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TECHNOLOGY DEVELOPMENTS IN NATURAL GAS EXPLORATION, PRODUCTION AND PROCESSING

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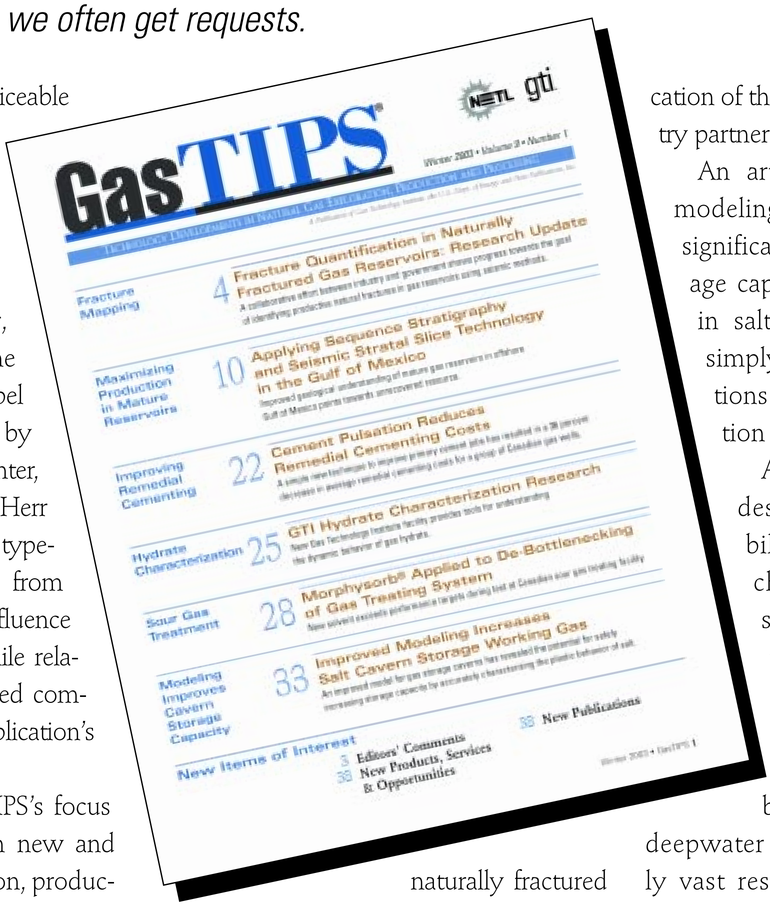
Same Book, New Look

Publications, like many of us, can benefit from refinements to their "look" every now and then. The look of this issue of **GasTIPS***, now beginning its eighth year, reflects changes in style and structure that we believe improve the journal's readability. The format has been "tightened up" to make it more reader-friendly and improve the visual appeal of single article reprints, for which we often get requests.*

Perhaps the most noticeable change is the new typeface for the body text. The previous choice was from the Bodoni family of typefaces, of a lineage designed by a famous Italian printer, Giambattista Bodoni, in the 1700s. The new typeface, Stempel Schneidler, was designed in 1936 by a German teacher and has a lighter, more modern look. However, Herr Schneidler based his design on typefaces used by Venetian printers from the Renaissance, so the Italian influence is still there. These changes, while relatively minor, reflect our continued commitment to maintaining the publication's utility to readers.



Behind this new look GasTIPS's focus remains where it has been, on new and developing natural gas exploration, production and processing technologies. From a content standpoint this issue is very diverse, with six contributed articles falling under five separate topic headings. To deal with updates regarding research that is focused on finding more efficient ways to locate gas reserves. In one case, by using a better understanding of stratigraphy to locate unrecovered gas within geologically complex, mature, Gulf Coast fields. In the second case, by developing seismic tools to identify permeable fracture zones within naturally fractured gas-bearing formations. Both of these articles describe ongoing research that has been under way for a number of years.

The remaining articles cover a wide range of topics. Two of these highlight newly commercialized research products from Gas Technology Institute. One, a service for improving casing cement integrity via pressure pulses, the other, a new solvent system for removing contaminants from sour gas streams. Both of these articles provide case studies of the application of these new technologies by industry partners.

An article on natural gas storage modeling provides evidence that a significant amount of additional storage capacity may be made available in salt cavern storage facilities by simply altering pressure specifications during the injection/ production cycle.

And in a sixth article, we describe the expanding capabilities of GTI laboratories for characterizing and understanding gas hydrates. These unique combinations of hydrocarbon and water molecules are coming under increased scrutiny, both as a plugging agent in deepwater pipelines and as a potentially vast resource trapped in submarine sediments.

We hope you'll find this issue of GasTIPS informative. Please contact the individuals listed at the end of each article to obtain more information on specific topics. If you have any questions or comments, please contact the Managing Editor, Karl Lang, at *klang@chemweek.com/*.

The Editors

Fracture Quantification in Naturally Fractured Gas Reservoirs: Research Update

by Ernest L. Majer,
LBNL

A collaborative effort between industry and government shows progress towards the goal of identifying productive natural fractures in gas reservoirs using seismic methods.

As part of the US Department of Energy's Natural Gas Program, Lawrence Berkeley National Laboratory (LBNL) is leading a multi-institutional project to develop methods for mapping the fractures that control flow in naturally fractured gas reservoirs. While current technology can often locate fracture trends, it remains unable to provide the accuracy necessary to site wells based upon fracture permeability. The work has progressed from lab studies to controlled field studies and now to a full scale application in the San Juan Basin in New Mexico. This article summarizes ongoing efforts to apply high resolution fracture identification methods (logging, single well seismic and VSP) and integrate the results with previously acquired 3-D surface P-wave imaging. The goal is to determine the optimum technique for not only locating fractures but quantifying their properties in a manner such that the fractures controlling flow can be identified.

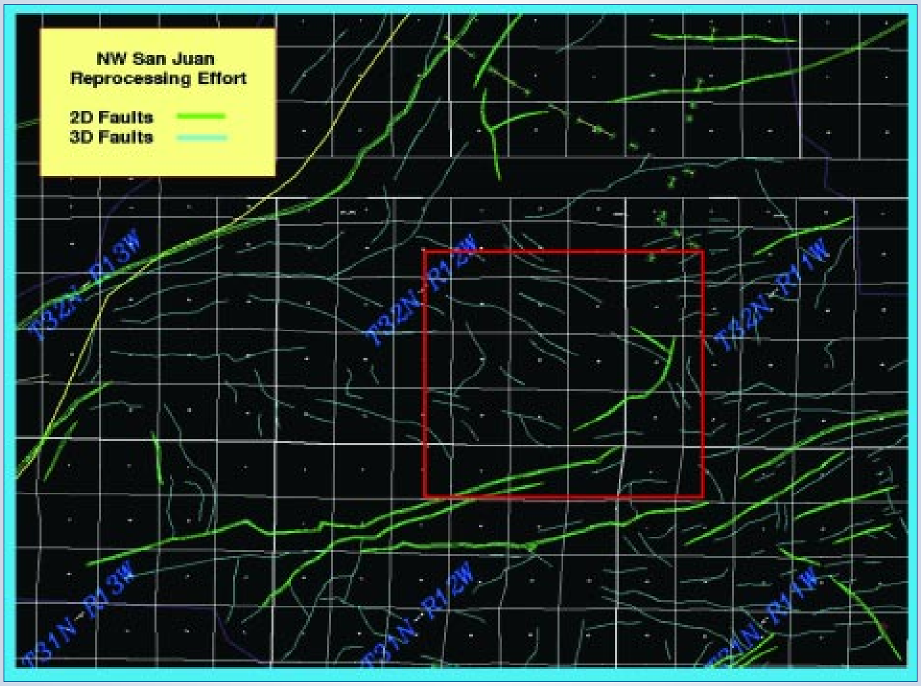


Figure 1: Study Area (Red Box) in Relation to the Fault Structure as Determined by 2-D and 3-D Seismic

Background

Current methods rely on gross definition of fracture properties using attributes such as P-wave anisotropy, AVO or AVA. While useful for gross fracture detection, these approaches have not been able to define the specific fracture sets that control permeability. Past work *(Majer et al, 1997)* has shown that such fractures sets, even single fractures, can control flow from a large reservoir volume.

The current research is based on the hypothesis that to obtain the required resolution it will be necessary to gather data at higher frequencies and with greater spatial sampling than conventional surface seismic methods can provide. This implies that the data must be recorded using sources and/or receivers placed in the subsurface. Although the use of subsurface sources and receivers on a semi-permanent or permanent basis may be years in the future, this project hopes to extend surface information with current borehole methods (VSP, crosswell and single well seismic) in order to quantify fracture characteristics. However, since surface seismic is often all that is available, a primary goal of this work remains the development of a methodology to extract as much information as possible from surface data *(Daley et al, 2002)*.

Research efforts to date have focused on field experiments in well-characterized field sites at both intermediate and full field scale. These include a Conoco test site in Oklahoma, an MIT test site in Michigan, and a NIPSCO gas storage field in Indiana *(Majer et al, 1997)*. Researchers are now working at industry sites of opportunity while linking this work with the service industry so that the technology can be deployed rapidly when ready.

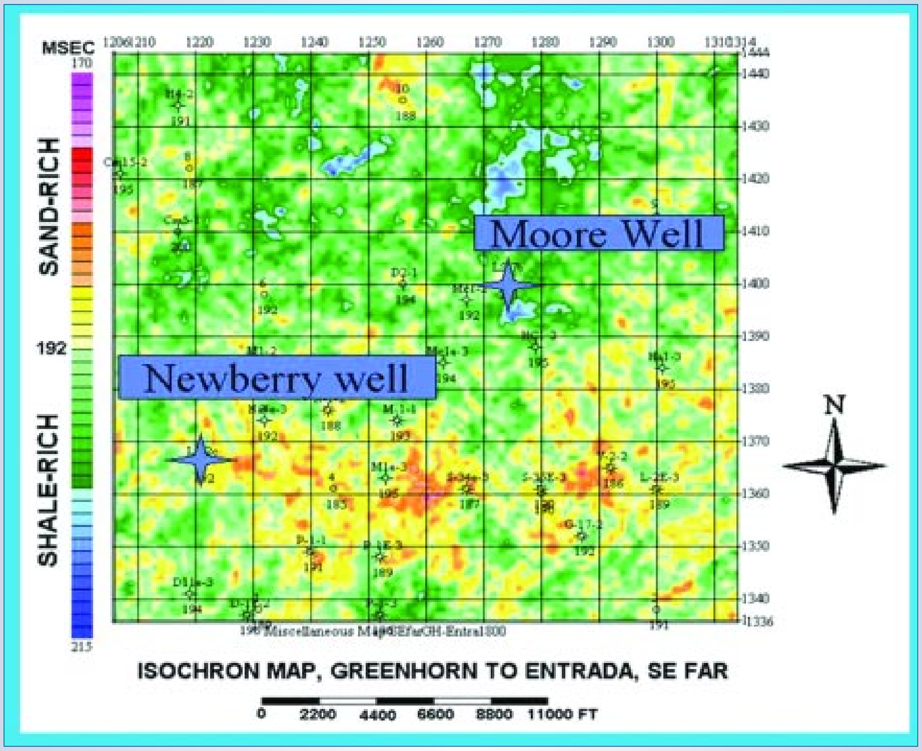


Figure 2: Two Well Sites Selected (Newberry and Moore Wells)

The field site that is the subject of this article is a ConocoPhillips property in the San Juan Basin of New Mexico. Because it is in an area of ongoing commercial interest and has a wealth of geologic and geophysical information, it is anticipated that commercial wells will ultimately be drilled based on the results of this work, ideally validating the methodology.

Project Organization

The overall project work plan is divided into four broad tasks: Modeling, Field Measurements, Processing and Interpretation, and Reservoir Simulation. Overall organization of the project is managed by LBNL, and the other participants include ConocoPhillips, Schlumberger, Lynn Inc., Stanford University, and Virginia Tech.

LBNL has responsibility for modeling, with support from both Stanford and Virginia Tech. As for actual field measurements, LBNL is responsible for VSP work and some of the single well data collection. Schlumberger is responsible for the high frequency single well work. ConocoPhillips is responsible for 3-D surface reflection measurements and co-share the responsibility with LBNL for the semi-permanent/permanent array measurements

ConocoPhillips is responsible for data processing of surface 3-D seismic data and Lynn Inc. is providing data processing support for fracture specific processing. LBNL and Schlumberger will process their data sets and Schlumberger will also provide experimental processing of multicomponent VSP data for fracture imaging. Virginia Tech will aid in interpretation, as will LBNL and Stanford. Virginia Tech will also perform interpretation of fracture spacing based upon stochastic analysis.

Schlumberger Reservoir Technologies is providing reservoir modeling and simulation based upon the results of the seismic imaging. Schlumberger will also work with ConocoPhillips production engineers to refine and improve production models as a result of the fracture imaging.

Theory and Methods

Because fractures represent a significant mechanical anomaly, seismic methods can potentially be used to identify not only the presence of fractures, but such attributes as orientation, density, aperture, and filling. Additionally, the partially saturated rock in gas reservoirs (usually heterogeneous), is difficult to image. However, this complication also presents an opportunity in that the highest resolution images can be constructed using the information contained in the shear and converted waves, along with

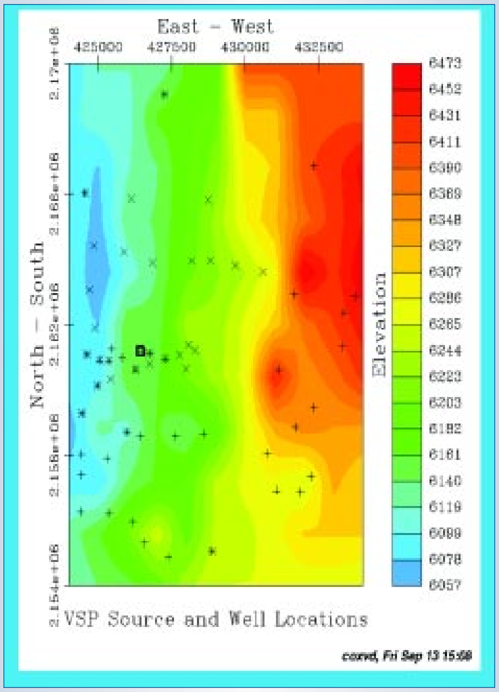


Figure 3: Layout of 9-C VSP for Newberry and Moore Wells

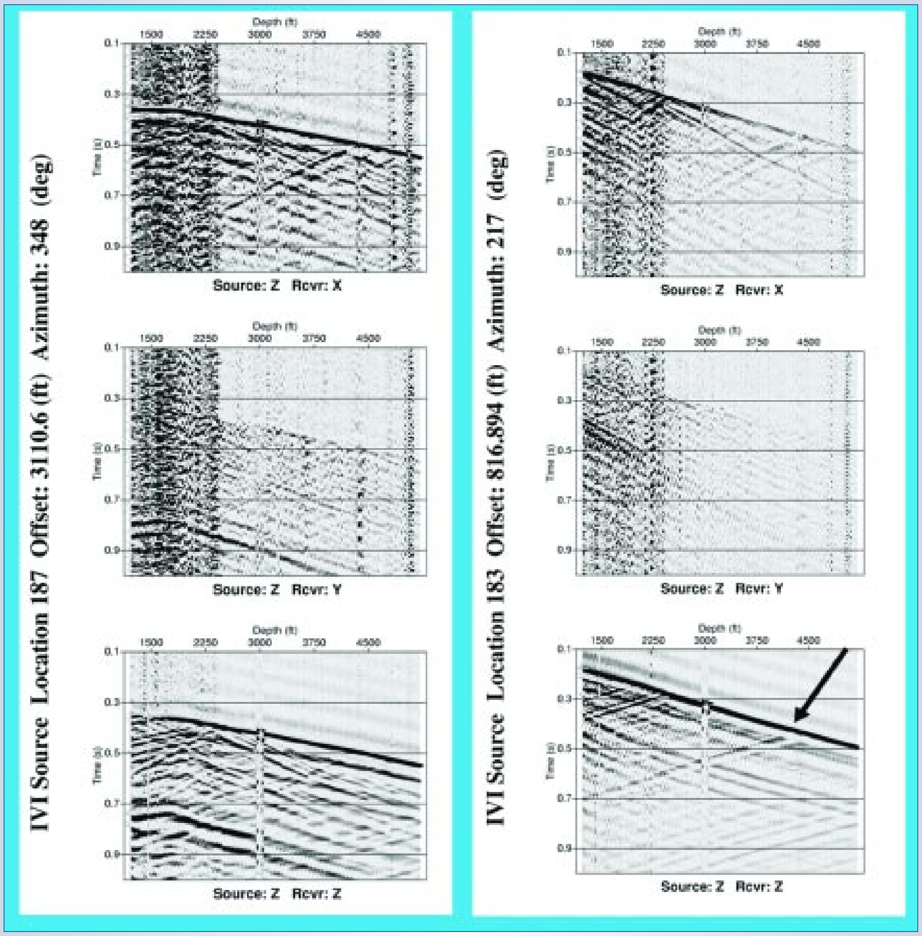


Figure 4: Field Data Corresponding to Modeled Distances Showing Possible Fracture Events (Arrows)

compressional waves. Imaging naturally fractured gas reservoirs should involve a wide range of scales and distances. The frequencies and wavelengths required will vary by orders of magnitude, depending upon the problem at hand.

For example, to characterize within 10 meters a target at a depth of 3000 meters, an image resolution of centimeters is unnecessary. On the other hand, if delineation of flow processes is required around the wells, meter-scale or better resolution is needed. For most applications a three-dimensional picture of the elastic properties in the earth on a scale less than a meter near the surface to no more than a few tens of meters at depths of several kilometers would suffice. The greatest obstacle, however, is to determine the significance of an image, once it is obtained. The challenge is to define the seismic properties that control reservoir flow and permeability, rather than simply the geologic features. Given the proper conditions (i.e., enough measurement points and computing power, sufficient frequency content, etc.), it is possible, in theory, to attain this resolution. However, many practical obstacles inhibit achieving this goal.

Image resolution with current techniques is limited by the amplitude and frequency content of the seismic waves, and by the level and complexity of the ambient and signal-generated noise fields. With surface sources, a heterogeneous surface weathered layer (often tens of meters thick) means that the high frequency content and coherence of the signal that is input through the ground is severely limited. VSP solves this problem in part, by placing receivers beneath the highly attenuating and variable surface layer (so that the signal is not required to pass through the surface layer twice), and also by recording the wave field with a vertical array in the borehole so that "up going" and "down going" waves can be identified and separated. An approach that does address the fundamental imaging limitations is one which incorporates properties of the secondary (S) and the converted waves (P to S, S to P) that are generated in the earth. Potentially by incorporating amplitude and converted waves into the analysis, surface based methods could be very useful. This approach is particularly well suited for applications where the primary (P), secondary (S) and converted waves can be examined directly. In recent years the use of S-waves has become more common, particularly in defining anisotropy and fracture content of rock. Fracture detection using P- and S-wave surface reflection coupled with VSP methods is demonstrating that the full

> The objective of the field tests was to augment the existing data sets at both the borehole scale (logging and single well seismic) and surface seismic scale (VSP).

potential of seismic methods requires 3-component data.

In addition to the continuum properties approach on shear wave splitting, recent laboratory and theoretical work explains shear wave anisotropy in terms of mechanical properties of the fracture discontinuity itself, i.e., a surface of a finite stiffness affecting velocity as well as attenuation of a seismic wave of any wavelength. In the stiffness theory, the lateral extent of a target fracture is still important to seismic resolution but with sufficiently low fracture stiffness the thickness of the fracture can be much less than the seismic wavelength and still have a detectable frequency-dependent effect on the seismic wave. A large amount of information exists in the properties of the secondary waves, which offers promise for substantial improvement in the resolution of seismic methods.

Modeling Progress During 2002

The project effort during 2002 was focused on three areas: modeling seismic wave propagation in fractured media, acquisition of an extensive set of VSP data, well logs, and single well data, and initial processing of the field data.

The thrust of the modeling effort has been to model the actual field data that was processed in both 2-D and 3-D. A 20 square mile volume was selected by the research team based on an analysis of the geologic and seismic data available and ConocoPhillips' drilling program. Once the 20 square mile volume was selected the next step was to determine model parameters. In order to do so, maps and actual field inspections were used to determine fracture spacing, width, orientation and overall geometry with respect to the bedding. Initial processing of the 3-D data by ConocoPhillips had focused on deeper targets than those of this investigation. Therefore, new conceptual models were derived into which fractures could be introduced to determine the effect on seismic reflection data. The model's fractures were spaced at 20 meters and "large" faults wereplaced at 610-meter spacing, on a 40 layer geologic model including the Menefee and the Dakota formations. The modeling was done with a finite difference model solving for the full elastic wave field using anisotropic stretched grids to model fracture properties.

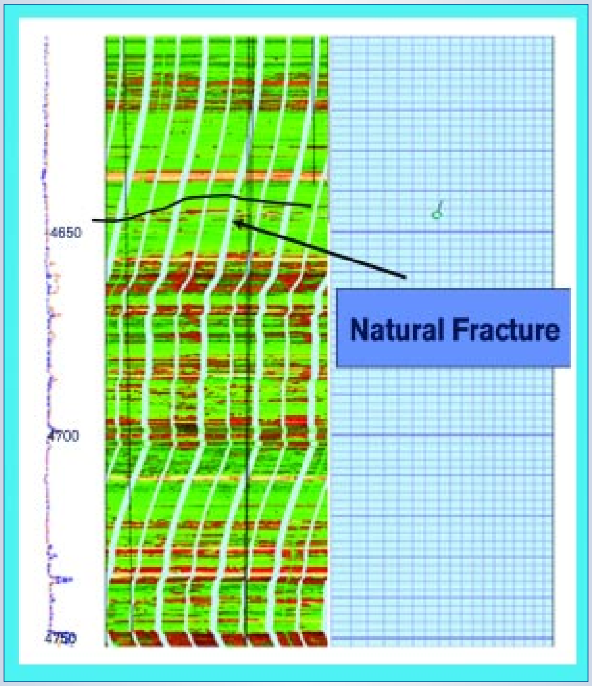


Figure 5: FMI Log Showing Natural Fracture

Existing 3-D data from the 20-square mile target area (Figure 1) was reprocessed with state-of-the-art and experimental processing methodologies. The objective has been to apply processing that would enhance interpretation for fracture and fault identification. ConocoPhillips and Lynn Inc. have been involved in this effort with the objective being to derive a processed data set that Lynn Inc. interpreted for fault and fracture structure. Lynn Inc. utilized the single-fold and the partially-stacked azimuth gather data, selected from locations of interest as identified by ConocoPhillips. The azimuthal variations in seismic signatures (travel time, amplitude, frequency, coherence, etc.) were derived with the one-fold versus stacked-data response and compared, and the magnitude of the azimuthal anisotropy estimated.

These magnitudes were compared to well production data (where known) and a recommendation was made as to how to separate the azimuths for the creation of 3-D limited-azimuth imaged volumes. These 3-D volumes allow the evaluation of the coherently-reflected wave field's response to the presence of natural fractures at target level. Anomalous zones, which indicate a high fracture density, were then inspected in the one-fold (unstacked) domain in order to document their incoherently scattered wavefield response. The result was an analysis of predicted well performance across the 20 square mile study area. Two well sites were selected by ConocoPhillips operations, one in the SW (Newberry) and one in the NE (Moore) portions of the study area (Figure 2). The location of the two new wells is shown in relation to the velocity difference derived from analysis of the surface 3-D seismic. The warm colors in the figure indicate zones where production in is likely to be better.

Field Data Acquisition

The objective of the field tests was to augment the existing data sets at both the borehole scale (logging and single well seismic) and surface seismic scale (VSP).

Field testing involved performing multi-component/multi-azimuth VSP and single well seismic in a well where surface 3-D seismic had been performed. This provided for a range of data resolution at the same site. Schlumberger's role was to carry out conventional logging along with cross dipole sonic, FMI and single well sonic tool runs in these wells. VSP was then performed in both wells using multi-offset multi-azimuth 9-C collection. The VSP design was based upon the modeling and theoretical work performed to date *(Daley et al 2002)*. Locations were selected to gather reflected and scattered energy from the near vertical features (fractures).

The data were collected according to initial modeling of a range of anticipated fracture geometries. Single well seismic was performed in the same well to obtain higher resolution images. Both P-wave (Piezoelectric bender) and S-wave sources (Conoco AC orbital vibrator) sources are being used in this work. Shown in Figure 3 is the design of the VSP shot points around the Newberry and Moore wells (each symbol is the location of a shot point). Vertical, S1 and S2 components using a multi-component vibrator were collected at each shot point. The VSP recorded vertical, S1 and S2 components at 20 foot intervals over a deep and shallow interval (total of 1500 feet) in each well. After the VSP was done LBNL performed the single well work in each well using the orbital vibrator and three component sensors, and the piezoelectric and hydrophones. The data spans from the well log scale to the surface seismic scale (8000 hz to 10 hz) in a continuous fashion.

Interpretation and Processing

The objective of the interpretation and processing effort has been (and will be) to derive images that are indicative of fracture characteristics. Each method (surface seismic, VSP, crosswell, single well) has a different image produced at a different scale. The initial hypothesis that higher resolution is necessary to define the "important" (permeable) fractures will be tested based upon the different images produced. A second hypothesis, that there is information in surface seismic attributes not yet identified that is indicative of permeable fractures, will also be tested.

The following data have been compiled for each well:

- Multi offset (approx 70 source points per well) 3-D , 9-C VSP at 20 foot spacing (10 to 100 hz)
- Single well with three component receivers at 10 foot spacing using orbital source (50 to 400 hz)
- Single well with hydrophones at 5 foot spacing using piezoelectric source (200 to 4000 hz)
- FMI and dipole sonic, (4000 to 8000 hz.)
- Single well sonic (in Moore well only).

Together with the reprocessed seismic data, this information will form the basis of a unique multi-scale data set to process for fracture properties. Each well will be put on production after the seismic studies are completed to check the predictions.

Shown in Figure 4 is an example of the data with some possible fracture events. The data processing and examination are very preliminary at this point and much more work needs to be done.

Figures 5 and 6 are examples of the well log and single well data. Anisotropy at the well as well as discrete fractures are evident in the data at both the log scale and single well scale. This is very encouraging for using seismic for understanding fracture flow.

> Overall the project has made good progress towards the goal of developing and testing seismic methods for fracture quantification.

Next Steps During 2003

Overall the project has made good progress towards the goal of developing and testing seismic methods for fracture quantification. The team of LBNL, ConocoPhillips, Schlumberger, Stanford, and Virginia Tech has made good progress. The drilling of the well by ConocoPhillips (over $1.5 MM investment alone) and the acquisition of the field data sets mark a significant milestone in this work and in general a significant scientific contribution to the discipline of fracture imaging. The team now has the data set needed to progress towards our goal. The final phase of the project will involve additional work in modeling, data processing, and reservoir simulation.

With respect to modeling, the groups at Virginia Tech and Stanford will concentrate on the characterization of heterogeneity and seismic processing with regard to enhancing fracture signals in the VSP and single well data. The seismic heterogeneity estimator has been expanded into a fully 3D seismic volume attribute. Seismic heterogeneity may be caused by data acquisition and processing, by complex stratigraphy and lithology, and maybe by subsurface structure such as faults, joints, and fractures. Acquisition and processing footprints should be removable with methods currently being developed for other applications. Through analysis of the field data, the team will examine the cause of seismic heterogeneity at the San Juan test site.

It has been observed that seismic

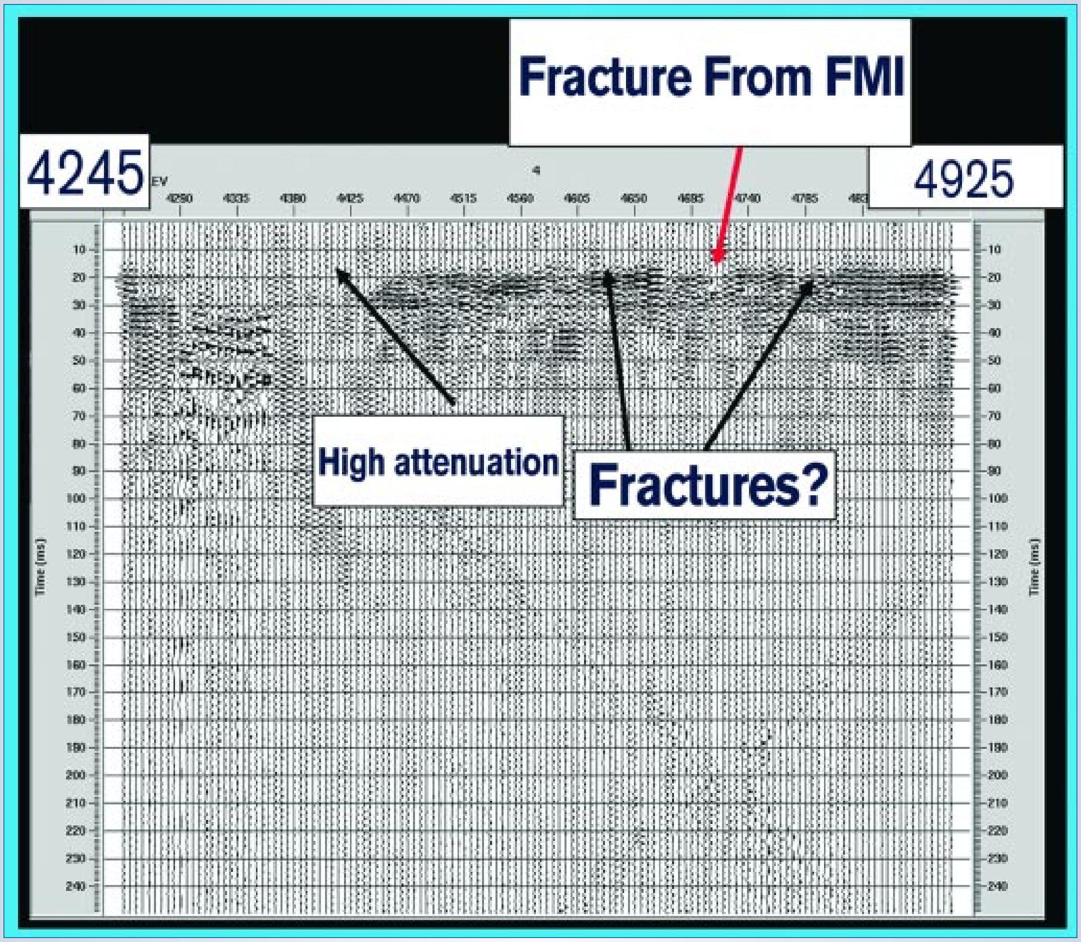


Figure 6: Example of Single Well Data Showing Possible Natural Fractures

heterogeneity varies spatially. Typical methods of reservoir modeling cannot handle spatially heterogeneous statistics. Hence, Virginia Tech will develop an algorithm to simulate small-scale heterogeneity with spatially heterogeneous statistics. In a later stage, the algorithm will even be extended to condition the realizations to seismic data and well logs.

The second remaining focus is on data processing. Numerical simulations by LBNL showed that the seismic signature of fractures is similar to diffraction hyperbola. Seismic data processing traditionally suppresses such features because they are considered "noise." Using a very simple model, the team derived and examined processing flows that enhance diffraction-like signals but suppress reflection signals and noise. Currently, Virginia Tech is testing these processing algorithms using the synthetic 2D dataset computed by LBNL. Later, the methods will be extended to 3D, tested with synthetic data, and applied to field data to examine if fractures can be detected from the surface.

Finally, Schlumberger will investigate the relationship between discrete fractures detected on the finest scale and their manifestation in effective medium theories at intermediate scale. To do this they will compile formation micro-imager (FMI) data and cross dipole acoustic logs together with supporting information (monopole compression, shear and Stoneley, gamma ray, 4-arm borehole caliper). This data will be processed to provide compressional and shear slownesses, anisotropic parameters, borehole ovality (an indication of intrinsic stress directions), breakouts, and natural and drilling induced fractures in the zones of interest. The data will be analysed to test the hypothesis that a quantitative relationship exists between the density and orientation of fractures as seen on the FMI log and the effective anisotropy observed on the acoustic logs. These results along with the results of the other fracture imaging work will be used to develop a reservoir model to predict well performance. The prediction will then be compared with actual performance. ✧

For more information on the status of this research contact Ernie L. Majer at LBNL by email at elmajer@lbl.gov *or at 510-486-6709.*

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Applying Sequence Stratigraphy and Seismic Stratal Slice Technology in the Gulf of Mexico

by Lesli J. Wood, T. Hentz, H. Zeng, M. DeAngelo, S. Dutton
Bureau of Economic Geology – The University of Texas

Improved geological understanding of mature gas reservoirs in offshore Gulf of Mexico points towards unrecovered resource.

The Bureau of Economic Geology (BEG) at the University of Texas at Austin, has been working to improve gas-recovery efficiency in complex onshore reservoirs since 1988 through Secondary Gas Recovery (SGR) research sponsored by the U.S. Department of Energy, with secondary sponsorship by the Gas Research Institute (now Gas Technology Institute). A quantitative assessment of the benefits of SGR research and technology transfer over the period 1988 through 1998, indicates that incremental gas production in seven fields studied under the SGR program is projected to total 231 Bcf.

SGR projects in onshore Gulf Coast sandstones, sandstones of the Fort Worth Basin, and karsted carbonate reservoirs of the Permian Basin have successfully defined secondary, or incremental, gas recovery on the basis of targeting stratigraphic and diagenetic reservoir heterogeneity. Past projects have been collaborative, with industry partners ranging from majors, such as Shell and Mobil, to midsize companies, such as Oryx and Union Pacific Resources, to small independents.

In 1998, the BEG decided to pursue similar research that would demonstrate SGR principles and practices in an established natural gas field in the Federal offshore of the Gulf of Mexico. The goal of the pro-

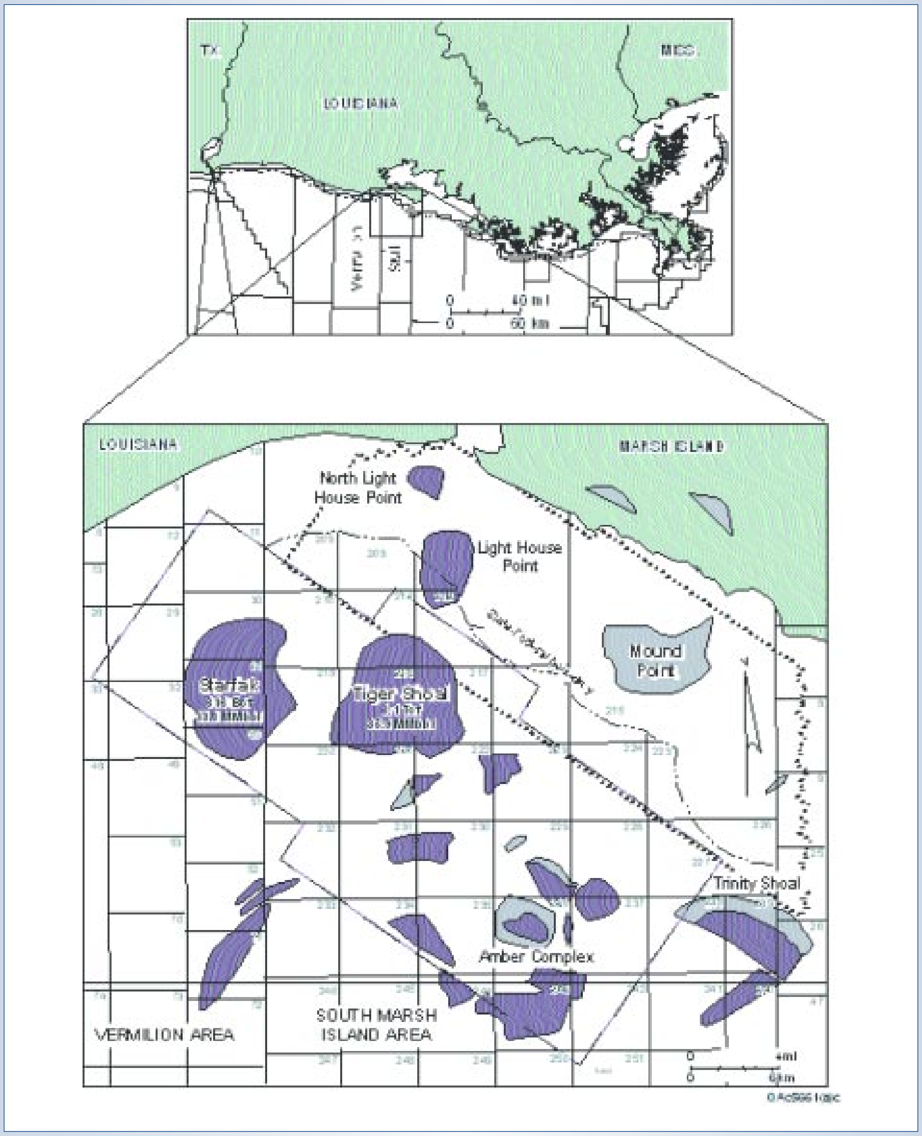

Figure 1: Location of OSGR Study Area

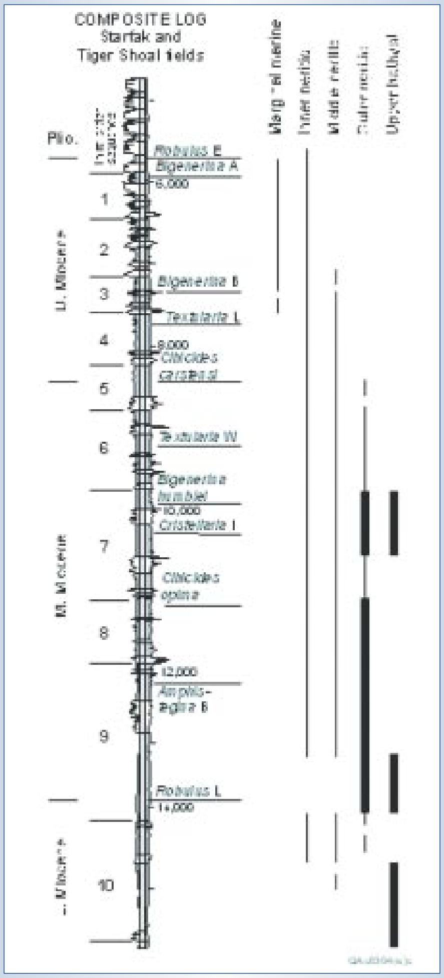

Figure 2: Ranges of Paleobathymetric Zones Recorded within the Study Interval.

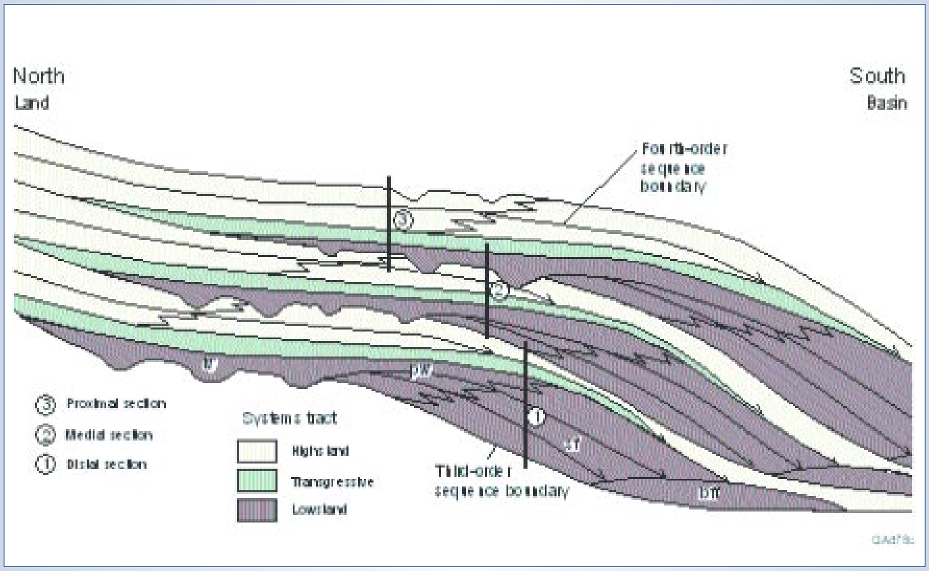

Figure 3: Relative Positions of Distal, Medial and Proximal Third-Order Sequences and Systems Tracts.

gram was to research new techniques in defining heterogeneity and compartmentalization in mature gas reservoirs through the use of multidisciplinary reservoir characterization and innovative technology applications for enhancing production from untapped, bypassed, incompletely drained, or intrawell reservoirs.

Significant recoverable gas resources remain undiscovered, undocumented and unproduced in the Miocene strata of the northern Gulf of Mexico. More than 41 percent of the known gas in the GOM Miocene strata remains to be produced. One of the most significant plays remaining in the Miocene of the northern GOM is the numerous lowstand prograding wedges that characterized the Miocene-age depositional shelf-edge locations throughout the Gulf subsurface.

The OSGR research has shown that a variety of sub-regional reservoir sandstones pinch-out within thick, stacked lowstand prograding wedges. Their setting within slope and basinal shales creates ideal conditions for potential hydrocarbon migration and entrapment. These wedges are composed of distal, medial and proximal portions each identifiable in logging cross-sections and mappable within stratal slice (proportional sliced) images. Within the BEG study area, the lowstand prograding wedge sandstones of the Robulus "L" zone contain the most gas reserves of any identified zones of opportunity: 41 percent of the total oil and gas in place (421 Bcf) and 40 percent of unrisked reserves (251 Bcf). The combination of unique stratal slice imaging of the seismic performed within a sequence framework of key chronostratigraphic surfaces enable geoscientists to define these resource targets and reduce both their risk and cycle time in exploiting these reserve addition opportunities.

Significant recoverable gas resources remain undiscovered, undocumented and unproduced in the Miocene strata of the northern Gulf of Mexico.

Application of Specific Tools Improves Accuracy

Sequence stratigraphy has revolutionized the manner in which geoscientists, geophysicists and geoengineers examine, map and produce reservoirs *(Van Wagoner, et al., 1990; Mitchum et al., 1993)*. The concept of reservoirs compartmentalized by sequence-

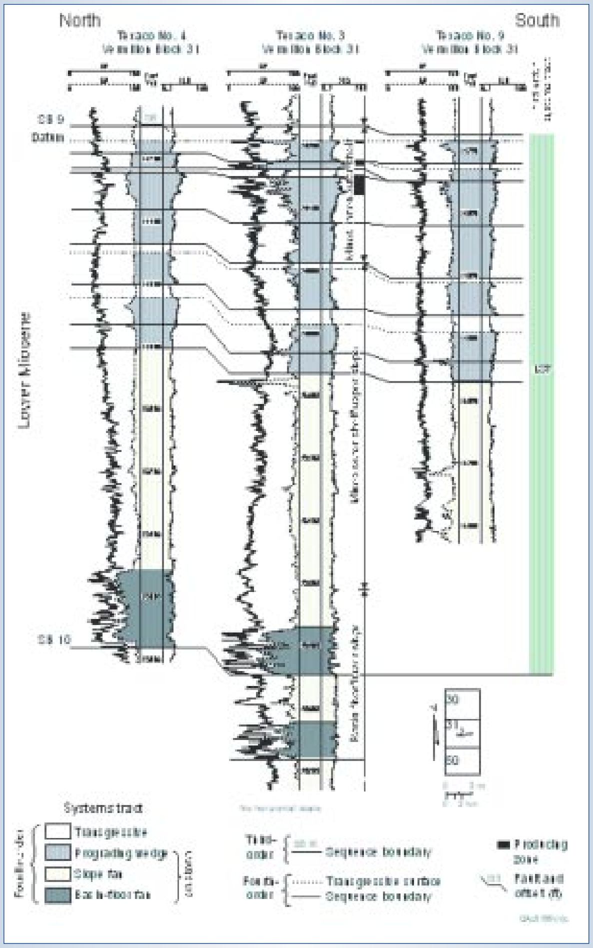

Figure 4: Dip Cross Section of Distal Third-Order Sequence 10 (Lower Miocene), Starfak Field.

bounding unconformable and conformable surfaces has enabled geoscientists to better understand reservoir behavior by explaining and targeting previously unnoted baffles and barriers to fluid flow. Likewise, 3D seismic technology in the past decade has revolutionized the science of seismic interpretation by significantly improving our ability to image and resolve many of these same key surfaces and flow-inhibiting horizons. Recent advances in attribute or pseudo-attribute extraction and analysis have significantly increased the interpreters ability to transform petrophysical information from their seismic data. Analysis of lateral continuity and variations in frequency spectrum, and comparison of both lateral and vertical impedence relationships have increased our ability to define and recognize stratigraphic and structural features. With so many and varied options available for viewing the 3D data volume it is often easy to get lost as to what attributes mean and how to translate them into meaningful prospects. By applying a select number of specific tools in a systematic approach within a framework of key sequence stratigraphic surfaces, interpreters can improve the efficiency and accuracy of their reservoir characterization process and identify numerous new opportunities for resource additions.

> More than 41 percent of the known gas in the Gulf of Mexico Miocene strata remain to be produced.

Study Area Targets Shelf Miocene

Siliciclastic Miocene strata are currently the most productive of all chronostratigraphic units in the northern Gulf of Mexico (GOM) outer continental shelf, accounting for 40% of all hydrocarbons produced and 40% of all remaining proved reserves. Most of these Miocene resources (99% of cumulative production, 61% of remaining proved reserves) are restricted to the present continental shelf *(Crawford, et al., 2000)*, where the majority of active fields are considered mature. These statistics indicate that significant potential exists for interfield and intrafield development in the shelf area (<650 ft water depth). Moreover, deep Miocene strata (>15,000 ft subsea) below established reservoirs in the shelf area hold the promise of additional resources. Only 5% of all wells drilled on the GOM shelf have penetrated strata below 15,000 ft, in which there is an estimated 10.5 Tcf of deep gas recoverable resources *(Minerals Management Service, 2001)*. Bypassed and underproduced oil and gas are waiting to be tapped and developed in mature fields, and new plays and numerous stratigraphic traps exist that can contain significant undiscovered resources both shallow and at depth. The challenge is to recognize the traps and design an integrated approach to capitalizing on the resources.

The most recent OSGR study area included two major producing fields, Tiger Shoal and Starfak fields in the Vermilion Block 50 and South Marsh Island Areas, northern GOM (Fig. 1). Although originally designed to look at data from a single field, the project evolved to encompass two fields in detail, as well as to consider surrounding fields of Mound Point, Lighthouse Point, and Amber. This evolution reflected the need to consider more regional applicability of research results:

to move from the postage-stamp application of research results from a single field to the broader distribution of observations throughout the GOM Miocene. The study area contains predominantly progradational deposits consisting of upward-coarsening deltaic deposits, as well as distributary- and fluvial-channel deposits. The study area as noted in previous publications (Seni, *et al., 1997)* is included in four large gas-dominated plays. The combination of asset size and potential, regional productivity of the field intervals, and data availability and quality made this an excellent area for pursuing the objectives of the OSGR program.

Sequence Stratigraphy Framework

The sequence stratigraphic framework interpreted over the study area provided a genetic context for all phases of the SGR study of the Miocene succession *(Hentz et al., 2000, 2001, 2002; Zeng et al., 2000a, 2001a–c; Badescu and Zeng, 2001; DeAngelo and Wood, 2001; Rassi and Hentz, 2001; Zeng, 2001; Rassi, 2002a–c; Zeng and Wood, 2002; Hentz and Zeng, 2003)*. Moreover, it established the groundwork for investigations of reservoir-specific attributes and the identification of previously undetected hydrocarbon resource addition opportunities within the two-field area, this project's 3-D seismic volume, and adjacent on-shelf areas.

Well-log curves from over 156 logs were provided by Texaco, the project's industry partner, for analysis and integration with over 352 square miles of 3-D seismic data. Faunal occurrence, abundance and diversity data were provided from 15 wells across the study area. Paleobathymetric indicator fauna, benthic organisms that lived within certain ranges of water depth *(Picou et al., 1999)*, enabled reconstruction of

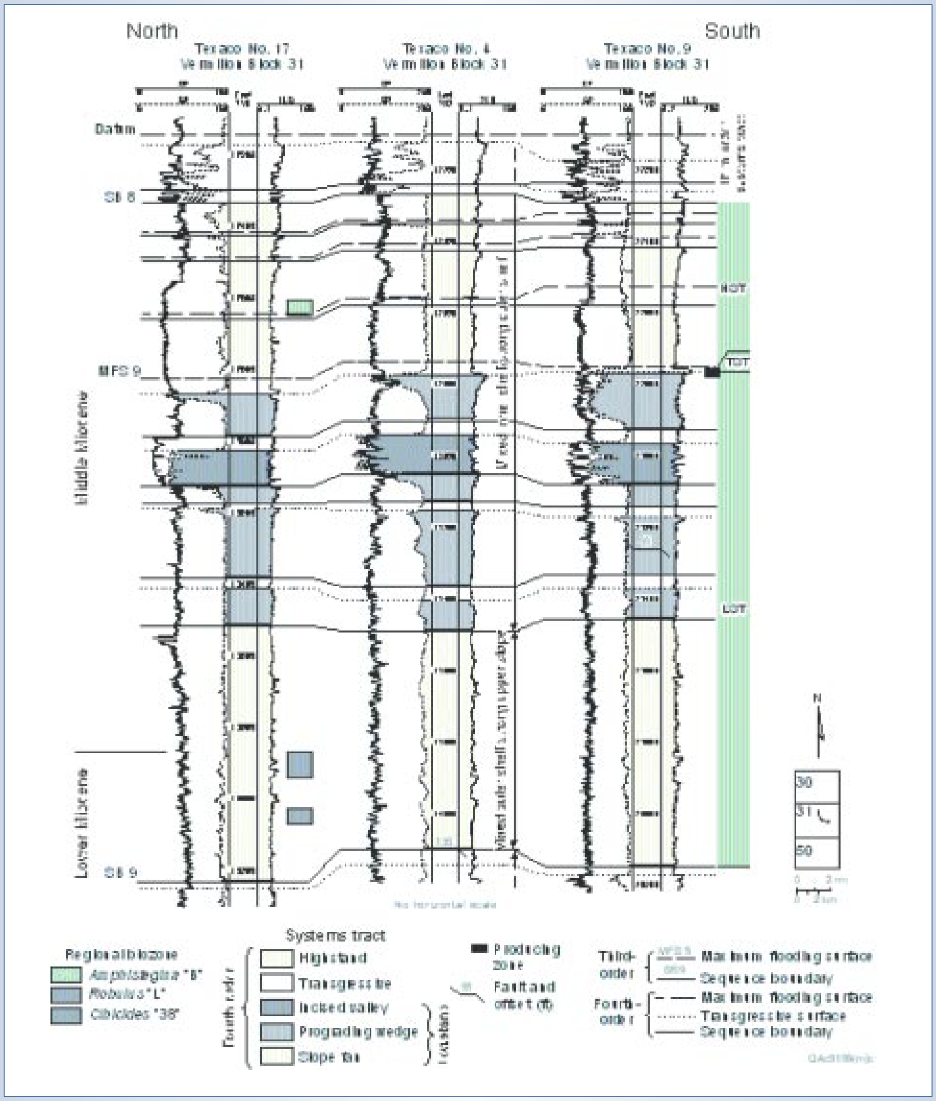

Figure 5: Dip Cross Section of Distal Third-Order Sequence 9 (Lower and Middle Miocene), Starfak field.

water depths within which reservoir-scale (fourth-order) systems tracts were deposited. In most wells, sample faunal-counts were recorded in the wells every 30 ft from immediately above the study interval to the bottom of the well. These lists provide an accounting of fossil assemblages, abundances of individual species, and stratigraphic positions of major faunal "floods." Indicator fossils within faunal floods, which typically coincide with marine condensed sections, can be used to estimate the paleobathymetric conditions under which the sediments containing the fossils were deposited. The indicator fossils in wells within the study area record an overall upward-shallowing trend within the entire study interval (Fig. 2), coinciding with the overall regressive stratal-stacking pattern. The widest portions of zone bars in the figure represent stratigraphic intervals of particularly abundant indicator fauna. Many sandstones and immediately adjacent shaly strata in the

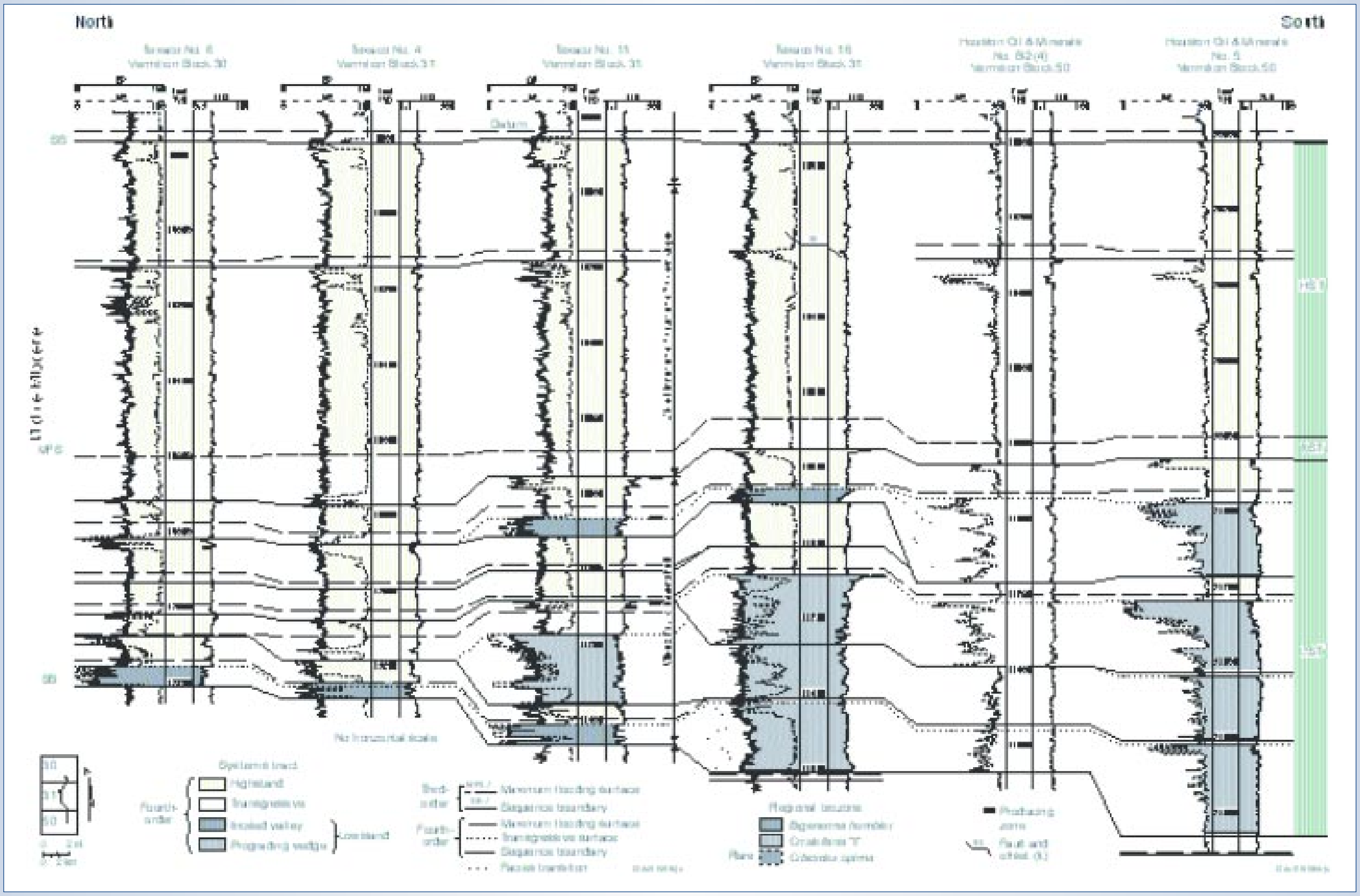

Figure 6: Dip Cross Section of Medial Third-Order Sequence 7 (Middle Miocene), Starfak field.

lower two-thirds of the study interval were deposited under marginal-marine conditions; however, indicator fossils of this environment are sparsely preserved. Information provided by the indicator fossils also offers corroborative evidence for interpretations of systems tracts.

Paleogeographic Setting

The upper lower Miocene-to-Pliocene strata of the ancestral Mississippi River depocenter form a dominantly regressive succession 10,000 ft thick. This remarkable interval of thick siliciclastics accumulated during a period of high sedimentation rates. Sandstone-bearing depositional systems, particularly deltaic deposits (both lowstand and highstand), are therefore very well developed. Depositional facies of the Miocene section grade upward from shale-rich slope and sandy basin-floor deposits to sandstone-dominated, inner-shelf facies. The sequence-stratigraphic framework for the study area comprises 10 third-order sequences, at least 58 fourth-order sequences, and the full array of systems tracts within both sequence hierarchies *(Hentz and Zeng, 2003)*.

Conceptually, stratal stacking patterns within third-order systems tracts vary relative to their position in the shelf-to-basin depositional profile *(Mitchum and Van Wagoner, 1990; Mitchum and others, 1993)*. Furthermore, these variations coincide with changes in stratal attributes of the component fourth-order systems tracts. Therefore, the study interval can be subdivided into distal, medial, and proximal parts (Fig. 3), each of which share sequence-stratigraphic characteristics, to systematically document larger scale stratal and depositional trends within the ~10,000-ft study interval. The study interval comprises two distal, four medial and four proximal third-order sequences. (Note: In the schematic, iv = incised valley, pw = prograding wedge, sf = slope fan, and bff = basin-floor fan.)

Lowstand Prograding Wedges

Among the most well-represented systems tracts in the Miocene interval are lowstand prograding wedges, deltaic deposits that accumulated during episodic lowstands of relative sea level. Wedges are typically sandstone-rich, more so than highstand deltas, reflecting focused sedimentation via the funneling of fluvial sands to the wedges through incised-valley feeder systems during lowstand periods. Moreover, wedges are commonly encased within outer-shelf and slope shales and are thus prime exploration targets. In fact, most Miocene hydrocarbon production from the modern shelf of the northern Gulf of Mexico originates in third-order lowstand systems tracts (LST) containing these prograding lowstand wedges. Prime hydrocarbon targets exist where fourth-order prograding wedges stack to form third-order prograding complexes.

The upper lower and lower middle Miocene section of offshore south-central Louisiana records an upsection gradation from distal to medial to proximal prograding complexes and associated third-order lowstand facies.

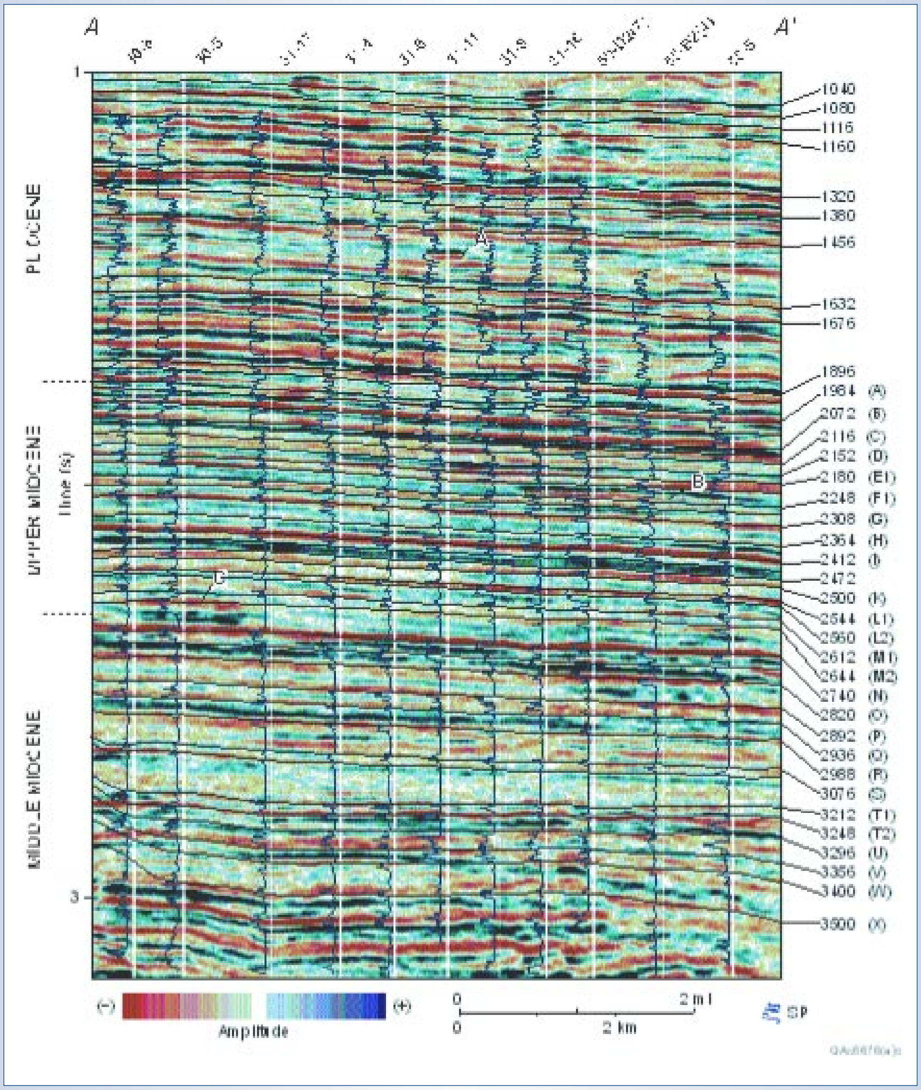

Figure 7: North-South Cross Section of Starfak Field Showing Well-to-Seismic Correlation in Two-Way Traveltime.

Distal Prograding Complexes

The distal third-order lowstand systems tract (LST) comprises a basin-floor-fan sandstone at the base; an overlying, shale-dominated, slope-fan complex; and a series of stacked fourth-order prograding wedges at the top *(prograding complex of Mitchum et al., 1993)* (Figure 4). Third-order transgressive and highstand shales probably exist in shales overlying the LST; however, consistent well-to-well log patterns identifying these deposits are not evident. Benthic paleofauna record an overall upward-shallowing succession that ranges from basin-floor and lower and upper slope (upper bathyal) deposits in the interval's bottom half to inner shelf (marginal marine to middle neritic) facies in the upper part. Whole cores from individual prograding wedges contain a mix of terrestrial, estuarine, and marine palynomorphs. Prograding complexes of stacked fourth-order prograding wedges occur as a series of inter-stratified, upward-coarsening, progradational shale-and-sandstone units, totaling 580 to 770 ft, each unit as much as 200 ft thick. Sandstones are very fine to medium grained, with very fine sandstone predominating *(Dutton and Hentz, 2002)*. Fourth-order prograding-wedge sandstones compose the hydrocarbon reservoirs. Thin (40 ft), typically poorly developed retrogradational sections (transgressive systems tracts) over-lie the progradational units.

Basin-floor-fan and slope-fan facies form 60 percent of the third-order LST. The thick shale intervals (as much as 1,100 ft) represent outer-neritic to upper bathyal slope-fan deposits. A thick (as much as 250 ft) aggradational basin-floor-fan sandstone that records little or no incision marks the base of the third-order LST. The base of another well-developed

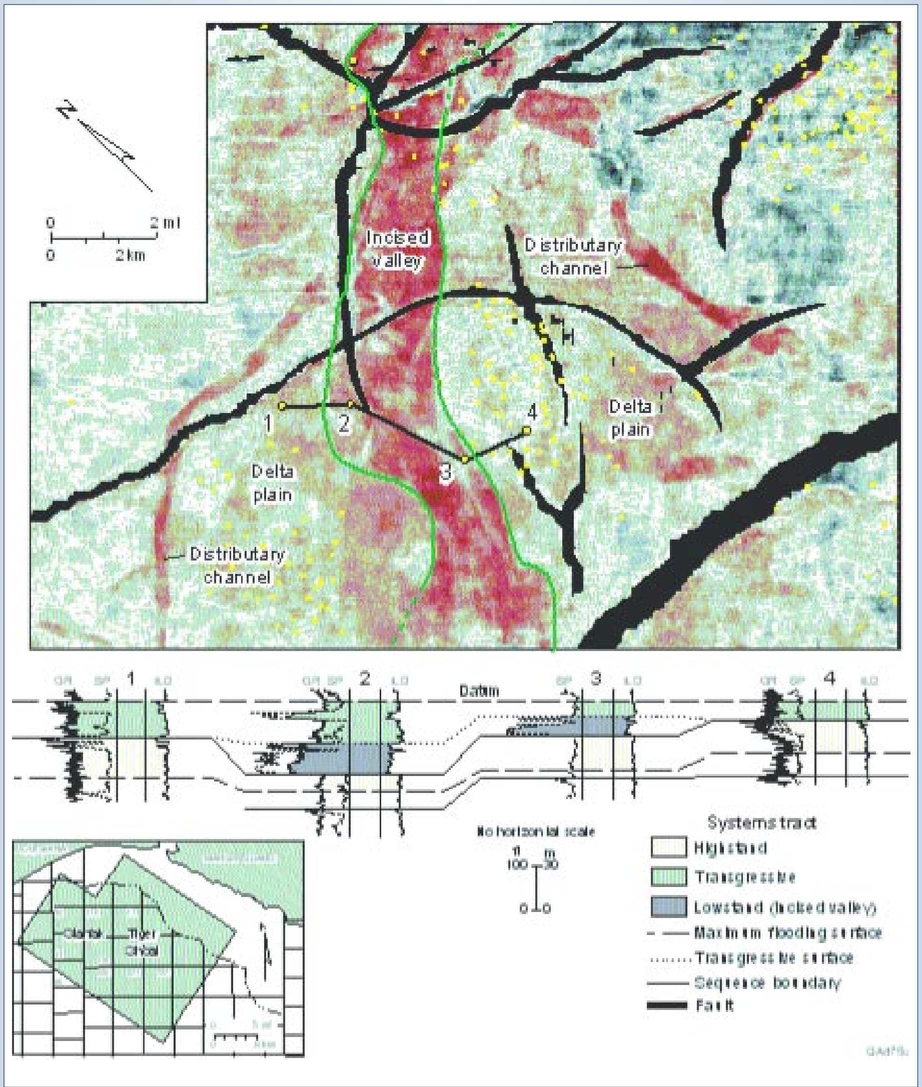

Figure 8: Amplitude Stratal Slice and Well Log Expression of a Lowstand Incised Valley Fill Incising Highstand Delta Plain Deposits.

basin-floor-fan sandstone 150 to 200 ft below the third-order sequence boundary (Texaco No. 3 well in Figure 4) may represent another third-order sequence boundary near the distal margin of an older fan deposit.

Medial Prograding Complexes

Several features differentiate the distal and medial prograding complexes and associated lowstand facies. In contrast to the distal lowstand successions, medial third-order LST's contain no basin-floor-fan sandstones (Figure 5). Moreover, the medial prograding complexes (upper part of third-order LST) contain blocky, blocky-serrate, and, more rarely, upward-fining aggradational sandstone units as thick as 120 ft. These units have sharp erosional bases that incise correlated marine-shale marker beds and represent incised-valley fills. Also in contrast to the distal LST's, the upper part of the medial third-order sequence contains a thin, but definable, third-order transgressive systems tract and a well-developed third-order high-stand systems tract (HST). This HST occurs as a progradational set of stacked upward-coarsening units in the upper part of the third-order LST. The progradational set ranges from 400 to 500 ft in thickness, with each unit ranging from 60 to 160 ft in thickness. These characteristics of the medial prograding complex and associated lowstand facies record a more landward position relative to that of the distal complex. Reservoirs are restricted to the prograding-wedge sandstones.

Proximal Prograding Complexes

Well logs penetrating the proximal portions of third-order complexes record the transition from upper-slope, proximal portions of fourth-order prograding wedges to the on-shelf portions of fourth-order HST deposits locally incised by valley fills that are equivalent to the wedges (Figure 6). The third-order TST and basal HST record a basinwide transgressive flooding event. The lower fourth-order HST of the third-order HST may contain additional fourth-order sequences. Individual wedges range from 50 to 180 ft in thick-ness. Hydrocarbons are concentrated in prograding wedges, incised valley fills, and highstand deltaic/strandplain sandstones of the third-order LST. In marked contrast to the distal and medial LST's, thick slope-fan shales are not developed in the proximal third-order lowstand successions.

Stratal Slice Imaging of Lowstand Depositional Architecture

Stratal slicing *(Zeng et al., 1995; Zeng et al., 1998a,b)*, or proportional slicing *(Posamentier et al., 1996)*, improves seismic-surface display mainly by making slices linearly between geologic time-equivalent seismic-reference events. Geologically, a time-equivalent reference event represents a geological surface or a depositional unit that dominates the reflection energy of the event because it is isolated, thick, or acoustically abnormal, and can be correlated over a large area. Marine condensed sections associated with third-order maximum flooding surfaces and thin sandstone sheets in relatively sand-poor sequences are probably among the best candidates. Common geologic time markers, for example lignites or coal, and thin limestone beds, may also generate good reference events. Commonly the time-equivalent seismic references are also the most continuous and coherent events on seismic profiles, which can be correlated easily, in many cases even without well control. In doing stratal slicing, it is assumed that deposition is laterally proportional in thickness for all depositional units that are thick enough to be detected by the seismic signal. Moreover, no unconformities (truncations) and other discordant reflections (onlap, offlap, toplap, etc.) can occur between the reference events, unless they are below seismic resolution.

A stratal-slice volume was been generated among 13 middle Miocene-Pliocene-age reference seismic events interpreted from the original 3-D seismic data volume from the study area in the northern Gulf of Mexico shelf (Figure 7). This process resulted in the generation of 776 stratal slices in the roughly 3.0-s data interval. The stratal slice volume has an x, y coordinate system that is the same as that of the original 3-D seismic volume, but the z-axis in the stratal slice volume is relative geologic time. In Figure 7, stratal slices are numerically ordered according to increasing geologic time (no scale). Industry designated reservoir (lithostratigraphic) units are identified by numbers in the parentheses. Three lenticular sandstones tied to patchy seismic events are designated by letters A, B, and C.

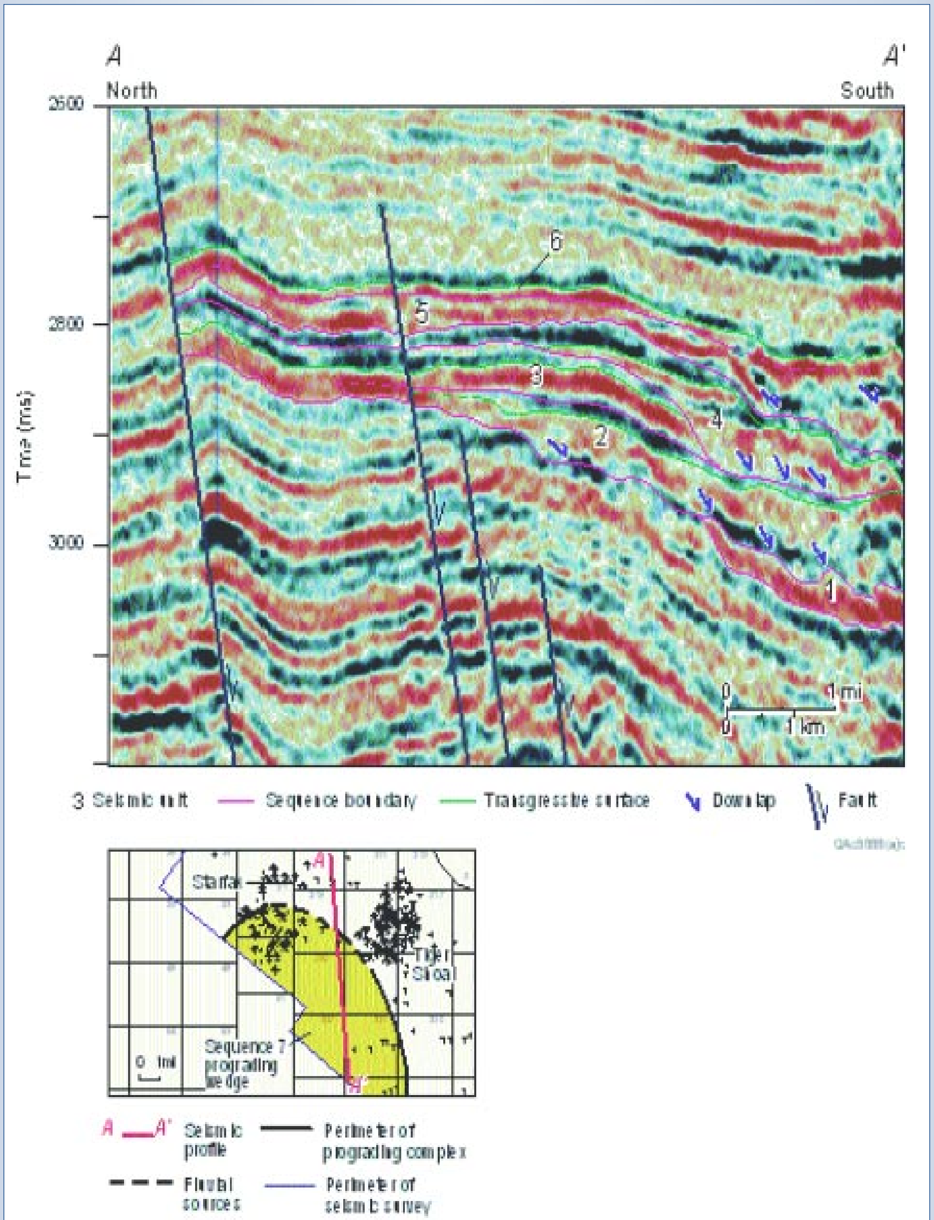

Figure 9. Depositional dip-oriented seismic line showing a lowstand wedge complex.

This process is equivalent to stretching or squeezing the seismic traces in time, guided by the reference events, to form a new 3-D seismic volume having traces of the same data length or "thickness." All reference events used in the process are flattened. The resulting slices are the plan-view geomorphology of depositional systems that are snapshots of 3-D bodies of genetically related, high-frequency sequences and systems tracts (Figure 8). In the figure, note well-developed delta-plain sandstones below the sequence

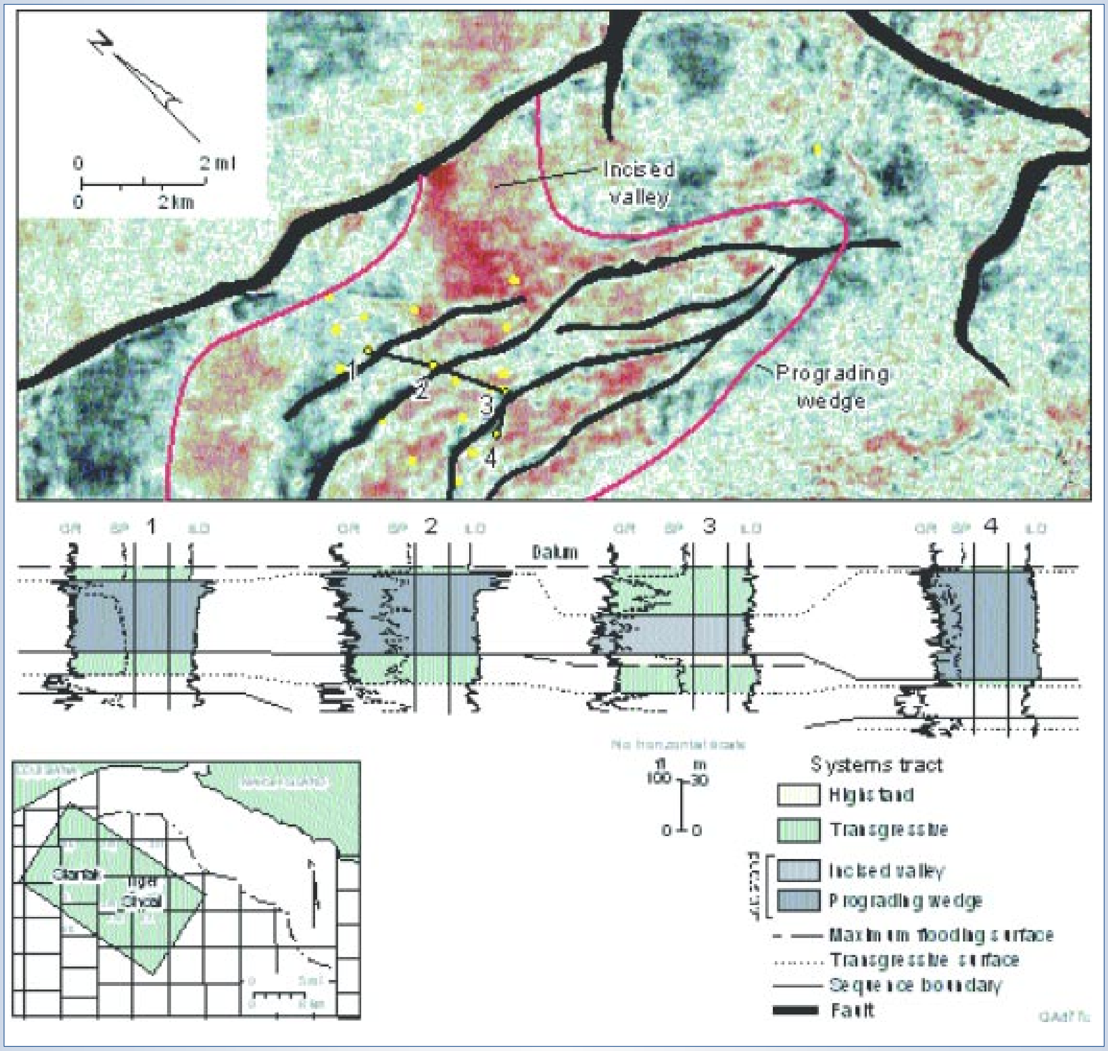

Figure 10: Amplitude Stratal Slice and Well Log Expression of Uppermost Fourth-Order Prograding Wedge in Sequence 9

boundary (exposure surface) equivalent to that below the valley fills (unconformity) in wells 1 and 4.

A depositional-dip-oriented seismic profile of a proximal prograding complex is shown in Figure 9. Seismic units 6, 5, and 4 correspond to fourth-order sequences defined in the area of well control. However, the seismic stratigraphy of seismic unit 3 is more complex; well log correlation with the seismic indicates that unit 3 comprises the basal two fourth-order sequences in the area of well control. Seismic units 1 and 2 were deposited south and southeast of well control and represent coastally onlapping fourth-order prograding wedges. The third-order sequence boundary at the base of the prograding complex was a major sediment-bypass surface across which the sediments in seismic units 1 and 2 were transported.

Amplitude stratal slices *(Zeng et al., 2001)* and cross sections illustrate aspects of the areal and internal geometry of fourth-order pro-grading wedges (Figure 10). Well 1 captures the log expression of the shalier portion of the wedge, whereas wells 2 and 4 exhibit the sandier accumulations within the central portion. Well 3 probably represents fluvial deposition within an incised valley (sharp-based, blocky-serrate sandstone) concurrent with wedge progradation, followed by estuarine and bayhead delta (retro-gradational middle portion and upper pro-gradational sandstone, respectively) deposition. Imaging of the

Lowstand prograding wedges exist along all the Tertiary paleo-margins of the northern Gulf of Mexico. Within the study area, the lowstand prograding wedges are relatively new prospecting opportunities; therefore, core data is limited through these reservoir intervals.

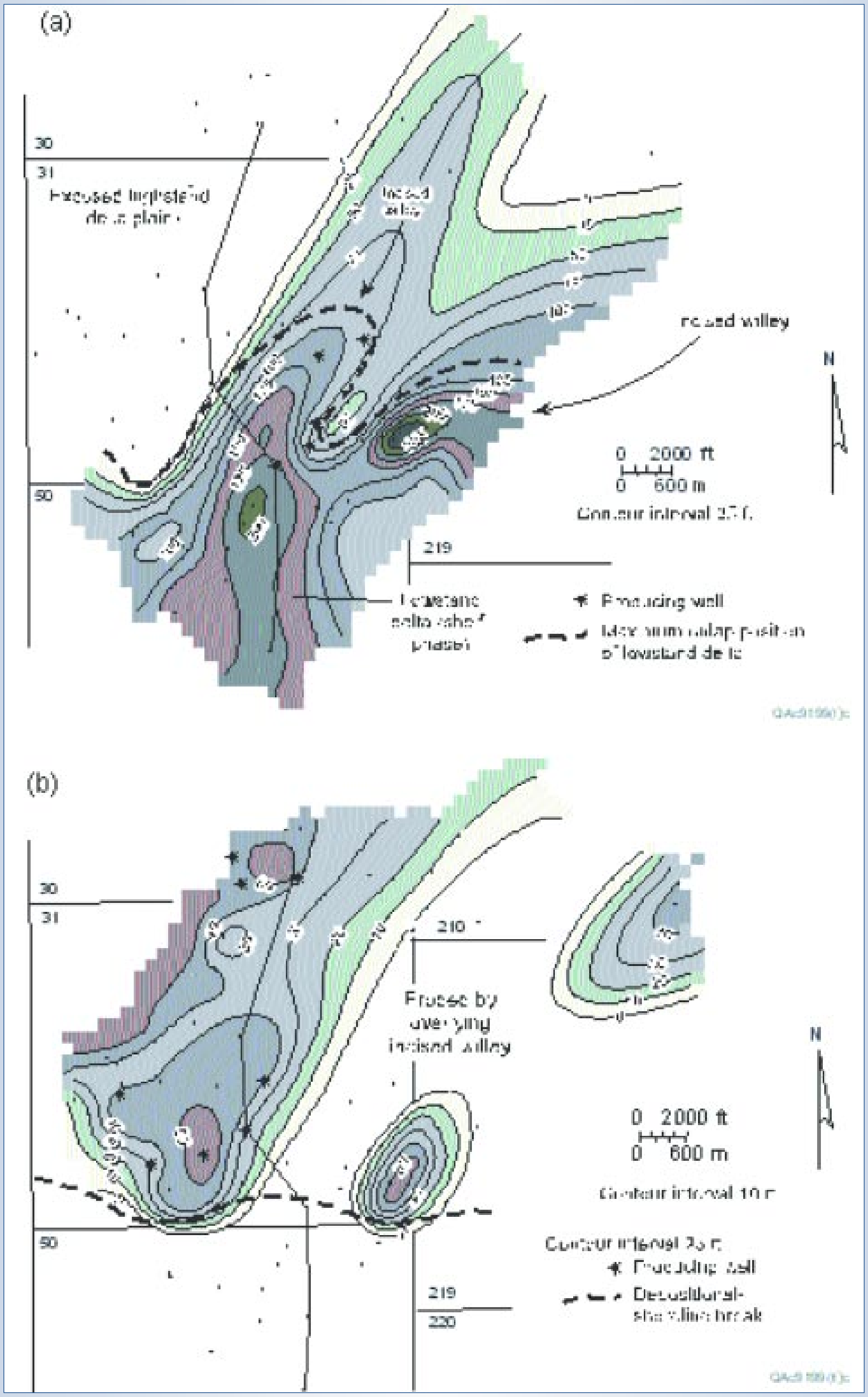

Figure 11. (a) Isochore map of the incised-valley-to-prograding wedge transition in the fourth-order sequence

(b) Isochore map of the fourth-order highstand systems tract that directly underlies, and was partially incised by, the valley/wedge complex.

distal parts of most wedges is limited by the southwestern boundary of the 3-D seismic data volume. Relief on the first-order growth fault just north of the wedge probably formed the exposed shelf edge below which relative sea level fell during lowstand deltaic deposition.

Seismic imaging of the sandier upper parts of the prograding complexes in distal and medial sequences by amplitude stratal slicing shows that fourth-order wedges are as much as 9 mi in strike width and >3 mi in the dip dimension. Third-order prograding complexes are only marginally wider along depositional strike (as much as 12 mi), indicating focused lowstand deltaic deposition within the third-order (1.1 m.y.) time frame. These dimensions contrast markedly with the much greater areal dimensions of the highstand deltas.

Reservoir Character and Prospectivity of Lowstand Prograding Wedges

Lowstand prograding wedges exist along all the Tertiary paleo-margins of the northern Gulf of Mexico. Within the study area, the lowstand prograding wedges are relatively new prospecting opportunities therefore core data is limited through these reservoir intervals. A petrophysical study was performed on a single core from two fourth-order prograding-wedge sandstones occuring from depths of 14,292 to 14,910 ft in Starfak field; the Robulus L-2 and L-5 sandstones. These sands represent portions of a distal third-order prograding wedge from the Middle Miocene. Study results show that the Robulus L-2 sandstones are somewhat coarser grained than are the L-5 sandstones, 3.0ϕ (0.13 mm) versus 3.5ϕ (0.09 mm), respectively. The sandstones have an average composition of Q82F12R6 and are mostly subarkoses. Average porosity in L-2 sandstones is 19.2 percent, and average permeability is 111 md. Geometric mean permeability is 18 md. Sandstones from the L-5 interval (all samples from the L-5 [lower]) have average porosity of 18.3 percent and average permeability of 100 md (geometric mean = 13 md). Good reservoir-quality sandstone at the top of the Robulus L-5 (lower) and L-2 intervals is interpreted to represent proximal-delta-front/ shoreface deposits. Muddy deposits above Robulus L-5 (lower) are inferred to compose a transgressive systems tract. However, porosity as high as 27 percent and permeability as high as 766 md were reported. These high porosity and permeability numbers in lower Miocene sandstones between 14,000 and 15,000 ft in the study area suggesting that deeper sandstones probably retain adequate reservoir quality for economic hydrocarbon production.

Isochore maps of incised-valley-to-prograding-wedge transition in the middle Miocene, from Starfak field show little evidence of fault control of the shelf break (Figure 11a and b). In contrast deeper prograding wedges show more structural control on their character and possible locations. Figure 11 (a and b) show a lowstand prograding wedge formed basinward of the depositional-shoreline break of the underlying highstand delta platform. There is no evidence of fault control of the shelf break, in contrast to the structural control on deeper wedges (Figures 8 and 9). Instead, this shelf-phase lowstand delta formed basinward of the depositional-shoreline break of the underlying highstand delta platform. Both the lowstand and highstand systems tracts contain productive sandstones; petrophysical and engineering analysis suggests that sandstones of the two systems tracts form separate reservoir compartments. Production in the wedge (shown by the starred wells) is limited to basinward of the onlap point. Collectively, within this small study area, among identified reserve addition opportunities the Robulus “L” sandstones contain the most gas reserves: 41 percent of the total oil and gas in place (421 Bcf) and 40 percent of unrisked reserves (251 Bcf).

> Stratal slicing, or proportional slicing, improves seismic-surface display mainly by making slices linearly between geologic time-equivalent seismic-reference events.

Lowstand Prograding Wedge Sands Zones of Opportunity

Significant recoverable gas resources remain undiscovered, undocumented and unproduced in the Miocene strata of the northern Gulf of Mexico. More than 41 percent of the known gas in the GOM Miocene strata remain to be produced. This four-year phase of the Secondary Gas Recovery research program was initiated to develop new play concepts, new processing designs and imaging tools and identify new resource addition opportunities that will enable small and large companies to arrest the decline in capital performance and extend the life gas exploration and development on the GOM shelf.

One of the most significant plays remaining in the Miocene of the northern GOM is the numerous lowstand prograding wedges that characterized the Miocene-age depositional shelf-edge locations throughout the Gulf subsurface. A variety of sub-regional reservoir sandstones pinch-out within thick, stacked lowstand prograding wedges. Their setting within slope and basinal shales creates ideal conditions for potential hydrocarbon migration and entrapment. They are composed of distal, medial and proximal portions each identifiable in logging cross-sections and mappable within stratal slice (proportional sliced) images. Within our own study area, the lowstand prograding wedge sandstones of the Robulus “L” zone contain the most gas reserves of any identified zones of opportunity: 41 percent of the total oil and gas in place (421 Bcf) and 40 percent of unrisked reserves (251 Bcf). The combination of unique stratal slice imaging of the seismic performed within a sequence framework of key chronostratigraphic surfaces enable geoscientists to define these resource targets and reduce both their risk and cycle time in exploiting these reserve addition opportunities. ✧

For more information on the status of this research effort contact Dr. Lesli Wood at lesli.wood@beg.utexas.edu *or at 512-471-0328.*

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Cement Pulsation Reduces Remedial Cementing Costs

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A simple new technique to improve primary cement jobs has resulted in a 36 percent decrease in average remedial cementing costs for a group of Canadian gas wells.

A chronic problem for the oil and gas industry is failure to achieve reservoir isolation as a result of poor primary cement jobs, particularly in gas wells. A new technology designed to address this problem, cement pulsation (CP), has proven technically and economically successful in Canada. CP technology has demonstrated excellent results in preventing early gas leaks in over 150 cemented wells. The basic approach of this technology is to improve reservoir isolation by mitigating fluid migration during the cement setting process.

Primary Cementing Failures Costly

Approximately 15% of all primary cement jobs fail, costing the oil and gas industry an estimated $470 million annually *(Newman, et al., 2001)*. One-third of these failures are attributed to fluid influx into the cement-filled annulus that results in channeling and subsequent communication. Fixing this problem is challenging for several reasons: channels are difficult to locate and often too small to easily fill, and remedial squeeze treatment are expensive and treating pressures may breakdown the formation. The best solution to the problem is the prevention of fluid migration in the initial (primary) cement job.

Studies have shown that in the Gulf of Mexico there are more than 11,000 strings of casing in over 8,000 wells that exhibit sustained casing pressure (SCP) *(Bourgoyne, et al., 1998)*. SCP is defined as a build up of pressure on any string of casing that can not be attributed to an applied pressure or temperature fluctuation. SCP is an indication of communication between a reservoir and the surface. SCP can be the result of tubing or casing leaks, cement damage after setting or what is more likely, a poor primary cement job. The problem can lead to tubular failures, and at the extreme, an underground or surface blowout.

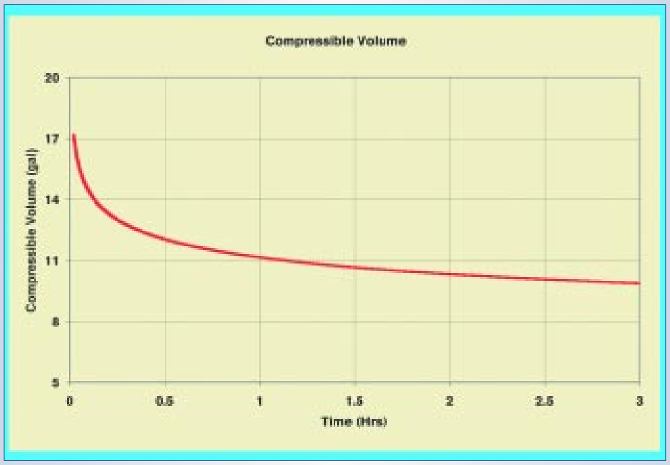

Figure 1: Compressible Volume Response

Defining the Problem

With fluid migration, the fluids invading the cement matrix can be either gas or liquid. Fluid migration in primary cement jobs can be attributed to four general factors. First, with a pressure differential across the curing cement, fluid can leak from the cement into the formation causing a volume reduction. Second, during the hydration process, the volume of the slurry contracts up to 6%, allowing micro-annuli to form along the casing and formation surfaces. Third, the unset cement is very permeable until it develops sufficient strength to prevent fluid influx. And fourth, the development of gel strength in cement slurries causes a lowering of the hydrostatic pressure in the annulus that can lead to influx.

The combination of volume losses due to fluid loss and hydration, loss of hydrostatic pressure because of gel strength and a weak, permeable cement matrix provides a perfect environment for fluid influx to take place. If this occurs, bonds between the formation and casing can be destroyed. If there is sufficient pressure and if the invading fluid volume is great, channels can become quite large and ultimately lead to fluid communication.

Attempted Solutions

To increase the chances of a successful cement job and provide good bonding between the formation and casing, the annular space must be completely filled with cement and drilling fluids must be completely displaced by the cement slurry. Cement properties must be controlled to minimize fluid-loss, free fluid and gel strengths, in order to help to lower the risk of a poor cement job. Additional techniques are used to attempt to prevent fluid migration, but no universal solution exists. Techniques include carefully controlling cement properties and the use of casing hardware to isolate the producing zone. Many of these solutions are costly and complicated to implement.

Cement Pulsation

Cement pulsation is the application of low-intensity pressure pulses to the annulus after a primary cement job to delay gel strength development in the cement slurry. Gel strength of the cement causes a lowering of the hydrostatic pressure transmitted through the annulus *(Newman, et al., 2001)*. By delaying gel strength development, the hydrostatic pressure on the formation is maintained until the cement has built sufficient strength to prevent the influx and migration of reservoir fluids through the cement matrix.

The pulsation process starts immediately after pumping stops and the annular BOP is closed. Low-pressure pulses, typically in the range of 80 to 200 psi, are applied to the casing annulus at a time interval of 30 to 60 seconds. Pulsing continues until the compressible volume levels-off or the thickening time test indicates the cement has reached 70 Bc, usually 4 to 6 hours (Figure 1). The compressible volume is the volume of fluid required to pressurize the annulus when the pulse is applied.

The cement pulsation system employs an air compressor to continuously pressurize an air tank on the unit. To pressurize the annulus, a controller opens a value between the air and water tanks (Figure 2). Air pressure forces water into the casing annulus and pressurizes it for a specific time. After pressurization, the control system releases the pressure by closing the pressurizing valve and opening an exhaust valve. Water returns from the casing annulus back into the water tank, de-pressuring the casing annulus. As the cement sets, the compressible volume decreases, giving a real-time indication of the setting process.

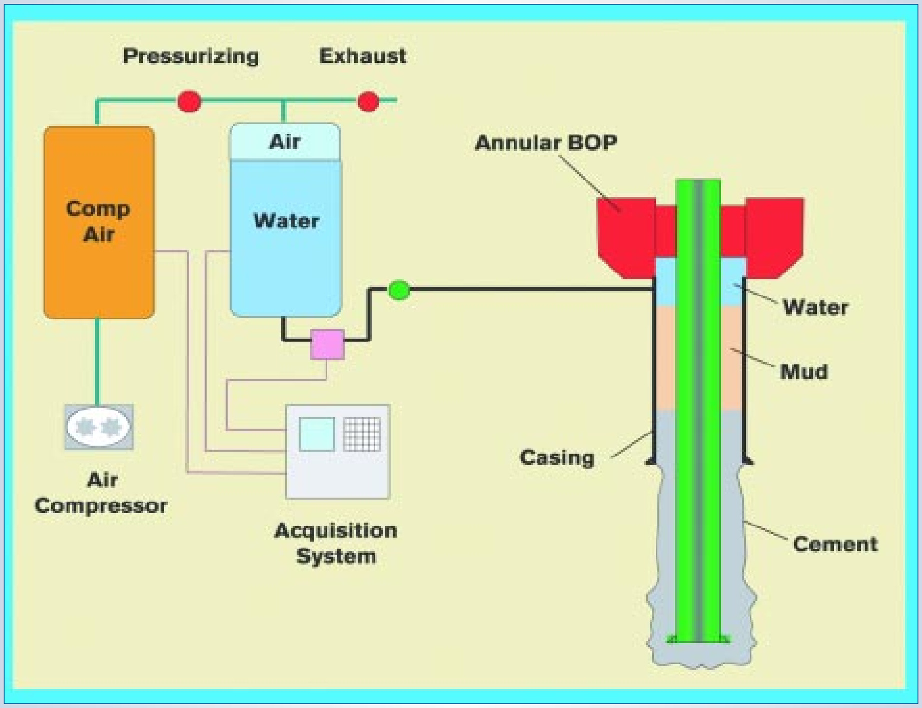

Figure 2: Cement Pulsation Layout

History of CP

In the early 1990's, John Haberman at *Texaco E&P* proposed the application of pressure pulses to the casing annulus after a primary cement job to control fluid influx and migration. GTI and *Texaco E&P Technology Company* collaborated in the development of a simple procedure to achieve these goals. In a recent effort to extend this technology, CTES L.C. developed the system and collected downhole annulus pressure data during the pulsation procedure. Concurrently, efforts to model a well's response to cement pulsation were undertaken by researchers at Louisiana State University *(Chimmalgi, 2001)*.

The goal has been to gain a better quantitative understanding of how successful the procedure is in maintaining the pressure throughout the column and also to develop tools for modifying the procedure to suit specific conditions. After verifying that the pressure pulse did transmit completely through the cement column, a field trial was conducted on a group of Canadian wells *(Dusterhoft, et al., 2002)*.

Canadian Results Impressive

Cement pulsation was applied during 2000-2002 in areas of Alberta and Saskatchewan that historically have had problems with gas migration. Typically, these wells are vertical with a depth ranging between 1900 to 5900 feet. On average, 57% of these wells develop leaks after the primary cement job. Canadian regulations mandate that any

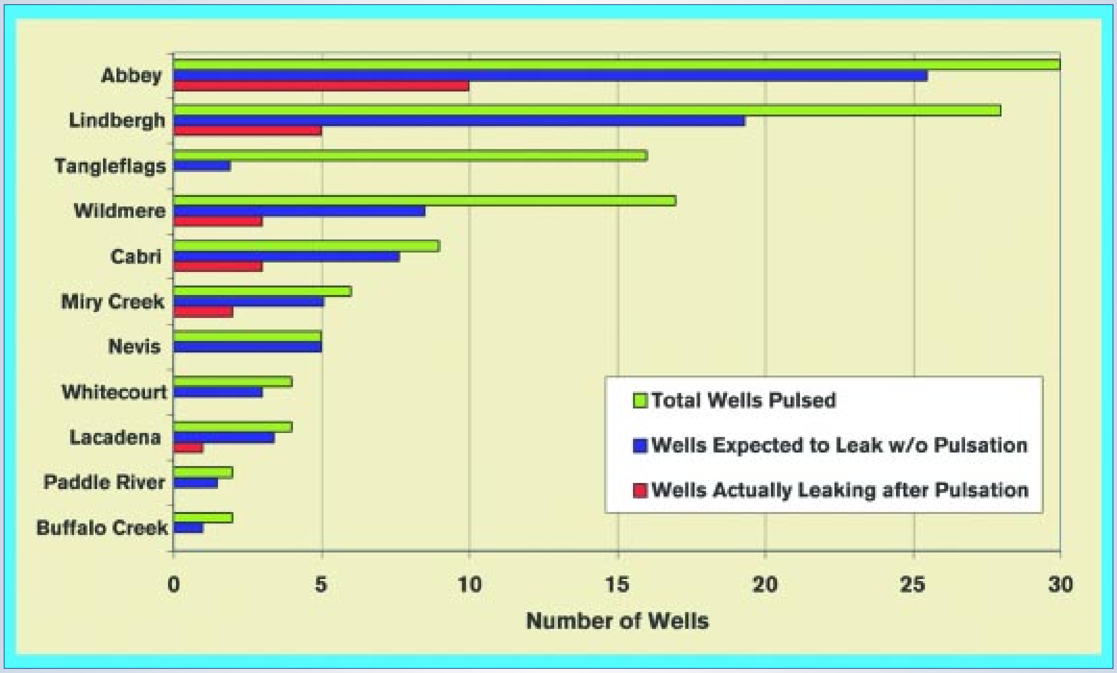

Figure 3: Summary of the Top 11 Fields Pulsed in Canada

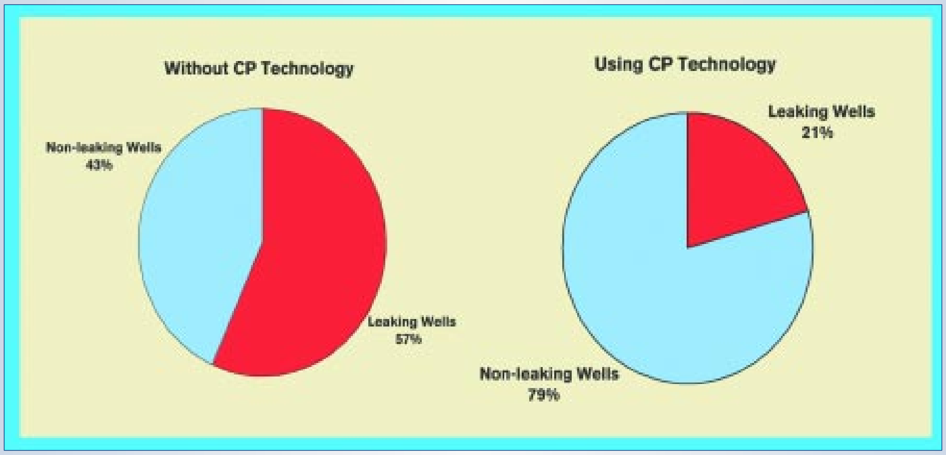

Figure 4: Improvement in Number of Leaking Wells

well with casing pressure problems must be fixed before abandoning. Repairing the leaks can cost anywhere from $30,000 to $50,000. If the problem is related to poor zone isolation, remediation costs can become significant.

Cement pulsation was applied on over 150 shallow gas wells in Alberta and Saskatchewan. A comparison of the total number of wells pulsed, the expected number of leaking wells without pulsing (based on historical data) and the actual number of leaking wells after pulsing is shown for the top 11 fields, which account for 88% of the total (Figure 3). Overall, with the use of CP the percentage of leaking wells declined from 57% to only 21% and the cost of performing remedial cement squeezes related to leaks was reduced from 59% to 43% of average total cementing cost (Figure 4). This results in an overall average cementing cost (primary plus remedial) reduction of 35%.

Based on these results, cement pulsation appears to provide a simple and cost effective solution for controlling fluid migration in gas wells. However, it is still mandatory to maintain good cementing practices to ensure the overall success of the primary cement job. The work in Canada is still continuing and now the service is available in US. ✧

For more information on cement pulsation contact David Stein, RITS Manager, at 936-521-2212; E-mail: david.stein@rits.cc *(or see www.rits.cc).*

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GTI Hydrate Characterization Research

by Iraj Salehi,
Gas Technology Institute

New Gas Technology Institute facility provides tools for understanding the dynamic behavior of gas hydrate.

A consensus of virtually all experts in the field agrees that the annual demand for natural gas in the United States will grow to more than 30 trillion cubic feet (TCF) by 2020. Considering the persistent annual shortfalls of reserve replacement, significant new natural gas reserves must be discovered and brought on line if this demand is to be met. This situation demands serious attention to unconventional natural gas resources, production of which has been hampered historically by both technical and economic hurdles. Of all unconventional natural gas resources, methane hydrate represents the largest in-place accumulation, and therefore, holds the promise of playing a role in meeting U.S. energy demand in the future. The mean average of the U.S. in-place hydrate resource is 320,000 TCF. If only one per cent of this resource producible, the reserve would be enough to meet the entire U.S. gas demand for 100 years. Accordingly, attention to methane hydrate as a potential energy resource for the United States is imperative.

Methane hydrate is formed through the entrapment of hydrocarbon molecules inside cages of ice crystals. Such crystals can contain amounts of methane up to 170 times their volume. That is, one cubic foot of hydrate can contain up to 170 standard cubic feet of gas. Considering their global abundance, methane hydrate has the potential to meet the world's energy demand for many decades if not centuries.

Another interesting characteristic of gas hydrate is in that, under moderately high pressure, the material is stable at temperatures several degrees above the freezing temperature of water. As a result, the occurrence of natural gas hydrate is not limited to cold regions such as Alaska and northern Canada. It is also present at or near the sea floor in deeper portions of the Gulf of Mexico, offshore North Carolina, and many other locations. However, it must be emphasized that estimates of in-place resource should not be mistaken for producible reserve. In fact, it is currently impossible to predict what portion of this resource can be safely and economically produced.

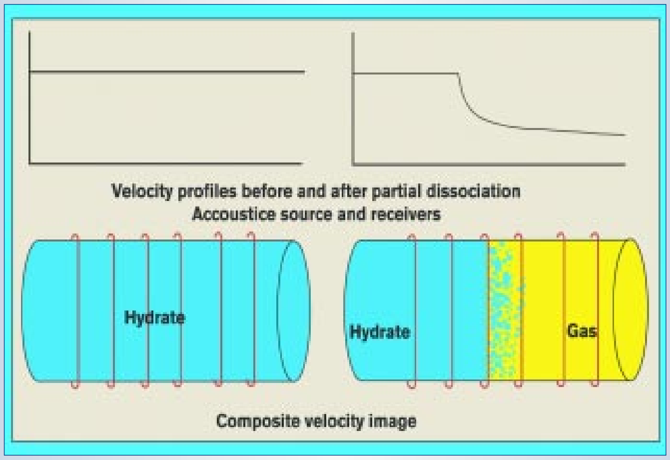

Figure 1: Conceptual Design of GTI's HRCL Pressure Vessel

The potential of this resource has moved work on identification and characterization of methane hydrate to the forefront of energy supply research and development. Specifically, the increased attention and financial support of the U.S. Department of Energy's National Energy Technology Laboratory (DOE-NETL) has played a decisive role in the creation of several joint industry projects involving the participation of the U.S. Geological Survey (USGS), universities, and several major gas production and E&P service companies.

Research on natural gas hydrates is by no means new. DOE has been funding work on this concept for many years, and several USGS laboratories have been working on various aspects of hydrate characterization as an energy resource. In parallel with these efforts, several major universities have been evaluating the physical chemistry and petrophysical properties of methane hydrate. Nearly all these efforts have been noticeably accelerated during the last few years.

Hydrate Resource Characterization Research at GTI

At the Gas Technology Institute (GTI), research programs on hydrate have been designed with an awareness of all other ongoing research, to ensure that GTI efforts will augment, not duplicate, the work of other R&D organizations.

In general terms, the principal objectives of work at GTI's Hydrate Resource Characterization Laboratory (HRCL) have been to develop data and information needed for

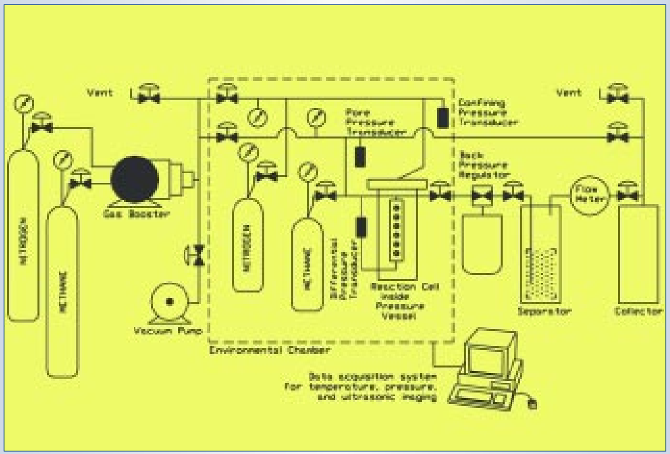

Figure 2: Schematic Diagram of the HRCL Experiment Station

Figure 3: Instrumented Sample Sleeve Held Above the Cell Body

(a) precise seismic identification and delineation of hydrate-saturated sediments and (b) determination of the effects of rock properties on the rate of dissociation of hydrate in a variety of rocks with different lithologic and flow properties. This work involves laboratory determination of seismic (elastic) properties of hydrate-impregnated sediments of different compositions, porosities, and permeabilities, under controlled pressure and temperature conditions that replicate *in situ* conditions. Results from this laboratory work will provide a set of reliable data for seismic modeling and interpretation as well as log analyses. A second category of laboratory measurements includes ultrasonic monitoring of hydrate dissociation rates in specimens with differing porosity, permeability, and saturation, as a means for predicting gas production rate.

The economics of gas production from methane hydrate accumulations hinge upon production rate and ultimate recovery, both of which vary as a function of dissociation rate and depend on the behavior of the reservoir unit as a whole. Currently, neither the flow mechanisms within hydrate "reservoirs," nor the dynamic changes that may result from the hydrate dissociation process are clearly understood. In fact, it is likely that severe sediment deformation and seafloor instability may result from the dissociation of hydrate in rocks that form ideal reservoirs for conventional hydrocarbon production (e.g., 30% porosity, coarse grain unconsolidated sands). Such damage could render production from these formations unsafe and impractical. It is therefore conceivable that more competent rocks with low to moderate porosity and permeability—but with high hydrate saturation—may constitute the reservoir condition most amenable to production of the trapped gas. The dissociation rate (as a function of pressure decrease, or temperature increase) is the key factor controlling production from such formations. For this reason, accurate determination of the dissociation mode and rate within a host formation is crucial to the identification of promising host formations and estimation of expected production from these formations.

Laboratory Measurements

Laboratory measurements at HRCL evaluate the elastic properties of hydrate-bearing sediments and map the propagation of the dissociation front resulting from depressurization or temperature change. Design of the laboratory has been based on the well-established fact that the presence of free gas in the pore space of sedimentary rocks reduces their compressional wave velocity significantly. Therefore, a reaction cell containing arrays of shear and compressional sources and receivers (Figure 1) enables researchers to measure the velocity of the front through the medium during synthesis/dissociation cycles. In addition, if the dissociation takes place along a progressing front (e.g., through activation of a heat source at one end of the reaction cell) it is possible to map the progress of the front in real time. Thus, careful experiments can determine the compressional and shear velocity of the specimen

Figure 4: Assembled Reaction Cell Placed Inside Temperature-Controlled Chamber

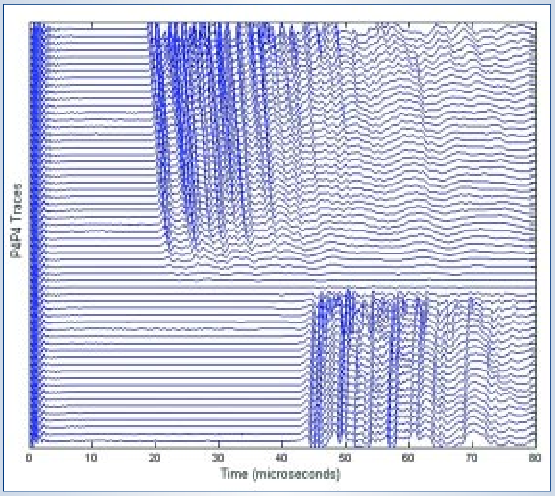

Figure 5: Monitoring of Dissociation Process in Real-Time

for use in seismic and log analyses and determination of dissociation rate for reservoir simulations. Finally, by performing these experiments on samples with different properties, researchers can develop baseline data needed for all geophysical and reservoir engineering studies. GTI's HRCL was designed and assembled to permit just these kinds of experimental operations.

Central to the HRCL is an instrumented reaction cell that houses an array of six compressional and six shear wave source and receiver pairs. Pressure and temperature are computer controlled in ranges from 220 to 350°K (-63.7 to 170° F) and 0 to 35 MPa (0-5076 psi). The unit also incorporates pressure and temperature transducers, volume and rate measurement devices, and automated data acquisition system (Figures 2, 3, and 4).

Concurrent recording of pressure, temperature, and time allow characterization of the anticipated dissociation-reconsolidation cycles. In the case of loosely packed unconsolidated sands held together by the hydrate matrix, severe attenuation or the absence of shear wave signals clearly indicate the onset of the dissociation process.

Progress to Date

Design, construction, assembly, and testing of GTI's HRCL were completed in the summer of 2002. Experimental results to date clearly have been in line with expectations derived from theoretical studies. In addition to determining the elastic properties of hydrate-bearing sand packs, researchers also have been able to monitor the progress of dissociation fronts in a few laboratory-synthesized samples. One example of recorded data shows the change in travel-time (velocity) as a sample undergoes dissociation (Figure 5). In particular, signal deterioration during the phase change period contributes to quantification of the observations. Comparison of the dissociation of a pure methane hydrate sample and the dissociation of a hydrate sample created in the pore space of a batch of 60/80 sand provides an indication of the effects of rock properties on dissociation and production rates (Figures 6 and 7).

As research continues at the HRCL, a reasonably complete database covering an acceptable range of parameters will be developed. This database will be of great assistance to the research and operations community involved in data analysis and modeling. ✧

Figure 6: Dissociation of Pure Hydrate

Figure 7: Dissociation of Hydrate in Medium Porosity/Permeability Sand at 10% Hydrate Saturation

For more information on the ongoing research at GTI's HRCL, contact Iraj Salehi, at 847-768-0902, or via e-mail at iraj.salehi@gastechnology.org.

Morphysorb® Applied to De-Bottlenecking of Gas Treating System

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New solvent exceeds performance targets during test at Canadian sour gas treating facility.

(Article excerpted from paper presented at the 2003 Laurance Reid Gas Conditioning Conference, February 23-26, 2003)

A new solvent process for treating sour gas, developed by *Uhde GmbH* and *Gas Technology Institute (GTI)*, has been demonstrated for the first time on a commercial scale in *Duke Energy Gas Transmission's (DEGT)*, Kwoen Gas Plant in Northeastern British Columbia. The Morphysorb® process was shown to be a cost effective and environmentally beneficial method for de-bottlenecking the DEGT Pine River processing system.

Instead of recovering sulfur, the plant is designed to inject over 30 MMscfd of extracted acid gas (primarily H_2S and CO_2) into depleted gas reservoirs, simultaneously minimizing sulfur and carbon dioxide emissions and saving gas producers significant sulfur marketing costs. The process exceeded all performance targets set by DEGT, which were substantially above expectations for alternative solvents.

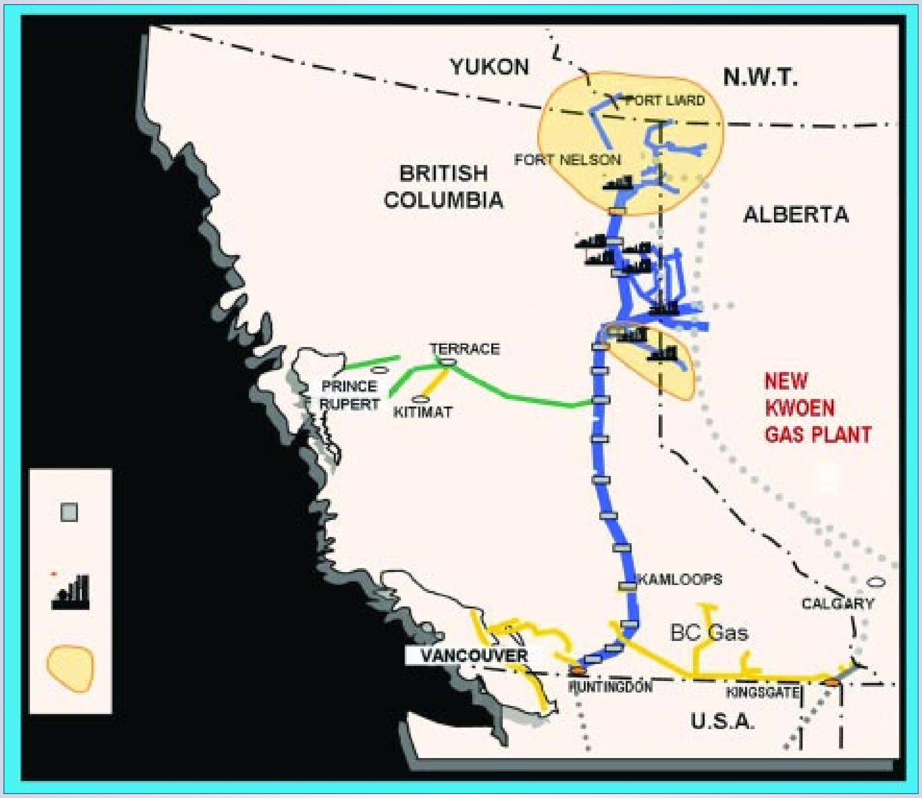

Figure 1: Conceptual Design of GTI's HRCL Pressure Vessel

Background

The Kwoen Gas Plant is a new addition to the Pine River gathering and processing system operated by DEGT in British Columbia (Figure 1). The system includes the Pine River gas plant, with three identical processing trains that include Shell Sulfinol-D gas treating units, triethylene glycol dehydration and MCRC sulfur recovery units. The plant's capacity is 560 MMscfd sour gas, 94 MMscfd acid gas and 2000 LT/day sulfur production with a design plant feed containing 16.8 % total acid gas, 9.3% H_2S and 7.5 % CO_2.

The sour gas feed sources to the Pine River system range from 5% to 40% acid gas. Producers dehydrate their gas prior to its entering the system, typically via molecular sieve adsorption. Natural gas liquid (NGL) content of the gas is extremely low (about 1.4 bbl/MMscf), and NGL recovery is not required. The plant feed contains a significant amount of sulfur, with carbonyl sulfide (COS) and mercaptan content in excess of 300 ppm. The Sulfinol-D system is designed to achieve a sales gas specification of less than 16 ppm total sulfur. Although the raw feed volume to the Pine River plant was less than capacity, the plant was fully utilized due to a higher-than-design acid gas quantity in the feed gas (21.0% versus 16.8%). In addition, new sources of sour gas in excess of 130 MMscfd flow capacity were in need of transportation and processing service.

System Expansion Alternatives

In order to process additional sour gas, DEGT was faced with the decision of either adding more treating and sulfur conversion capacity at the Pine River plant or installing additional processing capacity elsewhere in the system. Two alternatives were considered: the addition of a fourth 130 MMscfd train at the Pine River plant, or the installation of a 300 MMscfd sour gas upgrader (the Kwoen Gas Plant). The Kwoen Plant option was chosen due to significant economic advantages.

Table 1: Predicted Performance of Morphysorb Solution at Kwoen Gas Plant

Stream	Sour Feed Gas	Upgraded Acid Gas	Acid Gas
Flow, MMscfd	300	266	34
Pressure, psia	1085	1074	1015
Temperature, oF	63	55	120
mol%			
CO_2	8.60	7.21	19.60
H_2S	13.54	5.33	78.71
CH_4	77.26	86.81	1.47
C_2H_6	0.21	0.23	0.09
C_3H_8	0.02	0.02	0.02
CO_S	0.02	0.02	0.05
CH_4S	0.01	0.00	0.04
N_2	0.34	0.38	0.00
H_2O	0.01	0.00	0.04

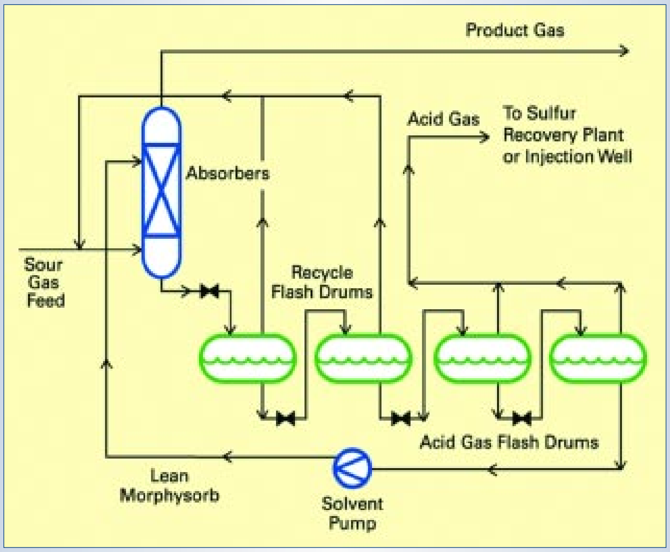

Figure 2: A simplified flow diagram for Morphysorb® process.

For example, the capital cost for the Kwoen Plant was $94 MM CND versus $258 MM CND for a new processing train at the Pine River Plant. As a ratio of capital cost over treated sour gas volume, the Kwoen Plant was installed at $0.8 MM/MMscfd versus $2.0 MM/MMscfd for a new processing train.

In addition, the Kwoen Plant design is expected to yield 3.0 MMscfd more sales gas than a traditional gas treating/sulfur recovery design. No fuel is required to run compressor engines, large power generators or large heat medium systems. Partially offsetting these advantages are slightly higher operating costs due to purchased power requirements.

The plant is designed to dispose of over 860 LT of sulfur as H_2S every day through injection of liquefied acid gas into a depleted gas reservoir. Sulfur disposal by injection will result in a cost savings for producers since the netback price for sulfur in the Pine River region is currently negative and the price is forecast to stay quite low for the foreseeable future. At an elemental sulfur netback price of minus $10/LT, the Pine River producers can expect to save over $3 MM CND/yr.

In addition, the Kwoen Plant is designed to produce significantly less emissions than a new gas processing/sulfur recovery train. The upgrader design is predicted to have 5,250 LT/yr less SO_2 emissions and 105 LT/day less NO_x emissions. Re-injection of extracted CO_2 equates to an emissions reduction of 176,000 LT/day as compared to a new train. This advantage is quite timely given Canada's recent ratification of the Kyoto Accord.

Kwoen Plant Design

The Kwoen Plant, located 18 miles upstream from the Pine River Plant, is sized to remove and inject 28 MMscfd acid gas into depleted reservoirs and to permit an additional 130 MMscfd gas to flow into the Duke gathering system and the Pine River Plant. In addition to the plant, a new 9,500 hp centrifugal sour compressor was also installed upstream of the processing unit to hydraulically de-bottleneck the sour gas gathering system.

The Kwoen Plant is the first full-scale application of the new, patented gas treating solvent Morphysorb®. Co-developed by

Figure 3: The Kwoen plant was completed in August 2002.

Gas Technology Institute (GTI) and *Uhde GmbH* (KU), Morphysorb is a physical solvent that consists of a mixture of N-Formylmorpholine (NFM) and N- Acetylmorpholine. The solvent was extensively tested in bench-scale and pilot plant facilities through the early and mid-1990s and is now available for commercial application (*Palla,* et al*., 1998; Gross* et al*., 1999).* Morphysorb was selected for the Kwoen Plant based on KU's prediction of lower hydrocarbon losses to acid gas, larger capacity for acid gas removal, and lower pumping and recycle horsepower requirements.

The benefits of Morphysorb were expected to be partially offset by higher solvent losses than could be expected with other physical solvents. However, actual Morphysorb losses measured by a variety of techniques were in line with losses expected with alternate solvents. This situation is being monitored and a more accurate value for the losses will be determined after a year of operation.

Like other physical solvents used for gas treating, Morphysorb has a strong selectivity for removing H_2S over CO_2. Despite the addition of 740 LT/day of additional feed sulfur in the volume of sour gas undergoing processing, the selective nature of Morphysorb actually reduced the sulfur plant feed to the Pine River plant, from a pre-expansion rate of 2000 LT/day to 1900 LT/day. At design flow rates, the Kwoen Plant will be reducing the H_2S/CO_2 ratio of the Pine River Plant feed from 1.3 to 1.1.

Kwoen Plant Process Description

The Kwoen Plant is a simple flash regeneration design (Figure 2). A total of 300 MMscfd of sour gas is directed to the plant, which operates at 1100 psia. The gas is absorbed by a Morphysorb solution in two parallel 150 MMscfd packed column absorbers. The lean Morphysorb flow rate to each absorber is below the maximum plant capacity of 1500 USgpm. Rich Morphysorb leaves the bottom of the absorbers loaded with extracted H_2S and CO_2. The rich Morphysorb is consecutively flashed at 425 psia and 185 psia. The off gas from these drums is recycled to the absorber feed via a 1750 hp 2-stage reciprocating compressor. The recycle operation is necessary in order to minimize methane losses. However, these losses are so low with Morphysorb that consideration can be given to recycling only the first flash if more acid gas rejection is desired. The final two flash drums yield the gas feed to the acid gas compressors as well as producing

Table 2: Methane Loss and Mass Balance Performance

Test Period (MMScfd)	Feed Gas Flow (MMScfd)	Acid Gas Flow (MMscfd)	Recycle Gas Flow (mole%)	CH4 Losses in Acid Gas Stream (Based on GTI Analysis)	Overall Mass Balance (Based on Duke's Analyzers)	Overall Mass Balance
1 (30 hrs) *	138.1	21.18	9.9	1.2	107.37	108.76
2 (24 hrs)**	146.8	22.35	11.0	1.0	105.99	106.35

** Period 1 Conditions*
Feed Gas: 1076.8 psig, 60.9°F
Acid Gas Composition in Feed Gas: 15.3 mole% H_2S, 11.8% CO_2

*** Period 2 Conditions*
Feed Gas: 1084.9 psig, 51.4 °F
Acid Gas Composition in Feed Gas: 14.8 mole% H_2S, 12.6% CO_2

a regenerated (lean) Morphysorb stream. The acid gas flash drums operate at 65 psia and 25 psia, respectively. The lean Morphysorb flows from the final flash drum back to the absorbers via booster and high-pressure pumps. The plant also contains a mechanical and carbon filtration system. The filtration flow rate is 9% of the total Morphysorb circulation.

The Morphysorb solvent is designed to remove 33 MMscfd of acid gas from the sour gas feed (actual conditions in the plant indicate over 40 MMscfd is possible), resulting in an upgrade from 22.1% acid gas to 12.5% (Table 1). The design acid gas quality is 78.7% H_2S, 19.6% CO_2 and 1.7% hydrocarbon and trace sulfur. Thirty percent of the inlet trace sulfur is removed by the Morphysorb solution.

Flash regeneration and auto refrigeration of the Morphysorb eliminates the need for a number of traditional gas treating unit operations (e.g., all of the equipment attached to an amine plant regenerator system such as the still, reboiler, process heat medium system, overhead condenser, etc.). In addition, the plant has no requirement for a residue gas dehydration system.

The lack of process heating requirements and a third party power supply for the large process and compression load keep fuel consumption low. The flash regeneration design of the Kwoen plant requires no process heat input. Plant heating is only required to keep the plant process piping, vessels and tanks warm during the winter when the ambient temperature can reach –40°F. The total design running power load of the inlet compressor and plant is 22,000 hp. This load is entirely supplied by the local power generator and distributor.

In order to maintain a high level of reliability, the plant was designed with a significant amount of sparing for rotating equipment. The plant has three 50% capacity acid gas compression units, two 100% recycle compressors and 100% sparing for the Morphysorb booster and high-pressure pumps.

Acid Gas Handling and Disposal

The acid gas that flows from the final flash drum is compressed in the first stage of three 4000-hp reciprocating four-stage acid gas compressors. This compressed stream is combined with 16.6 MMscfd of 65 psia flash gas and compressed to a final discharge pressure of 1100 psia. The compressor aftercooler liquefies the acid gas prior to its entering a nine-mile, 6-inch-diameter pipeline. The liquefied acid gas arrives at the injection well as a liquid and flows down the tubing to a depth of 8200+ feet. The depleted reservoir will be filled with acid gas to a pressure less than 80% of the hydrostatic head of the tubing, at a sandface pressure less than fracture pressure. Even at this reduced volume, the estimated storage capacity is over 200 Bcf, which should provide for thirty years at projected rates.

Plant Performance Testing

Construction of the Kwoen plant was completed in early August 2002 (Figure 3). Morphysorb solvent was loaded to the process train and brought up to operating pressure with sweet gas in the system. Initial testing with sour gas in a single column running well below capacity began in early September, utilizing 90 MMscfd of gas available at that time. Operations at this level were continued while various mechanical issues involving compression equipment and solids deposition ahead of the injection well were resolved.

At the end of October 2002, plans for an acceptance test were made. Originally anticipated to be full flow in both contactors, the test was constrained to one contactor with a feed of ~150 MMscfd due to availability of gas and the presence of downstream bottlenecks. The test was designed to demonstrate that the Morphysorb process is capable of achieving required performance on several metrics: recycle gas flow rate, methane losses to injection well stream, solvent

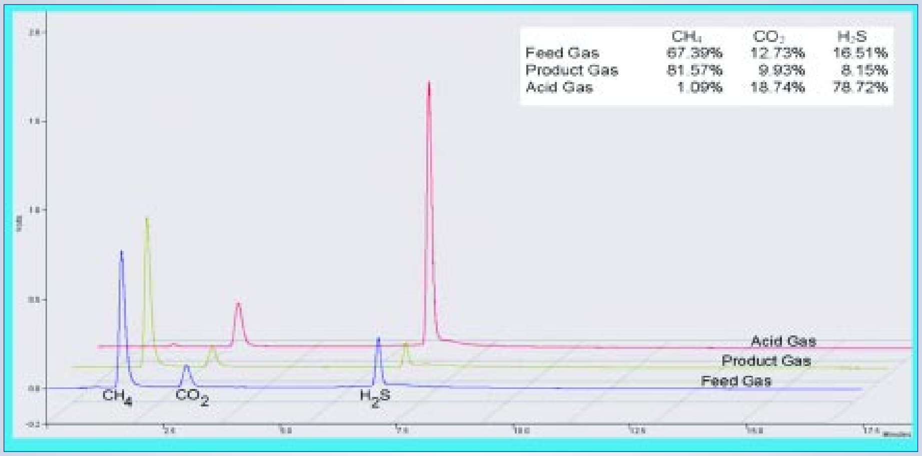

Figure 4: All the gas and liquid samples collected during the test period (November 12 to November 15) were analyzed immediately.

loss, specific circulation rate, total acid gas removal, and operability. GTI had responsibility for collecting and analyzing gas and liquid samples and developing a performance report, funded in part by the U.S. Dept. of Energy's National Energy Technology Laboratory (NETL). DEGT observed the testing and sample analysis and reviewed the results. A total test run of 53 hours was achieved.

A total number of seven gas sampling points and two liquid sampling points were used for sample collection during the performance test. GTI established a temporary laboratory at the site to analyze the gas and liquid samples collected during the performance test. In addition, Duke had its own independent online analyzers for measuring: CO_2 and H_2S in feed and product; and CO_2, H_2S and CH_4 in acid gas streams.

All the gas and liquid samples collected during the test period (November 12 to November 15) were analyzed immediately (Figure 4). The plant performance was consistent throughout this period, with some plant down-time discontinuities due to compressor and mechanical problems. The liquid circulation rate was set at a fixed value below the maximum value possible in the plant with current hardware. The testing resulted in two useful "steady state" periods (which differ in conditions significantly) for the purpose of computation of the adjusted performance specification metric values and analysis of results (Table 2).

In all cases the metrics satisfied the criteria established by *Duke Energy*. Measured solvent losses on product gas samples collected during the performance test were well within expected levels. Two different techniques were used to accurately measure solvent losses: UV absorption spectroscopy and GC FID analysis. Analysis of the samples indicated a solvent concentration of 3.1 to 4.0 ppmv, well below the expected maximum limit of 8 ppmv.

No foaming incidents or upsets occurred prior to, during, or after the performance test. (As of this writing the plant has been in operation in excess of four months, and approximately 8 Bcf of raw gas have been processed.) This is interpreted as a positive indication of the solvent's low propensity for foaming, a problem often exacerbated in the early stages of plant operations by the presence of foreign contaminants in the system. Operations personnel reported that the Morphysorb unit was stable and required no special attention once it reached a steady state condition.

Application Potential

Sour gas upgrading with Morphysorb shows great promise as a process for de-bottlenecking existing gas plants in situations where feed acid gas content climbs above the optimum host plant design. Preferentially, the feed gas should be hydrocarbon dry in order to reduce the impact of losing heavier hydrocarbons to the gas treating solvent. Additionally, acid gas injection can help to maintain capital costs and emissions lower than is possible with other sulfur recovery technology alternatives, provided that suitable reservoirs are accessible. ✧

For more information on the application of Morphysorb to gas treating problems, contact Dennis Leppin, Associate Director, GTI Gas Processing Program. Phone 847-768-0521; E-mail: dennis.leppin@gastechnology.org/.

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Improved Modeling Increases Salt Cavern Storage Working Gas

by Kerry L. DeVries,
RESPEC

An improved model for gas storage caverns has revealed the potential for safely increasing storage capacity by accurately characterizing the plastic behavior of salt.

Changes in natural gas market and regulatory environments have created a significant demand for large capacity storage facilities with flexible gas storage capability. Some of the recent demand for natural gas is being addressed through the planning and development of solution-mined storage caverns in Gulf Coast salt domes in Alabama, Mississippi, Louisiana, and Texas and bedded salt formations in Arizona, New York, and Wyoming. The major advantage of storing natural gas in salt caverns is immediate availability during peak demand. A disadvantage is the high cost of facility construction compared to conventional porous rock storage.

To improve the economics of storing natural gas in salt caverns and increase the total storage capacity of natural gas in the United States, the Department of Energy's National Energy Technology Laboratory sponsored research performed by RESPEC aimed at pushing the technical limits and improving the performance of compressed natural gas (CNG) storage in salt caverns. An important aspect of the project was addressing the ability to accurately characterize the behavior of salt under changing pressure conditions. This necessitated use of an appropriate constitutive model and numerical techniques to predict the creep and brittle response of salt under the loading conditions expected in the salt during gas storage operation. Using such a model, researchers were able to determine that minimum gas pressures could be lowered in the caverns studied, increasing working gas capacities up to 20 percent with zero increase in cavern size.

Cavern Storage and Salt Behavior

Product movement to and from CNG storage caverns is accomplished simply by compression and expansion of the stored gas. Consequently, the internal pressure on the walls of a CNG storage cavern can vary considerably. Because a minimum level of internal pressure is necessary to ensure cavern stability, a certain quantity of gas (cushion gas) must always remain in a cavern.

The economics of CNG storage in salt caverns are largely dependent on maximizing the ratio between the working gas and the cushion gas volumes. This ratio depends directly on the relative values of the maximum and minimum gas pressures permitted in the storage cavern. The *maximum* storage pressure is limited by regulation to a fraction of the weight of the overburden (typically 0.75 to 0.85 of the vertical stress) to prevent loss of containment by hydraulic fracturing of the salt and/or cemented well casing. Determination of the *minimum* pressure required to ensure the structural stability of the cavern is much more difficult and has often been based on conservative assumptions because accurate modeling techniques and material properties for the salt are unavailable.

The important characteristics of salt response for natural gas storage cavern development are *creep* and *dilation* (microfracturing resulting in increased porosity). A constraint that often limits the minimum gas pressure in a CNG storage cavern is the potential for salt dilation that can lead to spalling in the cavern roof and/or walls and subsequent damage to the cavern or hanging casing string(s). Depending on the stress and strain conditions, salt may or may not dilate as it deforms.

Figure 1 illustrates two deformed salt core specimens. Both specimens experienced creep deformation at the same stress difference (difference between the axial stress and the confining pressure) but were subjected to different axial stresses and confining pressures. The specimen on the left (high confining pressure) did not dilate and the specimen on the right (low confining pressure) not only dilated but the microfracturing progressed to a state that resulted in failure of the salt as evidenced by the crumbling of the specimen. The key to optimizing cavern performance is

Using such a model...minimum gas pressures could be lowered...increasing working gas capacities up to 20 percent with zero increase in cavern size.

Figure 1: Creep Deformation of Salt With and Without Dilation

to determine the minimum allowable gas pressure that will limit microfractures from coalescing and growing uncontrollably as exhibited by the specimen on the right in Figure 1.

Conventional Design Criterion

Conventional cavern design practice embraces the use of both conservative design criteria and numerical simulations of typical gas service cycles comprising different minimum operating gas pressures to predict the states of stress in the salt surrounding the cavern. The predicted states of stress are compared to states of stress known to cause dilation in laboratory tests and the minimum gas pressure is established as the lowest pressure that can be experienced without inducing stresses in the salt that cause dilation.

Criteria based solely on stress have been used extensively in the last several years to estimate the minimum allowable pressure of CNG storage caverns. These criteria are often based on a limited amount of laboratory testing that provides a crude approximation for the stress states at which dilation is expected. The uncertainty in determination of the stress states that produce dilation has lead to a generalized criterion that has been applied to salt at several Gulf Coast domes and Permian, Paradox, Appalachian, and Green River Basin bedded salt formations.

Salt-Damage Design Criterion

Limited damage or dilation is permissible without compromising the mechanical integrity of salt. In addition, salt damage is known to be recoverable under hydrostatic and/or high mean stress conditions. In gas storage caverns, high mean stress conditions are induced in the salt when the gas storage pressures are high; e.g., during maximum storage pressure conditions. Therefore, any damage induced in the salt surrounding the cavern at low storage pressures is likely to be recovered or healed at high storage pressures. Conventional stress-based design criteria do not allow for any salt damage nor do they account for salt healing. Advanced constitutive models for salt have been developed that address the shortcomings of the conventional method. Advanced constitutive models and design criteria have not been applied to gas storage caverns before the current research.

Proof-Of-Concept Research

The idea that the minimum gas pressure in CNG salt caverns may be reduced using a continuum damage approach with advanced constitutive models is based on the hypothesis that a better prediction of the behavior of salt can be obtained by models that track the history of damage and healing. By incorporating damage accumulation and healing in the material model for salt, some of the conservatism reflecting the uncertainty in a stress-based criterion can be reduced, and a more accurate criterion may be established. If a more precise design criterion is established for cavern analysis, the uncertainty in the minimum gas pressure requirement would also be reduced. A reduction in uncertainty should produce less conservative minimum gas pressure estimates, which would result in increased economic benefits for the CNG storage industry.

RESPEC, an engineering consulting firm, and Bay Gas Storage Company, Ltd. (Bay Gas), a natural gas storage company, performed a demonstration project to prove this concept. The demonstration project consisted of site characterization, laboratory testing, constitutive model evaluation, model refinement, and numerical analyses. The goal of the project was twofold: establish the minimum testing requirements necessary to accurately define the parameter values of the continuum damage model used to describe the behavior of salt; and assess possible improvements for the working gas capacity of an existing and planned cavern over a conventional stress-based criterion.

Technology Transfer Into the Project

Considerable improvements in the ability to predict the deformation and deformation rate around underground openings in salt deposits have been obtained as a result of research efforts in various countries related to the permanent disposal of radioactive waste. However, coupling of creep deformation and damage to describe the response of rock salt has been treated by only a few constitutive models. One of these models, referred to as the Multimechanism Deformation Coupled Fracture (MDCF) model, was developed for the Waste Isolation Pilot Plant (WIPP) near Carlsbad, New Mexico, for the disposal of nuclear waste products generated by U.S. defense programs. Development of this model started over 30 years ago and has been supported by multimillion dollar research and laboratory testing programs.

This model was used for the proof-of-concept project to determine the minimum allowable gas pressure in two CNG storage caverns (one existing and one under development) owned and operated by Bay Gas in the McIntosh Dome, north of Mobile, Alabama. The existing cavern had been solution mined to a volume of 2.7-million-barrels, while the cavern under development is expected to be about 4.22-million-barrels in volume when complete. The casing shoes of the wells for both caverns are at a depth of about 4,000 feet subsurface. The height of the existing cavern is approximately 1200 feet and a similar height is planned for the cavern under development.

Applicability of MDCF Model to CNG Storage

The operating conditions of a CNG storage cavern are significantly different than a radioactive waste repository. The internal pressure in a cavern can vary considerably through-out the lifetime of the cavern and is directly related to the amount of gas in the cavern. Conversely, the nuclear waste repository conditions are relatively static, with the possible exception of large temperature changes generated by certain high-level radioactive waste packages. These differences in operating environments necessitated modifications to the MDCF model to better predict the response of CNG storage caverns.

Supported by laboratory testing, researchers at RESPEC made theoretical changes that improved the predictive capability of the MDCF model. A test matrix of approximately 35 tests that can be performed by most rock mechanics labs was found to be sufficient to derive site specific properties for the modified model. Using the newly developed model and a quantitative design limit for salt damage, numerical simulations were used to determine the minimum allowable pressure for the two Bay Gas caverns.

Numerical Simulations

Two sets of numerical analyses were performed using the geometrical, geological and material properties gathered for the project. One set of analysis used a conventional stress-based criterion and the other used the newly developed MDCF model damage-based criterion. Because development of the second Bay Gas cavern was not complete at the time of this investigation, the final geometry of the cavern was based on a prediction of solution-mining software. The calculations closely simulated the actual or expected history of the caverns including cavern excavation by solutioning, dewatering, and 20 years of natural gas service.

The gas service cycle used for this study was similar to that experienced for the existing cavern during its first 8 years of service. This gas service cycle consisted of a single injection and withdrawal phase during each year of operation. The maximum gas pressure specified for the caverns was 3290 psi or about 0.82 psi/foot depth at the casing shoe.

Minimum gas pressures of 1200 and 1000 psi (0.3 and 0.25 psi/foot depth at the casing shoe) were determined using the stress-based criterion for the existing and planned caverns, respectively. A minimum gas pressure of 800 psi (0.2 psi/foot depth) was determined for both caverns using the MDCF model damage-based criterion.

Working Gas Increased

The lower minimum gas pressure predicted by the MDCF model would increase the initial working gas capacity of the existing cavern by about 20 percent. An 8 percent increase in the initial working gas capacity is expected for the cavern under development. This increase in deliverable gas comes without any increase in cavern size. Thus other than the cost of laboratory testing to develop site-specific properties and performing a geomechanical study using the MDCF model, no additional operating or capital expenses are associated with the capacity increase.

However, the closure rate of the cavern is very sensitive to the internal pressure

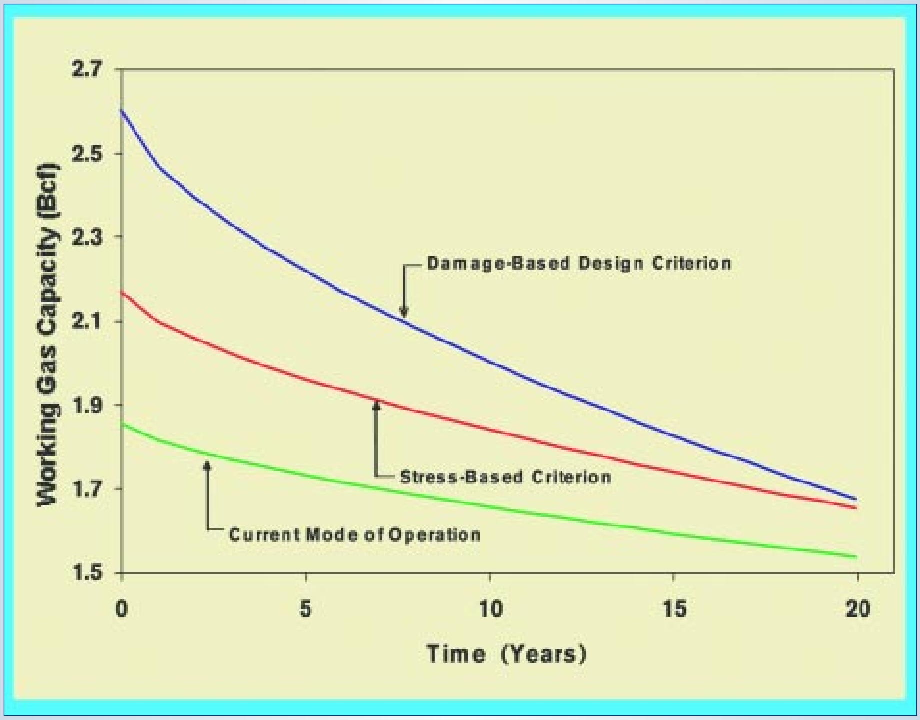

Figure 2: Simulated Working Gas Capacity of a Salt Storage Cavern.

within the cavern. The lower the pressure in the cavern the faster the cavern volume will be reduced because of time dependent salt deformation (salt creep). This means that the benefit of lowering the minimum gas pressure will eventually be negated. Figure 2 illustrates the predicted 20-year working gas capacity history of the existing Bay Gas cavern assuming minimum gas pressures determined using both the stress-based and MDCF model damage-based criteria. The cavern can be operated with the lower minimum pressure determined using the MDCF model for about 20 years before the loss of volume reduces the working gas capacity of the cavern to that determined using the conventional stress-based criterion. During this 20-year period, an additional 4 Bcf of gas would pass through the cavern assuming it is only cycled once each year. Also shown in Figure 2 is the expected working gas capacity of the cavern based on the current historical pressure cycle for this cavern. This figure illustrates how a change in the conservative operation currently used by Bay Gas could improve performance.

The key to optimizing cavern performance is to determine the minimum allowable gas pressure that will limit microfractures from coalescing and growing uncontrollably

Next Steps

Based on the results of this research project, the continuum damage mechanics approach using the MDCF model appears to be a viable option for determining the minimum gas pressure for CNG storage caverns. Determining the total potential savings attributable to adopting the MDCF model depends on a number of unknowns (e.g. actual cavern service cycles, outcome of geomechanical analyses for a specific site). Still, this proof-of-concept project demonstrated that less conservative estimates for the minimum gas pressure can be determined. However, further refinement and development of the model should be performed before it is routinely applied to cavern analyses. Specifically, the model should be validated over stress conditions ranging from triaxial *extension* to triaxial compression. The MDCF model's development was based solely on the results of laboratory tests performed at triaxial compression states of stress. Based on salt strength testing data available in the literature and the results of a creep test performed during this project, salt characterization in triaxial extension is important for evaluating CNG storage caverns. Most rocks behave differently in triaxial compression and extension with the material being weaker in extension. Research in this area would further reduce the uncertainty in predicting the behavior of salt surrounding natural gas storage caverns. ✧

For more information on the topic of salt cavern modeling using the MDCF model, contact Kerry L. DeVries at 605-394-6400.

Corrosion Study Moves Ahead

Gas Technology Institute (GTI), in an effort to enhance the industry's ability to characterize and control microbiologically influenced corrosion, is soliciting the natural gas industry to provide samples of gas pipeline liquids and solids that may contain microorganisms associated with pipeline corrosion. Companies submitting samples will receive a conventional analysis of each sample as well as a more comprehensive analysis – completed using newly developed characterization techniques – at no cost. The purpose is to identify the organisms in the microbial communities present in gas pipelines throughout the U.S., and to obtain data correlating the presence of certain bacterial species with internal corrosion. Eventually, this information will be used to develop effective counter measures to help control microbiologically induced corrosion. For sample preparation and shipping instructions contact **John J. Kilbane** at GTI (847-768-0723 or *john.kilbane@gastechnology.org*). A description of the project is also available online at *http://www.gastechnology.org/*. GTI can cover the shipping charges. ✧

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GTI Developing Pipeline Integrity Catalog

Gas Technology Institute (GTI) – under industry sponsorship – is developing a comprehensive catalog of worldwide natural gas pipeline integrity products and services. GTI is offering vendors the opportunity, at no charge, to provide product and service information for the catalog. The goal is to develop an all-encompassing guide to the various tools, hardware, consulting services, software applications, survey crews, turnkey "solutions," and other services available to help meet pipeline integrity management requirements. The catalog will address such areas as: over-the-ground indirect survey methods and equipment, leak detection, unique pipeline surveying methods, and software resources. Release is scheduled for early 2003. The project is being supported through a GTI consortium of 27 natural gas distribution companies in a collaborative effort to enhance the efficiency of the industry's pipeline integrity management activity. These project participants are contributing to the catalog as well, providing source companies and information on products they use. The catalog will initially be available in print and electronic form only to the members of the consortium. A modified version may be made available industry-wide at a later date. To have your company's product or services included in the Pipeline Integrity Management Catalog, contact: **Josie Riggio, Materials Engineer, Gas Technology Institute at 847-768-0537** (*josie.riggio@gastechnology.org*). ✧

Vortex VX Device Reduces Turbulence, Boosts Production

A Denver-area company, **Vortex Flow LLC**, announced that its VX tools are demonstrating impressive results after nearly one year of use in the field. The Vortex VX tool improves production by reducing flowline backpressure from flow turbulence. The device separates gas and liquids into a two-phase flow pattern with the liquids flowing in a spiral along the pipe wall and the gas flowing down the center. This vortex pattern prevents liquids from dropping out and hindering flow, even over long distances and substantial changes in elevation and direction. Vortex Flow tools, available in several sizes and pressure ratings, have been installed in seven gas producing regions across the United States. After approximately 100 installations, Vortex Flow reports that wells with VX tools are exhibiting significant improvements over their projected decline rates. Field experience is showing that the unit is eliminating flowline freeze-ups in cold weather as well as enhancing the movement of liquids in flowlines. Producers are seeing improved plunger-lift performance at the wellhead an a reduction in the need for pigging in lines that frequently become blocked. The Vortex Flow VX tool is one of a number of new technologies that was developed with support from the Stripper Well Consortium, an industry/government partnership sponsored by the Department of Energy's Strategic Center for Natural Gas. **For more information visit** *www.vortexflowllc.com/*. ✧

New Publications

CBM Produced Water Costs Quantified

The Department of Energy undertook an effort to quantify the impact of alternative water management approaches on the volume of economically recoverable coal seam gas in the PRB. The results of this effort, carried out by Advanced Resources International, a consulting firm in Arlington, VA. They show that under the most likely set of economic and infrastructure assumptions, a blanket regulation requiring produced water to be "actively" treated (e.g., reverse osmosis) before discharge would result in a shift in status of between 12 and 15 Tcf of gas from economic to uneconomic (depending on the mode of RO residue disposal).

The complete report (Impacts of Alternative Water Management Practices on Coalbed Methane Development in the Powder River Basin) is available on-line at the National Energy Technology Center's Strategic Center for Natural Gas website at ***www.netl.doe.gov/scng***. The report is also available on CD.

Assessment of Undiscovered Oil and Gas Resources in Rocky Mountain Basins

The USGS has completed an assessment of undiscovered, technically recoverable oil and natural gas resources in five geologic basins in the Rocky Mountain region: Uinta-Piceance of Colorado and Utah, Southwestern Wyoming (Greater Green River Basin), San Juan Basin of New Mexico and Colorado, Montana Thrust Belt, and the Powder River Basin of Wyoming and Montana. Overall findings in the assessment indicate a mean of about 183 trillion cubic feet (TCF) of undiscovered gas, of which 92 percent (a mean of 169 TCF) of the undiscovered gas resource is unconventional. Of the 169 TCF of unconventional gas, about 25 percent (42 TCF) is coalbed methane. Of particular interest is the mean estimate of 14.3 TCF of coalbed gas in the Powder River Basin (Wyoming), a substantial increase from 1.1 TCF in a previous assessment. The increased estimate is based upon new geologic information from increased exploration and drilling operations. **Detailed fact sheets of each basin are available at http://greenwood.cr.usgs.gov/maps/factsheets.html.**

Canadian Reports Published

GTI-Canada Group plans to distribute four reports related to Canadian unconventional gas resources. Two relate to coalbed methane: Upper Mannville Coals and Their Equivalents Western Canada Sedimentary Basin: CBM Play Types and Potential (GRI-02/0189), and Coalbed Methane in Western Canada (GRI-02/0157). The other two relate to shale gas: Organic Geochemical Analysis of the Second White Speckled Shale and Belle Fourche Formations, Upper Cretaceous Colorado Group, West Central Alberta: Implications for Shale Gas Production (GRI-02/0163), and Shale Gas Potential of the Late Cretaceous Second White Speckled Formation (2WS)In the Medicine Hat Area of Southern Alberta, Canada (GRI-02/0218). These publications can be obtained on CD-ROM by contacting **Ann Priestman at the GTI/IPAMS Information Center at 303-575-9030 or via e-mail at *gricentr@ix.netcom.com/*.**

Events Calendar

April 6-8

20th SPE Hydrocarbon Economics and Evaluation Symposium, Dallas, TX.
Held at the Hotel Inter-Continental. Theme is "Prospering Through Economic Cycles." ***www.spe.org/***.

April 7-8

North American Gas Strategies Conference, Houston, TX.
Ziff Energy Group conference to be held at the Houstonian Hotel. ***www.ziff-energy conferences.com/***.

April 8-9

SPE/ICoTA Coiled Tubing Conference and Exhibition, Houston, TX.
Held at The Woodlands Waterway Marriott Hotel and Convention Center. ***www.spe.org/***.

May 5-8

2003 Offshore Technology Conference, Houston, TX.
Held at Reliant Center at Reliant Park. **www.otc.org/**.

May 5-9

Biennial International Coalbed Methane Symposium, Tuscaloosa, AL.
Held at the University of Alabama's Bryant Conference Center. **Call 205-348-9718, or*www.pmdp.ccs.ua.edu/***.

May 11-14

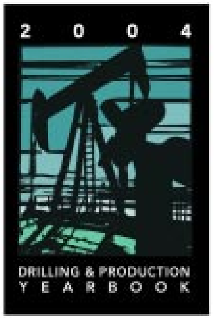
AAPG Annual Meeting, Salt Lake City, UT.
American Association of Petroleum Geologists Annual Meeting to be held at the Salt Palace Convention Center. ***www.aapg.org/***.

Oct. 5-8

SPE Annual Technical Conference and Exhibition, Denver, CO.
Society of Petroleum Engineers to be held at Colorado Convention Center. ***www.spe.org/***.

2004 Drilling & Production Yearbook
Record Nomination Form

Note: Be as specific as possible. **Records with incomplete data will not be accepted.** Official documentation must be attached and the following information provided. Creation of new and unique categories is encouraged.



Date record submitted: ______________________ Photo attached?________

RECORD CATEGORY

■ Bits
- ❑ Single-run footage
- ❑ Cumulative footage (>1 run)
- ❑ Penetration rate (1,000 ft or 5 hours minimum)

❑ Stimulation
❑ Casing
❑ Completion
❑ Coiled tubing
❑ Horizontal wells

❑ Seismic
❑ Offshore
❑ Production
❑ Miscellaneous

Record description: ______________________

Bit size, style, type: ______________________

Other equipment used: ______________________

Footage:______________ ROP (ft/hr): ______________ Runs: ______________

Well name/number: ______________________

Field: ______________ Operator: ______________

Rig: ______________ Platform: ______________

Onshore location (city, county, state, country): ______________________

Offshore location (nearest city, state, country; body of water, block): ______________________

Measured depth (ft): ______________ True vertical depth (ft):______________

Water depth (ft):______________ Date record achieved: ______________

■ Data supplied by:

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