SESSION 1

NATURAL GAS RESEARCH

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ABSTRACT

The Natural Gas Research program is focused on geologically complex resources that have low permeability and production mechanisms which are not understood. The thrust of research focuses on maximizing supply from marginally productive (existing fields) and geologically complex resources (eastern/western). It is also developing the knowledge base to develop new supplies for the future from speculative resources (gas hydrates, deep and subducted sediments, overthrust regions, and covered sediments). The program goal is to increase confidence in future gas supplies. The objective is to establish guidelines for a strategy of resource development based on least costs for the produced gas.

In the eastern resources, emphasis is on the research to define the extent of fractured reservoirs (where and how they vary) and in technology tests to verify well stimulation concepts that could prolong the life of marginal productive wells producing multiple strata. This includes establishing a test site for multiple completion research at a location where shales, sands, and coalbeds exist. A technology development program is underway to increase performance and cut costs for drilling horizontal wells.

In the western resources, emphasis is on the documentation of what was learned at the multiwell site and extrapolation of the results to other similar basins. New thrusts to advance the state of knowledge include a two-step approach to drill and evaluate a slant hole as an effective recovery concept for both the lenticular sands and coalbeds that coexist in as the tight strata of the Piceance Basin. Supporting research on drilling and formation diagnostics would provide the necessary confidence for acceptance by industry.

In the speculative resources, one initiative is to acquire in situ data in cooperation with industry in an area where hydrates are known to exist. The hydrate formation at the site would be cored and stimulated in an attempt to recover the gas. A second thrust looks at the detection of hydrate deposits offshore using seismic surveys. A third activity is on the verification that deep source rocks exist under shallower reservoirs, and that a pathway can exist for the migration of deep source gas to the shallower sedimentary reservoir. New activities are being considered to increase knowledge of overthrust

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regions and covered sediments along the Atlantic coast to determine their attractiveness as exploration targets in the future.

Complementing these activities is an investigation to increase the ultimate natural gas recovery from water driven gas fields that are primarily depleted or approaching depletion. In addition, research is emphasizing the conversion of natural gas to liquids, so that the production from wells in disadvantaged locations can become a new way of doing business.

In summary, research needs now should be based on a strategy for gas development that combines sands, shales, and coalbeds, as appropriate, to reduce the risks of achieving a noneconomic well. The application of recovery concepts like lateral well drilling would serve to increase the profitability. This includes marginally productive sands as likely targets for research as well wherein the secondary recovery of gas becomes likely. Then, program emphasis would be broadened to include all eastern and western formations, and more speculative resources, such as hydrates and deep formations, as the likely sources for future gas supplies. Coupled with this, a research is needed with the principal goal to enhance the value of all gas produced by economically converting this gas to a liquid fuel and/or to a chemical intermediate.

TECHNICAL CHALLENGES AND OPPORTUNITIES IN METHANE CONVERSION

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Methane or natural gas is in tremendous excess world wide with proven reserves of more than 3500 trillion cubic feet. Up to two-thirds of these reserves are located in remote areas where an economic transportation system does not exist for bringing the gas to market. While the rewards for converting this methane to more easily transportable liquids are clearly great, many technical challenges remain for gas conversion to be economically practiced on a world-wide scale. Methane is a refractory molecule and so high energy input is required to break the C-H bond and form products. As a result, the gas conversion process must be carefully controlled because the products are often much more reactive than methane. The challenge of methane conversion is therefore to achieve both high methane conversion and high selectivity to desirable products. A number of possible routes for methane conversion will be discussed, including oxidative coupling, direct oxidation to methanol, synthesis-gas based routes, and pyrolysis. The successful process will undoubtedly combine imaginative chemistry with creative engineering to handle the "demanding" reactions.

SECONDARY NATURAL GAS RECOVERY: TARGETED TECHNOLOGY APPLICATIONS FOR INFIELD RESERVE GROWTH

1. <u>CONTRACT NUMBER</u>: DE-FG21-88MC25031

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   CONTRACT PERIOD OF PERFORMANCE: September 1, 1988 to August 30, 1991

2. <u>SCHEDULE/MILESTONES</u>:

Program Schedule

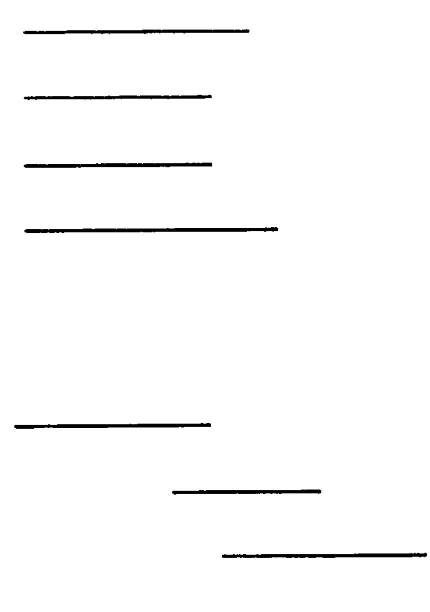
1988 | 1989
S O N D | J F M A M J J A

Task 1.0 Methodology for Choosing Study Areas (Sandstones)

- Evaluation of Operator Activity
- Initial Simulator Configuration
- Initial Field Screening
- Refined Field Screening

Task 2.0 Untapped Compartments: Integrated Characterization of Candidate Reservoirs (Sandstones)

- Geological Characterization
- Development of Cross Section Frameworks
- Mapping of Target Reservoirs
- Engineering Characterization



1988 | 1989
S O N D | J F M A M J J A

Task 3.0 Formation Evaluation for Bypassed Gas Zones

Geological Support for Formation Evaluation

Sample Analysis for Shaly Sandstone Evaluation

Task 4.0 Interwell Extrapolation and Related Deeper Pools

Subregional Stratigraphic Analysis

Field-Scale Analysis of Deeper Play Components

3. OBJECTIVES:

Reserve growth from existing reservoirs is a major source of oil reserve additions. Therefore, it is appropriate to determine the potential for incremental natural gas recovery using new approaches to reservoir characterization. In the last 10 years, characterization of the internal geometry of reservoirs, mainly oil reservoirs, has demonstrated a higher degree of compartmentalization than previously recognized. This compartmentalization is primarily a function of depositional system and, secondarily, of the structural and diagenetic history of the reservoir after deposition. Where significant geologic variation occurs, untapped or bypassed reservoir compartments remain to be drained of natural gas by drilling or recompleting strategically placed development wells. Deeper pool potential, which is closely related to producing depositional systems, can be better defined by sequence stratigraphy and also offers opportunities for increased reserves. It is the objective of this project to define and demonstrate the potential for incremental gas recovery, or gas reserve growth potential, within existing nonassociated gas fields.

Approaches to defining the distribution of unrecovered resources by depositional system and methods for maximizing their recovery will be developed and tested as part of the Secondary Gas Recovery (SGR) Project. This project, a joint effort of the Gas Research Institute (GRI), the U.S. Department of Energy (DOE), and the State of Texas, will focus specifically on Texas natural gas reservoirs as a major subset of the Nation's natural gas resource base.

Results of this project will better enable producers to economically recover this discovered but undeveloped natural gas resource through integrated geological, engineering, petrophysical, and geophysical assessments. Depositional systems studies of major gas reservoirs in South Texas have already indicated the complexity of fluvial-deltaic reservoirs in the Frio Formation; thus, Frio reservoirs will be a likely first target for improved recovery in the first half of the SGR project. A second target is likely to include heterogeneous carbonate reservoirs either in East Texas or in the Permian Basin of West Texas. Geological, engineering, and geophysical data will be integrated to provide models of reservoir continuity and pressure distribution in representative reservoirs in these gas plays.

4. BACKGROUND STATEMENT:

This study will involve delineation of gas resources in untapped compartments, of bypassed reservoirs in existing wells, and of closely related deeper pool targets. The latter target will be defined with more extensive use of seismic sequence analysis as a predictive tool. The project will be field oriented and will involve cooperative data collection with operators drilling current development wells as a cost-effective means of acquiring data and performing interim tests of research results. In this way the eventual users of the project technology are involved in its development. Knowledge gained from the cooperative wells will be used to design Staged Field Experiment (SFE) wells that are specifically drilled for research purposes, to confirm or challenge research progress on the largest scale, and to test novel applications of newly developed technologies.

Duration of the Secondary Natural Gas Recovery project will be 3 years divided into two periods. Cooperative data collection early in each of the two periods will define sites for the research wells. The initial 18 months will focus on sandstone reservoirs, culminating with the drilling of an SFE well and analysis of results. Next, a carbonate reservoir will be selected, and the special requirements of advanced production technologies in that reservoir lithology will be investigated within an 18-month period.

5. PROJECT DESCRIPTION:

BYPASSED RESERVOIRS

Initial emphasis of the project will be on bypassed gas in sandstone reservoirs. Where contemporaneous subsidence and deposition of fluvial-deltaic reservoirs has taken place, 30 (or more) vertically stacked reservoirs have been deposited. Not all of these have been fully drained, particularly those in which sand-rich depositional axes are separated by floodplain mudstones and poorly interconnected crevasse splay deposits. Operators have taken advantage of recompletions in many such fields using selected cased-hole logs.

For this SGR project, an advanced cased-hole logging suite will be applied in conjunction with geological modeling designed to fully characterize the interwell area. This modeling will better define the interconnection of producing facies and incorporate engineering assessments of pressure histories, production decline rates, and other key parameters. With the drilling of new wells to deeper targets in the field being studied, open-hole pressure data can be collected to help assess the potential for recompletions in older wells. Core will be recovered for analysis of diagenetic heterogeneities and for calibration of open-hole and cased-hole logs. The overall result will be a fully integrated reservoir analysis that can be used to define the distribution of bypassed gas. Initiating the program with study of bypassed reservoirs and working in an interval with abundant well control will complement the main emphasis of the study, that of untapped compartments.

Untapped Compartments

Depositionally heterogeneous reservoirs are likely to have untapped compartments where wells have been sited largely on the basis of geographic-spacing rules rather than on geologic variation. Because this phenomenon has been increasingly demonstrated in oil reservoirs, a key question for this SGR study is whether natural gas, having lower viscosity than oil, is subject to similar incomplete recovery due to reservoir heterogeneity. We believe that heterogeneity within the 320- to 640-acre spacing typical of gas reservoirs with conventional permeability allows for untapped and incompletely drained compartments in selected depositional systems.

Data and interpretations made during the initial investigation of bypassed gas will be used in developing reservoir models necessary for targeting untapped compartments. Defining component facies from abundant well data within gas-bearing depositional systems containing bypassed gas is a key first step in assessing (1) the degree of continuity of reservoir types between wells, (2) the relationship between reservoir size and the expected area of gas drainage, given specific reservoir quality parameters, and (3) the likelihood that undetected heterogeneities are affecting gas production. These heterogeneities, if sufficient barriers to flow, lead to untapped compartments within reservoirs that can be predicted using geological, engineering, and geophysical approaches at the facies, reservoir, and field scale.

Deeper Pool Potential

This project will investigate the deeper pool development potential of gas resources in deeper reservoirs that are closely related in depositional system to currently productive shallower reservoirs. Development of deeper pool potential emphasizes vertical reservoir sequences below producing intervals in related depositional systems. Entirely different depositional systems involve more of an element of deeper pool exploration that is not a significant focus of this research program. The deeper pool potential being considered here is therefore termed "related deeper pool" resource potential. In many fields, few wells have penetrated the deeper parts of producing depositional sequences below well-established limits of gas production. A sounder basis for predicting related deeper pools will help maximize recovery from known natural gas fields.

6. RESULTS/ACCOMPLISHMENTS:

GEOLOGICAL INVESTIGATIONS

The results to date, within the first 6 months of the project, focused on geological and engineering screening of potential areas of study, operator contacts and monitoring of drilling and permitting activity in the areas of interest, configuration of engineering tools and testing approaches, and use of existing data to further refine approaches to shaly sandstone reservoir evaluation. With the initial focus on sandstones, operator activity reports and personal contacts with operators active in South Texas were utilized to determine planned activity in the Frio fluvial-deltaic play along the Vicksburg Flexure and in the Vicksburg deltaic sandstones of the Rio Grande Embayment. These two plays essentially overlap, with the Vicksburg reservoirs lying below and partially transitional with the overlying Frio. The Frio fluvial deltaic play ranks third in cumulative production (11.8 Tcf through 1986) and the Vicksburg deltaic play ranks fifteenth in cumulative production (3.5 Tcf through 1986) among 72 established gas plays in Texas. Because of their known heterogeneity, both lateral and vertical, these reservoirs are particularly suited to the SGR project.

Field Screening and Operator Activity

Discussions have been held with five operators active in South Texas, and written project descriptions have been placed with two others. Two operators are considering project participation in the near term, one during drilling of a deeper pool test in the Frio in Seeligson field and another during conventional development drilling in the Vicksburg in McAllen Ranch field. The Frio test will pass through a series of some 20 productive sands that will be examined for bypassed gas potential. Seeligson and McAllen Ranch are among more than a dozen fields that were evaluated in the screening process.

McAllen Ranch Field, Hidalgo County

McAllen Ranch field was discovered in 1960 when the Shell A. A. McAllen No. 1 well was completed as a gas producer. Shell initiated a successful development program in which 14 wells were drilled (no dry holes) from late 1960 through 1963. More than 130 wells have been drilled in the field to date, with production from 33 Vicksburg reservoirs. Six wells were completed in 1988.

A growth-fault-related anticline characterizes the McAllen Ranch field area. Structure in the upper Vicksburg is relatively simple, with an anticlinal nose formed on the downthrown side of a major growth fault. Middle and lower Vicksburg faults form elongate closures within the field, and dip-reversal becomes more pronounced with depth.

The lower Vicksburg in McAllen Ranch field includes several sandstone intervals up to 1,000 ft thick displaying upward-coarsening log patterns. A net sandstone isopach map of the uppermost sandstone section of the lower Vicksburg shows a dip-elongate depositional axis and general lobate pattern that suggest distributary and channel-mouth bar deposition. Detailed studies of individual sandstones in McAllen Ranch field have identified one or more distributary-channel systems that terminate in the area, resulting in well-to-well heterogeneity. The middle Vicksburg also contains several upward-coarsening sandstone sequences up to 400 ft thick.

The complex structural configuration, particularly in the lower Vicksburg, provides numerous fault closures and structural traps. Stratigraphic traps occur where facies changes result in permeability barriers and reservoir compartmentalization. The entire Vicksburg section has abnormal fluid pressures.

McAllen Ranch field has produced more than 770 Bcf of gas from 33 Vicksburg reservoirs ranging in depth from 7,000 to 15,000 ft. Fourteen reservoirs have produced more than 10 Bcf each; the largest producer is the McAllen Ranch Vicksburg S, S reservoir with cumulative production of more than 124 Bcf.

Porosity and permeability data from McAllen Ranch field indicate low reservoir quality. The majority of whole-core samples show permeabilities less than 1 md; only a small percentage have permeabilities greater than 10 md. Porosities range from about 16 to 25 percent. Because of the generally poor reservoir quality, fracture stimulation techniques are used in about half of the completions; however, reservoirs often flow 1 to several million cfd of gas prior to fracture treatment.

Seeligson Field, Jim Wells and Kleberg Counties

Seeligson field is located in Jim Wells and Kleberg Counties, about 5 mi north of the town of Premont, Texas. Seeligson field covers approximately 50 mi^2, and was discovered in 1937 when the Magnolia A. A. Seeligson No. 7 was drilled to a depth of 8,141 ft, at which point hydrocarbons were encountered in non-unit Zone 22-5. More than 1,000 wells have since been drilled in the field, and cumulative production exceeds 2.5 Tcf.

Seeligson field is located along the eastern margin of the extensive Vicksburg Fault Zone. The field is bounded updip by a large northeast-southwest trending growth fault that offsets Frio sands several hundred feet. The eastern, downdip boundary of the field is defined by the limits of production. Within the field, subsidiary highs occur on the primary rollover anticline that defines the structural configuration of the field.

Over 130 Frio and Vicksburg reservoirs have been documented across Seeligson field. These multiple, vertically stacked, dominantly fluvial sandstones exhibit varying degrees of complexity. Although each zone is generally less than 100 ft thick, the majority are composite intervals of several genetic cycles. Aggregate sandstone patterns illustrate dominantly dip-parallel depositional trends generally indicative of fluvial environments. The interbedded sandstones and shales reflect the diversity of environments of deposition within each zone.

Seeligson field has produced approximately 2.5 Tcf of gas from 131 Vicksburg and Frio reservoirs ranging in depth from 4,000 to 8,500 ft; 27 reservoirs have produced more than 10 Bcf each. Most of the gas is trapped on the crest of the rollover anticlinal structures associated with the major Vicksburg growth fault, although the contribution of stratigraphic controls (sand-body pinch-outs or facies changes) is substantial in terms of macroscopic heterogeneity.

Reservoir quality in Frio sandstones within Seeligson field is expected to be good. Whole-core analyses indicate porosities of 19 to 27 percent and permeabilities from 60 to 1,100 md in point bar and crevasse splay sandstones. Reservoir stimulation techniques are generally limited to acidizing. Recompletions with pressures 1,000 psi above average reservoir pressure show compartmentalization of fluvial splay sandstones.

ENGINEERING INVESTIGATIONS

The identification of reservoir compartmentalization and selection of optimum infill drilling sites based on engineering criteria is a process involving several steps. First, available field pressure and production data are analyzed for evidence of compartmentalization. This is accomplished using P/Z versus cumulative production type curves. The deviation of actual P/Z behavior from the ideal straight line behavior is an indicator of compartmentalization. With these type curves, certain physical properties of the drained and undrained compartments, and the barrier itself, can be quantified.

The engineering assessment of a reservoir, or field, is being integrated with the geological evaluation to generate a refined interpretation. Then, hypotheses for the reservoir configuration, developed to that point, will be confirmed through transient pressure well testing in the field.

Initial Simulator Configuration

Two reservoir simulators were configured to address natural gas reservoirs exhibiting the heterogeneous depositional character typical of those in the onshore Gulf Coast Basin. Boast II, a three-dimensional, three-phase simulator will be used in the more complex, larger scale studies while a fully implicit, Newton-Raphson model will be used in the smaller scale, one- or two-dimensional investigations. Whereas much has been written on characterizing heterogeneous reservoirs and generating input data for simulation studies, little research has addressed simulation techniques for these reservoirs. How one represents a heterogeneity in permeability in the discretized format of a simulator can greatly influence the results of the simulation.

An important element in these simulations is the manner in which a well is represented in the simulator. A representation was evolved to be consistent with the gas reservoir systems to be studied. As most gas wells are operated at a constant flowing bottomhole pressure, rather than a constant volumetric rate, it is critical to have the same capabilities in any simulators that will be used. Unfortunately, most of the common well representation techniques described in the literature are not applicable to the more complex grid systems that will be used in modeling these heterogeneous reservoirs. Thus, more intricate schemes were investigated and implemented in the simulators.

Demonstration of Simulation and Well Testing

Using the previously configured Newton-Raphson reservoir simulator, various example studies were conducted to construct materials which can be used to demonstrate to industry operators how undrained compartments can be identified using certain analytical techniques. This involved configuring a "typical" reservoir and constructing sample P/Z curves to illustrate the anticipated behavior. These simulations also provide type curves which will be used with field data to identify compartmentalization.

Background and Analytical Model

To provide insight into the effect of specific reservoir parameters on P/Z plots and to guide the design of these simulations of compartmentalization, an analytical model was formulated. This model is a linear reservoir partitioned into two compartments, having pore volumes V_1 and V_2, by a plane low-permeability barrier of thickness L and permeability K_b (figure 1). Only Volume No. 1 is drained by a well, this having constant rate q_s (scf).

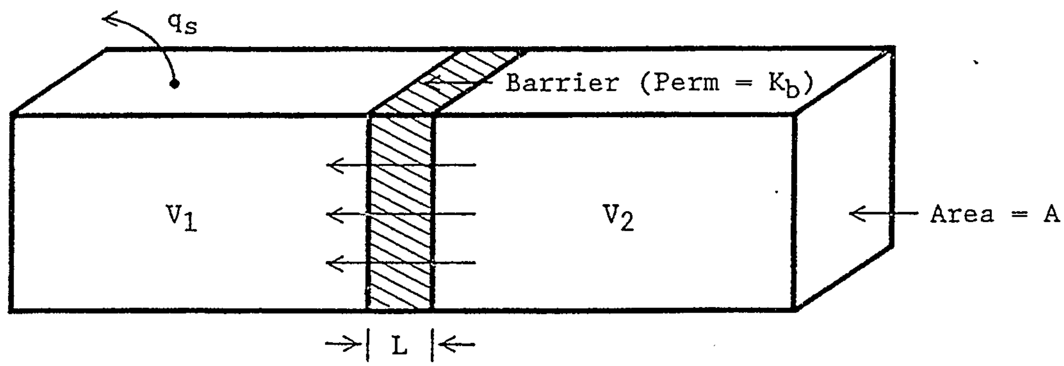


Figure 1

Differential equations constructed using the conservation of mass of gas for each chamber, with the real-gas equation-of-state and Darcy's law for flow through the barrier, yield a solution for static P/Z versus time at the well in the drained compartment. This analytical solution treats gas viscosity, μ_i, and compressibility, C_i, as constant at their initial values, indicated by the subscript i.

With this analytical solution, it is shown that P/Z versus cumulative production, $q_s t$, appears as in the figure below (figure 2).

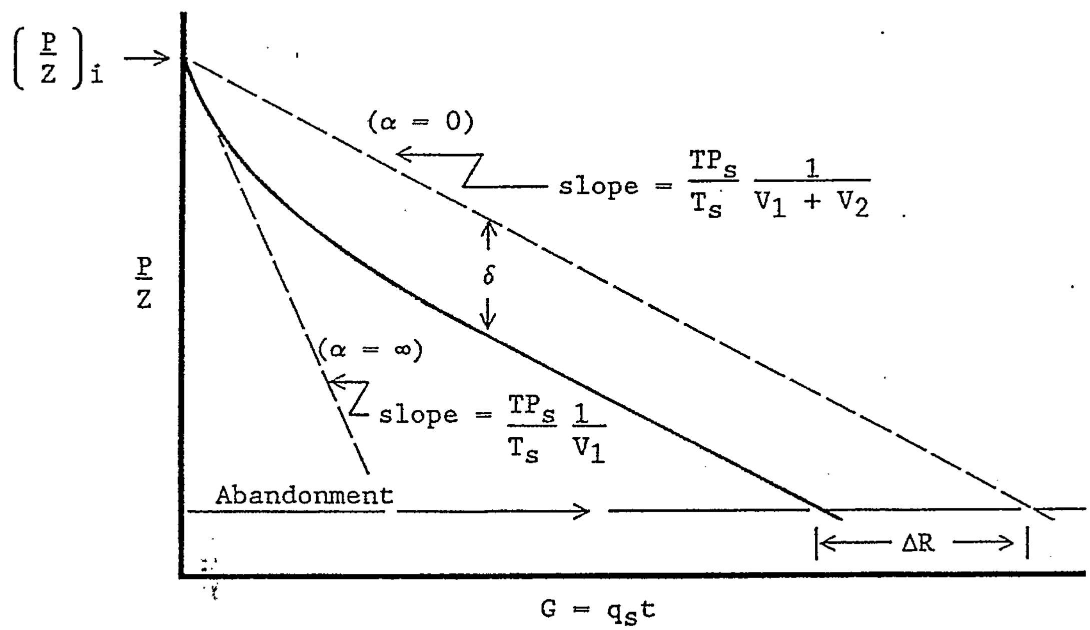


Figure 2

This curve is characterized by two dimensionless groups given by

$$\alpha = \frac{q_s \mu_i C_i L \, TP_s}{K_b A \, T_s} \quad \text{and} \quad \beta = \frac{V_1}{V_2}$$

Here the upper dotted line is the solution that exists for no barrier, $\alpha = 0$, having slope inversely proportional to $V_1 + V_2$ while the lower dotted line is the solution for an impermeable barrier, $\alpha = \infty$, having slope inversely proportional to V_1. This solution shows that the actual ultimate recovery is reduced below that with no barrier by an amount

$$\Delta R = \frac{q_s \mu C L V_2^2}{K_b A (V_1 + V_2)}$$

Thus, the more the well is drawn down (higher q_s) the lower is the ultimate recovery. This also corresponds to a downward displacement of the straight line portion of the graph by an amount δ proportional to $\alpha/(\beta + 1)^2$. Therefore, it was anticipated that the two slopes and δ might be determinable from plots of field data and these could be used to determine parameters of a compartmentalized reservoir. However, the simulation studies described below demonstrated that this might not always be possible.

Simulation Studies of Compartmentalization

The Newton-Raphson simulator described above was configured for the same systems in the analytical study, but the compartments had finite permeability K, and the pore volume of the barrier was included. Also, μ and C were proper functions of pressure everywhere. Typical solutions are exhibited as a family of curves in which the dimensionless group α is the varied parameter (figure 3). These results reveal that under certain configurations the curves produce the anticipated shape and are readily analyzable.

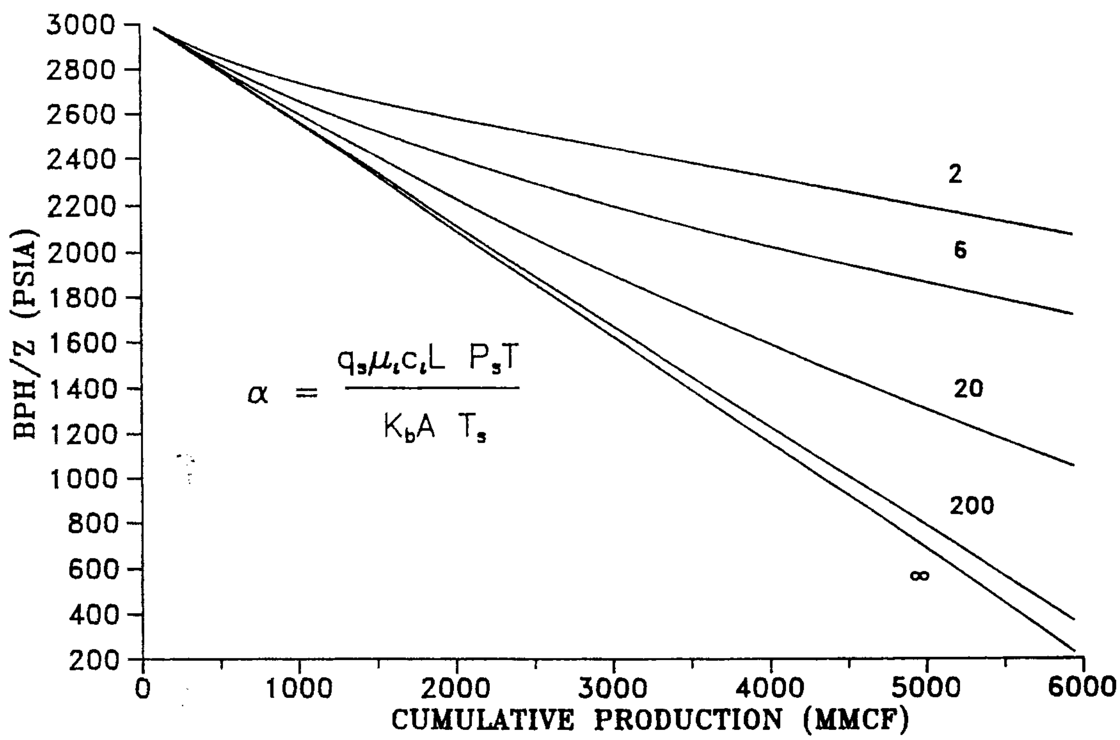


Figure 3. Effect of Alpha on P/Z Curve (BETA = 1/3).

However, under other conditions the approach to the asymptotic straight line discussed above may not occur until very late in the production life of the well. Consequently, early well history could not be exploited in the manner outlined above. Thus, efforts are in progress to develop supplemental analyses of other aspects of production data to complement this type of analysis.

In order to reduce this P/Z curve analysis to a practical format, the generation of families of type curves has been undertaken. These are dimensionless P/Z versus cumulative production curves for various values of the dimensionless parameters α, β, and γ where γ is K_b/K. It is to be noted that for a sufficiently small value of γ, (high reservoir permeability), these graphs are essentially independent of γ. These graphs can then be used with field data to determine V_1, V_2, and K_bA/L for a well.

At this time the simulator is essentially complete and a schedule of computer runs is being designed to provide answers to practical questions about well testing.

Field Studies and Screening

Initial engineering studies were conducted on Stratton field in Nueces, Kleberg, and Jim Wells Counties and on McAllen Ranch field in Hidalgo County, Texas. Stratton field includes Frio fluvial-deltaic reservoirs generally similar to those of Seeligson field described above. Owing to the complex nature of both fields and the large amount of data associated with each, it was first necessary to develop some unique engineering techniques that would aid in characterizing the reservoir production quality. Methods were developed that provide a "quick-look" at the production decline character of a well and the pressure decline history within a reservoir. The techniques allow for qualitative observations regarding historical production and provide much insight into reservoirs exhibiting possible compartmentalization. These techniques were applied to both fields, and several reservoirs were identified as candidates for further investigation.

FORMATION EVALUATION AND PETROPHYSICAL INVESTIGATIONS

New interpretation strategies using recently introduced state-of-the-art logging tools will be pursued for evaluating reservoirs within 5 ft of the borehole. Emphasis will be placed on integrating all available field and well data with cased hole logging data for a unique view of the reservoir. In addition, several evolving technologies will be pursued for imaging the reservoir at distances greater than 5 ft from the cased borehole. These technologies include borehole gravity surveys and through-casing resistivity measurements. Formation evaluation using accurate consistent near borehole and far well bore through casing is the research objective.

In addition to the cased-hole formation evaluation, a study will be undertaken to determine the contribution of neighboring shales to gas reserves. Although the industry has made significant progress in understanding and modeling shaly sandstone reservoirs using formation evaluation, there are still some major problems. For example; in log analysis it is common to assume that the fractional shale volume associated with sand in a shaly sandstone bed carries with it an associated fractional porosity that is the same as that found in adjacent shale beds. Further, it is usually presumed that the shale pore volume contains only immobile water, that it cannot contain free gas regardless of how the shale is distributed in the sand (laminar, dispersed, or detrital), and regardless of the capillary pressure level in the sandstone body. As a result, in shaly sandstone gas reservoirs, in place and recoverable gas may be significantly higher than would normally be estimated using traditional shaly sandstone evaluation methods. The objective of the combined core and log analysis study is to provide the basis for a new model for evaluating the shaly sands that properly recognizes the type of shale distribution in the sandstone and reflects the shale properties found in adjacent shales.

In the absence of key data collected in open hole, cased-hole logging technologies are the most economic option for additional data acquisition in existing fields. Cased-hole logging programs will be tailored around pulsed neutron logs, full waveform acoustic logs, and spectral gamma-ray logs. Certain borehole and near-borehole environments (such as low-porosity and low-salinity conditions) force existing cased-hole tools beyond their accuracy limits. In these cases, better use of full waveform acoustic technology for through casing porosity determination, a new method for resistivity measurements for through casing saturation determination and borehole gravity survey technologies, will be critical.

7. FUTURE WORK:

Project work is now moving from preliminary field screening, both geological and engineering, to refined field screening during which further detailed reservoir data will be collected from company files and during cooperative well studies with operators. The focus of initial data collection will be on bypassed reservoirs during deeper pool tests. By working in a data-rich environment, multiple reservoirs can be examined for their geometry and for continuity of natural gas flow between wells, with the result that untapped compartments can be more effectively defined. Completion records, production histories and current reservoir pressures collected in cooperative wells will be utilized. Results will define the degree of macroscopic (between-well) heterogeneity that acts to restrict flow of natural gas between wells in fluvial-deltaic settings. In addition, full suites of open-hole logs will be calibrated against cased-hole logs and vertical seismic profiling (VSP) will be used to image between-well reservoir volumes.

The first cooperative well program is expected to be carried out in Seeligson field, South Texas. There, Mobil Exploration & Producing U.S. Inc. will be drilling two deeper pool tests approximately 3,000 ft apart in a heretofore underdeveloped part of the field where new seismic lines have recently been run. A cooperative program including coring, logging, extensive formation pressure testing, and VSP work has been proposed. Initial work in one well will be closely followed by a second well that will provide an opportunity to examine pressure continuity across the intervening distance, and possibly in relation to surrounding producing wells. Most of the reservoirs being tested are part of a unit operated by Sun Exploration and Production Co., which is also cooperating in the SGR project. All these activities are aimed at screening potential locations for a future research well, as outlined in the project plan, as well as conducting specific project tasks.

8. REFERENCE:

Kosters, E. C., and others, in preparation, Atlas of major Texas gas reservoirs: The University of Texas at Austin, Bureau of Economic Geology Special Publication.

THE GEOPRESSURED-GEOTHERMAL RESEARCH PROGRAM: AN OVERVIEW

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NATURE OF THE RESOURCE:

The geopressured-geothermal resource consists of deeply buried reservoirs of hot brine, under abnormally high pressures, that contain dissolved methane. Geopressured brine reservoirs with pressures approaching the lithostatic load are known to occur both onshore and offshore beneath the Gulf of Mexico coast, along the Pacific west coast, in Appalachia, as well as in deep sedimentary basins elsewhere in the United States. The Department of Energy (DOE) has concentrated its research on the northern Gulf of Mexico sedimentary basin (Figure 1) which consists largely of Tertiary interbedded sandstones and shales deposited in alternating deltaic, fluvial, and marine environments. Thorsen (1964) and Norwood and Holland (1974) describe three generalized depositional facies in sedimentary beds of the Gulf Coast Geosyncline (Figure 2):

- a massive sandstone facies in which sandstone constitutes 50 percent or more of the sedimentary volume.
- an alternating sandstone and shale facies in which sandstone constitutes 15 to 35 percent of the sedimentary volume.

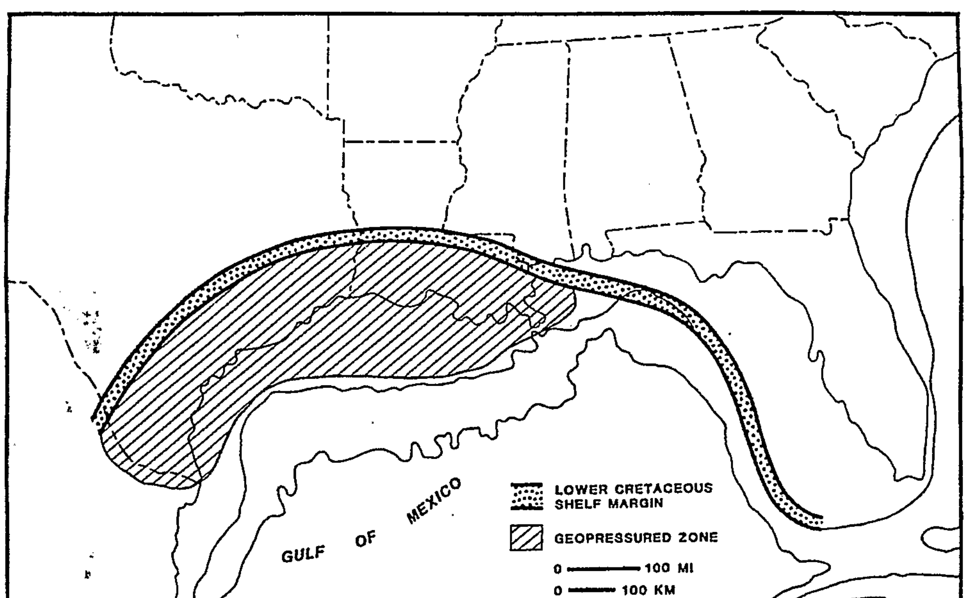

Figure 1. Subsurface Lower Cretaceous Shelf Margin And Geopressured Zone In The Northern Gulf Of Mexico Basin (From Bebout et al 1982).

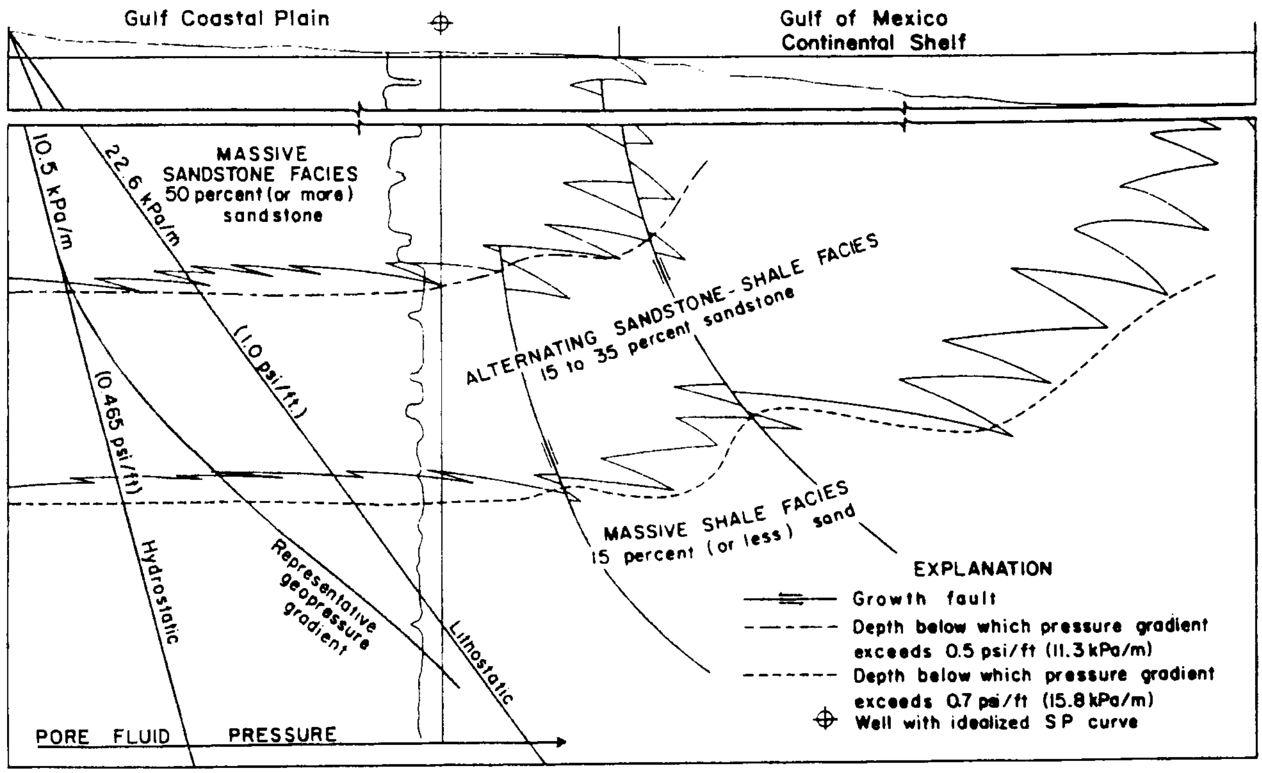

Figure 2. Generalized Sedimentary Model Of The Northern Gulf Of Mexico Basin, Based On Percentage Sandstone And Showing, Diagrammatically, The Relation Of Gross Lithology To Fluid-Pressure Gradient And Growth Faulting (From Wallace et al 1978).

- a massive shale facies in which sandstone constitutes 15 percent or less of the sedimentary volume.

In general, at any given location the volume of sandstone decreases with increasing depth. The datum of higher-than-normal fluid pressures is associated with the alternating sandstone and shale facies and the massive shale facies. Faulting and salt tectonics have complicated the depositional patterns and influenced the distribution of geopressured reservoirs (Wallace et al 1978).

The sandstones in the alternating sandstone and shale facies have the greatest potential for geopressured-geothermal energy development. Due to the insulating effect of surrounding shales, temperatures of the geopressured-geothermal brines typically range from 250°F to over 350°F, and under prevailing temperature, pressure, and salinity conditions, the brine contains 20 or more cubic feet of methane per barrel. Wallace et al (1978) estimated the geopressured-geothermal energy in Gulf Coast sandstone pore fluids to a depth of 22,500 feet to be 5,700 TCF of methane and 11,000 quads of thermal energy.

GEOPRESSURED-GEOTHERMAL RESEARCH PROGRAM GOAL AND OBJECTIVES:

Since its inception in 1975, the goal of DOE's Geopressured-Geothermal Research Program has been to provide a technology base sufficient for industry to make rational investment decisions about the economic use of the resource. Recently, the goal was amended with a quantitative objective based on the cost of power: improve the technology for producing energy from the geopressured-geothermal resource at a cost equivalent to 6 to 10 cents/kWh by 1995. This compares with a current cost estimated at about 30 cents/kWh (Negus-deWys et al 1989). The goal has served as the planning focus throughout the course of the Program.

At present, program objectives are being pursued under four research categories: resource analysis, brine production, energy conversion, and support operations. The objective of resource analysis is to improve the understanding of how geopressured reservoirs behave over extended periods by decreasing uncertainty in reservoir performance. This will enable predictions of reservoir performance with 90% confidence over a ten-year operating period. Research under this objective is focusing principally on determining reservoir-drive mechanisms. The objectives of brine production are to prove the long-term injectability of large volumes of spent brine at multiple sites and to minimize fluid production operating expenses. Long-term, large-volume injection has been shown to be feasible at two well sites. Under energy conversion, the objective is to improve methods for extracting commercially-useful energy from geopressured fluid. A small (1-MWe) power plant will soon be tested at a well site to evaluate a hybrid power system. Under support operations, the objectives are to determine the environmental acceptability of production and disposal of geopressured fluids and to develop the technology for automated operation of geopressured production facilities. All design well sites are monitored periodically for signs of accelerated subsidence, abnormal seismicity, and ground-water contamination.

PAST ACTIVITIES AND RESULTS:

The strategy adopted by DOE to achieve the goal and objectives involves testing geopressured reservoirs via "wells of opportunity" and "design wells." This field activity is supplemented by a comprehensive program of university-based research.

"Wells of opportunity" include commercial oil and gas wells that have ceased economic production and dry holes that have not yet been abandoned. In exchange for the right to study the geopressured zones in these wells, DOE assumes liability for final disposition from the owners. The wells are recompleted by perforating geopressured zones of interest and flow testing the zones for 10 to 20 days. Parameters such as gas/water ratio, salinity, temperature, and pressure are monitored regularly. Since 1977, nine such wells have been tested successfully. The results are shown in Table 1. In general,

Table 1. Well Of Opportunity Data* (From Lombard And Wallace 1987).

Well	Dates Tested	Formation	Producing Interval Depth (m)	Sand Thickness (m) Gross	Sand Thickness (m) Net	Reservoir Pressure (MPa)	Temperature (°C)	Salinity (mg/L)	Porosity (%)	Permeability (md)	Maximum Flow Rate (m^3/d)	Production Gas/Water Ratio (m^3/m^3)
1 Coastal States. Edna Delcambre No 1	Jan 29-July 21. 1977	Planulina Zone (Sand 1)	3801 to 3842	10 7	9 1	74 86	112	134 600	~ 29	100 to 364	~ 1900	3 6 to 11 0
		Miocene (Sand 3)	3923 to 3935**	15 2	14 6	75 93	114	114 100	~ 26	~ 447	~ 1390	8 5 to 15.3
2. Neuhoff Oil Co Fairfax Foster Sutter No. 2	May 19-July 10. 1979	MA-6 Lower Miocene	4810 to 4851	41 2	17 7	84 25	132	190 900	~ 19	~ 14	~ 1220	~ 4 1
3. Southport Exploration. Beulah Simon No. 2	Nov 17-Dec 31. 1979	Camerina Upper Oligocene	4473 to 4502**	63 4	56 7	89 74	130	103 900	~ 19	~ 12	~ 1750	~ 4.3
4 Wainoco Oil & Gas Co P R Girouard No. 1	July 22-Aug 7. 1980	Frio-Marginulina texana No 1. Middle Oligocene	4494 to 4517**	32 6	27 7	91 03	134	23 400	~ 26	200 to 240	~ 2380	~ 7 1
5. Lear Petroleum Exploration. Koelemay No 1†	Sept 12-25. 1980	Yegua "Leger" Middle Eocene	3548 to 3591	42 4	23 5	65 16	127	15 000	~ 26	100 to 200	~ 510	5 3 to 56 6
6. Riddle Oil Co Saldana No 2	Nov 16-25. 1980	Upper Wilcox Upper Eocene	2970 to 2993**	27 4	24 1	45 69	149	12 800	~ 20	~ 17	~ 310	8 4 to 9 6
7 Houston Oil & Minerals. Prairie Canal No 1	Feb 21-April 4 1981	Hackberry Upper Frio	4506 to 4517	7 6	4 3	89 23	146	42 600	~ 25	~ 95	~ 1130	7 7 to 9 8
8 Don Ross Pauline Kraft No 1	March 19-20. 1981	Frio "Anderson" sand. Middle Oligocene	3880 to 3920	40 2	26 8	76 (est)	128 (est)	23 000 (est)	23 (est)	39 (est)	21	8 6 (est)
9 Martin Exploration. Crown Zellerbach No 2	June 5-28. 1981	"Tuscaloosa" Upper Cretaceous	5096 to 5105**	11 0	10 7	69 46	164	32 000	~ 17	~ 17	~ 450	~ 5 9

*Well locations are shown in Fig 3
**Perforated interval
†Producing gas and oil at test completion

permeabilities of the geopressured reservoirs were found to be higher than initially expected (Wallace 1989). Also, in five of the nine wells of opportunity, the brine salinity was less than that of sea water. Given inherent limitations, such as wellbore diameter which restricts flow rate, wells of opportunity are mainly useful as indicators of resource potential. In addition to using wells acquired from industry, DOE has drilled wells expressly designed to tap geopressured aquifers. To date, four "design wells" have been employed to investigate long-term, sustained flow of geopressured brines at high production rates. Such wells provide useful data about reservoir-drive mechanisms and ultimate recoveries. Results from the design well tests are given in Table 2. These tests have established the existence of very large geopressured reservoirs.

Table 2. Design Well Data* (From Lombard And Wallace 1987).

Well	Years Tested	Formation	Perforated Interval Depth (m)	Sand Thickness (m) Gross	Sand Thickness (m) Net	Reservoir Pressure (MPa)	Temperature (°C)	Salinity (mg/L)	Porosity (%)	Permeability (md)	Maximum Flow Rate (m^3/d)	Sustained Flow Rate (m^3/d)	Production Gas/Water Ratio (m^3/m^3)
A. General Crude Oil-DOE. Pleasant Bayou No 2	1979-1980	Frio Oligocene	4463 5 to 4481 8	18 3	16 2	77 00	152	~ 131 320	~ 18	~ 192	4600	~ 3000	~ 4 1
B Magma Gulf-Technadril-DOE. Amoco Fee No 1	1981	Miogypsinoides Sand Upper Oligocene	4646 7 to 4649 7 4651 3 to 4657 4 (Sand Zone 3)	10.4	7 3	81 96	145	~ 168 650	~ 20	~ 42 to 140	~ 1050		3 6 to 4 3
			4690 8 to 4715 3 (Sand Zone 5)	9 9	8 2	83 30	148	~ 165 000	~ 22	~ 162 for $r \leq 60$ m** ~ 12 for $r \geq 60$ m	~ 5800	~ 2500	4 1 to 4 8
C Technadril. Fenix & Scisson-DOE. Gladys McCall No 1	1982-present	Lower Miocene Sand	4620.8 to 4715 3 (Sand Zone 8)	103 0	101 5	88 25	144	~ 97 800	~ 16	~ 160	5800	~ 5300	~ 5 3
			4727.8 to 4763 1 (Sand Zone 9)	39 0	34 7	89 02	148	~ 96 500	~ 16	~ 67	~ 700		~ 5 7
D Dow Chemical Co -DOE. L R Sweezy No 1	1981-83	Upper Frio Oligocene	4068 8 to 4080 7 4082 8 to 4086.2	22 3	17 5	78 67	114	99 700 ± 240	27	126	~ 1700		~ 3.6

*Well locations are shown in Fig 3
**Flow data indicate that permeability may change 60 m from the wellbore Alternatively, the wellbore may be near the apex of a 26° pie-shaped reservoir

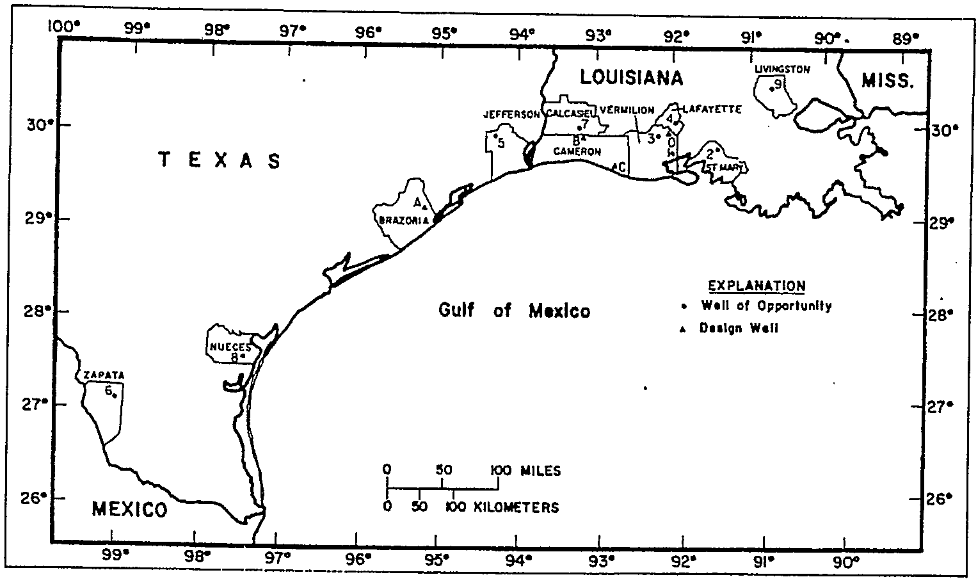

Figure 3. Locations Of Wells Of Opportunity And Design Wells (From Lombard And Wallace 1987; Letters And Numbers Refer To Wells In Tables 1 And 2).

Locations of the wells of opportunity and design wells are shown in Figure 3. Two design wells, the Gladys McCall No. 1 well in Louisiana and the Pleasant Bayou No. 2 well in Texas, are still operational. The Hulin No. 1 well in Louisiana is a well of opportunity currently in the process of recompletion. Testing at all other well sites has been completed.

The wells of opportunity and design wells have tested upper Cretaceous to lower Miocene reservoirs that ranged in depth from 9,745 feet to 16,750 feet at temperatures from 234 to 327°F and salinities from 12,800 to 190,900 mg/L (Wallace 1986). This testing confirmed the size and extent of the resource, demonstrated that the brine is generally saturated with methane, and proved that modified oil and gas technology could be used for brine production, gas separation, and brine disposal. In addition, long-term, high-volume brine production has been accomplished at two wells, and a highly effective scale inhibitor process was developed and successfully tested (Wallace 1986; Lombard and Goldsberry 1988).

Several Gulf Coast universities supported the well testing activities. Geologic studies of the Gulf Coast region identified a number of "fairways" containing prospective geopressured reservoirs where thick sandstone bodies have fluid temperatures higher than 300°F (Bebout et al 1978). Analyses of geopressured brines discerned the presence of aromatic compounds of geologic origin; the concentration of the aromatics was found to vary with cumulative brine production (Keeley and Meriwether 1988). The aromatics appear to be important for understanding hydrocarbon origin and migration in the geopressured zone. Researchers also determined, experimentally, the solubility of methane in brine over a wide range of pressures, temperatures, and salinities (Price et al 1981). Salinities derived from the self-potential log were shown to be influenced by changes in make-up water resistivity and mud additives used during drilling (Dunlap et al 1985); accurate salinities from logs are necessary for determining the amount of methane that could be dissolved in the brine.

CURRENT RESEARCH - WELL TESTING:

The Program has three active well sites: the Pleasant Bayou site, about 40 miles south of Houston, Texas; the Gladys McCall site, about 6 miles east of Grand Chenier, Louisiana; and the Willis Hulin site in Vermilion Parish, Louisiana, about 23 miles south of Lafayette.

The Pleasant Bayou No. 2 well is completed with 5½-inch production tubing and is perforated from 14,644 to 14,704 feet in the Oligocene Frio Formation. The brine contains about 130,000 mg/L total dissolved solids and has a flowing wellhead temperature of 290°F. At the surface, the solution gas is separated from the brine by two parallel gravity separators at a pressure of about 700 psia. At this pressure, about 19 cubic feet of gas per barrel is removed from the brine, which contains 23 cubic feet of gas per barrel. By mole percent, the separator gas contains 85% methane, 10% carbon dioxide, 3% ethane, 1% propane, 0.5% nitrogen, and smaller quantities of heavier hydrocarbons (C_{4+}), helium, and hydrogen. The gas has a gross dry heating value of 955 BTU/SCF (60°F, 14.73 psia) (Randolph et al 1988). Except for a slightly high carbon dioxide content, the gas is of acceptable pipeline quality. After separation, the brine flows into a disposal well perforated from 6,226 to 6,538 feet. The journey of the brine from the production well, through the surface facilities, and into the disposal well is driven by the inherent hydraulic pressure of the geopressured brine, obviating the need for brine pumps.

The Pleasant Bayou No. 2 well has been producing geopressured brine since May 1988 at a rate of roughly 20,000 barrels per day. This well produced about 4-million barrels of brine, intermittently, from 1979 through 1983, but testing was plagued by scaling of the production tubing. The current phase of testing has been aided by application of a downhole treatment, whereby scale inhibitor is pumped into the reservoir and adsorbed onto the reservoir-rock grains. During brine production, the inhibitor is released gradually and flows to the surface in sufficient quantities to prevent scaling. Similar inhibitor treatments in the Gladys McCall No. 1 well have been effective for periods up to 21 months, at flow rates up to 30,000 barrels per day.

The Gladys McCall No. 1 well is undergoing long-term, pressure-buildup that began October 29, 1987, after production of more than 27 million barrels of brine and 676 million standard cubic feet of gas. Downhole temperature and pressure measurements are taken periodically to provide data for reservoir analysis.

The Willis Hulin No. 1 well, a well of opportunity, was recently recompleted by DOE for geopressured-geothermal testing. The first phase of recompletion concluded in February 1989. The reservoir of interest is a lower Miocene sandstone that lies at depths between 20,135 and 20,690 feet, the deepest zone to be studied by the Program. The bottomhole pressure and temperature are about 17,850 psia and 350°F, respectively. A 3½-inch production-tubing string is currently installed in the well, down to a packer at 15,950 feet. In order to clean-out mud used in workover operations, the well was perforated from 20,670 to 20,690 feet and allowed to flow briefly. Preliminary analysis showed that the brine contains about 194,000 mg/L total dissolved solids, 18,400 mg/L calcium, 48,800 mg/L sodium, and 115,000 mg/L chloride. Analysis of the dissolved gas indicates methane to be the most abundant component; a high carbon dioxide content is indicated; very small amounts of other hydrocarbons are present. (Randolph 1989).

CURRENT RESEARCH - SUPPORT STUDIES:

In support of geopressured-geothermal well activities, university-based research is being conducted in rock mechanics, well logging, geology, reservoir engineering, geochemistry, and environmental monitoring.

Compaction testing on cores from the Gladys McCall and Pleasant Bayou wells is providing data to study the effect of pore-pressure reduction on well performance. Data soon to be generated by tensile-failure testing of the cores will be used to study the extent to which rock strength, depth, fluid-flow rate, temperature, and formation stresses are involved in wellbore stability during fluid production. Recent creep testing produced inconclusive results due to a large amount of noise in the data; improved test equipment is needed before more creep testing is attempted. No further work on creep is planned, pending completion of the compaction testing (Gray and Fahrenthold 1988).

Well-logging research is concentrated in two areas: 1) the effect of rock stress, wettability, and shale content on the resistivity log, and 2) the effect on the neutron log of trace elements having very-high thermal neutron cross-sections. The resistivity research is supported in part by industry and the Gas Research Institute. Early experimental work on glass bead packs and Berea sandstone cores showed that the primary variable affecting rock resistivity is wettability; stress has a much smaller effect (Lewis, Sharma, and Dunlap 1988). Theoretical work to study the effect of wettability and shale content on rock resistivity supports the experimental finding that oil-wet rocks typically show substantially higher resistivity than water-wet rocks, for a given level of saturation (Wang and Sharma 1988). Researchers recently have developed a computer program to measure the resistance. Boron, a trace element with a very-high neutron cross-section, has been shown to occur in quantities large enough to affect the logs of several formations in Texas Gulf Coast wells. Boron concentrations of more than 10 parts per million in the reservoir rock will have a significant effect on neutron-log porosity effect of clay lining in a brine-filled capillary tube on its measurements and gas-detection capabilities. Researchers have found a clear trend toward higher boron content in Frio shales and shaley sands than in relatively clean sand. Boron also occurs in significant amounts in drilling mud constituents, such as bentonite, barite, and lignosulfonate (Dunlap and Coates 1988). The resistivity and neutron-log research enhances the interpretation of these logs for evaluation of conventional oil and gas reservoirs, as well as geopressured reservoirs.

Geologic analysis of the Pleasant Bayou reservoir was completed recently; included were sandstone and mudstone geometries and continuities, structural configuration and fault barriers, effective pore volume, and gas production and pressure trends from nearby wells. This analysis, coupled with pressure and temperature data from the Pleasant Bayou well, is being used to refine the reservoir model. The current model geometry, shown in Figure 4, has a main, high-porosity layer, sandwiched between two low-porosity layers that represent thinner, more isolated sandstones considered to comprise the remote volume of the reservoir. The low-porosity layers are connected to the main, high-porosity layer by cross-flow along circuitous flow paths around shale interbeds and internal faults (Riney 1989).

Figure 5 compares downhole pressure measurements with the pressure buildup response predicted by the computer simulation of the Gladys McCall reservoir with cross-flow as the assumed reservoir-drive mechanism. The cross-flow model requires that other sands be connected to the main Gladys McCall reservoir at some distance from the wellbore. Agreement of predicted and measured values is good, except for the two most recent downhole pressure measurements which are above the predicted downhole pressures.

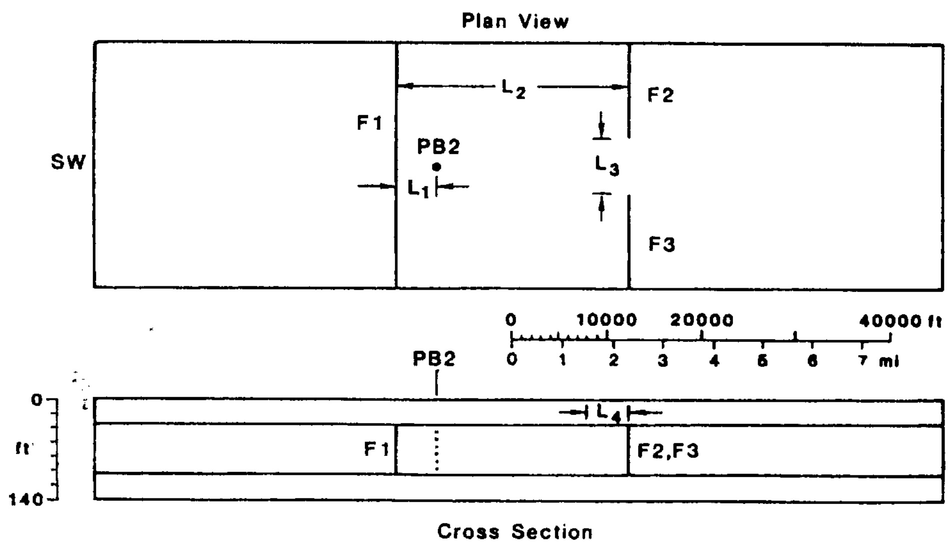

Figure 4. Reservoir Simulation Model Geometry For Pleasant Bayou No. 2 Well. F1, F2, And F3 Are Faults. L1 Equals 990 Meters, L2 Equals 4887 Meters, L3 Equals 1420 Meters, And L4, The Distance Of Vertical Communication Between The Main Reservoir And The Overlying/Underlying Low-Porosity Layers, Equals 1667 Meters (From Riney 1989).

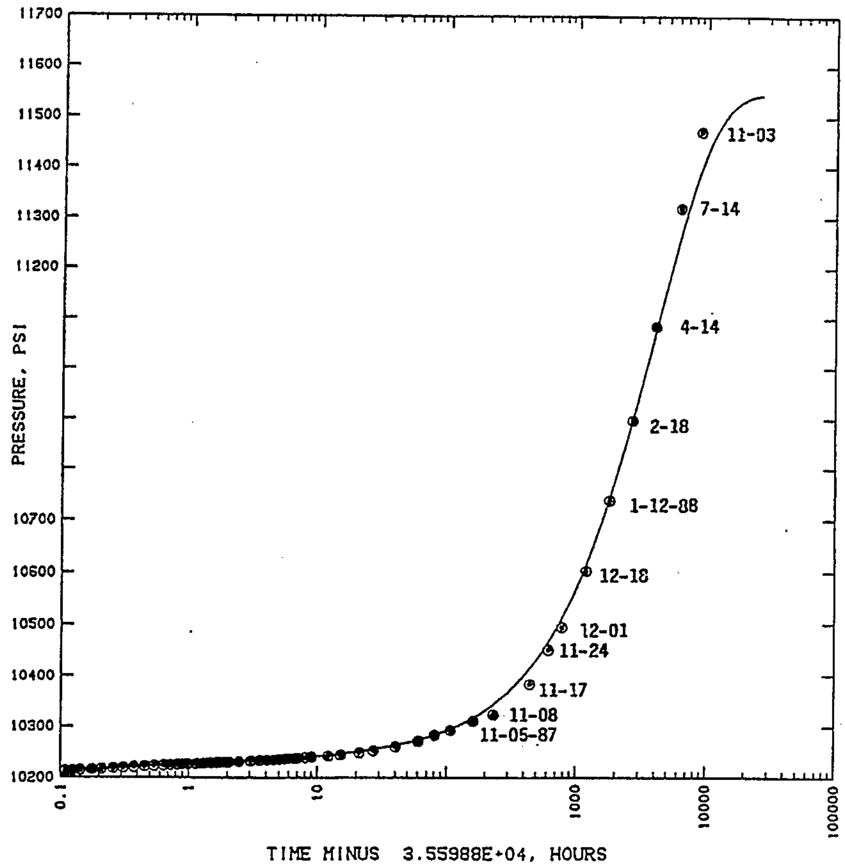

Figure 5. Gladys McCall Well History-Match Simulation Using Cross-Flow Model Compared With Downhole Pressure Data (From Riney 1988).

Models that match observed reservoir behavior at Gladys McCall can be devised based on other reservoir-drive mechanisms. Besides cross-flow, other possible drive mechanisms include stress-dependent rock-formation compressibility, long-term formation creep, recharge from shales, leakage along or across faults, and free-gas evolution.

Parametric reservoir simulations, using rock mechanics data for Gladys McCall reservoir rocks, found that the effects of stress-dependent rock-formation compressibility were insignificant. Parametric reservoir simulations of free-gas evolution found that any free gas evolved during production would be confined to the immediate neighborhood of the well. The ongoing test program for the design wells will help to distinguish between reservoir-drive mechanisms (Riney January 1988). Downhole-pressure measurements at Gladys McCall are continuing and are scheduled to be completed by October 1989.

All geopressured brines sampled by the Program contain small amounts (less than 50μL/L) of C_{6+} hydrocarbons that are primarily aromatic in nature and range from benzene to substituted anthracenes. The brines also contain a variety of ions and light C_1 to C_6 aliphatic hydrocarbons (Keeley and Meriwether 1988). On a monthly basis, the aromatic hydrocarbons in the gas at Pleasant Bayou are sampled, using a dry-ice/acetone bath. The aromatic hydrocarbons in the brine also are sampled using an ice/water bath. These cryocondensate samples, as determined by gas chromatographic analysis, contain over 95 different compounds (Keeley and Meriwether 1985). At the Gladys McCall well, the concentration of cryocondensate in the brine was observed to increase, followed by the onset of oil production. Keeley and Meriwether (1988) postulated that the change in cryocondensate concentration, as a function of cumulative brine volume, results from extration of additional aromatic components from oil migrating into the production zone from adjacent shale.

Environmental monitoring at the geopressured-geothermal well sites assesses whether brine production and disposal have had adverse effects, such as land-surface subsidence, growth-fault activation, or surface and/or ground water contamination. Subsidence monitoring, by means of leveling surveys, has not detected significant correlation between subsidence and withdrawal and disposal of geopressured brine. Also, no significant correlation exists between well testing and microseismicity, as detected by microseismic monitoring networks at the well sites. Quarterly sampling of surface and ground water around the well sites has not detected significant contamination (Van Sickle et al 1988).

DOE and the Electric Power Research Institute (EPRI) are cosponsoring a hybrid-power system test at the Pleasant Bayou site. The hybrid-power system (Figure 6) will use both natural gas and hot geothermal brine for power generation. The system is designed for 10,000 barrels per day of geopressured brine, containing 22 standard cubic feet of gas per barrel of brine. The working fluid in the binary cycle is isobutane. The design output is approximately 650 kWe from the gas engine/generator and 540 kWe from the binary turbine/generator, with parasitic loads of 210 kWe. The power produced will feed into the local power grid. The hybrid-power system will be operated in conjunction with the reservoir testing program of the Pleasant Bayou No. 2 well. Construction of the hybrid-power system will be completed in May 1989; a nominal 12-month testing period is planned. As designed, the system can produce at least 15 percent more electricity than the same amount of fuel and geothermal fluid used in separate power plants. The hybrid concept provides greater flexibility to developers in deciding how to market the energy produced from geopressured-geothermal resources.

The purposes of the DOE/EPRI geopressured hybrid-power experiment are: (1) to evaluate the potential of combustion/geothermal hybrid-power cycles for use in the development of geopressured and low-temperature hydrothermal resources, and (2) to evaluate the role of thermal energy in geopressured development economics.

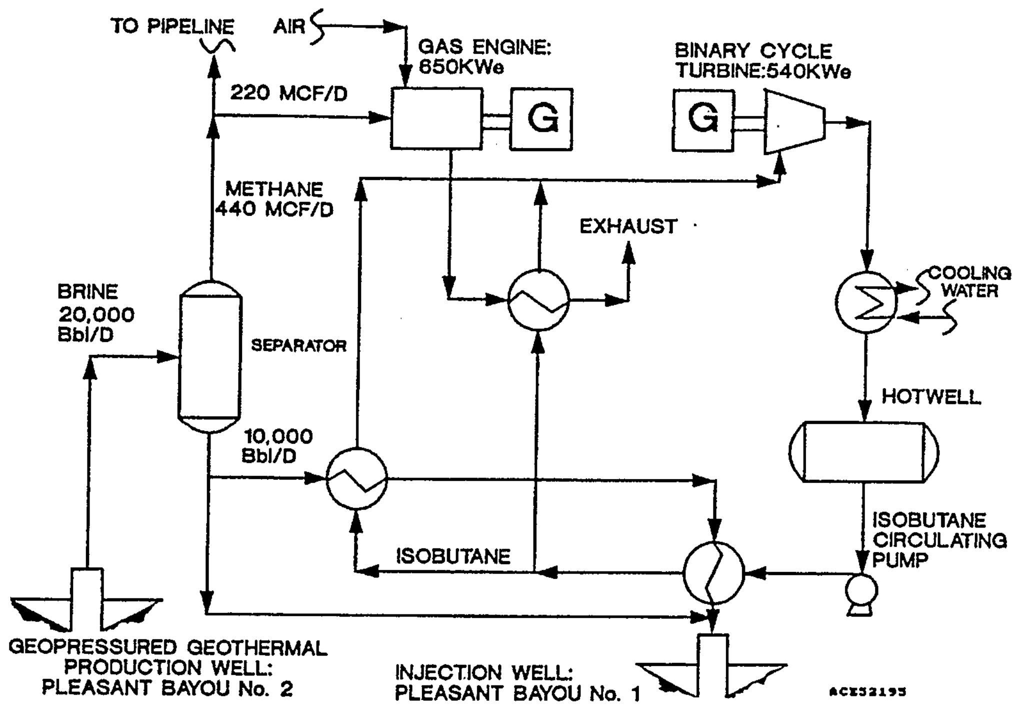

Figure 6. Hybrid Power System Schematic.

POTENTIAL FUTURE ACTIVITIES:

After the pressure buildup test at the Gladys McCall well is completed in October 1989, a final scientific testing program at the well may be implemented. Two questions that need to be answered are: (1) what has been the effect of high-volume production on the sandstone reservoir and surrounding shale units, and (2) what are the drive mechanisms responsible for pressure maintenance in the reservoir? The first question could be answered by coring the reservoir sandstone and the overlying and underlying shales and comparing the cores with pre-production cores; logging the well for comparison with pre-production logs should also be helpful. The second question could be answered by isolating and pressure-testing adjacent sandstone zones to determine if cross-flow from adjacent sandstone zones into the main reservoir has occurred.

The Pleasant Bayou well is currently being tested to acquire pressure drawdown data and to provide geopressured brine and gas for operation of the hybrid-power system, beginning in the summer of 1989. Long-term flow testing will continue at least until the summer of 1990. A long-term pressure buildup test is tentative, pending the outcomes of the drawdown test at Pleasant Bayou and the buildup test at Gladys McCall.

Finally, the Hulin well, which penetrates the deepest, hottest reservoir in the geopressured program, will be flow tested in 1989 for a short period; if the reservoir is capable of long-term production, permanent production facilities may be installed, and a long-term testing program initiated.

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NATURAL GAS PROCESSING RESEARCH

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ABSTRACT

The Gas Research Institute, as part of its overall R&D program has defined a new activity that is addressing the evaluation and development of new technology for the processing and upgrading of natural gas to meet pipeline standards. This research is being pursued by the Chemical Process Research Department. This activity has the dual objectives of: (1) decreasing the cost of existing production; and (2) expanding the gas resource base by making lower quality gas economical to produce. The strategy is to work with process developers, licensors of existing processes and equipment, and the gas industry through cofunded/applied R&D in order to accelerate the development and commercialization of new technology having economic advantages over existing technology.

The current program, begun in 1988, consists of a blend of technology-base and applied research on emerging and advanced processes and is focused on small-scale processing systems for low quality natural gas. The overall GRI program on advanced gas processing includes:

- Characterization and specification of the resource base of lower quality natural gas;
- Development of new separation processes via exploratory research including advanced adsorbents, membranes, and gas-liquid contacting devices;
- Performance testing through field tests on emerging processes and equipment to quantify their applicability to lower quality gas; and
- Improved materials and instrumentation for gas processing facilities; and
- Technoeconomic assessment of the potential cost benefits of new separation approaches.

Processing of natural gases is practiced routinely near the wellhead to recover high-value constituents and to make the gases acceptable for transport via the domestic gas pipeline system. A conservative estimate is that more than half of the nearly 18 trillion cubic feet (TCF) of natural gas produced annually requires some treatment in addition to dehydration. These treatments can be as simple as a separator, dehydrator and iron sponge treating the effluent from a single well to large plants that remove, and recover where economical, natural gas liquids, sulfur compounds, carbon dioxide, nitrogen, helium, hydrogen, ammonia and oxygen from multiple wells with combined production to 500MMscf/day. The number and sequence of unit operations in any given processing plant will vary dependent on gas composition, site specific design constraints and the feedstock costs of gas.

The variety of unit processes indicates a number of areas of potential improvement exist for current natural gas production. Moreover, natural gases containing high nitrogen, or nitrogen in combination with carbon dioxide and/or hydrogen sulfide, provide troublesome processing problems. At present, gas discoveries of this type are not being developed because of a lack of economic purification processes. Development of new processes to treat these natural gases could add materially to the domestic gas resources. Further, if these developments are successful in identifying economic processes at smaller scale, the current large capital costs for gas processing plants may be avoidable.

Recent data suggest that new lower 48 reservoirs will be smaller, of marginal or lower quality, and more remote than existing fields. If new natural gas discoveries are remotely located as in current trends, smaller scale processing plants, including single well installations, may be critical in marketing these new gas resources. Small-scale systems are not now sufficiently cost-effective for commerical entry at current gas spot market prices. One key to cost-effectiveness in small-scale gas processing plants may well be low labor costs resulting from automation. For economic processing, this must be achieved without major increases in capital cost per unit of output, or any decrease in system reliability or safety. Moreover, any by-products and wastes generated in small-scale plants must be produced in a readily storable form for periodic collection and/or disposal. Clearly, these are some of the challenges for the development of small-scale natural gas processing plants of the future.

The GRI is currently funding or initiating the following projects in gas processing:

- Advanced Adsorbents for the Enrichment of Natural Gas: Carbon molecular sieves as an adsorbent in a pressure swing adsorption process for the removal of nitrogen from natural gas.

- Selective Gas Separation with Higee Gas Contactor: Rotating bed of packing as a high efficiency contacting device for mass transfer limited reactions, such as selective H_2S removal.

- Resource Assessment of Subquality Natural Gas: Data base that relates gas quantity and gas quality for discovered and undiscovered natural gas resources.

- Structure-Permeability Relationship in Polymer Membranes for the Separation of Gas Mixtures: The fundamental relationship between polymer structure and permeation characteristics to allow the engineering of membranes for specific gas separations.

- Liquid Membrane Removal at Carbon Dioxide from Methane: Hollow fiber, liquid contained membranes as novel facilitated transport gas contacting devices for the separation of carbon dioxide from methane.

- Evaluation of Gas Permeable Membranes for Application to Landfill Gas Cleanup: Hollow fiber, polymeric membranes to establish optimum operating conditions to reduce the cost of removing CO_2 from methane.

- Advanced Chemical Process Technical Evaluation: Technical and economic assessments to identify limitations of existing technology, to estimate potential cost benefits of new technology and to help prioritize goals.

HYDROCARBON-RELATED RESEARCH IN DOE, OBES/GEOSCIENCES

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ABSTRACT

The Geosciences Activity in the Office of Basic Energy Sciences, Office of Energy Research, supports basic research in the geosciences. OBES operates primarily under a peer-reviewed, unsolicited proposal system. In FY 88, OBES Geosciences supported 64 projects at 8 national laboratories and 57 projects at 40 universities. This research is of a fundamental nature and although it is relevant to DOE's interests, the emphasis is on projects with long-term payoffs, ranging from studies of the structure and properties of the continental crust to solar-terrestrial studies, including properties of the earth's magnetosphere. One-fifth of the OBES Geosciences research, about $3.5 M in FY 88, is hydrocarbon-related. Studies of permeability, rock-fluid interactions, and physical properties of rock all contribute basic information needed for understanding hydrocarbon reservoirs. More directly related is research in underground imaging, reservoir studies, and organic geochemistry. Results from several on-going projects will be presented. These include the crustal stability of hydrocarbons and C-O-H fluids, organic geochemistry of sediments from the continental margin and shelf, attenuation and dispersion of seismic energy in partially saturated rocks, and a compositional kinetic model of petroleum formation.

Interesting new projects begun in FY 88 include research related to Procambrian oil and oil from evaporites. An emphasis on high-resolution seismic imaging was started in FY 89 with proposals now under review. Jointly with the NSF and USGS, OBES Geosciences is sponsoring research in Continental Scientific Drilling. Until now, OBES Geosciences has concentrated on thermal regimes provinces of the West but future drilling projects under consideration include hydrocarbon research drilling. An OBES Geosciences-funded NAS/NRC study recommended a very large program in hydrocarbon research drilling for DOE.