reservoir in the Medicine Lodge North field (Figure 1) were investigated. To establish geologic and petrophysical guidelines for these possible treatments, data from core petrophysics, wireline logs, and oil-field maps were developed and analyzed to located a coring location within the Medicine Lodge North Field.

The target field for this study, the Medicine Lodge North field, is a stratigraphic trap in Barber County, Kansas. The field presently covers 1550 hectares (3840 acres). Approximate well spacing is 16 hectares (40 acres). The main reservoir, Mississippian (Osagean) chat, gently dips to the southeast at a rate of 4.7 m per km. (25 ft per mile). Average depth to the reservoir is 1365 m (4480 ft) (-850 m subsea datum; -2800 ft) and thickness averages 25 m (80 ft). Gross pay thickness decreases from ~15 m to 4 m (50 ft to 13 ft) from the northwest to southeast side of the field.

The discovery well, F.B. Anschutz #1 Lonker (NE NE NE, sec. 25-T.32S.-R.13W.), was drilled in 1954. Initial production recorded by wells in the first year of development averaged 6.4 m^3/day (40 bopd), but was as high as 116 m^3/day (730 bopd). Production peaked in the years shortly after discovery, but additional field development and expansion occurred between 1974 and 1982, when the number of producing wells increased from 18 to 52. A second peak annual oil production of 16,667 m^3 (104,832 bbls.) was in 1979, from 43 wells. Total cumulative recovery, as of 2000, has been 417,638 m^3 (2,626,858 bbl.) of 32° API gravity oil, and 217,811,000 m^3 (7,692,010 mcf) of gas. Annual oil production in 2000 was 5,267 m^3 (33,128 bbls.) from 46 wells -- an average of 0.31 m^3 (1.97 bbls.) per day per well. Gas production in the last five years has been relatively steady at approximately 2,980,000 m^3 (100,000 mcf) per year from 22 wells. This gas is mostly solution gas.

The reservoir drive mechanism is attributed to a combination of solution-gas drive and weak edge-water drive. The portion of the field operated by Woolsey Petroleum Corporation has been under primary production without any artificial pressure support. Shut-in pressures from drill-stem tests recorded in the first few wells in the field indicate the initial reservoir pressure to be close to 11,000 kPa (1600 psi), but some wells recorded shut-in pressures as low as 6500 kPa (950 psi) in the first year of production. This indicates permeability heterogeneity within the pay zone.

EXECUTIVE SUMMARY

Included in “Results and Discussion” section below

EXPERIMENTAL

Included in “Results and Discussion” section below

RESULTS AND DISCUSSION

One core in the Medicine Lodge North field was located and described were described (Figure 2). These lithologies were tied to core porosity measurements and then measured wireline log porosities (Figure 3). The chat reservoir at this location consisted of layers reservoirs, from top to base, these layers are: (1) 1st brecciated, (2) 1st nodular, (3) 2nd brecciated, and (4) 2nd nodular.

Well-level production data was not available for the field, but static reservoir pressure data available for most wells since 1998. Effective oil permeability from build-up tests indicate that K (md) in the field drainage area is very low. Example values of calculated K (md) from build-up tests are: 1.08, 0.051, 0.056, 0.272, 0.174, 0.116, and 0.56.

Available data indicate little water production from wells over their production life. The main leasehold in the field is the 13-well Thomas-Forsyth lease, from when the core was obtained. Current production from Thomas-Forsyth lease is 10 bopd, 45.5 bwpd, and 110 mcfd. Only one well (Warwick #3) has been classified as gas well, but gas production data from individual wells was not available. For modeling purposes, it was assumed that the reservoir produces under solution-gas drive.

Well Log Analysis

The majority of the wells in the field did not have a porosity log. Porosity was estimated from neutron log (API counts) using a low porosity = 3% and a high porosity = 33%. A core was available from Thomas-Forsyth #12 (see Figure 2). Porosities measured on core-plugs from this well were compared with porosity estimated from neutron counts and by using the above constraints (Figure 4).

Available petrophysical logs at each well were analyzed with the GEMINI well-log analysis package (available from the Kansas Geological Survey) using the Super-Pickett plot technique and assuming $R_w = 0.04$, and Archie exponents m = n = 2. Using these constants, the fieldwide volumetric original oil in place (OOIP) was calculated between 15 - 25 Mmstb.

Cementation values (m) were measured and found to vary with porosity. However, for plugs belonging to the same petrofacies whose K/(Phi) values were similar (between 0.1 to 0.3), the measured value of m ranged between 2.0 to 2.3 (Figure 5).

Identification of Effective Pay at Each Well

An initial set of cut-offs were applied to identify effective pay (oil-ft) at each well in the field. The water saturation (S_w) at and above which only water can be produced was determined to be 0.6. The minimum porosity necessary to produce hydrocarbons was determined to be 0.12. The maximum bulk volume water (BVW) for the chat reservoir for it to still be able to produce water was determined to be 0.12. At each well, these cut-offs were used to isolate effective pay within the chat interval. The reserve potential was estimated by summing [porosity * (1-S_w)] over effective pay at each well.

The reservoir was assumed to produce under solution-gas drive, and available production data indicated limited water production from most wells. Also, drill-stem test (DST) and build-up tests indicated that effective permeability in the reservoir is very low (<1 md). From these characteristics, it was concluded that external drive mechanism(s) do not influence reservoir production, and fluid production from the reservoir will be accompanied by (near) proportional decline in reservoir pressure. Under such a scenario, reservoir pressure in the well vicinity may serve as a proxy for cumulative production lacking actual well-level cumulative production data. As a corollary, areas with low pressures in the field are likely indicative of significant fluid production and therefore have low remaining potential. Conversely, areas in the field with high pressures are indicative of limited fluid production and therefore higher remaining potential. As a test of this hypothesis, the calculated effective pay in oil-ft (i.e., OHIP - original hydrocarbon volumes in place) should be relatively high for wells located in low pressure (well drained) areas of the field. The following section discusses the validation of this hypothesis.

Delineation of Production Fairway

A production fairway can be delineated by volumetric mapping, and the fairway is definable as those areas in the field where wells have low pressure in their drainages and also have higher volumetrically estimated effective pay (oil-ft). A 1998 map of static reservoir pressure made available to the Kansas Geological Survey by Woolsey Petroleum is integral to this exercise, assuming that there are no high-pressure pockets in the intervening regions between wells. The net pay map, with net pay defined as:

Net pay, ft = porosity*(1-Sw)*(pay thickness ft that qualifies the cut-offs)

The calculated net pays (oil-ft) for most wells in the production fairway (where there is low reservoir pressure) are high, therefore the volumetric procedure is validated.

Evaluation of Prospective Infill Locations

Three prospective localities (namely “A”, “B”, and “C”; see Figure 6) where infill wells could be drilled and cored for testing integral to this project were defined in the field. The criteria for picking these infill locations are locations both the calculated net pay and the current reservoir pressures are relatively high, and where calculated original reserves are high, with a significant fraction of it still in place.

The process of selecting which prospective infill location is best for drilling a test core hole is done by a series of overlays onto the reservoir pressure map (see Figure 5). The first overlay is that of bulk volume water (BVW) determined by Super-Picket plots (see Figure 7). BVW represents the fraction of the pore-volume occupied by water. Above the transition zone, BVW values are clustered around BVW_i (bulk-volume-water-irreducible). At BVW_i, there is little or no mobile water. Water production increases with increasing BVW values above BVW_i. Within the production fairway, the BVW values are clustered between 0.07 and 0.09.

Assuming that the petrofacies of the reservoir rock remain unchanged between wells, BVW values are tightly clustered if the structure does not vary or if the producing zones are above the transition zone (i.e., above the transition zone is where BVW values are, in fact, BVW_i). The question of variation of BVW with structure can be answered by comparing BVW with geologic structure (see Figure 8). Within the fairway, structure varies from a high of -2791 to a low of -2835 ft.

A cross plot of BVW with depth (Figure 9) indicates the BVW remains clustered despite structural variation of 44 ft, so the reservoir can be assumed to be above the transition zone and BVW_i for this field is around 0.09. Data measured were from whole core segments from the Thomas-Forsyth #12. The core-data span over 27 ft in vertical depth. BVW values (blue circles) for plugs belonging to the same petrofacies - similar K/(Phi) values (red triangles) have been plotted. The trend of increasing BVW with depth is indicative of a transition zone with a minimum BVW value around 0.09.

The shaliness of a reservoir, expressed by the log-derived value of V_{shale} is important for determining variability of reservoir quality. In addition, in a hydraulic fracture treatment, a significant amount of shale in a reservoir may dampen or inhibit the induced fracturing. An overlay of clean V_{shale} (fraction) on the reservoir pressure map (Figure 10) will answer the question of whether wells in the production fairway have a characteristic V_{shale} (fraction) value. The V_{shale} spread over the reservoir interval in each well was split into high and low sections. The low V_{shale} (fraction) at each well indicates that wells along the fairway have characteristically low V_{shale} (fraction) values (i.e. <0.2).

In Figure 11, the total footage of low V_{shale} values (i.e. values <0.2) at each well is been plotted against the reservoir pressure map. For this exercise, the V_{shale} spread over the reservoir interval in each well was split into high and low sections. Wells within the fairway have at least 20 ft of clean reservoir, with low V_{shale} values. This indicates a relatively uniform and thick reservoir section is available for hydraulic fracturing. In addition, reservoir analysis is subject to less complication by knowing that there is a relatively uniform and low amount of shale in the reservoir interval.

An overlay of fractional porosity values onto the reservoir pressure map (Figure 12) answers the question of whether wells in the production fairway show an average minimum porosity. This map (Figure 12) shows that wells in the production fairway have an average porosity of 30%.

Water-saturation measurements at each well are also critical in evaluating prospective coring locations. Inasmuch as the reservoir is assumed to be solution-gas driven, there is no external influx of water to change S_w over time. S_w cut-offs calculated from Super-Pickett plots will thus remain valid from the days of initial field development to current time. An overlay of average S_w values calculated at each well (Figure 13) indicates that wells in the production fairway show an average S_w that is no higher than 30% (using Archie exponents $m = n = 2$ and $R_w = 0.04$).

CONCLUSION

In order to optimize chances for production, overlays of critical reservoir parameters against the reservoir pressure maps of the field (see Figures 6-13) indicates that the following characteristics are necessary for production from the reservoir interval: (A) porosity = 0.3 or more, (B) S_w = 0.3 or less, C) BVW = 0.09 or less, and D) at least 20 ft or more of reservoir interval with a low V_{shale} (< 0.2).

Based on the above criteria, “Location B” is deemed the best location for follow-up infill drilling, followed by “Location C”, then lastly “Location A”.

REFERENCES - None

Index Map

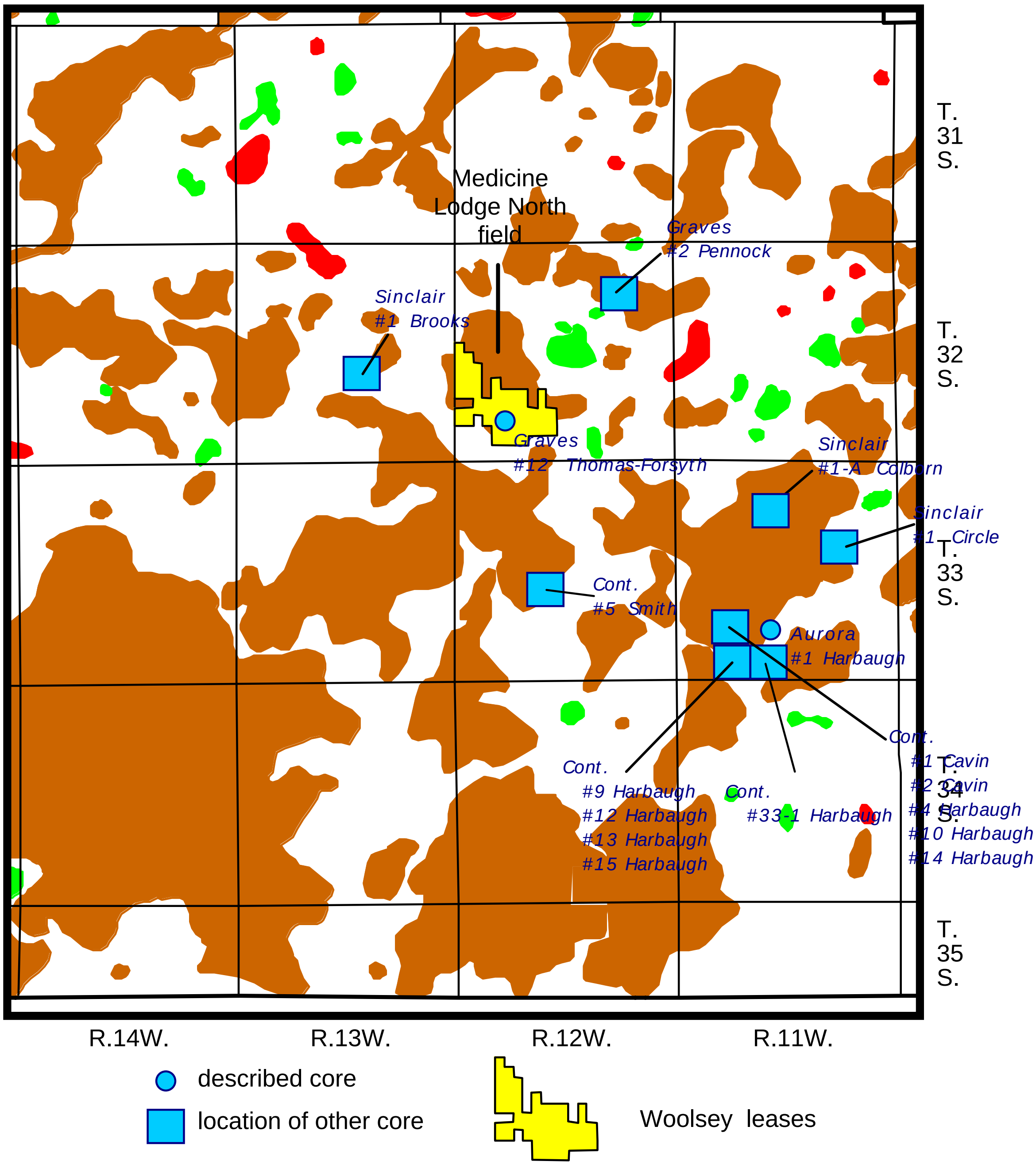

FIGURE 1. Index map and core locations.

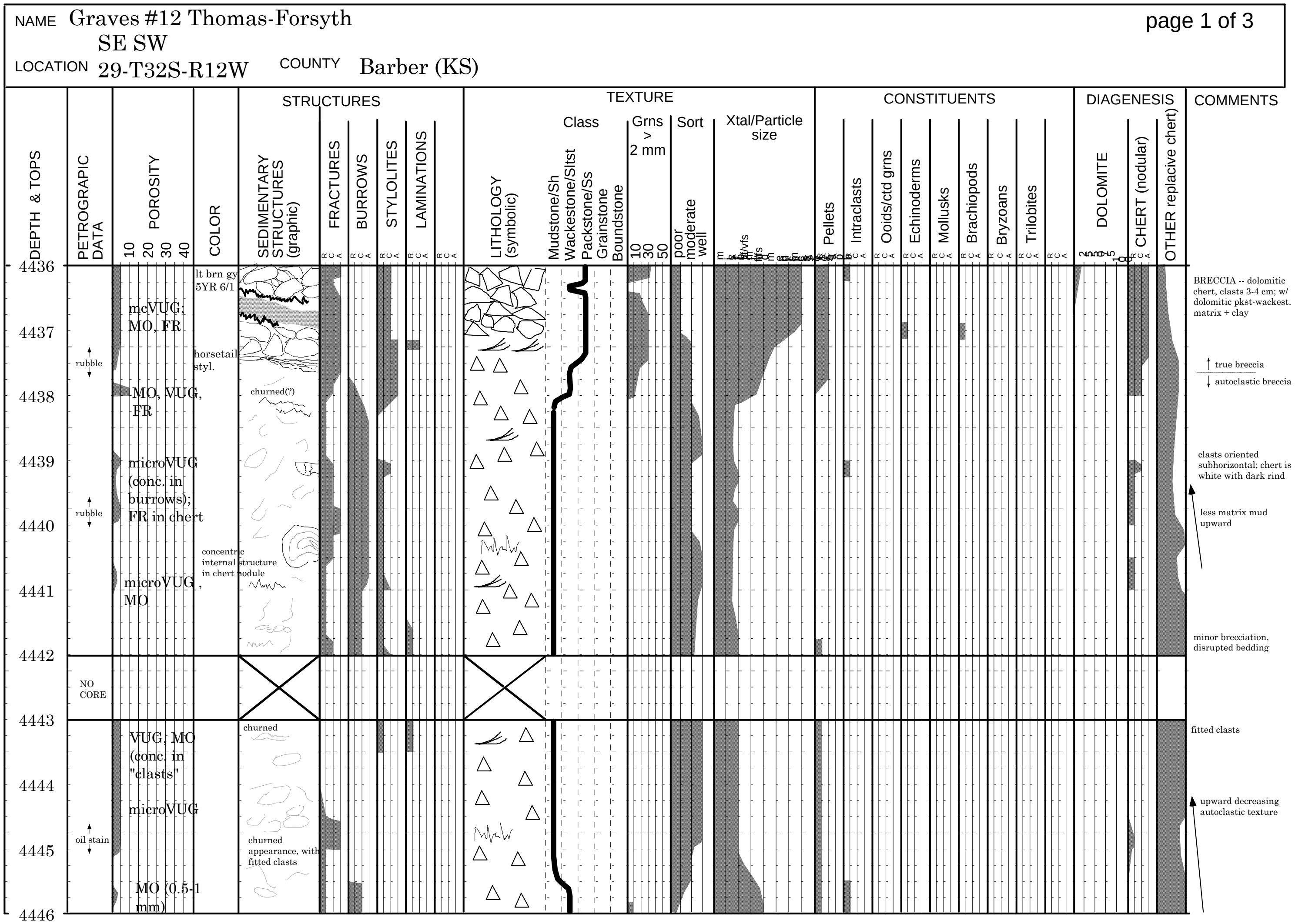

FIGURE 2(a) Lithology of the Graves #12 Thomas-Forsyth core in the Medicine Lodge North Field.

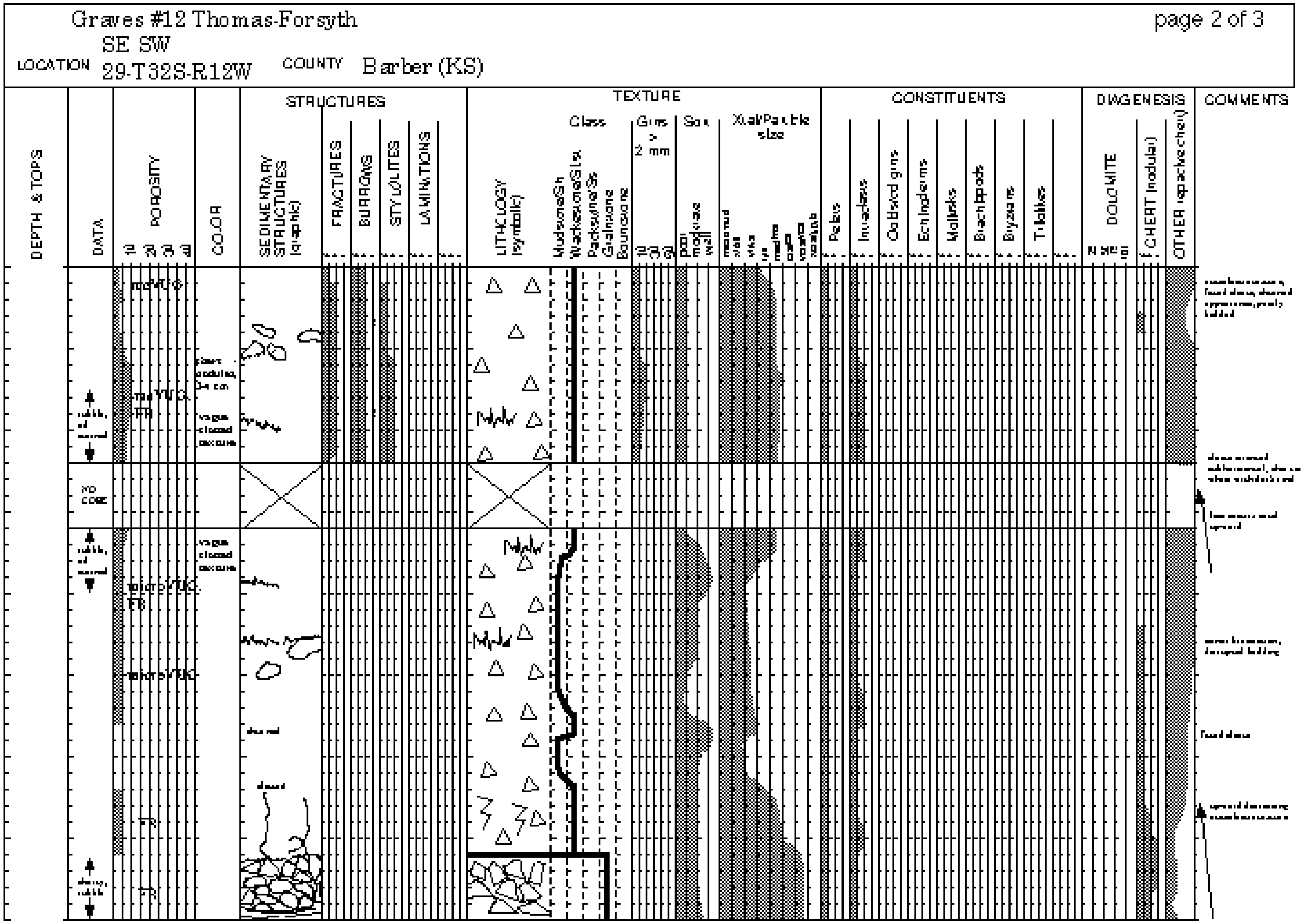

FIGURE 2(b) Lithology of the Graves #12 Thomas-Forsyth core in the Medicine Lodge North Field.

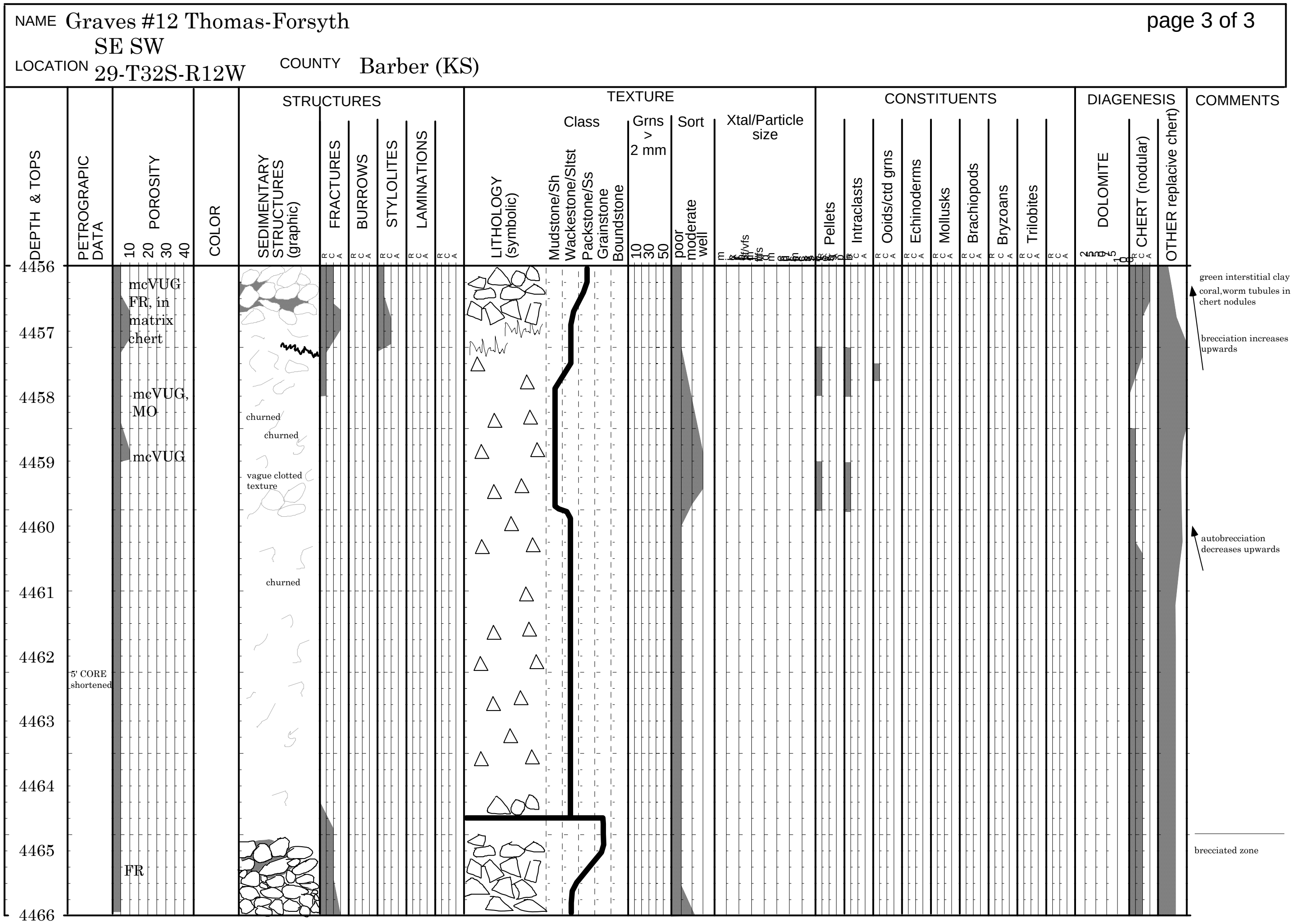

FIGURE 2(c) Lithology of the Graves #12 Thomas-Forsyth core in the Medicine Lodge North Field.

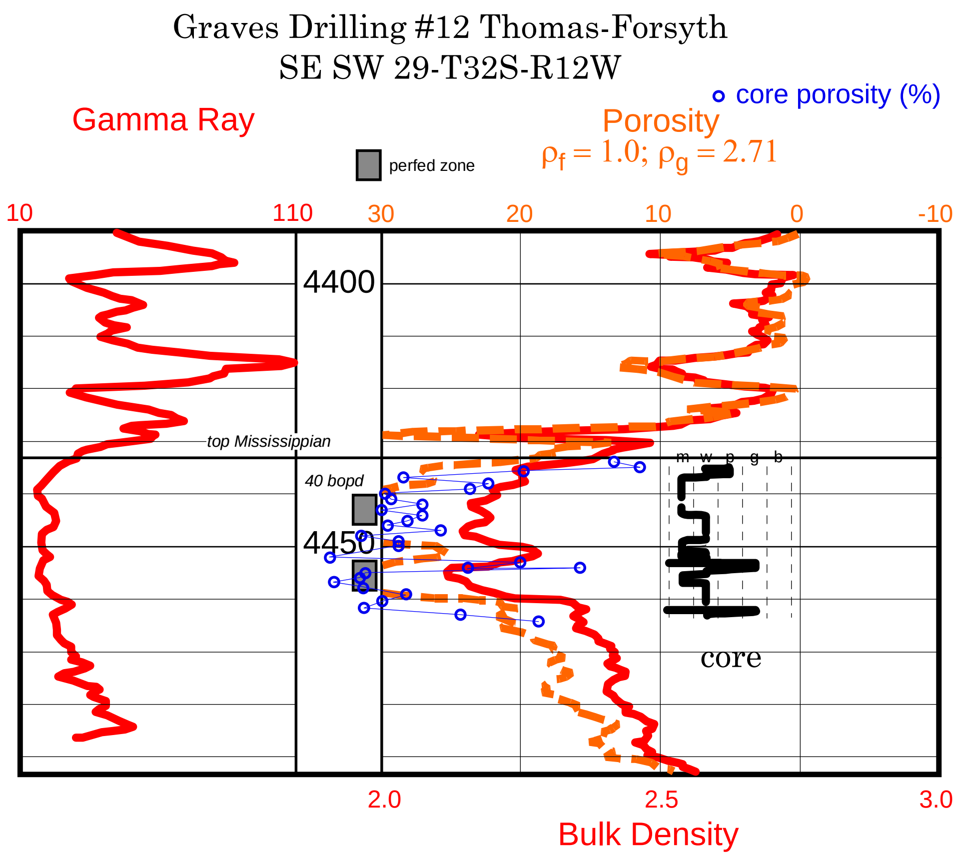

FIGURE 3. Core porosity vs. log porosity, with core lithology for #12 Thomas-Forsyth core.

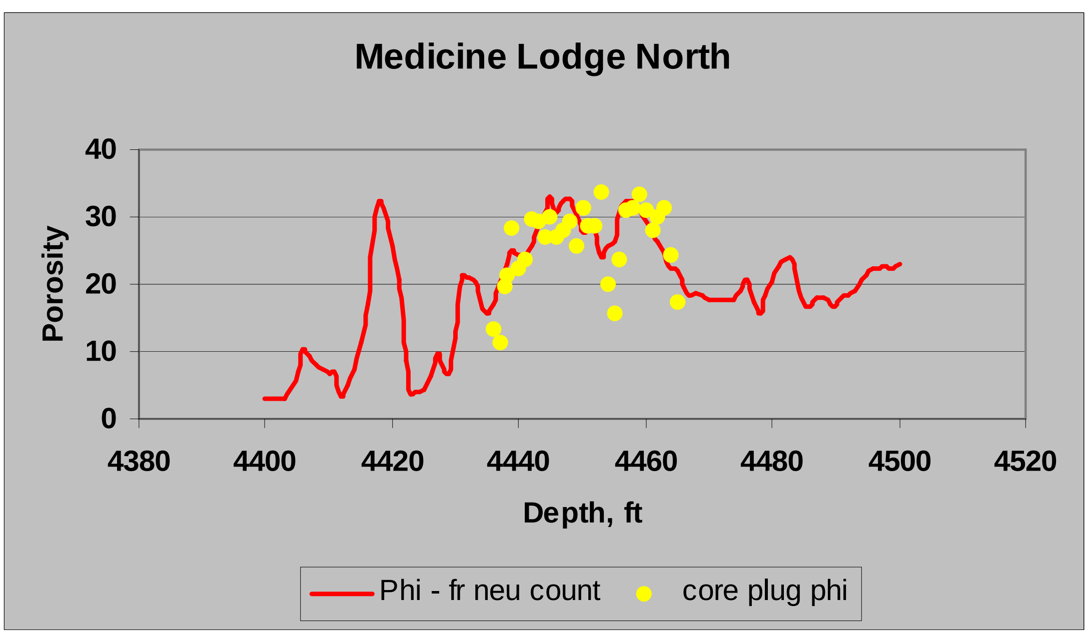

FIGURE 4. Comparison of core-plug porosity to log porosity (neutron counts) for #12 Thomas-Forsyth core.

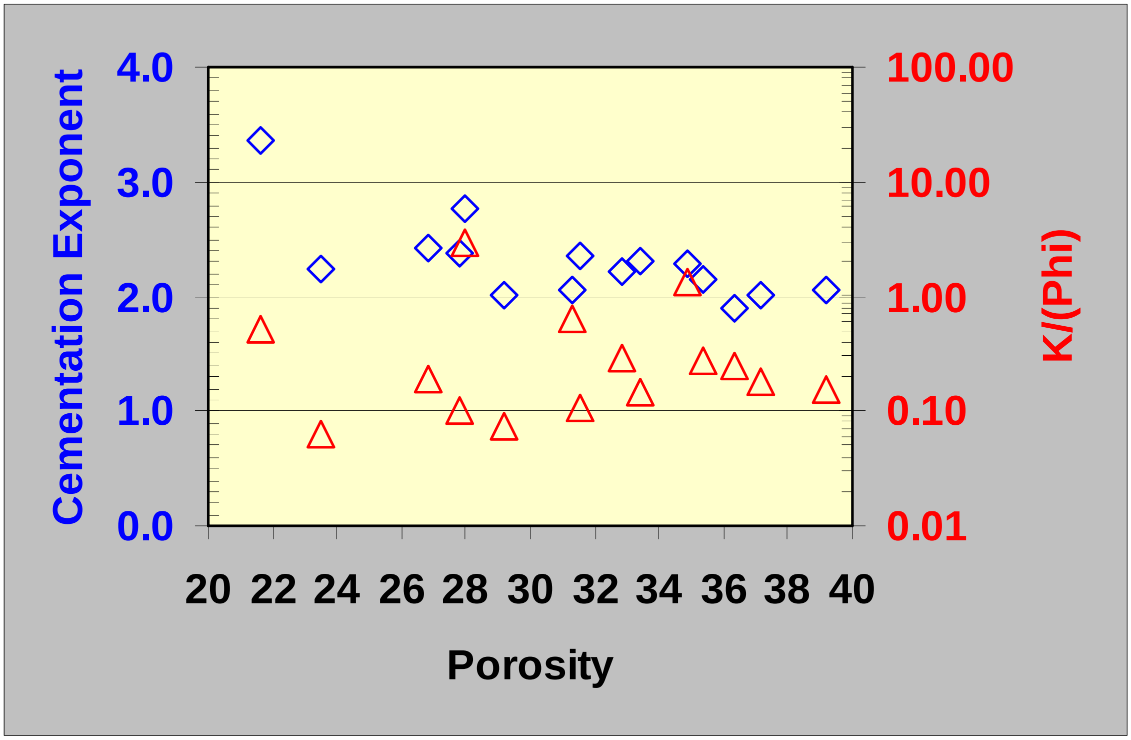

FIGURE 5. Measured cementation exponent vs. porosity for #12 Thomas-Forsyth core.

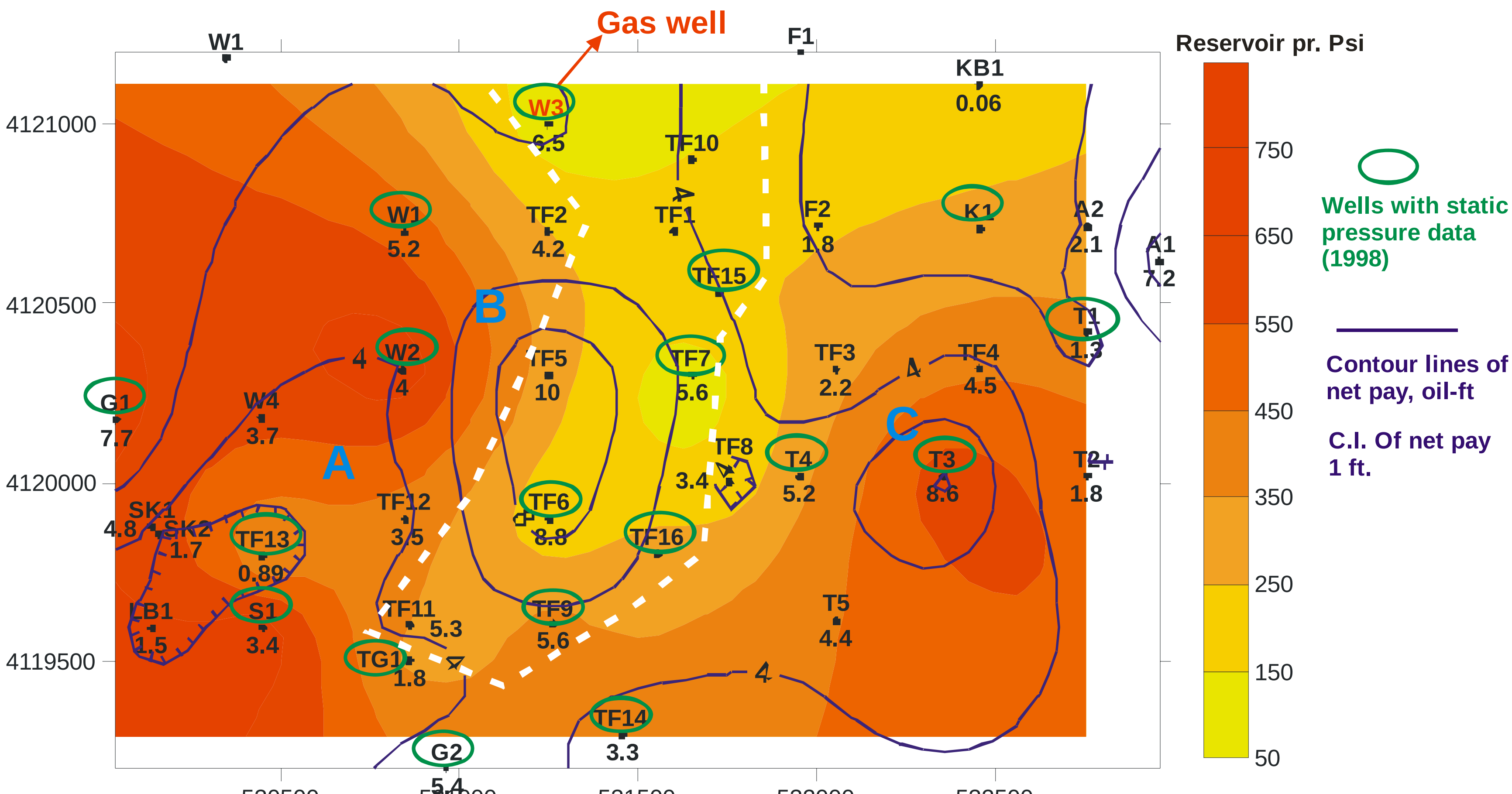

FIGURE 6. Net pay (contour lines) spatially compared to reservoir pressure (shaded contours). Prospective coring locations are denoted by the light blue letters, "A", "B", and "C".

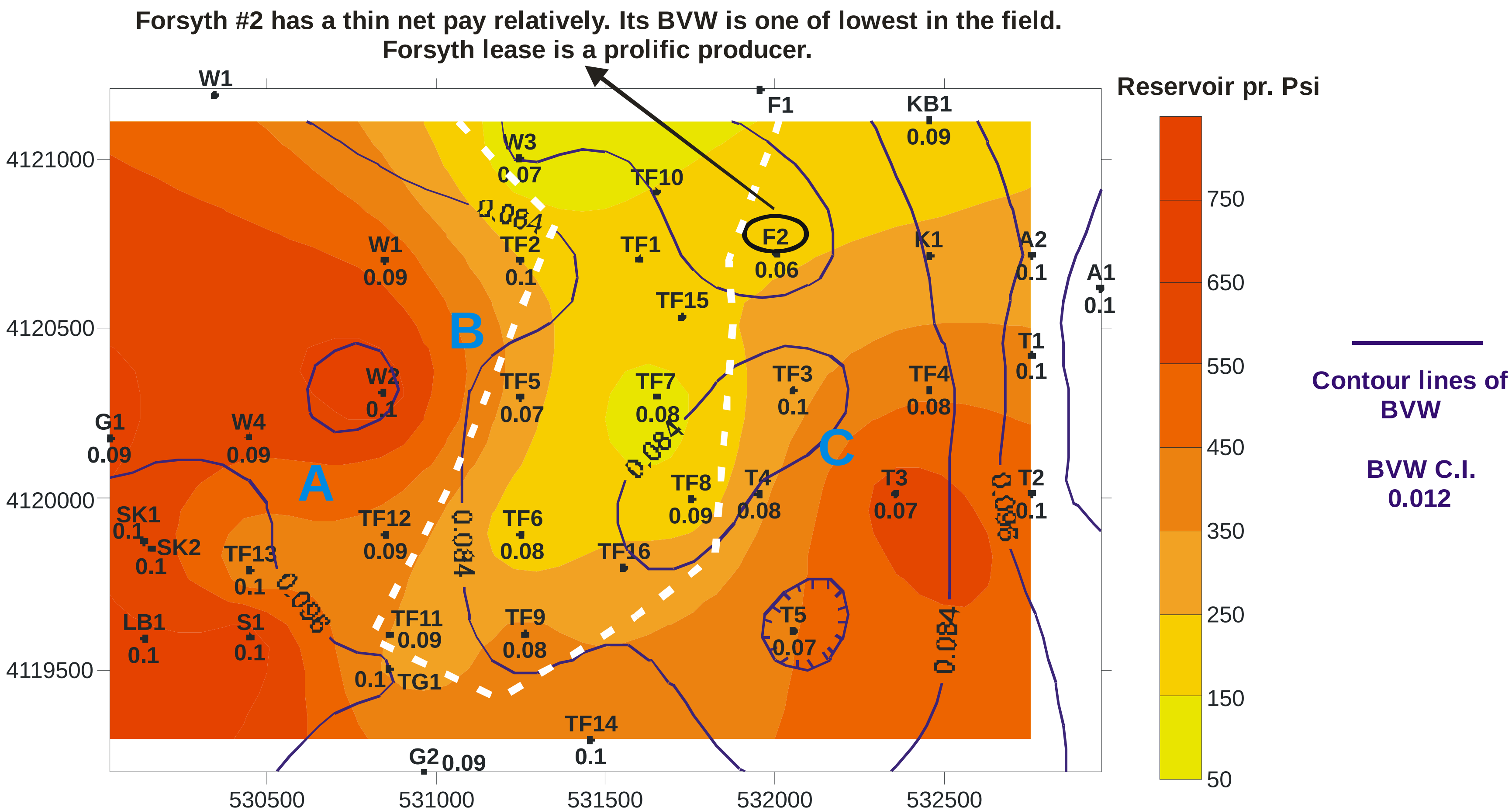

FIGURE 7. Comparison of reservoir pressure map (shaded contours) with BVW (contour lines). See text for discussion.

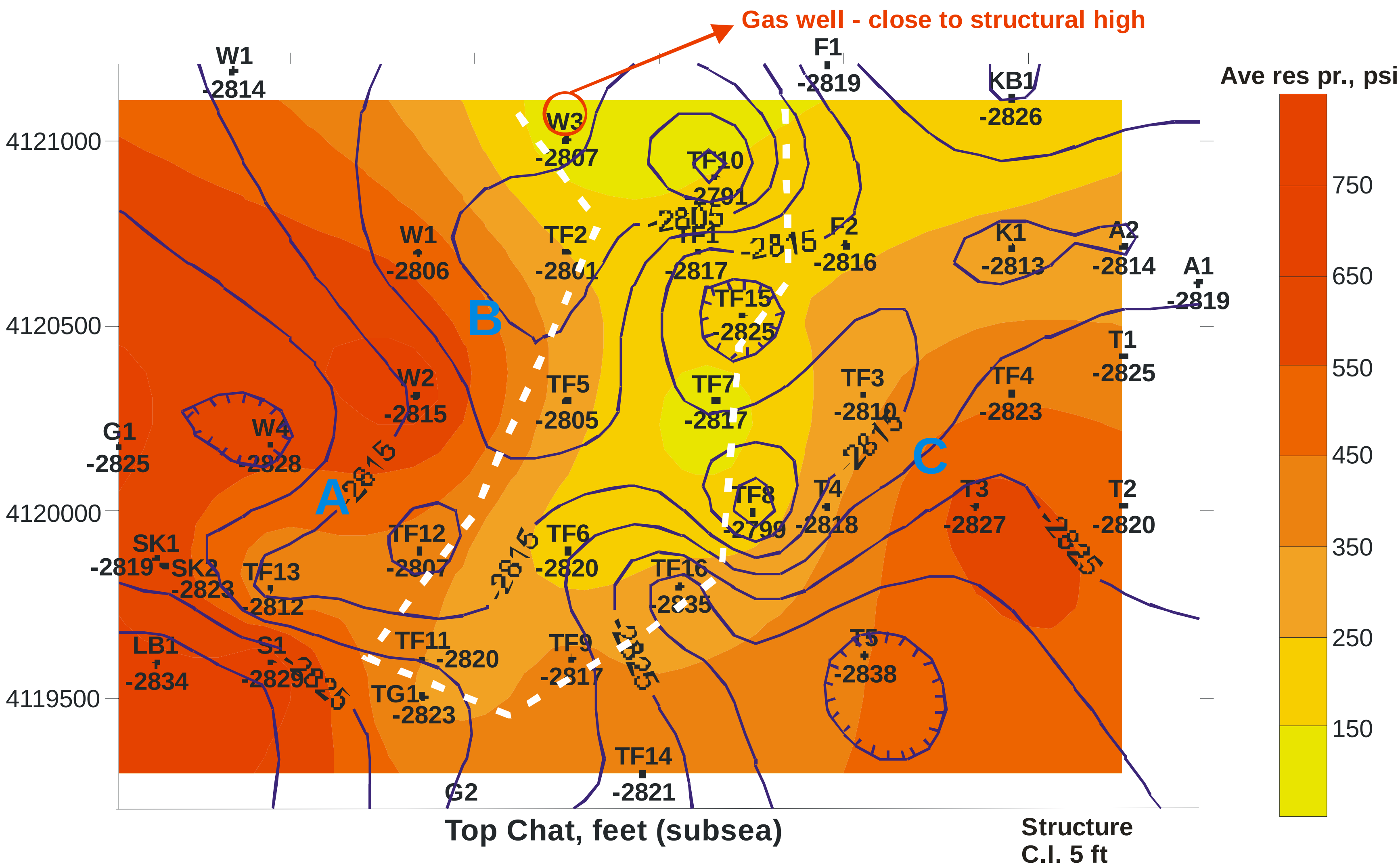

FIGURE 8. Reservoir pressure map (shaded contours) overlain by structure map (contour lines). See text for discussion.

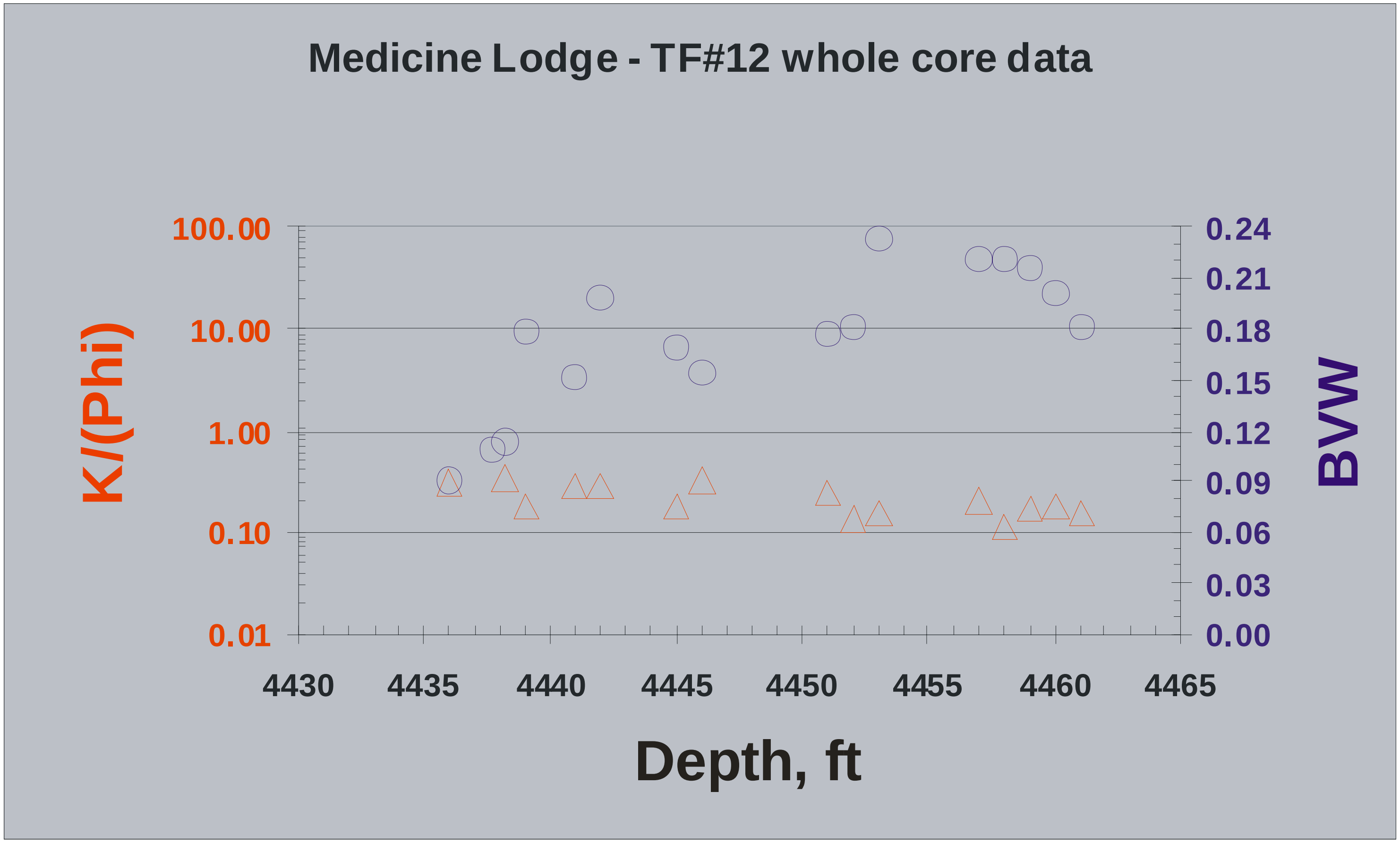

FIGURE 9. A crossplot of BVWI values vs. depth for data measured on whole cores from the #12 Thomas-Forsyth well. The core data span over 27 ft in vertical depth. BVW values (blue circles) for plugs belonging to the same petrofacies - similar K/(Phi) values (red triangles) have been plotted. The trend of increasing BVW with depth is indicative of a transition zone with a minimum BVW value around 0.09.

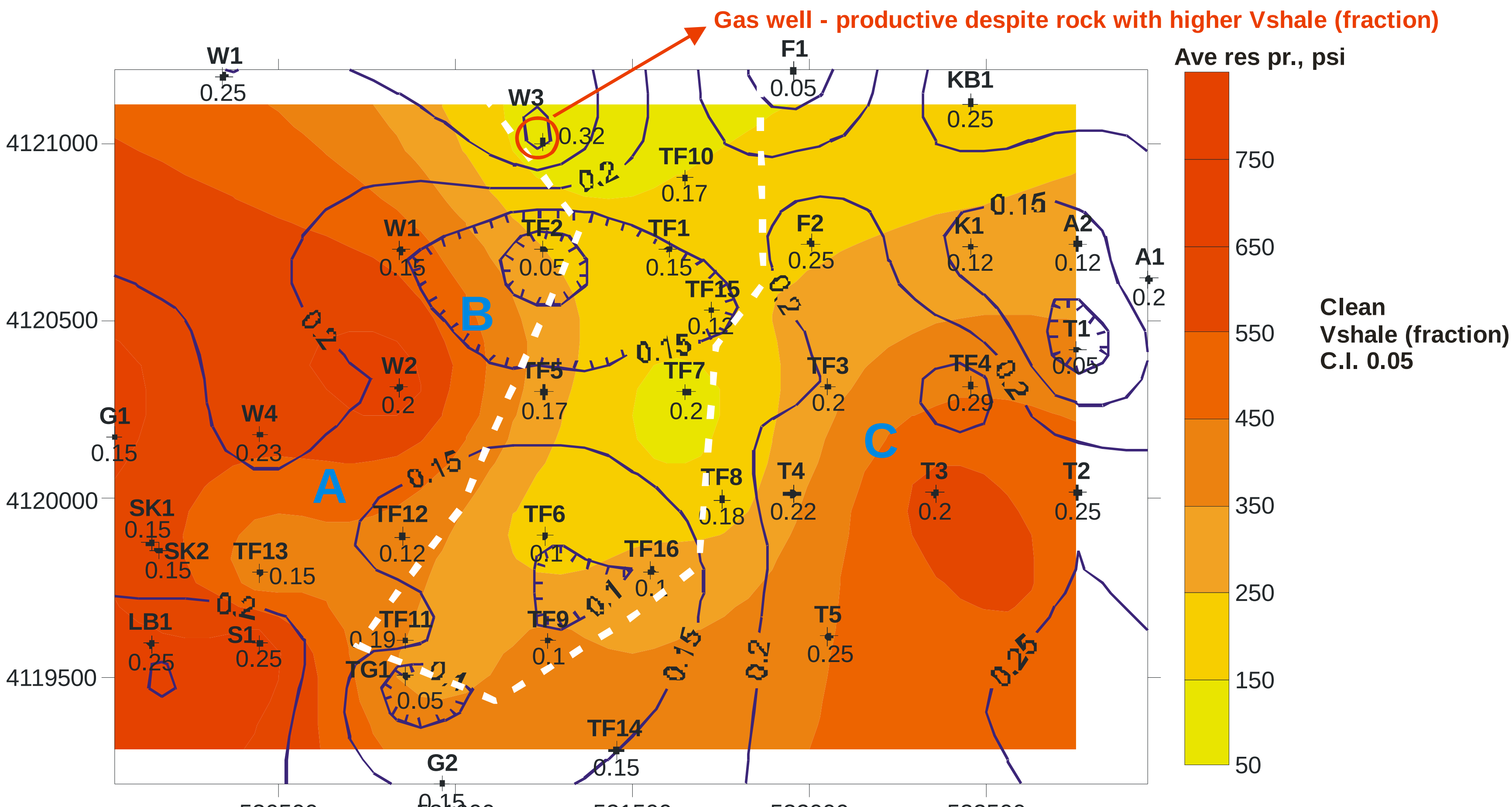

FIGURE 10. An overlay of V_{shale} (fraction) (contour lines) on the reservoir pressure map (shaded contours). See text for discussion.

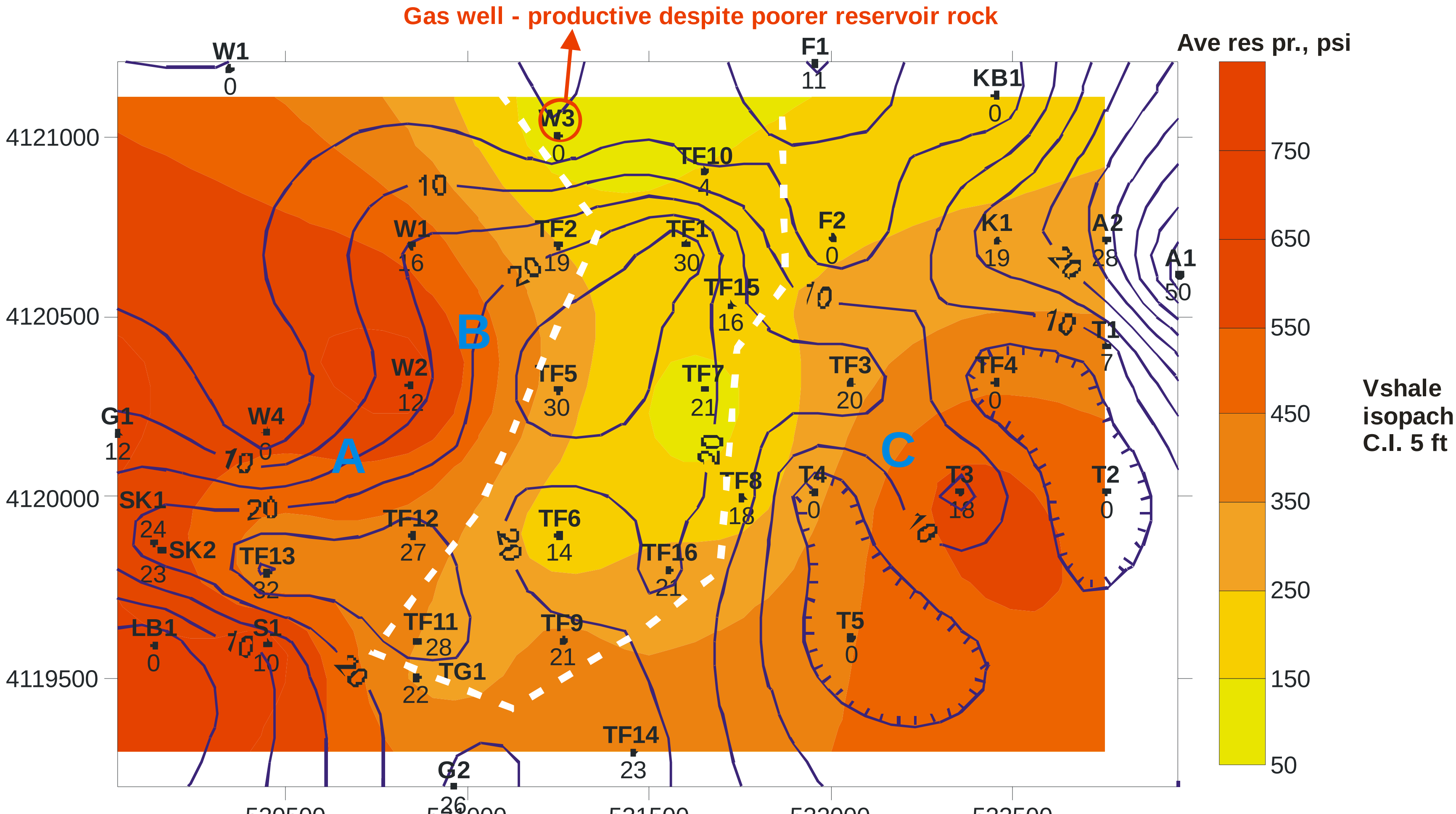

FIGURE 11. Isopach of low V_{shale} footage at each well (contour lines) compared to reservoir pressure (shaded contours). See text for discussion.

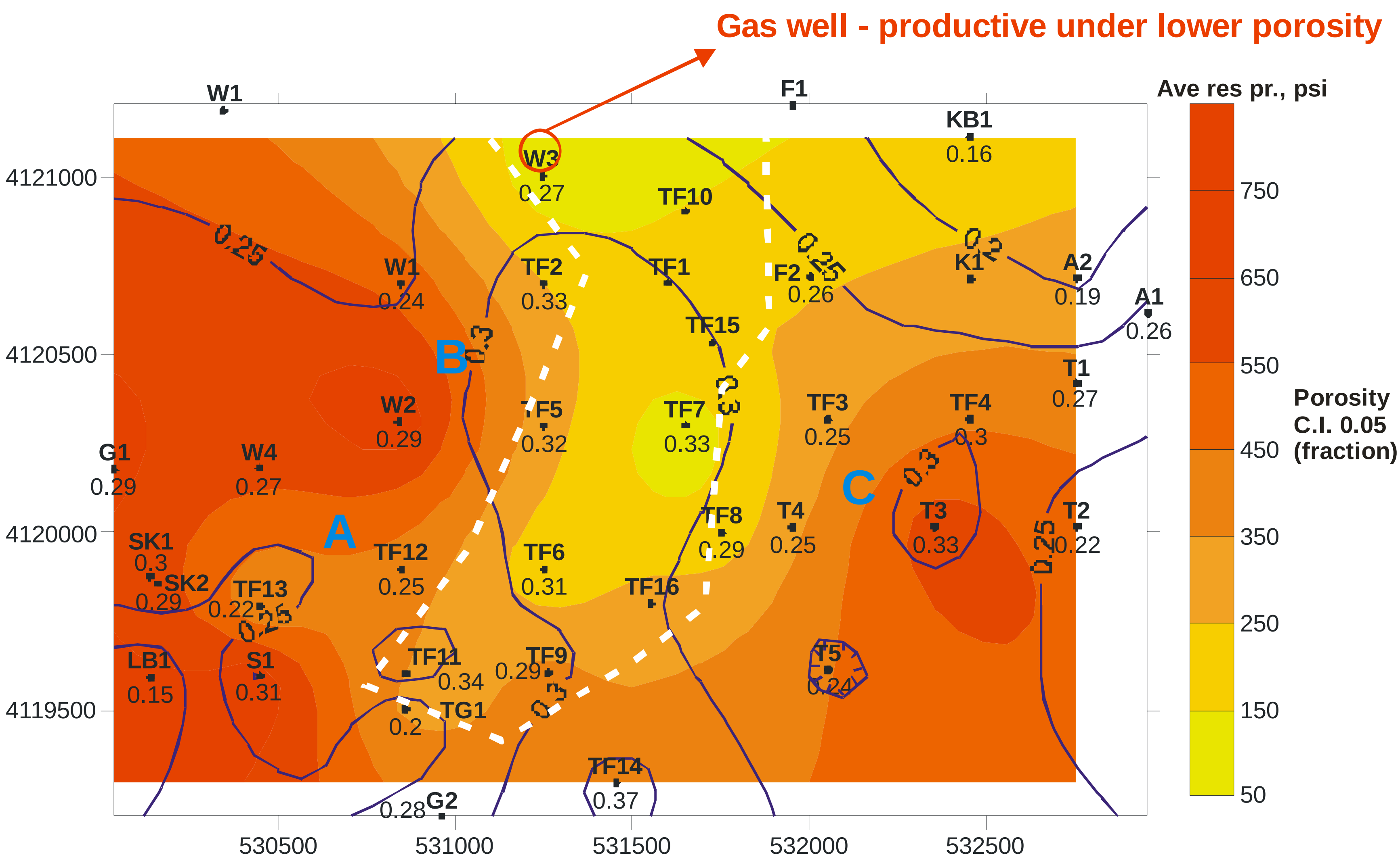

FIGURE 12. Average fractional porosity calculated for reservoir interval at each well (contour lines) compared to reservoir pressure (shaded contours). Wells in the production fairway have an average of 30% porosity.

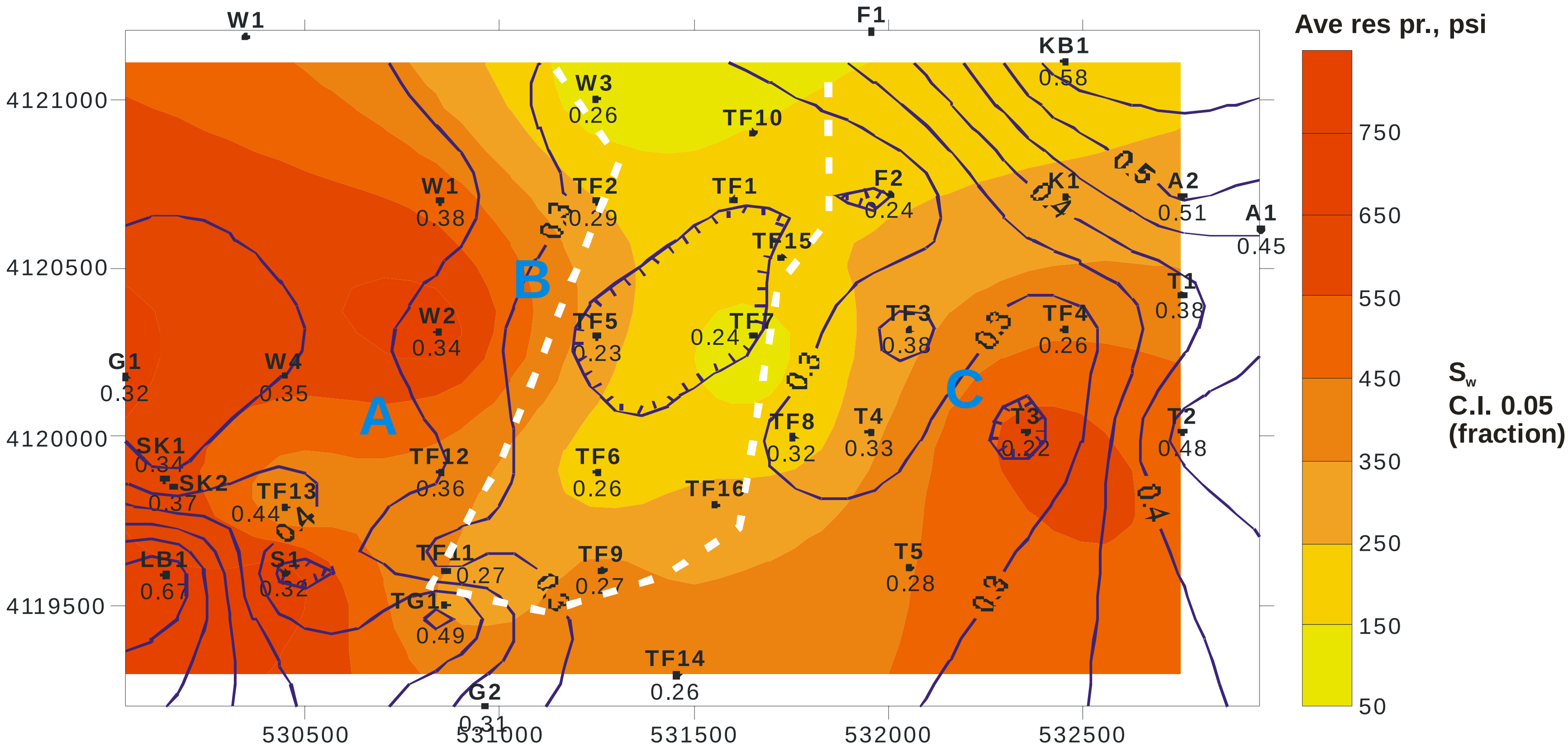

FIGURE 13. Average S_w calculated at each well (contour lines) compared to reservoir pressure (shaded contours). See text for discussion.