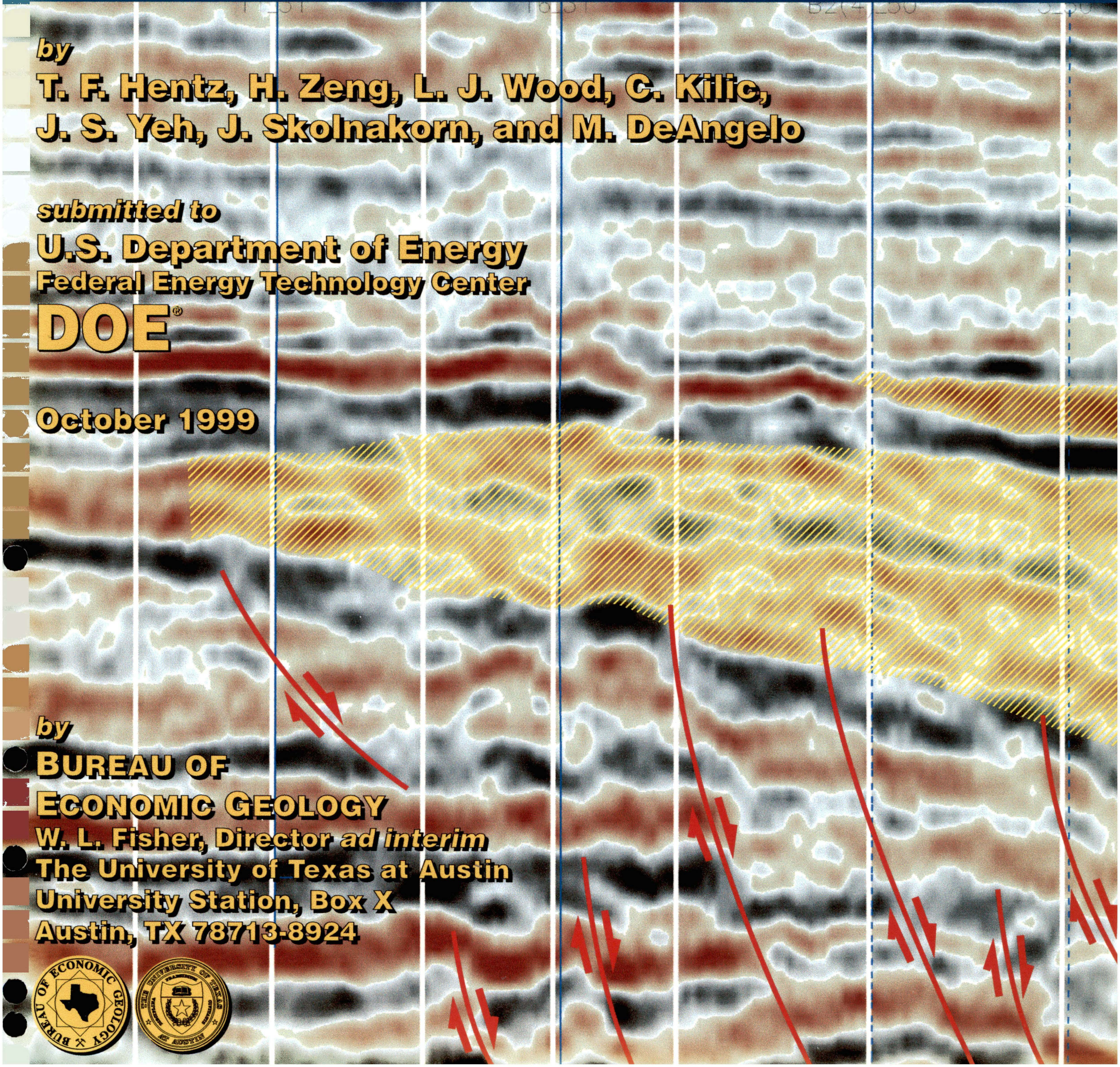
Technical Progress Report: Year 1

Targeting Reserve Growth Opportunities in the Northern Gulf of Mexico Basin: Transferring Secondary Gas Recovery Technology to the Offshore Environment



by

T. F. Hentz, H. Zeng, L. J. Wood, C. Kilic, J. S. Yeh, J. Skolnakorn, and M. DeAngelo

submitted to

U.S. Department of Energy
Federal Energy Technology Center
DOE®

October 1999

by

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EXECUTIVE SUMMARY

The Bureau of Economic Geology's Offshore Secondary Gas Recovery project is a multi-fiscal-year project funded by the U.S. Department of Energy, whose goal is to identify additional natural gas resources in a major field in the northern Gulf of Mexico Basin through multidisciplinary field and reservoir characterization study. PHASES 1 and 2 of the project workplan (PROJECT PREPARATION and DATA GATHERING AND LOADING, respectively) are nearly complete and scheduled to be completed by the end of October 1999. PHASE 3 of the plan (DATA ANALYSIS) is well under way, and a list of preliminary leads is currently being compiled to convey to our industry partner. Reservoir tops have been spotted to facilitate production evaluation and recompletion opportunity. Key regional sequence surfaces have been identified in well logs and seismic, and mapping is being completed in the seismic data set. Some of these surfaces have provided horizons to initiate a continuity processing of the seismic data volume for mapping depositional architecture. Well log interpretation of stacking patterns and systems tracts is well under way. Correlation surfaces have been compiled, and cross sections have been generated and interpreted for depositional elements. These data are being integrated with seismic data via Landmark® software. The project is on track within its projected time frame, and additional personnel are being added as per the technical analysis plan. The key objective in the next fiscal year is to do the bulk of the technical analysis, focusing on generating a prioritized portfolio of infill and exploration prospects. Direct hydrocaron indicator (DHI) modeling and analysis, continuity and impedance analysis, a general attribute interpretation of the seismic data, continued log-facies and parasequence interpretation, fault-seal analysis, and rigorous petrophysical analysis of well data are critical components of this objective.

INTRODUCTION

The Bureau of Economic Geology, The University of Texas at Austin, has been working to improve gas-recovery efficiency in complex onshore reservoirs since 1988. Projects in onshore Gulf Coast sandstones, sandstones of the Fort Worth Basin, and karsted carbonate reservoirs of the Permian Basin have successfully defined secondary, or incremental, gas recovery on the basis of targeting reservoir heterogeneity. These heterogeneities have largely been stratigraphic and diagenetic rather than structural, given that fault compartmentalization of reservoirs is a well-known barrier to completion of hydrocarbon recovery. These past projects have been collaborative, with industry partners ranging from majors, such as Shell and Mobil, to midsize companies, such as Oryx and Union Pacific Resources, to small independents. With the success of the onshore SGR program, it was decided to pursue a similar strategy to demonstrate secondary gas recovery principles and practices in an established natural gas field in the Federal offshore of the Gulf of Mexico.

In fall of 1998, the Bureau received DOE funding for a 4-yr project to carry out a fully integrated field study of a complex, heterogeneous, multireservoir natural gas field in the Federal offshore. Initiation of this program depended on our identifying an industry partner/field operator. After extensive discussions with various potential partners, it was decided to work with Texaco in its Vermilion Block 50 (Starfak) field. Texaco contributed the in-kind value of all field data, such as well log data, production histories, sample and core data, and, most important, a 3-D seismic survey. This survey had been recently acquired and processed but not yet interpreted. The Bureau field study is proposed to incorporate 3-D seismic interpretation; geologic-facies, structural, and well log analysis; petrophysical interpretation; and a complete reservoir-engineering study. The objective is to make industry as a whole aware of the potential for incremental natural gas recovery and the revitalization of mature natural gas fields. The result will be the definition of specific drilling and recompletion opportunities for additional gas recovery, as well as new approaches, technologies, and paradigms for exploration in Miocene strata across the Gulf of Mexico.

Middle Miocene gas reserves contribute 37.7 percent of gas reserves in the northern Gulf of Mexico, the largest fraction by age of any producing reservoirs. Within these deposits, progradational depositional settings have produced the most gas (75.3 percent) of all settings in the northern Gulf of Mexico. Vermilion Block 50 field (also known as Starfak field) contains predominantly progradational deposits consisting of upward-coarsening deltaic deposits, as well as distributary- and fluvial-channel deposits. Vermilion Block 50 field, as named in the offshore atlas (Seni, 1997), is included in four large gas-dominated plays. The combination of asset size and potential, regional productivity of the field intervals, and data availability and quality make Vermilion Block 50 an excellent area for pursuing the objectives of the Offshore Secondary Gas Recovery program.

Summary of Project Objectives and Key Accomplishments

The Offshore Secondary Gas Recovery (OSGR) project began October 1998 as a 4-year joint research venture between the Bureau of Economic Geology (BEG) and the U.S. Department of Energy (DOE). The project is an outgrowth of a previous DOE -sponsored BEG project that produced the *Atlas of Northern Gulf of Mexico Gas and Oil Reservoirs, Volumes 1 and 2* (Seni and others, 1997; Hentz and others, 1997). The OSGR project is focused on practical application of products from the atlas study and providing owners of offshore Gulf of Mexico leases a process road map for increasing hydrocarbon reserves and their asset base. The goal of the OSGR project is to identify additional natural gas resources in a major field in the northern Gulf of Mexico through multidisciplinary field- and reservoir-characterization study. Broader objectives are to create exploration and production models using the project data, which will allow explorationists and producers to target their efforts in the most productive intervals and stratigraphic levels of the Gulf of Mexico Miocene. The specific objectives of the project are to (1) increase reserves, (2) prioritize newly identified prospects and development opportunities, (3) develop and apply new technologies, (4) create transferable knowledge, and (5) achieve these objectives with quality products in a timely fashion. The objectives of the project will be achieved through completion of a nine-phase workplan and the tasks associated with that workplan (fig. 1 and plate 1).

The first year of the project has focused heavily on PHASES 1 and 2 of the workplan (PROJECT PREPARATION and DATA GATHERING AND LOADING, respectively), significant progress being achieved in PHASE 3 of the plan (DATA ANALYSIS). Associated tasks have included locating a suitable industry partner, obtaining all the necessary and available data, establishing a team and appropriate resources, populating an integrated data base, and preliminary interpretation of the geological and geophysical data. An integrated project of this type requires several different software types and hardware platforms for full analysis of the data. This has meant maintaining working data bases in a variety of formats. By our target date of October 15, 1999, we will have compiled all available data in-house and more than 50 percent of those data downloaded from these disparate platforms and entered into a comprehensive Access data base. Such compilation of disparate data types (that is, engineering, geologic, geophysical, and drilling data) has never been done for this area, and the process will serve as a road map for future integrated secondary recovery projects.

The Gantt Chart for the project (plate 1) is a living document that provides a template of process and graphic display of duration and deadlines for all aspects of the project. As information becomes available from the chosen study areas, adjustments are made in the workplan to accommodate changing data availability and customer priorities. For example, although AVO Analysis is listed as a task in the current plan, the lack of availability of raw seismic data, or the cost of processing for AVO Analysis, may eventually drive a decision to forgo that technology application. In addition to our professional staff, the project has three Ph.D. students currently addressing some aspect of the data evaluation as part of their dissertation research. Their work is being conducted in tandem with the overall project time line to maximize the value that their work brings to the project. The Gas Research Institute is considering funding a secondary proposal tied to this project titled “High-Resolution, Gas

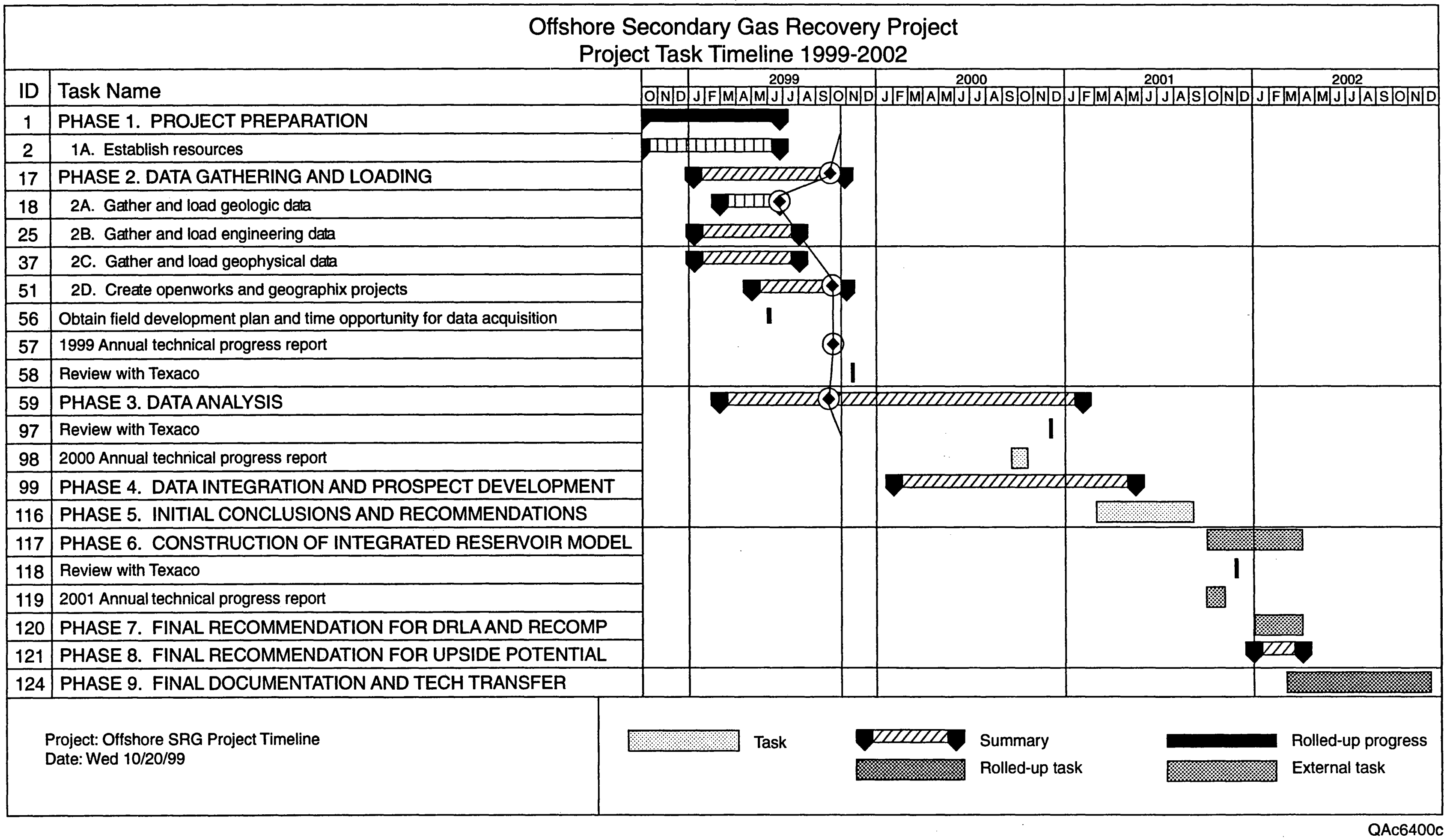

Figure 1. Simplified Gantt chart of project timeline showing key project phases and events.

Reservoir Model Derived from Integrated Neural Net Pattern-Mapping Technology and 3-D Reservoir Modeling." The associated research would focus on development of an attribute-mapping technique using neural network technology that will significantly reduce the time and labor involved in mapping attributes extracted from the 3-D seismic data in this and other projects. We believe that leveraging the DOE's research dollars through such supplemental secondary research grants and graduate student thesis study is a win-win situation for all participants.

Summary of Progress

The project's technical analysis is currently on schedule with our project plan (fig. 1 and plate 1). Our decision to push back the deadline for population, quality checking, and cleanup of the digital data bases from September 1 through October 15 was necessitated by the decision to create a single master Access data base for the project. Our decision to fully integrate many different types of data to maximize the value of the analysis necessitated a more robust platform, such as Access. We think this organization of data will significantly reduce analysis cycle time in the coming year, and, as a result, all parties will receive better research products. Review of the data, discussions with our industry partner, and consideration of the project goal led us initially to focus our detailed technical work in Starfak field. Evaluation of the prospectivity of Starfak field must be conducted within the context of the area's petroleum system, however, and requires a regional study framework that includes Tiger Shoal field, the structural saddle separating the two fields, and their surrounding areas (fig. 2). Regional correlation of key lithostratigraphic and chronostratigraphic surfaces is well under way, and they are currently being integrated with the 3-D seismic data. In addition, initial interpretation of well-log stacking patterns and depositional-element analysis based on log motif has resulted in a preliminary systems-tract framework for the study area (plate 2). Third-order stacking-pattern cycles have been confidently tied to the most recent coastal onlap curve for the Gulf of Mexico Miocene. Parasequences are readily

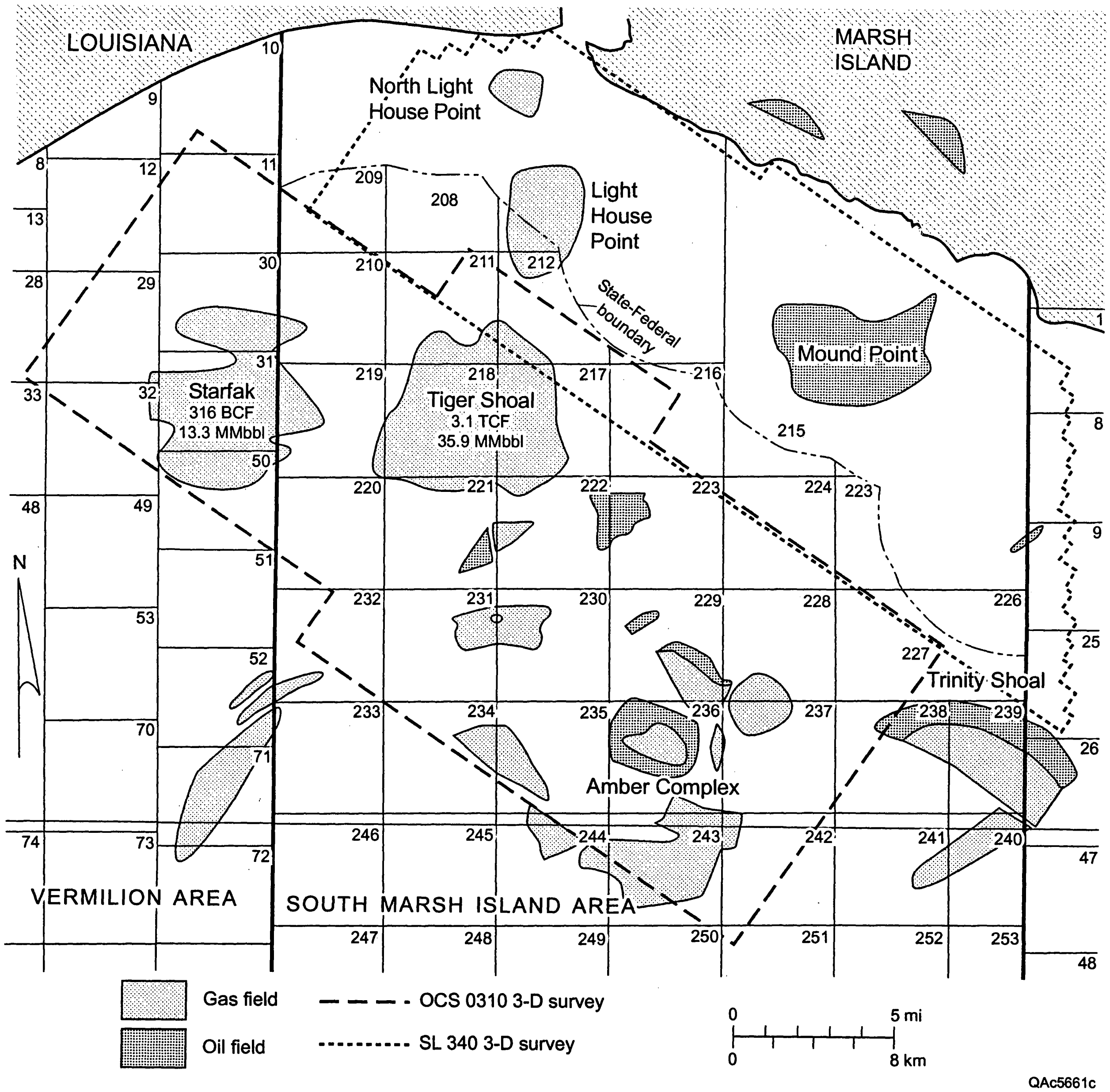

Figure 2. Map of the Vermilion and South Marsh Island Areas showing the study's primary target field, Starfak, and the secondary study field, Tiger Shoal, as well as surrounding fields and the outline of the two major 3-D seismic surveys being used in this resource assessment.

identifiable on well logs, and their mapping will be key to explaining interwell stratigraphic complexity and to targeting infill well locations. Initial review of the seismic data volume shows it to be of high signal-to-noise ratio, thus offering excellent opportunity for DHI evaluation, attribute analysis to resolve stratigraphic complexity and improve the structural interpretation, and seismic facies interpretation. Deep structural elements (>4 s) are well imaged, and their interpretation is key to defining the deep structural potential of the area. Initial stratal-slicing technology has shown remarkable potential for resolving the preserved depositional elements of reservoir intervals across the area and will be a key technology application in defining stratigraphic traps and accurately assessing reservoir and seal uncertainty in structural prospects.

Early observations have allowed us to identify five general targets of potential untapped reserves across Starfak field and associated areas of interest. These include

(1) additional structural traps within the Starfak production area imaged on the new 3-D seismic data,

(2) possible deep closures and structural traps beneath existing Starfak production,

(3) deep structural traps that extend into the structural "saddle" between Starfak and Tiger Shoal fields,

(4) stratigraphic traps that lie in the structural "saddle" between Starfak and Tiger Shoal fields, and

(5) widespread variation in stratigraphic architecture within reservoir units (stratigraphic pinch-outs).

Design of a detailed sequence-stratigraphic framework has focused on three specific plays, which include lowstand and transgressive architectural elements trapped within incised-valley features, distributary-mouth-bar elements of the highstand systems tracts, and, most important, the lowstand-wedge architectural elements of the distal lowstand systems tracts. Primary technical risks in these plays are thought to be seal quality, reservoir presence, and trap definition, the latter being due to the subtle nature of many of the structural closures. Our technical work is therefore focused on maximizing the value of an accurate sequence-stratigraphic framework, the quality 3-D seismic data, abundant information for seal analysis, and quality of the data for seismic attributes toward resolving uncertainly in proposed prospects. By collecting the production, petrophysical, and sand-seal dimensional data in a framework of key stratigraphic surfaces, we can assess potential and more readily translate findings from this to other areas in the Gulf of Mexico.

1999–2000 WORKPLAN

The 1999–2000 workplan for the OSGR project focuses on integrated interpretation of the structural and stratigraphic framework of Starfak and associated areas, with the goal of preliminary identification and ranking of prospects across the areas and defining a portfolio of recompletion opportunities in the field. Key technical tasks include fault-plane and horizon interpretation on the seismic data volume, integrated depositional-sequence analysis, detailed seismic and well log facies analysis, engineering-parameters analysis, fault-seal study, seismic-attribute and hydrocarbon-indicator analysis, and risk analysis. By October 2000, the project team plans to be well into Phase 4 (Data Integration and Prospect Development) of the workplan, including final prospect risk analysis and ranking and reserve estimates. In addition, we will have begun developing several more generic predictive models for the distribution of hydrocarbons and play types within the Gulf of Mexico Miocene section.

The team will present two papers at the 2000 American Association of Petroleum Geologists Annual Convention in New Orleans (app. A), and a tentative late-1999 meeting is planned with Texaco's New Orleans office at their convenience to discuss the 1998–1999 research products and the proposed 1999–2000 project workplan. Details of this workplan are contained on plate 1.

Current and ongoing tasks include

(1) completing sequence-stratigraphic interpretation of study interval in all available well logs, constructing maps of key lithostratigraphic and chronstratigraphic surfaces and zones, and formulating process/depositional models for the reservoir succession;

(2) integrating seismic-facies analysis from stratal-slice studies into the existing log-element analysis for a more comprehensive sequence-stratigraphic framework, to reduce uncertainty, and to locate additional prospects and increase the resolution of future reservoir models;

(3) performing petrophysical analyses: building a shale-index model of gross sand for each reservoir; constructing porosity and permeability models; determining cutoff porosity and permeability values; determining net sand, Phih, and kh values; calculating reservoir-saturation values; and integrating results with production-distribution and structure maps and special core analysis;

(4) modeling reservoir-fluid content and petrophysical parameters to quantify gas effect on seismic signal (a prerequisite for attribute analysis and reservoir modeling) and establishing a template for use of seismic information as DHI in the study area and the regional Miocene;

(5) performing attribute analysis and constructing 3-D porosity models for selected reservoirs;

(6) refining the structural interpretation of both the immediate field areas, the deeper target section, and the field-adjacent areas;

(7) performing well-to-seismic correlation using available sonic and density logs and mapping key corresponding horizons throughout the entire seismic volume; and

(8) continuing design, population, and testing of a comprehensive Access data base.

PREVIOUS WORK

Published studies of Starfak and Tiger Shoal fields do not exist, and there is a paucity of basic regional lithostratigraphic, sequence-stratigraphic, and structural data for the Miocene Series near the study area. Van Wagoner and others (1990) presented a regional cross section of middle Miocene fourth-order sequences in onshore south-central Louisiana. However, the authors cited no published study for this work to enable access to primary data. Using seismic data, Wagner and others (1994) studied the lower Miocene sequence stratigraphy of the nearshore West Cameron and East Cameron Areas in the Federal Outer Continental Shelf (OCS) about 25 mi west of Starfak field. The well data from Starfak and Tiger Shoal fields do not penetrate the portion of the lower Miocene examined by these authors; however, we do have seismic coverage of the lower Miocene in our study area, and their conclusions will be useful in our deep seismic interpretation. Paleontological studies of foraminiferal abundances (Rosen and Hill, 1990), general calcareous nannofossil diversity (Jiang and Watkins, 1992), and basin-scale faunal zones (Fillon and others, 1997) of the northern Gulf of Mexico provide critical constraints on the age of the reservoir succession in Starfak and Tiger Shoal fields.

DATA AVAILABILITY

Well Log Data

Tiger Shoal field, considerably older than Starfak field, has been producing since 1958 from 103 total oil and gas wells. Almost every Tiger Shoal well is vertical, a few wells at the margins of the field being deviated. Oil-producing wells were drilled to depths shallower than those of the gas-producing wells, and they are located exclusively on the east side of the field, mainly in Block 217. A limited number of data were recorded from the logged wells, mostly as resistivity and SP curves. A few of the oil wells have sonic and porosity logs; however, no open-hole gamma-ray logs exist from the oil-producing, east part of Tiger Shoal field. Gas-producing wells, relatively deeper penetrations, have more complete log suites than do the field's oil wells. The gas wells are mostly in Block 218 and display a more areally diffuse distribution than do the oil-producing wells. Use of the gamma-ray curve was crucial to the precise identification of sequence-stratigraphic boundaries and the accurate depiction of sandstone log facies. Its absence from most wells in Tiger Shoal field is a limitation of this field's well log data base.

Starfak field, discovered in 1975, has a total of 53 wells, and 8 of them are deviated. The log suites from this field are significantly more complete than those of Tiger Shoal field. More than half of the Starfak wells have gamma-ray, neutron-porosity, bulk-density, and sonic logs. Log suites from most Tiger Shoal wells do not include these log types, a significant limitation of this well-data subset. No shear-wave sonic logs are available from Starfak or Tiger Shoal fields.

Geophysical Data

The 3-D seismic data were acquired between 1994 and 1995 in an area of approximately 300 mi^2. The data were merged from two surveys: OCS 310 (southwest) and SL 340 (northeast), covering five of Texaco's offshore fields: Starfak, Tiger Shoal, Mound Point, Lighthouse Point, and North Lighthouse Point (fig. 2). Both surveys are oriented NW-SE in the inline direction and SW-NE in the crossline direction. Western Geophysical Corporation (WGC) of New Orleans conducted the acquisition by using a cable crew with airgun source. Both WGC and Texaco's New Orleans office were involved in the data processing. Although some acquisition problems (dead cable, time breaks, etc.) resulted in difficulties and delays, there is no evidence of major quality problems in the final product (Texaco Exploration and Production Inc., 1996).

From an interpreter's point of view, the 3-D seismic data set is of good quality. Dominant frequency varies from 40 Hz in the shallow section to 20 Hz in the deep section, many of the gas reservoirs or reservoir groups being clearly resolved. Visible direct seismic indicators of gas-bearing zones include bright spots on structural highs and against faults and a significant velocity sag observed in the gas-bearing area of Tiger Shoal field. The signal-to-noise ratio is high, with no multiples or other coherent noises, and no migration problems are apparent. The merged data volume, however, does show some subtle differences in dynamic characteristics between the OCS310 subvolume and the SMI subvolume. The potential effect of this difference on the project should, however, be minimal because both Starfak and Tiger Shoal fields are well within the OCS310 subvolume.

We applied two types of post-stack processing to the 3-D volume to improve interpretability of the data. First, a 90° phase shift was applied to the original, approximately zero-phase data. The resulting 90° phase data coincide better with impedance logs and therefore with gamma-ray, SP, and resistivity curves—those with which geologists are most familiar. We then calculated continuity (Landmark) cubes from the original data to aid in fault interpretation and identification of stratigraphic features. The primary benefit of these cubes to the project is that they have imaged numerous faults of different scales (from regional [tens of miles] to local [hundreds to thousands of feet]) and resolved important depositional features (for example, channel systems and slope fans).

We have paid particular attention to the accurate tying of wells to seismic data. Five check shots in Starfak field were loaded into the data base. Analysis of the check-shot curves resulted in an allocation of different time-depth (T-D) curves to different wells on the basis of their distance from check-shot wells and structural location. Although most sonic and density log curves are partly spurious because of borehole washout, we have been able to edit sonic/density logs in two wells to produce good-quality synthetic seismograms that show a reliable tie between well logs and nearby seismic traces. A constant shift was applied to the log curves from all other wells to match the tie with the two wells with good synthetics (fig. 3 and plate 3). Available log-interpreted picks of sequence boundaries and tops of main reservoir units (mainly in Starfak field) were then loaded into the data base and checked for consistency in correlation.

Interpretation of the 3-D seismic data is in an early stage. We have picked almost all the faults in the shallower section (<3 s) with the aid of coherency cubes. Fault picking in the deeper section (>3 s) has just started and is expected to consume much more time because of the structural complexity related to salt tectonics. Tremendous potential for deep gas prospects, however, is already apparent; many newly interpreted deep-seated faults have been identified in the structural saddle between Starfak and Tiger Shoal fields (fig. 4) and to the northwest of Starfak field. Eighteen horizons have been picked and identified as the seismic responses of major marine flooding surfaces. Guided by these reference horizons, several stratal-slice

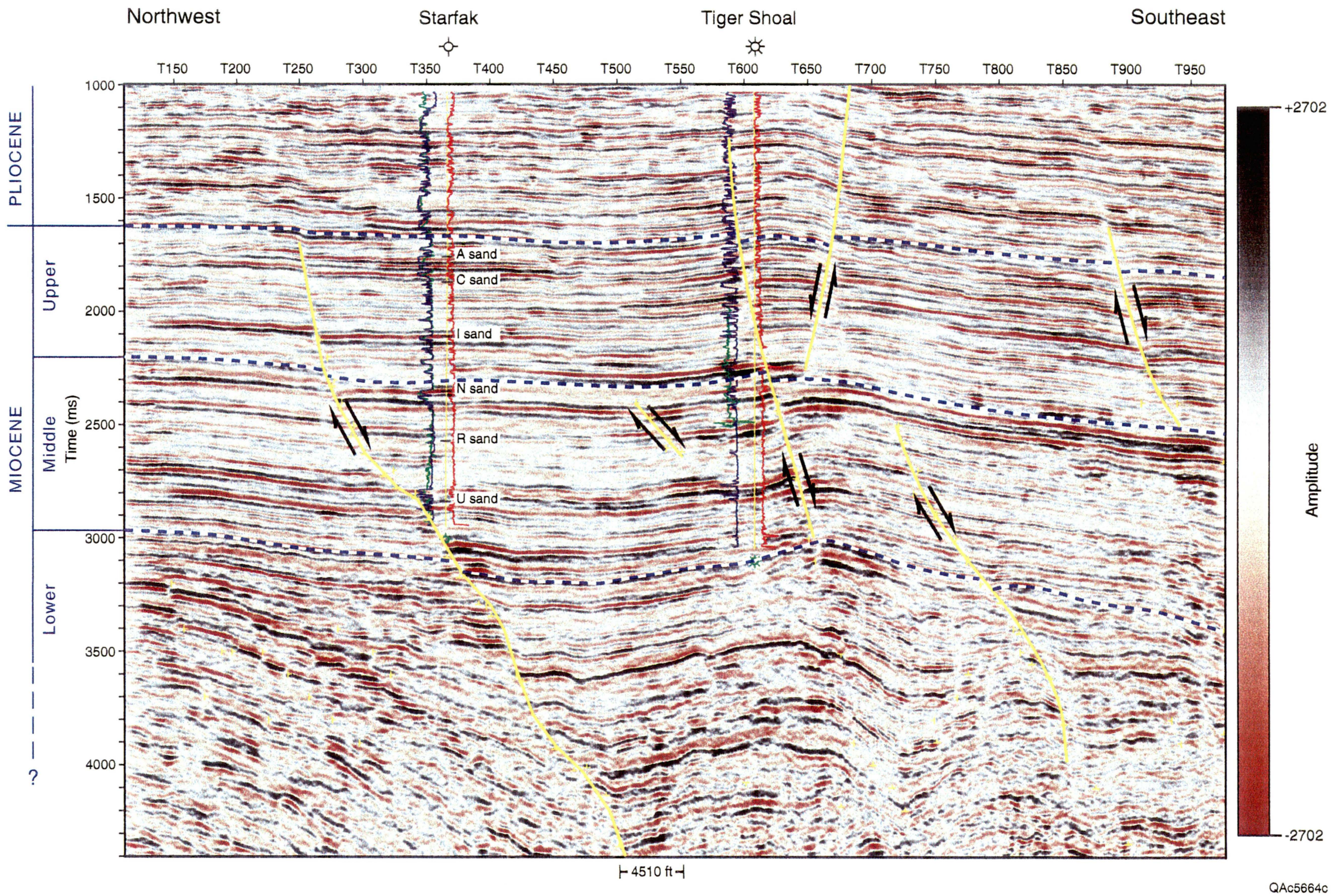

Figure 3. Northwest-southeast regional strike-oriented seismic profile across Starfak and Tiger Shoal fields illustrating relatively simple structure within the field areas. Northernmost (left) fault is the major growth fault that forms the north boundary of the fields.

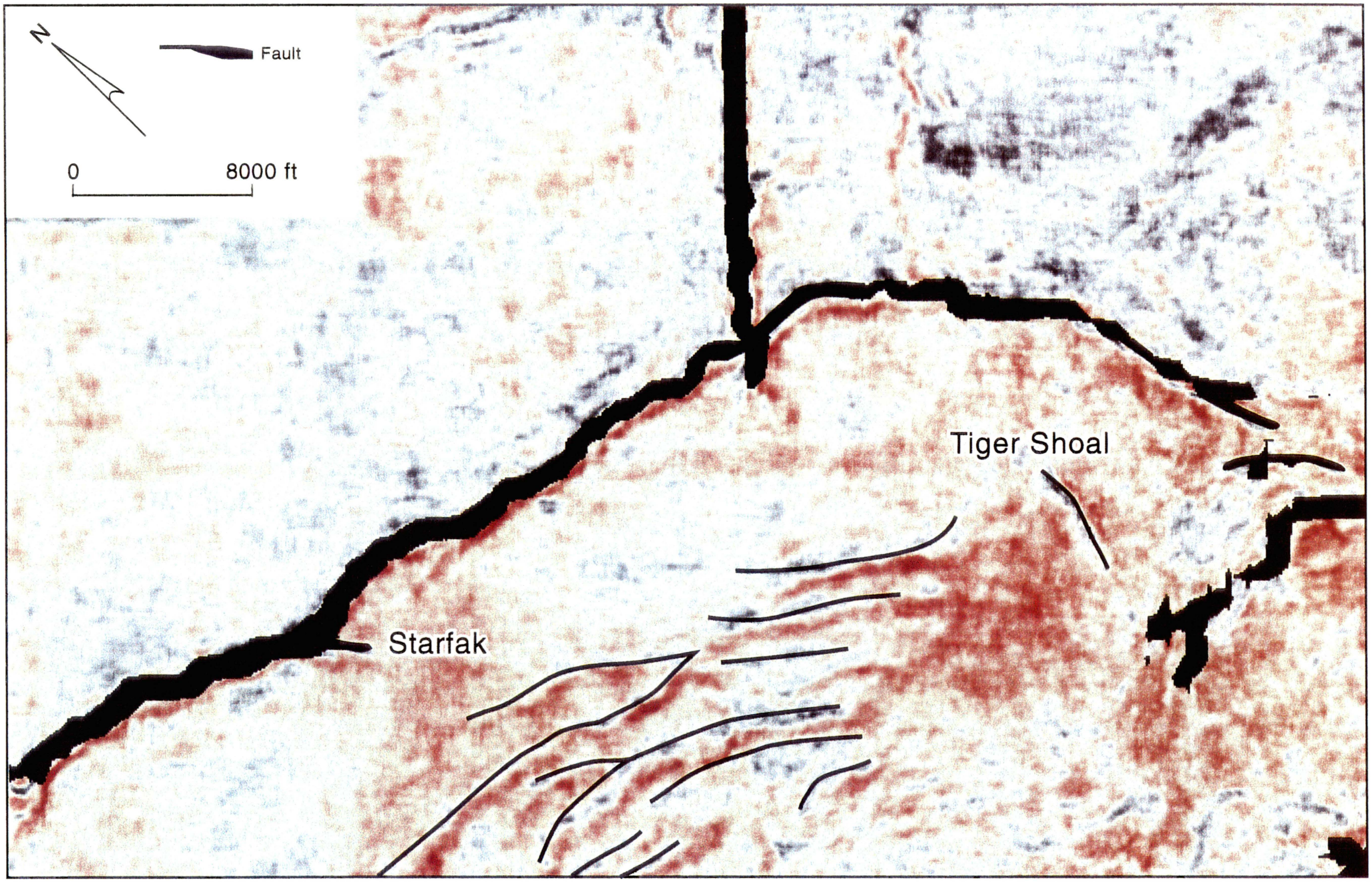

Figure 4. Amplitude stratal slice from 3-D seismic data of a *Robulus* L zone (below 13,000 ft) within the greater Starfak and Tiger Shoal region. Both amplitude and continuity stratal slices clearly illustrate several deep W-E-trending faults in the area between the two fields. These faults offer great potential for deep gas prospects and are being closely inspected for hydrocarbon traps.

volumes have been created to help image depositional-facies patterns. Initial seismic-sedimentological analysis based on the stratal slices has revealed amplitude patterns that represent inferred incised-valley fills at several stratigraphic levels (middle to upper Miocene). Sand trends depicted on these stratal slices coincide with those of incised-valley-fill sands interpreted from log-facies analysis. Additional stratal slices from the 3-D volume show numerous fluvial channels in the shallower section (Pliocene) and inferred slope and basinal channels and fans in the deeper section (lower Miocene).

Core Data

Texaco provided sidewall-core data for 41 vertical and sidetrack wells in Starfak field and 58 wells in Tiger Shoal field. Between approximately 10 and 160 sidewall cores, representing 1 to several sand-body reservoirs, were taken from each well. We have constructed spreadsheet data bases that contain all laboratory-derived measurements: permeability (some cores measured for both air and oil permeability), porosity, porosity saturation (oil), porosity saturation (water), percent volume of oil, and percent volume of gas.

Texaco archives yielded only one whole-core description of an 82-ft interval in the Texaco No. 6, Block 31 well. Texaco conducted special core analysis of this interval (Rob. L-2 sand) by recording PVT data and permeability, porosity, and relative permeability values.

Engineering Data

Engineering data provided by Texaco will form a firm basis for later reservoir-specific analyses. Production-history data include cumulative production; monthly production values for oil, gas, and water; and starting/ending date of production for each reservoir and reservoir segment. All perforation intervals provided by Texaco have been individually tied to production history in the company's Oil Field Manager (OFM) data; we have supplemented these data with perforation information from hard-copy well log annotations, well-history files, and well-bore schematics. Reservoir-gas composition and pressure/volume/temperature (PVT) analyses from four wells in Tiger Shoal field have also been provided. There are 14 water analyses from Tiger Shoal field and 3 analyses from Starfak field. Two wells from Starfak field have yielded pressure-buildup test data. We have access to numerous bottom-hole pressure (BHP) tests from various wells, reservoirs, and reservoir segments throughout their production history.

Data-Base Unification

Texaco has provided the project with abundant seismic, geologic, engineering, and production data for the Miocene reservoirs in the two fields. Our near-term objective is to unify these myriad data into a single, easily accessible, comprehensive data base. Currently we have separate data bases for both fields that are fully populated with (1) geologic-marker picks derived from well log correlation (reservoir tops, fault locations), (2) all perforated and completed intervals, (3) inventory of all digitized well log curves, (4) inventory of hard copies of well logs, (5) core-analysis data, (6) cumulative oil/water/gas-production data, (7) geographic coordinates and elevations of surface (kelly bushing) and bottom-hole (for deviated and sidetrack wells) locations, and (8) azimuths and deviation directions for all deviated and sidetrack wells. Sequence-stratigraphic data, depositional-facies data, and quantitative petrophysical data derived from in-house well log analysis, and other recently acquired Texaco data (for example, results of well-completion tests), will also be included as data sets. As of today, several separate data bases have been populated in a variety of applications: Seisworks, Stratworks, Petroworks, Zmap, GeoGraphix Exploration System (GES), Petcom, Prizm, Oil Field Manager (OFM), and the Interactive Reservoir Analysis Package (IRAP). We are currently unifying these data bases into an Access data base, which is designed to be an integrated, comprehensive data platform from which disparate software will draw the most current data for analysis.

The data that are currently in the Access data base are now being updated and reviewed for accuracy. We are also currently moving our well log data base to Prizm and Openworks so that log analyses can be easily transferable among seismic interpreters and geologists. The GES project, which is also under construction, will aid in the visualization and interpretation of production data for future reservoir modeling.

TECHNICAL PROGRESS

Regional Stratigraphic and Structural Framework

The reservoir-bearing lithostratigraphic interval in Starfak and Tiger Shoal fields includes most of the entire Miocene Series and composes an overall regressive, progradational succession (fig. 5). The interval grades upsection from (1) slope depositional facies to (2) distal shelf and transitional distal shelf/lowstand-delta (lowstand prograding wedge) facies to (3) medial and proximal shelf facies, and finally to (4) aggradational coastal-plain deposits a few hundred feet above the reservoir-bearing study interval. This upward-shallowing trend of depositional facies coincides with that of the entire Miocene interval in the offshore northern Gulf of Mexico (Seni and others, 1997). Paleontological data from selected wells indicate that the 9,900-ft section from the oldest reservoir (*Robulus* L-8 sand) at the base of the study interval to the uppermost reservoir (A sand) represents about 15.5 m.y. of deposition and ranges in age from early Miocene (about 22 m.y.a) to latest Miocene (about 6.5 m.y.a) (Fillon and others, 1997).

Reservoir intervals were initially identified in our study by annotated well logs provided by Texaco for most wells in the two fields. Our subsequent detailed correlation among well logs using the full array of log curves available enabled a fine tuning of reservoir-top depths. We have identified the tops of all reservoirs on all well logs in Starfak and Tiger Shoal fields. Although reservoir tops are strictly nongenetic designations (that is, they do not necessarily represent correlative time lines or laterally persistent depositional surfaces or boundaries), we paid careful attention to consistency in the precise correlation of reservoir tops among well logs on the basis of the signatures of all available log curves (especially gamma-ray, resistivity, and sonic logs). In the construction of structure-contour maps, for example, where elevation variation (structure) in

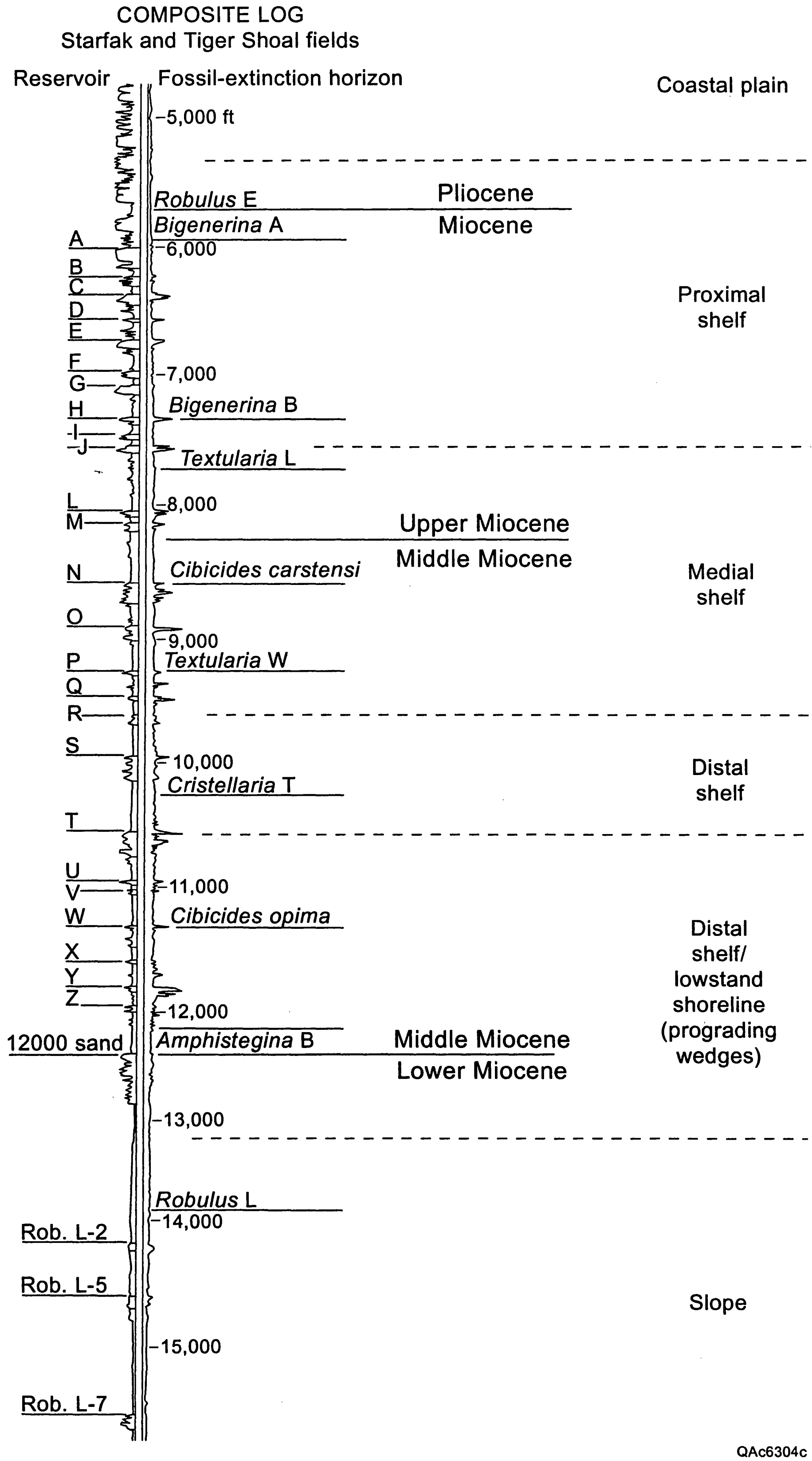

Figure 5. Composite type log of Starfak and Tiger Shoal fields. Delineation of stage boundaries is approximate and is based on micropaleontological data from several wells in both fields. Depositional settings interpreted by log-facies analysis, inferred lateral facies transitions, and vertical sand-stacking patterns.

the reservoir-top surface may be subtle (a few tens of feet), this precise correlation is critical in identifying additional potential hydrocarbon traps. It is important to note that Texaco's annotated logs generally display only SP, resistivity, and conductivity curves. All of our correlations were made on hard-copy well logs that we prepared using Petcom® software, which enables printing and display of all available types of log curves for each well on a single log sheet. Precise lithostratigraphic and sequence-stratigraphic correlation was greatly enhanced by the display of the full array of log curves, especially the gamma-ray curve, a nearly unequivocal indicator of sandstone quality (shaliness) and of maximum clay and organic content of shales (for identification of marine condensed sections). Identification of both of these features, among others, is critical to log interpretation of principal sequence-stratigraphic boundaries.

After constructing a digital data base listing all top-of-reservoir log picks from Starfak and Tiger Shoal fields, we integrated these data with the 3-D-seismic data volume. Resulting seismic profiles indicate a nearly one-to-one correlation between reservoir sands and prominent seismic reflectors (plate 3). Log response to reservoir occurrence is remarkably consistent in both fields. We have completed construction of a digital data base containing all the petrophysical parameters of reservoir facies derived from sidewall-core analyses in both fields.

Starfak and Tiger Shoal fields are located in the South Louisiana Shelf Diapir Province of the Gulf of Mexico Basin (Ewing, 1991). Although this region is generally characterized by large-scale structural folds, a product of deep salt movement, geologic conditions in the greater two-field study area are structurally simple compared with those of the complex, diapirically deformed strata that occur to the south. The two fields are associated with several subregional normal growth faults and associated antithetic faults that cause additional structural partitioning. There are two major growth faults in Starfak-Tiger Shoal fields. A broadly arcuate W-E growth fault forms the north boundary of the two fields and probably acted as a major control on basin geometry and depositional systems track development during the Miocene (fig. 4). A N-S growth fault roughly bisects Tiger Shoal field, generally separating primarily gas-producing reservoirs in the west part of the field from oil reservoirs in the east. Subsidiary, deep-seated faults in a structural saddle between the two fields (fig. 4) and to the northwest of Starfak field are mostly parallel to the major W-E growth fault. Preliminary findings indicate that these faults may form high-potential, untested hydrocarbon traps. Structurally, the two fields are fault-cut anticlines, the Starfak structure being much deeper seated but having a lower relief.

Reservoir Framework

Thirty-six potential gas and oil reservoirs occur within any one well in the Starfak and Tiger Shoal fields. In accordance with Texaco's established reservoir nomenclature, these sand-body reservoirs are named as follows (in descending order): A through Z sands (some are variously subdivided using alphanumeric designations, such as F-1 sand and M-1 [lower] sand), 12000 A sand, 12000 B sand, and the *Robulus* L-1 through *Robulus* L-8 sands (fig. 5). Reservoir sands range in depth from about 6,200 to 16,200 ft in Starfak field and 6,000 to 15,400 ft in Tiger Shoal field. Productive sands generally occur stratigraphically higher in Tiger Shoal wells.

Most of these Texaco-designated reservoir sands approximately coincide with key sequence-stratigraphic (chronostratigraphic) boundaries that are discussed in the next section. Among other benefits, this approximate coincidence of markers greatly aided in the precise correlation of sand-bearing intervals across the 4-mi undrilled saddle between Starfak and Tiger Shoal fields (plate 2). With only two exceptions, Texaco-designated reservoir sands are approximately correlative between the fields. The Texaco-designated E and L sand reservoirs in Starfak and Tiger Shoal fields are not time-stratigraphic equivalents between the two fields, although the true equivalents are within only 100 to 150 ft of the miscorrelated intervals.

Sequence-Stratigraphic Framework

During the first year of activity on the project, we developed a firm sequence-stratigraphic framework that integrates the genetic stratigraphic framework and systems tracts within and between Starfak and Tiger Shoal fields (plate 2). This achievement represents a fundamental step in the reservoir characterization of these two fields and lays the critical groundwork for all subsequent, more focused analyses of reservoir-specific attributes and the identification of previously undetected gas and oil prospects—one of the principal objectives of this project. The model establishes a robust genetic framework from which finer scale (that is, reservoir-specific) attributes can be predicted and derived. Our sequence-stratigraphic model allows precise delineation of key chronostratigraphic surfaces (sequence boundaries and flooding surfaces), identification of sand-bearing depositional systems tracts within the reservoir-bearing succession, prediction of the areal geometry of sand-body reservoirs (and after forthcoming full petrophysical analysis, identification of reservoir flow units), and formation of a robust reference system within which all engineering, production, and petrophysical data can be placed. This model allows interpolation of boundaries within the field areas and prediction of field-scale depositional attributes, observations that can extend our knowledge of hydrocarbon prediction to other areas of the region. The sequence-stratigraphic framework of the Miocene Series can be readily extrapolated to surrounding offshore fields, especially if complemented by paleontological data to improve correlation confidence.

There are a total of 34 fourth-order sequences within the 9,000- to 10,000-ft reservoir-bearing Miocene interval in Starfak and Tiger Shoal fields (plate 2). In almost all instances, sequence boundaries occur at the top, base, or within the Texaco-designated reservoir sands. The fourth-order (about 0.3- to 0.5-m.y.) sequence cyclicity was interpreted from integrated log-facies and 3-D-seismic analysis. Select sequence boundaries identified in this project precisely coincide with third-order cycle tops established by Fillon and others (1997). These third-order cycle tops define broad coastal-onlap trends in the northern Gulf of Mexico during the Miocene (fig. 6). The agreement of these published basin-scale, time-stratigraphic boundaries and those independently derived for this study improve confidence in the designation of sequence boundaries in the two-field study area.

The overall regressive, progradational Miocene succession comprises (in ascending order) slope and slope-fan deposits, distal shelf and lowstand-delta (lowstand prograding wedge) facies,

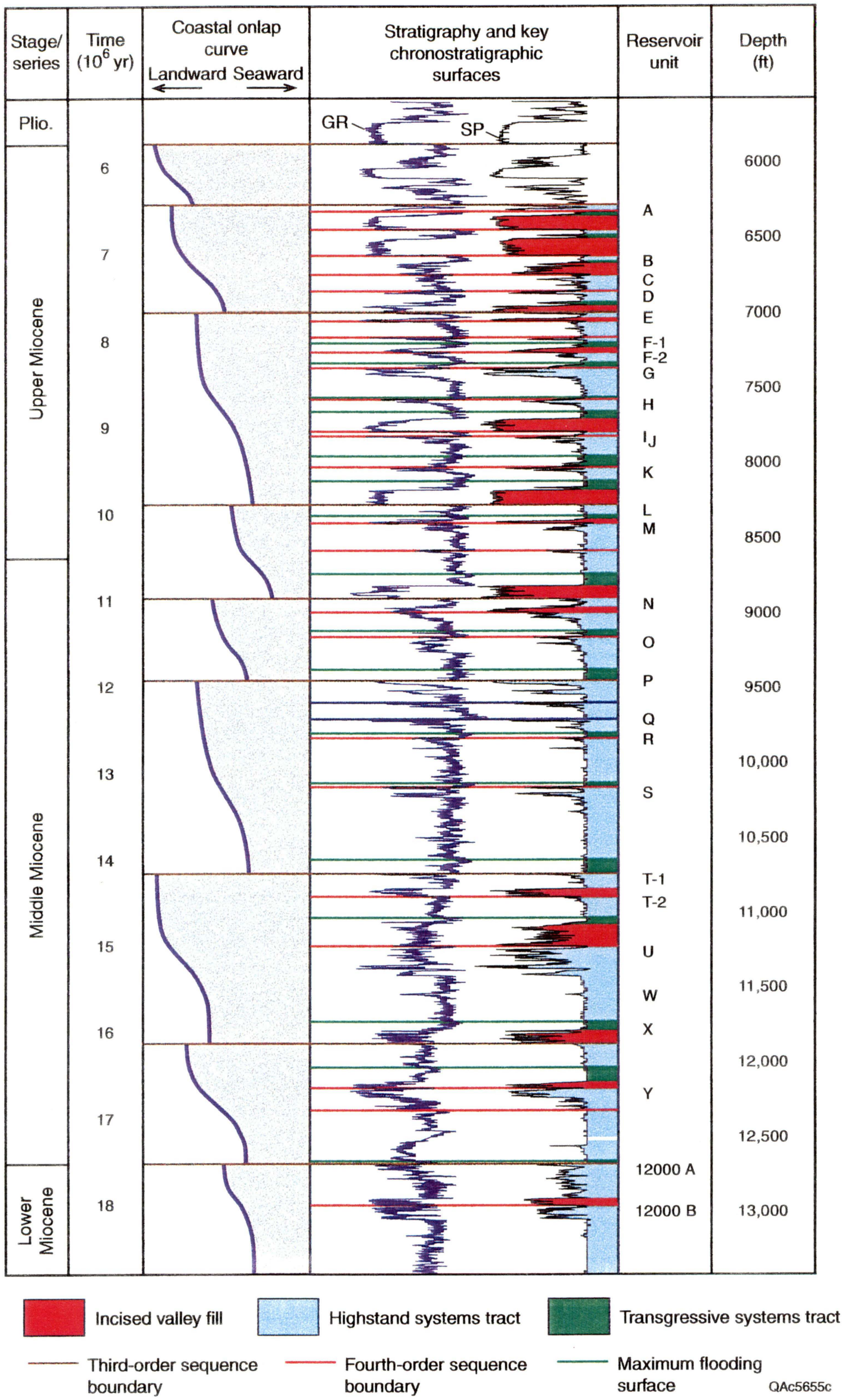

Figure 6. Sequence boundaries, maximum flooding surfaces, and systems tracts depicted in a representative log (from Texaco No. 8-31 well) in Starfak field. Paleontologic data from this well allowed correlation with the regional coastal onlap curve of Fillon and others (1997), determination of absolute ages of sequences, and location of stage boundaries within the study succession.

and medial and proximal shelf systems (fig. 5). Inferred coastal-plain deposits occur within 200 to 300 ft above the top of the study interval. Delineation of the 34 sequences within these general facies tracts allows further division of the slope and shelf systems into finer scale lowstand, transgressive, and highstand systems tracts that honor precise time-stratigraphic boundaries. Reservoir sand bodies are key components of all of these systems tracts.

Slope and Slope-Fan Facies

Slope and slope-fan deposits compose the basal 30 percent of the drilled Miocene section in the deeper wells. Approximately 90 to 95 percent of these deposits are shale. Gamma-ray curves of these deposits display the characteristic broadly (over several hundreds of feet) sinusoidal log signature that records well penetration of upper, medial, and possibly minor lower slope facies. Slope-fan sands (*Robulus* L sands), which are the primary gas reservoirs in many wells in Starfak field, occur primarily in the medial slope intervals and display gamma-ray readings lower than those of the adjacent shales. These zones of thin fan sands and associated much thicker silty deposits having moderately to slightly lower gamma-ray values are generally 300 to 400 ft thick and are cyclically distributed within the shale succession; this cyclic distribution produces the diagnostic sinusoidal log curve of slope deposits. However, the reservoir-quality fan sands range in thickness from only 10 to 50 ft.

The slope and slope-fan succession in the two-field study area cannot be divided into sequences primarily for two reasons. The shale-dominated succession comprises mostly upper and medial slope deposits; no clearly defined lowstand basin-floor fan deposits occur within the drilled interval. The absence of basin-floor fans in the study area is unfortunate because the bases of these fans coincide with sequence boundaries (downlap surfaces) at the boundaries' most distal (basinward) extent. Moreover, the upper and medial slope is a physiographic zone of primarily sediment bypass of sand and silt. With the exception of the generally thin turbiditic slope-fan deposits (*Robulus* L sands) that locally accumulated on the medial slope where the angle of the slope's depositional surface decreases slightly (point of inflection in the slope's profile), most slope sediment was deposited by the settling of clay- and silt-size particles from the water column.

Lowstand Systems Tract

In Starfak and Tiger Shoal fields, lowstand systems tracts consist of basal incised-valley fills (fig. 7) and all deposits of prograding deltaic wedges that developed basinward of the shelf edge (figs. 8 through 10). Shelf facies compose 50 to 60 percent of the study interval (A to T-1 sand) and contain third- and fourth-order sequence boundaries that mark pronounced fieldwide erosional surfaces and their correlative surfaces of exposure. The sequence boundaries formed by significant basinwide drops of relative sea level (base level). Erosional surfaces occur at the bases of thick (50 to 150 ft) blocky to spiky log facies that represent incised-valley fills composed of lowstand fluvial facies overlain by transgressive estuarine and bayhead-delta deposits (figs. 8, 11). Juxtaposition of fluvial facies over shelf facies represents significant basinward shifts in coastal onlap. Sequence boundaries at surfaces of exposure that are equivalent to the erosional surfaces mark the tops of major upward-coarsening log motifs that record subaerial exposure of these progradational (late-highstand deltaic) deposits.

Changes in log motif (indicating changes in net-sand or sand/shale distribution) that characterize valley-fill facies are associated with the spatial location of the lowstand valley relative to the proximal, medial, or distal paleoshelf. The magnitude of valley incision increases and valley fills thicken to the south, downdip on the paleoshelf. Log signatures of the valley fill in those reaches of the valleys incised into proximal and medial paleoshelf settings are blocky, blocky serrated, or upward fining (figs. 8, 11). This character records well-developed (low-clay-content), high-porosity stacked fluvial-channel architectural elements. Minor gamma-ray highs (thin shale partings or shale-pebble lag conglomerates) separating individual channel elements represent reactivation surfaces that may form localized reservoir flow barriers. These are

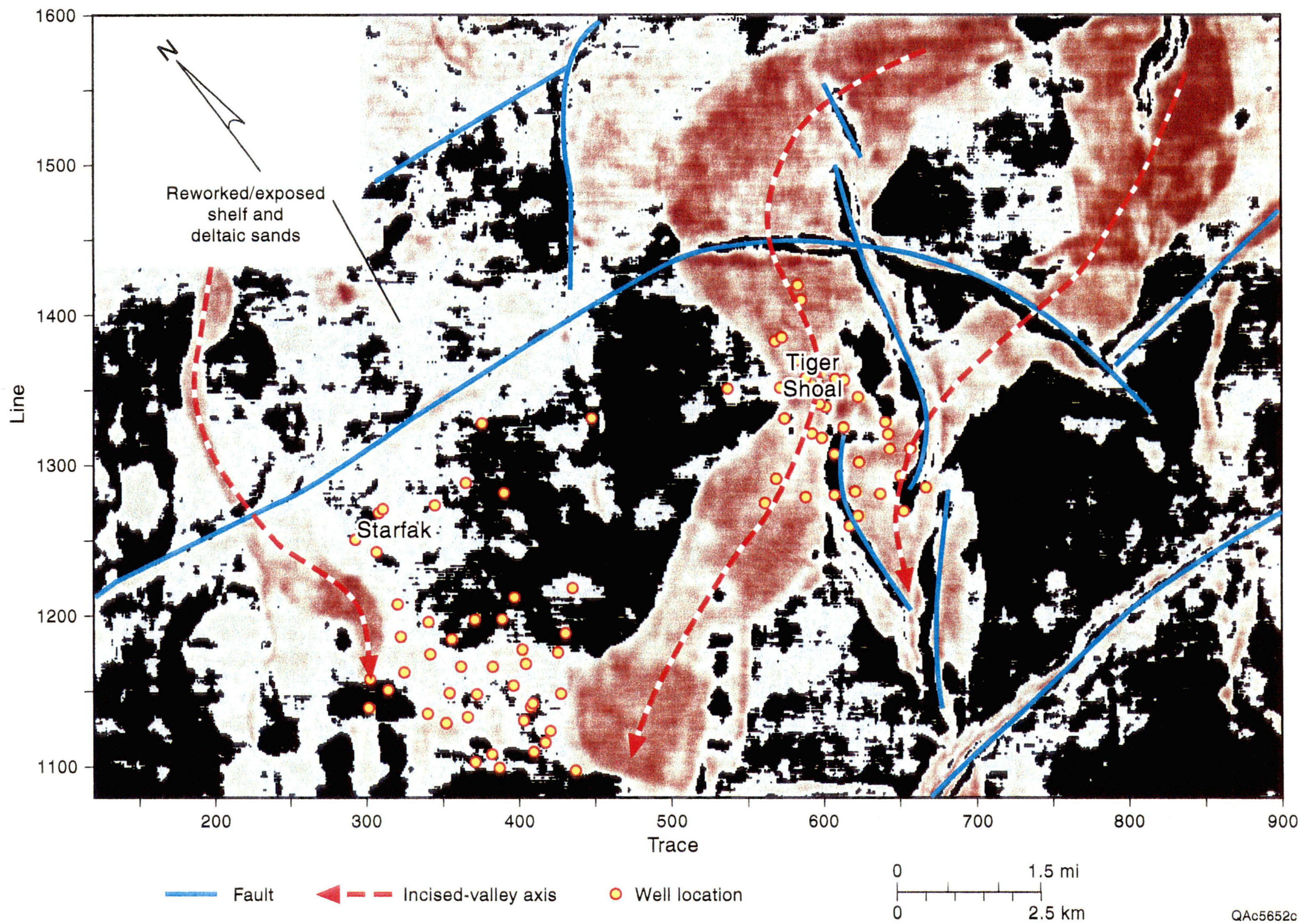

Figure 7. Amplitude stratal slice from 3-D seismic data depicting the areal distribution of lowstand incised-valley deposits of the C sand reservoir within the greater Starfak and Tiger Shoal area. Such stratal slices show remarkably focused resolution of depositional and paleophysiographic trends in the study area and serve as accurate guides to facies mapping from well log data.

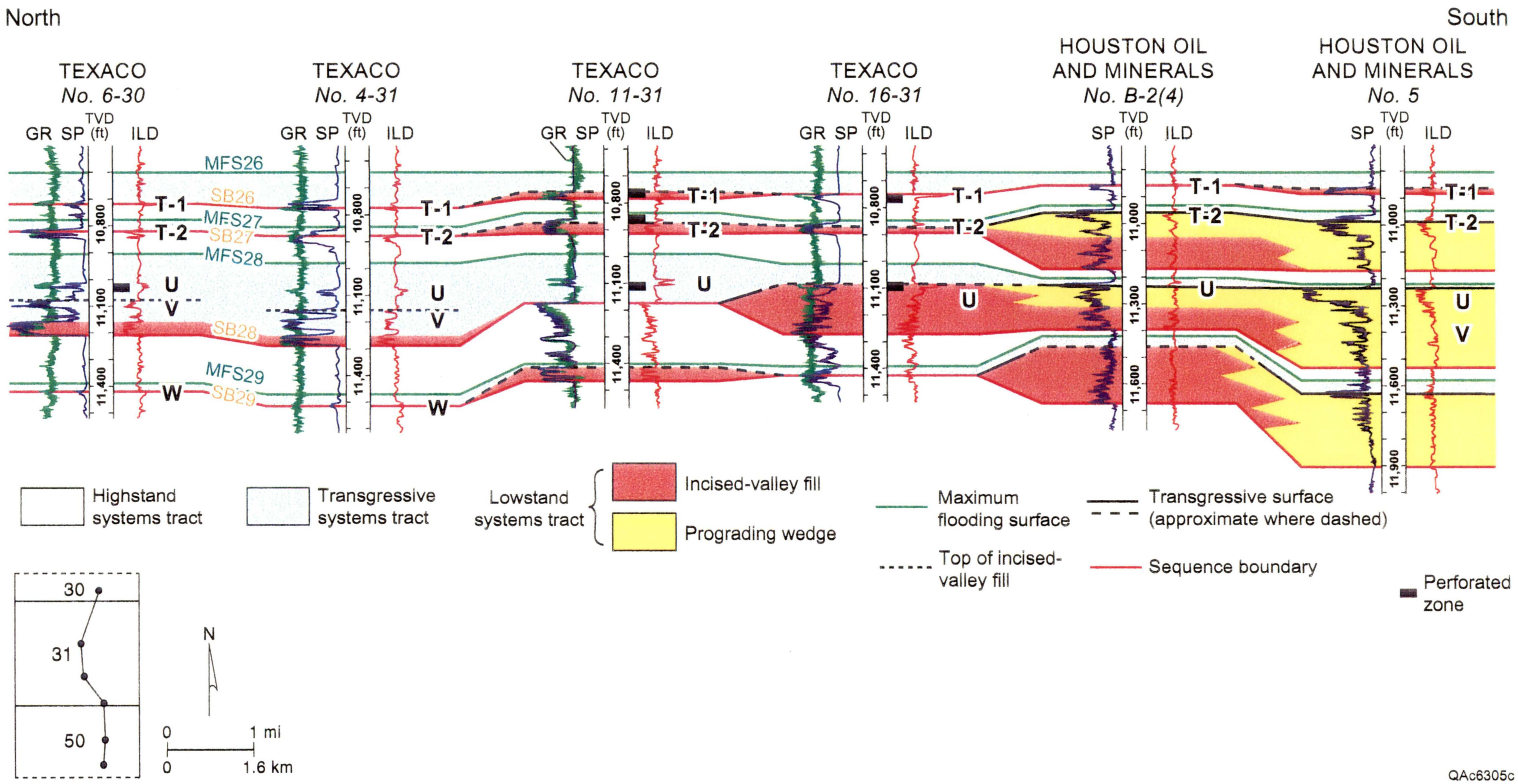

Figure 8. North-south regional dip cross section showing interpreted shelf-to-lowstand-prograding-wedge systems-tract transition in Starfak field. See figure 10 for line of section and figure 9 for seismic profile. The inferred shelf edge at U- to V-sand time is located close to, or more likely just south of, Texaco No. 11-31 well (fig. 10). Note the pronounced lateral variability in the (1) log-facies expression of individual Texaco-designated reservoir sands and (2) systems tracts of which individual reservoir sands are a part. The U sand, for example, occurs within two inferred systems tracts (transgressive and lowstand systems tracts) and three major depositional regimes (distal deltaic/shoreface shelf facies in the north, incised-valley fill basinward of the shelf edge, and lowstand prograding wedge in the south). Such field-scale (and local) variability will be closely examined for sand location, flow-unit geometry, and prediction of stratigraphic-trap location.

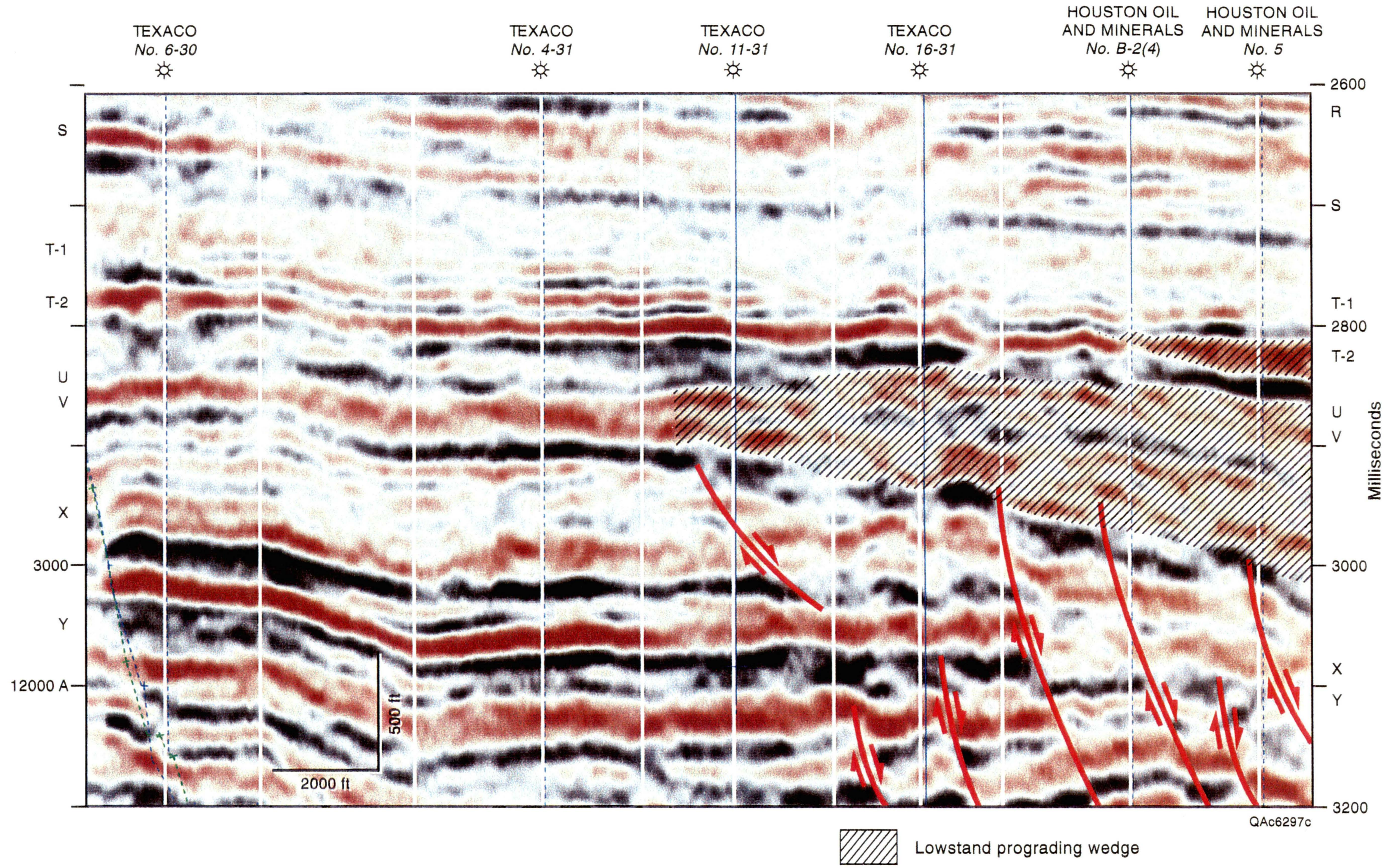

Figure 9. Seismic dip profile of the R- to 12000-A sand succession in Starfak field showing geometry of the U- and V-sand (lower) and T-2-sand (upper) lowstand prograding wedges. Wells identified are the same as those in figure 8. Sand-body reservoirs are labeled on the margins. Typically these lowstand wedges and associated distal-shelf to upper-slope stratigraphic zones immediately overlie or contain numerous penecontemporaneous (growth) faults, strongly suggesting that movement on these faults influenced the position of shelf edges.

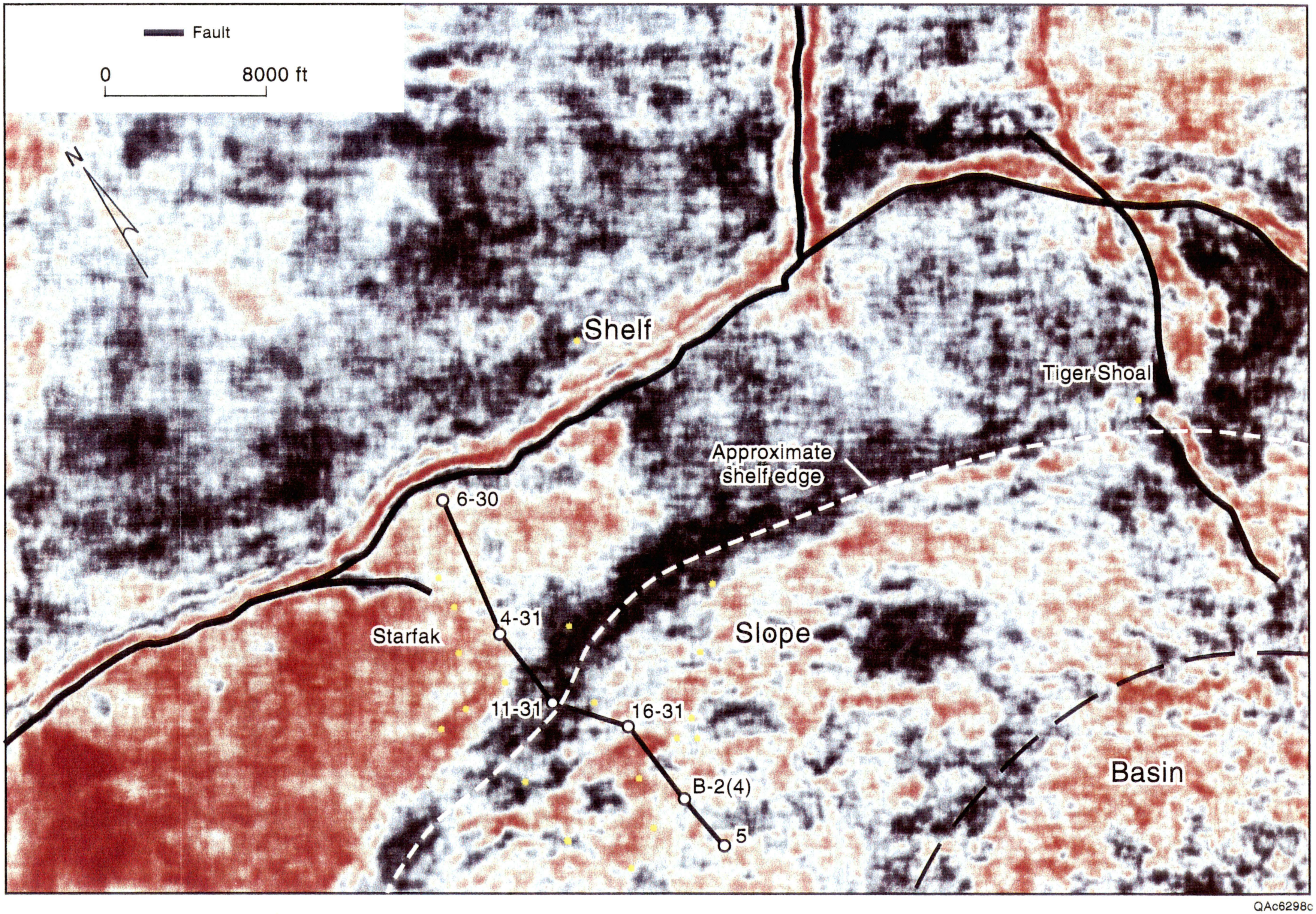

Figure 10. Amplitude stratal slice from 3-D seismic data of the U to V sand interval of the greater Starfak and Tiger Shoal area. Cross section shown in figure 8. Stratal slices can delineate not only depositional trends but also physiographic features. This image depicts the approximate shelf edge during deposition of the U to V sand interval in the middle Miocene. Interpretation of systems tracts shown in figure 8 supports the shelf-edge location.

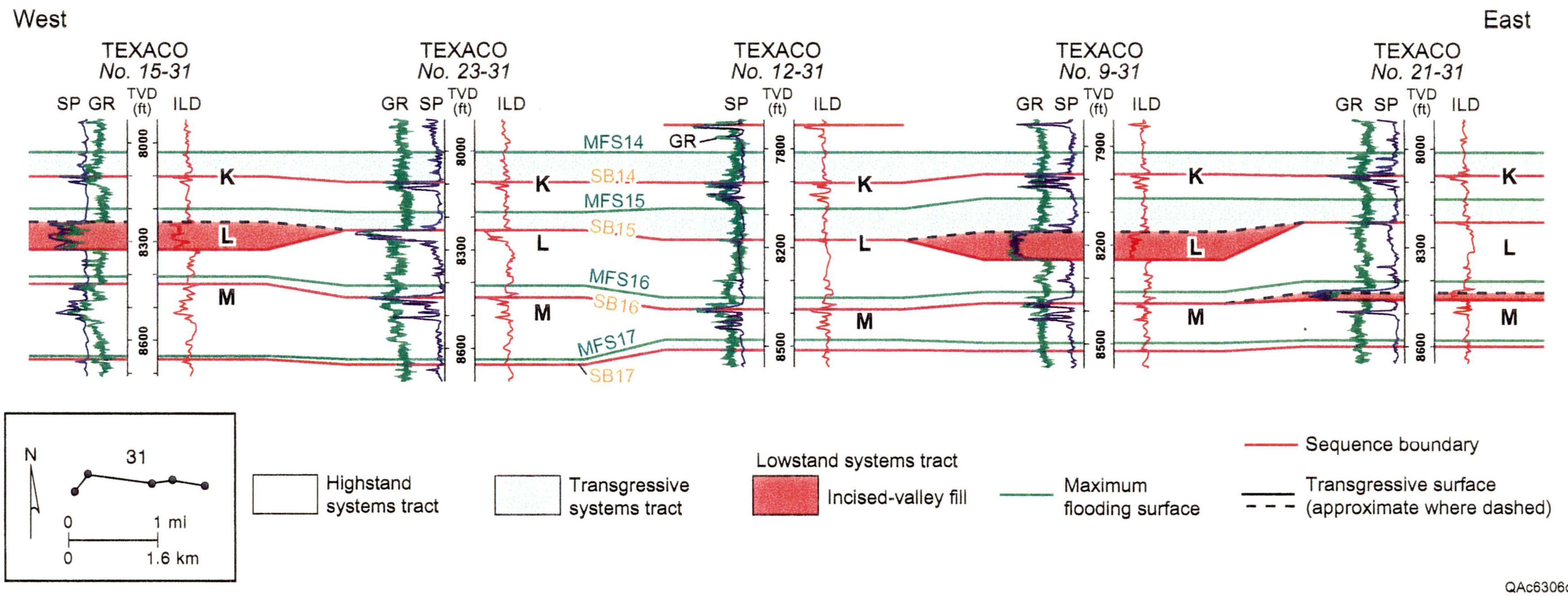

Figure 11. West-east regional strike cross section showing sequence-stratigraphic correlations and inferred systems tracts in medial shelf facies of Starfak field. Progradational parasequence sets compose well-defined highstand systems tracts; overlying, thinner, retrogradational parasequence sets depict major transgressive successions that culminate in maximum flooding surfaces typically marked by maximum gamma-ray peaks. Note the contrast in log-facies signatures between incised-valley fills of the proximal and medial shelf (this figure, fig. 8) and those of the distal valley fills located immediately upslope of lowstand prograding wedges (fig. 8, 11,270 to 11,080 ft in well 16-31 and 11,670 to 11,460 ft in well B-2[4]).

dominantly lowstand fills inferred to have aggraded during late lowstand time when relative sea level was stable or slowly rising. Lowstand fluvial fills are overlain by valley-confined transgressive deposits (described in the following section). In contrast, thicker valley fills (as much as 210 ft) (fig. 8, 11,270 to 11,080 ft in well 16-31 and 11,670 to 11,460 ft in well B-2[4]) are located in more distal shelf locations. These valleys form topographic "notches" in the paleoshelf margin. Valleys are located immediately upslope from lowstand prograding wedges that were fed with sediments cannabalized from erosion of the underlying highstand shelf deposits as "knickpoints" eroded landward, forming the final lowstand river profiles. Distal valley fills may have locally preserved lowstand fluvial deposits in their bases, but preliminary interpretation indicates that they are dominantly filled with the late lowstand-wedge deltaic deposits, which onlap the base of the valley landward.

Lowstand prograding wedges are composed of facies that are transitional between shallow-marine shelf deposits of the late highstand and deposits of the deep (over the shelf) marine deposits of the upper slope. Identification of this lowstand facies at the shelf-to-slope transition is one of the more significant findings of this study. These wedges, where unfaulted, are well defined on 2-D seismic profiles and compose about 10 to 20 percent of the section in Starfak and Tiger Shoal fields. Generally sand-rich progradational parasequence sets that range from 50 to 300 ft in thickness form the lowstand prograding wedges (fig. 8), which represent deltaic progradation at the lowstand shoreline located basinward of the preceding shelf edge (fig. 10). The transition zone between each wedge and its associated updip feeder fluvial system, marks the approximate position of the contemporaneous shelf edge. Lowstand wedge facies and other time-equivalent distal-shelf to upper-slope facies typically overlie or are cut by numerous penecontemporaneous (growth) faults (fig. 9), strongly suggesting that movement on these faults influenced the position of the shelf edges. Lowstand wedges exhibit a forward-stepping pattern, younger wedges being located progressively farther south. This pattern coincides with progressive southward shift in time of the regional Miocene shelf edge in response to overall Miocene progradation.

Transgressive Systems Tract

The thin (10- to 40-ft) backstepping, progradational successions (retrogradational parasequence sets) that compose transgressive systems tracts disconformably overlie the transgressive surfaces within lowstand valley-fill deposits and above lowstand wedges and merge with the sequence boundaries in interfluve areas (figs. 8, 11). These parasequence sets form stacked, upward-fining log-facies successions that culminate in a high gamma-ray response signifying the maximum marine flooding event, the marine condensed section (fig. 12). In the most landward locations of the study area, the condensed section is difficult to recognize, being landward of the updip limit of deposition of marine shales. In these successions (approximately the sequences containing the A through D sands), the surface of marine flooding is contained within an overall sandy section, and more work will be required to deduce the stratigraphic response to maximum marine flooding. In most of the study area, however, the condensed sections are composed of regionally correlatable organic-rich shales deposited under tranquil marine conditions during inundation of the shelf.

In the Miocene section of Starfak and Tiger Shoal fields, transgressive systems tracts are generally 60 ft thick or less but locally attain thicknesses as much as 180 ft (plate 2). Lateral thickness within any one systems tract systematically varies; transgressive deposits are commonly thicker and comprise more parasequences in the updip areas, reflecting increased lobe switching in the backstepping deposits as a function of steady decrease in accommodation space as the depositional systems moved more landward (fig. 8, transgressive systems tracts capped by MFS 26 and 28). Parasequences are also commonly sandier in the updip areas of the proximal and medial shelf deposits because of closer proximity to source area(s) and the increased reworking of deposits as one moves from high-accommodation locations near the lowstand shelf margin to low-accommodation proximal areas of the stable coastal plain. Sand content within parasequences of the transgressive systems tracts also increases upsection toward the most landward (proximal-shelf) depositional facies within the study interval.

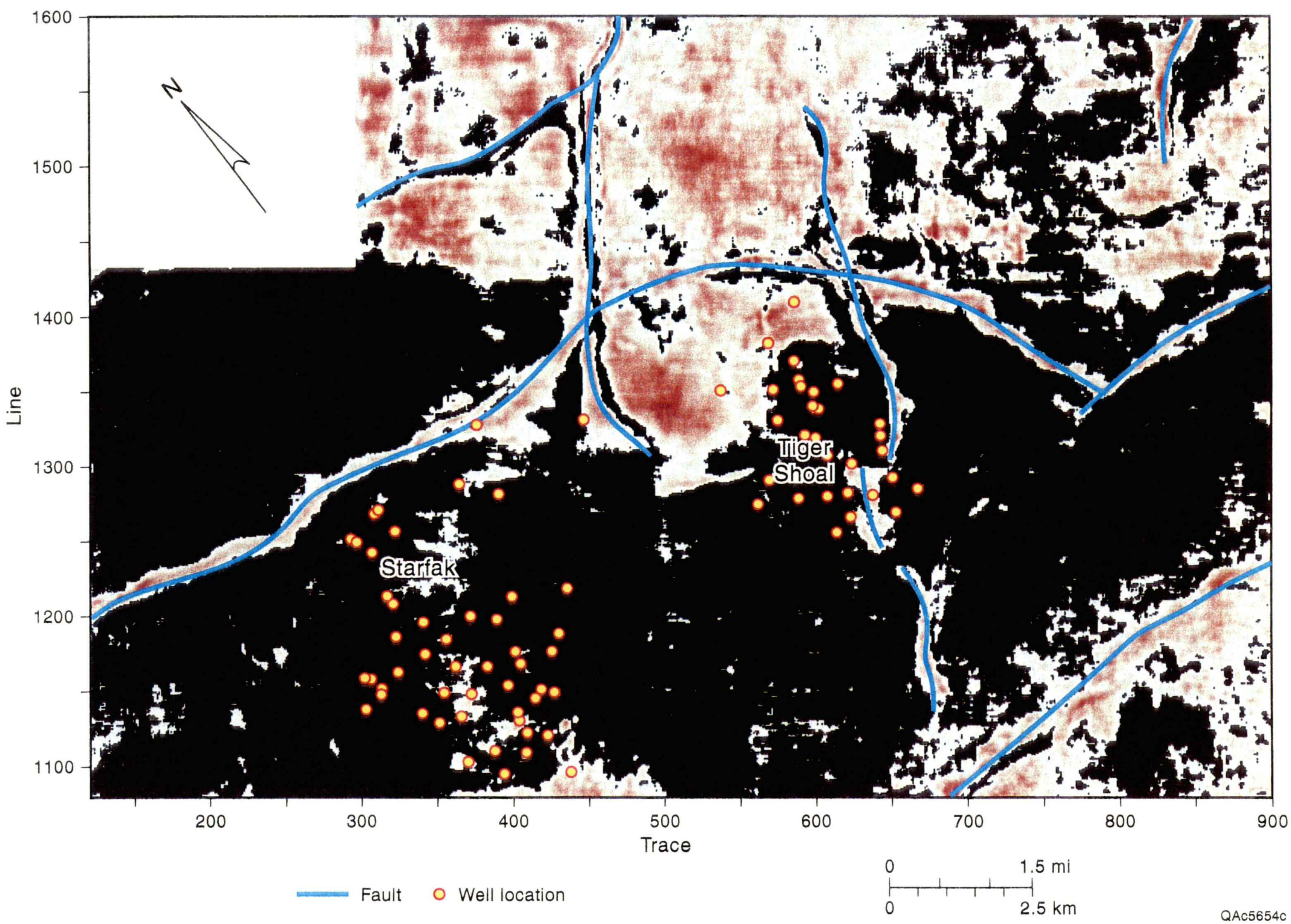

Figure 12. Amplitude stratal slice from 3-D seismic data depicting the aerial distribution of the marine condensed section above the O sand reservoir within the greater Starfak and Tiger Shoal area. Marine condensed sections are regionally correlative, organic-rich shales that record maximum marine flooding of the Miocene shelf. Transgressive systems tracts culminate in marine condensed sections in all but the most shoreward successions.

Incised valleys in the proximal to medial shelf facies of the study interval generally contain less than about 50 percent transgressive-system-tract deposits, which are thinly interstratified silty sands and shales in an overall upward-fining interval (figs. 8, 11; plate 2). These transgressive sands and shales are interpreted to represent fine-grained estuarine and coarser grained bayhead delta sediments, both of which are areally restricted to the confines of the physiographic incised valley. The more distal valleys that are incised into the upper slope and filled with late-lowstand sands separated by thin, intervening shales within a generally overall aggradational succession (fig. 8, 11,270 to 11,080 ft in well 16-31) contain little transgressive fill.

Highstand Systems Tract

Sediments of highstand systems tracts form progradational parasequence sets that generally display upward trends of parasequence thinning and increase in percentage of sand within parasequences (figs. 8, 11; plate 2). These upward-coarsening successions are typically 150 to 200 ft thick in most of the study interval, but they range from as thin as 60 ft in the most proximal shelf locations to as thick as 600 ft in the distal-shelf areas.

Sands within late-highstand parasequences, the uppermost parasequences of the progradational parasequence sets, represent delta-front deposits, locally developed distributary channel fills, delta-mouth bars, and interdeltaic shoreface facies. Early-highstand parasequences originated as more distal variations of these same deltaic and shoreface environments of deposition. Seismic stratal slices of highstand successions illustrate generally lobate and digitate aerial geometries (fig. 13).

Reservoir Occurrence and Hydrocarbon Distribution

Producing gas and oil reservoirs in the study interval occur primarily in five depositional elements within the two fields. In Starfak field, hydrocarbons are produced from slope-fan,

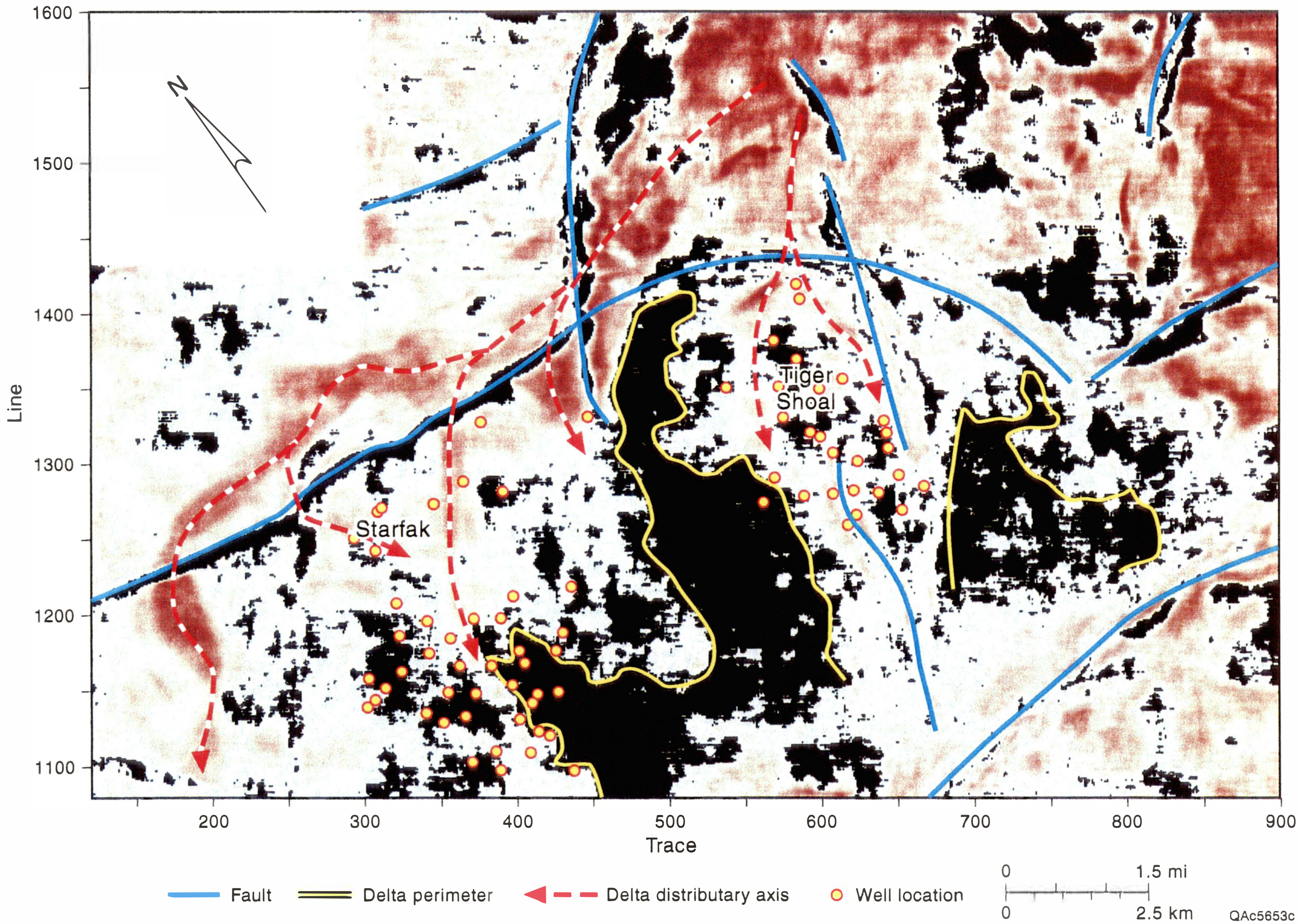

Figure 13. Amplitude stratal slice from 3-D seismic data of the J sand interval depicting the areal distribution of a lobate to digitate highstand delta within the greater Starfak and Tiger Shoal area. Note apparent control by the major growth fault bounding the north side of Starfak field on distributary-channel development and transport directions.

prograding-wedge, valley-fill, bayhead-deltaic, and shelf-deltaic sands of the T-1 to 12000 A reservoirs (lower to middle Miocene section). In Tiger Shoal field, reservoirs occur in generally stratigraphically higher shelf-deltaic, incised-valley, and prograding-wedge sands in the lower to upper Miocene section (B to 12000 B sands).

Qualitative evidence for potential new reservoirs and recompletions within existing reservoirs is considerable. Gathering of quantitative evidence is planned future work; however, preliminary inspection of petrophysical data (for example, neutron-density and bulk-density log crossover combined with high-resistivity readings) indicates that many unnamed, untested sands contain gas and oil (fig. 14). Moreover, we noted (1) pronounced subregional variation in thickness and log character of sands at sequence and parasequence boundaries and (2) marked lateral variation in the architecture of a single Texaco-defined reservoir (figs. 8, 11; plate 2). These variations indicate the potential for locating stratigraphic traps and identifying stratigraphic impact on well performance that can only be understood by the precise mapping and strategic targeting of sand pinch-outs and facies changes at the interwell scale. Preliminary inspection of seismic profiles confirms apparent wavelet terminations corresponding to predicted areas of local and subregional stratigraphic pinch-out.

Sands within each of the three primary systems tracts offer potential completion targets. Within the transgressive systems tracts, the highest potential for stratigraphic traps is in the landward (northern) sections where transgressive sands are thicker, better developed, and more numerous. The trap risk involved in these plays is a function of the landward limit of overlying seal, specifically the landward limit of the marine flooding shales. Specific sand-rich depositional elements of the transgressive systems tract (bayhead-delta and estuarine sands composing transgressive valley fills) are most likely sealed laterally by onlap onto adjacent valley walls. Accurate prediction of valley trends is an important component in locating potential prospects. Additional stratigraphic traps may be found in the distal distributary-mouth-bar elements of highstand systems tracts. Stratigraphic traps may also be present at sand terminations within distal distributary-mouth-bar facies of highstand systems tracts. However, thick sand-rich

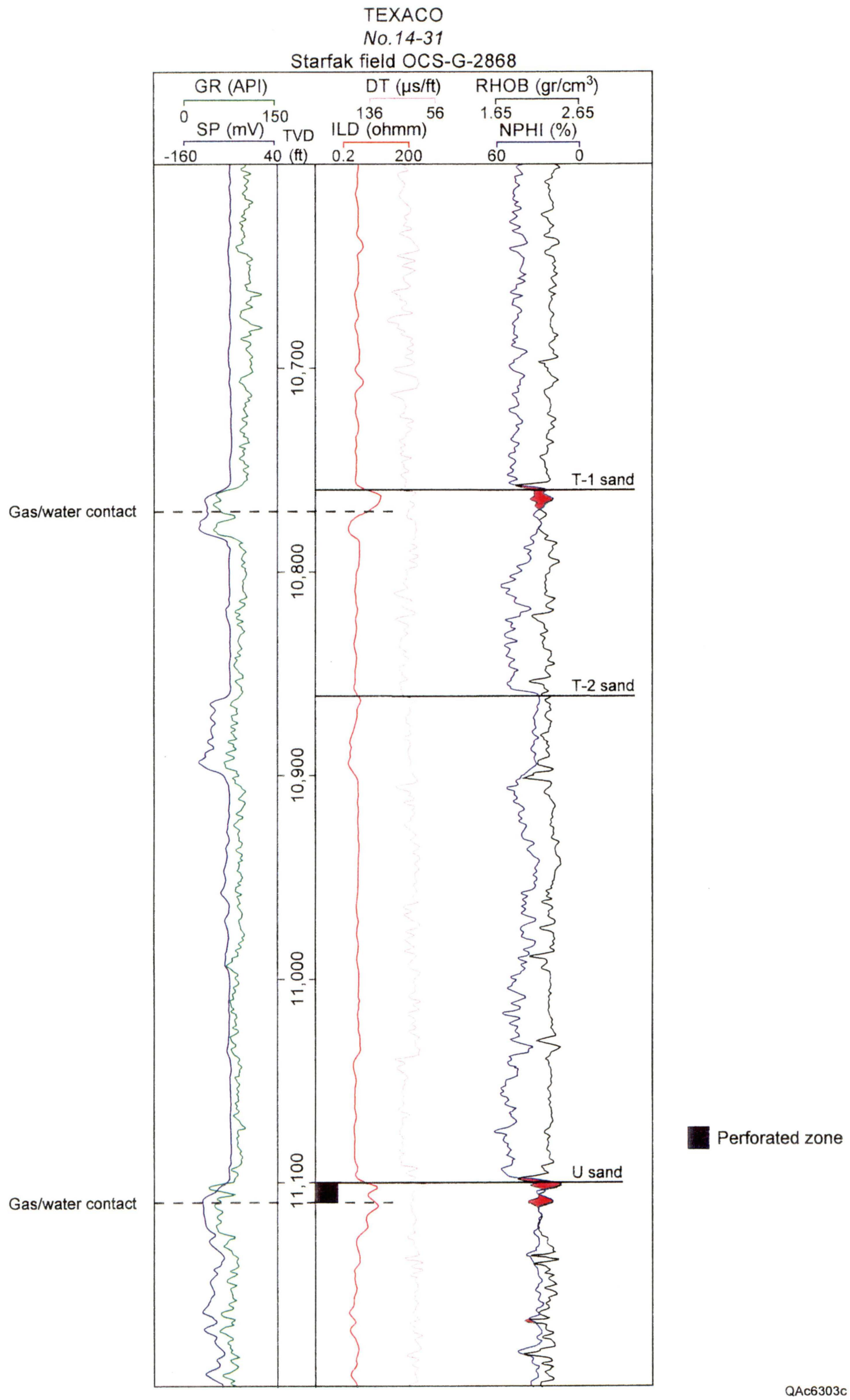

Figure 14. Example of untested sand containing gas. Part of well log from Texaco No. 14-31 in Starfak field shows both a 15-ft-thick completed reservoir at 11,100 ft (top of U sand) and a 10-ft-thick uncompleted gas sand at 10,760 ft (top of T-1 sand). Presence of gas is shown by the (1) high resistivity of the interval, (2) pronounced crossover of the neutron-porosity (NPHI) and bulk-density (RHOB) curves, and (3) suppressed SP value of the gas-bearing sand interval relative to that of the equally "clean" T-1 sand bed immediately below (as indicated by the gamma-ray curve).

lowstand-prograding-wedge deposits are perhaps the most promising of all potential new reservoirs found thus far. These deposits are concentrated in the southernmost parts of both fields. The sequence-stratigraphic model predicts that significant volumes of reservoir-quality lowstand-wedge sands (and possibly basin-floor-fan sands), within mostly slope and basinal shales, exist just south of the field areas.

Lateral and vertical facies variation also has a direct control on flow-unit geometry and, therefore, the compartmentalization of hydrocarbons within a single sand-body reservoir. After sequence-stratigraphic analysis, it is clear that considerable facies variation exists along the depositional tracts of the Texaco-designated reservoir units (figs. 8, 11). The nature of any permeability barriers or baffles created by facies variability will be investigated more fully during rigorous petrophysical, production, and reservoir-pressure analyses later in the project.

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APPENDIX A

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