P12 Gas Hydrate Detection and Mapping on the U.S. East Coast

CONTRACT INFORMATION

Interagency Agreement	DE-AI21-83MC20422
Contractor	U.S. Geological Survey Reston VA 22092 703-648-6470
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Schedule and Milestones

FY94/95 Program Schedule

	D	J	F	M	A	M	J	J	A	S	O	N
analyze Blake Ridge seismic data												
carry out lab testing of hydrates												
support ODP drilling proposal												

OBJECTIVES

Project objectives are to identify and map gas hydrate accumulations on the U.S. eastern continental margin using remote sensing (seismic profiling) techniques and to relate these concentrations to the geological factors that control them. In order to test the remote sensing methods, gas hydrate-cemented sediments will be tested in the laboratory and an effort will be made to perform similar physical tests on natural hydrate-cemented sediments from the study area. Gas hydrate potentially may represent a future major resource of energy. Furthermore, it may influence climate change because it forms a large reservoir for methane, which is a very effective greenhouse gas; its breakdown probably is a controlling factor for sea-floor landslides; and its presence has significant effect on the acoustic velocity of sea-floor sediments.

BACKGROUND INFORMATION

A gas hydrate is a crystalline solid; its building blocks consist of a gas molecule surrounded by a cage of water molecules. Thus it is similar to ice, except that the crystalline structure is stabilized by the guest gas molecule within the cage of water molecules. Many gases have molecular sizes suitable to form hydrate, including such naturally occurring ones as carbon dioxide, hydrogen sulfide, and several low-carbon-number hydrocarbons, but most marine gas hydrates that have been analyzed are methane hydrates. Gas hydrates are stable at the temperatures and pressures within ocean floor sediments at water depths greater than about 500 m, and at these pressures they are stable at temperatures above those for ice stability. Gas hydrates also are stable in association with permafrost in the polar regions, both offshore and onshore. In deep sea sediments, where temperature normally increases downward, a temperature eventually is reached at which hydrate is unstable, even though the pressure continues to increase with depth. The base of the hydrate stability zone will approximately parallel the sea floor at any particular water depth because the thermal gradient within a restricted area is generally fairly constant. Thus a layer within the sediments will exist in which gas hydrate is potentially stable from the sea floor down to a depth at which the gas hydrate phase boundary is reached, commonly several hundred to a thousand meters below the sea floor. If gas (methane) saturation exists within this zone, gas hydrate will form.

Gas hydrates bind immense amounts of methane in sea floor sediments. Hydrate is a gas concentrator; the breakdown of a unit volume of methane hydrate at a pressure of one atmosphere produces about 160 unit volumes of gas. The worldwide amount of methane in gas hydrates is considered to contain at least 1×10^4 gigatons of carbon in a very conservative estimate (Kvenvolden, 1988). This is about twice the amount of carbon that resides in all fossil fuels on earth. Furthermore, hydrates also seem to have the capacity to fill sediment pore space and reduce permeability, so that hydrate-cemented sediments act as seals for gas traps. Thus, there are two ways in which hydrates can create accumulations of energy gases (primarily methane, but other hydrocarbon gases, as well), both by binding gas into hydrates within sediments and by creating a trap, using hydrate-cemented sediments as the seal.

PROJECT DESCRIPTION

Recognition of Gas Hydrates in Sediments by Remote Sensing Methods — Seismic Reflection Profiles

Although hydrates have been recognized in drilled cores, their presence over large areas can be detected much more efficiently by acoustical methods, using seismic reflection profiles (Tucholke and others, 1977; Shipley and others, 1979; Dillon and Paull, 1983; Collins and Watkins, 1985; Miller and others, 1991; Rowe and Gettrust, 1993). Hydrate has a very strong effect on acoustic reflections because it has a very high acoustic velocity (~3.3 km/s — about twice that of seafloor sediments; Sloan, 1990), and thus cementation of grains by hydrates produces a high-velocity deposit due to the mixing of hydrate with the sediment. Sediments

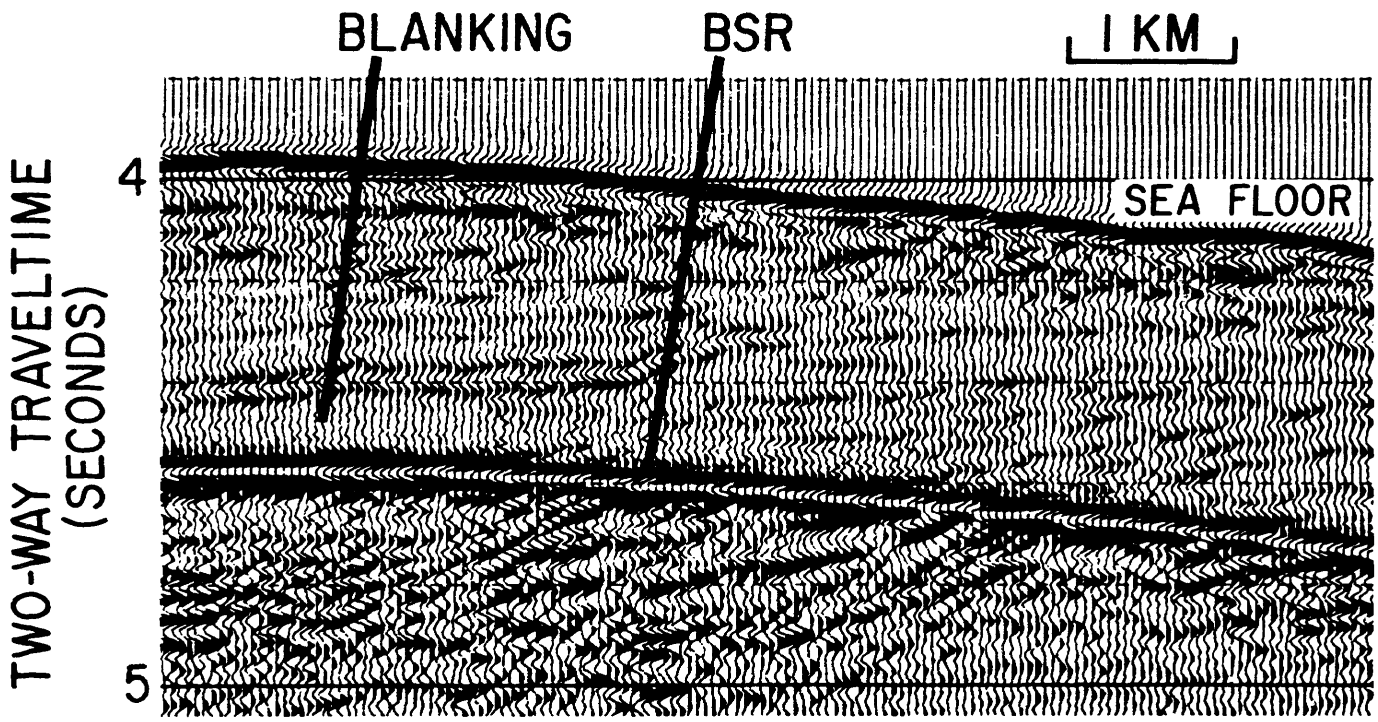

Figure 1. Seismic profile showing the reflection from the base of the gas hydrate-cemented zone (bottom simulating reflection, or BSR) and blanking of reflections in the cemented zone between the sea floor and BSR

below the hydrate zone, if water saturated, have lower velocities (water velocity is ~1.5 km/s), and if gas is trapped in the sediments below the hydrate, the velocity is much lower (even with just a few percent of gas; Brandt, 1960). Because reflection strength at an interface is a function of the change of acoustic impedance, which is the product of velocity times density, the base of the hydrate-cemented zone produces a very strong reflection. The reflection is also very sharply defined, because the phase boundary is a distinct, not diffuse, limit to hydrate occurrence, whereas the top of hydrate within the sediments has no such precisely defined boundary, so it does not produce a sharp reflection. As noted above, the base of hydrate stability occurs at an approximately uniform sub-bottom depth throughout a small area, and therefore the reflection from its base roughly parallels the sea floor, hence it is called the "Bottom Simulating Reflection" or BSR; the BSR is characteristic of hydrate-bearing sediments. A very strong BSR is shown in Figure 1, in which it intersects reflections from strata at locations where the stratal surfaces do not parallel the sea floor. The coincidence in depth of the BSR to the theoretical, extrapolated pressure/temperature conditions that define the hydrate phase boundary at various locations in the world and the sampling of hydrate above BSR's give confidence that this seismic indication of hydrates is dependable (Kvenvolden and Barnard, 1982, 1983; Shipley and Didyk, 1982, Kvenvolden and Kastner, 1990).

A second significant seismic characteristic of hydrate-cementation, called "blanking" is also very well displayed in Figure 1; blanking is the reduction of the amplitude of seismic reflections caused by hydrate cementation. The amplitudes of reflections (shown by the excursions of the filled wiggle traces) are much smaller above the BSR, where sediments are cemented by gas hydrates, than they are below the BSR. This phenomenon consistently appears in sediments containing gas hydrates, indicating that the acoustic impedance changes between the strata are much reduced by hydrate cementation. A third characteristic of gas hydrates in a near-bottom layer of sediment is the abrupt velocity decrease at the level of the BSR caused by moving from hydrate-cemented sediments above the horizon to non-cemented sediments below it, where sediments are water- or even gas-filled.

The BSR and velocity inversion, as seismic manifestations of hydrates in sea floor sediments, have been used to recognize gas hydrates in seismic profiles on the U.S. Atlantic continental margin (Tucholke and others, 1977; Shipley and others, 1979; Dillon and others, 1980; Paull and Dillon, 1981; Krason and Ridley, 1985). The BSR and velocity inversion are related solely to the bottom boundary of the hydrate zone. The blanking effect, however, occurs across the entire hydrate-cemented zone and can be quantified to estimate the amount of gas hydrate that is present (Lee and others, 1993a).

Estimating Volume of Gas Hydrate in Sediments from Seismic Reflection Data

The strong effect of gas hydrate on interval velocity would allow quantitative mapping of gas hydrate in marine sediments if the distribution of velocities in the near-bottom sediments were completely known. Interval velocity is assumed to depend on the proportions of sedimentary volume filled by rock (the sediment grains), water, and hydrate and their respective velocities. Velocity in the hydrate layer can be estimated from multichannel seismic reflection profiles or wide-angle seismic measurements, but unfortunately such data are not widely available on the east coast of the United States. The only type of digital seismic data that is available in a grid that is dense enough to allow mapping is vertical-incidence seismic data. Vertical-incidence data are collected with no moveout, and therefore do not allow the calculation of interval velocities but do allow the measurement of blanking. Our strategy to estimate hydrate concentration is to quantify interval velocity and amplitude blanking due to hydrates in the few available multichannel seismic reflection profiles; estimate the amount of hydrate indicated by velocity; establish the relationship between hydrate and blanking; then apply this relationship to measure hydrate concentrations indicated by blanking in the vertical-incidence data (Lee and others, 1992; 1993a; 1993b; in press).

Initially, interval velocity and median reflectance were determined for a layer 250 milliseconds thick within the gas hydrate-stable layer (above the BSR) in six U.S. Geological Survey multichannel seismic profiles located in the survey area. Blanking is measured as the decrease in median reflectance within the layer. Median reflectance is the seismic amplitude adjusted for factors other than hydrate cementation that are also known to affect amplitude; these are travel distance due to

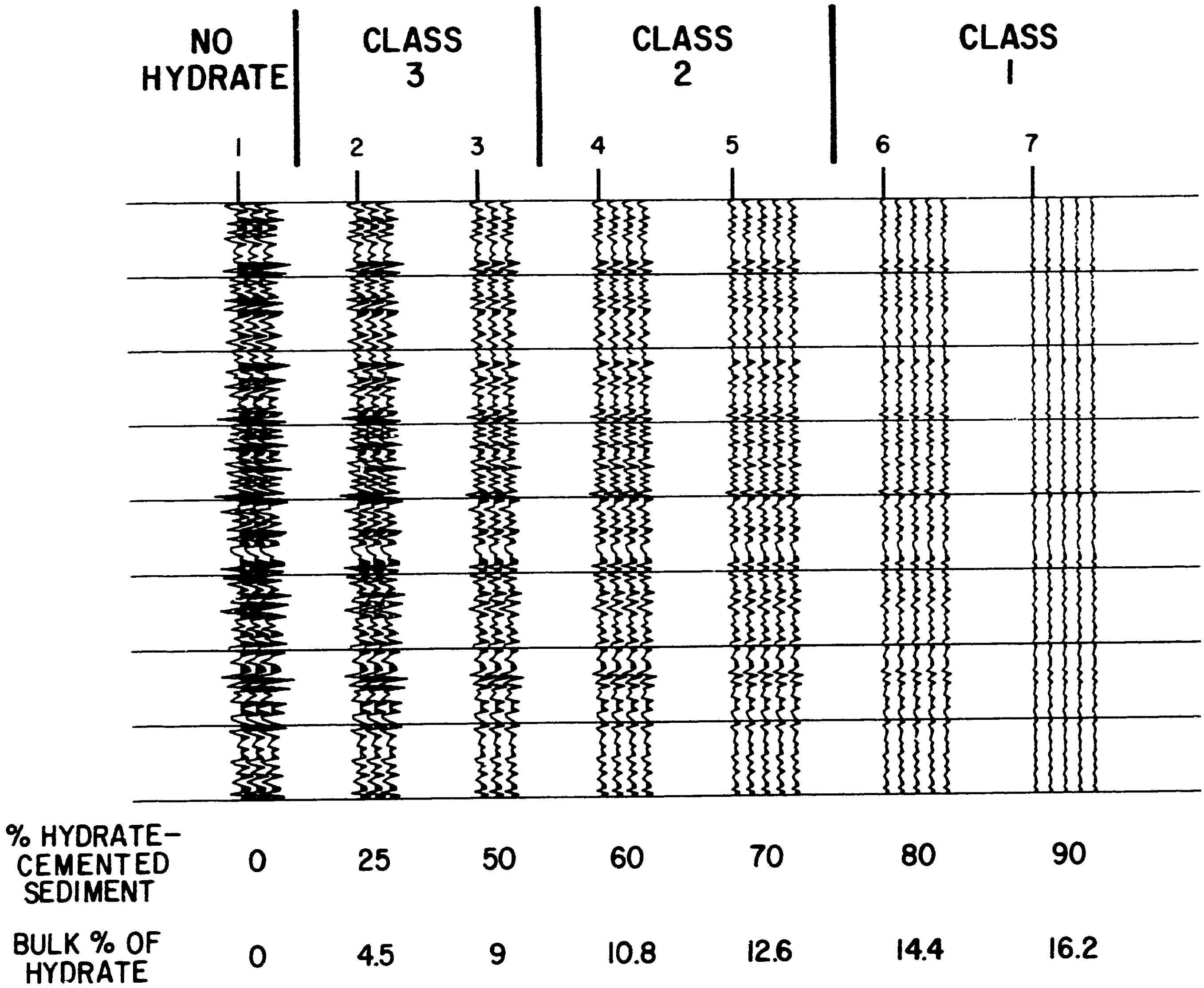

Figure 2. Synthetic seismograms showing the effect of increasing proportions of gas hydrate cement

water depth variations, and sea floor reflectivity. Concentrations of gas hydrate were calculated using the known velocities of rock, water and hydrate and the porosity, which is the proportion of sediment volume occupied by water plus hydrate. The porosity of nearbottom sediments off the southeastern United States was estimated from results of scientific drilling (Hollister, Ewing and others, 1972; Sheridan, Gradstein and others, 1983). Once the hydrate concentrations for the six multichannel seismic lines were calculated, variations in concentration of hydrate could be correlated with the measured blanking. This relationship then was used to estimate the proportion of hydrate in the vertical incidence, two-channel profiles for which the calculation of velocity was not possible.

The relationship of degree of blanking to concentration of hydrate is not considered to be a precise one, so in estimating blanking in profiles, we divided the effect into just three blanking classes. Class boundaries were selected at amplitude reductions of 6 dB. To illustrate the effect of increasing proportions of gas hydrate cement in sediments on seismic reflections and the three classes of blanking we modeled a series of synthetic seismograms (Fig. 2). In order to simulate a seismogram for non-cemented sediments, 200 random porosities in the porosity range of 50% to 70% (similar to the range in measurements for the study area) were generated and the corresponding velocities and densities were computed. We then computationally "replaced" non-hydrate-cemented sediments with increasing amounts of a representative hydrate-cemented sediment (hydrate concentration 27.5%, porosity 57.5%) and velocities and densities were modified accordingly. A reflection coefficient series was computed on the basis of the modified velocities and densities and an appropriate band-pass filter was applied. To illustrate the relationship of amplitude blanking to hydrate concentration, synthetic seismograms were plotted (Fig. 2) in which the representative hydrate-cemented sediment was replaced in non-hydrate-bearing sediments in proportions of 0%, 25%, 50%, 60%, 70%, 80%, and 90%. The class boundaries also are indicated on the figure. The characteristics of the classes are shown in Table 1.

DATA COLLECTION AND PROCESSING

The majority of the seismic reflection lines used in this study were collected during five U.S. Geological Survey cruises from February to May, 1987, of the R/V Farnella, which were intended primarily to collect GLORIA sidescan sonar data. A 160 in^3 airgun was fired at 10 second intervals, and data were recorded digitally at sea using a 2-channel hydrophone streamer. Sidescan sonar mosaics and unprocessed seismic reflection, bathymetric and magnetic profiles collected on these cruises are presented in EEZ-Scan 87, Scientific Staff (1991). Additional seismic reflection lines were run on the R/V Cape Hatteras in 1991. These lines were collected using a 120 in^3 airgun fired at 10 second intervals and also recorded digitally at sea from a 2-channel hydrophone streamer.

To enhance the appearance of the sub-

Table 1. Properties of the hydrate classes

	Class I	Class II	Class III
median reflectance	< 0.024	0.05-0.025	> 0.05
bulk volume of hydrate	12%-16%	8%-12%	0%-8%
average volume of hydrate	14%	10%	4%
range in interval velocity (km/s)	1.94-2.02	1.85-1.94	1.7-1.85

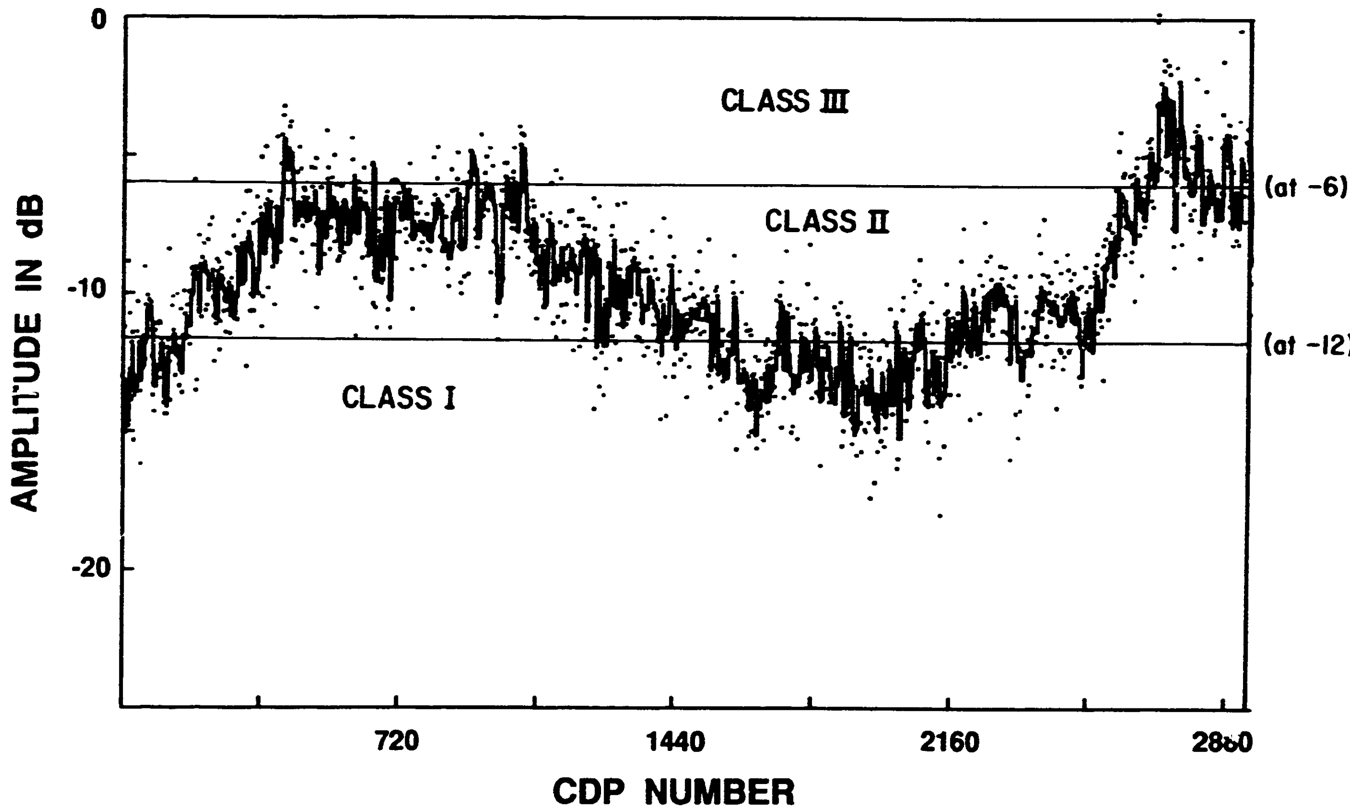

Figure 3. Plot of median reflectance in a window 250 to 500 milliseconds below the sea floor along a seismic profile. Dots indicate individual values, line represents a 5-point moving median of values shown by dots.

bottom region where blanking and the BSR are present, the following processes and process parameters were used: debias, mute, gain proportional to first power of travel time, deconvolution (design window = 0-1.4 seconds below the seafloor; filter length = .16 seconds; prewhitening = 10%; prediction distance = .02 seconds), bandpass filter (passed between 10-100 Hz), and 2-channel stack. The stack summed the two channels with no moveout correction applied, and served to increase the signal-to-noise ratio compared to single channel display. This processing strategy preserved relative true amplitudes. From these processed data, median reflectance was estimated for a window extending from 250 to 500 milliseconds below the sea floor (within the gas-hydrate stable zone) and a plot was created of median reflectance along the profile with a moving average applied (Fig. 3).

Mapping

Median reflectance plots along each seismic section allowed assignment of average class level (I, II or III) within the selected 250-500 millisecond window (Fig. 3). Using this calibration as a guide, an

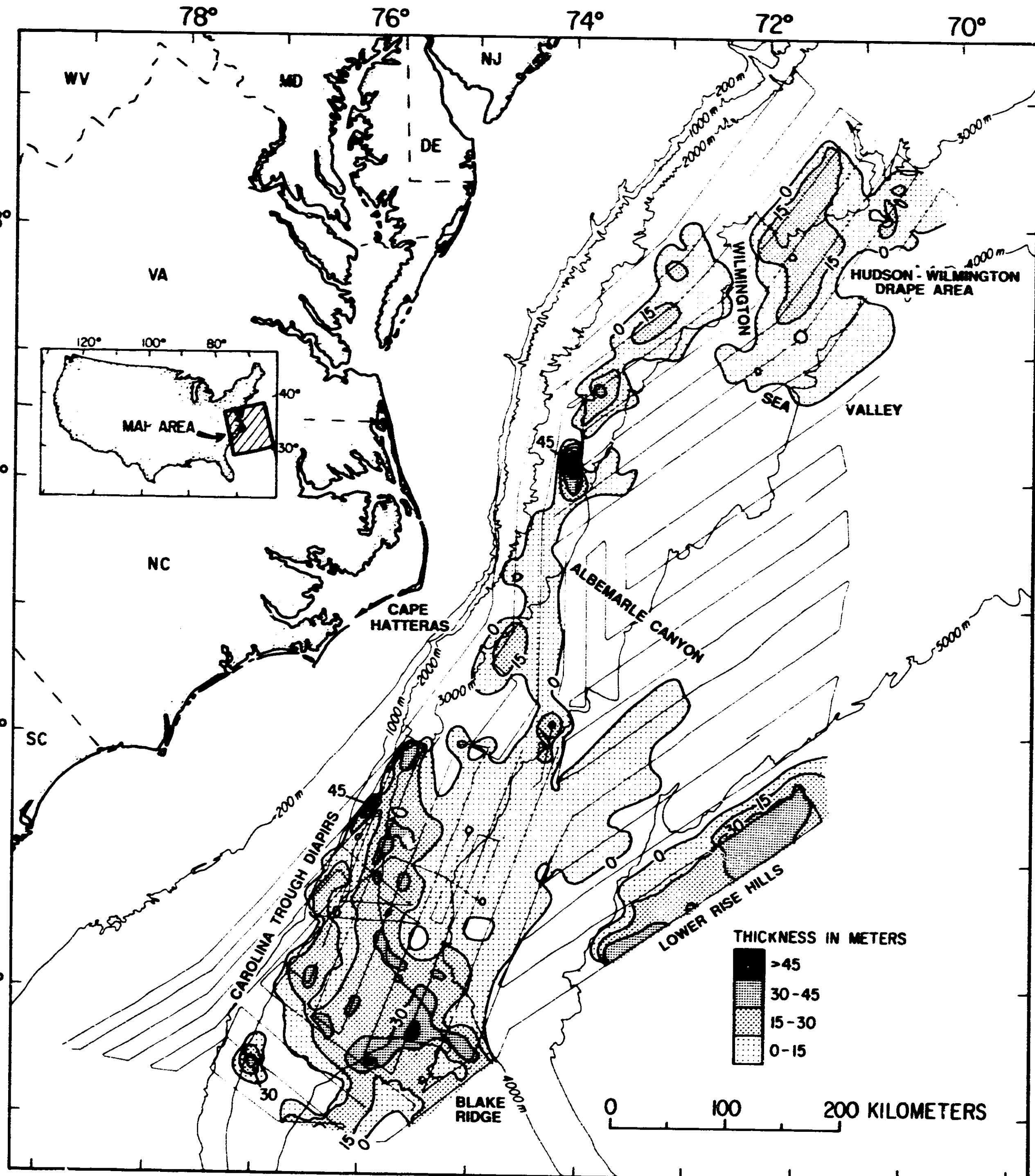

Figure 4. Volume of gas hydrate shown by isopach contours for the eastern continental margin of the United States — contour interval = 15 meters

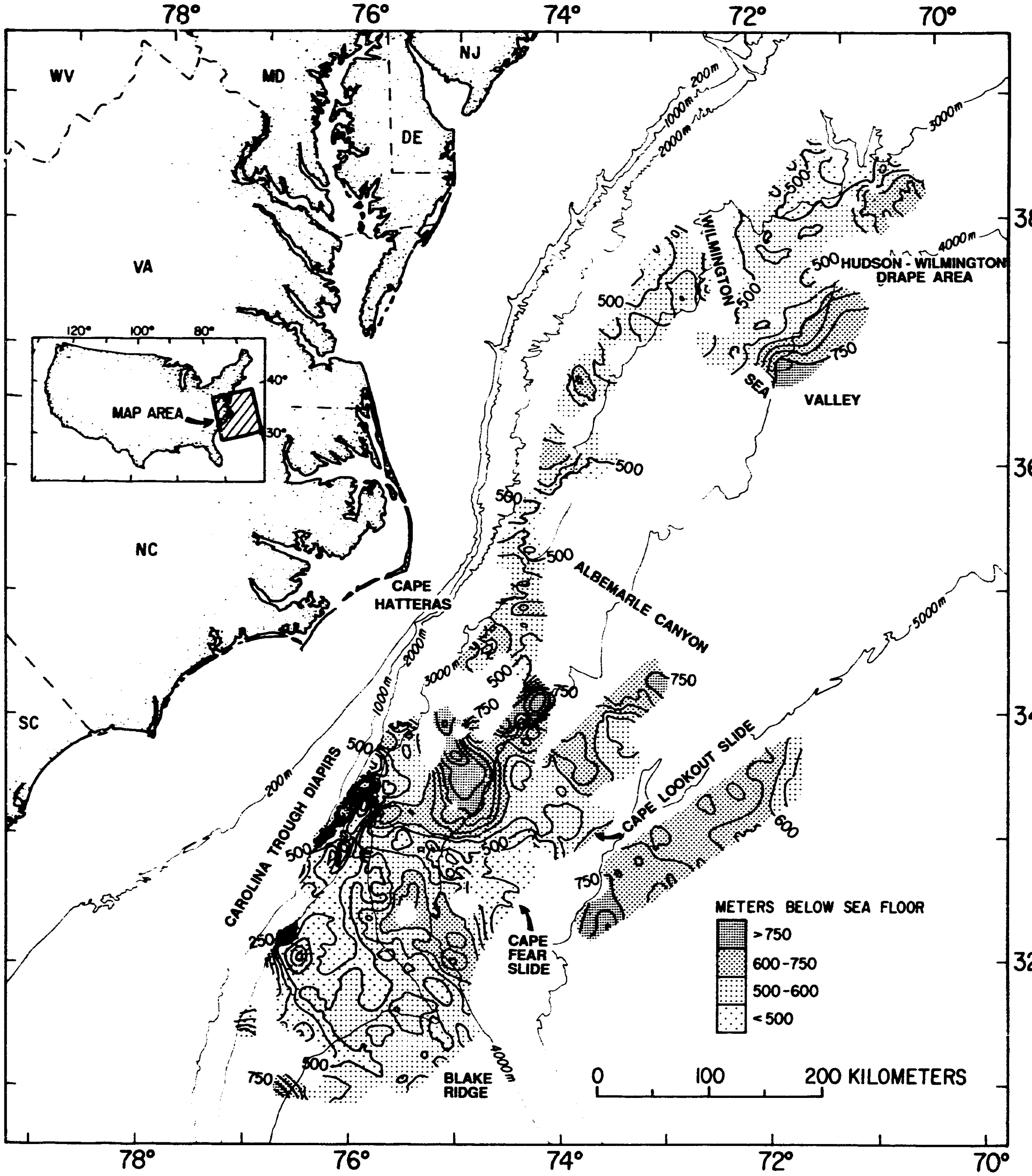

Figure 5. Thickness of the gas hydrate layer (sea floor to BSR) for the eastern continental margin of the United States — contour interval = 50 meters

interpretation of the areal extent of each class was drawn on each seismic section. Then each of these interpretations was digitized, the values of thickness in acoustic travel time for each class were multiplied by appropriate velocities for that class (Table 1), and a summary of the volume distribution of deposits representing each class was made by integrating between the profiles using a surface-modeling, gridding, and contouring program.

To map total hydrate, the volume of each class was multiplied by the average proportion of gas hydrate for that class and the results for the three classes were summed. This resulted in the estimate of total volume of gas hydrate for the study area that is shown by the isopach contours of Figure 4. The quantity of hydrate is expressed by contours showing inferred volume of hydrate existing within the sediments; that is, the amount of hydrate that would appear if all the hydrate dispersed in the sediments were extracted and piled on the sea floor above.

Figure 5 is a map of the depth of the BSR below the sea floor; this interval — from sea floor to BSR — represents the zone in which gas hydrate is stable. This map also was created using the seismic data and the interpretation of classes. The depth of the BSR at a point was calculated by identifying the thickness in acoustic travel time for deposits of each class and multiplying the time-thickness of each class by a characteristic velocity associated with that class (Table 1). These thicknesses were then summed to get the total depth to the base of gas hydrate. Velocities used were: Class I, 2 km/s, Class II, 1.9 km/s, Class III, 1.8 km/s.

RESULTS

These maps (Figs. 4 and 5) represent the first attempt to map volume estimates for gas hydrate. They present the inferred volume distribution (Fig. 4) of natural gas hydrate and the thickness of the hydrate-stable layer (Fig. 5) within the sediments of the eastern United States continental margin (Exclusive Economic Zone) in the offshore region from Georgia to New Jersey.

Gas Hydrate Distribution

Most concentrations of gas hydrate represent locations where sedimentation rates either are high or have been high in the geologically recent past, because these are areas where organic material is preserved and converted to biogenic gas by bacteria in the sediments (Dillon and others, 1993; in press). Regions of active high deposition and hydrate concentration include the Hudson Wilmington drape area and the Lower Rise Hills (Fig. 4). On the other hand, the Blake Ridge hydrate deposit (Fig. 4), which is the the greatest concentration of hydrate off the eastern United States, is located at a site of active Miocene/Pliocene deposition. Other concentrations of gas hydrate are located at sites of diapirs and associated faults (Carolina Trough Diapirs, Fig. 4; Schmuck and Paull, 1993). Note the very strong blanking around the diapir (Fig. 6). Gas near diapirs may have a thermogenic source, perhaps having migrated up faults from deep sources (Fig. 7).

Gas Hydrate Layer Structure

Because gas hydrate is stable to higher temperatures as pressure increases and because pressure increases as water becomes

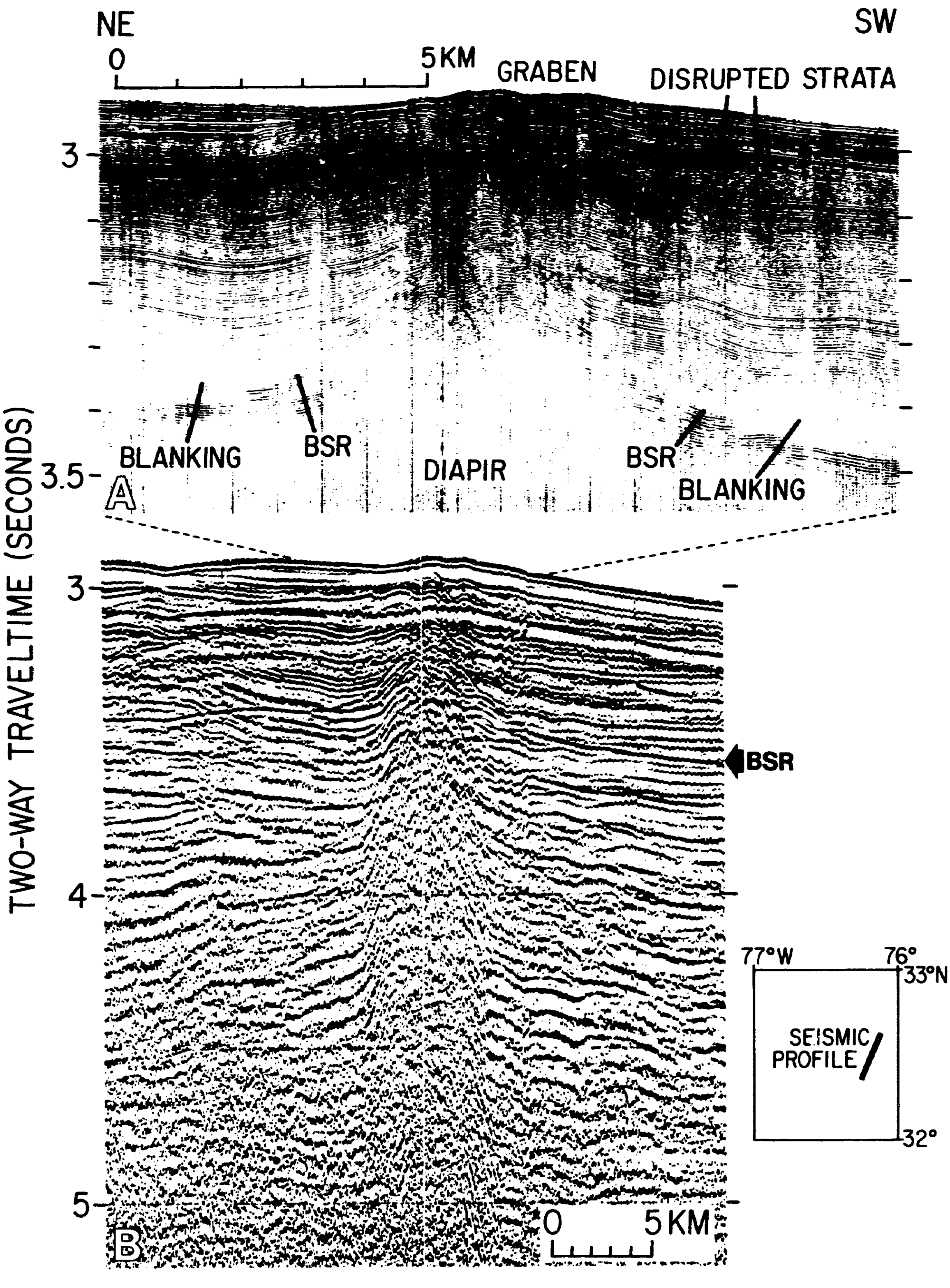

Figure 6. Seismic profile across a diapir on the South Carolina continental rise — A, high resolution profile (seismic source = 5 cubic inch airgun) — B, deep penetration profile (seismic source = two 500 cubic inch airguns)

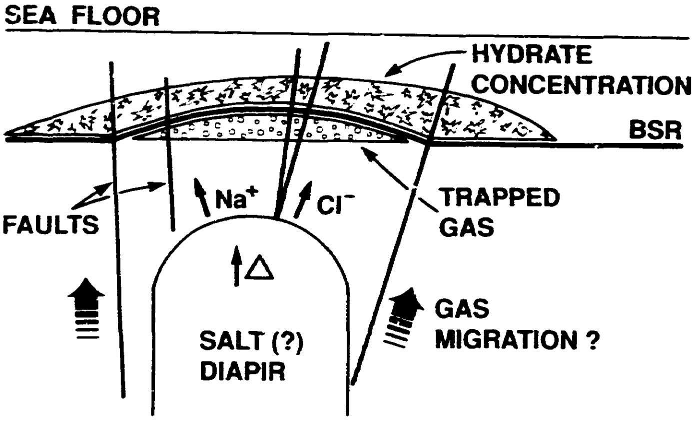

Figure 7. Conceptual sketch of the effects of a salt diapir on an overlying gas hydrate layer

deeper, the base of hydrate stability might be expected to extend progressively deeper into the sediments as water depth increases, assuming that pressure change depends only on change of water depth and that the thermal and chemical regimes are constant. Clearly, the structure of the gas hydrate layer (Fig. 5) is far more complicated than anticipated and thus is affected by factors other than just pressure due to water depth (Dillon and others, 1993; in press). Hydrate thins above diapirs (Carolina Trough Diapirs, Fig. 5), where the greater thermal conductivity of salt creates a warm spot and salt ions act as antifreeze, both effects resulting in a local shallowing of the base of the hydrate (Figs. 6 and 7; Schmuck and Paull, 1993). The thickness of the gas hydrate layer also decreases markedly at landslide scars (e.g. Cape Fear Slide, Fig. 5). The relationship might result because the slides may have been initiated by a breakdown of hydrate that was caused by glacial lowering of sea level and the accompanying pressure reduction at the sea floor. The slide itself then might cause a secondary pressure reduction by removing hydrate-cemented sediments and, in turn, initiate subsequent cascading slides (Fig. 8).

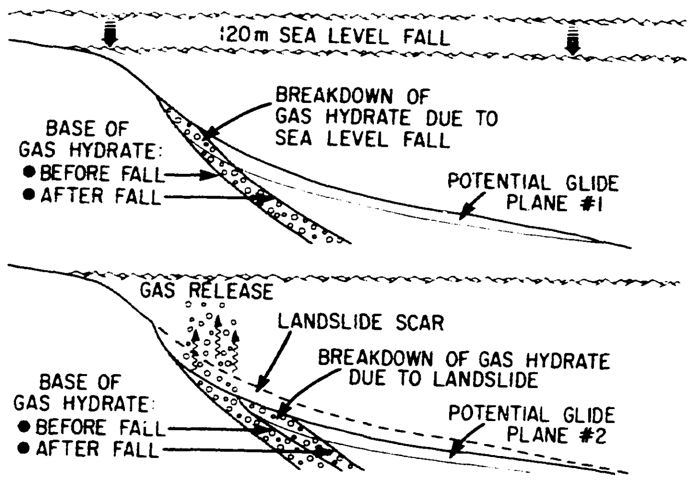

Figure 8. Conceptual sketch indicating pressure reduction effects of both sea level fall and removal of sediments by landsliding. These cause breakdown of hydrate and facilitate possibly cascading landslides.

Gas Traps Formed by the Hydrate Layer

Profiles show that the hydrate-cemented layer can form an impermeable seal and thus that hydrate-cemented sediments can create gas traps if configured properly. The simplest gas trap of this sort occurs when the sea floor, and therefore the hydrate layer forms a dome shape as occurs at the Blake Ridge (Fig. 4). A profile of the ridge is shown in Figure 9, in which the region marked by the strong BSR probably represents a region of trapped gas.

Strata that dip relative to the sea floor commonly are intersected at their updip ends by the gas hydrate layer. When these consist of alternating porous/permeable

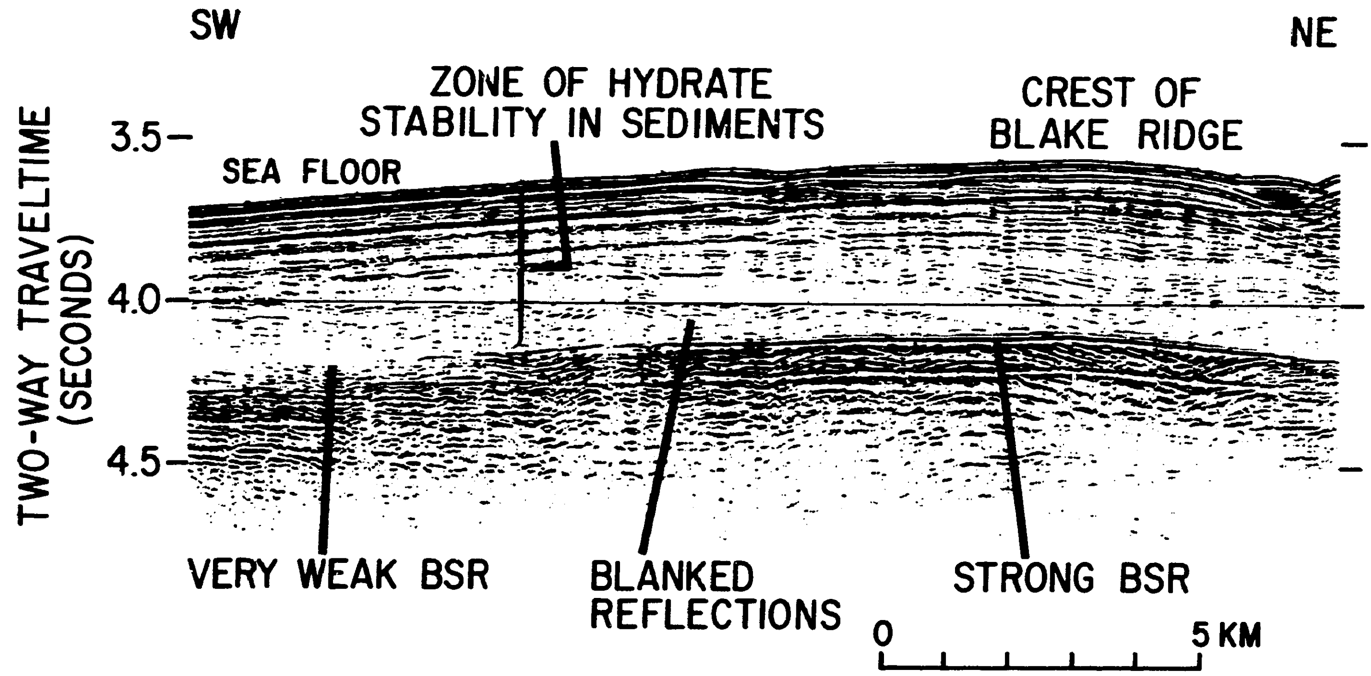

Figure 9. Seismic profile across the crest of the Blake Ridge off South Carolina. The crest of the ridge probably traps gas beneath the area of strong BSR.

and impermeable beds, the permeable layer can be sealed at its updip end by the gas hydrate cemented layer, forming a trap (Fig.10). The strongly-reflecting horizons that occur beneath the strong BSR probably represent strata containing free gas in Figure 10.

A dome can be formed in the gas hydrate seal above diapirs just by thinning of the gas hydrate stable layer by thermal and geochemical factors as discussed above (Figs. 6 and 7). Gas-charged layers sealed beneath such a dome appear in Figure 6A as a series of strong reflections that terminate against the blanked zone that contains hydrate. Gas traps formed by domes in the base of hydrate above salt diapirs commonly are small and perhaps are more significant as a drilling hazard than as a resource.

FUTURE WORK

Future work includes further seismic studies and laboratory analysis of simulated and natural marine gas hydrates. We collected 1367 km of new seismic data in 1992, mostly in a dense grid on the Blake Ridge, the region of highest hydrate concentration observed in our previous mapping. Processing of these data is underway. A laboratory system has been completed that will allow the formation of gas hydrate-cemented sediments at temperatures and pressures simulating ocean depths to 2400 m. (Figs. 11 and 12). Testing will include measurements of

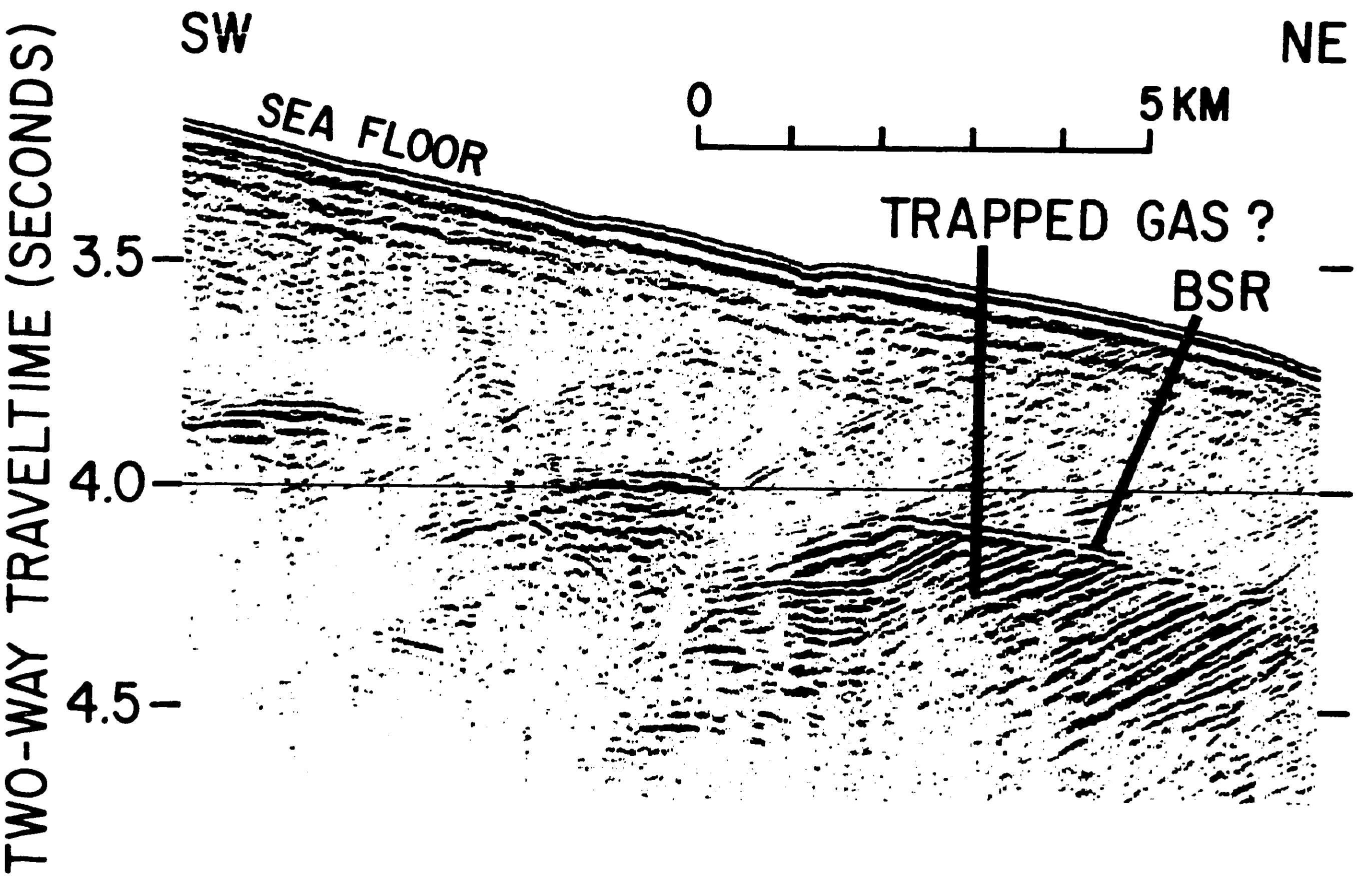

Figure 10. Dipping strata sealed at their updip end by the gas hydrate-cemented sedimentary layer and probably containing trapped gas

acoustic velocity, electrical resistivity, and physical properties. We also are involved in planning drillsites in the Blake Ridge region that have been proposed to the Ocean Drilling Project. Natural samples from areas that have been studied by seismic methods will provide ground truth and immensely increase our knowledge of hydrate distribution in nature.

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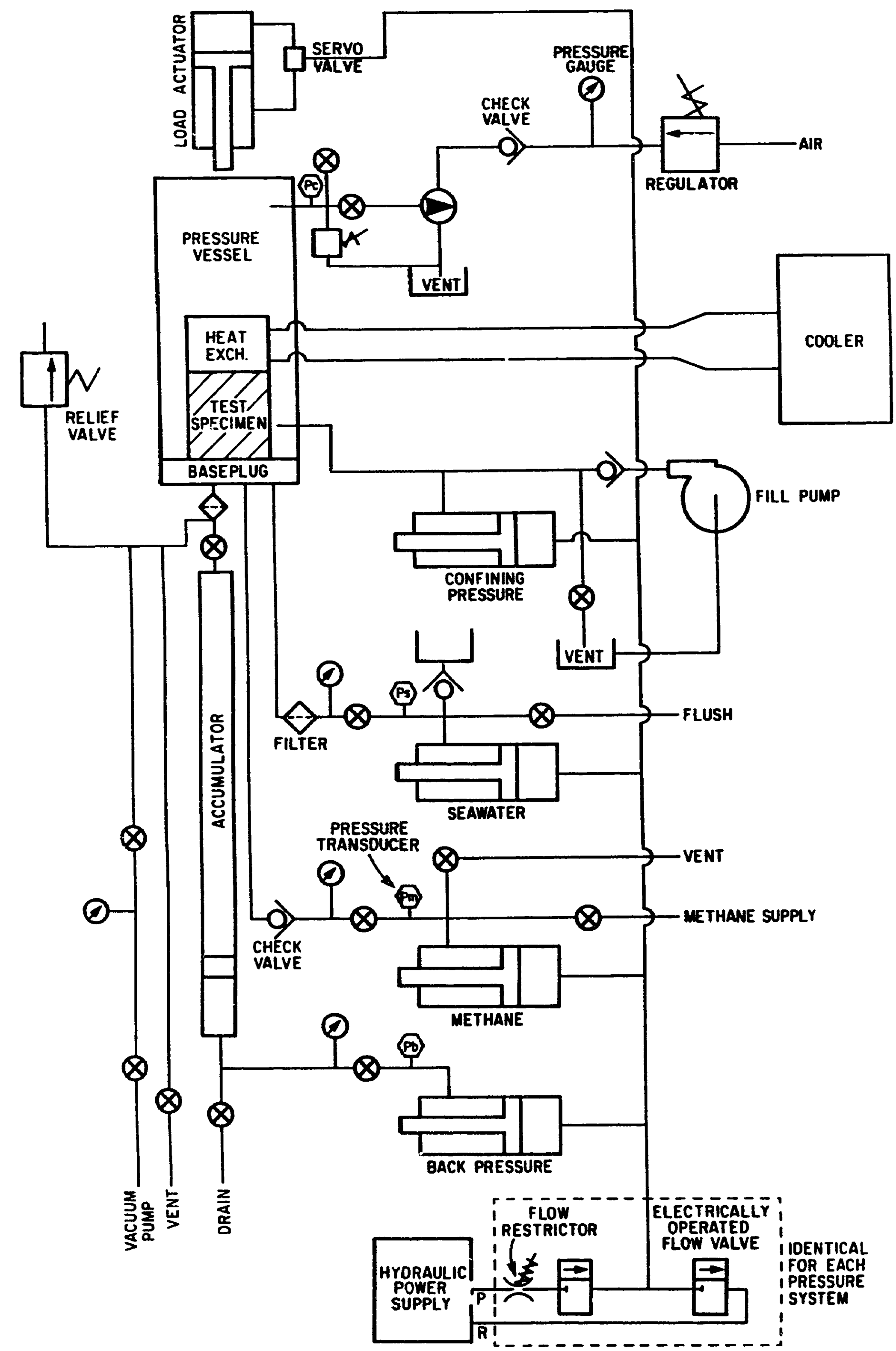

Figure 11. Diagram of the U.S. Geological Survey test system for analyzing gas hydrate-cemented sediments at sea floor conditions

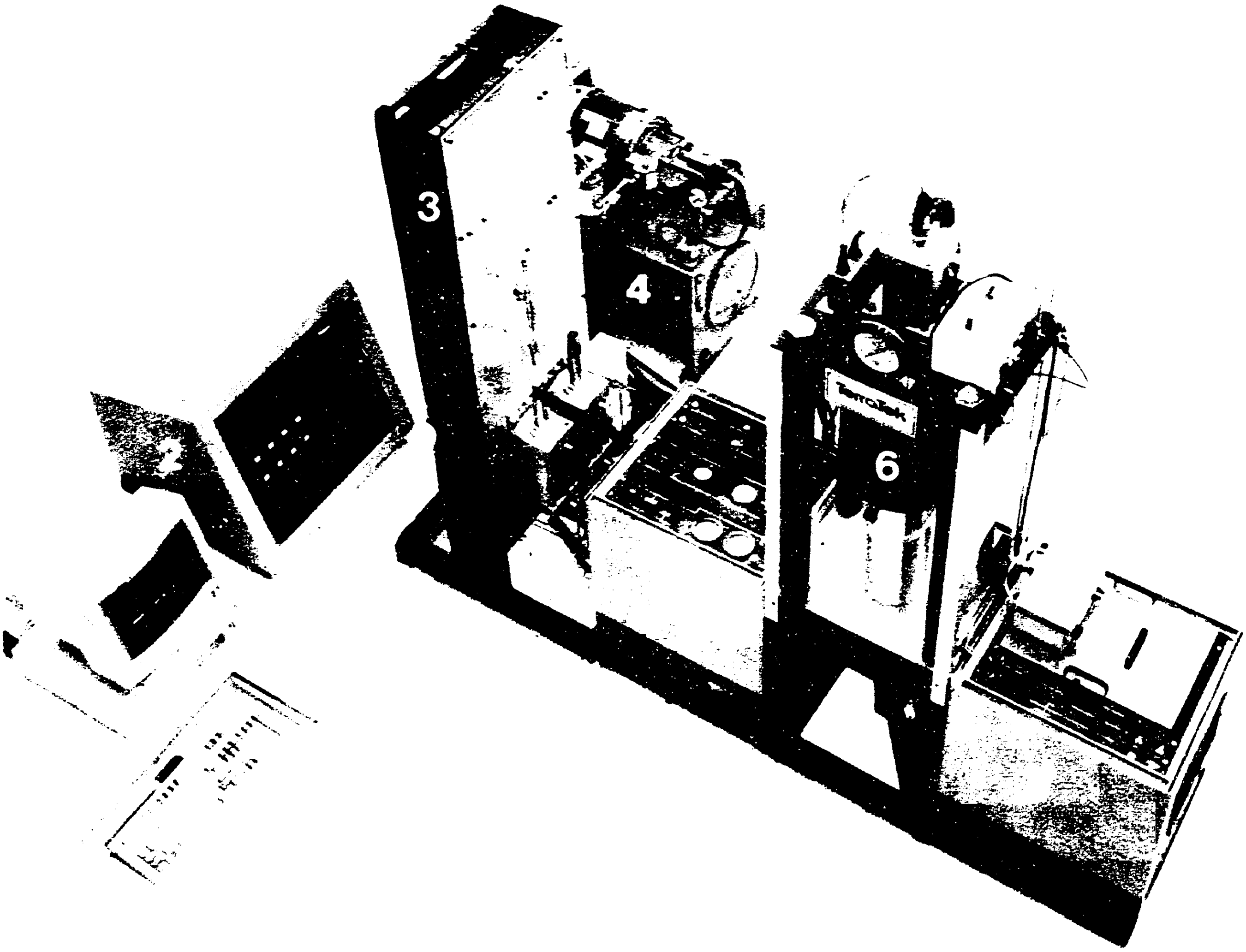

Figure 12. Photograph of the gas hydrate test system diagramed in Figure 11. 1. computer, 2. servo-controller and pressure control panel, 3. confining pressure, back pressure, seawater, and methane intensifier panel, 4. hydraulic power supply, 5. main valve control panel, 6. specimen chamber and load frame, 7. refrigeration system and pressure vessel valve control panel

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P13

Methodology for Optimizing the Development and Operation of Gas Storage Fields

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ABSTRACT

The Morgantown Energy Technology Center is pursuing the development of a methodology that uses geologic/reservoir modeling for optimizing the development and operation of gas storage fields. The methodology will result in defining how to provide a good geologic description of the reservoir, determine what type and how much data is needed to accurately model the field, maximize field/reservoir deliverability, minimize base gas requirements, and minimize field development costs.

Several Cooperative Research and Development Agreements (CRADAs) will serve as the vehicle to implement this product. Each CRADA will be in a different geologic setting. The first of these CRADAs has been signed with a gas storage operator. METC has developed a geologic model of an existing gas storage reservoir that is scheduled for further development. This description was based on geophysical well logs, core data, and pressure transient tests. A numerical simulator was used to history match early production and storage activities and two recent injection-withdrawal cycles. Good matches were obtained.

Projections of storage deliverability were made for many cases including adding vertical and horizontal wells. These runs were made based on a mix of 110-day baseload and 60-day peaking storage service schedules planned by the operator. The best results were obtained when four horizontal wells were added to the field which currently operates with ten vertical wells. Base gas was minimized and deliverability was maximized. A 4:1 vertical to horizontal well ratio was shown to exist.

P14 Feasibility Study To Evaluate Plasma Quench Process for Natural Gas Conversion Applications

CONTRACT INFORMATION

Contract Number	DE-AB05-30150
Contractor	Idaho National Engineering Laboratory/EG&G Idaho, Inc. P.O. Box 1625 Idaho Falls, ID 83415 (208) 526-0165
Contractor Project Manger	Charles P. Thomas
Principal Investigators	Peter C. Kong Brent A. Detering
METC Project Manager	Rodney D. Malone
Period of Performance	July 1, 1993 to September 30, 1993

FY1993 Program Schedule

	O	N	D	J	F	M	A	M	J	J	A	S
Feasibility Study										———	———	———

OBJECTIVE

The objective of this program was to conduct a feasibility study on a new process, called the plasma quench process, for the conversion of methane to acetylene. FY-1993 efforts were focused on determining the economic viability of this process using bench scale experimental data previously generated.

BACKGROUND INFORMATION

During the last decade most of the major oil companies have conducted internal studies on "remote gas" in efforts to capitalize on the large quantities of natural gas known to exist in various parts of the world. Such studies have typically been addressed at gas resources which are located too far away from population centers and end-use markets for conventional use, and cannot be economically liquefied for liquid natural gas carriers.

The Huels Company[1] in Germany has been using a plasma arc process to make light unsaturated hydrocarbons (acetylene and ethylene) from natural gas since the 1930's. These light hydrocarbons are subsequently converted to synthetic rubber and liquid hydrocarbons. The Huels process for arc plasma conversion of natural gas to acetylene requires quenching of the products by injection of cold liquefied hydrocarbons to prevent back reactions as the plasma is cooled. Quenching by this method is very energy intensive, inefficient, and the yield of the light olefin products is relatively low. The single pass yield of acetylene is less than 40% for the Huels process. Overall process yields are increased to 65% by recycling all of the hydrocarbons except acetylene and ethylene.

Patent protection for this novel process is being pursued by the inventors through the Idaho National Engineering Laboratory (INEL).[2] An internally-funded program at the INEL during FY-1991 demonstrated yields of acetylene as high as 70%. Further experiments during the FY-1992 resulted in higher yield (85%) of acetylene. Application of catalysts downstream of the quench reactor gaseous products can converted to higher molecular weight fractions such as liquid hydrocarbons. Optimization of the Plasma Fast Quench Reactor (PFQR) and the catalytic upgrading of acetylene could result in the development of a competitive process for the production of liquid hydrocarbons from natural gas.

The PFQR technology overcomes the limitations of other pyrolysis processes by adiabatic isentropic expansion of gases through a nozzle. Thermochemical modeling studies of the conversion of methane to acetylene were conducted to determine the equilibrium concentrations of acetylene and other reaction products between 500 to 3000 K. As expected, these studies determined that acetylene is a metastable compound that will decompose to carbon and other hydrocarbons if it is allowed to reach equilibrium at elevated temperatures (>800 K). The basic concept of the PFQR is that it will maximize the acetylene yield by "freezing" the product out of the reaction zone with extremely rapid decrease in temperature and pressure.

Significance to Fossil Energy Program

Successful development of the plasma quench technology (i.e., favorable product conversion and energy efficiencies) will result in a economic process for conversion of natural gas to high value hydrocarbons. This technology provide a means for the petroleum industry to capitalize on the vast quantities of natural gas which are known to exist (i.e., remote locations and shut-in gas wells) but are not in close proximity to population centers and thus end-use applications.

PROJECT DESCRIPTION

Historically, methane in non-fuel applications has been limited to feed stock for methanol, ammonia or hydrogen. With the discovery of natural gas in remote locations, such as, the North Slope of Alaska, the need for technology to convert gas to transportable fuels has arisen. To this date, much of the research effort has focused on the conversion of methanol (Mobil case) or the oxidative coupling of methane (ARCO Chemical , ACC, case). LNG is not a viable option in many cases due to the limitations on access to shipping lanes due to seasonally closed ports or other logistical considerations.

The key variable in the profitability of both the ACC and Mobil technologies is the cost of the natural gas and the value of the gasoline produced. With the current crude/gasoline pricing, natural gas cost must be less than $1/MSCF for an after tax return on investment of greater than 10%.

RESULTS

Methane to Gasoline Economics

In this analysis, an alternate route using acetylene from methane pyrolysis is considered. It has been demonstrated that acetylene can be produced from methane in high yields by high temperature, short residence time pyrolysis. Free energy favors the formation of acetylene at high temperatures. Methane pyrolysis has been practiced in the past with varying degrees of success. The major drawback is the inability to raise the temperature of the feed natural gas very rapidly and to quench the products to a non-reacting mixture in less than half of the reaction time.

To avoid the formation of non-selective byproducts via secondary reactions, the products must be quenched very rapidly. Historically, direct quench and direct reactive quench using LPG pyrolysis have been studied in this regard. Recently, the aerodynamic quench using a C-D nozzle has been demonstrated by INEL to provide quenching in under two milliseconds. Acetylene yields have exceeded 90%. After the reaction and quench, acetylene is hydrogenated selectively to ethylene. Subsequently ethylene is oligomerized to gasoline, a pumpable and transportable fuel.

Using this technology and "conventional" hydrogenation and oligomerization catalysts, an economic evaluation was performed. Given the current state of process development, the INEL technology is clearly the low raw material cost and the low cost capital option relative to ACC and Mobil. The estimated capital cost is about 80 % of the nearest competitor, ACC. The leveraging economic variable for the INEL reactor, however, is the amount of power consumed in the pyrolysis reactor and the cost of that power. In the INEL case, the power contribution to required netback can be 50%, easily the largest contributor and over twice the contribution of the cost of the natural gas feed.

The overall economics for the instantaneous construction/operation case indicate that the ACC Redox case is the most attractive for the conversion of natural gas to gasoline. Assuming a 4.5 ¢/kwh power cost and a consumption of 3.6 kwh/lb gasoline for the INEL case, the required netback is 30% greater than the ACC Redox case. With lower cost power, less than 3 ¢/kwh, INEL technology becomes the most attractive of the conversion technologies.

However, the current and forecasted economic situation does not favor using natural gas conversion to make gasoline in any of the processes. Historical data indicate that the refinery gate price of gasoline reaches about $1/gal only when crude rises to $35/bbl. Currently, gasoline and crude oil are much lower, about 60% of these figures. As a target, natural gas would have to be free, when crude is $ 35/bbl in order for the ACC case at 12,500 BPSD to approach a 12% ATROI. There are significant economies of scale that tend to improve the economics substantially, when dealing with large gas fields. The North Slope of Alaska, has a gas supply that would require up to 20 plants of the size evaluated in this report. With these volumes, the ACC technology attains a 12% ATROI when the natural gas price is a maximum of $1/MSCF at $35/bbl crude oil.

With $ 35/bbl crude and a 2 MMMSCFD field, the INEL technology shows break-even economics (12% ATROI, capital USGC basis) at a gas price of $ 1/MSCF, a power cost of 2.5 ¢/kwh and a consumption of 2.5 kwh/lb gasoline. If crude oil prices remain flat on average, as in the 1980's, then the target numbers get more severe.

Alternative Methane Conversion Technology

Even given the gloomy economic picture for gas conversion technologies caused by the low crude oil cost, the INEL technology shows significant promise due to low capital cost and high yields. The key process questions that must be addressed are the scalability of the pyrolysis-quench, the reduction in the required power, and the reactor design for the acetylene hydrogenation to insure selective conversion to ethylene rather than ethane.

Developments in the cyclotrimerization of acetylene to benzene provide the possibility of additional improvement in the economics by reducing the capital and operating costs. The downside is the likely inability to use benzene directly as a motor fuel due to environmental and toxicity issues. Since benzene has a higher value than gasoline, the economics could be greatly improved if this market could be exploited. Technologies such as the direct coupled pyrolysis and oligomerization developed at NREL should be investigated. There may be operating conditions in the Plasma- Quench process where the NREL technology may be applicable.

Along the same lines as the benzene argument, the INEL technology may provide an attractive route to ethylene. Rough calculations indicate that the INEL technology is nearly competitive with Ethane/Propane steam pyrolysis. Although much of the US olefin capacity is already in place, there may be another, aggressive round of olefin plant construction in the next two decades, some of which will be based on non-conventional technology. This should be studied in further detail. In order to properly assess the INEL technology in an ethylene case, it is suggested that an entire petrochemical facility be considered based on natural gas. Products should include acetylene, ethylene, hydrogen, benzene, ethylbenzene and styrene. All of these products are potentially recoverable in controllable, high yields and with high purity.

Conclusion

The major conclusion of this analysis is that the INEL technology could be competitive with existing natural gas conversion technologies given the proper power consumption and pricing. However, none of the technologies will be economical if the predicted long term crude pricing is correct. The INEL technology does have the advantage of providing high yields of valuable chemicals (ethylene and acetylene) at low cost. Downgrading these to gasoline value, although taking advantage of the market demand, reduces the product value significantly and the margins are insufficient to carry the project.

FUTURE WORK

Future activities will focus on technical development of the plasma quench process and pilot demonstration of this process within 3 to 5 years. A combination of empirical development, advanced spectroscopic diagnostics, modeling, and catalyst applications will be used to gain understanding of the process and lay the groundwork for a process to convert natural gas to high value liquid hydrocarbons.

A combination of empirical development, advanced spectroscopic diagnostics, modeling, and catalyst applications will be used to gain understanding of the process and lay the groundwork for an economic process to convert natural gas to high valued liquid hydrocarbons.

REFERENCES

1. Gladish, H., "How Huels Makes Acetylene by DC Arc," Hydrocarbon Processing & Petroleum Refiner, Vol. 41, No. 6, pp. 159-64, June 1962.
2. B. A. Detering, P. C. Kong, and A. D. Donaldson, "Method to Convert Methane and/or Natural Gas to Acetylene and Other Unsaturated Hydrocarbons in a Plasma Fast Quench Reactor," EGG-PI-655, March 3, 1993, Patent Pending.

P15 Natural Gas Recovery, Storage, and Utilization SBIR Program

Harold D. Shoemaker
Morgantown Energy Technology Center

SUMMARY

The Small Business Innovation Research (SBIR) program was created in 1982 by Public Law 97-219 and reauthorized in 1992 until the year 2000 by Public Law 102-564. The purposes of the new law are to (1) expand and improve the SBIR program, (2) emphasize the program's goal of increasing private-sector commercialization of technology developed through Federal R&D, (3) increase small business participation in Federal R&D, and (4) improve the Federal Government's dissemination of information concerning the SBIR program.

Eleven agencies, those with extramural R&D budgets of over $100 million, were required to establish an SBIR program using a set-aside of a stated percentage of that budget. The percentage has grown from an initial 0.2 percent in Fiscal Year (FY) 1983 to 1.25 percent in FYs 1986-1992 for the civilian agencies. Public Law 102-564 increases the set-aside gradually, beginning with 1.5 percent in FYs 1993-1994 and attaining a maximum of 2.5 percent in FY 1997.

The funding for the DOE SBIR program has totaled $330 million over the first 11 years. The program's budget for FY 1993 was $49.7 million. These funds are used to support an annual competition for Phase I awards of up to $75,000 for about 6 months to explore the feasibility of innovative concepts. Phase II is the principal research or R&D effort, and the awards are up to $600,000 for 1994 and $750,000 for 1995 and beyond for a 2-year period. Phase III is the commercial application of the research and R&D effort by small businesses with non-Federal capital and may also involve follow-on, non-SBIR funded Federal contracts for products or services intended for use by the U.S. Government. To date, the DOE has funded about 140 Phase I applications and 55 Phase II applications per year. Success ratios for applications have been about 12 percent in Phase I and 45 percent in Phase II.

Each agency issues at least one annual solicitation for Phase I grant applications. DOE's solicitation contains topics in technical areas such as Basic Energy Sciences, Health and Environmental Research, High Energy and Nuclear Physics, Magnetic Fusion Energy, Energy Efficiency and Renewable Energy, Nuclear Energy, Fossil Energy, Environmental Restoration and Waste Management, and Arms Control and Nonproliferation. Each year, about 45 topics are allocated among the technical areas in proportion to their contributions to the budget. These funds are placed in a common pool, and applicants are selected competitively for awards on scientific and technical merit.

DOE's SBIR program has two features that are unique:

- It provides for uninterrupted funding between Phases I and II for those awardees that choose to submit their Phase II applications 6 weeks before the end of their Phase I grants. Funding continuity has been provided to these awardees for each of the past 10 years.

- The DOE has sponsored a Commercialization Assistance Project (CAP) for the past

4 years to aid awardees in seeking follow-on funding for Phase III. This effort has provided individual assistance in developing business plans and in preparing presentations to potential investment sponsors. Forty-three percent of the companies that participated in the 1991 CAP achieved further funding for their projects, resulting in a total of more than $5.5 million in private-sector support toward commercialization. In the 1993 CAP, potential awardees made presentations to about 55 sponsors from venture capital firms and large corporations.

In the 1994 DOE SBIR solicitation, the DOE Fossil Energy topics are

- Innovative Fossil Solids and Liquids Processing and Related Crosscutting Applications
- Advanced Environmental Control Technology for Fossil Energy
- Advanced Technology for the Recovery, Storage, and Utilization of Natural Gas
- Coal-Based Power Systems Technology
- Enhanced Oil Recovery

The subtopics for this solicitation's natural gas topic are (1) Advanced Geotechnology in Production Applications, (2) Advanced Geotechnology in Gas Storage Operations, (3) Advanced Environmental Considerations in the Recovery of Natural Gas, and (4) Advanced Concepts for Transportation and Utilization of Natural Gas.

The 1994 DOE SBIR solicitation was mailed to prospective proposers on November 15, 1993, and the proposals are due to DOE by February 14, 1994. Questions about the DOE SBIR program may be addressed to Mrs. Kay Etzler, Program Spokesperson, c/o SBIR Program Manager, ER-16, U.S. Department of Energy, Washington, DC 20585, telephone (301) 903-5867.

A Fossil Energy natural-gas topic has been a part of the DOE SBIR program since 1988. To date, 50 Phase I SBIR natural-gas applications have been funded. Of these 50, 24 were successful in obtaining Phase II SBIR funding. The current Phase II natural-gas research projects awarded under the SBIR program and managed by METC are presented below by award year. The presented information on these 2-year projects includes project title, awardee, and a project summary.

1992 PHASE II PROJECTS

Landfill Gas Recovery for Vehicular Natural Gas and Food Grade Carbon Dioxide -- Acrion Technologies, Inc., 6027 Castlehill Drive, Cleveland, Ohio 44143

Landfill gas (LFG), composed of methane and carbon dioxide in roughly equal proportions, along with a myriad of trace contaminants, is now essentially a wasted resource that could provide locally significant supplemental energy. Research is ongoing to further develop a process that recovers both high form-value methane and food-grade carbon dioxide. The process requires no solvents, absorbents, or other physical separating agents, which often themselves become environmental problems.

Vehicular natural gas (VNG) ties the value of methane recovered from LFG to transportation fuels rather than pipeline gas. The market for VNG is expanding rapidly with the advent of clean air concerns and the push for alternative clean transportation fuels. LFG methane is scrubbed clean of trace contaminants by condensed, liquid, carbon dioxide. Food-grade carbon dioxide is produced in one stage of triple-point crystallization. Phase I established the technical and economic feasibility of the technology. The primary objective of Phase II is demonstration of carbon dioxide purification by triple-point crystallization on a scale commensurate with landfill gas recovery applications. Production of approximately 25 tons per day of pure liquid carbon dioxide corresponds to treatment of about 2 million standard cubic feet/day of raw LFG. Secondary objectives are the continued expansion of the process data base, examination of final LFG dehydration, and completion of a refined design and economic analysis of the Phase I commercial LFG recovery process.

A Brine Disposal Process for Coalbed Gas Production -- Aquatech Services, Inc., P.O. Box 946, Fair Oaks, California 95628

In Phase II, a brine disposal process is being developed that converts the entire brine production stream of a typical coalbed gas-production site into (a) clean water for agricultural and other uses, combustion products, and water vapor that can be released into the atmosphere; and (b) dry solids that are recycled for industrial consumption.

Coalbeds in the U.S. contain gas reserves estimated at 401 trillion cubic feet. The energy in these reserves could meet the entire U.S. energy requirements for a period of 5 years. As coal gas is recovered, brine also is produced. Federal, state, and local regulations governing health and environmental protection have made existing brine disposal methods, such as the use of injection wells, more complex and costly. This Phase II research will provide an environmentally acceptable and cost-effective alternative disposal technique.

Phase I research successfully demonstrated a viable, submerged, combustion evaporation process that reduced brine volume by more than 95 percent. In Phase II, a reverse osmosis unit will be evaluated for its efficiency and cost effectiveness as a first step in the brine reduction process. The produced fresh water could be used for agricultural purposes. The submerged combustion evaporator would reduce the remaining brine volume so that the combined processes would then reduce the brine stream of a typical producing site by a factor of 25 or more. A pulse combustion dryer could reduce the resulting concentrated brine slurry to disposable solids, water vapor, and combustion products.

Phase II research consists of the following parts: (1) pilot tests of reverse osmosis units to determine their operating performance and cost effectiveness (coal-gas brine elements and conditions that would damage the membranes will be isolated); (2) tests of a pulsed-combustion dryer apparatus and solids handling facility to reduce the concentrated brine that is discharged from the submerged combustion evaporator to a zero liquid level; (3) tests of the combined components of reverse osmosis, submerged combustion evaporation, and pulsed combustion drying (or alternates determined later) to provide an integrated brine disposal process; and (4) a study of the cost effectiveness of a range of the basic three components. These components will be evaluated against each other to arrive at an optimized solution to the brine disposal problem.

Development of Hollow-Fiber Modules for the Purification of Natural Gas -- Bend Research, Inc., 64550 Research Road, Bend, Oregon 97701-8599

All natural gas at the wellhead contains contaminants such as water vapor that must be removed before the gas can be transported in the pipeline. Conventional natural-gas purification processes are coming under increased environmental scrutiny because they emit harmful treatment chemicals, undesirable components from the natural gas, or both. While membrane processes are potentially ideal for the purification of natural gas, current membrane systems cannot be used for a number of important applications because of limitations of membrane materials and module designs. Those disadvantages lead to excessive gas losses and other performance problems.

The overall goal of this program is the development of hollow-fiber membrane modules capable of dehydrating natural gas with minimal gas loss. Development of these modules would make it possible to use the membrane-based process to dehydrate natural gas at the wellhead economically, thus advancing full utilization of domestic gas reserves. During Phase I, significant progress was made toward developing technology that meets this goal.

Hollow fibers were made of hydrocarbon-resistant polymers and tested at pressures of 1,000 lb per square-inch-gage (psig). Shortcomings in the selective coating and in the coatability of the inside surfaces of these preliminary high-burst-pressure fibers led to higher-than-desired gas losses; however, tests at 500 psig demonstrated the feasibility of this technology and its potential for providing a low-cost, energy-efficient method to dehydrate natural gas.

Phase II is aimed at improving the coatability of the inside surfaces of the fibers. In addition, a coating that is optimized for low gas losses at 1,000-psig operation will be developed. The ultimate goal of Phase II is to perform a field test in collaboration with a Phase III commercialization partner. The performance targets for this field test are (a) dehydration of natural gas to 7 lb water per million standard cubic feet with a gas loss of 3 percent or less, and (b) a productivity of at least 2 standard cubic feet per minute per square foot of membrane area.

Spontaneous Natural Gas Oxidative Dimerization Across Mixed Conducting Ceramic Membranes -- Eltron Research, Inc., 2830 Wilderness Place, Boulder, Colorado 80301-5455

This project will be directed towards developing mixed proton- and electron-conducting perovskite membranes that promote the spontaneous and highly selective oxidative dimerization of methane. Membranes behave as short circuited electrochemical cells with both ionic and electronic transport proceeding through the membrane bulk.

Work performed during Phase I identified mixed conducting membranes possessing high selectivity to promote the subject reaction. This was achieved by avoiding the presence of mobile oxygen anions at the membrane oxidizing surface that could lead to undesirable deep methane oxidation products (carbon dioxide).

Phase II includes (1) selecting preferred perovskite mixed conducting membranes; (2) performing an in-depth study of membrane performance; (3) optimizing preparation techniques for membranes to be incorporated into internally and externally manifolded methane reactors; (4) conducting extensive performance testing of methane reactors; and (5) characterizing performance enhancement that may be realized from supported membrane structures prepared using metal oxide chemical vapor deposition techniques. Application of the mature technology will be expected to be both simple and inherently low cost, and should circumvent many of the conversion efficiency restrictions currently limiting analogous heterogeneous reactions. Results and experience gained during Phase II will provide the technical and engineering basis from which Phase III development and commercialization will proceed.

A Low-Cost Offshore Drilling System for Natural Gas Hydrates -- Quest Integrated, Inc., 21414 68th Avenue South, Kent, Washington 98032

Accumulations of methane hydrates in marine sediments have implications for a variety of offshore activities, including geotechnical engineering of bottom-founded structures, geochemical exploration for oil and gas exploration, deepwater drilling operations, marine sediment acoustics, evaluation of the global methane budget, and potential exploitation as an unconventional gas resource. Numerous studies have observed or inferred the occurrence of hydrates in the sediments of continental margins over large areas; however, observations of the structure and distribution of these hydrates have been limited by conventional drilling, coring, and sampling technology.

Phase I research identified critical development requirements for an integrated drilling/completion system for characterizing methane hydrate accumulations and assessing the potential for gas production.

Phase II includes fabrication and testing of a low-cost system for drilling small-diameter holes in water depths of up to 3,000 meters with sediment penetration depths of 500 meters. Drill cuttings will be returned to the surface for the analysis of sediment gas concentration and composition.

A Motorless Directional Drill for Oil and Gas Wells -- Quest Integrated, Inc., 21414 68th Avenue South, Kent, Washington 98032

Currently, much of the U.S. oil reserve exists in depleted reservoirs and tight formations that could greatly benefit from directional drilling. However, the high cost of directional drilling cannot always be justified, and, therefore, these resources face abandonment. Modern materials, analysis, and more knowledge of directional drilling requirements provide an opportunity to reduce drilling costs by eliminating the downhole motor for many directional drilling applications.

Phase I demonstrated the feasibility of a motorless directional drilling (MDD) concept for oil and gas wells. The elimination of the high maintenance and high cost components in downhole motors is estimated to save about 60 percent in motor costs. In addition, the MDD could enable the rapidly advancing coiled tubing and slim-hole drilling technology to steer precisely to formation reservoirs.

Phase II will include analysis and component, functional, and field testing. Early in the program, applications that have the best chance of technical and commercial success will be identified, and the MDD will be developed for those market areas.

Development of a Multiple Fracture Creation Process for Stimulation of Horizontally Drilled Wells -- TPL, Inc., 3754 Hawkins NE, Albuquerque, New Mexico 87109

Pulsed fracturing processes, capable of multiple fracture creation, are attractive for oil and gas well stimulation because of low cost, increased production efficiencies, and enhancement of production economics. Naturally fractured reservoirs are primary targets because of the higher probability of fracture intersection. This approach to stimulation has numerous benefits for horizontal wells. The economics are particularly attractive for mature oil and gas wells. The effectiveness of early pulsed fracturing tests was marginal, believed attributable to erroneous multiple fracture creation design methodology.

A new design methodology has been formulated that is applicable to a variety of wellbore conditions. In Phase I, the new multiple-fracture-creation design methodology was applied to representative Devonian Shale and Western Tight Gas Sands wells. Fracture requirements were defined. Based on closed bomb tests, an appropriate propellant system was formulated. A calibrated combustion model was applied to a realistic pulsed fracturing/wellbore situation. Computed results indicated that multiple fractures could be created.

The Phase II project, through gun barrel testing that includes a projectile mass to stimulate fracture creation, will formulate a propellant material system to optimize fracture creation and extension. Refined modeling capability will be developed. An improved engineering system for downhole applications will be designed and tested. Two field test series (4-6 wells) are planned for a shallow sandstone and deeper limestone fields. Reservoir characterization and wellbore logging will accompany the stimulation tests to quantify the created fracture systems. Production will be monitored to assess stimulation effectiveness. Successful field tests are anticipated, establishing a data base to support a commercialization effort.

1993 PHASE II PROJECTS

A Process for Sweetening Sour Gas by Direct Thermolysis of Hydrogen Sulfide -- Bend Research, Inc., 64550 Research Road, Bend, Oregon 97701-8599

About 25 percent of the natural gas produced in the U.S. contains excessive amounts of hydrogen sulfide. Current methods for treating this sour natural gas (e.g., amine scrubbing coupled with flaring or the Claus process, and liquid redox systems) produce environmentally objectionable by-products. As increasingly stringent environmental regulations are legislated and enforced, current gas-sweetening technology will become inadequate for economically utilizing the nations' sour-gas reserves -- estimated to be 135 trillion cubic feet.

Continued development of a membrane-reactor-based process to sweeten sour natural gas without releasing sulfur compounds (such as SO_x) to the atmosphere or producing other toxic or polluting by-products appears promising. The membrane-reactor process will be energy- and cost-efficient compared to currently used processes. The membrane-reactor achieves high efficiency in the direct conversion of hydrogen sulfide in the sour-gas feed to elemental sulfur and hydrogen, by employing a platinum-coated, hydrogen-permeable metal membrane that catalyzes the decomposition of hydrogen sulfide and simultaneously separates hydrogen as it is produced.

In Phase I, the hydrogen sulfide thermolysis reaction catalyzed by the membrane surface was shown to be very rapid, and the rate of conversion of hydrogen sulfide to hydrogen and elemental sulfur (beyond the equilibrium value) was shown to be proportional to the rate of hydrogen removal by the metal membrane. Tests at realistic operating conditions showed that the formation of coke and other by-products on the membrane surface was insignificant.

Phase II is directed at increasing hydrogen flux by reducing the thickness of the Pt coating on the feed surface of the membrane. Using a prototype reactor that utilizes this high-flux membrane, a synthetic sour natural-gas feed (at 1,000 psi) will be treated by reducing hydrogen sulfide from an initial concentration of about 0.5 percent down to ≤ 4 parts per million (pipeline specifications).

Remote Leak Survey Capability for Natural Gas Transport Storage and Distribution Systems -- Deacon Research, 2440 Embarcadero Way, Palo Alto, California 94303

The detection of natural gas and coal mine methane leakage is important for both worker safety and environmental considerations. The accepted techniques to detect such leaks are based upon slow air-sniffing systems that detect the major constituent of natural gas (methane) by chemical means. While such techniques are sensitive, they are slow and must be employed in the immediate vicinity of the suspected leak. Remote optical detection of methane has been demonstrated, but such systems have been too complicated for field use.

Phase I developed a small and rugged remote optical sensor for the detection of dilute gaseous methane in air that utilizes a proprietary stabilization scheme. The approach is considerably less complicated than other schemes, such as distributed feedback frequency stabilization, and will be inexpensive enough to manufacture for several commercial areas. The sensitivity, ruggedness, and simplicity of this approach was demonstrated in Phase I.

Phase II will develop a prototype system design suitable for field testing for performance and regulatory certification.

Electrochemical Natural Gas Reduction to Alcohols -- Eltron Research, Inc., 2830 Wilderness Place, Boulder, Colorado 80301-5455

The purpose of this project is to develop advanced electrolytic technology to promote methane hydroxylation at practical rates, selectivities, and efficiencies that leads to the synthesis of commercially significant alcohols.

Phase I identified advanced electrocatalyst and catalyst sites that were incorporated into gas diffusion electrodes, demonstrating high activity towards promoting initial oxygen reduction, from a methane/oxygen reactant gas mixture. Subsequent proton abstraction from the methane intermediate was found to be followed by reaction to yield methanol and ethanol. Experimental conditions were identified that gave high efficiencies for this process and provided a technical foundation for optimization. Methanol synthesis rates observed during Phase I using electrodes that were not yet optimized, were up to three orders of magnitude greater than those for conventional heterogeneous methanol synthesis.

Phase II will include (1) preparing selected electrocatalysts and catalysts; (2) performing an in depth electrochemical study of electrocatalyst and catalyst optimization for improved selective methane hydroxylation; (3) incorporating preferred dispersed electrocatalysts and catalysts into gas diffusion electrodes, compatible for application with aqueous and polymer electrolyte-based electrolytic technology; and (4) fabrication and performance testing of electrolytic stack technology. The application of mature technology for methane hydroxylation leading to alcohol synthesis will be expected to proceed with higher selectivity and efficiency and at a higher rate than for related heterogeneous reactions that lead to the same reaction products.

Reinterpretation of Existing Wellbore Log Data Using Neural-Based Pattern Recognition Processes -- Jason Associates Corporation, 1500 West Canal Court, Suite 400, Littleton, Colorado 80120.

A significant portion of the known gas reserves is contained within heterogeneous reservoirs for which well logging, using current analytical techniques, often can only provide qualitative information. This is because of the indeterminate nature of geologic signal processing, combined with the inherent limitation of utilizing mechanistic approaches to analyze the interrelationships of multiple signals in complex geologic formations.

Hydrocarbon Signature Logs (HSLs) identify producing zones with a greater degree of accuracy than can be derived using conventional wellbore analysis. This greater accuracy can substantially increase the hydrocarbon discovery rate for obscure reservoirs. HSLs are created using a proprietary process termed PROWLS (Pattern Recognition for Wellbore Log Suites). PROWLS is based upon an emergent pattern recognition technology called neural computing that has been developed primarily through Department of Defense-sponsored research to address the problems of identifying military targets in difficult environments.

Phase I successfully adapted this technology so that it can be used to identify oil-producing zones in a well, using a suite of conventional wellbore logs. Initial proof-of-concept demonstration used the Silurian Interlake formation, which is an Upper Interlake Subgroup of the central Williston Basin that produced oil and gas from sequences of thinly interbedded peritidal dolomites and calcareous dolomites. On the Nesson Anticline, the Silurian interval is recognized as an area with a high potential for by-passed production because of the extreme difficulty of identifying pay zones using conventional log analysis. HSLs developed for wells in this formation identified producing intervals to a high degree that were not achievable with conventional analysis.

Phase I demonstrated that PROWLS can reliably estimate production of tight gas sands based upon patterns contained within the log suites. Further, PROWLS accurately identified all of the dry wells within the study field. HSLs were produced that showed definitive signatures, indicating downhole porosity and permeability of the producing sand. Maps were produced that identified producing trends for the study field.

Phase II will define process capabilities and limitations. Procedures for model verification and validation will be designed. The PROWLS process will be imbedded into an existing commercial well-log software system. Extensive demonstration cases will be developed to show system capabilities.

An Advanced Liquid Membrane System for Natural Gas Purification -- LSR Technologies, Inc., 898 Main Street, Acton, Massachusetts 01720

The cost associated with contaminant removal from natural gas is considerable. Impurities such as hydrogen sulfide, carbon dioxide, nitrogen, moisture, and natural gas liquids must be removed in order for the gas to be suitable for pipeline transport. Hydrogen sulfide removal and recovery, in particular, can involve costly processing steps because of the low selectivity of this contaminant by chemical solvents that also have an affinity for carbon dioxide.

This project will develop a novel Moving Liquid Membrane System (MLMS) for the selective removal of hydrogen sulfide. The MLMS combines absorption and regeneration in the same processing unit. Its design utilizes a large surface area for high mass transfer in a compact control volume. Also, the liquid circulation rate is much lower than that of conventional absorption systems. Phase I has shown that the MLMS has the ability to produce very high hydrogen sulfide permeability and hydrogen sulfide/carbon dioxide selectivity. The bench-scale membrane apparatus has also proven to be completely stable with no evidence of membrane dryout or degradation. The concept needs further refinement of its design through additional laboratory and pilot-scale testing.

Phase II will focus on further testing for hydrogen sulfide removal using simulant feed gases. It is also important that new gas processing technology be brought to the field to validate its operability with real gas. Therefore, a larger pilot-scale unit will be constructed to evaluate the long-term operability of the system with industrial gas. A key aspect of the research will be to bring the technology to the demonstration stage.

P16 Greater Green River Basin Well-Site Selection

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INTRODUCTION

Recent estimates of the natural gas resources of Cretaceous low-permeability reservoirs of the Greater Green River basin indicate that as much as 5,000 trillion cubic feet (Tcf) of gas may be in place (Law and others 1989). Of this total, Law and others (1989) attributed approximately 80 percent to the Upper Cretaceous Mesaverde Group and Lewis Shale. Unfortunately, present economic conditions render the drilling of many vertical wells unprofitable. Consequently, a three-well demonstration program, jointly sponsored by the U.S. DOE/METC and the Gas Research Institute, was designed to test the profitability of this resource using state-of-the-art directional drilling and completion techniques. DOE/METC studied the geologic and engineering characteristics of "tight" gas reservoirs in the eastern portion of the Greater Green River basin in order to identify specific locations that displayed the greatest potential for a successful field demonstration.

The demonstration is planned to include vertical, high-angle, and horizontal wells drilled from closely spaced locations. The vertical well will be used to characterize the reservoirs. The high-angle wellbore is intended to test a thick section of lenticular reservoirs. In contrast, the horizontal well will target a relatively thin, yet laterally continuous, "tight" gas reservoir with limited internal heterogeneities. For production, both wells will depend heavily on the occurrence of natural fractures.

The appraised area includes townships 12-26N and ranges 93-105W. This area encompasses the Rocks Springs Uplift, Wamsutter Arch, and the Washakie and Red Desert (or Great Divide) basins of southwestern Wyoming. The work was divided into three phases. Phase 1 consisted of a regional geologic reconnaissance of 14 gas-producing areas encompassing 98 separate gas fields. In Phase 2, the top four areas were analyzed in greater detail, and the area containing the most favorable conditions was selected for the identification of specific test sites. In Phase 3, target horizons were selected for each project area, and specific placement locations were selected and prioritized.

PHASE 1: SELECTING THE TOP FOUR AREAS

Phase 1 consisted of a reconnaissance of the geology and production characteristics of 14 areas of closely spaced and geologically similar gas fields in the eastern half of the Greater Green River basin. The area studied included townships 12-26N and ranges 93-105W (Figure 1). Each area was evaluated for current rates of gas, oil, and water production, estimated ultimate recovery (EUR), unit status, typical well spacings, core availability, and discovery date. Phase 1 work occurred in FY 1992, and a synopsis of that work was presented at a DOE/GRI Green River Basin Workshop in Denver, Colorado.

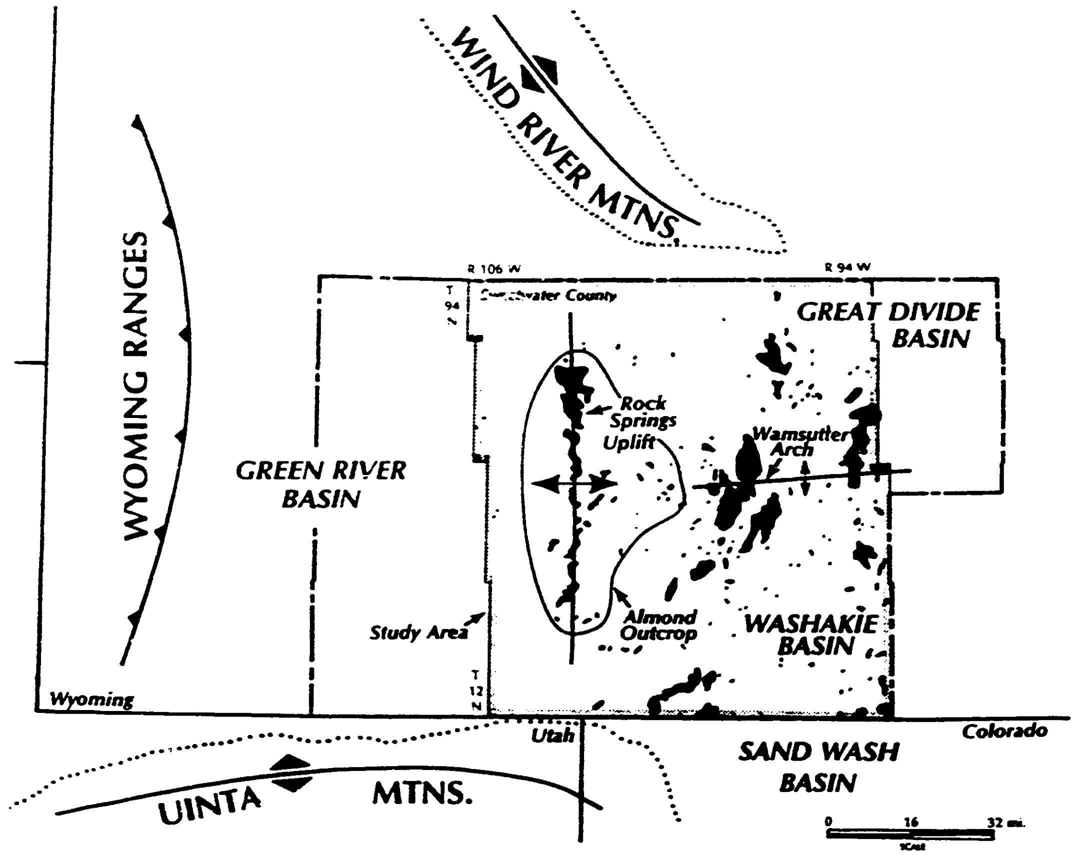

Figure 1. Location of the Study Area; major geologic features of the Greater Green River basin are noted.

Selection criteria

Phase 1 screening was based on six criteria: (1) production from the Mesaverde Group or Lewis Shale (because of the large resource base of those units); (2) drilling depths less than 12,500 feet (in order to maintain reasonable costs for the project); (3) field economics described as marginal or sub-commercial (a subjective criterion based on current levels of drilling and production - intended to ensure that the project would be useful to industry); (4) well spacing of 640 acres (necessary in order to provide sufficient undrained reservoir within field limits); (5) availability of quality log, core, and production data (to allow for the mapping and correlation necessary to minimize geologic risk); and (6) unitized production (necessary to simplify the project logistics).

Phase 1 results

The geologic characteristics of the 14 areas appraised in Phase 1 are presented in Table 1. The names represent the dominant field in each area. The areas selected for further geological evaluation in Phase 2 are Desert Springs, Wamsutter, Wild Rose, and Hay Reservoir (Figure 2).

Table 1. Characteristics of the 14 Areas Screened in Phase 1

Area	Reservoir*	Unitized	Spacing (acres)	Data Available	Depth (feet)
Antelope	Al, Fr, Lw	Yes	160-640	Fair	7,000
Baxter Basin	Dk, Fr	Yes	320-640	Poor	3,500
Canyon Creek	Mv	--	--	--	--
Deadman Wash	Bl, Fr	Yes	640	Fair	7,000
Desert Springs	Al	Yes	640	Fair	6,000
Dripping Rock	Al, Lw	Yes	640	Limited	13,000
Freighter Gap	Fr	Yes	640	Good	14,000
Hay Reservoir	Lw	Yes	640	Good	10,000
Jacknife Springs	None	--	--	Limited	--
Nitchie Gulch	Dk, Fr	Yes	320	Fair	8,000
Powder Springs	None	Yes	640	Limited	--
Salt Wells	Fr, Rk	Yes	320-640	Poor	5,000
Wamsutter	Al	Yes	640	Good	11,500
Wild Rose	Al	Yes	640	Fair	9,500

* Al = Almond, Bl = Blair, Dk = Dakota, Fr = Frontier. Lw = Lewis, Mv = Mesaverde

PHASE 2: SELECTING THE TARGET FIELD FOR DETAILED STUDY

The objective of Phase 2 was to conduct broad-based geologic investigations of the four areas selected in Phase 1. Investigation focused on the nature of the reservoirs, data quality, and risk of reservoir depletion. The goal was to select the one area that would provide the best potential test sites. The results of these analyses are summarized below.

Desert Springs area (T19-22N: R97-99W)

The Desert Springs area includes several highly-productive oil and gas fields that lie at depths of less than 6,000 feet on the eastern flank of the Rock Springs Uplift. The biggest producing fields were discovered in the 1940s and 1950s and include Table Rock -- 461 billion cubic feet of gas (bcfg) cumulative through 1991, Desert Springs -- 267 bcfg, Patrick Draw -- 152 bcfg, and Arch -- 84 bcfg.

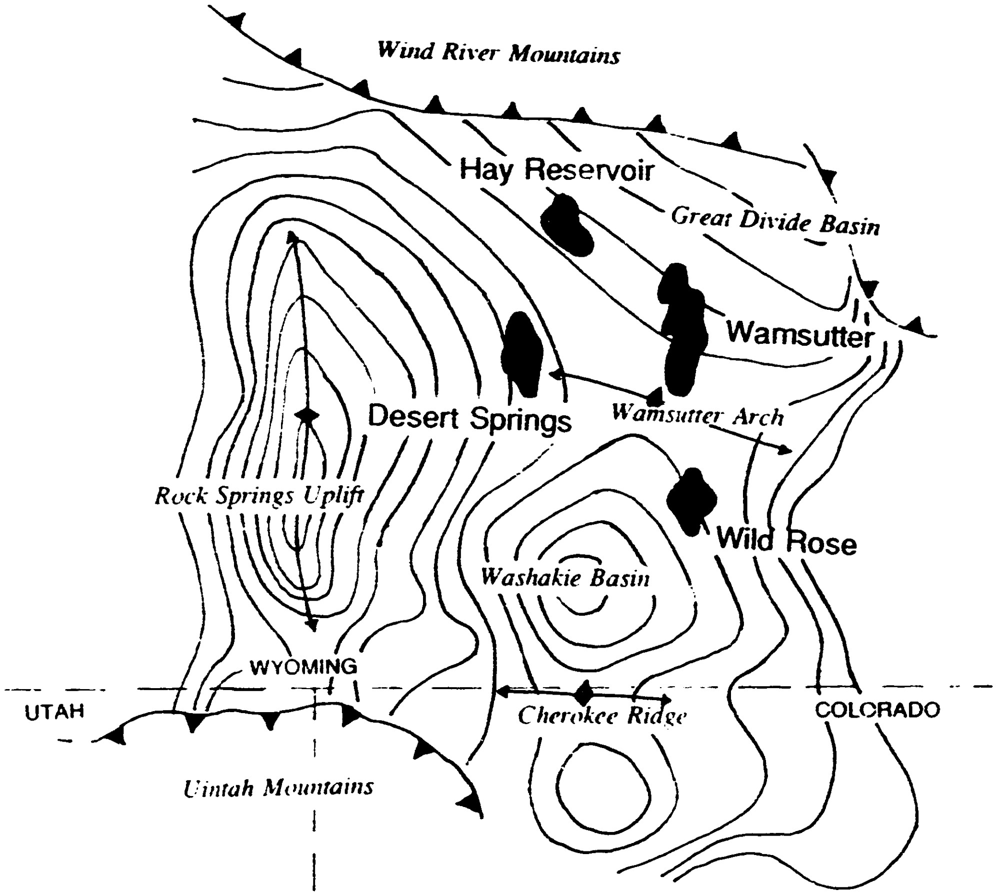

Figure 2. Location of the Four Areas Selected for Detailed Study

However, with the exception of Desert Springs Field, the reservoirs are drilled on extremely close spacing and produce large amounts of oil. Gas production at Desert Springs is primarily from shoreline sandstones of the upper Almond Formation.

Two upper Almond reservoirs attain thicknesses of 30 feet. Although determination of reservoir quality is difficult because of limited porosity data, available log and production data suggest that reservoir quality may be too good to allow the area to be an appropriate example of a "tight" gas reservoir. In addition, Desert Springs is not a good candidate area because of the probable widespread reservoir depletion and a lack of high-angle well opportunities.

Hay Reservoir area (T23-26N: R96-99W)

The Hay Reservoir area is located on the northeastward-dipping southern flank of the Red Desert (Great Divide) basin. Within the area, Hay Reservoir Field, 57 bcfg cumulative through 1991, is the only candidate location for the field demonstration. Several recent wells drilled on 320-acre spacing in the Hay Reservoir area have encountered near original reservoir pressure, indicating that vertical wells have not been able to effectively drain the reservoir at the prevailing 640-acre spacing.

Well demonstration targets at Hay Reservoir field are limited to eight separate sandstone reservoirs scattered throughout a pay interval that is 400 feet thick. Only one of these reservoirs is widespread and consistently greater than 20 feet in thickness. Furthermore, acid stimulation and hydraulic fracturing are commonly necessary to maintain a completion. The only potential high-angle project would be an attempt to drill where several Lewis sandstones are vertically-stacked. Furthermore, the Mesaverde Group, which is the preferred target because of its enormous estimated resource base, is not productive at Hay Reservoir. Consequently, Hay Reservoir area is not recommended as a possible location for the proposed field demonstration.

Wild Rose area (T16-19N: 94-96W)

The Wild Rose area contains a number of small gas fields that occur upon the crest and southern flank of the Wamsutter Arch. Gas production in the area is dominated by the Standard Draw (127 bcfg cumulative through 1991), Wild Rose (89 bcfg), and Barrel Springs (27 bcfg) fields. The various fields of the Wild Rose area produce from low-permeability Mesaverde Group reservoirs at moderate depths.

Logging suites from the Wild Rose area are highly variable, making net porosity and cross-over maps less accurate than desired. Although the assessed risk of reservoir depletion is low, none of the productive Almond or Ericson reservoirs displays the necessary continuity or thickness to be a suitable horizontal well target. Individual reservoirs generally do not exceed 20 feet in thickness and are highly lenticular.

Wamsutter area (T21-24N: R94-96W)

The Wamsutter area includes the Wamsutter (84 bcfg cumulative through 1991), Siberia Ridge (17 bcfg), and other smaller fields that occur along the northward-dipping north flank of the Wamsutter Arch. The area produces primarily from north-south trending marginal-marine sandstones of the upper Almond Formation.

The 98 productive wells in the Wamsutter area are located at a 640-acre spacing. Many of the wells, especially those in the Siberia Ridge field, are of exceptional quality. Average pay thickness is greater than 30 feet. The main field reservoir has the lateral continuity and thickness necessary to be the horizontal-well target. The reservoirs in the lower Almond and Ericson formations are highly-lenticular and gas-charged, and provide multiple potential targets through a thick pay zone. The drilling depth is marginal, up to 14,500 feet to the base of the fluvial sequence at the northern end. However, to the south, over 2,000 feet of non-marine section, containing up to 40 percent sandstone, exists above the 12,500 feet drilling depth. Most Ericson reservoirs display low porosity and permeability, making them ideal subjects for the high-angle-well field demonstration.

Phase 2 results

Of the four areas reviewed in Phase 2, the Wamsutter area displays the best conditions for selecting specific horizontal and high-angle well sites. The results of Phase 2 are summarized in Table 2.

PHASE 3: SELECTING SPECIFIC WELL TARGETS AND LOCATIONS

The objective of Phase 3 was to investigate the geology of the Wamsutter area to delineate specific potential locations for the horizontal and high-angle field demonstration wells. During the course of this investigation, differences in the geology and the nature of the potential targets related to decreasing drilling depths resulted

Table 2. Results of Phase 2 Screening

Area (Location)	Depth	Reservoir	Data Quality	Typical "Tight" Field	Horizontal Well Targets	Slant Well Targets	Risk of Depletion
Desert Springs (T19-22N : R97-99W)	○	○	●	●	●	●	●
Hay Reservoir (T23-26N : R96-99W)	○	◒	○	○	○	●	○
Wamsutter (North) (T21-24N : R94-96W)	◒	○	○	○	○	●	◒
Wamsutter (South) (T19-20N : R94-96W)	○	○	◒	○	●	○	○
Wild Rose (T16-18N : R94-96W)	○	○	◒	○	○	◒	○

○ = Good (Low Risk of Depletion) ◒ = Fair (Medium Risk of Depletion) ● = Poor (High Risk of Depletion)

in the separation of the Wamsutter area into northern and southern parts.

The criteria used for selecting the horizontal well target from among the various reservoirs in the field are (1) thickness of at least 30 feet, (2) limited internal heterogeneities expected, (3) proven or likely gas productivity, and (4) blanket geometry. The specific site at which to drill the well was chosen by identifying areas with optimal reservoir quality that have not been drained by surrounding wells.

The high-angle well target was chosen based on the following criteria: (1) a thick sequence of vertically-stacked reservoirs, (2) proven or expected gas productivity, and (3) highly lenticular geometry. Since reservoir depletion was not an issue for the high-angle targets, the main factors in choosing the specific sites were (1) proximity to good horizontal well locations, and (2) maximization of sand-to-shale ratio in the sequence.

Horizontal well

Within the Wamsutter area, only the reservoirs within the upper Almond Formation fit the general criteria for a horizontal well target. Mapping of total thickness and density-neutron crossover was completed for each of six sandstones. Four main upper Almond sandstones occur, designated from top to bottom as MA-1, MA-2, MA-3, and MA-4 (Figure 3). To the south and east, the upper four units shale out, leaving the MA-4 sandstone as the uppermost Almond sandstone throughout most of the Wamsutter area. Isopach maps of various sandstones reveal that depositional strike was roughly to the north-northeast. As recognized by numerous previous workers, the mapped trend, the outcrop character, and the nature of surrounding lithologies indicate that the upper Almond sandstones were deposited in marginal-marine settings such as shallow near-shore shelves, beaches, and barrier islands (Weimer, 1965; McCubbin and Brady, 1969; Van Horn, 1979).

MA-1: The MA-1 sandstone is a thin, texturally fining-upwards, marine sandstone that occurs in only the northernmost sections of Wamsutter area (Siberia Ridge Field). Maximum thickness in the Wamsutter area is only 20 feet. The unit is not productive in the Wamsutter area.

MA-2: The MA-2 sandstone is a thick, clean, texturally coarsening-upwards, marginal-marine sandstone. The sandstone has been penetrated by 18 wells in the Wamsutter area; however, it was perforated for production in only one well, where it was commingled with several other Almond zones. Although porosity in the unit is typically 8 to 10 percent, gas indications on the neutron-density log are rare.

MA-3: The MA-3 sandstone is clean, textually coarsening-upwards unit like the overlying MA-2. The unit is seen in 20 wells. Maximum thickness of the sandstone in the Wamsutter area is 25 feet. "Tight" streaks are common in the center of the unit. Porosity is commonly 8 to 10 percent. Commingled production has occurred in two wells, both of which were sand-fraced and acidized. Neither well was an economic success (.103 and .135 bcfg cumulative).

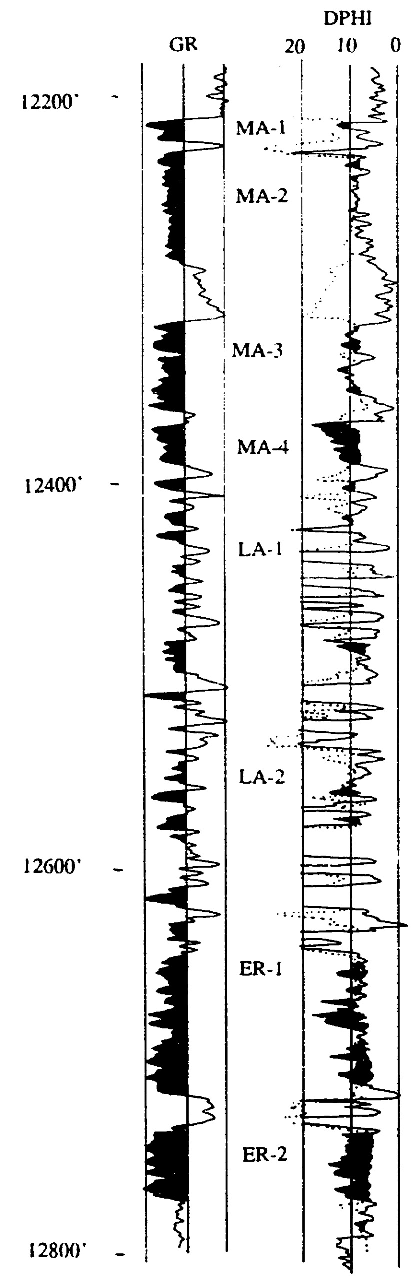

Figure 3. Type Log for the Northern Portion of the Wamsutter Area

MA-4: The MA-4 sandstone is the lowermost clean, blocky sandstone that occurs in the Almond Formation in the Wamsutter area. The sandstone is especially well-developed in T22N R94W, where it forms the main pay sandstone for the field. Sandstone thickness ranges from 25 to 35 feet. Porosity ranges from 10 to 14 percent. From 10 to 20 feet of neutron-density crossover is typical.

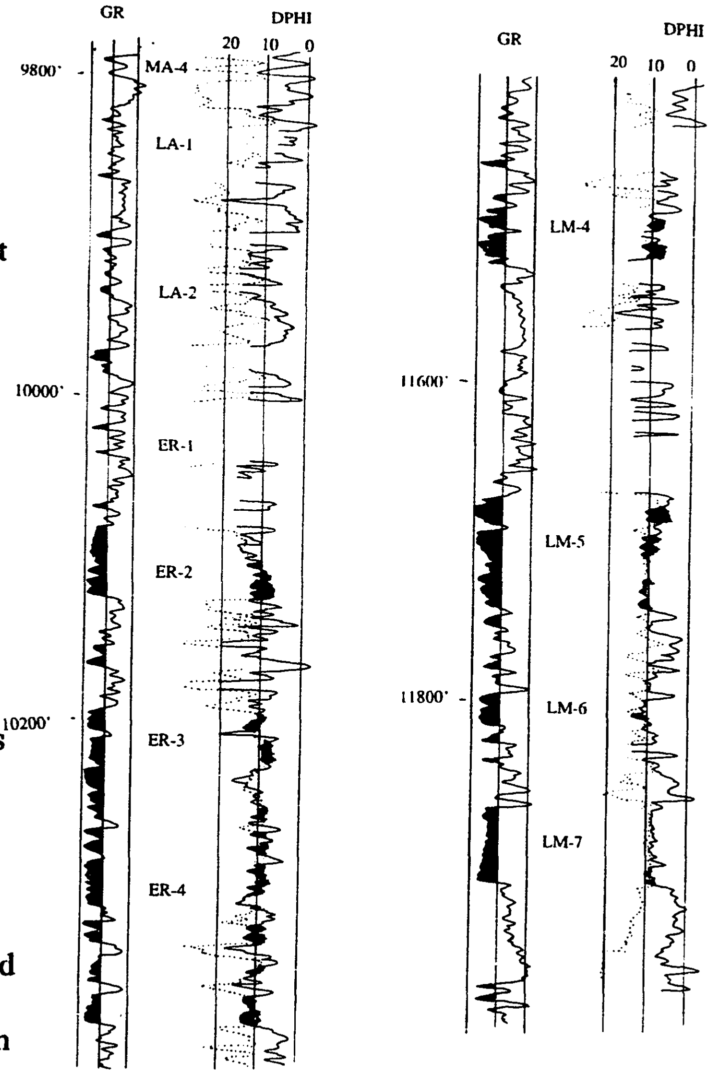

Figure 4. Type Log for the South Wamsutter Area

Based on data summarized above, the most favorable horizontal well locations occur in the thick MA-4 lobe located in T22N R94W. This area contains the thickest, most continuous reservoir in the area. In addition, the productivity of the unit is well established. To the south, reservoir thickness decreases and risk of reservoir depletion increases; to the north, there is a significant increase in depth and deterioration in data quality. Within T22N R94W, the best locations were found in sections 8, 17, 14, and 11.

Industry may be currently developing plans on its own to develop the Almond reservoirs at Wamsutter with a horizontal well. Of course, this event would greatly reduce the need for a U.S. DOE demonstration program in the Almond. Consequently, alternative target horizons were considered. Analysis of well logs and production data in the southern part of the Wamsutter area reveal that no single reservoir in the productive interval meets the stated criteria for a horizontal well. The only candidates occur 2,000 feet stratigraphically below the Almond main field pay at the base of the Mesaverde Group. These units, although not proven reservoirs, are generally regarded as good prospects. A successful test of these units by U.S. DOE would provide significant benefits to industry. The concept of targeting these reservoirs was first brought to the attention of U.S. DOE by the USGS.

Five major basal Mesaverde sandstones exist and are designated LM-4, LM-5, LM-7, LM-9, and LM-10 (Figure 4). The upper two units can be observed in four wells; the lower two units are penetrated by only three wells. The units, especially the lower three, are likely to be marginal marine sandstones with blanket geometry and limited internal heterogeneity. However, the data are insufficient to allow these predictions to be tested through mapping. None of the units were perforated or tested in the four wells.

LM-4: The LM-4 interval contains one lobe that can be traced between the several deep well logs. The unit contains over 20 feet of pay with a water saturation of approximately 35 percent. However, the unit is most likely nonmarine in origin, and can be expected to contain significant internal heterogeneity as well as overall lenticularity. Therefore, it is not recommended as an appropriate horizontal well target.

LM-5: This unit consists of a clean blocky sandstone separated by a persistent shale break into two lobes. The upper lobe varies in thickness from 8 to 26 feet. The lower lobe is 42, 45, and 50 feet thick in three wells; however, in the fourth, the unit is reduced to three thin sandstones totaling 14 feet. Porosity in the thicker units range from 11 to 13 percent. Two measured water saturations are 36 and 47 percent. The apparent lenticularity of the unit and its stratigraphic position render it difficult to determine whether the unit is marine or nonmarine in origin.

LM-7: This sandstone is a clean, blocky unit. Thicknesses in the four wells are 28, 44, 45, and 47 feet. Porosity is 9 to 10 percent and there is no crossover on the neutron-density log. The induction log shows 20 ohm/m resistivity, corresponding to 60 percent Sw or more, depending on formation water resistivity.

LM-9: The LM-9 sandstone is a thick, slightly shaly unit with multiple shale breaks. Total sandstone thickness is greater than 70 feet in all three wells. The upper part of the unit is the cleanest and displays thicknesses of 34, 40, and 47 feet. The top of the unit occurs at 11,900 to 12,100 feet in depth. The porosity is low, roughly 8 percent. The induction log indicates a very high occurrence of water.

LM-10: The basal Mesaverde sandstone occurs at a depth of 12,100 to 12,300 feet. The unit is divided into two lobes. The shale content of the sandstone is high. In two wells, the lower lobe is best developed (24 and 30 feet thick); in the other well, the lower lobe is thinner (15 feet) and shaly. The upper unit is clean and thick (34 feet) in only one of the three wells. Porosity in the lower lobe approaches 10 percent. However, water saturation is 75 percent in the Frewen Deep Unit No. 4 well.

Of these five candidate lower Mesaverde sandstones, the most promising is the LM-5. This particular unit appears to be the most gas-prone and is largely shale-free. However, the depositional origin of the unit is unclear. Given the limited data available on the lower Mesaverde targets, it is advisable to reduce geologic risk by locating the test as close as possible to the control points. Therefore, the best sections from which to drill the horizontal well at Wild Rose would be sections 6, 7, 18, or 19 of T19N R94W or sections 12, 13, or 24 of T19N R95W.

High-angle well

The high-angle well at the original North Wamsutter location (T22N R94W) would target reservoirs in the Lower Almond and Ericson formations. This interval is up to 1,000 feet in thickness and contains up to 350 feet of sandstone. Below the Ericson is over 1,000 feet of lower Mesaverde Group, which is also a potential horizontal well target. However, this interval lies below the 12,500 feet drilling depth at the planned location. The sandstones are thin and discontinuous at the top of the interval; however, the lower Ericson is marked by several massive sandstones that combine to form a 250- to 300-foot thick unit. Porosity in the units is usually less than 10 percent. As much as 100 feet of this total sandstone thickness may show gas indications on the neutron-density log; however, the amount of crossover is commonly only 60 to 70 feet. The best fluvial section at Wamsutter is located in the southern half of

T21N R94W and the northern halves of T20N R94W and T22N R95W. No effort has been made to determine the proper azimuth for the well. The well should be designed so as to intersect the largest number of fractures (i.e., perpendicular to the trend of major fractures). However, no fracture data has been collected at this time.

The entire 2,000 feet of non-marine section, stretching from the base of the upper Almond to near the base of the Mesaverde Group, can be tested by a slant well at the alternative South Wamsutter location. The top of the target section occurs at approximately a 9,500-foot measured depth. As much as 250 feet of gas pay can be expected. However, a 1,000-foot thick, reservoir-barren zone directly below the Ericson divides the targets into two separate zones. As with the Wamsutter location, no data on fractures has been collected, so no recommendation as to the orientation of the well is given.

DISCUSSION

Two potential test locations have been described. The North Wamsutter is located in T22N R94W, based on the lowest-risk horizontal well target. The location provides the best chance for a good gas well while minimizing the risk of a thinned, missing, or depleted reservoir. However, there are two main drawbacks to this location. First, industry is planning to drill horizontal wells into the Almond in this area. If this occurs, the need for U.S. DOE to expend its resources on a similar project is reduced. Second, the area is not an optimal location for drilling a high-angle well: half the prospective target lies below the 12,500 feet drilling depth, and the units that can be drilled are relatively sandstone-poor compared to surrounding areas.

Consequently, an alternative program in the South Wamsutter area was investigated. This location takes advantage of the decreasing structural elevation of the reservoirs. Although the Almond and Ericson formations do not provide suitable targets for the horizontal well, alternative targets occur in the marine sandstones at the base of the Mesaverde Group. Because these units have not been produced, there is no risk of encountering a depleted reservoir. In addition, the lack of available data on these units indicates that a successful demonstration by the U.S. DOE would have a major impact on the industry. However, with this increased "potential" comes a significantly increased risk because of the uncertain reservoir quality, geometry, and producibility. An additional advantage to the South Wamsutter location is the ability to drill the entire 2,000-foot thick non-marine sequence with the high-angle well. Reservoir characteristics of the North and South Wamsutter areas are provided in Tables 3 and 4.

No specific recommendation for locating the field demonstration project can be given at this time. Instead, the following three alternatives are presented. These alternatives will continue to be investigated.

Option 1: Drill at North Wamsutter: The least risk of total project failure occurs if the project is located in T22N R94W at Wamsutter. The horizontal well target is a proven productive reservoir with sufficient porosity and permeability to be an economic success even if fracture porosity is non-existent. The high-angle well can be drilled into the lower Almond and Ericson formations to a depth of 12,500 feet, or the entire non-marine section can be drilled if the decision to go to 13,500 feet is made. The nature of the lower Mesaverde in this area is not well understood. It is known, however, that the Ericson in this area contains less sandstone than elsewhere.

Option 2: Drill at South Wamsutter: Of the current options being considered, the greatest

Table 3. Characteristics of Reservoirs in the North Wamsutter Area

Unit	Depth (Feet)	Pay (Feet)	ϕ (Percent)	Sw (Percent)
Main Almond-1	11,500	0	--	--
Main Almond-2	11,525	0	--	--
Main Almond-3	11,550	0	--	--
Main Almond-3a	11,560	0	--	--
Main Almond-4	11,600	9-23	10-15	45-65
Lower Almond-1	11,650	0-3	8	40-60
Lower Almond-2	11,750	4-11	9-11	20-35
Ericson-1	11,850	0-14	9-12	20-40
Ericson-2	11,950	0-13	8	15-25
Ericson-3	12,025	10-26	7-9	12-25
Ericson-4	12,125	19-24	6	10
Ericson-5	12,350	42	9	20
Ericson-6	12,500	0	--	--

potential benefit to industry would be achieved by a successful field demonstration along the boundary of T19N R94W and T19N R95W in the Wild Rose area. The high-angle well would test the entire 2,000 feet of the Ericson and Allen Ridge non-marine sequence at moderate depths. The horizontal well and the vertical characterization well would test the underlying marine reservoirs at the base of the Mesaverde Group. Total drilling depth for the project would be approximately 11,900 feet. Both intervals are estimated by the USGS to contain large volumes of gas that are currently not being exploited. However, the potential that both targets could be non-economic even with directional drilling is very real. Furthermore, the general lack of wells that have fully penetrated the sequence renders the geologic interpretation less assured than is desirable. Finally, as with Option 1, the presence of fractures will play a key role in the success of the project; yet little is currently known about the existence or orientation of fractures.

Option 3: Separate the two wells geographically: In this scenario, the high-angle well would be drilled first through the Ericson, Allen Ridge, and Rock Springs formations in the Wild Rose area. If the high-angle well shows potential in the basal Mesaverde sandstones, then locate the horizontal well there. However, if the sands appear too "tight," and if the slant hole shows no hint of extensive fracturing, then shift the project 25 miles to the north and

Table 4. Characteristics of Reservoirs in the South Wamsutter Area

Unit	Depth (Feet)	Pay (Feet)	ϕ (Percent)	Sw (Percent)
Main Almond	9,750	0-3	10	45
Lower Almond	9,850	8-10	12-13	40
Ericson-2	10,050	10-12	12-15	23-40
Ericson-3	10,200	48-61	9-14	27-41
Ericson-4	10,300	68-79	9-14	25-51
Ericson-5	10,400	25-27	10-12	50-59
Lower Mesaverde-1	10,500	0	9	66-71
Lower Mesaverde-2	10,900	0	7-9	60-97
Lower Mesaverde-3	11,200	0-14	7-11	43-68
Lower Mesaverde-4	11,450	22-67	12-13	34-37
Lower Mesaverde-5	11,650	16-30	11-13	30-61
Lower Mesaverde-6	11,750	0-7	10-11	54-70
Lower Mesaverde-7	11,850	0	9	85-97
Lower Mesaverde-8	11,950	0	10	97
Lower Mesaverde-9	12,050	0	9	90
Lower Mesaverde-10	12,200	0	6-9	75-100

horizontally drill the Almond MA-4 sandstone in the heart of the Wamsutter area.

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Appendices

Appendix A

Agenda

TUESDAY, NOVEMBER 16, 1993

7:30 a.m.		Registration/Continental Breakfast

OPENING SESSION

8:15 a.m.		*Welcoming Remarks* Rodney D. Malone
8:25 a.m.		*Summary Liquid Fuels Program* Hugh D. Guthrie

SESSION LF – LIQUID FUELS TECHNOLOGY

Chairperson: J. Keith Westhusing

SESSION LF-1 – OIL SHALE

8:45 a.m.	LF-1.1	*Status of LLNL Hot-Recycled-Solid Oil Shale Retort* Robert J. Cena Lawrence Livermore National Laboratory
9:15 a.m.	LF-1.2	*Shale Oil from the LLNL Pilot Retort: Metal Ions as Markers for Water and Dust* Alan Burnham Lawrence Livermore National Laboratory
9:45 a.m.	LF-1.3	*Shale Oil Value Enhancement Research: Separation Characterization of Shale Oil* James W. Bunger James W. Bunger and Associates, Inc.
10:15 a.m.		BREAK

10:30 a.m.	LF-1.4	*Oil and Gas Yields from Devonian Oil Shale in the 50-lb/hr KENTORT II Process Demonstration Unit: Initial Results* Scott D. Carter University of Kentucky

SESSION LF-2 – TAR SANDS

11:00 a.m.	LF-2.1	*University of Utah Oil Sand Research and Development Program* Francis V. Hanson University of Utah

SESSION LF-3 – MILD GASIFICATION

11:30 a.m.	LF-3.1	*Development of an Advanced, Continuous Mild Gasification Process for the Production of Co-Products* Richard A. Wolfe Coal Technology Corporation
12:00 p.m.	LF-3.2	*Value-Added Co-Products from K-M/IGT Facility* John A. L. Campbell Kerr-McGee Coal Corporation
12:30 p.m.		LUNCH

PLENARY SESSION

Chairperson: William J. Gwilliam

1:30 p.m.	PS-1.1	*Fuels Technology Remarks* Louis A. Salvador Morgantown Energy Technology Center
1:45 p.m.	PS-1.2	*Summary-Natural Gas Fuel Cells and Natural Gas Turbines* William T. Langan Morgantown Energy Technology Center
2:00 p.m.	PS-1.3	*Summary-Gas Related Environmental Issues* Jerry D. Ham Metairie Site Office

SESSION LF-4 – GAS TO LIQUIDS

Chairperson: Rodney D. Malone

2:15 p.m.	LF-4.1	*Overview of PETC's Gas-to-Liquids Programs* Gary J. Stiegel Pittsburgh Energy Technology Center
2:30 p.m.	LF-4.2	*Direct Methane Conversion to Methanol* John L. Falconer University of Colorado
3:00 p.m.	LF-4.3	*Catalytic Conversion of Light Alkanes Proof of Concept Stage* James E. Lyons Sun Company, Inc.
3:30 p.m.		BREAK
3:45 p.m.	LF-4.4	*Selective Methane Oxidation Over Promoted Oxide Catalysts* Richard G. Herman Lehigh University
4:15 p.m.	LF-4.5	*Steady-State and Transient Catalytic Oxidation and Coupling of Methane* Enrique Iglesia Lawrence Berkeley Laboratory
4:45 p.m.		ADJOURN
5:00 - 6:00 p.m.		Tour of METC Facility • Scanning Electron Microscope (SEM) Lab • Sorbent Screening Unit and Inductively Coupled Plasma (IDP) • Combustion Facility • Geoanalysis Lab and Computer Room

<u>WEDNESDAY, NOVEMBER 17, 1993</u>

SESSION NG – NATURAL GAS TECHNOLOGY

OPENING SESSION

8:20 a.m.		*Welcome Back* William J. Gwilliam
8:30 a.m.		Keynote Address: *Managing Change* Rex J. Lysinger Energen Corp.
9:00 a.m.		*Summary Natural Gas Program* Leonard E. Graham Morgantown Energy Technology Center

SESSION NG-1 – HYDRAULIC FRACTURING TECHNOLOGY

Chairperson: Karl-Heinz Frohne

9:15 a.m.	NG-1.1	*Fracturing Fluid Characterization Facility (FFCF)* Ronald D. Evans University of Oklahoma
9:45 a.m.	NG-1.2	*Introduction to the GRI/DOE Field Fracturing Multi-Sites Project* Richard E. Peterson CER Corporation
10:15 a.m.		BREAK
10:30 a.m.	NG-1.3	*Slant Hole Completion Test, Cozzette and Paludal Production Testing* F. Richard Myal CER Corporation

SESSION NG-2 -- NATURAL FRACTURES

Chairperson: Royal J. Watts

11:00 a.m.	NG-2.1	*Integrated Seismic Study of Naturally Fractured Tight Gas Reservoirs* Gary M. Mavko Stanford University
11:30 a.m.	NG-2.2	*Fracture Detection, Mapping, and Analysis of Naturally Fractured Gas Reservoirs Using Seismic Technology* Heloise Lynn Lynn Incorporated, for Coleman Research Corporation
12:00 p.m.	NG-2.3	*Geotechnology for Low Permeability Gas Reservoirs* David A. Northrop Sandia National Laboratories
12:30 p.m.		LUNCH
1:30 p.m.	NG-2.4	*LBL/Industry Heterogeneous Reservoir Performance Definition Project* Ernest L. Majer and Jane C. S. Long Lawrence Berkeley Laboratory

SESSION NG-3 -- RESOURCE ASSESSMENTS AND MODELING

Chairperson: Karl-Heinz Frohne

2:00 p.m.	NG-3.1	*Preliminary Results on the Characterization of Cretaceous and Lower Tertiary Low-Permeability (Tight) Gas-Bearing Rocks in the Wind River Basin, Wyoming* Ronald C. Johnson U.S. Geological Survey
2:30 p.m.	NG-3.2	*Reserves in Western Basins* Robert H. Caldwell The Scotia Group
3:00 p.m.		BREAK

SESSION NG-4 – SECONDARY NATURAL GAS RECOVERY

Chairperson: Charles W. Byrer

3:15 p.m. NG-4.1 *Infield Natural Gas Reserve Growth Joint Venture (Secondary Gas Recovery)*
Robert J. Finley
Bureau of Economic Geology
The University of Texas at Austin

SESSION NG-5 – COAL SEAM GAS

Chairperson: Charles W. Byrer

3:45 p.m. NG-5.1 *Multistrata Exploration and Production Study*
Linda K. Hawkins and Ronald G. Brunk
The College of West Virginia

4:15 p.m. NG-5.2 *Process for Coalbed Brine Disposal*
Harry Brandt
Aquatech Services Inc.

4:45 p.m. NG-5.3 *Commercialization of Previously Wasted Coal Mine Gob Gas and Coalbed Methane*
Bruce J. Sakashita, Resource Enterprises Inc.
Milind D. Deo, University of Utah

5:15 p.m. ADJOURN

POSTER SESSION

November 17, 1993
5:15 - 6:30 p.m.

P1 *Natural Gas Display*
Rodney D. Malone and Charles W. Byrer
Morgantown Energy Technology Center

P2 Site Selection and Evaluation of a Horizontal Well in the Clinton Sandstone
Thomas H. Mroz
Morgantown Energy Technology Center
William A. Schuller
EG&G WASC, Inc.

P3 *Natural Gas Product and Strategic Analysis*
Abbie W. Layne, John R. Duda, Anthony M. Zammerilli
Morgantown Energy Technology Center

P4 *Evaluation and Optimization of Vertical Gob Gas Ventilation Wells*
Jeffrey J. Schwoebel
Resource Enterprises, Inc.

P5 *Computer Modeling of Geologic Strata in the Multi-Strata Project Area (Beckley)*
Thomas H. Mroz
Morgantown Energy Technology Center

P6 *Inorganic Polymer-Derived Ceramic Membranes*
C. Jeffrey Brinker
Sandia National Laboratories

P7 *Appalachian Basin Gas Plays in Ordovician and Mississippian Carbonates and Silurian and Pennsylvanian Sandstones*
Douglas G. Patchen
Appalachian Oil and Natural Gas Research Consortium

P8 *Offshore Northern Gulf of Mexico Oil and Gas Resources Atlas Series*
Robert J. Finley
Bureau of Economic Geology
University of Texas at Austin

P9 *The Synthesis and Characterization of New Iron Coordination Complexes Utilizing an Asymmetric Coordinating Chelate Ligand*
Bruce E. Watkins
Lawrence Livermore National Laboratory

P10 *Evaluation of the Hydrocarbon Potential of a Possible Hidden Basin in Southwest Washington*
William D. Stanley
U.S. Geological Survey

P11 *Analysis and Evaluation of Gas Hydrate on Alaska's North Slope*
Timothy S. Collett
U.S. Geological Survey

P12 Gas *Hydrate Detection and Mapping on the U.S. East Coast*
William P. Dillon
U.S. Geological Survey

P13 *Methodology for Optimizing the Development and Operation of Gas Storage Fields*
James C. Mercer and James R. Ammer
Morgantown Energy Technology Center

P14 *Feasibility Study to Evaluate Plasma Quench Process for Natural Gas Conversion Applications*
Peter C. Kong and Brent A. Detering
Idaho National Engineering Laboratory
EG&G Idaho, Inc.

P15 *Natural Gas Recovery, Storage, and Utilization SBIR Program*
Harold D. Shoemaker
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P16 *Greater Green River Basin Well Site Selection*
Karl-Heinz Frohne, Morgantown Energy Technology Center
Ray Boswell, EG&G WASC, Inc.

THURSDAY, NOVEMBER 18, 1993

SESSION NG-6 – DRILLING, COMPLETION, AND STIMULATION

Chairperson: Albert B. Yost II

8:15 a.m.	NG-6.1	*CO_2/Sand Fracturing in Low Permeability Reservoirs* Raymond L. Mazza Petroleum Consulting Services
8:45 a.m.	NG-6.2	*Evaluation of Target Reservoirs for Horizontal Drilling: Lower Glen Rose Formation, South Texas* Gery Muncey PrimeEnergy Corporation
9:15 a.m.	NG-6.3	*Horizontal Drilling in Shallow Reservoirs* William F. Murray, Jr. Belden & Blake Corporation

9:45 a.m.	NG-6.4	*An MWD System for Air Drilling* Llewellyn A. Rubin Geoscience Electronics Corporation
10:15 a.m.		BREAK
10:30 a.m.	NG-6.5	*Steerable Percussion Drilling System* Huy D. Bui Smith International, Inc.

SESSION NG-7 -- NATURAL GAS ATLASES AND DATA MANAGEMENT

Chairperson: Harold D. Shoemaker

11:00 a.m.	NG-7.1	*Development of the Natural Gas Systems Analysis Model (GSAM)* Mark R. Haas ICF Resources Incorporated
11:30 a.m.	NG-7.2	*Preliminary Analysis of User Needs Forecast for GASIS* Robert H. Hugman Energy and Environmental Analysis, Inc.

SESSION NG-8 -- LOW-QUALITY NATURAL GAS UPGRADING

Chairperson: Harold D. Shoemaker

12:00 p.m.	NG-8.1	*Low Temperature H_2S Separation Using Membrane Reactor with Redox Catalyst* John Pellegrino National Institute of Standards and Technology
12:30 p.m.		LUNCH
1:30 p.m.	NG-8.2	*Upgrading Natural Gas By Means of Highly Performing Polyimide Membranes* S. Alexander Stern Syracuse University
2:00 p.m.	NG-8.3	*Low-Quality Natural Gas Sulfur Removal/ Recovery System* Kaaeid A. Lokhandwala Membrane Technology and Research, Inc.

2:30 p.m.		**BREAK**
2:45 p.m.	NG-8.4	*Low-Quality Natural Gas Sulfur Removal/Recovery* Lawrence A. Siwajek Acrion Technologies, Inc. for CNG Research Company
3:15 p.m.	NG-8.5	*Evaluation of High-Efficiency Gas-Liquid Contactors for Natural Gas Processing* James T. Semrau and Anthony L. Lee Institute of Gas Technology
3:45 p.m.		**ADJOURN**
3:45 - 4:45 p.m.		Tour of METC Facility (Tentative)

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Appendix B

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