Session NG -- Natural Gas Technology

Session NG-4

Secondary Natural Gas Recovery

NG-4.1 Incremental Natural Gas Resources Through Infield Reserve Growth/Secondary Gas Recovery

CONTRACT INFORMATION

Contract Number DE-FG21-88MC25031

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Period of Performance September 1, 1988 to April 30, 1995

Schedule and Milestones

FY93 Gulf Coast Program Schedule

	O N D J F M A M J J A S
Task 1.0 Methodology for Choosing Study Areas	
• Evaluation of Operator Activity	Completed
• Initial Simulator Configuration	Completed
• Initial Field Screening	Completed
• Refined Field Screening	Completed
Task 2.0 Untapped Compartments:	
Integrated Characterization of Candidate Reservoirs (Sandstones)	
• Geological Characterization	Completed
• Development of Cross Section Frameworks	Completed
• Mapping of Target Reservoirs	Completed
• Engineering Characterization	Completed
• Geophysical Characterization	Completed

	O N D J F M A M J J A S
Task 3.0 Formation Evaluation for Bypassed Gas Zones	
• Geological Support for Formation Evaluation	____________Completed ____________
• Sample Analysis for Shaly Sandstone Evaluation	____________Completed ____________
Task 4.0 Interwell Extrapolation and Related Deeper Pools	
• Subregional Stratigraphic Analysis	____________Completed ____________
• Field-Scale Analysis of Deeper Play Components	No activity as advised by TAC

FY94 Midcontinent Program Schedule

	O N D J F M A M J J A S
Task 1.0 Selection of Resource Targets and Depositional Settings Within the Midcontinent	
• Evaluation of Suitable Plays and Resource Volumes	__Completed
• Contact Operators to Determine Level of Activity and Interest	__Underway
• Selection of Fields for Cooperative Studies	Site 1 selected
• Definition of Reservoir Targets	__Underway
Task 2.0 Determination of Controls on Unrecovered Gas Resources	
• Framework for Target Reservoir Characterization	___Underway
• Initial Reservoir Architecture Delineation	___Underway
• Integrate Geophysical Analysis, Engineering Assessments, and Well Log Analysis	__Underway
• Define Cooperative Data Collection and Testing	__Underway
• Integrate Results of Field Data Collection to Refine Reservoir Characterization	No activity scheduled
Task 3.0 Synthesis of Results and Development of Advanced Gas Recovery Strategies	
• Establish Extent of Flow Unit(s)	No activity scheduled
• Define Flow Units Characteristics of Reservoirs	No activity scheduled
• Determination of Extrapolation Potential	No activity scheduled
Task 4.0 Technology Transfer	
• Printed Reports and Presentations	No activity scheduled
• Workshops to Transfer Results to Operators	___*_______**___Underway
• Development of Advanced Technology Transfer Products	__Underway
• Economic Analysis of Reserve Growth Strategies	__Underway

* Houston **Proposed for San Antonio

OBJECTIVES

The primary objective of the Infield Reserve Growth/Secondary Natural Gas Recovery (SGR) project is to *develop, test, and verify technologies and methodologies with near- to midterm potential for maximizing the recovery of natural gas from conventional reservoirs in known fields.* Additional technical and technology transfer objectives of the SGR project include:

- To establish how depositional and diagenetic heterogeneities in reservoirs of conventional permeability cause reservoir compartmentalization and, hence, incomplete recovery of natural gas.
- To document examples of reserve growth occurrence and potential from fluvial and deltaic sandstones of the Texas gulf coast basin as a natural laboratory for developing concepts and testing applications to find secondary gas.
- To demonstrate how the integration of geology, reservoir engineering, geophysics, and well log analysis/petrophysics leads to strategic recompletion and well placement opportunities for reserve growth in mature fields.
- To transfer project results to a wide array of natural gas producers, not just as field case studies, but as conceptual models of how heterogeneities determine natural gas flow units and how to recognize the geologic and engineering clues that operators can use in a cost-effective manner to identify incremental, or secondary, gas.

The SGR project is a joint research effort of the Gas Research Institute (GRI), the U.S. Department of Energy (DOE), and the State of Texas conducted in cooperation with industry partners. Approaches to defining the distribution of unrecovered resources by depositional system and methods for maximizing their recovery are being developed and tested. The Gulf Coast research effort focused specifically on Texas natural gas reservoirs as a major subset of the Nation's natural gas resource base. The recently initiated SGR Midcontinent project is designed to test and expand the application and benefits of reserve appreciation concepts and technology in a second major natural gas province.

Results of the SGR project are enabling producers to economically recover this discovered but undeveloped natural gas resource through integrated geological, engineering, petrophysical, and geophysical assessments. Case studies conducted with the cooperation of independent producers have demonstrated the cost-benefit viability of an integrated SGR approach for small operators producing from gas reservoirs in similar and different depositional systems.

BACKGROUND STATEMENT

Between 1918 and 1975 half of the natural gas wells in the United States were drilled. The second half were drilled between 1976 and 1992 for a total of more than 410,000 wells. Almost 80,000 of these wells were drilled between 1981 and 1985. The per-completion gas recoveries have almost doubled since the first half of the 1980's. However, what producers found during the 1980's was that reservoirs were more complex internally than previously thought and that reservoir heterogeneity leads to compartmentalization that traps secondary (incremental) gas in many reservoirs that have been commercially producing from known fields.

In the late 1970's and 1980's, the characterization of the internal geometry of reservoirs, mainly oil reservoirs, clearly demonstrated a greater degree of compartmentalization than had been previously recognized. Factors affecting this compartmentalization include the depositional system of the reservoir, structural configuration, and diagenetic history of the reservoir following deposition. These lessons were first learned for oil reservoirs, but starting in the late 1980's became increasingly evident for gas reservoirs. The conceptual view of the resource base in the lower 48 states changed drastically from the middle and late 1970's when estimates by M. K. Hubbert of more than 90 percent depletion were revised based on more recent analyses indicating that the natural gas resource base is only about 40 percent depleted (Fisher, 1993). Strategies developed during this research are being used by producers and pipeline companies to target 236 Tcf of reserve growth potential. This potential constitutes part of the 1,295 Tcf of technically recoverable resources that the National Petroleum Council (NPC) identified as existing in the lower 48 states (NPC, 1992).

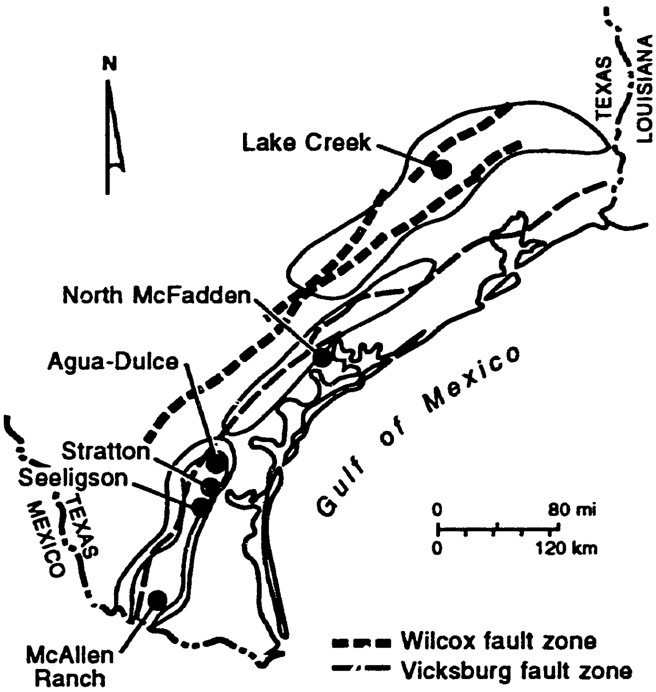

Figure 1. Location map of the fields and major gas plays investigated by the Secondary Gas Recovery (SGR) project in the Gulf Coast Basin.

The SGR project focused on three major gas plays in the Frio and Vicksburg Formations and Wilcox Group that have produced more than 18 Tcf of natural gas in the Gulf Coast Basin. Using six fields (McAllen Ranch, Seeligson, Stratton, Lake Creek, Agua-Dulce, and North McFadden) (figure 1), the project has cooperated with a broad spectrum of gas operators including Shell Western E&P Inc., Mobil E&P Inc., Union Pacific Resources Corp., Oryx Energy Co., Pintas Creek Oil Co., and Anaqua Oil and Gas Inc. Non-geopressured, conventional permeability reservoirs like the middle Frio Formation (cumulative production >12 Tcf) were the primary emphasis in these SGR studies. These reservoirs were deposited as part of a bedload-rich fluvial system that fed a major deltaic depocenter in South Texas.

PROJECT DESCRIPTION

The reserve growth resource in a natural gas field will be contained in *new infield reservoirs, untapped or incompletely drained reservoir compartments, bypassed reservoirs*, and *deeper pool reservoirs* (figure 2). The latter have long been a recognized target for the producing industry, and for natural gas, deeper pool development benefits from the more gas-prone nature of deeper stratigraphic intervals. The SGR project's Technical Advisory Committee (TAC) determined that deeper pool reservoirs should not be a focus of the project because industry recognizes deeper pool reservoir potential and that the other more difficult to develop resources should be given priority.

New infield reservoirs are new reservoirs separated vertically and laterally from adjacent reservoirs that were not contacted during original development of the field. Often, these reservoirs are found during deeper-pool development attempts. *Untapped or incompletely drained reservoir compartments* are parts of established producing reservoirs that may or may not have been

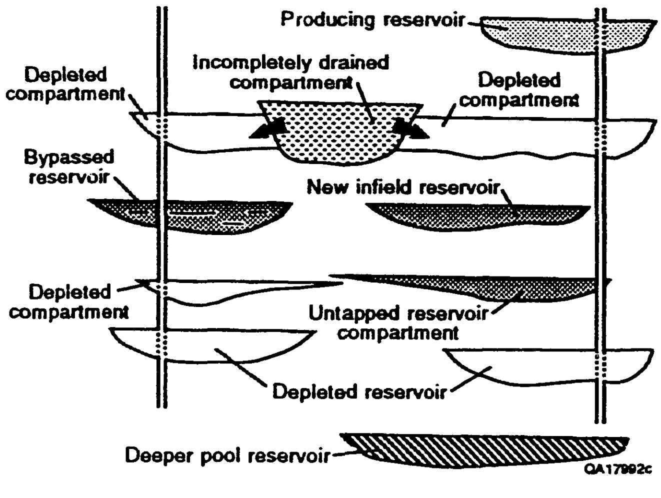

Figure 2. Diagrammatic sketch of reservoir compartment terminology used in the SGR project.

contacted during original development of the field and are not in flow communication, or are in incomplete flow communication, with existing completions. *Bypassed reservoirs* are reservoirs contacted by existing wells that have not been produced. Bypassed reservoirs may have been thought nonproductive or noneconomic based on previous well log evaluations. All of these types of reservoirs are targets for incremental natural gas recovery based on understanding of depositional and diagenetic heterogeneity that leads to reservoir compartmentalization. Although structural complexity also results in incomplete recovery, the focus of the SGR project has been to better understand depositional rather than structural reservoir variability.

RESULTS

Synopsis of Gulf Coast Basin Research

Results from this project provided strategies for evaluating infield development in fields that are from 30 to more than 50 years old (Finley and others, 1992). Significant natural gas reserve appreciation opportunities exist where reservoirs are heterogeneous and compartmentalized. Such compartmentalization, other than structural, is depositional and/or diagenetic in origin and can be defined through a geologically-centered approach to understanding reservoir flow units. Concept-driven integration of disciplines is crucial to recognizing and exploiting reserve growth opportunities. Although absolute rules on flow communication between different depositional facies are not apparent, smaller compartments often show evidence of baffles that affect reservoir flow units and can provide a significant incremental natural gas resource.

Several techniques exist for assessing the potential for secondary incremental gas recovery in a field, among a group of reservoirs, or within individual natural gas reservoirs. These techniques include the evaluation of geologic, engineering, and geophysical data at (1) the field-to-reservoir scale and (2) the reservoir-to-flow unit scale. Geological techniques include recognition of depositional and diagenetic facies in the field, determining the reservoir architecture stacking pattern, and identifying intrareservoir flow boundaries. Geophysical techniques include looking for variable seismic reflection response within the field and considering the thin-bed reflection amplitude behavior within a targeted reservoir horizon. Engineering clues can include identifying fields and reservoirs that are characterized by elevated completion or wireline pressure tests. Methods for detecting compartmented behavior in a reservoir include evaluating rate-time diagnostic plots for evidence of pressure support from a secondary volume to the primary volume produced by the well being analyzed.

Geologic strategies are often initially deterministic and include identifying which part of a field has reservoirs with the greatest depositional, diagenetic, and structural variability. Geophysical strategies include integrating vertical seismic profiles (VSP's) with 3-D seismic imaging for remotely mapping subsurface reservoir heterogeneity in the interwell space. The cost of 3-D seismic acquisition and processing continues to diminish and, depending on the size of the survey, surface conditions, and the nature of the target objectives, the acquisition cost of onshore surveys can be reduced to only a few tens of thousands of dollars per square mile. Engineering strategies include a newly developed PC-based compartment model simulator that was developed as part of the SGR project. Whereas geology and geophysics determine the shape and form of reservoir compartments, the simulator focuses on modeling reservoir function.

Deltaic Reservoir Characterization

Evaluation of heterogeneous deltaic gas reservoirs in the Wilcox Group at Lake Creek field indicates that a combination of capillarity and facies defines reserve appreciation opportunities. An SGR strategy of targeting distributary-channels in the developed and downdip flank areas could access 8.7 Bcf of incremental gas resources in a single operational reservoir (Grigsby and others, 1992). Most of this secondary gas resource is located downdip from existing development. Reservoir facies consist of delta-front, channel-mouth-bar, and distributary-channel sandstones (figure 3). A new advanced capillary pressure model (ADCAP) was employed to predict the downdip limits of gas production in the three reservoir facies. This ADCAP model relates the four important reservoir properties of porosity, water saturation, permeability, and capillary pressure with a single equation. The potential area containing the SGR resource is based on effective permeability to gas calculated from the mean value of air permeability for each reservoir facies and water saturation resulting from height above the free water level (figure 4).

Engineering evaluations of recovery and production performance indicate that the most effective development strategy involves targeting completions in the distributary-channel facies. Analysis of gas productivity by facies shows that distributary channel completions have 2.3 times the kh (14.1 versus 6.2 md-ft) and 3.9 times the EUR (2,265 versus 581 MMcf) of non-channel completions. The effective drainage areas for distributary channel completions were found to be 200 acres (or greater) compared to 40 acres for non-channel completions. Many Wilcox gas fields are characterized by multiple stacked gas deltaic packages. Each of these deltaic packages could also contain incremental gas resources. The integrated SGR methods and concepts of capillarity used in analysis of these deltaic reservoirs in Lake Creek field are transportable and should help identify additional gas resources in other heterogeneous gas fields with low- to conventional-permeability reservoirs.

Fluvial Reservoir Characterization and Stochastic Modeling

The Gas-Wizard (G-WIZ) PC-based compartmented gas reservoir simulator (figure 5), developed by the SGR project as a reservoir management tool (Lord and Collins, 1991; Collins and Lord, 1992) was applied to a set of reservoir compartment realizations modeled under different development timing and completion spacing scenarios. Three classes characterized by large, medium, or small reservoir compartment sizes were delineated from 10 groups of Frio reservoirs stacked over a 2,000 ft interval in Stratton-Agua Dulce field (figure 6a). Producing rate and static pressure data were used to determine the three fundamental reservoir parameters: primary drained pore volume, supporting pore volume, and barrier transmissibility. Statistical distributions of the primary pore volume and transmissibility were found to be closely approximated by a log-normal distribution in each of the 10 reservoir groups (figure 6b). Forward stochastic modeling of gas recovery from the three compartment size

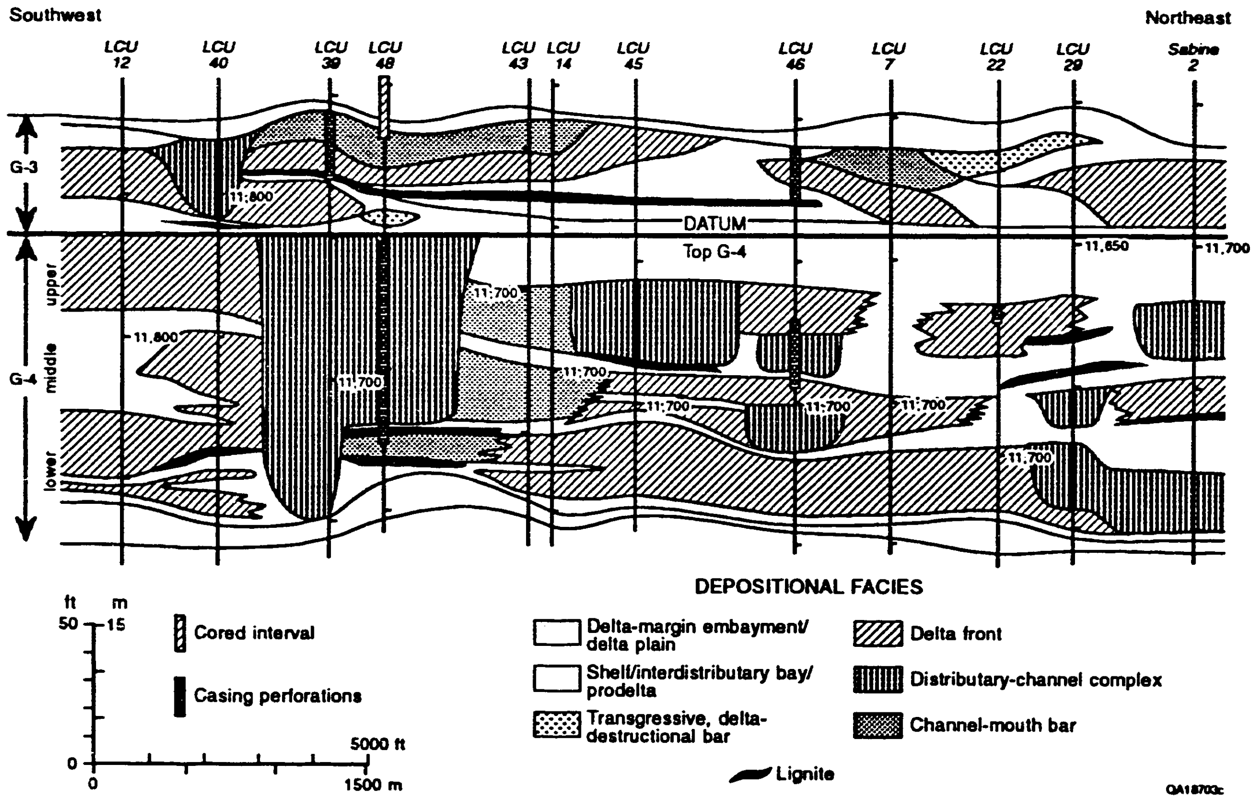

Figure 3. Depositional strike oriented stratigraphic cross section showing reservoir units and heterogeneity in Lower Wilcox Group deltaic reservoirs.

classes indicates that well spacings of 340, 200, and 60 acres (or less), respectively provides maximum gas contact efficiency (figure 6c). Building a stochastic modeling process with data and output from the G-WIZ simulator defined an approach to understanding effective well spacing in different classes of reservoir compartment size distributions.

The stochastic technique generates realizations of fluvial reservoirs having internal compartments with intervening barriers. Simulations of multiple reservoir realizations honoring statistical distributions determined from reservoir data yield a unique probability distribution of expected gas recovery. Recovery factors were evaluated for different well spacing and completion timing scenarios. By this method, statistical predictions of recovery are generated for each of the three classes representing a spectrum of fluvial reservoirs. For example, in the small compartment size class, incremental recovery potential of 24 percent is predicted by decreasing completion spacing from 320 to 160 acres (figure 7). The correlations developed should be transferable to other fields with similar fluvial facies architecture.

Reservoir Geophysics

Analysis of 3-D seismic imagery in a 7.5 mi^2 grid, coincident with multiple well tests in Stratton field, was used to investigate reservoir compartment boundaries identified by other SGR techniques. Flattening and seiscrop slicing above and below reference horizons were used to reveal depositional topography and to determine the extent of structural influence on reservoir horizons. Seismic time-to-depth calibration of seismic

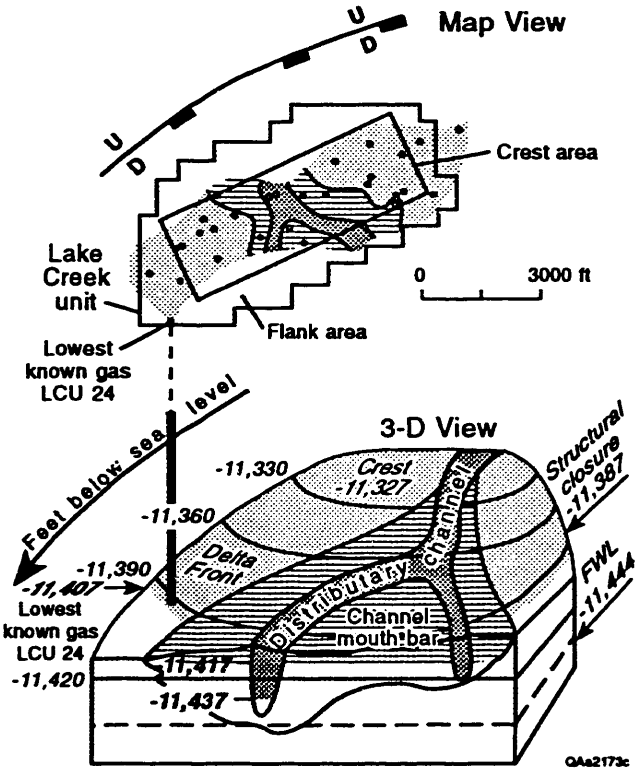

Figure 4. Reservoir model showing capillary control of incremental gas resources by depositional facies.

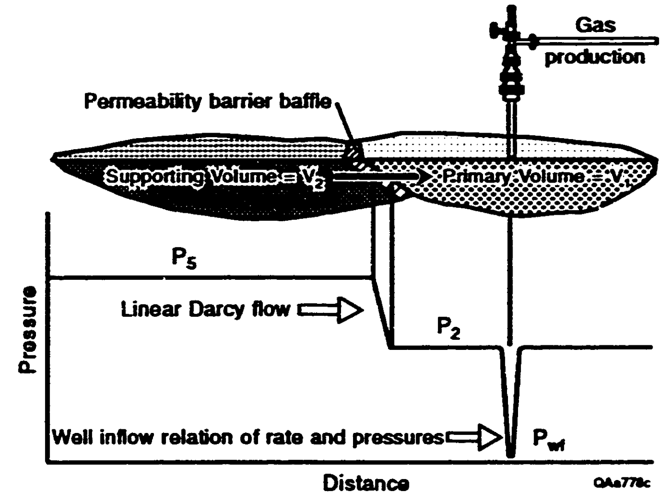

Figure 5. Compartment model (used in G-Wiz gas compartmented reservoir simulator) that describes heterogeneous reservoir function as a set of tank-like compartments having leaky barriers that separate compartments from wells that produce from these compartments.

thin-bed intervals was achieved by careful attention to detail during 3-D data acquisition and processing and by using high quality zero-offset VSP data to define exactly where thin bed time windows exist in the surface-recorded seismic responses. Many Stratton reservoirs are only 10 to 15 ft thick, and occur within seismic time windows as thin as 2 to 4 ms at depths as deep as 6,700 ft. Careful calibration is required to accurately locate these time windows in the reflection waveforms.

In many reservoirs, the depositional topology revealed in these thin bed seismic images clearly indicates where a compartment boundary should be positioned between well control and the reservoir compartment boundaries are imaged within, or adjacent to these channels (figure 8 a, b,). At other reservoir levels where either geologic or engineering data indicate a compartment boundary, the boundary is not obvious in the seismically-revealed depositional topography. In these latter instances, the seismic image usually shows a semi-continuous depositional unit, which implies this second type of compartment boundary does not significantly affect the reflected seismic wavefield. Although many subtle, fluvially deposited compartment boundaries are revealed in these 3-D seismic images, some boundaries cannot be seismically imaged due to minimal differences in the acoustic impedance of reservoir and non-reservoir facies and must be located by stratigraphically correlating geologic data, analyzing production histories, or performing well pressure tests. In all cases, the interpretation of 3-D images at 10 reservoir levels provided more information about the distribution of reservoir facies in the interwell spaces than could be obtained by only extrapolating geologic and engineering data from control wells. 3-D seismic provides a highly effective tool for imag-

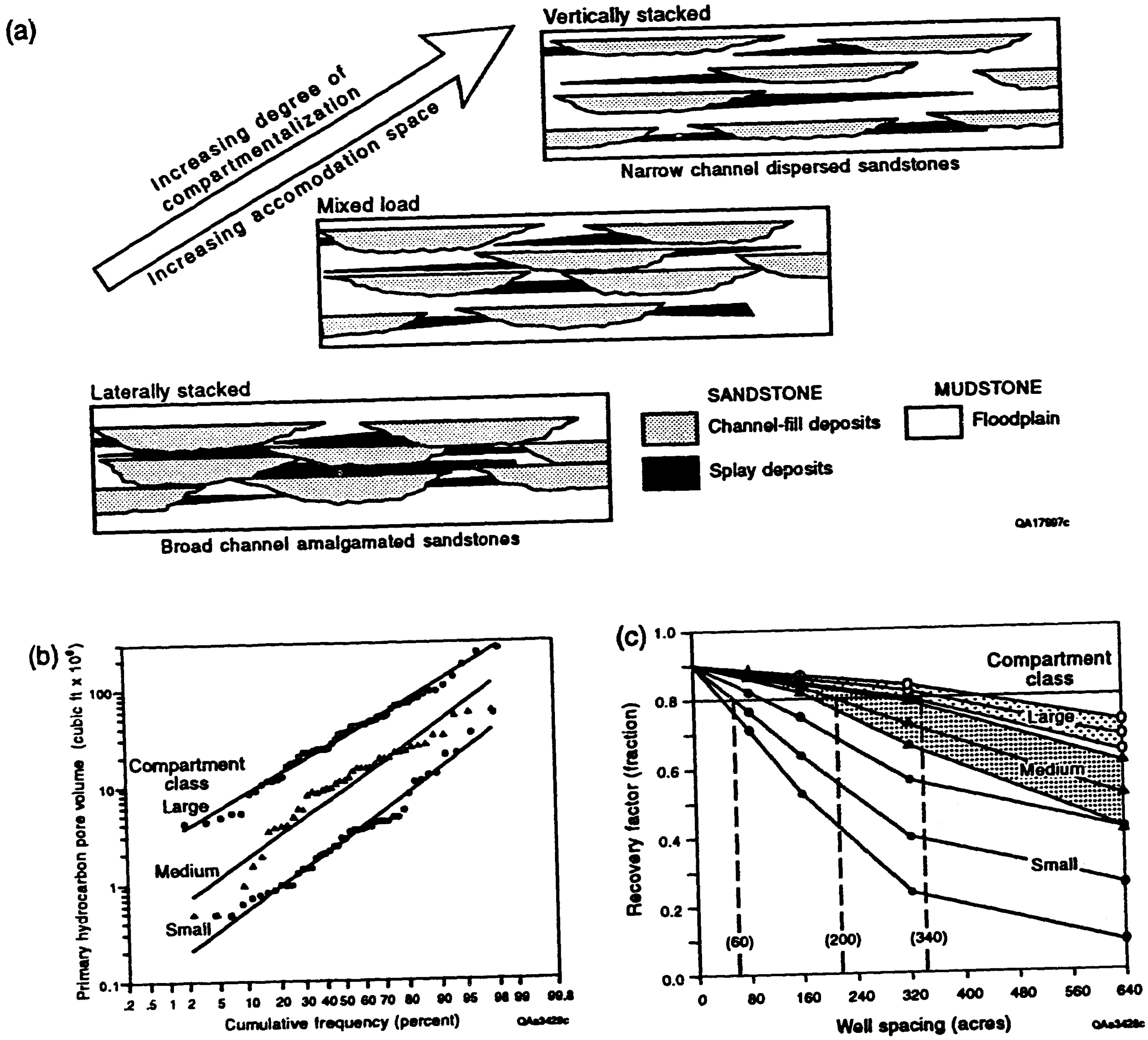

Figure 6. (a) Schematic diagram illustrating the fluvial architectural continuum of large, medium, and small size reservoir compartments, (b) cumulative frequency distribution of primary pore volume for the three reservoir compartment size classes, (c) recovery factor and predicted gas recoveries versus well spacing for large, medium, and small compartment size classes.

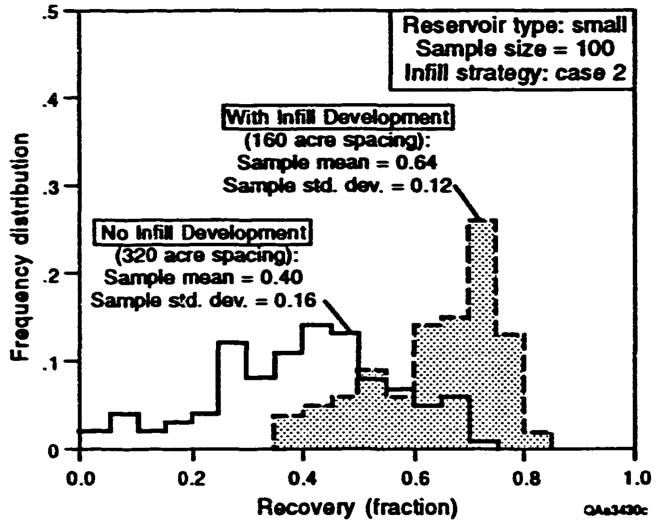

Figure 7. Frequency distribution illustrating effect of completion spacing on incremental gas recovery for the small compartment size class.

ing interwell space, even when targeting relatively thin reservoirs.

Case Histories (Mini-evaluations)

The SGR project, in cooperation with operator-initiated redevelopment in two fields that are over 50 years old, evaluated the application and benefit of SGR concepts and technologies (Levey and others, 1993b). Integrated geologic, engineering, and petrophysical analysis of 21 reservoirs defined original gas in place (OGIP) of 37 Bcf, of which 28 Bcf is technically recoverable. Economically recoverable gas reserves were estimated at 10 Bcf in two study areas totaling 2,300 acres. The reservoirs are normally pressured, primarily depletion-drive reservoirs, at moderate depths between 3,700 and 7,000 ft.

In case I, secondary gas resources occur in thin-bedded shoreface deposits. By using the state-of-the-art induction array tool, thin-bed high productivity reservoirs can be better identified than by using conventional electrical and induction logs. Detailed stratigraphic analysis of multiple thin-bed intervals in combination with resistivity cutoffs and spontaneous potential ratios provided a means of identifying locations for enhancing the operator's ability to recover these secondary gas resources. In case II, secondary resources were defined in fluvial depositional reservoir facies segmented by structural compartments and affected by stratigraphic variability and diagenesis. Integrated formation evaluation using high resolution logging, spectral gamma ray measurements, wireline pressure tests and core analysis were effective in identifying additional gas resources.

For cases I and II, the average ultimate recovery is 400 and 260 MMcf per completion, respectively. The total cost to develop and produce SGR reserves is projected at \$0.58 (case I) and \$0.83 (case II) per mcf (exclusive of royalties). The primary difference between the two case studies is that the case II area has smaller reservoir compartments caused by faulting and depositional and diagenetic effects on reservoir productivity. As a consequence of smaller compartment size, development costs are higher due to the requirement of more wells and recompletions to access the SGR resource. These mini-evaluations demonstrate the feasibility of using SGR approaches for converting technically recoverable resources into economically producible reserves at low to moderate cost.

Technology Transfer

Technology transfer to the gas industry has included more than 30 research presentations at international, national, and regional meetings and technical publications in 1992 and 1993. Invited SGR technical presentations that were made by project staff were co-sponsored by geologic, geophysical, and petrophysical groups especially interested in gas research directed at reserve appreciation.

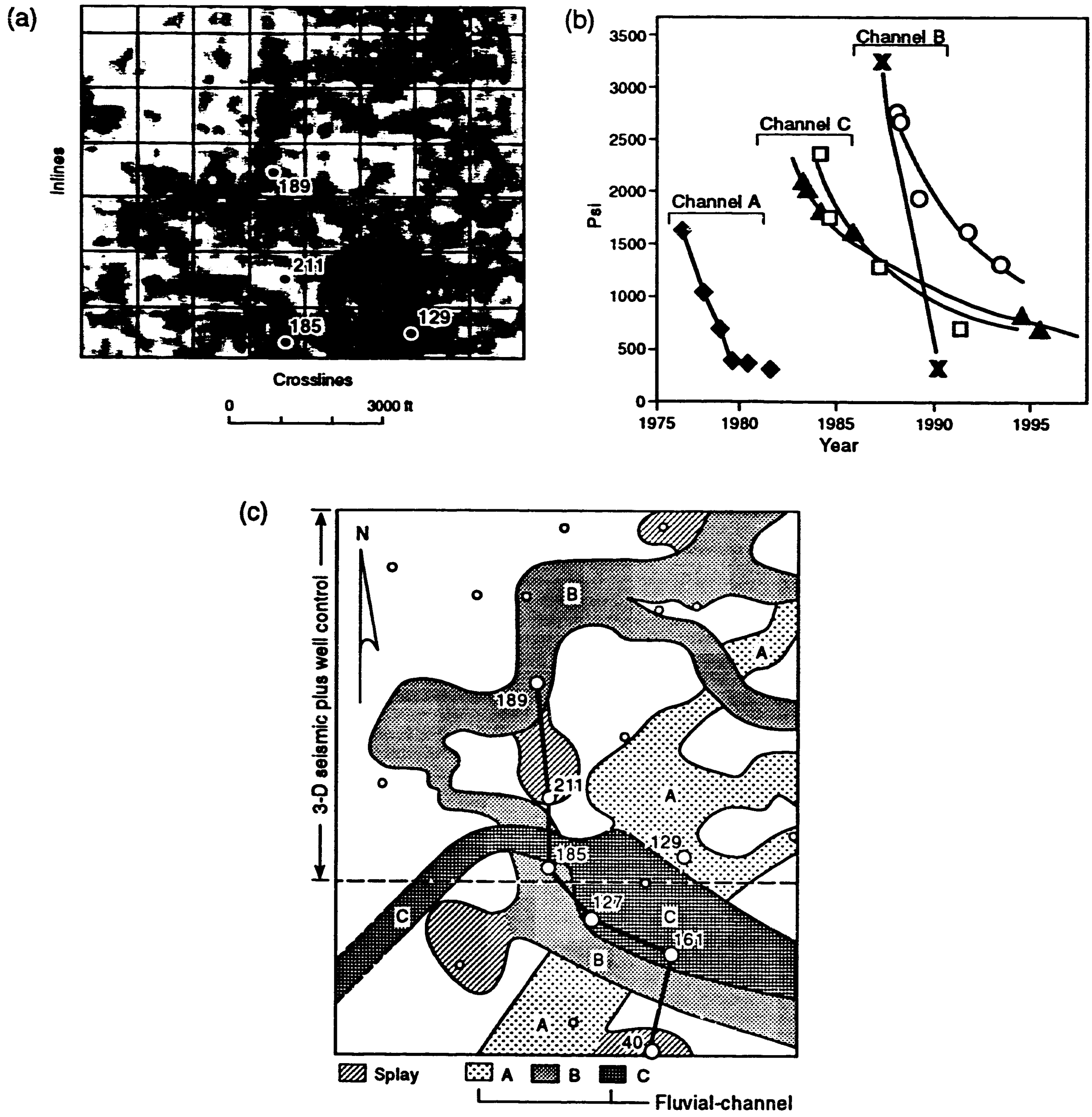

Figure 8. (a) 3-D seismic reflection amplitude image showing the position of three highly sinuous fluvial-channel and splay systems, (b) pressure history used to detect three fluvial reservoir compartments (c) integrated geophysical, geological, and engineering reservoir model showing three vertically stacked channel systems.

Beyond comprehensive written documentation contained in 7 technical reports of project results from the Gulf Coast research program (Ambrose and others, 1992; Collins and Lord, 1992; Grigsby and others, 1992; Langford and others 1992a, 1992b; Levey and others, 1993a, 1993b), short courses were conducted in three states (Texas, Oklahoma, and Louisiana) in the cities of Houston, Corpus Christi, Midland, San Antonio, Oklahoma City, and New Orleans. Over 700 people participated in full-day short courses and half-day presentations included in gas reserve growth technology workshops sponsored by the Texas Independent Producers and Royalty Owners in Austin, Dallas, Amarillo, and Houston. Participants from production, exploration, and pipeline companies attended these short courses presented by the SGR project staff on behalf of DOE and GRI and co-sponsored by national and regional technical societies. Sixty-eight percent of the short course survey participants indicated that they will make direct application of the materials presented to their gas reservoir development and 98 percent believe research of this nature is valuable. Additional short courses are now scheduled for November 1993 in Houston and February 1994 in San Antonio. A development plan for advanced technology products is now under consideration and may include a project video, a how-to manual for step-by-step reservoir evaluation by field operators, a CD-ROM containing project topical reports, and revised short courses that expand the use of 3-D geophysics for maximizing recovery in compartmented gas reservoirs. These products will help operators evaluate their own properties and implement low-cost reserve appreciation strategies.

FUTURE WORK

Technical Issues in Midcontinent Sandstone Reserve Growth

In contrast to fluvial deposits, many deltaic deposits have a cyclic component that should allow predictable quantification of the stratigraphic reservoir framework from standard well log control. Recent advances in sequence stratigraphic concepts to define reservoir architecture are more commonly applied in an exploration mode in contrast to an exploitation, or reservoir development, phase. Few gas operators outside of the majors have used this approach to resource evaluation in real, field-scale operations. However, reservoir flow units defined through this predictive stratigraphic approach should be measured and compared to known production to assess the degree of compartmentalization. The cratonic basins of the Midcontinent are an appropriate area to develop this approach. Confirmation of reservoir discontinuity by geophysical techniques will help operators identify those gas fields with the greatest potential for resource appreciation.

Deltaic depositional systems are characterized by gradational lithologic and facies changes that often provide only subtle discontinuities at sequence boundaries. Differences in subsidence rates between cratonic basins with supporting carbonate shelves, such as in the Midcontinent and the Gulf Coast Basin, will further affect reservoir architecture. Understanding the relationship between seismic resolution and these subtle changes in reservoir heterogeneity in transitional rock types is critical to establishing the limits of geophysical imaging using a diverse suite of techniques. In particular, cross borehole imaging techniques may be applicable to defining delta front, mouth bar, and distributary channel geometries in such Midcontinent settings.

Applications of this research are now being expanded and tested in the Midcontinent region of Oklahoma and Texas. More emphasis will be placed on deltaic facies in contrast to the fluvial facies of Seeligson and Stratton fields in the Gulf Coast program. Different subsidence rates prevailed in Midcontinent cratonic basins and some reservoirs will be closer to their source areas, affecting both reservoir geometry and quality. Increased emphasis is expected on geophysical technologies to establish a better balance with geology, engineering, and formation evaluation. Follow-up work on capturing technology transfer potential from the Gulf Coast effort will be used early in the Midcontinent program.

The Midcontinent region contains 33 to 41 Tcf of reserve growth resources at less than 15,000 ft—the largest volume after the onshore Gulf Coast Basin resource. The project will now focus on Pennsylvanian sandstone reservoirs in the Midcontinent region which contains 15 gas plays in Pennsylvanian-age sandstones (Bebout and others, 1993), suitable for extrapolation of the Gulf Coast results. Field study sites in the Midcontinent of Oklahoma and Texas will be selected to investigate the distribution of unrecovered resources, develop advanced recovery strategies, enhance geophysical applications in reserve appreciation, promote advanced technology transfer, and perform economic analysis of reserve growth strategies.

Midcontinent operators have actively sought participation in the SGR program and the first Midcontinent study site is in the Fort Worth Basin in North-Central Texas. The SGR project is actively involved with three companies (OXY USA Inc., Midland; Enserch Operating Partnership, Dallas; and Threshold Development Corporation, Fort Worth). The study site is the Boonsville field. Boonsville was discovered in 1945, had produced 53 Bcf in 1990 (ranked 32nd in the U.S.), and ranks 27th nationally in cumulative production. Operator cooperation and cofunding is highly leveraged (more than 10:1 operator-to-project funds) with all three operators agreeing to jointly acquire 3-D surface seismic comprising approximately 25 mi^2 in parts of Jack and Wise counties. This 3-D survey, costing about $1.2 million dollars, will be one of the most extensive surveys ever conducted in the Fort Worth Basin. Two project cooperative wells have already been evaluated and a third well is planned before the end of 1993. Cooperative data gathering has included extensive whole coring of Atoka productive intervals, a zero-offset vertical seismic profile, and a vertical wave test to evaluate the potential for seismic thin-bed resolution which has allowed optimum pre-seismic acquisition design parameters to be implemented.

The SGR Midcontinent project, in cooperation with the Oklahoma Geological Survey at the University of Oklahoma in Norman, is actively pursuing the search for the second study site in Pennsylvanian deltaic sandstones in Oklahoma. Initial contacts and discussions with Oklahoma gas operators are underway to identify the appropriate site.

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Session NG -- Natural Gas Technology

Session NG-5

Coal Seam Gas

NG-5.1 Multistrata Exploration and Production Study

CONTRACT INFORMATION

Contract Number DE-AC21-89MC26026

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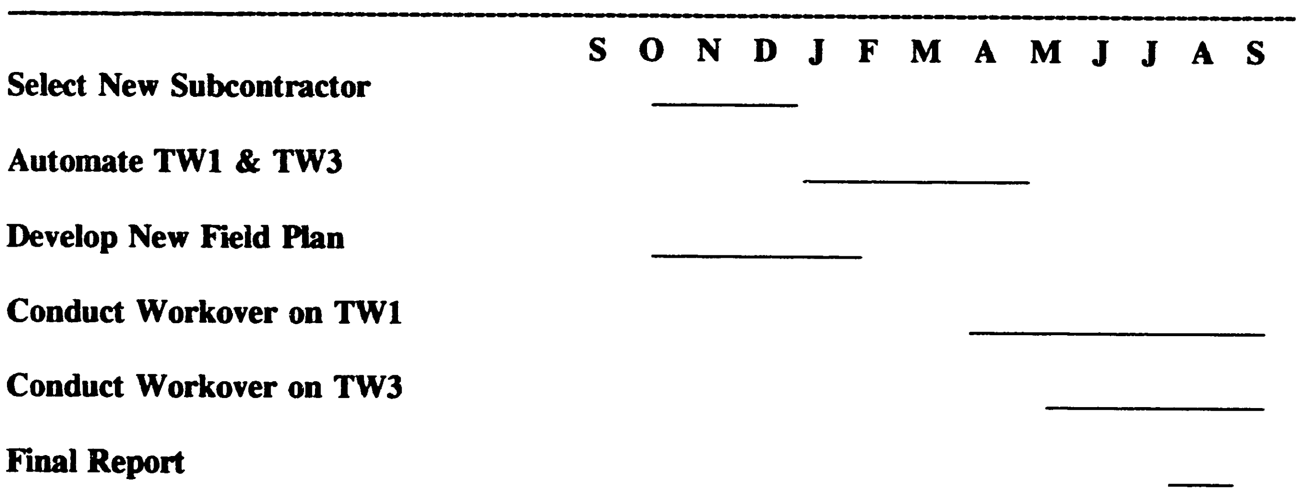
Period of Performance October 1, 1989 to November 24, 1993

Schedule of Milestones

FY 93 Program Schedule



OBJECTIVES

The objective of this project was to develop and verify a geotechnical/geostatistical approach to find natural gas resources and to verify the process by drilling, completing, testing, and producing wells located by the process.

BACKGROUND INFORMATION

Research conducted on the Eccles 7.5' quadrangle in Raleigh County, WV, in 1990, pinpointed several target areas. Immediate landowners, gas companies, and mineral rights owners were contacted to determine their willingness to assist the College in conducting the research. Extensive talks were held and as a result, agreements were drawn up between the College and the owners and Test Well 1 was completed in May 1991 and Test Wells 2 and 3 in November, 1991. The wells were shut in for one year thereafter while the parties involved negotiated agreements. The wells were placed on line at the close of fiscal year 1992. The following section summarizes the activities conducted in fiscal year 1993.

PROJECT DESCRIPTION

Activities for the Multistrata Project began in Fiscal Year 1993 with the placement of the three Test Wells into production full force. By turning all three wells in line October 1, 1992, gas began flowing as designed by the agreements negotiated in Fiscal Year 1992. All the parties involved began to see tangible results as the gas moved from the College's gathering lines into the systems of Ramco, Columbia, and Mountaineer Gas Companies.

The College of West Virginia began work as specified in the Field Test Plan for Phase II, Task 12. A new consulting agreement, based on the Task 12 Outline, was drafted and forwarded to potential new subcontractors. American Pump Company, headquartered in Monroe, LA, was selected as the College's subcontractor.

One of the first activities undertaken was to study possible results of installing a compressor in the College's system. This included assessment of such issues as: impact on the parties involved, effects on the wells' production and the system's overall performance, and sizing and pricing the compressor. This task has been addressed on an ongoing basis over the past ten months. No final decisions have been made due to constraints placed on us by gas companies involved and cost considerations.

The Test Well 1 and Test Well 3 sites were successfully automated. The College coordinated the automation activities which included selecting and installing electric motors and controls for each site. It also required electricians and Appalachian Power Company to set several poles, hang 5000 feet of line, and install two transformers.

Prior to running electricity to these sites, the pumps used to dewater the coal seams were operated on a manual basis. By running them 12 hours a day, three days per week, coal gas production increased an average 6 mcfd. Following automation, production from the coals increased another 4 mcfd on average. A number of pump rates and schedules were attempted in order to achieve maximum dewatering. None of the results, however, met our expectations.

Well data and histories were extensively analyzed to determine accurate tubing tallies and depth placement of the pumps on TW1 and TW3.

Evidence seemed to indicate that the pump on TW3 should be lowered approximately 60 feet. It also appeared that gas locking was a persistent problem on TW1. A decision was made, as a result of these problems, to develop a workover plan and to schedule workover rigs to move on site.

Rigs were contracted and moved on site July 19, 1993, and workover continued through July 30. Rigs were also on site for 13 days in August.

On TW1, the 2 and 3/8" and 1 and 1/2" strings were pulled, tallied, inspected, and repaired. The pump jack was replaced with a progressive cavity pump and a drip tube was added for better water/gas separation. All zones were swabbed independently with poor water recovery on each run. Each zone was producing less than three barrels of water per day.

TW1 was also flow tested extensively at atmosphere with good results. The coals averaged 30 mcfd, the Ravencliff Sandstone 60 mcfd, and the Big Lime 40 mcfd.

A small acid job utilizing 800 gallons of 15% HCL was attempted on the Big Lime formation. We felt that the acid might clean out the perforations and the fractures from the original frac job. The zone went on vacuum for a few days and then slowly began to recover. Production tailed off but returned to previous levels after four weeks.

Workover on Test Well 3 included pulling, tallying, and repairing the tubing strings, pump assembly, rods, and all parts downhole. A drip tube was also placed on this well below the pump for better water/gas separation. The improper depth placement of the pump on this well was verified. Two joints of 1 and 1/2" were inadvertently left out of the hole during some work about a year earlier. As a result, the pump was landed just above the perfs at the Poca Coal Seam. This was the cause, as suspected, of the continuous gas interference while pumping the coals. The pump has now been placed 60 feet below the Poca Coal and should enable us to adequately dewater the seam.

Attention was focused next on the Ravencliff Sandstone. This formation was found to be uneconomical with a maximum gas production of 2 mcf and 15 bbls of water per day. All necessary paperwork for plugging this zone was completed, but another approach was first attempted. Both strings were pulled out of the hole, and the 4 and 1/2" casing was cut at 1413 feet and removed. This opened the well up completely and allowed the water from the coal seam to simply fall downhole. Calculations indicated that the Ravencliff formation would accept the coal water, thereby solving our water disposal problems. The Ravencliff, however, has not taken the water up to this point.

The coals continue to show good potential, and averaged 35 mcfd when flowed to atmosphere. Dewatering of the Poca Coal, however, has been hindered by malfunctioning pump off switches and a high number of shut-in periods imposed upon us by Columbia Gas and Ramco Gas. The wells were shut in 6 days in June, 12 days in July, 4 days in August, and 13 in September. These shut-ins affected not only our wells, but all the wells in the area.

Water disposal has also been addressed on a continuing basis over the past few months. Currently, we have permission from the State of West Virginia to apply water from the coal seams directly to the surface since the coal seam water has been analyzed and found to be potable. There are certain guidelines, of course, such as requirements to monitor the disposal, to avoid erosion, etc. Several meetings have been held with the State Oil & Gas Division and the Division of Environmental Protection, and the subject will continue to be discussed. We hope to eventually obtain permission from them to implement our water disposal plan. Our plan will include a drainage field with perforated pipe for the coal water, and a line and tank at the foot of the hill for the brine from the deep zones.

It should also be noted that water production from the coals is minimal. Water from the coals on TW1 averages about 2.2 bbls per pumping hour, and TW3 coal water is only 1.2 bbls per actual pumping hour. Based on swabbing and echometer tests done during workover, the water influx rate appears to be near 2 bbls per day from the coals on each well.

The gas production overall from the three Project Test Wells has been exceptional. TW1 has proven to be extremely successful with an average production of 52 mcfd for 1993 (prior to workover activities). This well far surpasses most wells in the region since many wells in southern West Virginia typically produce 8 - 12 mcfd. This makes TW2 (10 mcfd), comparatively speaking, an average well for the area. TW3 may be the most interesting of the three since its production (15 mcfd) is drawn almost entirely from the Poca Coal Seam. Circumstances have thus far prevented us from adequately dewatering and producing this well; but, even so, it still outproduces the average conventional well in the area.

FUTURE WORK

The College has developed plans to tie directly into a main gas transmission line (KA-7), part of the Columbia Gas system, which runs within 1500 feet of TW1. This would eliminate Ramco Gas as a player in our gas transmission and sale arrangement. As a result, we will no longer be forced to operate within the constraints placed upon us by Ramco, nor will we be subject to Ramco compression and gathering charges. This will require, however, installation of a compressor and a new sales meter.

The College expects that, based on the atmospheric flow tests conducted in July and August of this year, gas production should double once a compressor is installed. Initial figures indicate that by pulling line pressure down to the 1-5 psi range, we may see $3500 in additional monthly revenue if our projections are accurate. The compressor will need to be three-phase and in the 100 hp range, and will provide 1 psi suction and 300 psi discharge. Several bids have been obtained and talks are continuing with the bidders and with Columbia Gas, who must approve the plan before it can be implemented.

REFERENCES

1. Overbey, W.K., T.K. Reeves, S.P. Salamy, C.D. Locke, H.R. Johnson, R. Brunk, and L.K. Hawkins. A Novel Geotechnical/Geostatistical Approach for Exploration and Production of Natural Gas from Multiple Geologic Strata. Topical report submitted to U.S. Department of Energy, under Contract DE-AC21-89MC26026, May 1991.

NG-5.2 Process for Coalbed Brine Disposal

CONTRACT INFORMATION

Contract Number	DE - FG03 - 91 ER 81105 A 003
Contractor	Aquatech Services, Inc. 7745 Greenback Lane P.O. Box 946 Fair Oaks, California 95628 Phone (916) 723 - 5107 Facsimile (916) 723 - 6709
Contract Project Manager	John H. Tait
Principal Investigator	John H. Tait
METC Project Manager	Charles W. Byrer
Period of Performance	March 31, 1992 to March 31, 1994

Schedule and Milestones

FY 1993 - 1994 Program Schedule

FY 1993 | FY 1994

S O N D J F M A M J J A S O N D J F M A M J J A

------------Reverse Osmosis------------

---------------Pulse Combustion---------------

-------------------------Testing-------------------------

-------------Integrated Performance-------------

-Commercial Scale System Fabrication-

Process for Coalbed Brine Disposal

H. Brandt[1] and K. J. Jackson[2]

ABSTRACT

This paper describes a brine disposal process that converts the brine stream of a coalbed gas producing site, or of a coal mine, into clean water for agricultural and other use, combustion products and water vapor that can be released into the atmosphere and dry solids that can be recycled for industrial consumption.

The process uses a reverse osmosis unit, a submerged combustion evaporator and a pulse combustion dryer. In addition, pretreatment facilities such as filters, pH control and anti-scaling units are used upstream of the reverse osmosis unit. A successful pilot operation was completed for brine disposal from a New Mexico coalbed gas producing site in the San Juan Basin.

A major consideration in the process is the pretreatment of the brine feedstream to prevent fouling of the membranes of the reverse osmosis unit and to separate from the brine stream hazardous metals and other constituents that may make the permeate from the reverse osmosis unit unsuitable for agricultural or other use. Pretreatment methods and solubilities of the salts in the brine as it flows through the reverse osmosis unit are determined prior to operations using a speciation-solubility computer model that computes a thermodynamic model of the aqueous solution using an extensive thermodynamic data base.

In a typical operation, a brine feedstream of 800 m^3/day (5,032 barrels/day) that may have a total dissolved salt concentration (TDS) of 7,000 ppm will be separated into a permeate stream of 600 m^3/day (3,774 barrels/day) with a TDS of 400 ppm and a concentrated brine stream of 200 m^3/day (1,258 barrels/day) with a TDS of 26,800 ppm. The submerged combustion evaporator will concentrate this latter stream to a concentration of 268,000 ppm and reduce the volume to 20 m^3/day (126 barrels/day). The brine in the submerged combustion evaporator consists of a mixture of saturated brine and a suspension of solid salt particles. The pulse combustion dryer can dry the concentrated brine mixture to a low moisture salt.

Energy costs to operate the reverse osmosis unit are primarily the pumping costs. The submerged combustion evaporator uses approximately 2.75 MJ/kg (1,182 Btu/lb) to evaporate water from the brine and the pulse combustion dryer about 3.65 MJ/kg (1,569 Btu/lb).

The cost of the overall process ranges from \$4.00 to \$5.50 per m^3 (\$0.64 to \$0.87 per barrel) of brine processed depending on the composition of the brine feedstream and the market values of the coalbed methane, the dry salt and the potable water.

1. Technical Director, Aquatech Services, Inc. and Professor of Mechanical Engineering, University of California, Davis, California.
2. Geochemist, Earth Sciences Division, Lawrence Livermore National Laboratory, Livermore, California.

OBJECTIVES

The Phase II research and development effort will determine the operating characteristics of the integrated processes of reverse osmosis, submerged combustion evaporation and pulse combustion drying. The purpose is to develop a brine disposal process that converts the entire brine production stream of a typical coalbed gas production site, or coal mine into clean water for agricultural and other use, combustion products and water vapor that can be released into the atmosphere and dry solids that can be recycled for industrial consumption.

The process will provide a cost effective and environmentally acceptable alternative solution compared to current brine disposal by means of injection wells. The Phase II objectives will provide the following results through laboratory tests and field operations:

1. Pretreatment required to precondition the brine for input to the reverse osmosis system.

2. Performance studies of the submerged combustion evaporator under field conditions while processing an actual brine from a coal seam.

3. Feasibility analysis for adapting a pulse combustion dryer to achieve material reduction to dry solid form suitable for recycling and sale, or transport off-site.

4. Establishment of major component performance characteristics, reliability and maintenance requirements for individual system elements.

5. Selection of optimum components leading to an integrated commercial system for brine reduction capable of handling 325 m^3/day (2,044 barrels/day) or greater volumes.

6. Assessment of environmental issues related to the performance and operation of the integrated process in various locations internationally.

BACKGROUND INFORMATION

This paper is concerned with the research to develop an environmentally acceptable and cost effective method for the disposal of formation fluids (brine) associated with the production of coalbed gas. Currently, approximately 3,000 U.S. coalbed gas wells are in production. The annual production from these wells is about 5.67 billion m^3 (200 billion ft^3) of gas. This amount is expected to double in the early 1990's [1][1]. The amount of brine that is produced from these wells will change during the life of a well, but typically a well may produce from 200 to 300 m^3/day (1,258 to 1,887 barrels/day) of brine that requires disposal.

Coalbed methane in place in the United States is estimated at 11.4 trillion m^3 (tm^3) (401 trillion ft^3 (tcf)) having an energy content of about 422 quadrillion kJ (422×10^{15} kJ, 400 quadrillion Btu). Most of these reserves [2] are located in the San Juan (2.49 tm^3, 88 tcf) and Piceance Basins (2.38 tm^3, 84 tcf) in Colorado, and in the Northern Appalachian region (1.73 tm^3, 61 tcf).

To put these gas reserves in perspective, it should be noted that in 1988 the energy consumption of the United States [3] was 84.4 quadrillion kJ (84.4×10^{15} kJ, 80×10^{15} Btu). Thus, coalbed methane could supply the energy needs of the United States for a period of five years. Alternatively, coalbed methane could supply the

1. Numbers in square brackets refer to the References at the end of the paper.

country's industrial sector for a period of 13.8 years, the transportation sector for 18 years, the residential sector for 25 years and the commercial sector for more than 30 years. Thus, the coalbed gas reserves are significant in terms of the total U.S. energy requirements and the development of these resources is important to the economy, welfare and national security.

A common method for brine disposal is by means of injection wells [4-8]. A desirable thickness of the formation into which the brine is to be injected is 60 m (197 ft) or more. However, such formations are not always available and formation thicknesses less than 60 m are used. In the San Juan Basin, the combined cost to drill and install casing in a Class II injection well ranges from $1.0 to $1.2 million. Completion expenses including formation fracturing and stimulation as well as injection facilities need to be added to this cost. These initial expenses, in combination with well operating costs, cause the brine disposal cost using injection wells to range from $\$3.15/m^3$ to $\$9.50/m^3$ ($0.50 to $1.51/barrel) [7].

In a comprehensive study, Cox et all. [7] show that brine production in the San Juan basin will increase from 18,280 m^3/day (115,000 barrels/day) in 1992 to 28,614 m^3/day (180,000 barrels/day) in 1995. During the next two decades, $105x10^6$ to $165x10^6$ m^3 ($1.04x10^7$ to $664x10^6$ barrels) of brine are projected to be produced. Although current injection wells can handle a large part of this brine volume, additional injection wells will need to be drilled. Furthermore, in some areas in the San Juan Basin, the brine production may exceed the available injection capacity of the injection zones. This latter limitation makes the Aquatech Services, Inc. (Aquatech) process an attractive alternative to the use of injection wells. If injection wells have not been drilled, the Aquatech process is a more economic method to process brine in many coalbed gas producing operations.

PROJECT DESCRIPTION

Overview

The Aquatech process integrates the processes of reverse osmosis, submerged combustion evaporation and pulse combustion drying into a treatment process for coalbed brine. During the contract period each of these processes were evaluated. The reverse osmosis and the submerged combustion evaporation processes were evaluated under field operating conditions.

Figure 1 shows a reverse osmosis unit and a submerged combustion evaporator in operation in the San Juan Basin. A schematic diagram of the integrated brine disposal system is shown in Figure 2.

In Figure 2, brine from a coal bed gas well is pumped into a storage tank. From this tank the brine flows through a filter, softener and a pretreatment unit to remove brine constituents that may harm the membranes of the reverse osmosis unit or that may adversely affect either the potable water or concentrate that flows from the reverse osmosis unit. After pretreatment, the brine again is filtered to remove any salts that were made to precipitate during the pretreatment process.

Reverse Osmosis

In the reverse osmosis process, brine flows under pressure past a porous membrane that is selected for the chemical composition of the brine to be treated. The pressure gradient across the membrane causes substantially salt free water to flow through the membrane, while a brine with high salt concentration stays behind. Thus two streams emerge from the reverse osmosis unit: one consisting of potable water, and the other consisting of brine of higher concentration

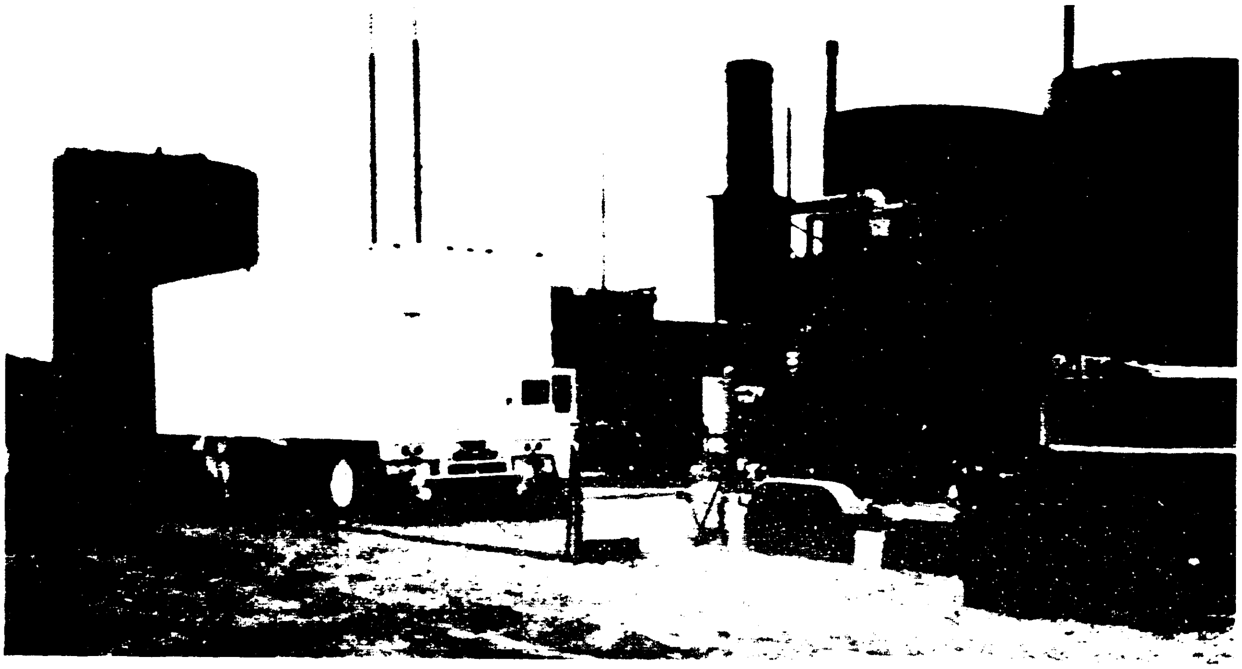


Figure 1. Reverse Osmosis Unit and Submerged Combustion Evaporator at San Juan Basin Test Site

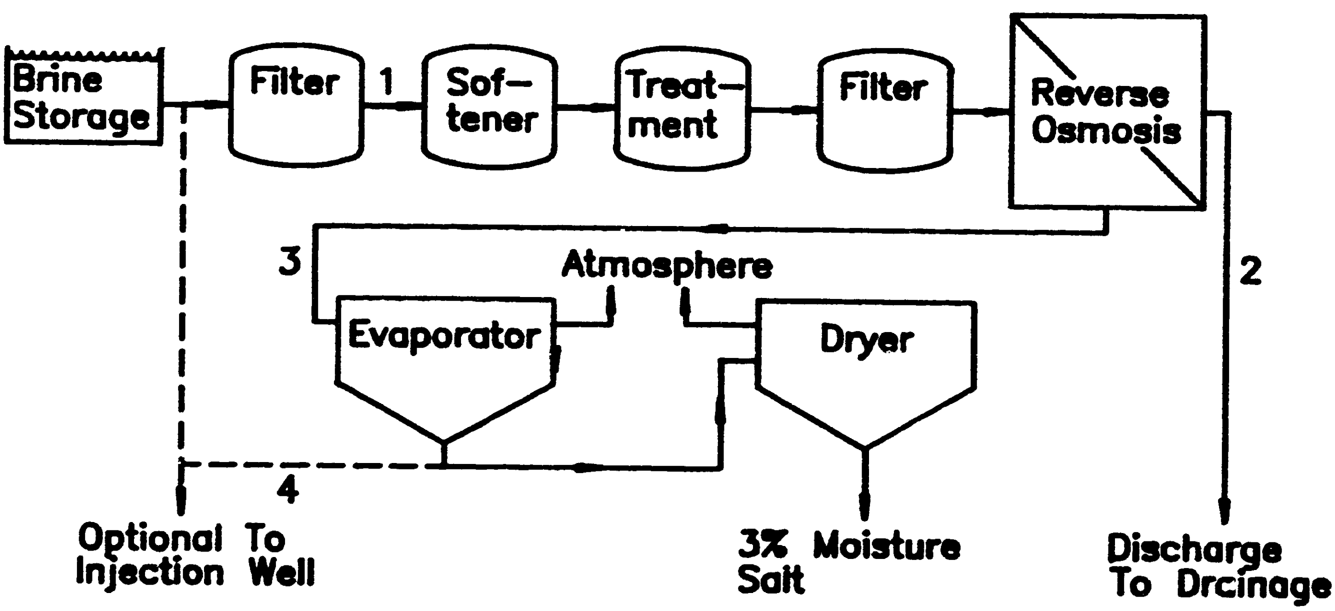


Figure 2. Schematic Diagram of Integrated Brine Disposal System

than the original feed brine.

As an example, the revere osmosis unit can be tailored to take 800 m^3/day (5,032 barrels/day) of brine with a salt concentration of 7,000 ppm (parts per million, 0.7 per cent solution) and deliver 600 m^3/day (3,774 barrels/day) of potable water with a salt concentration of 400 ppm (or less if required by local regulations) and 200 m^3/day (1,258 barrels/day) of brine with a salt concentration of about 26,800 ppm. The salt concentration of the potable water stream needs to be sufficiently low so that the water can be safely used for irrigation or for discharge into the local drainage system after appropriate discharge permits have been obtained from local regulatory agencies. The reverse osmosis step in the brine treatment process reduces the brine volume to be handled by 75 per cent of the original volume.

Submerged Combustion Evaporator

After the reverse osmosis process, the concentrated brine is delivered to a submerged combustion evaporator. In submerged combustion evaporation, a mixture of coalbed gas and air is ignited and combustion takes place in a burner that is placed in a liquid bath. Combustion takes place above the brine level while the combustion gases are vented through the brine. Heat transfer from the combustion gases to the brine is extremely efficient because the combustion gases are vented through the brine and therefore are in intimate contact with the brine. The combustion gases evaporate part of the brine in the evaporator. The water vapor along with the combustion products are vented into the atmosphere. Scrubbers are installed in the exhaust stack to insure that no brine droplets flow up the stack along with the exhaust gases and water vapor.

Brine from the reverse osmosis unit is continuously fed to the evaporator and concentrated brine is bled from the evaporator at a controlled rate so that a steady state brine concentration is established in the evaporator. In the above case, 200 m^3/day (1,258 barrels/day) of brine at a concentration of 26,800 ppm would be delivered to the evaporator. The water would be evaporated from the brine to produce a steady state salt concentration of 250,000 to 300,000 ppm in the evaporator. This concentrated brine is bled from the evaporator under computer control using both brine level and conductivity as control inputs. The control system balances the brine feed rate with the brine evaporation rate and brine discharge to give a steady state operation. The concentrated brine has a volume of about 20 m^3/day (126 barrels/day). Thus, at this stage of the process, the 800 m^3/day (5,032 barrels/day) of brine that need to be treated have been reduced by more than 97 per cent.

The concentrated brine in the submerged combustion evaporator has a temperature of about 80 °C (176°F) and consists of a saturated solution and a suspension of salt particles because the saturation solution of a brine consisting of sodium bicarbonate and 1,000 ppm of sodium chloride is about 140,000 ppm sodium bicarbonate at 60 °C (140°F) [9]. The salt particles are kept in suspension in the submerged combustion evaporator because of the agitation of the brine by the combustion products that are vented through the brine and the action of a recirculation pump.

Pulse Combustion Dryer

The concentrated brine mixture from the submerged combustion evaporator is delivered to a dryer, such as a pulse combustion dryer in which the concentrated mixture is sprayed into the flame of a pulsed combustion unit. A pulse combustion dryer is designed to generate a high-temperature pulsating flow of air and exhaust gas with sound levels above 160 dBA. The high sound levels in the exhaust of the dryer cause the brine stream to be atomized into a stream of fine droplets. These droplets in turn create a large amount of surface area for evaporation. Furthermore, evaporation of the water from the small droplets creates small and uniform salt particles which are desirable if the dried salt is to be marketed.

Thus, the pulse combustion dryer dries the concentrated brine mixture from the evaporator so that the resulting product is solid salt particles of low moisture content that can either be recycled for commercial use or taken to a landfill.

Reverse Osmosis Pretreatment Processes

A highly critical aspect of the use of the reverse osmosis process is the pretreatment of the brine to insure that salts and other constituents will not come out of solution in the reverse osmosis unit. Failures reported [10] in the use of reverse osmosis to process coalbed brine invariable resulted from taking inadequate account of the chemical saturation state of the brine solution as it flowed through the reverse osmosis systems. Changes in the aqueous chemistry of the solution and particularly in the change of saturation states for various salt components during the reverse osmosis process are complex, but they can be modeled using computer codes and a data base containing the thermodynamic properties of each of the brine components.

This section of the paper describes sample calculations that show the changes in some of the components present in a typical San Juan Basin brine. The chemical behavior of all of the brine components are simultaneously accounted for during the calculations, but the results are shown for only a few components. These components were selected because controlling their behavior might be critical to avoid plugging of the reverse osmosis membranes. The computer modeling allows optimization of the pretreatment processes by evaluating various options to process the brine.

Elements such as aluminum, barium, iron and strontium are some of the many constituents that may be present in the brine and that may cause problems in the treatment process. For purposes of discussion, the treatment of barium salts will be described here. Figure 3 shows the change of the barium concentration in an aqueous phase during a three-step pretreatment process of a typical brine from a well in the San Juan Basin. The axes represent the thermodynamic activities (rather than concentrations) of Ba^{++} and H^{+}. The initial solution is supersaturated with respect to several minerals and some of these minerals will precipitate to achieve a state of thermodynamic equilibrium. By minimizing the Gibbs energy of the system, the chemical modeling code selects a minimum number of solid phases that must precipitate from the solution in order to achieve an overall state of heterogeneous equilibrium.

The point labeled "1" in Figure 3 represents the initial composition of the aqueous phase of the brine projected onto the surface described by the two axes. Because this composition has a greater degree of supersaturation with respect to $BaCO_3$ than it does with respect to $BaSO_4$, the $BaCO_3$ will precipitate first.

Calculations were made using the Lawrence Livermore National Laboratory EQ3/6 speciation solubility and reaction path modeling codes [11,12]. These codes use an extensive thermodynamic data base to compute a thermodynamic model of reversible and irreversible reactions that determine the chemical changes of the aqueous phase. Because chemical kinetic constraints (in addition to the influence of equilibrium thermodynamics) impact the actual course of the chemical changes of this system, the actual reaction path that the system follows needs to be verified experimentally.

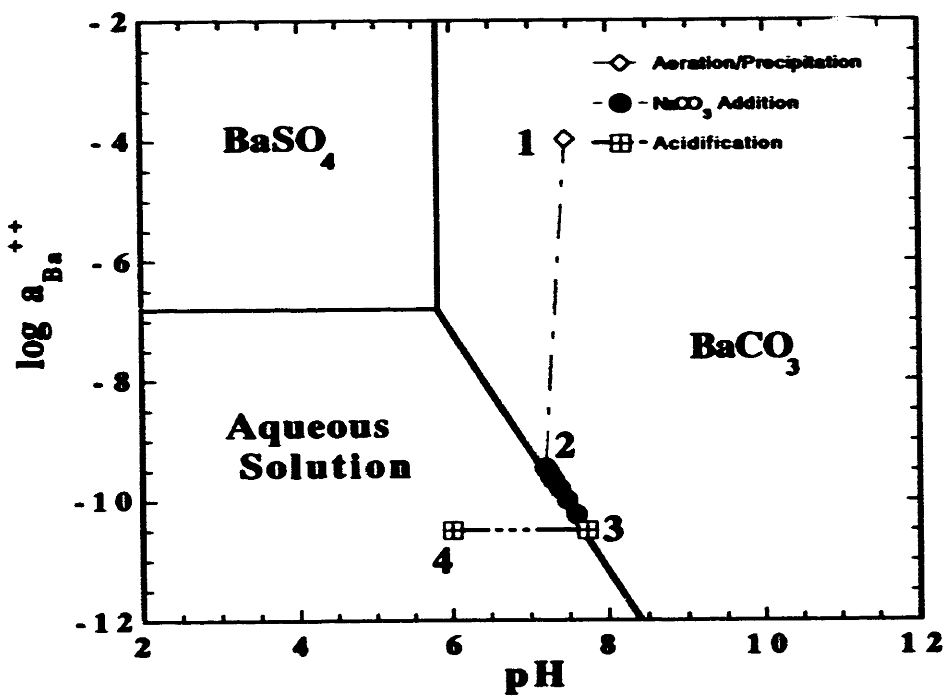


Figure 3. Chemical Evolution of the Aqueous Phase during Brine Pretreatment Steps

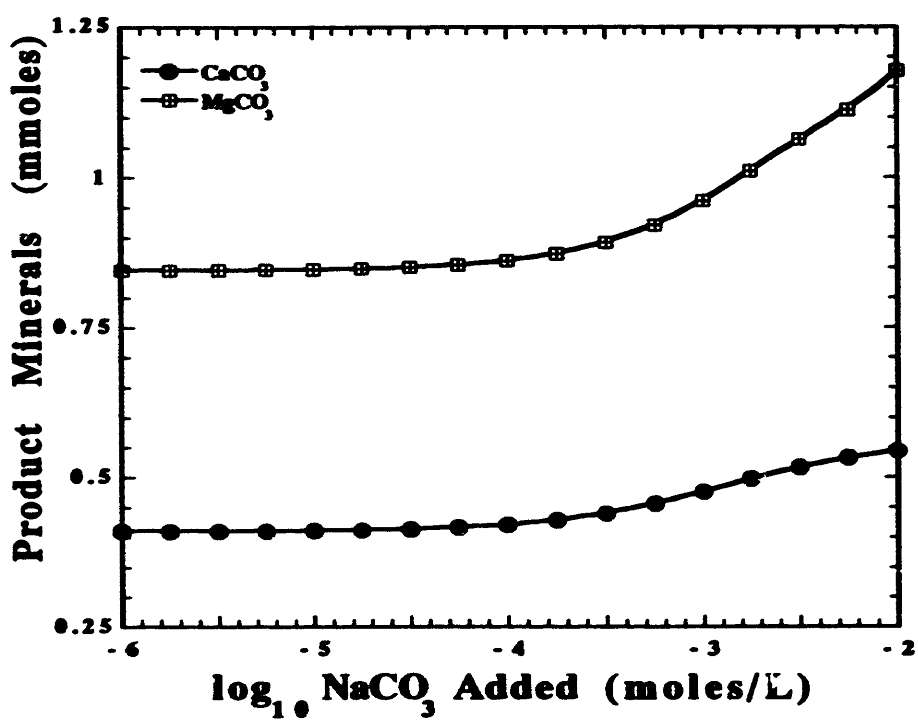


Figure 4. Production of Secondary Mineral Phases during $NaCO_3$ Addition

OF

1.0 2.8 2.5
3.2 2.2
3.6
4 2.0
1.1
1.8
1.25 1.4 1.6

During the treatment step from "1" to "2" in Figure 3, and throughout subsequent calculations, the solution remains in equilibrium with the oxygen content of air (i.e., log f_{O2} = 0.699) and the carbon dioxide content of the solution is limited by requiring the CO_2 fugacity to remain less than atmospheric pressure. The line between points "1" and "2" is not parallel to the vertical axis because the solution pH changes as the CO_2 concentration is altered. Barium decreases according to the reaction

$$Ba^{++} + CO_{2,g} + H_2O \Leftrightarrow BaCO_3 + 2H^+$$

Any solution in equilibrium with respect to $BaCO_3$ must have a composition consistent with the line separating the $BaCO_3$ and aqueous solution fields.

Point "2" represents an overall equilibrium state involving an aqueous phase, several precipitated minerals, and a gas phase. The reaction pathways between points "2" and "3" represents the stepwise addition of solid $NaCO_3$ to the brine as a second pretreatment step. This stepwise addition also is shown in Figure 4. Each of the symbols in the figure represents the addition of a small amount of $NaCO_3$ to the brine. As shown in Figure 4, the additions are in equal amounts on a log scale, from 10^{-6} to 10^{-2} moles. Along this line segment, the aqueous solution is in equilibrium with $BaCO_3$ and a small amount of the $BaCO_3$ is precipitated with each addition of $NaCO_3$. Other changes also occur in this step. $CaCO_3$ and $MgCO_3$ are computed to precipitate during the addition of $NaCO_3$. This reduces the total Ca and Mg content of the solution and therefore their subsequent concentration in the solid product phases formed at the end of the drying process.

The final treatment step from points "3" to "4" represents the re-acidification of the brine. This step provides a brine that is far from saturation with respect to any of the solids that potentially could damage the reverse osmosis membranes.

Filtration is used to remove the $BaCO_3$ and other solid phases such as carbonates, clay, minerals, silica, and an iron hydroxide phase. Removal of these components is necessary to preclude their participation in back reactions and to prevent precipitated material from clogging the membranes of the reverse osmosis unit and other parts of the equipment.

Operations of Integrated Process

A reverse osmosis unit and a submerged combustion evaporator were operated during an eighty five-day period to process the brine form a group of wells in the San Juan Basin. By agreement with the local operator of the field, the testing was to be performed within a ninety-day period. The pilot operation processed approximately 1,000 m^3 (6,290 barrels) of brine in a coalbed gas field. The concentrated brine from the reverse osmosis unit was then pumped to a submerged combustion evaporator which successfully concentrated the brine to a concentration ranging from 25 to 30 per cent.

Performance measurements were made of the units in operation during the pilot test period.

The concentrated brine mixture from the submerged combustion evaporator was dried to a low moisture salt in a pulse combustion dryer. The drying process was performed in a laboratory environment to avoid the cost of shipping a pulse combustion dryer to the gas field.

Aquatech subsequently has operated a submerged combustion evaporator on a commercial basis in the San Juan Basin and is planning to install additional units in the near future.

Aquatech also is preparing to install a large plant in Poland that combines reverse osmosis and submerged combustion to process the brine from coal mines.

RESULTS

Reverse Osmosis Operations

Treatment of the brine by means of reverse osmosis was highly effective. The salt concentration of the brine ranged 35,000 to 65,000 TDS. Membrane performance was within the manufacturer's specifications. The process used an equipment configuration similar to the one shown in Figure 2. Figure 1 is a photograph of the equipment at the test site. The pulse combustion dryer was not located at the test site. Instead, the concentrated brine from the submerged combustion evaporator was brought to the dryer in batch form. Table 1 gives the salt concentrations at the locations in the process indicated in Figure 2.

As discussed above, proper pretreatment procedures are essential to successful operation of the reverse osmosis unit. Furthermore the brine composition needs to be monitored frequently to make sure that it has not changed adversely with respect to the pretreatment process. For example, during a fourteen-month study of the variation of the composition a San Juan Basin brine, it was found that the barium content increased by 32 per cent, total iron decreased by 35 per cent, strontium increased by 380 per cent and chloride decreased by 25 per cent. Thus constant monitoring of the brine feed stream is essential to the success of the operation.

Submerged Combustion Evaporation

Table 1 shows the salt concentrations before and after the submerged combustion evaporator during one particular day of operation. The salt concentration of the brine flowing from the evaporator was 168,000 mg/l. Typically, the

Table 1

Brine Compositions at the Locations Indicated in Figure 2

ITEM	CONCENTRATION, mg/l			
LOCATION	1	2	3	4
TDS (mg/l)	14,000	330	41,500	168,600
Cl	995	67	2,820	13,460
Na	4,000	--	14,900	75,880
SO_4	5,300	210	17,600	76,100
CO_3	--	--	--	13,650
HCO_3	4,700	150	13,730	25,440
pH	8.3	6.8	8.1	9.25
ALK	--	--	11,200	43,600

submerged combustion evaporator can concentrate the brine to 250,000 to 300,000 ppm. At this concentration level, the brine has exceeded the solubility of several salts in the brine at the operating temperature of 80°C (176°F) of the evaporator and the brine consists of a mixture of a concentrated solution and solid particles that are kept in suspension. It is clear that during shutdown, the evaporator and piping components will need to be drained to avoid that salt will come out of solution in these components. During the tests, the concentrated brine from the evaporator was mixed with brine from the well to produce a mixture of low salt concentration and to permit discharge of the mixture into an injection well.

An important consideration in the operation of the submerged combustion evaporator is the composition of the stack gases that are vented into the atmosphere. These gases substantially consist of water vapor and products of combustion of the gas and air. To keep the oxides of nitrogen and the CO content below local environmental levels, the evaporator needs to be operated with an excess of combustion air. During the tests performed, it was found that with excess air greater than 65 per cent, the oxides of nitrogen could be kept below 22 ppm and the carbon monoxide below 30 ppm. With excess air above 75 per cent, both the oxides of nitrogen and the carbon monoxide were less than 20 ppm.

The evaporator uses approximately 2.65 to 2.75 MJ/kg (1,140 to 1,182 Btu/lb) to evaporate water from the brine.

Pulse Combustion Drying

The concentrated brine mixture from the evaporator was shipped to a plant for drying to evaluate the pulse combustion drying technique. The inlet temperature of the dryer was 925 °C (1,697°F) and the outlet temperature was 88°C (190°F). The energy to evaporate the water from the brine mixture was approximately 4.15 MJ/kg (1,785 Btu/lb). The pulse combustion dryer produced a very fine-grained dry powdery salt with excellent appearance. The drying process changes the sodium bicarbonate salt to a substantially sodium carbonate salt. The former has a higher resale value because it can be used, for example, to scrub the flue gases of power plants to reduce the sulphur content. The commercial value of the dry salt of the process is affected by the shipping cost of the dry salt from the gas field to the market place.

FUTURE WORK

Future work consists of two main areas of endeavor. First the pretreatment of the brines needs to be studied further from both a computer modeling as well as from an experimental point of view to make sure that the computer models accurately reflect the behavior of the brine as it passes through the pretreatment and reverse osmosis units. In addition, chemical analyses will be made of the vapors vented into the atmosphere by the submerged combustion evaporator to insure that environmental regulations are met at all operating conditions.

Aquatech will receive substantial assistance from the Lawrence Livermore National Laboratory. That Laboratory has received a grant from the Department of Energy to study brine pretreatment processes.

A second major activity is the translation of the results obtained during the Phase I and Phase II studies into a viable commercial operation. Aquatech currently is operating evaporation equipment in the Carson National Forest. U.S. Forest Service local conditions restrict traffic on unimproved forest roads, necessitating gas producing sites to be self-contained and to operate for extended periods when access is limited.

Aquatech has met the operating requirements for the disposal of brine and has averaged evaporation of 27 m^3/day (170 barrels/day) and reduced brine volume by approximately 95 per cent. The site is at an elevation of 2270 m (7448 ft) and has severe daily temperature variations and winter snow conditions. Because the operation of the evaporator was successful, contracts are being written for additional submerged combustion evaporator units for long term service in this and other areas of coalbed methane production in the southwestern United States.

A major commercial operation in Poland has been formulated to process brine from a mine. The process will combine a reverse osmosis unit and a submerged combustion evaporator with an ultimate combined capacity of 3,000 m^3/day (18,872 barrels/day).

Deployment of evaporator equipment to West Virginia for coalbed methane dewatering applications is being evaluated.

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NG-5.3 Commercialization of Previously Wasted Coal Mine Gob Gas and Coalbed Methane

CONTRACT INFORMATION

Contract Number DE-FG21-92MC29254

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Period of Performance August 7, 1992 to December 6, 1993

Schedule and Milestones

PROJECT TASKS	1992					1993											
AND DELIVERABLES	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
1. Evaluate Gas Resources																	
2. Evaluate Technology Options																	
3. Review Environmental Effects																	
4. Assess Market & Economics																	
5. Rank Alternatives																	
6. Identify Phase II Demo Site(s)																	
Technical Briefing to METC																	
Contractors Meeting																	
Final Report																	

OBJECTIVES

The objectives of the project were to: (i) conduct an assessment of the commercial potential of the gob gas and coalbed methane resources associated with coal mining operations, and (ii) evaluate alternative gas utilization technologies. The end results to be achieved are the exploitation of an energy resource that is presently being wasted as it is vented to atmosphere and the mitigation of methane liberations for improved environmental quality.

BACKGROUND INFORMATION

Methane contained in coal seams has plagued coal producers for centuries due to safety problems caused by gas emissions into underground workings. To cope with this problem, mine operators dilute methane concentrations by circulating large volumes of air through ventilation systems and vent gas to atmosphere through gob ventilation boreholes and other methane drainage systems (Trevits et. al., 1991). Unfortunately, most of this gas is contaminated with air and/or is inaccessible to pipelines. As a result, the resource has generally been regarded as unsuitable or uneconomic for use as a primary energy source.

An immense resource is presently being vented to atmosphere from coal mines throughout the world. For example, in 1988 an estimated 5.2 to 8.0 billion cubic meters (BCM) of methane was liberated from coal mining operations worldwide. Of this amount, 4.9 to 7.8 BCM was vented to atmosphere and only 0.4 BCM was utilized. This is a waste of a valuable energy resource and may be deleterious to the environment. Methane is deemed to be a large contributor to global warming since it is twenty times more effective at trapping heat in the atmosphere than carbon dioxide (over a one hundred year time frame). Furthermore, methane concentrations in the atmosphere have more than doubled during the past two centuries (EPA, 1993). Therefore, the economic potential and environmental benefits that would be realized through the use of methane produced in conjunction with coal mining activities are vast.

Recognizing an opportunity to exploit this gas resource, in 1984 Resource Enterprises, Inc. (REI) set out to identify potential commercial applications. The obvious utilization options involved use of the gas in direct combustion processes such as electric power generation and coal drying (Von Schonfeldt, 1982). REI's objective was to identify an alternative through which the value added to the gas resource could be maximized, thereby enhancing the economics of methane commercialization. The Public Utilities Regulatory Policies Act (PURPA), enacted by the US Congress in 1978, created a favorable environment to develop independent electric power generation projects in the US. This situation influenced REI's focus on using "waste" gas produced from coal mines for electric power production and ultimately resulted in REI's formation of a venture with a gas turbine manufacturer to develop independent power projects at various coal mine sites (Owen, 1988).

However, economic conditions were very depressed throughout the industrialized areas of the US during the 1980's and into the 1990's. This was especially pronounced in coal regions and caused a surplus of power generation capacity that discouraged electric utilities to acquire additional supply. Although PURPA required the utilities to purchase power at their "avoided cost" of producing electricity, REI quickly discovered that perspectives on the value of avoided cost varied widely. Despite support from various sources to develop electric power generation projects using the waste resource, acceptable power sale agreements (or back-up power purchase agreements for on-site use of produced electricity) could not be secured. This situation is believed to be peculiar to conditions that existed in the US at that time; power generation projects in other countries (and in the US under different circumstances) may be conducive to this methane commercialization option. As a consequence of the power generation experience gained by REI, REI began investigating non-electric alternatives for commercializing methane produced in conjunction with mining.

PROJECT DESCRIPTION

A non-electric coal mine gas utilization approach was expected to be well received by the coal industry since the gas would potentially displace other natural gas supplies (as opposed to coal). The targeted resources were gob gas (contaminated gas produced from mined-out areas), and pipeline quality methane produced in advance of mining. Methane contained in ventilation air was only expected to have some potential for use as combustion air (Glickert, 1991), and was disregarded due to its limited potential for commercialization using current gas conversion and separation technology. This pursuit resulted in a project co-funded by the US Department of Energy, Morgantown Energy Technology Center (DOE) and REI to evaluate gas conversion and enrichment technology options. REI was the project manager and prime contractor for the project that was initiated in late 1992. REI subcontracted the University of Utah Chemical and Fuels Engineering Department to assist REI in its evaluation of gas conversion and enrichment technology options. The gas utilization objectives of the project were to identify and evaluate existing processes for: (i) use of gas as a feedstock for production of marketable commodities, and (ii) enriching contaminated gas to pipeline quality. Satisfying the first objective was a priority since the technology would have broader application (as pipeline access would not be required).

The project was divided into two phases. The purpose of Phase 1 (the subject of this work) was to evaluate the gas resource associated with mining, and identify and evaluate various gas utilization technologies. Phase 2 would consist of a pilot demonstration of the technology deemed to have the most promise for commercializing this resource. Phase 1 was comprised of seven tasks, as summarized below:

Task 1: Evaluate the Gob Gas and Coalbed Methane Resources

REI evaluated the gas resource associated with US coal mining activities to characterize the potential fuel/feedstock source. This included an assessment of: (i) existing methane drainage techniques and opportunities for improving methane drainage effectiveness, (ii) coal mine characteristics, (iii) area logistics, (iv) environmental considerations, and (v) gas ownership implications. This task was primarily directed at addressing project development considerations.

Task 2: Evaluate Gas Utilization Options

The technology alternatives considered by REI under both the conversion and enrichment scenarios would be required to accommodate relatively low volumes (50,000 to 100,000 cubic meters per day) of methane flow and varying gas quality. The primary contaminants of the untreated gas stream would be air, carbon dioxide and water vapor. Since one of the priorities established for the project was to consider only commercially available technologies, the principal problem to be addressed was that of downsizing the applications and tailoring the gas processing system to the characteristics of the fuel source. Processes that traditionally have a high gas feedstock cost as a relatively large component of the total product cost were deemed to be the most desirable. This was because methane has a relatively low production/acquisition cost when it is extracted as a requirement of mining operations and, therefore, would result in lower overall product costs. Additionally, high value-added products (specialty chemicals, etc.) that could be produced from the gas were targeted since they could be readily marketed.

Task 3: Environmental Review

An assessment of the expected impact on the environment of the most favorable technologies was investigated. This included an estimate of the potential reduction of methane emissions to atmosphere and the identification of incremental environmental effects that would result from the application of the technologies.

Task 4: Market Assessment and Economic Analysis

The market potential for the gas conversion and enrichment options preliminarily determined to be feasible was evaluated. This included an investigation of the demand for the resulting product, pricing, shipping and other factors affecting marketability and economics. An economic model was constructed and utilized to incorporate this information with facility investment and cost information to perform an economic analysis of the most promising alternatives identified.

Task 5: Final Selection of Utilization Options

The information developed under Tasks 1 through 4 were integrated and evaluated to refine the appraisal of the gas conversion and enrichment options investigated. This resulted in a ranking of the technologies and overall recommendation for the Phase 2 demonstration.

Task 6: Selection of Candidate Phase 2 Demonstration Sites

Based on the results of Task 5, candidate sites for a Phase 2 demonstration were identified and preliminarily evaluated to determine their potential for satisfying the Phase 2 project objectives.

Task 7: Technology Transfer and Final Report

The results of Phase 1 are being transferred to industry through various mechanisms including the Final Report.

RESULTS

The following gas conversion technologies were evaluated: (i) transformation to liquid fuels, (ii) manufacture of methanol (and perhaps further processing to acetic acid), (iii) synthesis of mixed alcohols, and (iv) conversion to ammonia and urea. All of these processes involve a two-step conversion; synthesis gas is produced from the gas stream and then converted to the ultimate products. Synthesis gas, a mixture of CO and H_2, can be produced either by steam reforming or by methane partial oxidation. In practice, a combination of steam reforming and partial oxidation is used to generate CO and H_2 in the right proportion for the hydrocarbons/chemicals product slate of interest. Natural gas steam reforming typically produces a hydrocarbon-rich synthesis gas, the hydrogen from which, in principle, can be separated and used in a furnace. The synthesis of hydrocarbons or chemicals from the synthesis gas is governed by the catalysts employed, reaction conditions and type of reactors used. Specifically for hydrocarbon synthesis, two types of reactors have been used; a packed-bed reactor and a slurry reactor. It was determined that for the gob gas conversion application, a slurry reactor would be more appropriate.

Most of the conversion technologies evaluated were found to be mature processes operating at a large scale. A major drawback in all of the processes was the need to have a relatively pure feedstock, thereby requiring gas clean-up prior to conversion. As a result, gas enrichment would be needed in any conversion application and could not be avoided. Despite this requirement, the conversion technologies evaluated were preliminarily found to be economic with varying degrees of facility cost amortization. However, the prohibitively high estimated investment for a combined gas enrichment/conversion facility (greater than US $20 million for a typical mine site installation) required that REI refocus the project to gas enrichment.

Enrichment of a gas stream with only one contaminant is a relatively simple process (depending on the contaminant) using available technology. Most of the gas separation technology developed to date addresses this problem. However, gob gas has a unique nature, consisting of five primary constituents, only one of which has any significant value. These constituents are: methane, nitrogen, oxygen, carbon dioxide and water vapor. Each of the four contaminants may be separated from the methane using existing technologies that have varying degrees of complexity and compatibility. However, the operating and cost effectiveness of the combined system is dependent on careful integration of the clean-up processes.

Rejection of nitrogen from methane is one of the more difficult problems from a gas separation perspective. The nitrogen rejection unit was determined to be the most critical and costly component of the system. Three technologies were identified as being suitable for nitrogen removal: (i) cryogenics, (ii) selective absorption, and (iii) pressure swing adsorption (PSA). Cryogenic separation has been a standard process of choice for this separation, on a larger scale (e.g., exceeding 500,000 cubic meters per day of flow). This process was not expected to be competitive at a small scale with the other two processes. However, preliminary conclusions from another investigation indicated that at processing capacities of 50,000 to 150,000 cubic meters of gas per day, the cryogenic process would compete with PSA (GRI-91/0092). However, the cryogenics process was found to be very sensitive to the presence of impurities such as water and oxygen and, therefore, was considered to be inappropriate for the gob gas application.

The application of the selective absorption process for nitrogen rejection from a conventional natural gas source has been performed (Mehra, 1993). The process utilizes different solubilities of nitrogen and methane in specific solvents to effect the separation. The solvent-feed contacting is carried out in a conventional packed-column system, common in the chemical engineering process industry. The PSA process has been under development for the last five to ten years, and the concept and results have been published (Meyer, 1990; D'Amico, 1993). The process generally consists of the following four steps: (i) pressurization, (ii) adsorption and subsequent recycle, (iii) depressurization, and (iv) purge or evacuation. The separation is accomplished using wide-pore molecular sieves which exploit different equilibrium adsorption capacities for different gases, such as methane and nitrogen. Typically, four to five adsorbent beds would be used for the expected flow rates for the gob gas application. The selective absorption process responds to the variable composition and flow rate of the feed by adjusting the solvent/feed ratio. In PSA, the cycle times and the recycle ratio are adjusted to maintain a specified product composition for changing feed flow rates and compositions.

Both the selective absorption and PSA processes were assessed to be acceptable from both technical and economic perspectives. The overall hydrocarbon recoveries in both processes were similar and the capital and operating costs were also comparable. A primary difference between the selective absorption and PSA processes is their ability to handle oxygen. The selective absorption process requires oxygen removal prior to nitrogen rejection, whereas the PSA process removes part of the oxygen during the nitrogen separation process. Therefore, a smaller quantity of oxygen would have to be treated in the gas stream using PSA, thereby simplifying the operation and reducing the cost. Extreme caution must be exercised in designing a PSA nitrogen rejection system to ensure that gas mixtures passing through the explosive range are handled appropriately to maintain adequate operating safety.

The oxygen separation component added complexity to the integrated gas enrichment concept. Catalytic combustion was the process determined to be the best suited for the gob gas application. The process could be performed adiabatically or at lower temperatures using hydrogen as additional fuel. The adiabatic approach was favored due to safety and cost considerations. The adiabatic combustion unit would generally be designed to handle the maximum concentration of oxygen expected in the gas stream.

Technologies for carbon dioxide and water removal are well established. Carbon dioxide rejection may be accomplished using an amine absorption process, membrane separation (or possibly, a PSA process). Either the amine or membrane processes were determined to be suitable for the gob gas application. The PSA process was anticipated to still be experimental in nature and not as mature as the other alternatives. Therefore, PSA was not recommended for initial use to remove carbon dioxide. Conventional water removal techniques (e.g., glycol dehydration, membrane separation, etc.) are very adequate.

In summary, the system design that is expected to be the most favorable from both technical and economic viewpoints is a facility consisting of: (i) a PSA nitrogen rejection unit, (ii) a catalytic combustion deoxygenation process, (iii) an amine or membrane carbon dioxide removal system, and (iv) a conventional dehydration unit, as depicted in Figure 1.

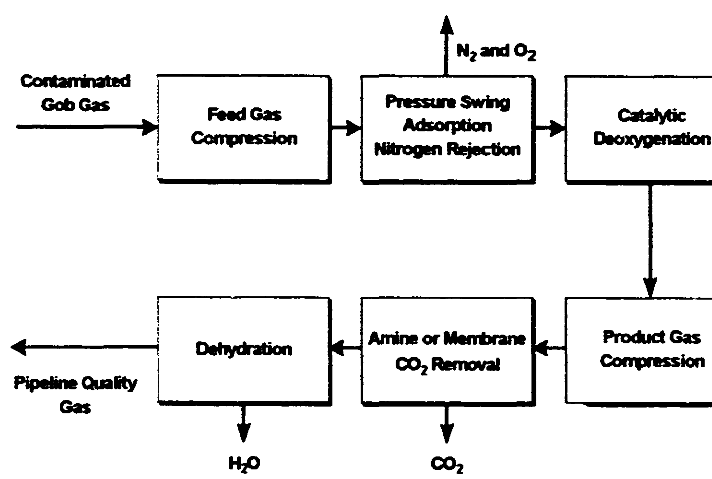

Figure 1. Generalized Gas Enrichment Facility Schematic

FUTURE WORK

REI is proceeding with a pilot demonstration of a waste gas enrichment facility using the approach described above. This is expected to result in the validation of the commercial and technical viability of the facility and the refinement of the design parameters. REI intends to develop subsequent projects on a global scale to facilitate the commercialization of a previously-wasted resource and the enhancement of environmental conditions.

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Session NG -- Natural Gas Technology

Session NG-6

Drilling, Completion, and Stimulation

NG-6.1 CO_2/Sand Fracturing in Low Permeability Reservoirs

CONTRACT INFORMATION

Contract Number	DE-AC21-90MC26025 Production Verification Tests
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METC Project Manager	Albert B. Yost II
Period of Performance	May 5, 1990 to November 10, 1994

Schedule and Milestones

FY94 Program Schedule

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                S    O    N    D    J    F    M    A    M    J    J    A   S

1.1  Work Plans -------------------------->
1.2  Pre-Frac   ------------------------------>
1.3  Fracturing ----------------------------------->
1.4  Post-Frac  ---------------------------------------->
1.5  Prod Mon   --------------------------------------------->
1.6  Option 1
1.7  Final Rep                                                            <-

2.1  Work Plans ----------------------------------->
2.2  Pre-Frac             <----------------------------->
2.3  Fracturing                 <---------------------------->
2.4  Post-Frac                        <--------------------------->
2.5  Prod Mon                         <-------------------------------->
2.6  Option 3
2.7  Final Rep                                                            <-
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OBJECTIVES

* To demonstrate the effectiveness of a non-damaging liquid, carbon dioxide (CO_2) in creating sand-propped hydraulic fractures in "tight" gas bearing formations within the Appalachian Basin.

* To compare and rank the gas production responses from wells treated with liquid CO_2 with other types of treatments (shooting, water based, nitrogen, etc.).

BACKGROUND INFORMATION

From a historical perspective, discussion in the public literature concerning the application of sand fracturing with carbon dioxide first appeared in 1982. It was reported that over 40 liquid CO_2/sand treatments had been performed by American Frac Master in the U.S. by 1982. Early results were encouraging, but frac equipment was moved out of the U.S. shortly thereafter eliminating the opportunity for operators to continue to test the fracturing process in the U.S. Of those 40 treatments, 60 percent were successful in gas wells, 25 percent were successful in oil wells, and 15 percent were considered noncommercial. Concurrently, during the early 1980's, more than 40 frac treatments were performed in Canada using gelled liquid CO_2/sand fracs. Early test results indicated a 50 percent increase in production response. Laboratory research proceeded in 1983 toward evaluation of different proppant mesh sizes using a proprietary gelling agent that adds viscosity to the liquid carbon dioxide. Subsequently, the continued use of viscous chemicals was suspended in future jobs executed in Canada. Research continued on understanding the mechanics of the CO_2 fracturing process and development of suitable way to improve the rheology of liquid CO_2. Hydrocarbon based gelling agents were tested that would yield over a 2 centipoise viscosity.

During 1985, numerical simulation models were developed for proppant transport that included flow turbulency and its effect on proppant settlement and pressures in the fracture. These numerical simulation models for CO_2/sand fracturing are quite different from conventional stimulation models.

During 1987, additional efforts were focused on a method to create viscosity in the presence of liquid CO_2, which resulted in the testing of a blend of high molecular weight fatty alcohol, a sorbitan fatty acid ester and diesel oil representing 2 percent by volume. This component was then combined with liquid CO_2 to create a viscous emulsion. A selective number of stimulations were performed in Canada using this emulsion system with mixed results. Shortly thereafter, the use of viscous agents was abandoned in favor of injecting proppant into 10 percent liquid CO_2. The obvious benefit was the elimination of residue and formation compatibility associated with the hydrocarbon-based viscous agents. By late 1987, it was reported that more than 450 100-percent liquid CO_2/sand fracs had been performed primarily in Canada. Over 95 percent of the wells were gas wells at depths less than 8200 feet with the largest sand volumes used at approximately 44 tons. Typical sand volumes pumped ranged from approximately 10 to 22 tons.

INTRODUCTION

Review of the literature indicated that the technology was available to the U.S. operators for a short period of time in the early

1980's but has since remained outside the U.S. and not available as a commercial service inside the U.S. In an effort to re-introduce this technology to U.S. operators and test the effectiveness of this stimulation technique in various geologic settings, a contract was developed with Petroleum Consulting Services to stimulate and test up to 27 wells using the carbon dioxide/sand fracturing methods in the Appalachian Basin.

To date, a total of five single stage stimulations have been completed with 22 additional stimulations planned in the Appalachian Basin over the next year. As part of re-introducing the process to those unfamiliar with the stimulation method considerable discussion will follow about the history of technology development primarily outside the U.S., discussion of field implementation of job execution, and preliminary results from the early stimulation tests.

The concept of transporting sand in a closed pressure vessel has been under development outside the U.S. since 1981. Although the concept of hydraulic fracturing underground gas formations is not new, the equipment requirements have changed drastically over the years. The CO_2/sand fracturing process (Fig. 1) differs substantially from conventional treatments in that job execution required a pressurized blender that can combine liquid CO_2 with proppants under pressure. The surface layout of the CO_2/sand fracturing process (Fig. 2) identifies the logistical position of the CO_2 storage, nitrogen pumper, blender, and pump trucks during fracturing operations.

SELECTION CRITERIA

A candidate well selection methodology was developed to improve the confidence in comparing technology results in various geologic settings. As a minimum requirement, emphasis was placed on providing an established background of production data from control wells to which the production responses from the candidate wells would be compared and an assessment made.

The candidate well selection criteria includes--

1. That the wells are located in accepted areas of legitimate, cost-effective, gas production.

2. That sufficient nearby background production information is available to enable the results of the procedure to be evaluated.

3. That any sand be removed from the wellbore immediately following the stimulation.

4. That the wells be turned in line no later than 30 days after treatment, and that the merits of using this technology be measured from production responses into the pipeline rather than interrupting operator plans for production by conducting an elaborate well testing effort and forecasting indirect indicators of response.

PROCEDURE - FIELD EQUIPMENT

Sand proppant is combined with liquid carbon dioxide (CO_2) in a pressurized blender (Fig. 3) to make a sand/liquid CO_2 slurry. The blender is operated at a pressure of approximately 300 psi, and, as presently configured, can store up to 47,000 pounds of sand. It can develop CO_2/sand slurries with densities of up to 5 pounds per gallon at outputs of 55 barrels per minute.

The slurry is discharged directly into the suction side of conventional pump trucks which increase the sand-laden CO_2 slurry to wellhead treating pressures and inject it into the wells.

The liquid CO_2 is stored in two 60-ton portable storage trailers which discharge directly into the blender. They are filled via 20-ton transport trailers prior to these treatments.

During the treatment, the CO_2 is displaced from the CO_2 storage vessels and into the blender with gaseous nitrogen, which allows a constant pressure to be maintained.

The sand concentration is monitored with a radioactive densometer throughout the treatment and is adjusted to create the desired sand schedule. All five treatments were executed with the densometer and resulted in the designed sand schedule being pumped.

Following the treatment, the well is flowed back on a choke. Care is exercised to allow the formation stresses to close on the sand pack and for the CO_2 to change to a gaseous phase. Flowbacks required 2 to 3 days.

JOB EXECUTION

The first series of single stage treatments involved five wells located in Perry (Fig. 4) and Pike (Fig. 5) Counties, Kentucky. They were all completed in the Devonian shale over perforated intervals ranging from 238 to 366 feet, and were selected on the basis of the treatment diversity and quality of the offset production information. They were all treated in January, 1993.

The mountainous terrain of eastern Kentucky was the location of the first five treatments, and with one exception, all were treated with equipment on the wellsite. One well was treated from the base of a hill through 4-1/2 inch casing which had been pressure tested prior to job execution.

The wells were all treated with liquid CO_2 and sand. They were all found to have some sand in them, which was removed by various methods: Coiled tubing, with field gas and tubing, and two were sand pumped with exceptional care exercised to minimize water volumes. The sand removal had only a minor effect on the gas production rate, which may be a result of the liquid-free sand pack which remains following the CO_2 vaporization.

A summary of candidate well stimulation information is shown in Table 1. The first well (permit no. 83961) was stimulated with 22,700 pounds of 20/40 sand and 120 tons of CO_2. A conservative volume of sand was injected to evaluate the ease of introducing sand into the liquid CO_2 stream for subsequent injection downhole. The first treatment went very smoothly, therefore subsequent jobs were executed with the blender loaded to its maximum capacity of 47,000 pounds. The second well (permit no. 83962) was stimulated with 40,200 pounds of 20/40 sand and 160 tons of CO_2 resulting in an effective increase from 1.9 to 2.6 pounds per gallon sand concentration. The remaining subsequent jobs were all executed with 120 tons of CO_2 and increasing sand volumes up to 46,000 pounds of 20/40 sand at an average concentration of 3.1 pounds per gallon sand.

PRELIMINARY RESULTS

The preliminary results are encouraging, and although only a few months of production is available, the rate of gas production from the CO_2 treated candidate wells is greater than that from the control wells (Tables 2 and 3). The average monthly production for the CO_2/sand fraced wells in Perry County is shown in Table 2. The CO_2/sand fracs appear to be 56 percent better than the nitrogen fracs in Pike County as shown in Table 3. In addition, the CO_2/sand fracs are 4.8 times better than conventional shot wells in the Pike County study area. It should be recognized that these results are from a very limited data set and overall conclusions may change as more control wells are added to the analysis. From a stimulation process achievement viewpoint, the maximum amount of sand pumped is 46,000 pounds at an average concentration of 3.1 pound per gallon. It should be pointed out that additional foam and nitrogen stimulations have recently been performed by the operator in the Pike County area, and subsequent discussions in the future will include additional control wells to the baseline data sets.

CONCLUSIONS

1. Preliminary monthly production rates of the wells stimulated with CO_2/sand are 56 percent better than nitrogen fraced wells in the Pike County study area.

2. Wells stimulated with CO_2/sand are 4.8 times more productive than shot wells in the early months of production for the Pike County study area.

3. The long term production from using CO_2/sand fracturing compared to nitrogen and foam conventional treatments needs additional investigation in other areas to verify the broad application of the technology in Devonian shale.

ACKNOWLEGEMENTS

The author wishes to thank J. W. Kinzer of Kinzer Drilling and K. L. Hall of C. D. & G. Development Company for providing wells of opportunity to test the effectiveness of this stimulation technique. In addition the author wishes to thank W. A Schuller of EG&G Analytical Services for his support in selected graphics development.

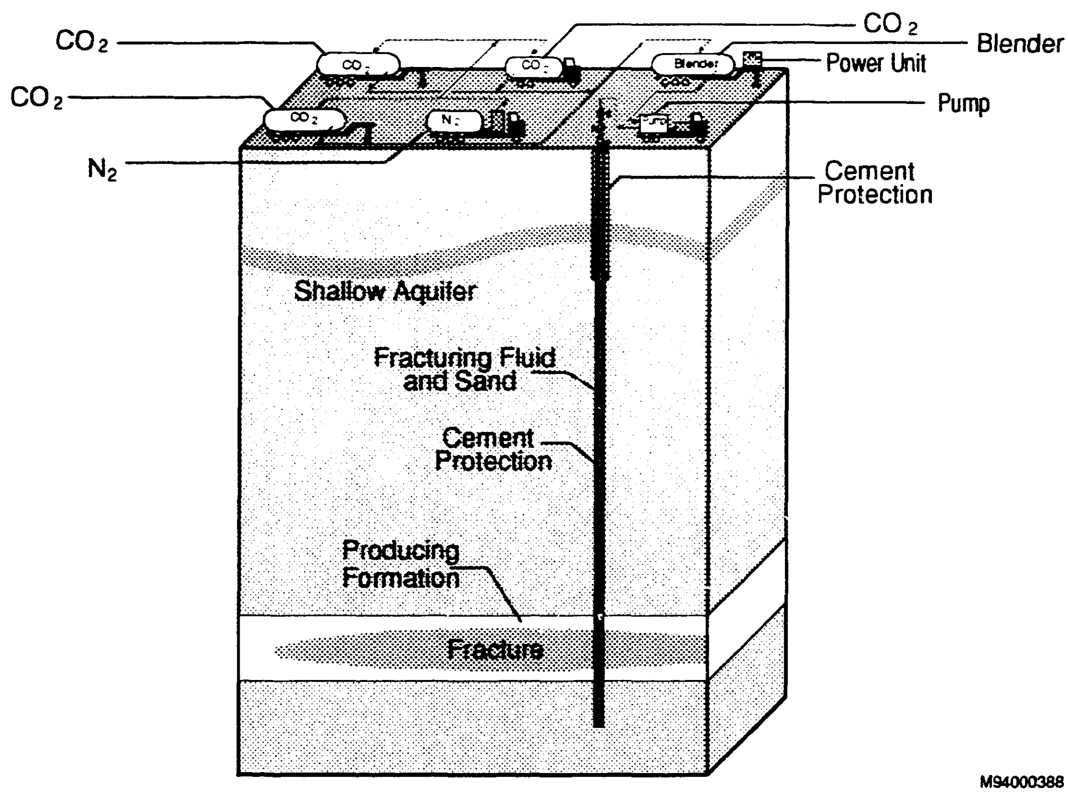

Figure 1. CO_2/Sand Fracture Process

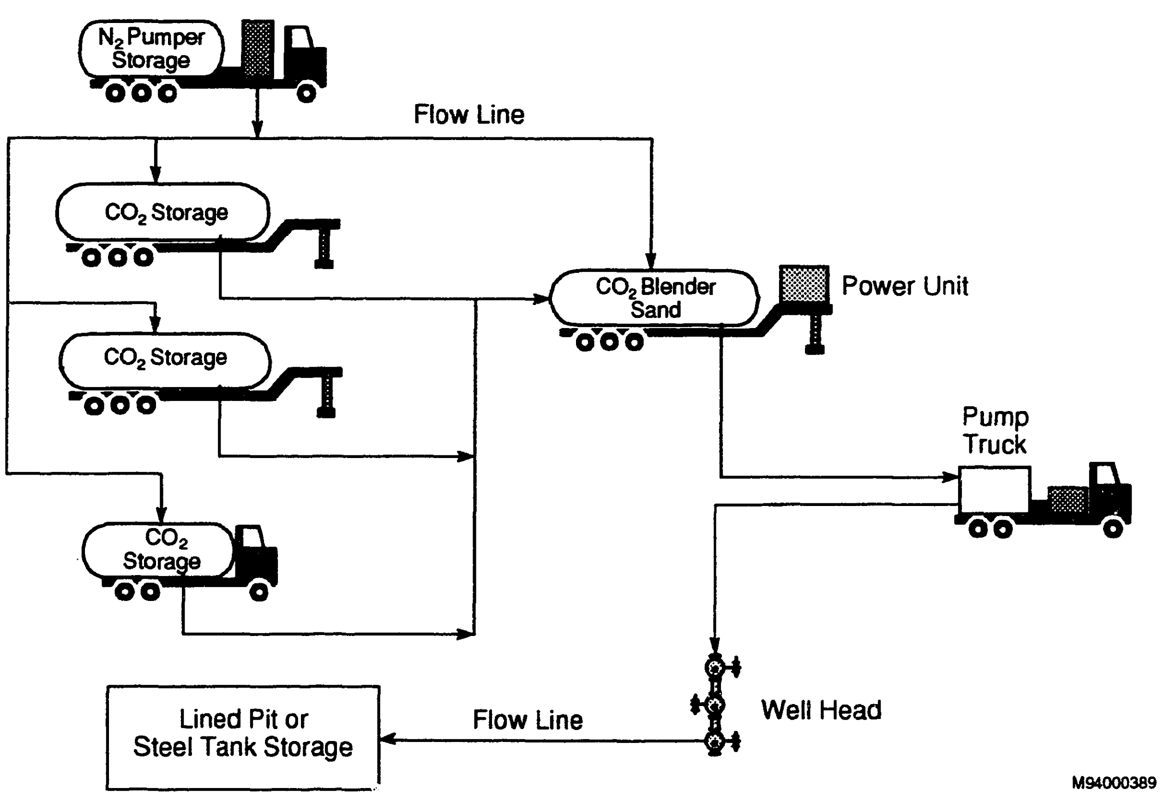

Figure 2. Liquia ◡O$_2$/Sand Stimulation Surface Layout

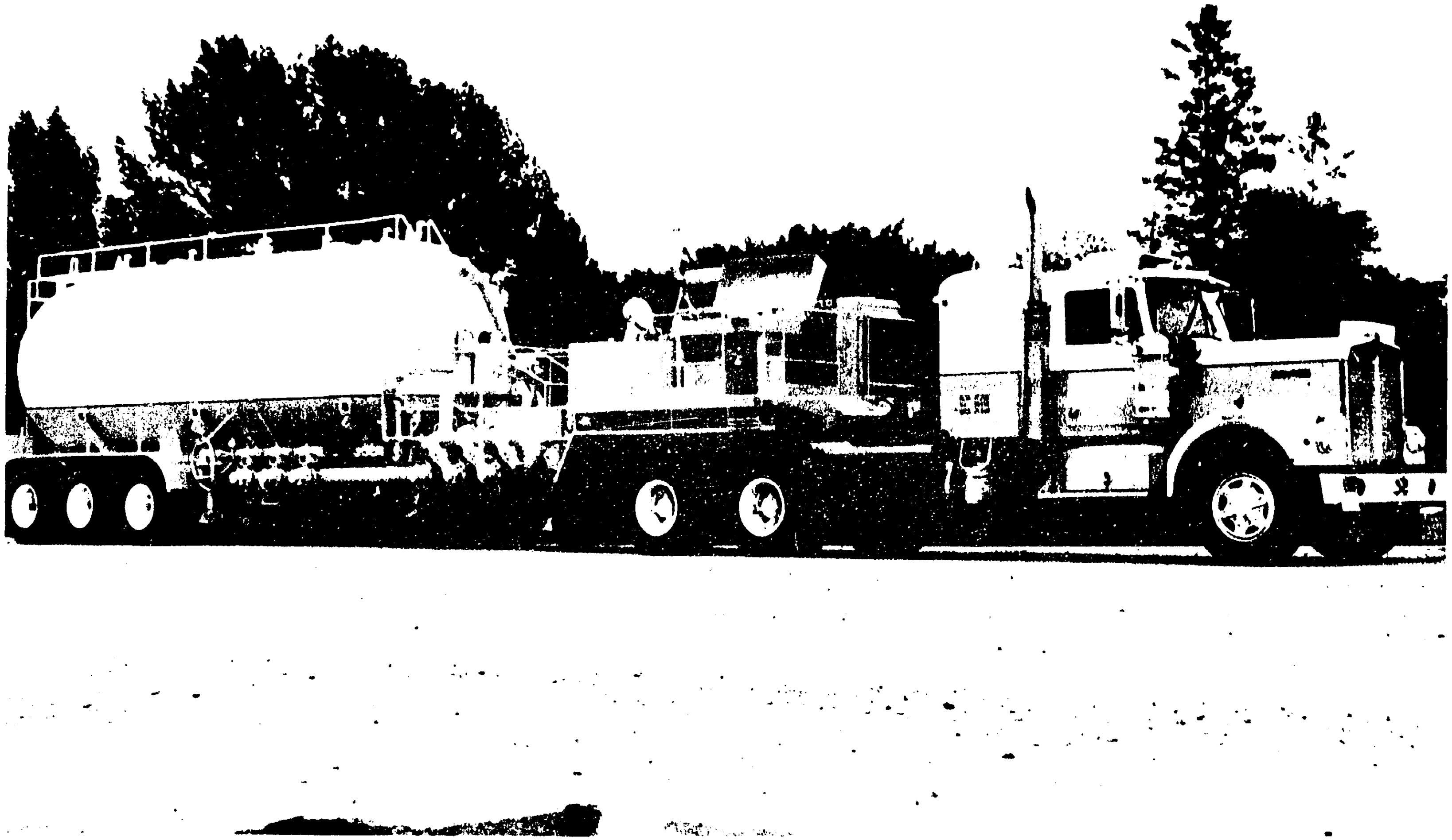

Figure 3. Liquid CO_2 Blender

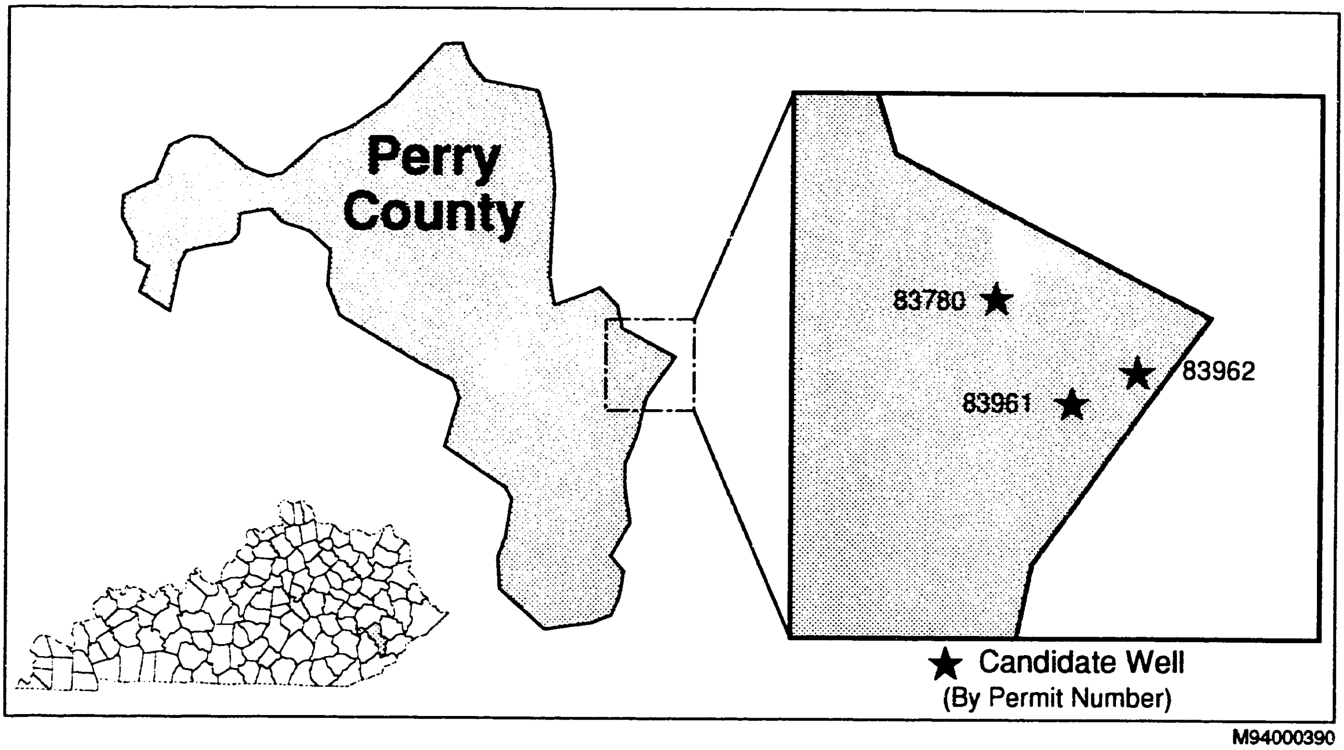

Figure 4. Location of Candidate Wells, Perry County, Kentucky

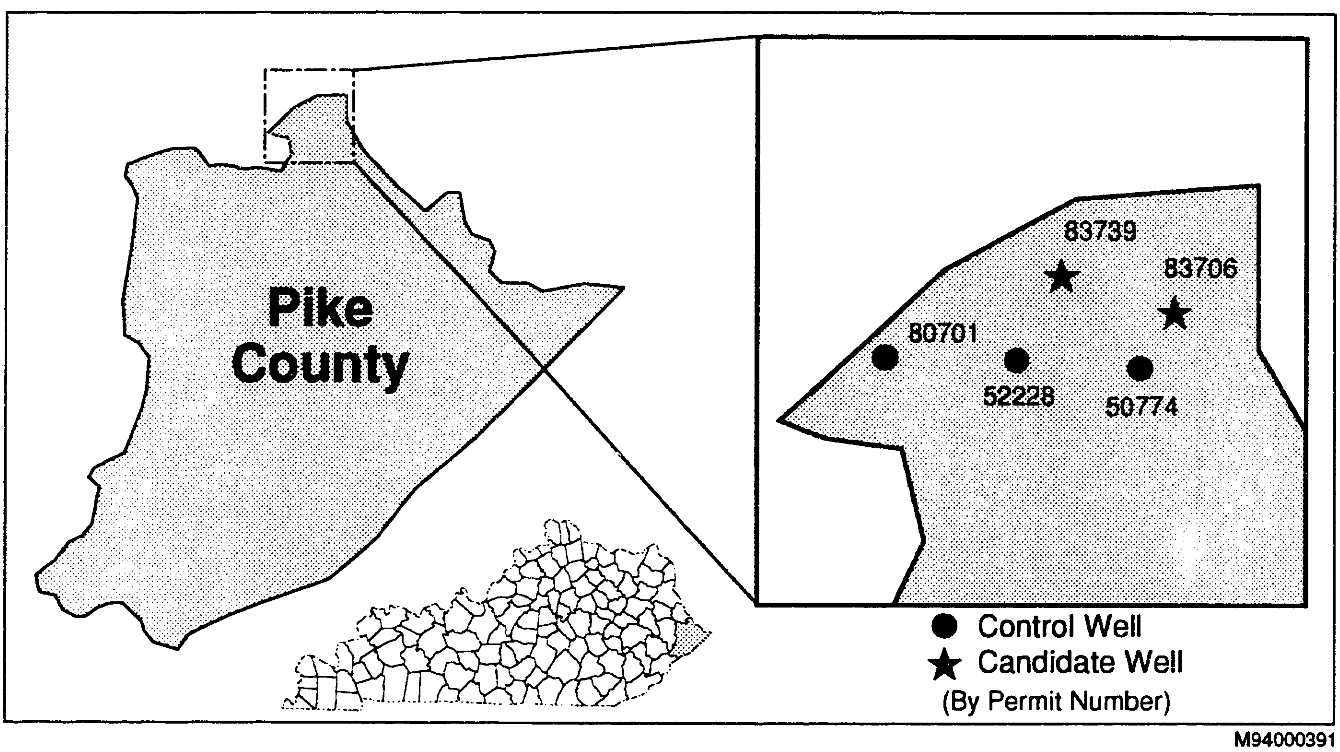

Figure 5. Location of Control/Candidate Wells, Pike County, Kentucky

Table 1. Candidate Well Stimulation Summary

Permit #:	83961	83962	83780	83706	83739
CO/ST:	Perry/KY	Perry/KY	Perry/KY	Pike/KY	Pike/KY
Completed:	01/08/93	01/10/93	01/11/93	01/14/93	01/17/93
PERFS:	19	17	18	22	18
Top:	2976	3412	3332	2984	3162
Bot:	3342	3748	3666	3248	3400
Interval:	366	336	334	264	238
Acid (Gal):	0	0	500	300	300
CO (bbls):	115	131	96	95	95
(bbls):	(120)	(160)	(120)	(120)	(120)
Pad (bbls):	240	255	106	121	135
SL (bbls):	338	463	435	419	408
Flush (bbls):	70	38	27	22	21
PMP (bbls):	648	756	568	562	564
Sand (SXS):	245	425	460	440	470
In Well:	18	23	31	10	10
Net (SXS):	227	402	429	430	460
MESH:	20/40	20/40	20/40	20/40	20/40
N_2 (MCF):	67	100	84	88	72
Rate (BPM) AVG:	42.3	44.3	35.2	43.4	33.2
Press (PSI) AVG:	2064	2804	1171	2195	3187
SND Conc (PPG) AVG:	1.9	2.6	2.8	2.9	3.1
Horsepower AVG:	2140	3045	1010	2335	2593

M94000944

Table 2. Perry County Production Summary

CO_2/Sand Stimulated Wells

Permit	STIM	(Tons)	CO_2 (SXS)	Sand MCF/MO	MO
83961	CO_2/sand	120	227	1078	4.1
83962	CO_2/sand	160	402	2118	4.1
83780	CO_2/sand	120	429	2279	4.1

M94000394

Table 3. Pike County Production Summary

Control Wells

Permit	STIM	Water BBLS	Sand (SXS)	5 MO MCF/MO
83961	Shot	0	0	518
83962	Shot	0	0	821
83780	N_2 Gas	0	0	2082

Candidate Wells

Permit	STIM	CO_2 (tons)	Sand (SXS)	MCF/MO	MO
83706	CO_2/sand	120	430	939	5.3
83739	CO_2/sand	120	460	5551	4.6

M94000470

NG-6.2 Evaluation of Target Reservoirs for Horizontal Drilling: Lower Glen Rose Formation, South Texas

CONTRACT INFORMATION

Contract Number	DE-AC21-91MC28239
Contractor	PrimeEnergy Corporation One Landmark Square Stamford, CT 06901 (203) 358-5700
Contractor Project Manager	Gery Muncey
Principal Investigators	Gery Muncey Charles E. Drimal, Jr.
METC Project Manager	Albert B. Yost II
Period of Performance	September 30, 1991 to June 30, 1994

OBJECTIVES

The primary objective of this project is to test the hypothesis that a horizontally drilled borehole can increase gas production sufficiently from the Lower Glen Rose Formation to provide an economic advantage over conventional vertical drilling. Additional objectives are to conduct detailed investigations of reservoir properties and completion methods.

BACKGROUND INFORMATION

This paper presents preliminary results of a project, co-funded by PrimeEnergy and the United States Department of Energy (DOE), to assess the economic viability of horizontal drilling in the Lower Glen Rose Formation of Maverick County, Texas. This project is part of an ongoing DOE investigation of directional drilling in the development of tight gas resources within the United States. This paper builds on data presented in Muncey (1992) with data from two vertical tests of the Lower Glen Rose Formation, both drilled in 1993, and the analysis of approximately 20 line-miles of high-resolution seismic data recorded in 1992 and 1993.

PROJECT DESCRIPTION

In June of 1992, PrimeEnergy obtained a farmout on approximately 7,680 acres (10,218 acres including "option" acreage) in Maverick County, Texas on which to drill a horizontal test well. The PrimeEnergy acreage lies on the crest of the Chittim Arch, on the northwest flank of the Chittim Field. Since its discovery in 1929, the Chittim Field has produced in excess of 50 billion cubic feet (BCF) of natural gas and approximately 200,000 barrels (BBL) of condensate from the Cretaceous-age Lower Glen Rose carbonates. Large well-to-well variances in reserves characterize the Lower Glen Rose production in the Chittim field. Ultimate reserves range from on the order of 100 million cubic feet (MMCF) to 10 BCF per well.

Analysis of available well control has shown that Lower Glen Rose gas and condensate production is primarily from porous grainstones, packstones, and boundstones associated with rudistid patch reefs. Subsurface depths of the porosity developments range from about 5,100 to about 5,700 feet within the field, depending upon structural position on the Chittim Arch. Seismic work on the PrimeEnergy acreage and adjacent leases has shown that the gross reef interval is seismically resolvable and that seismic data can be effectively used in selection of drilling locations.

Based on analysis of existing seismic data and well control, a high-resolution vibroseis seismic survey was designed and implemented to further detail Lower Glen Rose porosity distribution on the PrimeEnergy acreage. Based on this work, two wells were drilled in 1993. The first well targeted a seismic amplitude anomaly which exhibited virgin reservoir pressure and flowed gas and condensate at significant rates. However, the first well was not taken horizontal due to the possible presence of mobile water underlying the gas. The second well targeted a similar seismic anomaly but encountered a non-commercial reservoir and was abandoned. Based on data obtained from the two wells the reservoir model was revised. A third vertical test of the Lower Glen Rose is planned for February of 1994. Data from the third vertical well will determine whether another attempt will be made to drill a Lower Glen Rose horizontal well in this project area.

RESULTS

Geologic Setting

The study area, shown in Figure 1, lies in the east-central Maverick Basin in Maverick County, Texas. The Maverick Basin lies in the northwest end of the Rio Grande embayment where the Lower Cretaceous sedimentary rocks, primarily carbonates, accumulated in a rapidly subsiding basinal area (Rose, 1984).

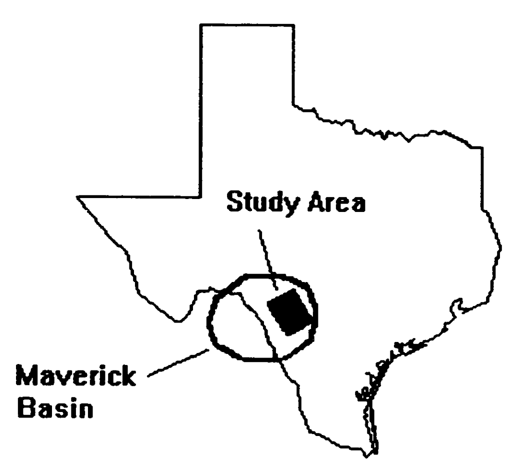

Figure 1. Study area location

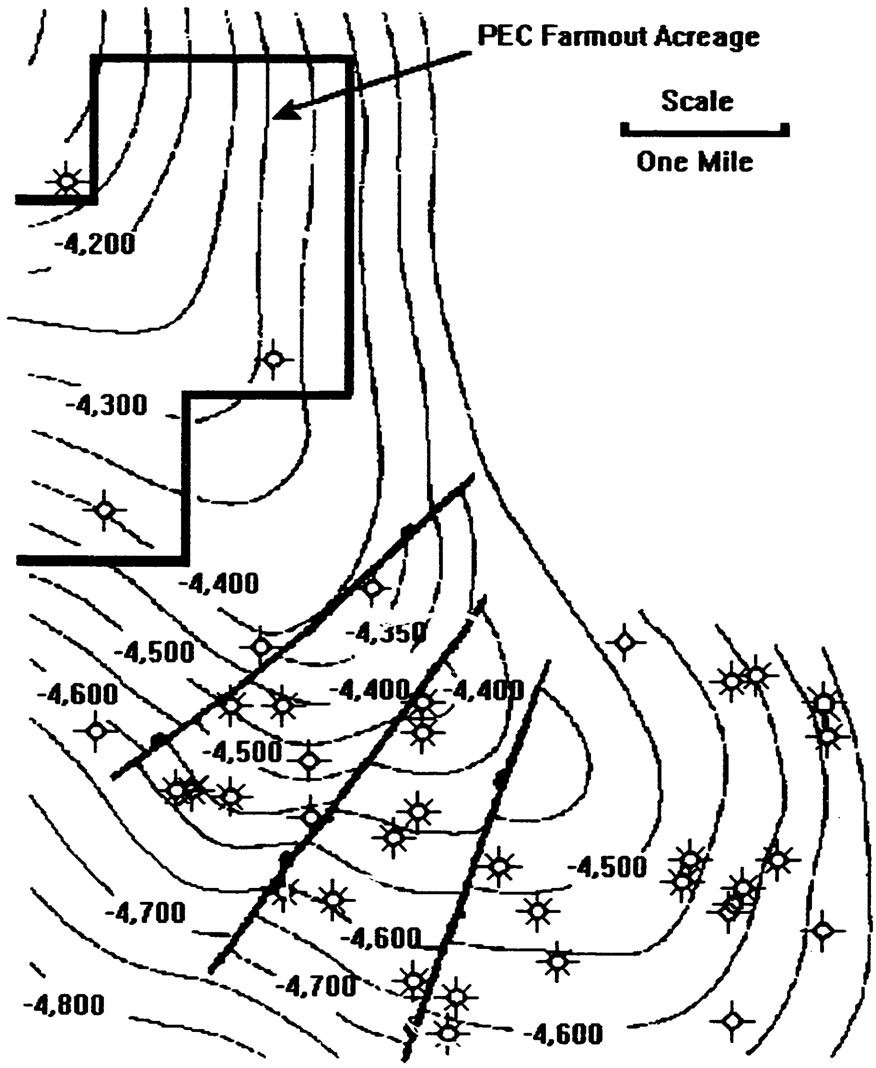

Figure 2. Structure on a Lower Glen Rose marker bed. Geology after Robert Scott, 1992.

The stratigraphy of the Lower Glen Rose in the study area is characterized by a middle shelf carbonate facies assemblage (see Wilson and Jordan, 1983 and Petta, 1977). The target reservoir is composed primarily of grainstones, packstones and boundstones which were deposited within or proximal to a mid-shelf patch reef. The porosity is complexly distributed and may be comprised of a variety of carbonate depositional facies (e.g., reef core, channels, bars, beaches) related to the presence of the patch reefs. Well control suggests that the primary allochems in the patch reef facies assemblage are rudistids, stromatoporoids and algae. Much of the original porosity has been lost to diagenetic processes with the remaining porosity greatest in the grainstones. Major porosity types are primary interparticle and secondary moldic which are locally enhanced by tectonic fracturing.

Structural geology of the Maverick Basin is char-

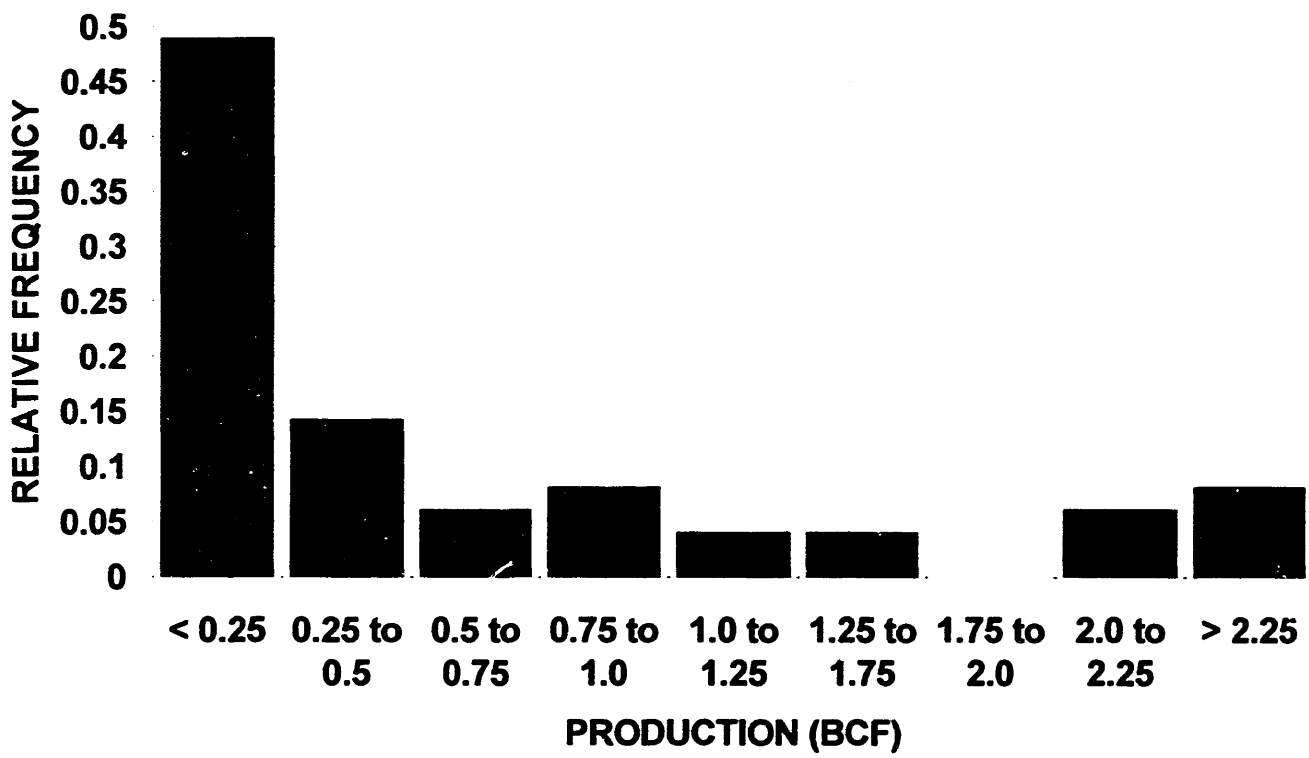

Figure 3. Histogram of Lower Glen Rose Formation ultimate gas recovery.

acterized by Laramide-age, long, open asymmetric anticlines with southeast plunge. One of these is the Chittim Arch which exhibits in excess of 1,000 feet of vertical relief on the Buda Limestone. It is comprised of approximately 448 square miles or approximately 287,000 acres of uplifted area, and is one of the largest surface anticlines in the state of Texas (Bunn, J., 1960). Miocene-age antithetic and synthetic faults with primarily northeast trends and local fracturing with northeast and northwest trends are also present in the study area. However, local seismic control suggests that faulting is significantly more common at depths shallower than the Lower Glen Rose.

Figure 2 illustrates the structure on a Lower Glen Rose marker bed in the study area. Also shown in Figure 2 is the eastern portion of the PrimeEnergy acreage which is located on the sparsely-drilled northwestern flank of the Chittim Field. Many of the 58 some-odd wells which have penetrated at least to the Lower Glen Rose reef interval are shown on this map. Also visible in Figure 2 is the broad, open geometry of the Chittim Arch.

Local well and seismic control suggest that, within the Chittim field, the Lower Glen Rose reef interval produces from a combination stratigraphic-structural trap where a belt of reef-related porosity and permeability intersects with the Chittim Arch structural high.

Reservoir Engineering and Economics

Production data were available for study for 49 wells which tested the Lower Glen Rose Formation in the study area. The results of that analysis are shown in the histogram of projected ultimate recoveries presented in Figure 3. Figure 3 shows that almost 50% of the wells drilled to date will recover less than 250 MMCF of gas. This group also includes 17 wells which were "dry" and abandoned. At least one of the early dry holes probably would have been capable of sustained commercial gas production by today's standards but was abandoned due to a lack of a gas market in the late 1920s and early 1930s.

Economic modeling suggests that at a cost of approximately $325,000 (drilling and completion costs only), a vertical well would have to cum on the order of 0.75 BCF to be considered economic. When seismic costs are included in the analysis, the minimum reserves number becomes even larger. Figure 3 shows that almost 70% of the 49-well population will cum less than the 0.75 BCF minimum. Economic modeling also shows that, with average yield rates of about 0.004 BBLS/MCF, condensate production is relatively unimportant to the drilling economics.

These factors suggest that the economics of vertical drilling in the Lower Glen Rose of the study area has been marginal at best. However, about 15% of the 49-well population have produced over 2 BCF per well, and among those wells, ultimate recoveries range from a minimum of approximately 2.2 BCF to a maximum of approximately 10 BCF. This potential for large reserves, combined with the directionally anisotropic porosity and permeability of the Lower Glen Rose, suggest that this area may be an appropriate one in which to apply directional drilling techniques.

Seismic Results

Over time, local operators have noted that commercial Lower Glen Rose gas production is correlated with a particular seismic amplitude anomaly. This amplitude anomaly is a "couplet" comprised of an onset trough with a following peak; both of which exhibit anomolously large amplitudes relative to adjacent traces, thus giving the appearance of a "bright spot" in stacked multi-fold seismic data. These amplitude anomalies may persist for two or more miles along a given seismic profile; however, lengths of less than 2,000 feet are more typical.

Studies of existing well and seismic control suggest that these amplitude anomalies are the seismic response to the gross Lower Glen Rose reef interval and that, where the anomaly is absent, it is unlikely that the reservoir facies would be present. In order to investigate its acreage for similar seismic anomalies, PrimeEnergy acquired a grid of approximately 20 line-miles of high-resolution vibroseis seismic data during 1992 and 1993.

A portion of an east-west oriented seismic section (Line 92-2) is presented in Figure 4. The data are 2D 30-fold vibroseis which have been migrated prior to stacking. No automatic gain control (AGC) was applied to the data. Surface-consistent trace balancing was applied to preserve relative amplitudes. Two examples of the characteristic seismic anomaly can be seen in Figure 4 at a two-way travel time of about 0.820 to 0.835 seconds. Also shown in Figure 4 are the locations of the PrimeEnergy No. 1-84 development well and the planned third vertical Lower Glen Rose test, the PrimeEnergy No. 2-84.

During analysis of the seismic profiles, an apparent subtle increase in the Lower Glen Rose interval transit time was noted in the vicinity of many of the amplitude anomalies. This apparent thickening was interpreted to indicate (1) local thickening related to the presence of a patch reef, and/or (2) a local velocity anomaly related to the presence of the relatively low-velocity reef complex. The porous rocks of the reef complex are known to have (compressional wave) velocities on the order of 15,000 to 16,000 feet per second whereas the surrounding,

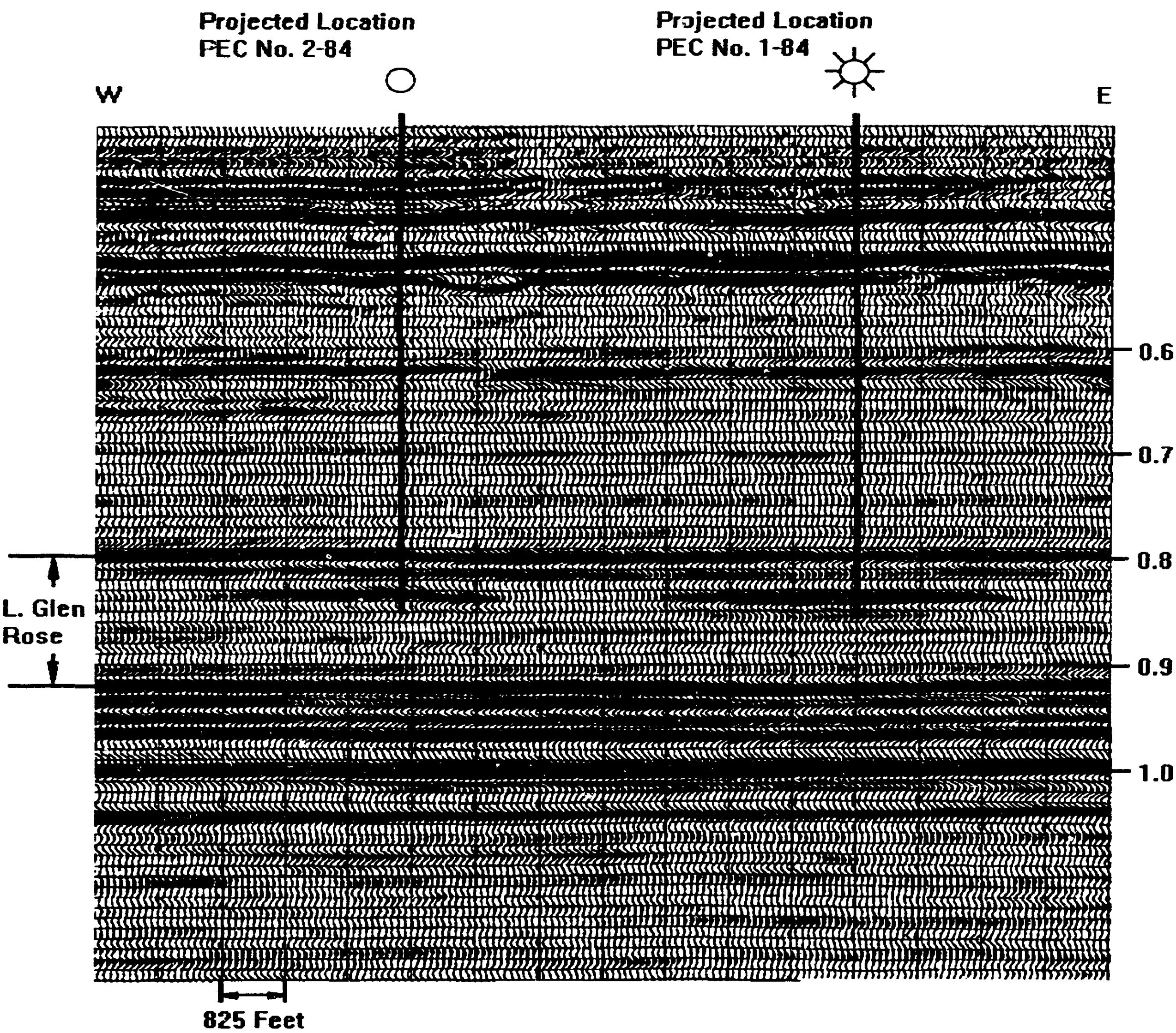

Figure 4. Seismic data for a portion of Line 92-2. Vertical axis equals two-way travel time in seconds.

relatively non-porous, wackestone facies typically exhibits velocities on the order of 20,000 feet per second.

Figure 5 presents a map of the Lower Glen Rose interval transit time (isochron). The Lower Glen Rose interval mapped in Figure 5 can be seen in cross-section in Figures 4 and 10. Also shown in Figure 5 are the PrimeEnergy acreage block and seismic grid, and relevant well control in the vicinity of PrimeEnergy's acreage. Locations of seismic sections discussed in this report (lines 92-2 and 93-1) are also shown in Figure 5. Local occurrences of the characteristic amplitude anomalies are indicated in Figure 5 by shading along the seismic traverses. Note the close correspondence of the amplitude anomalies and local thickening of the Lower Glen Rose isochron.

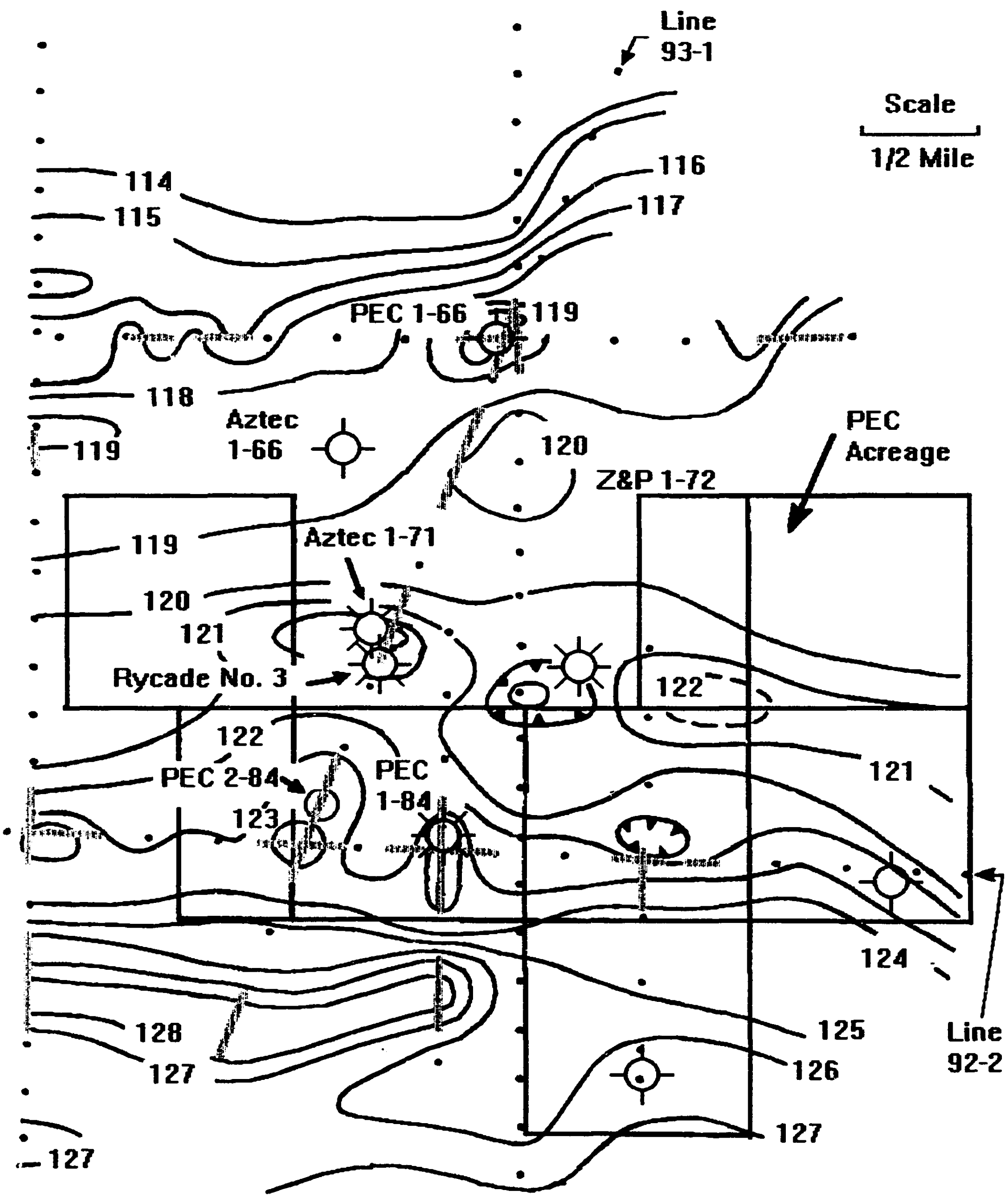

Figure 5. Isochron map of the Lower Glen Rose Formation. Shaded portions of seismic lines show positions of amplitude anomalies. Contour interval = 1 millisecond.

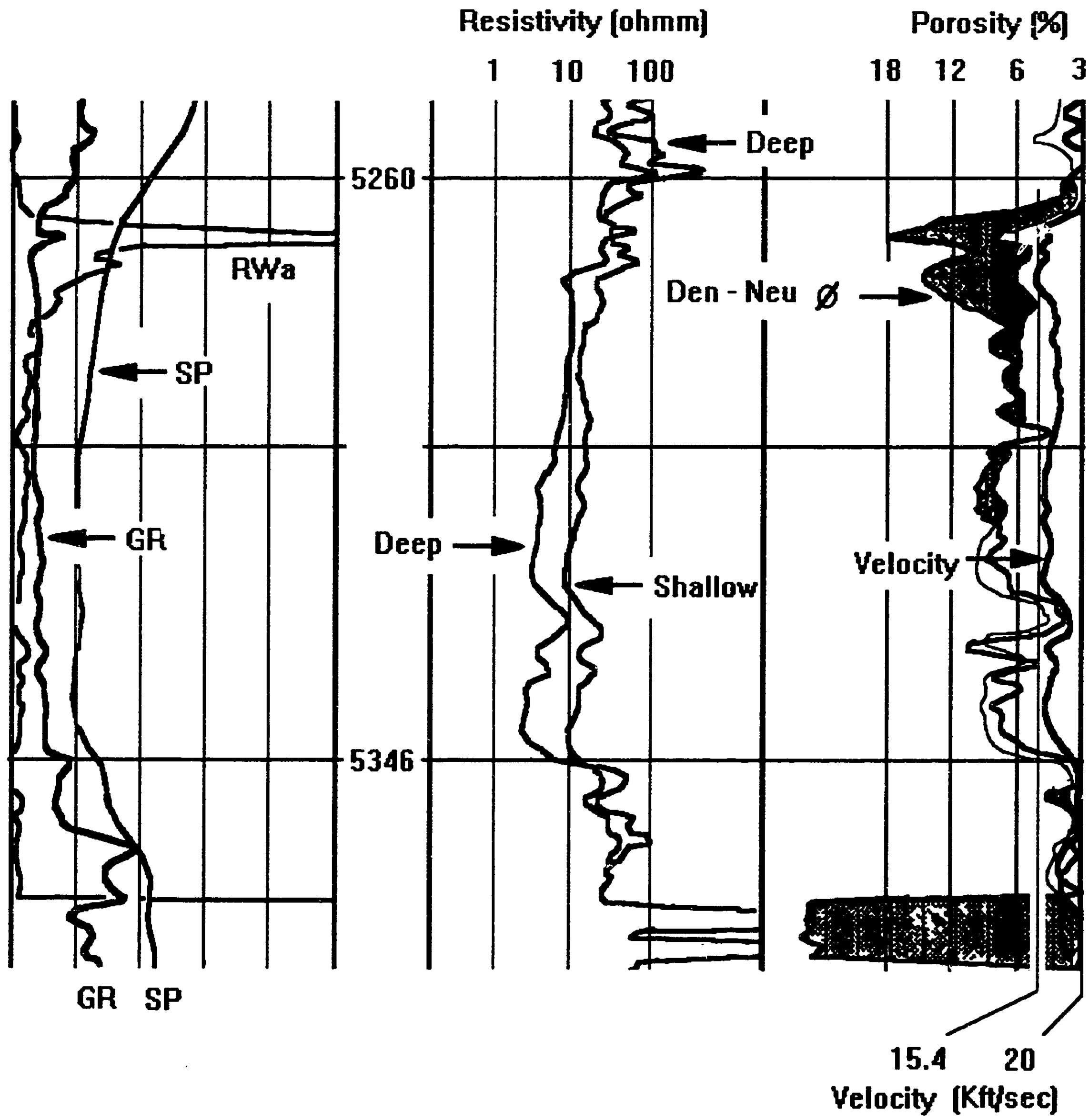

Figure 6. Gamma ray (GR), self potential (SP), apparent water resistivity (RWa), induction resistivity, neutron-density porosity, and long spaced sonic (velocity); PrimeEnergy La Paloma No. 1-84. Neutron-density gas effect (crossover) is indicated by shading. Lower Glen Rose reef interval is between 5,260 feet and 5,346 feet.

Figure 5 suggests a depositional strike ranging from east-northeast in the northern map area to east-southeast in the central and southern map area. The east-southeast trend is expressed by a belt of isochron maxima which trends approximately parallel to seismic line 92-2. Note also the apparent north-northeast (cross-strike) trend of isochron maxima which parallels seismic line 93-1 which may indicate the syn-depositional influence of tectonic activity along the nearby Texas Lineament (see Wood, 1980 and Rose, 1984).

Drilling Results

Based on the strong correlation of the seismic amplitude anomalies and isochron maxima with commercial gas production, two development wells were drilled by PrimeEnergy during 1993. The La Paloma No. 1-84 well was drilled in January of 1993 and was a commercial success. This well was intended to be the project test well. However, due to concerns regarding the mobility of the gas-water contact, plans to take the borehole horizontal were abandoned and the 1-84 well was completed as a vertical producer to obtain additional reservoir data. Plans were then made to drill a substitute well in which DOE would have the option, subject to log and core analysis, to join PrimeEnergy in drilling a horizontal borehole.

Logs from the 1-84 well are presented in Figure 6. The log suite is comprised of SP, gamma ray, apparent water resistivity (RWa), induction resistivity, density porosity, neutron porosity, and sonic velocity logs. In this well the gross reef interval is approximately 86 feet thick. The pay section is indicated by density-neutron crossover and by marked elevation in porosity and RWa values. The combined log suite suggests a clean limestone with considerable vertical heterogeneity. Note also the indicated decrease in velocity associated with the gross reef interval.

A saturation profile is presented for the 1-84 well in Figure 7. Porosity, derived from cross-plotting density and neutron porosity estimates, is shown on the left. Calculated water saturations are presented on the right. Based on this analysis, the 1-84 well is interpreted to have between 11 and 16 feet of net pay. This analysis suggests peak porosity of about 12% and an average porosity of approximately 8%. Calculated water saturations range from less than 10% up to 100%. The preferred interpretation is 16 feet of net pay, the base of which is picked at 60% water saturation based on empirical observations of gas production rates and water saturations throughout the Chittim field.

The 1-84 well is the first well in the field in which an attempt was made to whole-core the pay section. One hundred and twenty one feet of magnetically oriented core was cut in the gross reef section, from 5,261 to 5,382 feet, of which 86 feet was recovered. All of the lost core was from below the pay zone, approximately in the middle of the gross reef section, from a depth of 5,290 feet to 5,325 feet.

Petrographic analysis of the core confirmed the patch reef porosity model. The gross reef section is composed primarily of interbedded grainstones, packstones and boundstones. The pay zone is composed primarily of grainstones and packstones and has a fossil assemblage dominated by rudistids, stromatoporoids, and algae, some of which are in growth position. Specimens of caprinid, monopleurid, requienid, and hippuritid rudists were observed in the cores. Lesser amounts of other molluscs, foraminifera, and rare echinoderms were also present in the pay zone but become relatively more abundant toward the base of and below the gross reef section.

Analysis of the core shows porosities which range from 7% to 15% and permeabilities which range from approximately 0.01 millidarcies to 7.0 millidarcies. Average core permeability measured less than 1.0

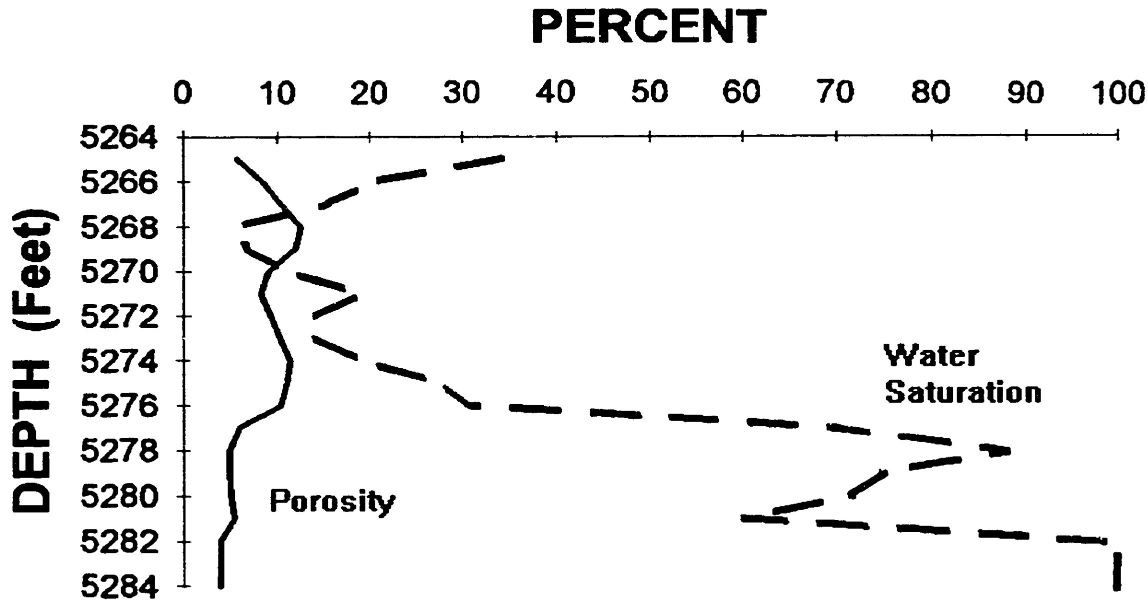

Figure 7. Calculated saturation profile and crossplotted porosity, PrimeEnergy La Paloma No. 1-84

millidarcy and average porosity is estimated to be in the 7% to 8% range.

A detailed fracture analysis was also performed on the core. A total of 304 fractures were noted in the cored interval. A rose diagram of the fracture strike azimuth is presented in Figure 8. A histogram of fracture dip angle is presented in Figure 9.

Two sets of extensional fractures and their conjugate shears can be seen in Figure 8. What is interesting is that only about 15% (44 of 304) of the total measured fractures are of the high-angle variety, the rest being low-angle bedding plane/flexural-slip fractures. Furthermore, virtually all open high-angle fractures are oriented in a direction parallel to the anticlinal axis or parallel to its conjugate shear direction. A zone of open high-angle fractures is present within and below the pay section, between subsurface depths of 5,271 feet and 5,279 feet.

During the six months ended September, 1993, the 1-84 well produced approximately 100 MMCF of gas and 750 BBL of condensate. The 1-84 well is currently producing at the rate of about 1,050 MCF and 7 BBL of condensate per day. In late September, 1993, the 1-84 well was shut in for a 72-hour pressure build-up test. This test showed that the reservoir pressure had declined only about 2%. From this new information gas reserves for the 1-84 well are estimated at approximately 3.0 BCF. An effective permeability of 8.8 millidarcies was also calcu-

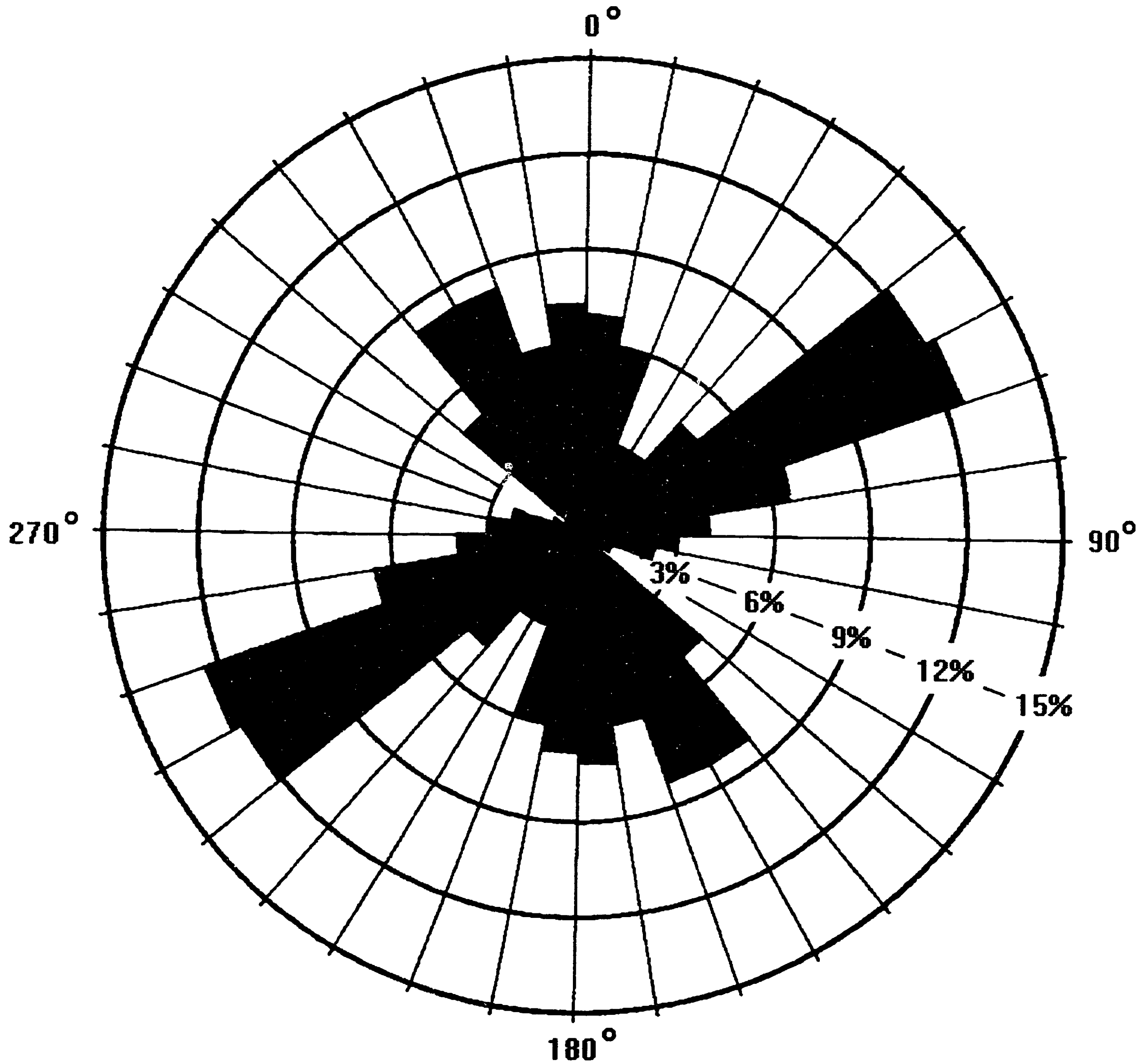

Figure 8. Rose diagram of fracture strike with respect to true north for 304 fractures measured at the PrimeEnergy LaPaloma No. 1-84.

lated from the pressure build-up data. This is significant as the core data suggested an average permeability of less than 1.0 millidarcy.

At the 1-84 location, well log and whole core data show that the Lower Glen Rose reefing was successfully delineated by the seismic data and that

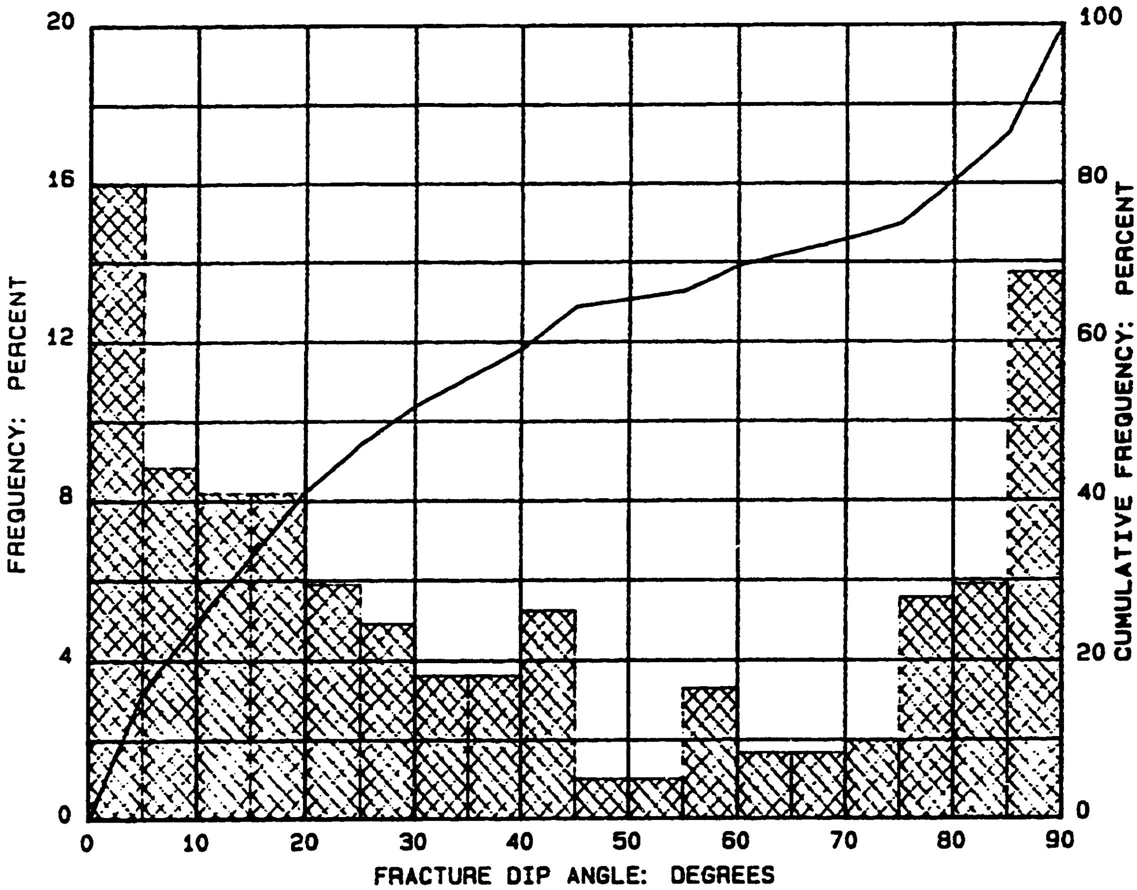

Figure 9. Histogram of fracture dip for 304 fractures measured at the PrimeEnergy La Paloma No. 1-84. Bar graph = relative frequency. Curve = cumulative relative frequency.

significant porosity is associated with that reefing. Subsequent analysis of well log, whole core, and production data suggests that, in the 1-84 well at least, concerns regarding a mobile gas-water contact were unfounded. Additionally, the importance of fracture porosity (i.e., the existence of a dual porosity system) is suggested by (1) the presence of open fractures in the pay zone, and (2) significant differences in core-measured permeability and effective permeability calculated from the pressure buildup data. This well is interpreted to lie within the main belt of Lower Glen Rose reef development in the project area.

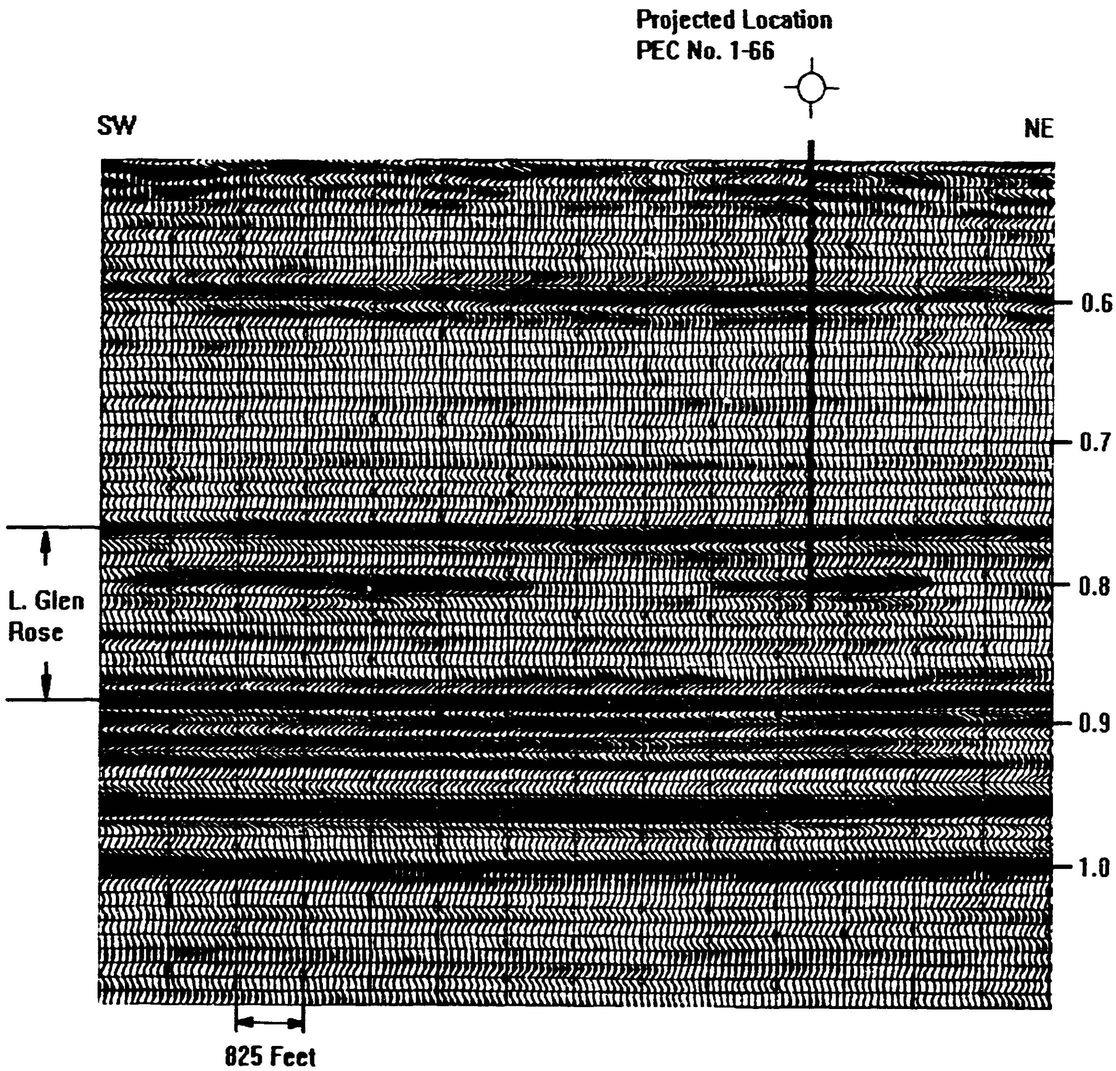

Figure 10. Seismic data for a portion of Line 93-1. Vertical axis equals two-way travel time in seconds.

Based on the success of the 1-84 well, a step-out location with similar seismic (isochron and amplitude) anomalies was selected. In June of 1993, PrimeEnergy drilled the La Paloma No. 1-66 well. A segment of a seismic line over the 1-66 location is shown in Figure 10. The 1-66 well location can be seen with respect to the 1-84 well in Figure 5.

This well was also designed so that it could be taken horizontal upon mutual consent of PrimeEnergy and DOE. Unfortunately, the 1-66 well tested non-commercial and was plugged and aban-

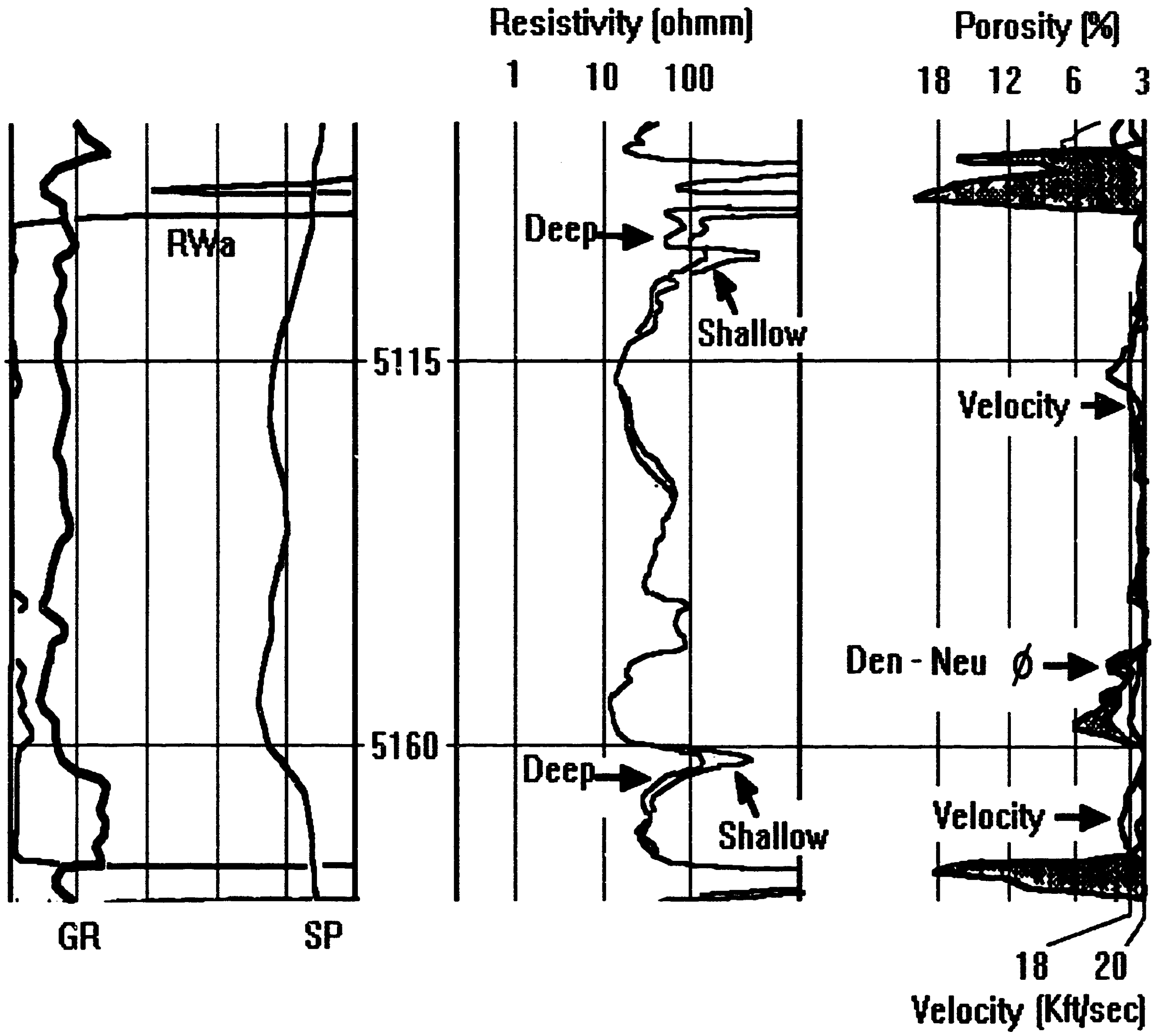

Figure 11. Gamma ray (GR), self potential (SP), apparent water resistivity (RWa), induction resistivity, density-neutron porosity, and long-spaced sonic (velocity) logs, PrimeEnergy La Paloma No. 1-66. Lower Glen Rose reef interval is between 5,115 feet and 5,160 feet.

doned. Logs from the 1-66 well are presented in Figure 11. Rotary-sidewall cores, rather than whole core, were taken in the 1-66 well. Petrographic study of the rotary-sidewall core samples indicates that the Lower Glen Rose reef interval in the 1-66 well is composed primarily of skeletal wackestones and mudstones. The highest porosity measured, about 6%, is associated with a minor occurrence of packstone at the base of the reef interval (just above 5,160 feet). Note also the much less significant velocity contrast between the reef interval and the encasing carbonates as compared to the 1-84 well.

Well log and rotary sidewall core data also show that, at the 1-66 location, the Lower Glen Rose reef interval is significantly thinned and that the reefing suggested by seismic data lacked sufficient porosity and permeability to constitute a viable reservoir. Based on the 1-66 well's result, it is speculated that the seismic amplitude anomaly tested by the 1-66 well may have been caused by or contributed to by a "tuning effect" due to thinning of the gross reef interval rather than by the actual presence of reef-related porosity. However, the tuning effect hypothesis has not yet been tested by modeling and so must be considered speculative. This well is interpreted to be in a landward ("back reef") position relative to the main trend of Lower Glen Rose reefing in the project area.

PrimeEnergy's seismic work and the 1-66 well result, suggest that much of the northern portion of the 7,680-acre farmout is non-prospective in the Lower Glen Rose reef interval. Based on this revised reservoir model PrimeEnergy elected to drop 3,200 acres, leaving its current Chittim Field acreage position at 4,480 acres as shown in Figure 5.

FUTURE PLANS

PrimeEnergy plans to drill a third vertical development well to the Lower Glen Rose in February of 1994. The PrimeEnergy 2-84 well will be located approximately 3,000 feet west-northwest of the 1-84 well. The 2-84 well will test the amplitude anomaly located due west of the 1-84 well on seismic line 92-2 (see Figures 4 and 5). Information from this third well and from the continued refinement of the seismic porosity-recognition technique will determine whether another attempt will be made to drill a Lower Glen Rose horizontal well in this project area.

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