GEOLOGIC ANALYSIS OF PRIMARY AND SECONDARY TIGHT GAS SAND OBJECTIVES, PHASE C

QUARTERLY REPORT
(February 1, 1984 - April 30, 1984)

prepared by

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for

GAS RESEARCH INSTITUTE
Contract No. 5082-211-0708

April 1984

DISCLAIMER

CONTENTS

FIGURES

TABLES

RESEARCH SUMMARY

Title	Geologic Analysis of Primary and Secondary Tight Gas Sand Objectives, Phase C
Contractor	Bureau of Economic Geology, The University of Texas at Austin, GRI Contract No. 5082-211-0708
Principal Investigator	R. J. Finley
Report Period	February 1, 1984 - April 30, 1984
Objective	To conduct depositional systems and basin analysis of the Corcoran and Cozzette Sandstones and the Travis Peak Formation as representative blanket-geometry, low-permeability gas sandstones. To integrate studies of sandstone distribution and reservoir geometry with responses to reservoir stimulation and to determine correlation with resource distribution.
Technical Perspective	Previous evaluations of blanket-geometry tight gas sandstones led to the selection of the Corcoran and Cozzette Sandstones of the Piceance Creek Basin and the Travis Peak Formation of the East Texas and North Louisiana Basins as major research objectives. The increased availability of tight gas resources and the development of technology with a high degree of transferability are expected results from the study of these stratigraphic units. Work reported here involves all aspects of the depositional systems and reservoir geology of these units as a basic element of resource characterization. Controls on the distribution of reservoir facies and an interface with engineering aspects of low-permeability reservoir development are emphasized.
Results	A map representing the sand-rich component of the Travis Peak Formation suggests that fluvial input came from the northwest, across Upshur County, Texas, to build a major fluvial-deltaic complex in the northeastern part of the East Texas Basin. This complex built out onto a relatively shallow shelf and is a dominant component of the Travis Peak in the multi-county area of research emphasis. Initial studies of reservoir diagenesis in the Travis Peak show that quartz overgrowths and calcite cement are major factors in occluding primary porosity. Good porosity and permeability remain in the Travis Peak "A" sand in the Clayton Williams, #1 Sam Hughes well, however, because quartz crystal terminations have not grown completely together. Studies of Travis Peak gas fields have shown that drive mechanisms vary from a weak to moderate water drive to a gas expansion drive only. Average permeability-thickness product varies from 65 md-ft to 5 md-ft in four fields investigated. Analysis of potential cooperative coring and logging operations was completed for wells in Pinehill Southeast field (Panola County, Texas) and in Percy Wheeler field (Cherokee County, Texas); review of the former area was part of cooperative studies which were carried out at the Clayton Williams, #1 Sam Hughes well in April, 1984.

Study of the Corcoran-Cozzette Sandstones resulted in identification of three genetic sandstone units in the Cozzette, two of which are interpreted as strandplains and one interpreted as a barrier or marine bar. Investigation of areal variation in gas productivity from the Corcoran-Cozzette is complicated by completion of wells in some combination of the Rollins, Corcoran, and Cozzette Sandstones, and almost always in more than one genetic sandstone unit, even if completed only in the Corcoran. Neutron-density crossover reflects primarily the distribution of the sand body, therefore porosity and water saturation mapping may be appropriate to compare potential rather than actual productivity of genetic sandstone units in the Corcoran-Cozzette.

Technical Approach

All phases of research on the Travis Peak Formation and the Corcoran-Cozzette Sandstones have continued to make extensive use of well log data for geological and engineering interpretations. To evaluate potential sites of cooperative coring and logging operations in the Travis Peak, all available offset well control and completion cards were acquired, cross sections prepared, and recommendations made in coordination with other Gas Research Institute (GRI) contractors.

Computer routines have been developed and are now being perfected to define porosity and water saturation distributions in the Corcoran-Cozzette. Initial application of these routines is being made in the Shire Gulch-Plateau-Buzzard field area where dense well control is available.

PROGRAM OBJECTIVE

Guiding basin analysis research at the Bureau of Economic Geology has been the concept that sandstone bodies are the product of a suite of processes operating within major environments or depositional systems that are active during infilling of a basin. Typically these systems include several major environments of sand deposition; resultant sand bodies are the genetic facies such as meanderbelt, coastal barrier, or crevasse splay facies. Each of these facies has consistent physical attributes within an individual system or major depositional element where processes and available sediment types were relatively uniform. Consequently, interpretive description and mapping of the depositional systems and their component facies are basic steps in the geologic characterization of a tight gas sand or any hydrocarbon reservoir.

Such factors as initial permeability, proximity to source or sealing lithologies, and interconnection with other permeable units are inherent attributes of genetic facies that control or affect migration and distribution of hydrocarbons. Thus, facies analysis may identify preferred reservoir types and provide the basis for improved resource estimation and geographic extrapolation or prediction of tight gas trends. The significance of these attributes is indicated by the fact that typically only limited zones that constitute a small percent of the total sand-bearing interval contain producible gas.

Delineation of the depositional framework has greatest application in providing the basis for characterization of tight gas reservoirs, both on a regional and local basis. Delineation of depositional systems outlines the principal building blocks of the basin fill that may produce gas. Within each of these building blocks, sand bodies of component facies will have similar dimensions, orientation, interconnectedness, and internal permeability variations or compartmentalization. Internal heterogeneity of sand bodies results from the style of sediment accumulation, which may include aggradation, progradation, and lateral accretion. Though similar in geometry, progradation and lateral accretion are characterized by coarsening-upward and fining-upward textures that are typically reflected in permeability trends. Quantification of sand-body geometry in a complex depositional system necessitates initial recognition of differing external and internal geometric elements. Further, extrapolation of detailed sand body studies based on limited areas of dense data is guided by the regional interpretation.

Composition of reservoir sandstones reflects depositional processes, is important in affecting certain petrophysical parameters, and affects the extent and mineralogy of diagenetic mineral phases that occlude pore space and affect reservoir quality. Recognition of mineralogic facies and a full understanding of all aspects of the depositional systems of tight gas reservoirs will vastly improve the ability of the gas industry to effectively delineate and develop the unconventional gas resource in tight sandstones. By studying two stratigraphic units in detail, methodologies and geologic relationships will be developed which can be extrapolated to an understanding of an even broader group of tight gas reservoirs.

SPECIFIC OBJECTIVES FOR THE CURRENT YEAR

Phase C: November 1, 1983 - October 31, 1984

During this time period, derivative geologic mapping and facies interpretation will be completed, having been initiated late in the previous contract year. Emphasis will now shift from framework and areal studies to more specific understanding of reservoir sand package geometry, the diagenetic history of the stratigraphic unit as a whole and of particular reservoirs, and to the correlation of reservoir quality with production data. The degree of success of fracture treatments will be specifically examined in relation to regional tectonic framework, facies, reservoir geometry, and diagenetic characteristics. Correlation will be made between all significant geologic and engineering variables, and a close interface will be maintained with concurrent GRI-funded research on log interpretation, reservoir modeling, fracture design, and development of stimulation treatments including fluids and proppants. Cooperative logging, coring, and testing with well operators will be of particular value during this period because geologic framework and genetic stratigraphic studies will allow more specific targeting of critical facies and reservoir types. A major objective of coring and logging opportunities will be to refine the process of selecting areas for staged field tests. The availability of leases and operator interest in areas of potential field tests will become important in 1985 as selection of possible sites proceeds.

Specific activities during the second contract year (November 1, 1983 - October 31, 1984) will include:

1. Analysis of reservoir dimensions and geometries to determine how to best quantify reservoir continuity and to determine the geologic parameters with the greatest influence on reservoir productivity in specific fields.

2. Specialized mapping of diagenetic characteristics and variability in texture and mineralogy for comparison with primary mapping (isopach, structure contour, etc.) and facies mapping.

3. Areal variation in producibility of tight gas reservoirs and the success of stimulation treatments will be mapped and overlain with maps delineating facies.

4. Overall favorability of different trends within primary and secondary research areas will be assessed as a synthesis of factors needed to locate the most suitable areas for staged field tests.

WORK PLAN FOR THE CURRENT YEAR

The following work plan provides details of the technical approach to be followed:

Phase C. Reservoir Geometry, Diagenesis, Responses to Stimulation and Resource Distribution

Task I. Analysis of Reservoir Geometry

Subtask 1. Complete derivative geologic mapping to complement the primary map suite.

Subtask 2. Continue to recommend coring, logging, and testing operations as part of the description of the component facies elements of principal depositional systems.

Subtask 3. Determine reservoir sand dimensions and geometries through localized detailed studies and determine how best to quantify reservoir continuity.

Subtask 4. Examine extrapolation potential of reservoir geometry studies between primary and secondary objectives and to areas of lower priority.

Subtask 5. Utilize geologic framework and reservoir geometry studies to isolate prospective fairways for staged field tests.

Task II. Studies of Diagenesis

Subtask 1. Summarize mineralogic composition, diagenetic history, and textural features that affect reservoir porosity and permeability.

Subtask 2. Map compositional or diagenetic facies and overlay with genetic facies mapping to characterize tight gas reservoirs.

Subtask 3. Utilize results in selection of coring and logging locations, in evaluation of extrapolation potential between areas, and in definition of prospective fairways for staged field tests.

Task III. Responses to Stimulation

Subtask 1. Analyze production history, extent of productive area, and success of stimulation techniques in relation to the combined factors of genetic facies, reservoir geometry, and composition/diagenesis.

Subtask 2. Illustrate relationships between geologic factors and production or engineering data using cross plots or derivative maps, as appropriate.

Subtask 3. Utilize results in selection of coring and logging locations, in evaluation of extrapolation potential between areas, and in definition of prospective fairways for staged field tests.

Subtask 4. Coordinate with other GRI contractors and provide necessary geologic input into studies of fracture diagnostics, fluids and proppants, and reservoir modeling.

Task IV. Evaluation of Resource Distribution

Subtask 1. Provide geologic data for GRI and its other contractors to utilize in resource analyses of primary and secondary objectives and areas of lower priority.

Subtask 2. Evaluate new formation tests and new trends in operator activity for implications regarding total resources in tight gas units under study.

Task V. Documentation

Subtask 1. Select representative maps, cross sections, cross plots, and photomicrographs for drafting and/or photographic reproduction.

Subtask 2. Prepare report incorporating results of Phase C.

Subtask 3. Recommend actions necessary to screen areas for designation of staged field tests.

RESULTS OF THE PREVIOUS QUARTER

During the previous quarter studies of the Travis Peak Formation were conducted primarily in a six-county area of Texas covering the western half of the Sabine Uplift. Included in this area are Rusk and Nacogdoches Counties and a part of Cherokee County wherein most Travis Peak drilling and production activity occurred in 1983. Two generalized facies were defined in the Travis Peak based on spontaneous potential (SP) log character in depositionally updip and downdip areas. Facies A (updip) is dominated by sand with no persistent shale breaks. The individual sands are broadly lenticular, range up to 50 ft in thickness, and fine upwards. The stacked sands are interpreted as multi-storied aggradational channels representing deposition in an alluvial plain or upper delta plain environment. Facies B occurs in the more depositionally downdip Travis Peak and is characterized by siltstones and thin, sheet-like sandstones interbedded with some very thin carbonates. This facies appears to have been deposited in shallow marine waters on a protected shelf. Both facies grade into one another across a broad transition zone.

Engineering studies of the Travis Peak Formation in the previous quarter emphasized analysis of production history and test data in North Lansing and Whelan fields in Harrison County. Results of these studies have shown that only a weak to moderate water drive mechanism is present in these fields, therefore a gas expansion drive mechanism is probably dominant. Productive area of each field, with high initial absolute flow potential and permeability-thickness product, is coincident with the structural high on which the field is located. Production with higher water/gas ratio in these fields occurs around the field margins, indicating higher water saturation in a gas/water contact zone, and also suggesting that water encroachment toward the gas reservoir might be coming from the edge rather than beneath the producing interval. The distribution of water/gas ratios and of initial pressures suggests that the direction of hydrocarbon migration was approximately from basin center toward basin margin across the North Lansing - Whelan structure.

Studies of the Corcoran-Cozzette Sandstones during the previous quarter were focused primarily on the Corcoran. Four major genetic sandstone units were identified within the gas-productive area of the Corcoran with an additional sandstone unit in updip areas only. In the Shire Gulch - Plateau field area the lowest Corcoran sandstone is interpreted as a regressive strandplain deposit that is laterally continuous over a wide area. The upper Corcoran was found to include three vertically and areally distinct sandstones, ranging from regressive to transgressive barrier sand bodies.

WORK PLANNED FOR THE CURRENT QUARTER

Work planned for the current quarter included an expansion of Travis Peak structure, isopach and initial facies delineation to cover a larger area of research emphasis in East Texas and several parishes of adjacent Louisiana. Engineering studies of Travis Peak producing fields were continued and expanded as part of continued analysis of Travis Peak production and trapping characteristics. Two cooperative well locations for coring and logging in the Travis

Peak were evaluated, and one of these, which became the first GRI cooperative well of the program, was evaluated in detail.

For the Corcoran and Cozzette Sandstones, an analysis of production data compiled by the Colorado Geological Survey was undertaken. This work indicated that additional well log analysis would be required to relate reservoir properties to production data. Three genetic sandstone units were defined within the Cozzette in the Shire Gulch - Plateau field area. The Colorado Geological Survey completed description and sampling of additional core, and initiated a study of coal distribution within the Corcoran-Cozzette.

RESULTS OF THE CURRENT QUARTER

Travis Peak Studies

Depositional Systems

The Travis Peak Formation in East Texas has continued to be one of the most active gas exploration areas in the Gulf Coast province. Because of increased activity in Cherokee and Smith Counties, Texas, regional study of the Travis Peak was expanded down the south and west flanks of the Sabine Uplift as far as well control would allow. The area of highest research emphasis (fig. 1), now covers almost the entire Sabine Uplift. The Pettet (Sligo), structure and Pettet-Travis Peak isopach maps have been extended and updated (figs. 2 and 3), and a map which approximately illustrates the distribution of sandstone in the Travis Peak was constructed. This map (fig. 4) shows the percentage of the combined Pettet-Travis Peak section that contains sandstone-rich intervals characterized by high spontaneous potential (SP) deflections. This type of presentation was necessary because the formations thin in the same direction that the sand content increases, such that gross or net sand contours would be smoothed out by the compensating effect of the thinning section. Our primary interest was to outline a potential Travis Peak delta complex that was believed to exist in the area; the percent sandstone interval map seems to have accomplished this. It appears that the major influx of sand was from the northwest across Upshur County, rather than from the north. Apparently the Ouachita fold belt in Oklahoma and Arkansas supplied detritus to a narrow delta plain which extended down into northeast Texas. According to Martin and others (1954) gravels from this northern source were composed mainly of quartzite and novaculite clasts whereas pebbles in the larger delta complex to the south are described as being composed dominantly of chert and quartz (McGowen and Harris, in press). The mature, quartzose, medium to fine-grained sands described from the Travis Peak Formation over the Sabine Uplift suggest a more diverse and distant source. The finer-grained clastics may possibly have originated from reworked Triassic red beds in north-central Texas and from quartz and chert-rich sandstones of the Late Jurassic formations in New Mexico. Future work on Travis Peak cores should indicate which source areas were dominant.

The fluvial-deltaic system apparently crossed the trend of the underlying salt folds almost at a right angle. Where the salt was thick in the mid-portion of the basin, salt anticlines continued to grow as the Travis Peak was deposited and apparently some of the streams were diverted toward the northeast and the southwest along synclinal axes. Depositional patterns across the Sabine Uplift were less affected by salt structures because the thinner, originally-bedded salt formed only low-relief anticlines that had little influence on depositional patterns.

The sediment transport direction across Panola County, Texas is indicated to be from the northwest to the southeast (fig. 4). In order to test the validity of this trend, two separate channel or distributary sandstone beds were chosen for more detailed study. Individual sandstone beds are impossible to correlate in the massive, sand-rich intervals of the lower and midddle Travis Peak therefore a more isolated sandstone within the upper marine transition zone (fig. 5) and the first channel sandstone above the Knowles Limestone were mapped (fig. 6). The isopach maps of these two sandstones indicate that the thicker channels in both units trend approximately N40!W. This trend is essentially identical to the trend direction across central Panola County shown on the regional percentage map. The two sandstones that were mapped are shown on a stratigraphic cross-section through Carthage field (fig. 7). The section also illustrates the sandstone intervals that were measured to obtain the sandy interval percent map (fig. 4), and demonstrates the distinctive character of the tops of the Pettet and Cotton Valley formations in electric logs over most of the Sabine Uplift.

In summary, the regional work this quarter has confirmed the existence and importance of contemporaneous salt anticlines on the flanks of the Sabine Uplift. A large Travis Peak delta complex has been outlined within the area of interest. This large delta complex appears to be a composite of high-constructive deltas that may have been very similar to the Pleistocene Mississippi delta system described by Caughey (1975) in South Louisiana. This large Travis Peak delta system was apparently fed by a major integrated fluvial system that flooded a broad, shallow shelf area with sediment over a period of perhaps 10 million years (Kupfer, 1976).

Future work will involve a subdivision of the Travis Peak and an attempt to define the various sedimentary facies to see how they are related to oil and gas production. A regional synthesis of East Texas and North Louisiana will be prepared so that a framework exists for incorporating the detailed studies that are to follow.

Reservoir Diagenesis

A Travis Peak sandstone sample from the Clayton Williams #1 Sam Hughes well, Panola County, was examined by scanning electron microscope (SEM). The sample is from 6843.5 to 6843.7 ft (Travis Peak "A"), from a 4-ft thick, very fine-grained sandstone that may be productive of gas or gas/condensate.

The original depositional porosity has been reduced by abundant authigenic cement. Quartz overgrowths (fig. 8) and calcite cement (fig. 9) are the most common authigenic minerals. Authigenic clays are present (fig. 10) but not abundant. The clays probably consist of chlorite and kaolinite. The remaining porosity is mainly primary, intergranular porosity which is bounded by crystal faces of the authigenic cements (fig. 10). Some pores have been completely occluded by the growth of interlocking cements.

Samples of upper Travis Peak sandstones were also available from the Humble #1-C Southern Pine Lumber well in Anderson County. Sample depths ranged from 8,844 ft, in the

Pettet limestone, to 9,120 ft. The samples are gray or red very fine-grained sandstones to coarse siltstones that are well-to-moderately well sorted.

The most common detrital minerals in these Travis Peak sandstones are quartz (90 to 98%), feldspar (2 to 9%), and rock fragments (0 to 2%). The sandstones are classified as quartzarenites and subarkoses (Folk, 1974). Feldspar types include plagioclase, orthoclase, and microcline; partial dissolution of feldspars has been observed. The most common rock fragments are very fine grained siliceous rock fragments and ripped up shale clasts. Accessory minerals, which generally form less than one percent of the rock volume, are biotite, muscovite, glauconite, zircon, hornblende, tourmaline, and epidote.

Authigenic minerals observed in the sandstones are quartz (fig. 11), dolomite (fig. 12), calcite, chlorite (fig. 11), pyrite, hematite, and feldspar. The volume of cement ranges from 12 to 52 percent; cement volumes that exceed approximately 35 percent indicate that cement has replaced some framework grains. The volume of porosity is correspondingly low, from 0 to 1.5 percent. Quartz overgrowths in one sample (fig. 4) have a rounded appearance, suggesting some dissolution has occurred.

Contacts have been made with Amoco Production Company and Sun Oil Company to borrow additional Travis Peak cores. Permission has been received from Amoco to borrow and sample the following two cores: No. 1 Michael Kangerga "C", Dirgin field, Rusk County, and Caldwell Gas Unit No. 2, Southwest Woodlawn (Travis Peak) field, Harrison County. We are requesting permission from Sun to borrow Travis Peak cores from the No. 2 Janie Davis well, N. Lansing field, Harrison County and the No. 2 D. O. Caudle well, Carthage field, Panola County. These four cores should contain approximately 700 ft of the Travis Peak Formation, and together with core obtained from GRI cooperative wells, should form the basis for initial studies of Travis Peak diagenesis.

Engineering Studies of Production History and Test Data

Field studies of production history and reservoir test data for the Travis Peak Formation in East Texas have been conducted for Whelan, Lansing North, Willow Springs, and Appleby North fields. Cumulative gas production (through June 1983) is 107 Bcf from Whelan field (developed in the late 1940's), 11 Bcf from Lansing North field (developed in the late 1970's), 106 Bcf from Willow Springs field (developed in the 1950's), and 3 Bcf from Appleby North field (developed beginning in 1978-1979). Appleby North field is a stratigraphic gas trap; the gas in the rest of the fields studied is structurally trapped. Both Whelan and Lansing North fields are on the same structural high. The production zones of the Travis Peak Formation were divided into several reservoirs with different designations from field to field, such as the Travis Peak, the Travis Peak prorated, and the Travis Peak lower in Whelan field, the Travis Peak and the Travis Peak lower in Lansing North field, and the Travis Peak (without any additional designation) in both Willow Springs and Appleby North fields. The most prolific reservoirs in Whelan and Lansing North fields are the Travis Peak prorated and the Travis Peak lower, respectively.

Production Mechanism and Original Gas in Place

The P/z versus cumulative gas production plot, which is based on the material balance in gas reservoirs, was used to estimate initial gas in place and to study the production mechanism. For some wells in Whelan and Lansing North fields, the pressure behavior in P/z versus cumulative gas production plots and slightly increased water/gas production ratio indicates weak to moderate water drive. It can be shown that the production mechanism is gas expansion with very weak water drive in Willow Springs field, and gas expansion only in Appleby North field. Total original gas in place is conservatively estimated to be 183 Bcf in Whelan field, 22 Bcf in Lansing North field, and 126 Bcf in Willow Springs field. There is not enough production test information to estimate original gas in place in Appleby North field.

Reservoir Productivity

Reservoir productivity is directly or indirectly related to selected engineering parameters, such as initial potential flow, stabilized flow rate, permeability-thickness product, and formation pressure. Thus, these engineering parameters associated with reservoir productivity were reviewed. Initial potential flow ranged from 10 to 59,000 Mcfd with an average of 7,700 Mcfd in Whelan field, from 150 to 24,000 Mcfd with an average of 4,120 Mcfd in Lansing North field (fig. 13), from 82 to 18,600 Mcfd with an average of 4,552 Mcfd in Willow Springs field (fig. 14), and from 54 to 4,410 Mcfd with an average of 1,606 Mcfd in Appleby North field (fig. 15). The productive area with high flow potential is coincident with the structural high in both Whelan and Lansing North fields (fig. 13). In Willow Springs field areas of both high and low flow potential are scattered within the area enclosed by the structural high (fig. 14). In Appleby North field, with no structural trap, the distribution of initial potential flow runs parallel with the structural contours (fig. 15).

The average value of permeability-thickness product is 65 md-ft (range from 0.04 to 750 md-ft) in Whelan field, 38 md-ft (range from 0.35 to 190 md-ft) in Lansing North field, 38 md-ft (range from 0.5 to 160 md-ft) in Willow Springs field, and 5 md-ft (range from 0.08 to 14 md-ft) in Appleby North field. From the distributions of initial potential flow and permeability-thickness product in each field it is evident that these two parameters relating to the productivity of a reservoir are correlated, i.e., both parameters increase or decrease in the same direction.

Initial formation pressure obtained from the back pressure test of each well (at a different depth) was corrected to an arbitrary datum of 8,500 ft by considering the static pressure gradient existing in the fluid column. Average initial formation pressures were 3,080 psi (range from 1,200 to 3,600 psi) in Whelan field, 3,480 psi (range from 2,800 to 3,900 psi) in Lansing North field, 3,440 psi (range from 1,480 to 4,160 psi) in Willow Springs field, and 3,810 psi (range from 2,900 to 4,900 psi) in Appleby North field.

Water/Gas and Gas/Condensate Production Ratio

Assuming no water coning during production, water/gas ratio is expected to be related to the water saturation surrounding the producing well and to the distance to the gas/water contact zone. In both Whelan and Lansing North fields, initial water/gas production ratio is low, about 70 bbl/MMcf on average, over the central part of the structure. Because water/gas production ratio increased to an average of approximately 140 bbl/MMcf during the production period and because reservoir pressure did not drop rapidly during that period, it is also concluded that some water influx into the gas reservoir is occurring. Based on the distribution of water/gas ratio in each well during production, it is inferred that more water influx occurs from the east than from the west for each of the fields. Perhaps this is because the gas/water contact zone is closer to the east side than the west side of each field.

Initial water/gas production ratio is not always available for wells in Willow Springs field. Therefore, the first available water/gas production ratio for some wells was used as an initial water/gas ratio. In this field, the water/gas ratio has increased from an average of 41 bbl/MMcf initially to 71 bbl/MMcf recently; however, the water/gas production ratio in Willow Springs field is small compared with Whelan and Lansing North fields. In Appleby North field, even though initial water/gas production ratio averaged 200 bbl/MMcf, it is believed that part of this water was coming from water injected during well stimulation. This conclusion is based on the pressure behavior shown in P/z plots and comments from Amoco Production Company (R. F. West, personal communication, 1984). Information on gas/condensate ratio, which may reflect the type of organic matter incorporated into the source sediments, is also included in this study. Production with gas/condensate ratios greater than 100 Mcf/bbl is commonly called lean or dry gas, although there is no generally recognized cutoff for this ratio. Wet gas reservoirs may be approximately defined as those reservoirs with gas/condensate ratios in the range of 5 to 100 Mcf/bbl. Overall, the fields studied are dry gas reservoirs because gas/condensate production ratios average over 100 Mcf/bbl. However, one-third of the wells in both Whelan and Willow Springs fields and one-half of the wells in Appleby North field have gas/condensate production ratios in the range of wet gas or gas-condensate reservoirs.

Analyses of Cooperative Well Locations

Well data were examined in two areas surrounding potential coring and logging operations to be conducted in cooperation with Travis Peak operators. In Cherokee County, Texas an assessment of Percy Wheeler field surrounding the Pennzoil Producing Co. #1 Armstrong indicated that this well would be an excellent location for GRI field activities. An agreement on cooperative studies was not reached with the operator; however, the characteristics of this area indicate that it or similar areas should be considered in the future.

Percy Wheeler field is developed on a faulted, northeast-trending anticlinal structure that probably has a core of salt. Hydrocarbon production from the Woodbine Formation was developed in the 1950's on this structure at depths of approximately 4,300 to 4,500 ft; Travis Peak gas resources have been developed in the same area mostly since 1980 and at depths of approximately 8,800 to 9,200 ft. This activity suggests that many other hydrocarbon-bearing structures within the East Texas Basin may, depending upon their time of development, be highly prospective for Travis Peak gas at depths greater than present oil or gas production.

Other characteristics of Travis Peak gas production in Percy Wheeler field make this area an attractive research candidate. The perforated interval of most wells includes two to three discrete sandstones that are 10 to 30 ft thick and are isolated by shales and/or siltstones that would act as well-defined barriers for purposes of fracture containment. These sandstones show "gas effect" on neutron-density logs and post-stimulation initial potential open flows range from 490 to 6,300 Mcfd with a mean of 1,990 Mcfd for 10 wells. Five of these wells exceeded a flow of 1,760 Mcfd. Operators have conducted four-point flow tests in several wells in Percy Wheeler field, and perforating has been selective, but over an interval of no more than 200 to 300 ft. This field, or similar locations in terms of development history and completion practices, should be sought for future cooperative GRI field activities.

The second area examined, Pinehill Southeast field in Panola County, Texas involved a coring and logging operation which was conducted in cooperation with Clayton W. Williams, Jr. as the operator at the No. 1 Sam Hughes during April, 1984. A total of 84.1 ft of core were recovered from two intervals at depths of 6,834 to 6,853 ft and 7,044 to 7,083 ft in the upper Travis Peak Formation. A well 1,500 ft to the north-northeast, the Seagull International Exploration, Inc., #1 E. Grubenman was used in predicting the interval to be cored (fig. 16). The sandstone in the upper core was thinner than expected (it was the operator's primary target) and the upper part of the lower cored interval contained abundant siltstone. Sandstones in the latter interval have been perforated and hydraulically fractured in other nearby wells in the field, hence the selection of this interval for coring. The interbedding of sandstone, siltstone, and shale on the scale shown in the #1 E. Grubenman well is typical of the uppermost Travis Peak in a transition zone just below the Sligo/Pettet Limestone (fig. 16).

The Clayton Williams No. 1 Sam Hughes is located on a west-plunging structural nose coming off the southwest margin of the Sabine Uplift. Upper Travis Peak and Sligo/Pettet completions are distributed along the structural nose mostly north and west of the well location. Gas and gas/condensate are derived from the Travis Peak and wet gas or oil are obtained from the Sligo/Pettet; no production from formations above the Sligo/Pettet has been developed in the Pinehill Southeast field area, other than limited production in the Rodessa Formation.

Corcoran - Cozzette Studies

Depositional Systems

During the quarter, the Cozzette Sandstone was subdivided into genetic sandstone units, three of which occur where the unit is gas-productive in the southern Piceance Creek Basin (wells 161-170, fig. 17). The stratigraphically lowest unit of the three is the most areally extensive within the Cozzette and forms the lower sandstone "bench" within the Shire Gulch-Plateau field area. This basal regressive unit is interpreted as a strandplain which is capped by, or contains, coal updip (wells 164 and 161, fig. 17), and which shales out into the Mancos downdip (well 170, fig. 16). An upward-coarsening gamma ray-log character is characteristic of this unit, and a lower to upper shoreface sequence probably forms much of the preserved sand body.

A younger sand body that is interpreted as a regressive barrier or marine bar sandstone is present along the southeast margin of Plateau field. This unit merges with the top of the underlying strandplain sandstone updip and is separated from the latter by marine shales downdip (wells 136 and 170, respectively, fig. 17). If shale depositionally updip of this sandstone is interpreted as marine rather than lagoonal, then a marine bar origin rather than a barrier origin is more likely for the sandstone.

The uppermost unit of the Cozzette Sandstone in the Shire Gulch-Plateau field area is interpreted as a regressive strandplain sand body on the assumption that the thin shale interval below it is marine rather than lagoonal. This assumption seems reasonable because the shale interval has fewer thin (lagoonal?) coals and sand splays associated with it than what appears to be a lagoonal deposit in the Corcoran Sandstone. This uppermost regressive sandstone is well defined in Shire Gulch field but did not extend to downdip parts of Plateau field (wells 37 and 136, respectively, fig. 17).

Interpretations of both Corcoran and Cozzette genetic sandstone units will be further evaluated by outcrop studies planned in the next quarter. Of particular interest will be outcrops southeast of Palisade, Colorado that are on strike with the barrier-strandplain units defined in the subsurface and approximately 10 mi from the nearest Corcoran-Cozzette gas production.

Gas Production Analysis

Net footage of neutron-density log crossover, representing gas-filled sandstone porosity, was counted for all available well logs in the Shire Gulch-Plateau-Buzzard field area. A correction factor of 3 porosity units was applied to account for shaliness (per consultation with

Ercill Hunt, ResTech, Inc.) after study of selected wells showed that corrections of 2 to 4 porosity units were required for most wells. Maps of neutron-density crossover were prepared for four genetic sandstone intervals in the Corcoran and three intervals of the Cozzette. The most areally extensive neutron-density crossover within the Corcoran exists in the lower Corcoran strandplain and in the upper Corcoran regressive barrier. Within the Cozzette, the most areally extensive crossover exists in the lower strandplain sandstone. Crossover is irregularly developed within the regressive barrier bar, and, within the upper strandplain, is developed mostly within the Shire Gulch field area.

The distribution of neutron-density crossover correlates primarily with the distribution of the sand body as a whole. Efforts to relate crossover to productivity as indicated by initial potential flow have been unsuccessful because wells are most often completed in some combination of the Rollins, Corcoran, and Cozzette Sandstones. Those wells which are completed in a single sandstone member, predominantly the Corcoran Sandstone, are frequently completed in more than one genetic sandstone unit, therefore it appears that relating gas production characteristics, including decline rates, to the geometry and reservoir properties of a given sandstone will be difficult. This effort is further complicated by the variability in fracture treatment afforded different wells by different operators. A plot of proppant volume vs. initial potential flow yielded a diffuse pattern of increased gas yield with increased proppant but not a trend that may be used in a predictive manner.

Because of the above difficulties, an effort has been undertaken to characterize individual genetic sandstones within the Corcoran and Cozzette based on calculated porosity and water saturation. Initial efforts are being made to calibrate log calculations by comparison with core analyses, and future consultation with GRI log analysis contractors will also be required.

Technical Problems

No major technical problems were encountered during the contract quarter covered by this report.

WORK PLANNED FOR NEXT QUARTER

During the next quarter the following actions will be taken:

1. Core from GRI cooperative well studies of the Travis Peak will be examined in detail and analyses coordinated with other GRI contractors.

2. Travis Peak depositional systems studies will focus on derivative mapping and facies delineation in an expanded area of research emphasis within which basic mapping has been completed.

3. Core analyses will be conducted on existing Travis Peak core borrowed from operators, and patterns of diagenesis established.

4. Engineering field studies of the Travis Peak will continue with addition of the Percy Wheeler field to the data set.

5. Potential Travis Peak cooperative well locations will continue to be reviewed in coordination with other contractors.

6. Porosity and water saturation mapping will be conducted in the Corcoran-Cozzette Sandstones as a method to relate potential gas productivity to individual genetic sandstone units.

7. Thin section and SEM studies will be initiated based on samples and descriptions of core obtained by the Colorado Geological Survey.

8. Outcrop studies of the Corcoran-Cozzette will be undertaken to verify log interpretations.

9. The Colorado Geological Survey will conduct a study of coal in the Corcoran-Cozzette as a potential gas source and as an aid to interpretation of depositional environments.

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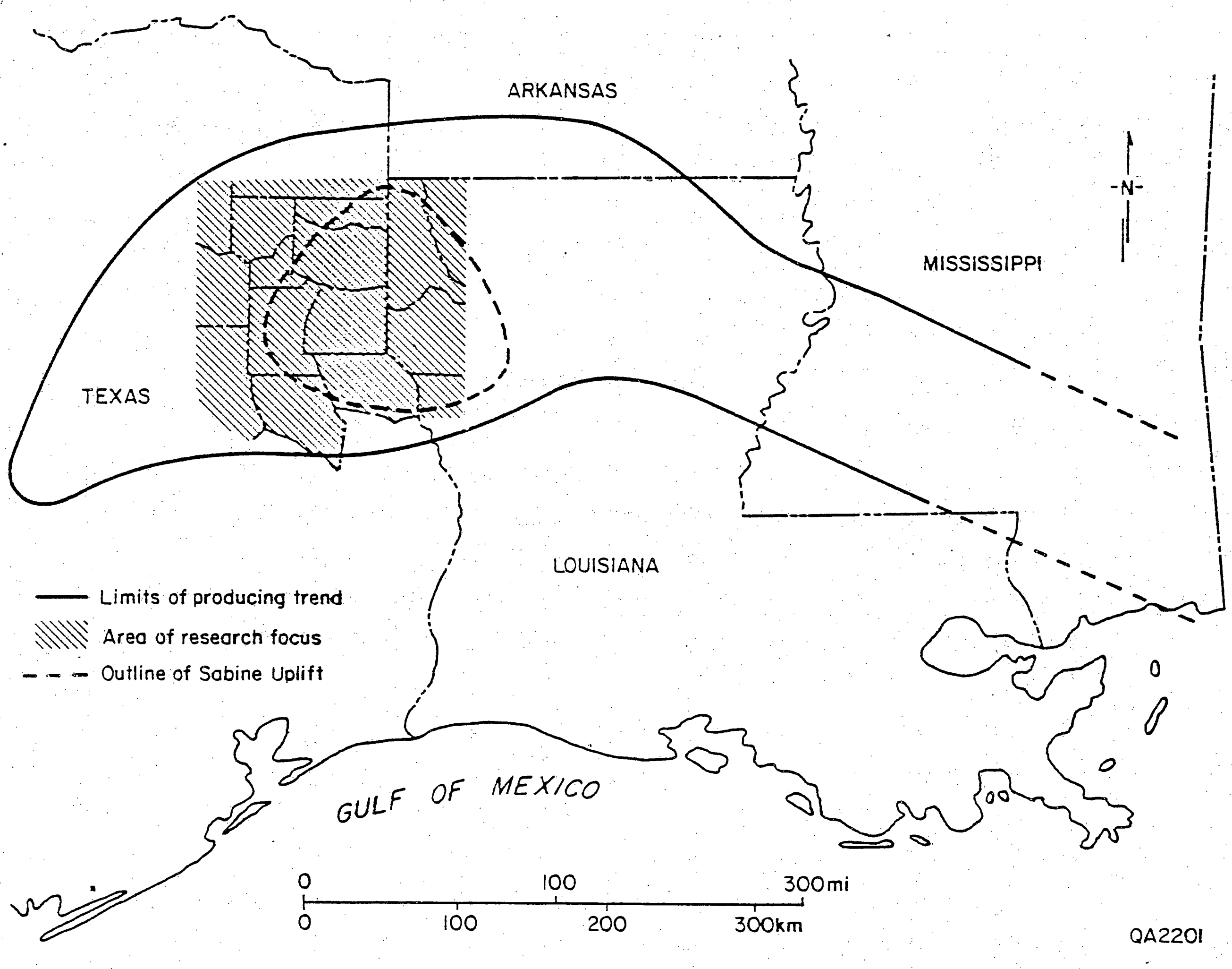

Figure 1. The area of research emphasis in East Texas and northwest Louisiana.

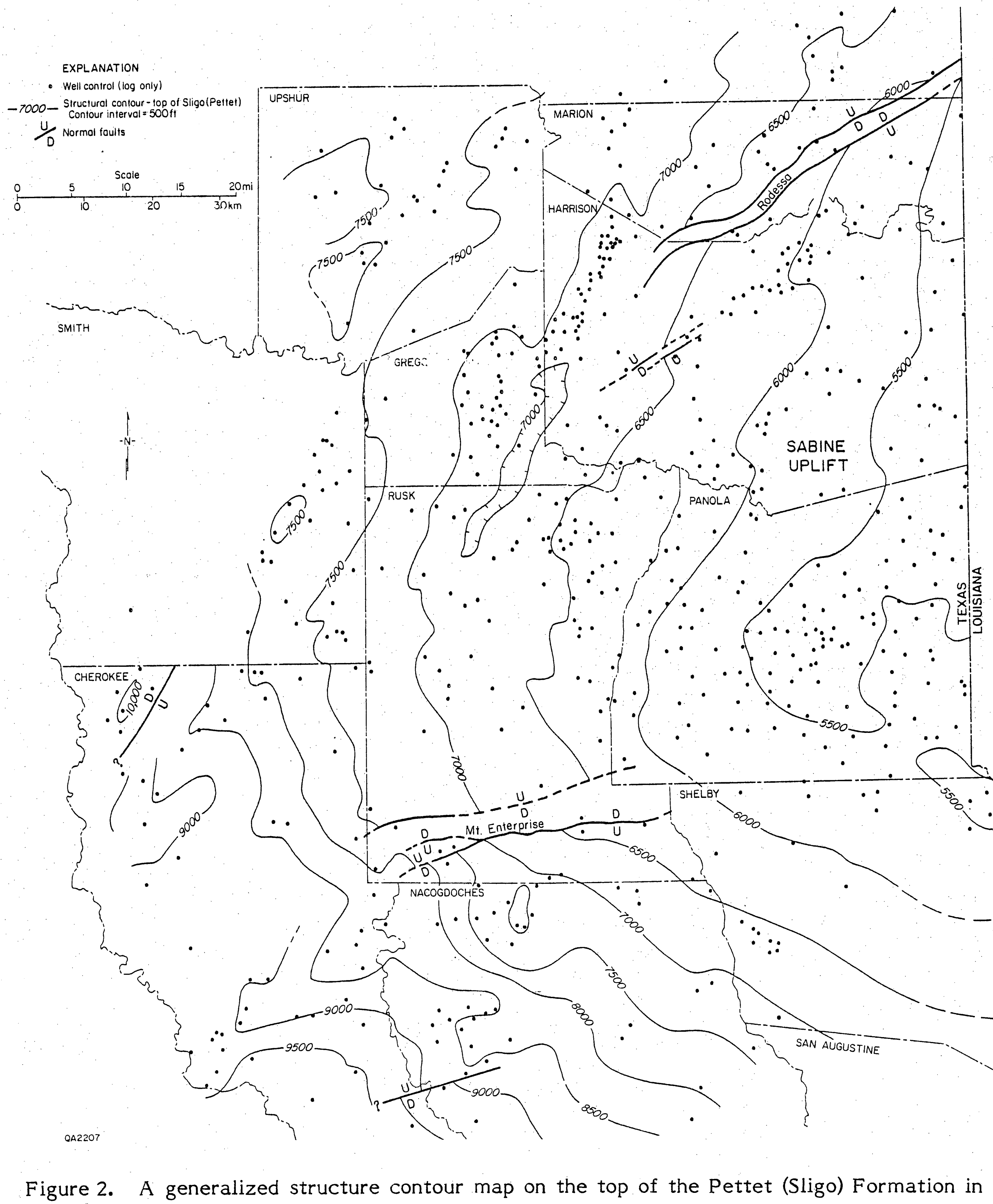

Figure 2. A generalized structure contour map on the top of the Pettet (Sligo) Formation in East Texas.

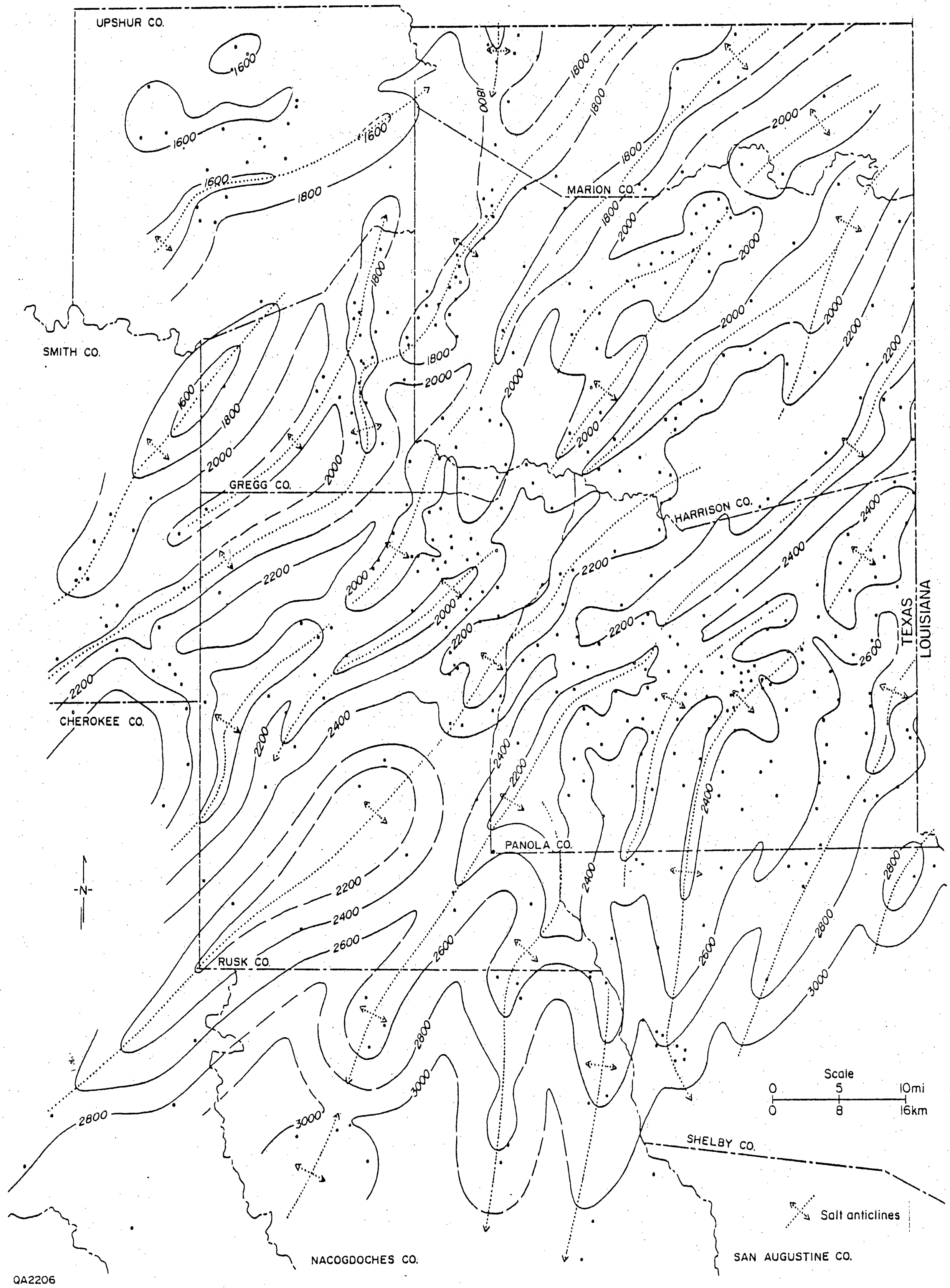

Figure 3. An isopach map of the combined Pettet-Travis Peak Formations in the area of research emphasis in East Texas.

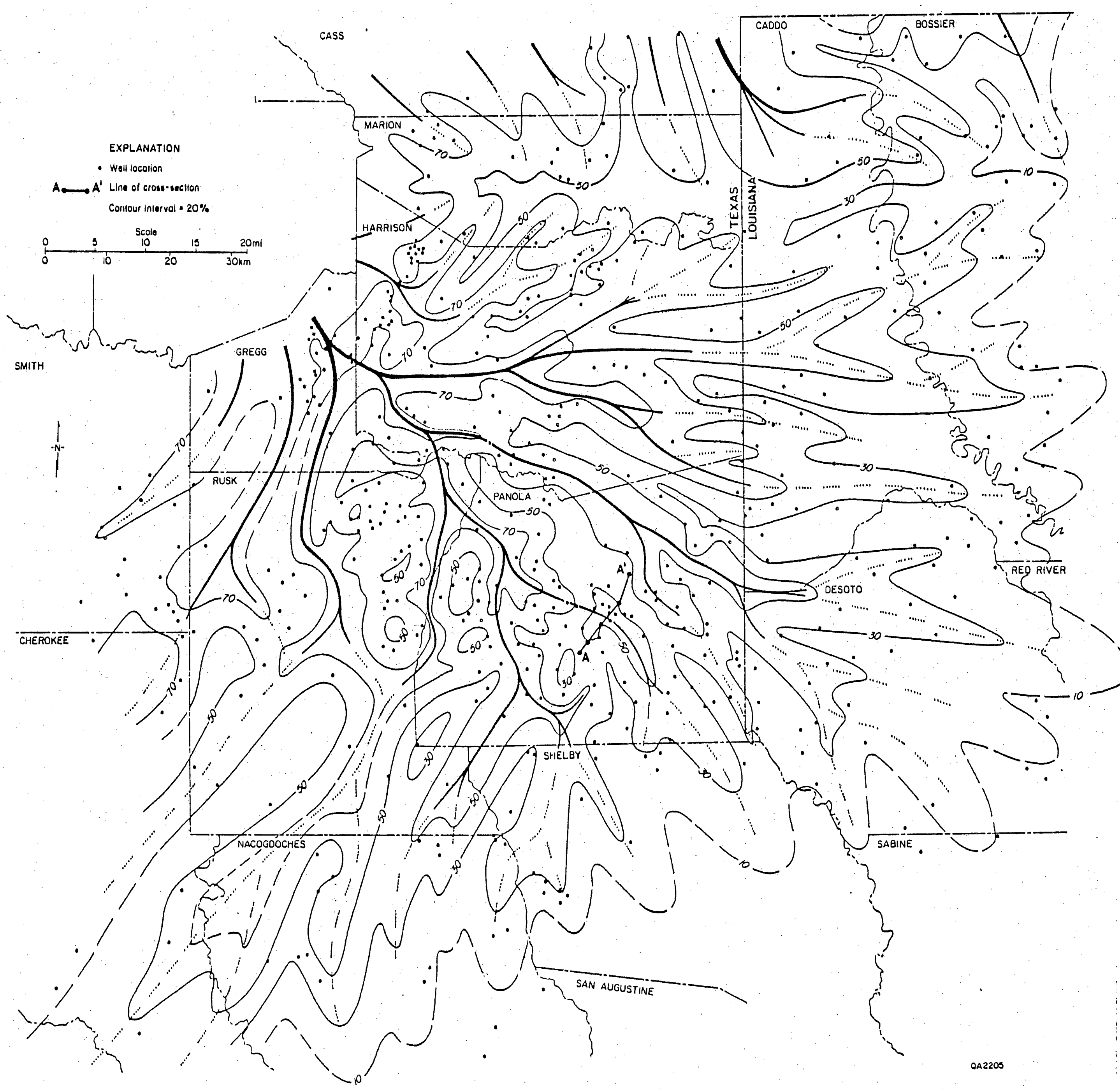

Figure 4. An iso-percent contour map based on the percentage of the total Pettet-Travis Peak section containing sand-rich intervals.

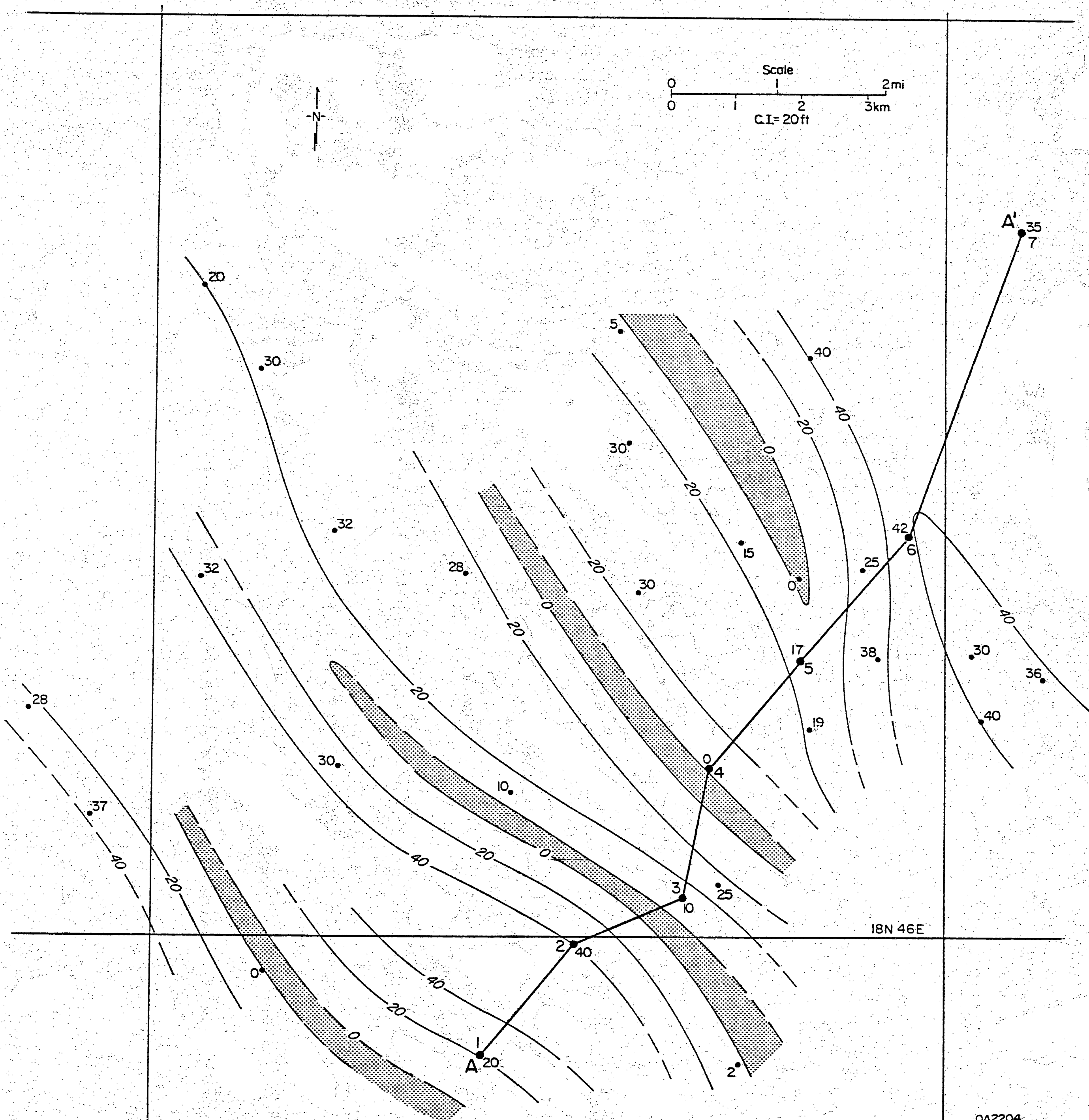

Figure 5. An isopach map of the upper Travis Peak sandstone shown in the cross section A-A'.

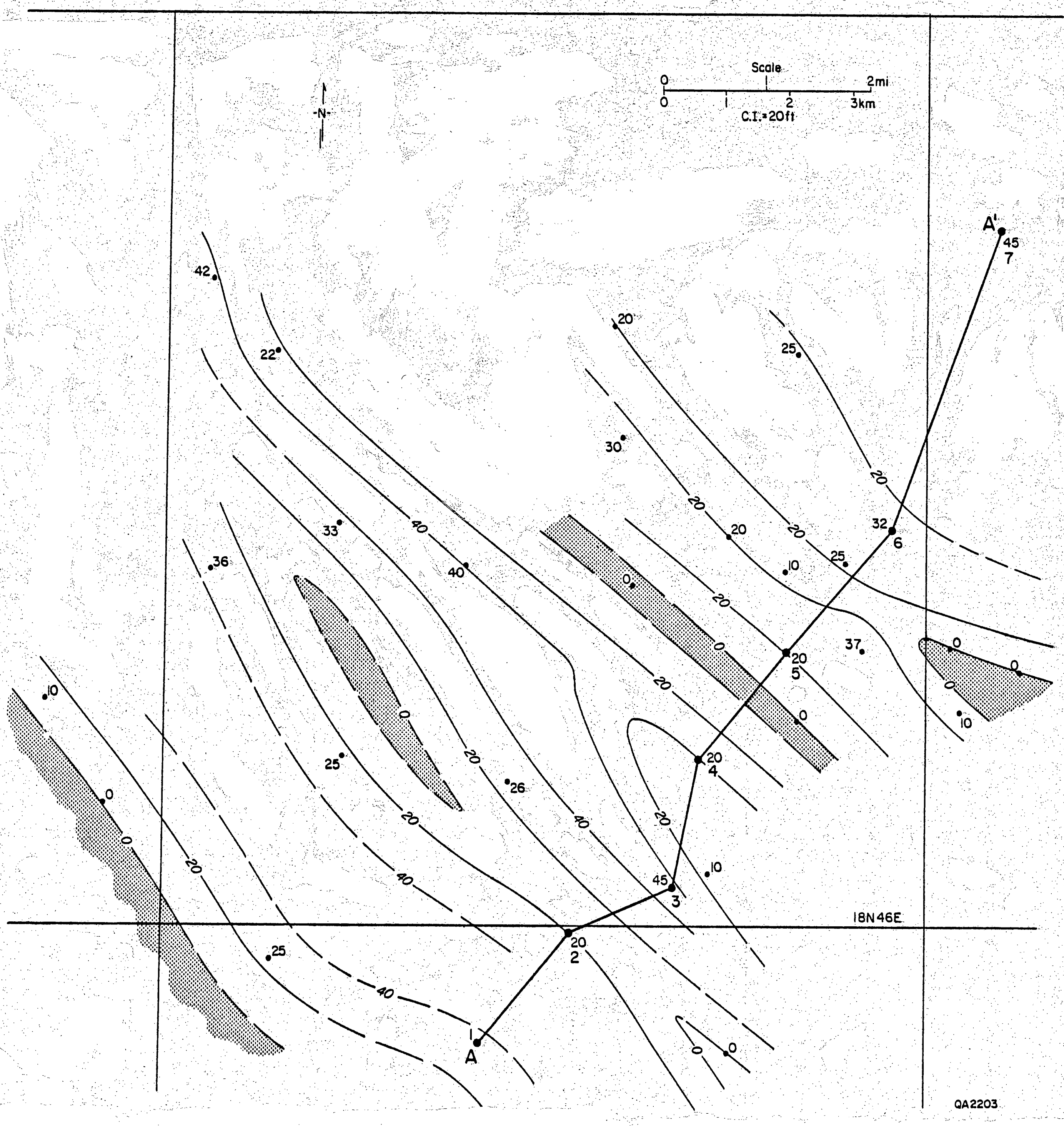

Figure 6. An isopach map of the lower Travis Peak sandstone shown on the cross section A-A'.

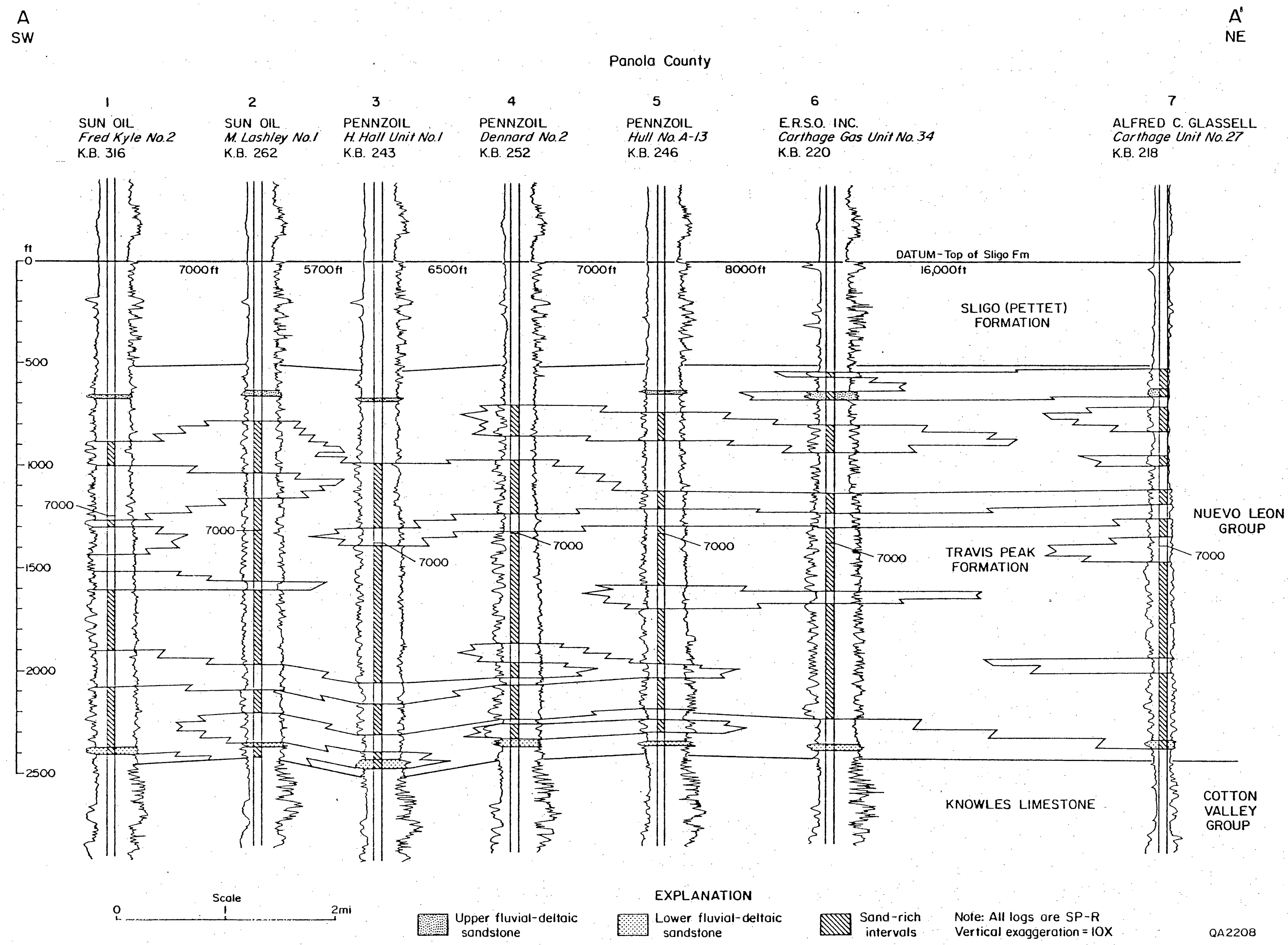

Figure 7. Stratigraphic cross section A-A' across Carthage field in Panola County, Texas, showing the upper and lower sandstones mapped in figures 5 and 6.

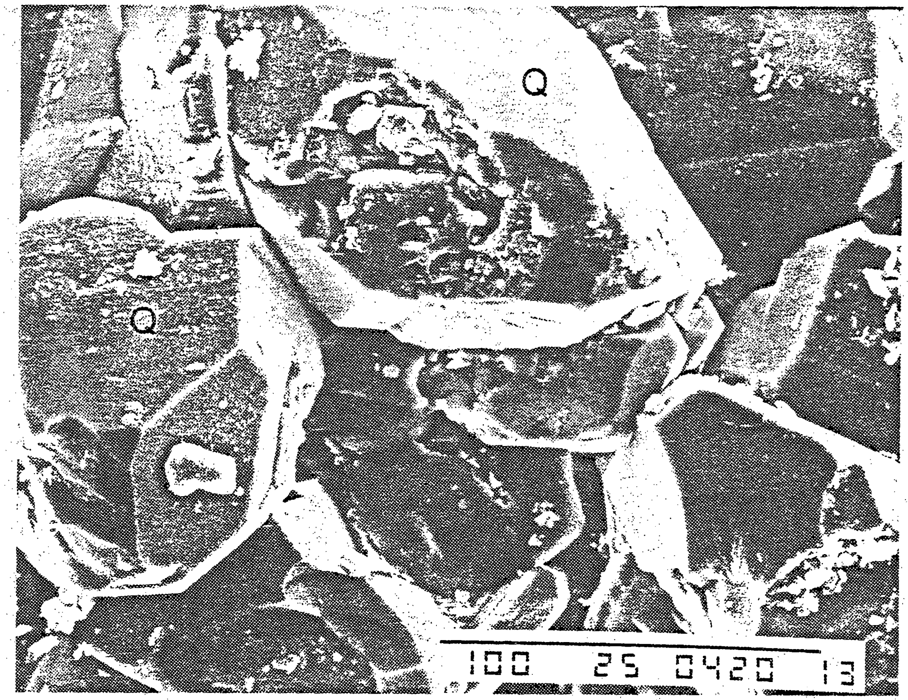

Figure 8. SEM photograph of quartz overgrowths (Q) covering detrital sand grains. Sample is from Clayton Williams #1 Sam Hughes well, Panola County; depth is 6,843.5 to 6,843.7 ft. Bar length is 100 μm; magnification is 500x.

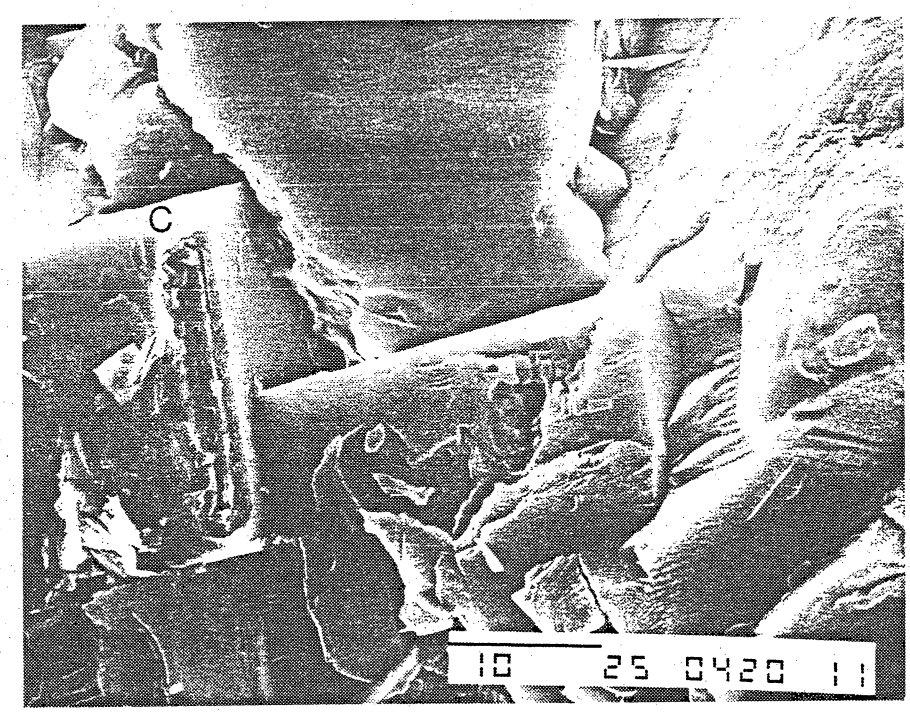

Figure 9. SEM photograph of calcite cement (C) occluding primary porosity. Sample is from Clayton Williams #1 Sam Hughes well, Panola County; depth is 6,843.5 to 6,843.7 ft. Bar length is 10 μm; magnification is 2,000x.

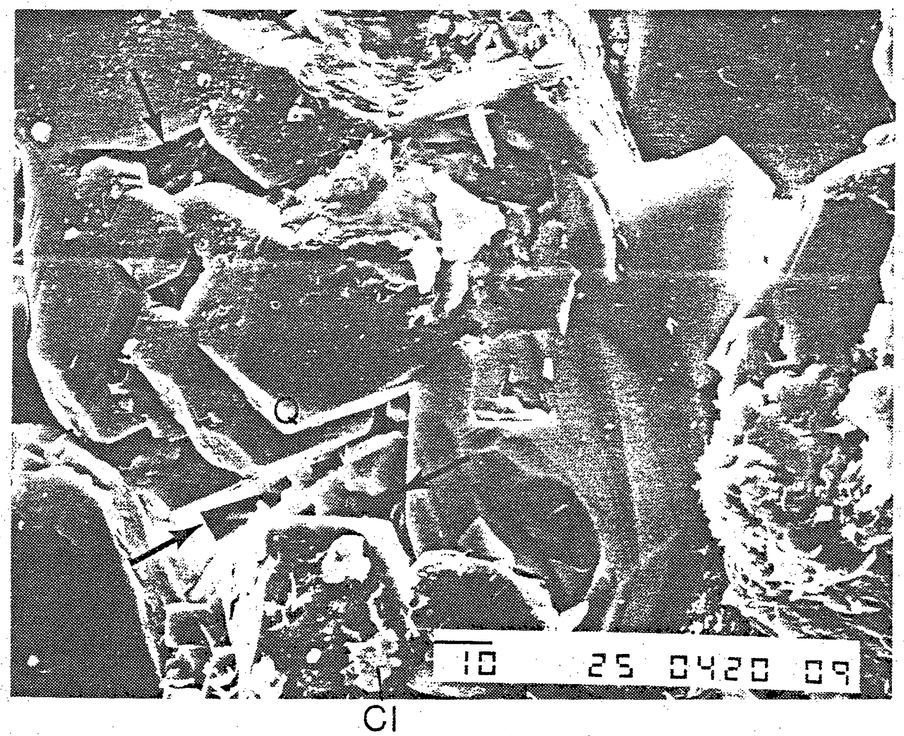

Figure 10. SEM photograph of quartz overgrowths (Q) bounding primary, intergranular porosity (arrows). Authigenic clays (Cl) also reduce porosity. Sample is from Clayton Williams #1 Sam Hughes well, Panola County; depth is 6,843.5 to 6,843.7 ft. Bar length is 10 μm; magnification is 750x.

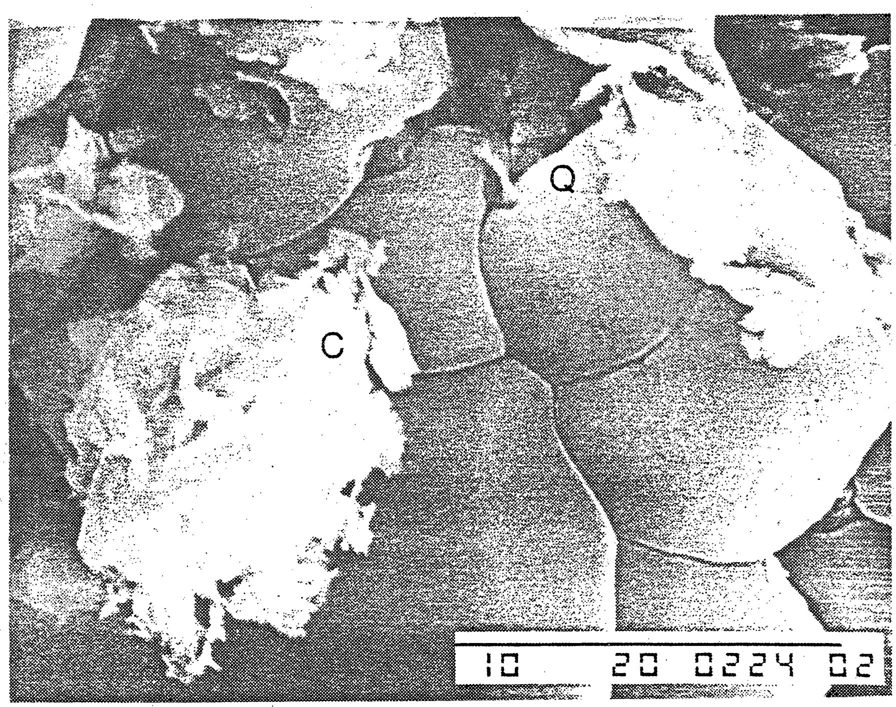

Figure 11. SEM photograph of rounded quartz overgrowths (Q) and authigenic clay (C), probably chlorite. Sample is from Humble #1-C Southern Pine Lumber well, Anderson County; depth is approximately 9,081 ft. Bar length is 10 μm; magnification is 5,000x.

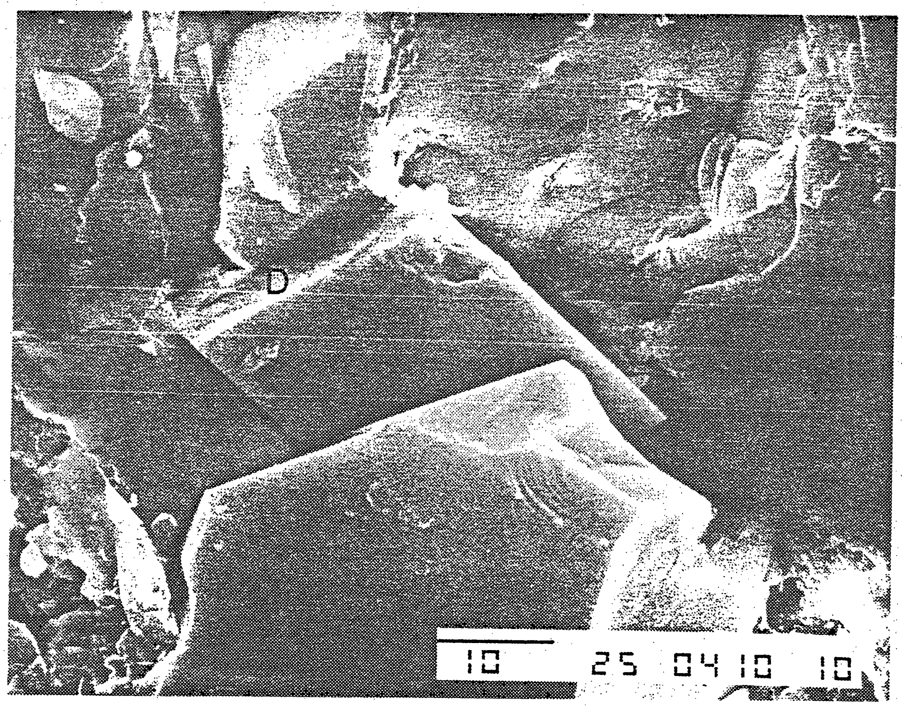

Figure 12. SEM photograph of authigenic dolomite rhomb (D). Sample is from Humble #1-C Southern Pine Lumber well, Anderson County; depth is approximately 9,079 ft. Bar length is 10 μm; magnification is 1500x.

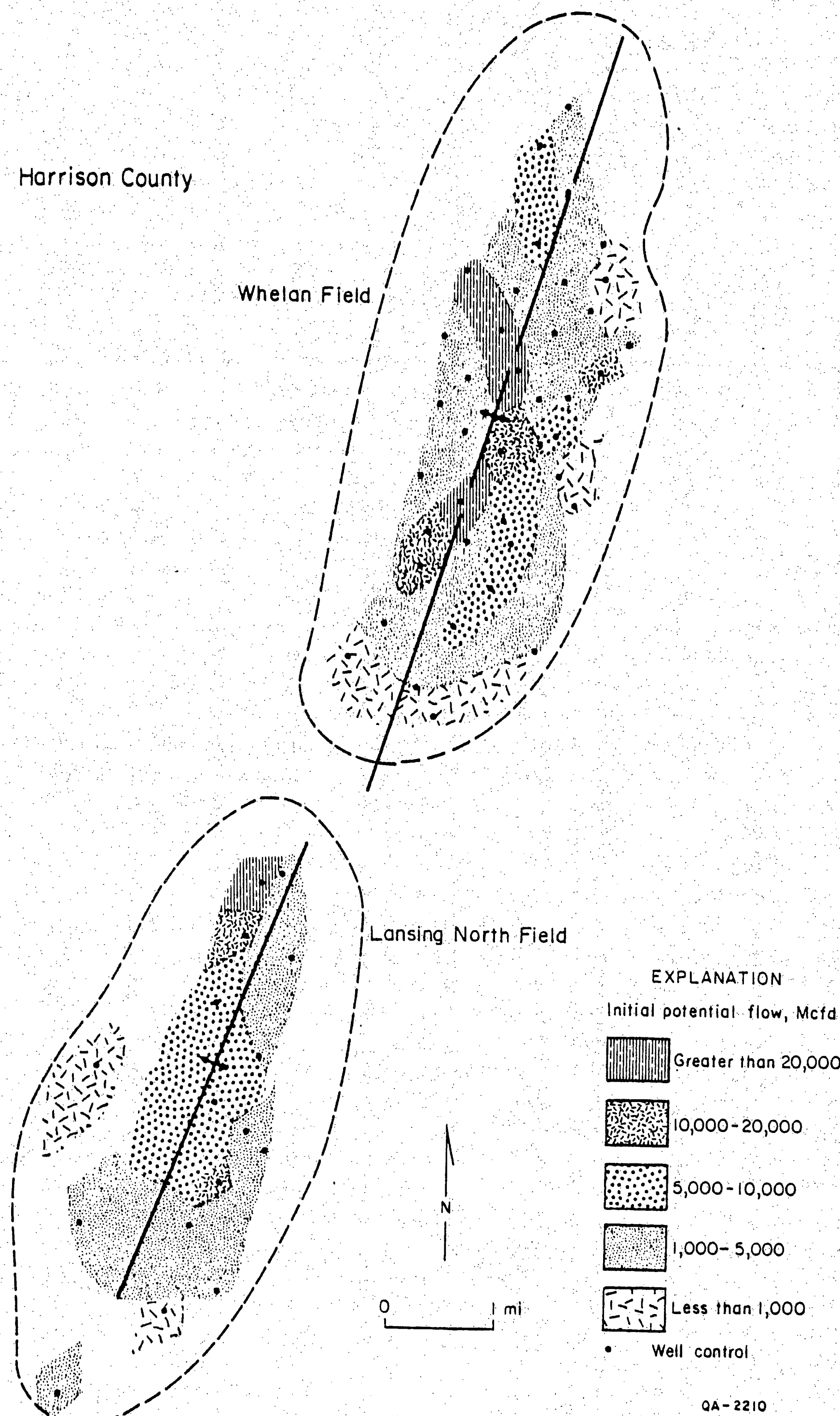

Figure 13. Distribution of initial potential flow in the Travis Peak Formation in Whelan and Lansing North fields.

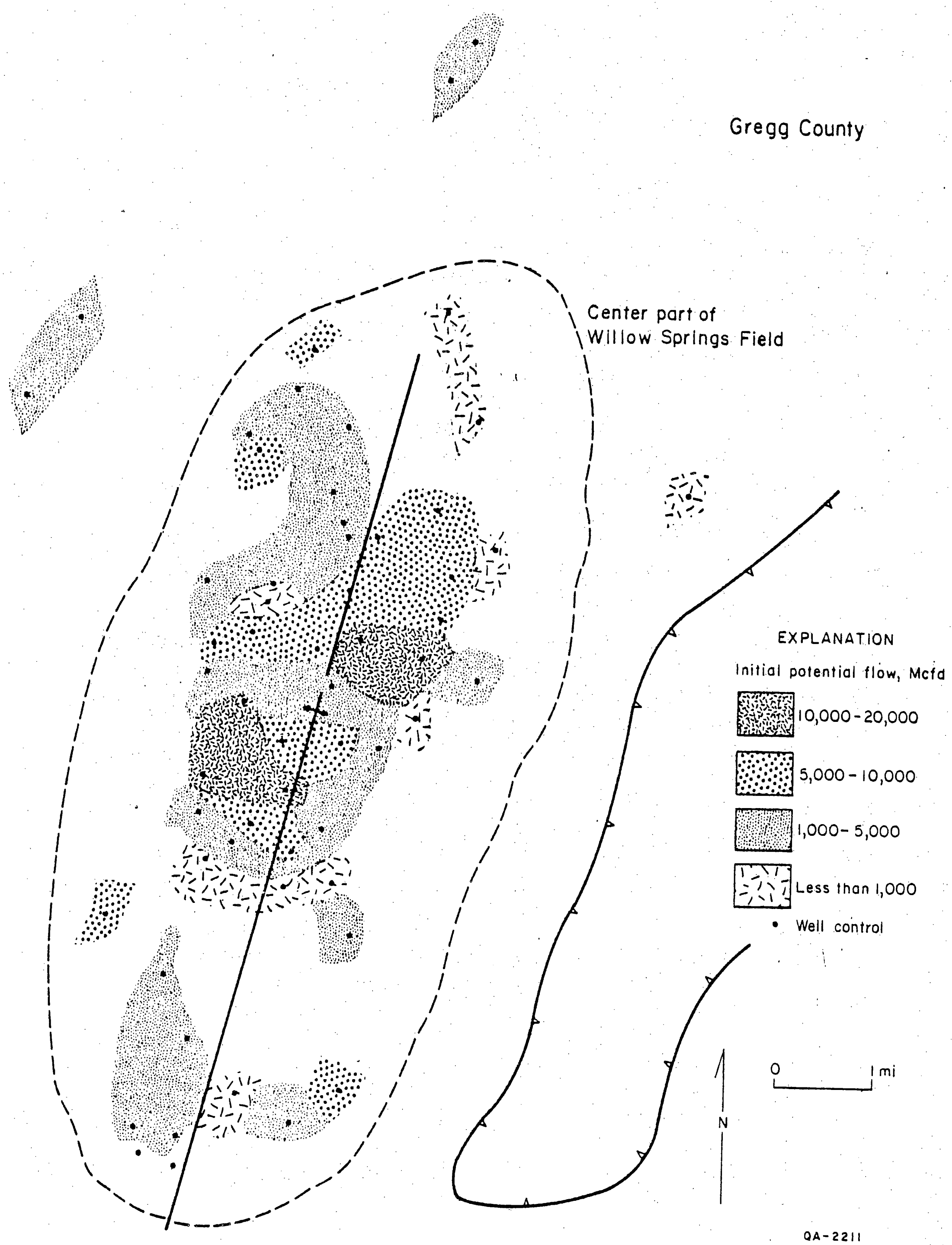

Figure 14. Distribution of initial potential flow in the Travis Peak Formation in Willow Springs field.

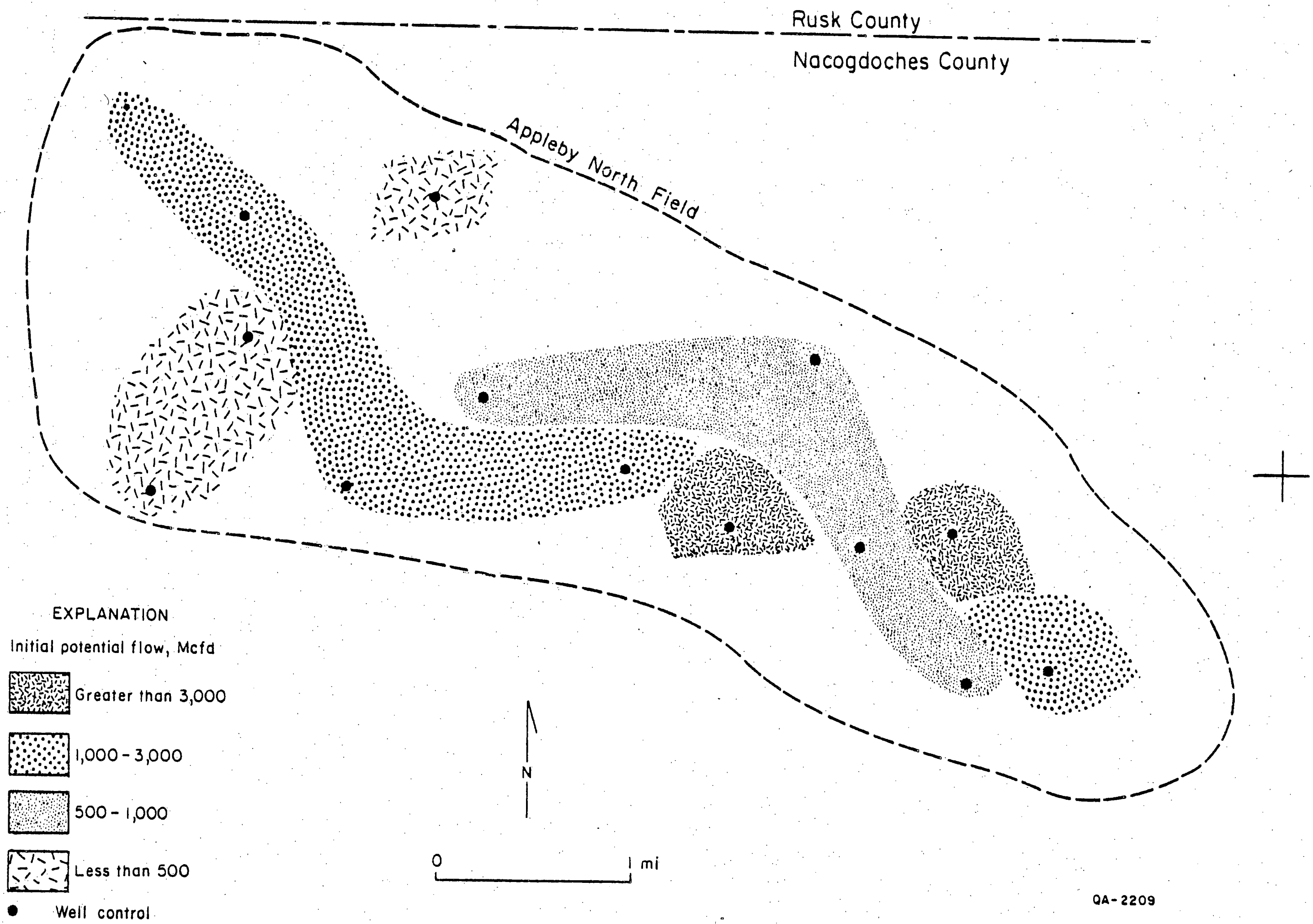

Figure 15. Distribution of initial potential flow in the Travis Peak Formation in Appleby North field.

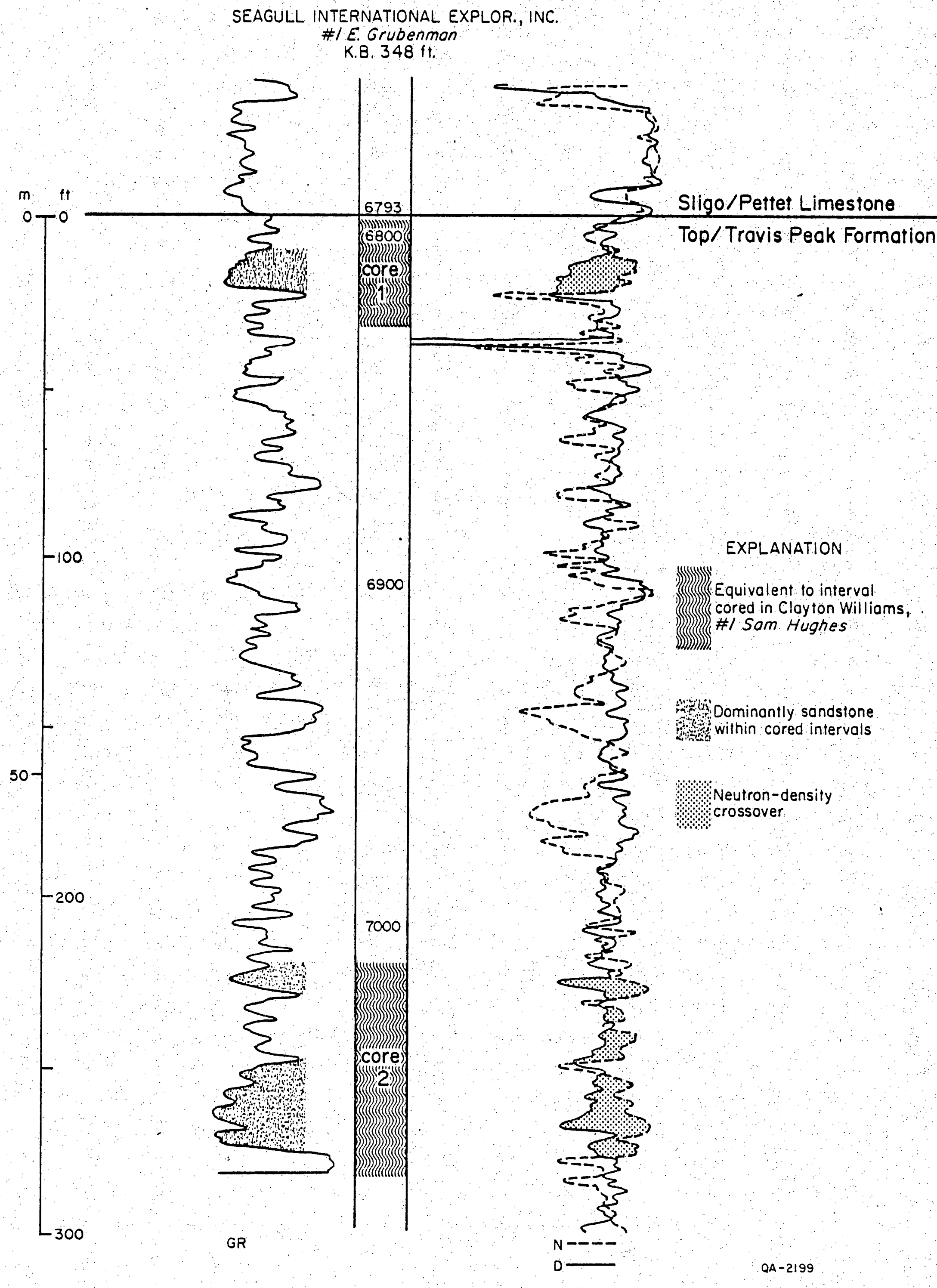

Figure 16. Gamma ray neutron-density log in Pinehill Southeast field, Panola County, Texas, used in predicting intervals appropriate to core in the Clayton W. Williams, Jr., No. 1 Sam Hughes cooperative well.

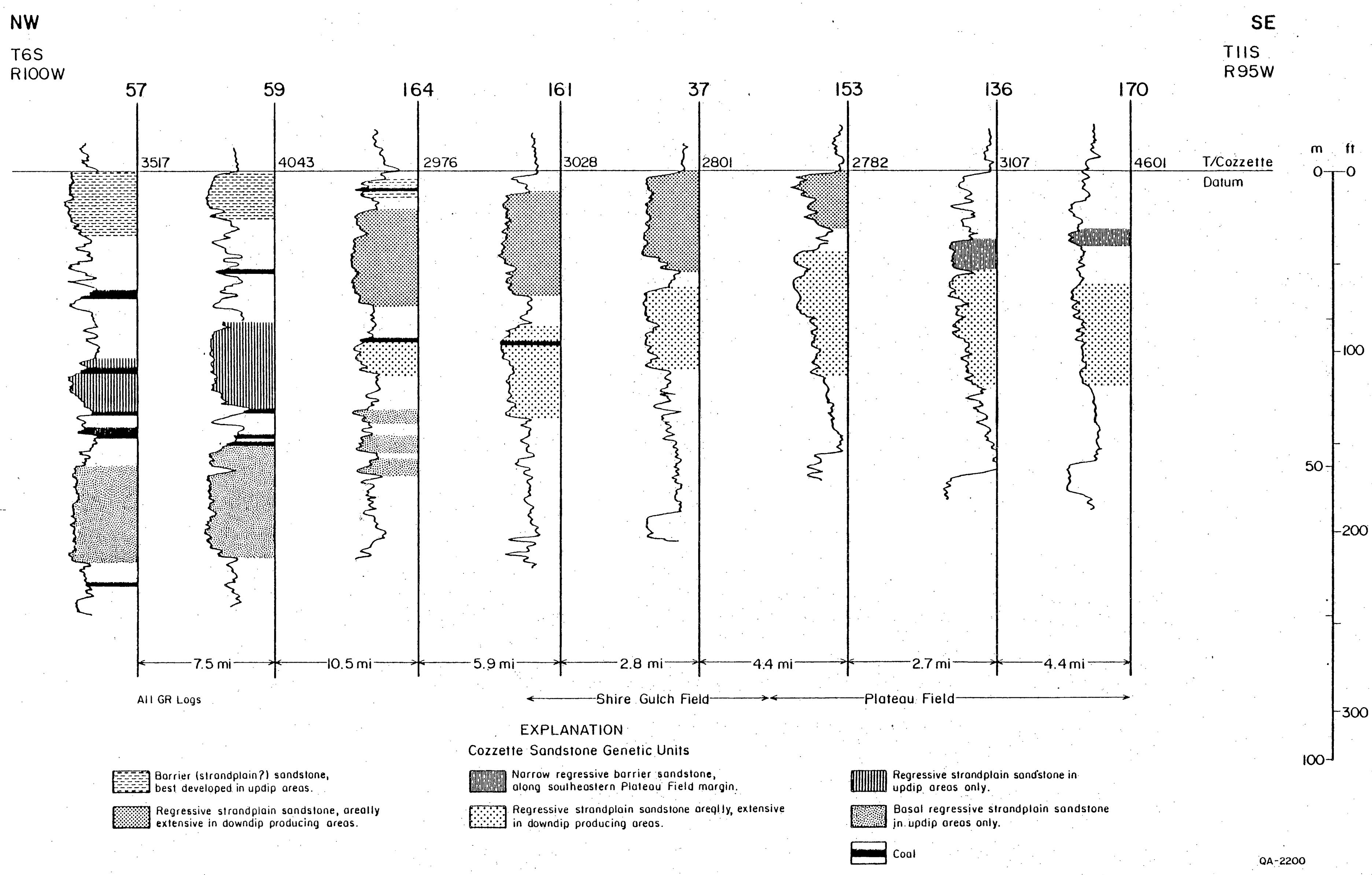

Figure 17. Stratigraphic cross section of the Cozzette Sandstone in the southern Piceance Creek Basin showing genetic sandstone units.

Table 1. Wells through the Cozzette Sandstone used in figure 16.

Number	Well		Location
37	Pacific Natural Gas	Shire Gulch 23-35	35-9S-97W
57	Nucorp Energy	Tate 1-25	25-6S-100W
59	Coors Energy	USA 1-33	33-7S-99W
136	S. Hammonds & Blanco Oil	U.S. Moran 27-1	27-10S-96W
153	Adolf Coors	Fetters 2-19	19-10S-96W
161	Koch Exploration	Horseshoe Canyon 1-21	21-9S-97W
164	Teton Energy	Roan Creek-Fed. 26-4	26-8S-98W
170	Coors Energy	Swetland 1-5	5-11S-95W