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

QUARTERLY REPORT
(November 1, 1983 - January 31, 1984)

prepared by

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for

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DISCLAIMER

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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	November 1, 1983 - January 31, 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 (Finley and others, 1983). 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	Studies of the Corcoran Sandstone in the Shire Gulch - Plateau field area defined four genetic sandstone bodies, varying from a regressive strandplain in the lower Corcoran to regressive and transgressive barriers in the upper Corcoran. Gamma ray-log character and the relation of each sandstone to adjacent lagoonal-coastal plain and marine facies define each sandstone body. Regional structure and isopach mapping of the Travis Peak Formation were completed in an approximately six-county area of East Texas. Linear features on the isopach and the structure maps suggest that early salt structures persistent from the Lower Cretaceous through present day are important to Travis Peak gas accumulations. Facies variations from aggradational alluvial plain updip to shallow marine downdip are present in the area of greatest early 1983 operator activity. Engineering studies of Travis Peak production history and well test data in North Lansing and Whelan fields show that a gas expansion drive mechanism is present and that minimum water/gas ratio corresponds with positive structure. Lower water/gas ratios occur on the side of the

Whelan structure that is toward the basin, and may be related to structural history or patterns of hydrocarbon migration.

Technical Approach

Corcoran Sandstone studies were undertaken using maps at a scale of 1" = 2,000 ft for detailed study of sand body distribution, and using additional recently available well logs in the Shire Gulch - Plateau field area. The log facies evident in cross sections, and the areal extent of each sandstone body isolated from adjacent sandstones allows interpretation of sand body origin.

Travis Peak structure and isopach maps were prepared using updated well log coverage. The improved data base has also been utilized to better define facies distribution in initial phases of facies mapping. Engineering studies of the Travis Peak in North Lansing and Whelan fields have utilized purchased data and the files of the Railroad Commission of Texas. Interpretations were made by mapping key engineering parameters for the two fields.

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

The annual report for the first year of the contract period was completed in the previous quarter, and consisted of two phases. Results of Phase B studies brought additional verification of the geological interpretations made during the study of six stratigraphic units (Phase A) and during the national survey of blanket-geometry tight gas sandstones (Finley, 1982). The three-part division of the Travis Peak Formation has been shown to be applicable in preliminary studies of selected fields producing gas from the Travis Peak. In Whelan Field, the middle braided fluvial section of the Travis Peak shows good lateral continuity of sand bodies over 1 to 3 mi. These sandstones are probably best classified as of broadly lenticular to blanket geometry, and would not present the fracturing problems that a truly lenticular sand would cause. The effectiveness of shale barriers between zones of interest may be of concern, however, because interbedded shales in the sand-rich Travis Peak vary from less than 10 ft up to 30 ft between major sandstone bodies. Vertical fracture growth out of the desired zone therefore becomes a potential problem.

The upper transitional facies of the Travis Peak is the perforated interval within much of the productive area of the formation, and this part of the formation is not tight in some areas (B. Brown, personal communication, 1983). The Railroad Commission of Texas (1983) recently sought to expedite designation of the Travis Peak as a tight gas sandstone in Commission Districts 5 and 6 by excluding the upper 200 ft of the Travis Peak in 45 wells from the application pending before FERC. The specific depositional or diagenetic factors leading to improved permeability in the upper Travis Peak will be examined in the forthcoming phase of research.

Shire Gulch and Plateau Fields form the largest area of tight gas sand production from the Corcoran and Cozzette Sandstones. Because this area contains one to three wells per section over approximately three townships, it is ideal for defining the types of lateral changes that may occur within these stratigraphic units. The strike-parallel nature of the lower Corcoran and lower Cozzette are well-defined by net sandstone trends, and it is probably the lower, upward-coarsening sequence of the Corcoran that determines the northeast trend of thick net sandstone in the entire Corcoran across the southern Piceance Creek Basin. It is unlikely, however, that the projection of the Corcoran-Cozzette trend to the northeast between Shire Gulch - Plateau and Rulison Fields will be confirmed by drilling in the near term. Rugged terrain and elevations on the order of 10,000 ft adversely affect the economics of the tight gas resource in the latter region.

The facies variability of the sandstones in association with shale and coal in the upper Corcoran and upper Cozzette must be evaluated using additional well data. Lateral changes in the number and thickness of coal beds are indicative of the variability that may occur where small deltas enter protected bay-lagoon environments. The associated framework sandstones may be of moderate areal extent (the delta front of a relatively small delta) or highly lenticular (a distributary channel sandstone). The distribution of stacked coals can be an indicator of local deltaic deposition or of sites of bay-lagoon organic accumulations, but the much lower density of well control northeast, north, and southwest of Shire Gulch Field will limit interpretation of the geometry of the coal-forming environments. Finally, petrographic data may contribute to interpretation of depositional environments and will complement studies of framework sandstones; Finley and others (1983) reported finer grain sizes in more distal, marine parts of the Corcoran-Cozzette sequence, and the allogenic clay content of these distal sandstones must also be examined as part of future studies.

WORK PLANNED FOR THE CURRENT QUARTER

Work planned for the current quarter involved extension of the Travis Peak/Hosston structure and isopach mapping from Louisiana into an area of approximately six counties in East Texas. Well log holdings were expanded to form a regional grid in this area wherein new discoveries and extensions of existing production had been made in the first half of 1983. Facies mapping was begun by first noting major differences in log character between the northern and southern parts of the map area. Engineering studies of particular Travis Peak fields emphasized differences in initial productivity, water/gas ratio, and other characteristics of gas production.

Work on the Corcoran-Cozzette Sandstones was planned to focus on genetic sandstone units within the Shire Gulch - Plateau field area. New logs were acquired, revised net sandstone maps were plotted, and core data were acquired.

RESULTS OF THE CURRENT QUARTER

Corcoran-Cozzette Studies

Analysis of the Corcoran and Cozzette Sandstones proceeded during the quarter with (1) core description and compilation of production data by the Colorado Geological Survey, (2) definition of genetic sandstone units within the Corcoran Sandstone of the Shire Gulch - Plateau field area, and (3) log analysis and updating of net sandstone maps using recently acquired well logs. Preparations were also begun for field studies to be conducted in the next quarter; these preparations involved posting accessible outcrops (based on published studies) to base maps and conversations with geologists at Exxon, U.S.A. and the Bureau of Land Management.

Shire Gulch - Plateau Field Area

Finley and others (1983) illustrated distinctive gamma ray-log facies on dip-oriented cross sections through the Shire Gulch - Plateau field area in Mesa County, Colorado. One of these cross sections (B-B') was redone using the top of the Corcoran Sandstone as a stratigraphic datum and was extended up depositional dip (northwest) using newly acquired well logs. Neither the new datum nor the previous time marker (bentonite stratigraphic datum) is ideal in that both introduce distortions in conceptualizing facies tracts. However, use of the Corcoran datum suggests a more apparent relationship between barrier sand bodies and associated lagoonal facies, shows that the major lower sand body within the Corcoran is continuous over a long distance northwest to southeast, and illustrates the relationship of regressive and transgressive sand bodies. Approximately one-third of the well logs on the revised and extended cross section are incorporated into figure 1, but the interpretations below are based on a more complete, large-scale working copy. A large-scale map (1" = 2,000 ft) was also prepared to show the distribution of gamma ray-log facies.

Lower Corcoran

Gamma ray-log facies of the lower Corcoran show a mostly well defined upward-coarsening sequence with a variable thickness of blocky sandstone at the top. This pattern is common in the producing area southeast of well 161 (fig. 1, table 1). Updip this sand body grades into interbedded sandstone, shale and coal, probably representing fluvial and coastal plain environments. Also updip, an older sandstone forms the basal regressive sandstone of the Corcoran of the Piceance Creek Basin, and the Sego Sandstone is present (fig. 1).

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. No lagoon-fill is distinctly associated with this sand body, and it is often capped by coal and underlain by a gradational contact with Mancos Shale (fig. 1). Much of the preserved sand body was deposited in the lower and upper shoreface; distal sandstones isolated in shale (well 170, fig. 1) are probably shoreface storm deposits.

Upper Corcoran

The upper Corcoran consists of three vertically and areally distinct sandstones. Lowermost in the sequence is a transgressive barrier sandstone (wells 153 and 136, fig. 1) present as only a narrow belt on the updip side of Plateau field. It separates the upper and lower sandstone benches present in most wells in the Shire Gulch - Plateau field area. This unit was deposited as a consequence of marine transgression followed by shoreline stabilization. A subsequent regressive barrier sandstone (wells 136 and 170, fig. 1) is confined by marine shale both above and below in downdip areas. The lower beds of this regressive sandstone may in part bound a lagoonal facies updip that is primarily isolated from marine environments by the older, areally-limited, transgressive sandstone below. The youngest upper Corcoran sandstone (wells 124 and 153, fig. 1) has sharp upper and lower contacts and few shaly interbeds. Its abrupt termination, and its position between lagoon fill or distal coastal plain sediments within the upper Corcoran and marine shale of the lower Cozzette, suggests that this is a transgressive barrier sandstone.

Further analyses of the Corcoran and similar in-depth studies of the Cozzette are planned for the next quarter. Supplementing the subsurface well log data will be field studies of outcrops along the Book Cliffs and the Grand Hogback, and core descriptions undertaken by the Colorado Geological Survey.

Production Data Analysis

Production histories for Corcoran-Cozzette wells have been purchased from Dwight's Energydata and were compiled from records of the Colorado Oil and Gas Conservation Commission by L. R. Ladwig of the Colorado Geological Survey. Production data will be compared to genetic sandstone bodies with concentration on single completions which would tend to isolate reservoir performance. Conventional core analyses available from commission files will be integrated into the study.

Travis Peak/Hosston Studies

Depositional Systems

Emphasis this quarter has been on the Travis Peak Formation in an approximately six-county area in East Texas which covers the west half of the Sabine Uplift (fig. 2). Moderate drilling depths combined with a highly gas-prone, sand-rich facies makes this area the center of Travis Peak exploration activity in Texas and one of the most active areas in the larger Travis Peak-Hosston fairway which extends eastward across north Louisiana and southern Mississippi (fig. 2). A closer look at East Texas (fig. 3), reveals that most of the recent activity and new discoveries are located in Rusk, Nacogdoches, and Cherokee Counties. Structural dip across these counties is to the southwest with drilling depths to the top of the Travis Peak increasing from 7,000 ft at location A in figure 3, to about 9,500 ft in central Cherokee County. As the dip increases, so does the thickness of the Travis Peak Formation (fig. 4). The Westland Oil, No. 1 Jordan well in Nacogdoches County penetrated 500 ft more Travis Peak than the updip Tomlinson, No. 1 Sheppard et al. well in Rusk County. There is also a pronounced difference in log character between these two wells (fig. 4). The Travis Peak Formation in the Tomlinson well is characterized by multi-storied aggradational channels representing deposition in an alluvial plain or upper delta plain environment. This section, called facies A, appears to be typical of the formation in Harrison, Gregg, Rusk, and Panola Counties. It 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 facies has thin, gradational boundaries with the shelf carbonates of the underlying Knowles Limestone member of the Cotton Valley Formation and the overlying Sligo-Pettet Formation.

Facies B penetrated in the Westland well is dominantly siltstones with thin, sheet-like sands interbedded with some very thin carbonates. This facies of the Travis Peak appears to have been deposited in shallow marine waters on a broad, protected shelf. Low wave energy is indicated by the absence of well-developed barriers or bars. Facies A and B interfinger and grade into one another across a broad transition zone with no clearly definable boundaries. Both facies A and B produce gas, but whereas facies A production is more clearly structurally controlled, facies B is productive across larger, less well-defined structures.

Structural trends during Travis Peak deposition are indicated by the Travis Peak-Pettet isopach map (fig. 5). The fairly regular spacing of sub-parallel linear thicks and thins which strike generally N40°E suggests that the growth of salt anticlines was an important structural element in Travis Peak time. Some of the anticlines persist and are well-defined present-day structures which produce hydrocarbons, such as Whelan and Willow Springs fields. Most of these subtle anticlines are no longer discernible in structure contour maps drawn on younger horizons. However, the northeast trends in new discoveries shown in figure 3 indicate that these early anticlines may still be the main controlling factor in shallow Travis Peak production. More detailed work is planned to investigate the effects of this possible early structural control on hydrocarbon accumulations in the Travis Peak Formation of East Texas.

Engineering Studies of Production History and Test Data for the Travis Peak Formation

Introduction

Engineering studies of production history and test data for the Travis Peak Formation were started with North Lansing field and Whelan field; both fields are on the same structural high in Harrison County, Texas. The data used in engineering studies included information purchased from Petroleum Information (PI) and Dwight's Energydata, and data collected from the Railroad Commission of Texas. This included information on 18-year historical gas and condensate production, 31-month gas production history, p/z versus cumulative gas plot, and gas well back pressure test results with completion report (G-1 or equivalent forms).

Based on the available data, the production zones of the Travis Peak Formation were divided into two reservoirs, such as the Travis Peak (11 wells) and the Travis Peak, Lower (16 wells) in North Lansing field, and three reservoirs, such as the Travis Peak (11 wells) and the Travis Peak Prorated (43 wells) and the Travis Peak Lower (2 wells) in Whelan field. The Travis Peak, Lower in North Lansing field and Travis Peak Prorated in Whelan field were selected for detailed studies in this work. Using these data, the engineering studies conducted were: (1) P/z versus cumulative gas production plot was analyzed in conjunction with production mechanism and original gas in place, (2) the distributions of initial absolute flow potential, stabilized flow rate, and permeability-thickness product were used to delineate the productive area, (3) the distribution of water/gas ratio, which is expected to be related to water saturation and the gas/water contact zone, was analyzed, and (4) the distribution of initial pressure was reviewed to infer the direction of fluid flow or the migration of hydrocarbon.

P/z versus Cumulative Gas Production Plot

The p/z versus cumulative gas production plot, which is based on the material balances in gas reservoirs (Craft and Hawkins, 1959), was used to estimate initial gas in place and to study the production mechanism. For a reservoir with no water encroachment and no water production, the initial gas in place may be estimated by extrapolating a straight line of data points in the plot to zero p/z value. The production test data, in the p/z versus cumulative gas production plot is not a straight line for a water-drive reservoir. It is impossible to estimate initial gas in place by using the plot for a strong water drive reservoir, i.e., almost no pressure drop in a reservoir during production. By examining the pressure behavior in the plot, there is no indication of a strong water drive production mechanism for wells drilled in North Lansing and Whelan fields.

For some wells in those fields, the pressure behavior in p/z versus cumulative gas production plots indicated weak to moderate water drive. The initial gas-in-place for these wells was estimated with some adjustment based upon pressure behavior in the wells at abandonment. Total initial gas-in-place in both fields is more than 205 Bcf, which includes 22 Bcf in North Lansing field and 183 Bcf in Whelan field. Total gas production (through June 1983) is 117 Bcf, including 11 Bcf for North Lansing field and 107 Bcf for Whelan field.

Distribution of Flow Potentials and Permeability-Thickness

The flow potentials used in this study include initial flow potential (or initial absolute open flow potential) and stabilized flow rate. Initial flow potential, which is the maximum flow at initial reservoir conditions and assuming the wellbore to be at atmospheric pressure (14.7 psi), is obtained from the Back Pressure Test and Completion Report (G-1 form) available from the Railroad Commission of Texas. Stabilized flow rate, based on the external reservoir area of 320 acres, and permeability-thickness product, based on 6% porosity, were calculated using the methodology suggested by Lee (1980). Permeability-thickness product is calculated instead of permeability because effective formation thickness is not available at this point in time.

Initial flow potential, stabilized flow rate, and permeability-thickness product are directly or indirectly related to the productivity and deliverability of a reservoir. Initial flow potentials range from 10 Mcfd to 59,000 Mcfd with an average of 7,700 Mcfd in Whelan field, and from 150 Mcfd to 24,000 Mcfd with an average of 4,120 Mcfd in North Lansing field. The average value of permeability-thickness product is 65 md-ft (range from 0.04 to 750 md-ft) in Whelan field, and 38 md-ft (range from 0.35 to 190 md-ft) in North Lansing field. From the distribution of those parameters, productive area, with high flow potential and permeability-thickness product, is coincident with the structural high in each field. Whelan field is more productive than North Lansing field.

Distribution of Initial Pressure and Water/gas Ratio

Initial pressure and water/gas ratio were obtained from back-pressure test data and from production test data, respectively. 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 North Lansing field and Whelan field, initial water/gas ratio is low over the center part of the structure. It is inferred that produced water was flowing from the field margins of the gas/water contact zone instead of from underneath. The observation of high initial water/gas ratio on the east side of Whelan field compared with the west side might be related to the migration of hydrocarbons, which will be discussed next with the distribution of initial pressure.

For purposes of interpretation, initial pressure obtained from the back pressure test for each well of different depth was corrected to an arbitrary datum of 8,500 ft by considering the static pressure gradient existing in the fluid column. No attempt was made to correct the pressure variations due to the effect of gas/water production, because sophisticated reservoir engineering calculations and knowledge of detailed reservoir parameters are needed. Instead, initial pressures for those wells with no effect of gas/water production from other wells were selected for interpretation. The initial pressures, at a datum of 8,500 ft, range from 1,200 to 3,600 psi in Whelan field, and from 2,800 to 3,900 psi in North Lansing field. Overall, the initial pressure on the west side of each field is higher than on the east side of each field. This suggests that the hydrocarbon migration was from west to east across the field area, or from basin center toward basin margin. Perhaps, water displaced by hydrocarbons during migration causes higher water saturation on the east side of each field at the same datum. This interpretation will be confirmed later by doing more field studies and integrating engineering interpretations with geological studies.

Summary

In this quarter, engineering studies of production history and test data for the Travis Peak Formation in both Whelan field and North Lansing field are summarized as follows:

1) Only a weak to moderate water drive mechanism is shown in these fields. Therefore, a gas expansion drive mechanism is probably dominant.

2) Productive area, with high initial absolute flow potential and permeability-thickness product, is coincident with the structural high in each field.

3) Production with higher water/gas ratio occurs around the field margins, indicating higher water saturation in a gas/water contact zone, and also showing that water encroachment toward the gas reservoir might be coming from the edge instead of beneath producing interval.

4) From the distribution of initial pressure and water/gas production ratio, it is possible that the direction of hydrocarbon migration was approximately from basin center toward basin margins.

Technical Problems

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

WORK PLANNED FOR THE NEXT QUARTER

During the next quarter the following actions will be taken:

1) Analyze production data compiled for the Corcoran and Cozzette Sandstones.

2) Continue delineation of genetic sand bodies in the Shire Gulch-Plateau field area with emphasis on the Cozzette.

3) Continue to direct core description by the Colorado Geological Survey.

4) Attain greater detail in and areally expand facies analysis of the Travis Peak in the East Texas Basin.

5) Review Travis Peak cooperative well locations in coordination with other contractors.

6) Continue engineering studies of Travis Peak producing fields within the East Texas Basin and interpret results in conjunction with geological studies.

7) Begin studies of Travis Peak reservoir quality and sandstone diagenesis using existing core and, as it becomes available, core from cooperative wells.

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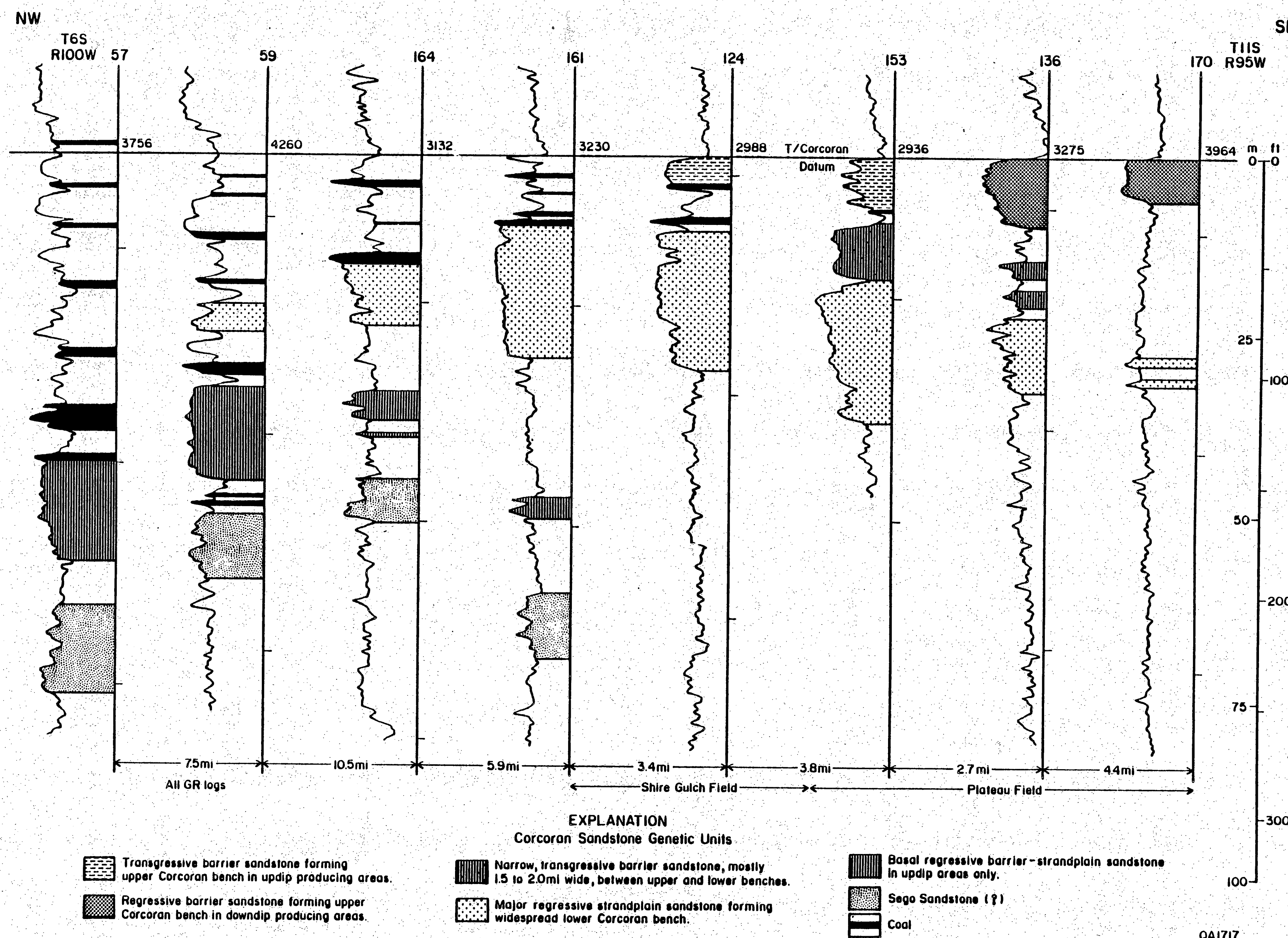

Figure 1. Genetic sandstone units within the Corcoran Sandstone, including part of the underlying Sego Sandstone, Piceance Creek Basin.

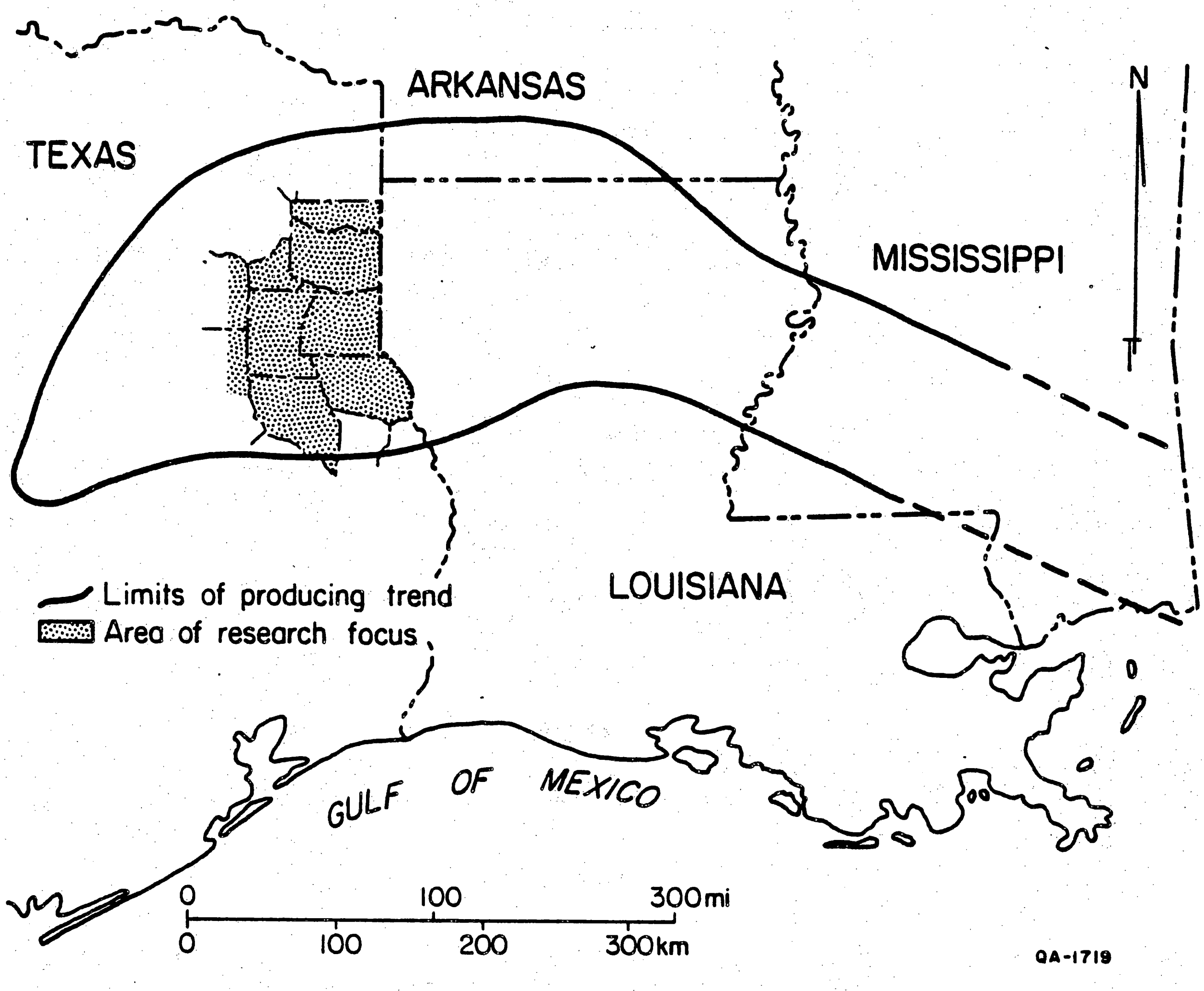

Figure 2. Index map of the mid-Gulf Coast region showing the general boundaries of Travis Peak production and the counties in East Texas where research has been focused.

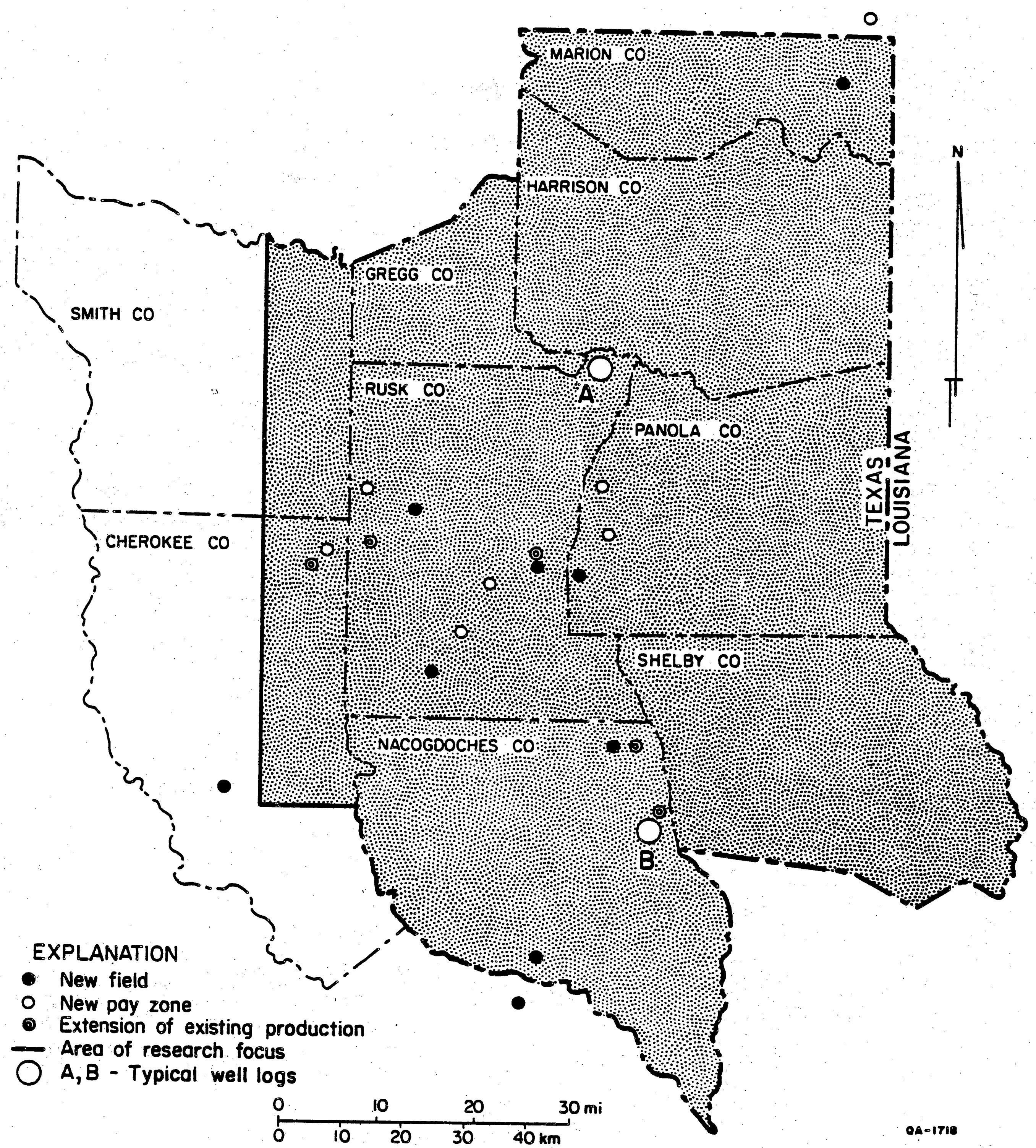

Figure 3. Area of research emphasis within the East Texas Basin, and recent operator activity within that area. Typical well logs A and B are illustrated in figure 4.

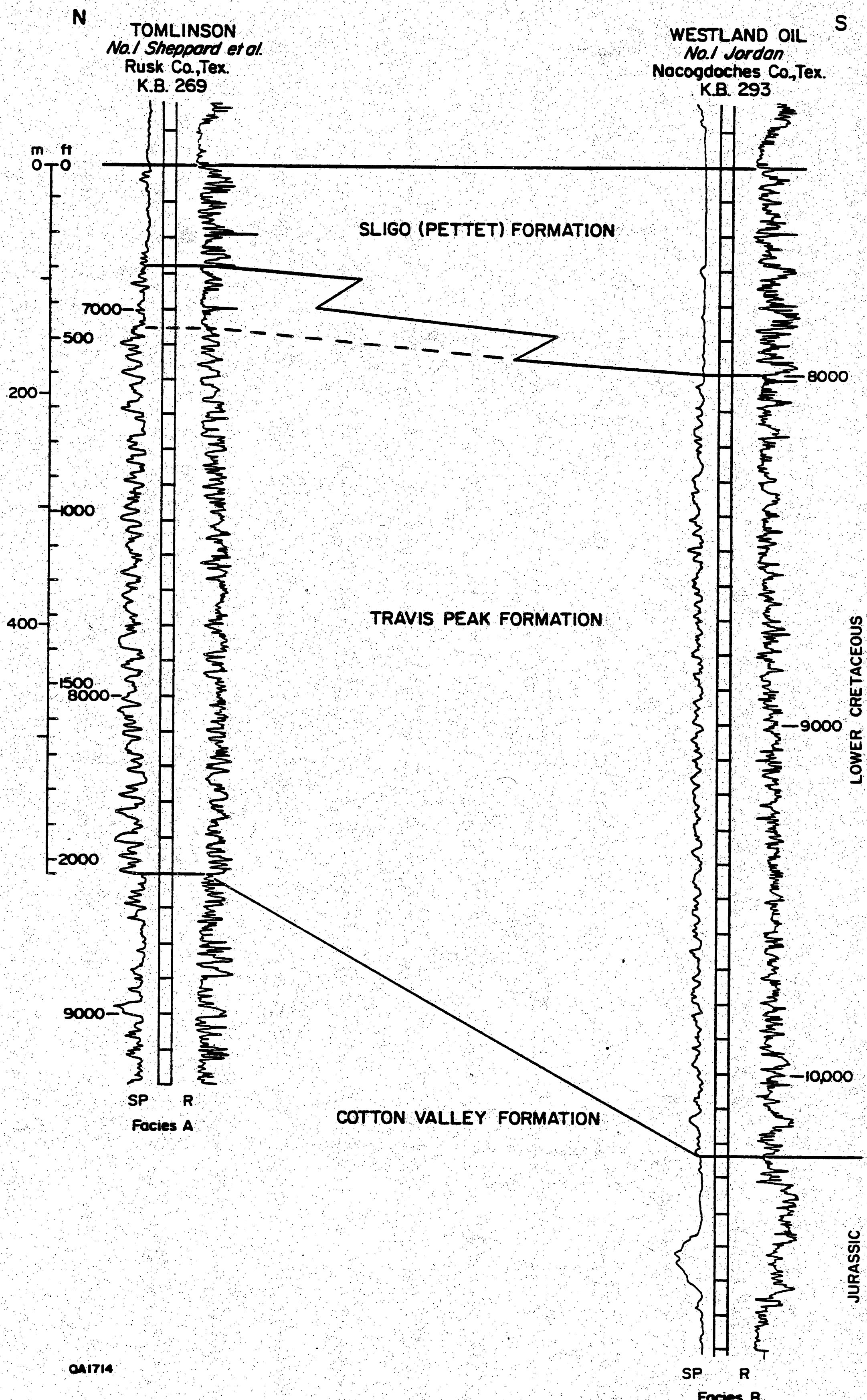

Figure 4. Typical Travis Peak well logs which display alluvial plain (Facies A) and shallow marine shelf deposits (Facies B). The locations of these two wells are shown in figure 3.

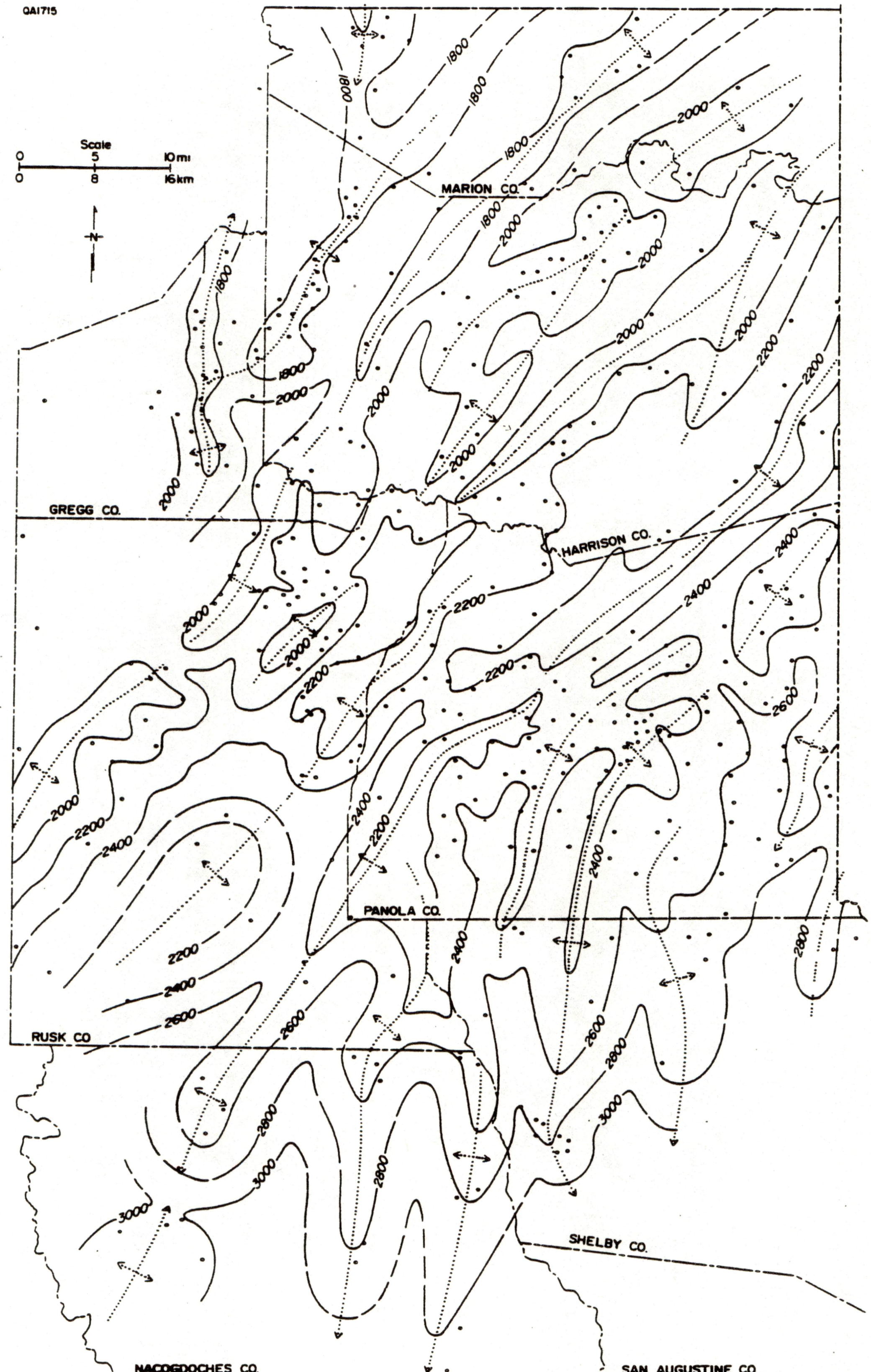

Figure 5. An isopach map of the Pettet-Travis Peak interval in the area of research emphasis.

Table 1. Wells through the Corcoran and Cozzette Sandstones used in figure 1.

Number	Well		Location
57	Nucorp Energy	Tate 1-25	25-6S-100W
59	Coors Energy	USA 1-33	33-7S-99W
124	Pacific Natural Gas	Shire Gulch 31-2	2-10S-97W
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