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Technology Developments in Natural Gas Exploration, Production and Processing

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CONTENTS

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Comments

Resource Assessments Key to Good R&D Planning

One of the most difficult challenges in designing a natural gas E&P research and development program is quantifying the potential benefits associated with a particular suite of research projects. Understanding and estimating how accelerating the development of a particular new technology will affect the recovery of a particular segment of the nation's gas resource, requires a fairly detailed characterization of that resource. The better that characterization becomes, the better our ability becomes to relate specific technology advancements to specific quantities of new reserves, increases in productivity, or reductions in operating costs. This ability is important when making decisions about how to spend research dollars, whether public or private.

The lead article in this issue of *GasTIPS* describes the first phase of an ongoing effort by the Strategic Center for Natural Gas at the National Energy Technology Laboratory to better characterize the natural gas resource found in the tight gas sands of the Rocky Mountains. New technology has repeatedly been shown to have reduced the cost or increased the efficiency of finding and producing reserves previously thought to be "unrecoverable" or "sub-economic." Understanding how much of the gas currently in those categories could become reserves with the help of new technologies, is an important element of our Nation's energy strategy. A distinguishing characteristic of the effort described here is the detailed disaggregation of the resource into numerous, uniquely-described geographic segments. This disaggregation will allow cost/benefit models to respond more sensitively to individual R&D scenarios, and also make it easier to assess the impact of various federal land access and environmental policies on future supplies.

The other articles in this issue of *GasTIPS* provide information on a wide range of technologies. However, each of these was at some point dependent on a cost/benefit analysis based on an assessment of how those technologies might impact the nation's gas supply. For example, the development of a 400-level seismic array ("A Quantum Leap in Borehole Seismic Imaging") was driven in a large part by the realization that the US industry has changed its focus from finding gas in new fields to finding "new" gas in producing fields through higher resolution images of known reservoirs. Borehole seismology has the potential to change the process of drilling infill wells by lowering the economic risks for new wells in reservoirs that are now recognized to be much more complex than previously thought.

Other topics in this issue have similar underlying resource assessment support: a cased hole testing tool for accessing behind-pipe reserves in older fields, a membrane contactor gas dehydrator for monetizing sub-quality gas reserves in remote locations, and produced water reverse osmosis desalination for reducing the cost of high water production-related gas reserves such as coalbed methane. In every case the connection between an R&D investment and a gas supply benefit was based on an assessment of the disaggregated resource. The resource characterization and assessment portion of the R&D program planning task can't easily be overvalued.

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

NOTE: It was brought to our attention that in Figure 10 on page 16 of the Spring issue of *GasTIPS* the notation "1998 USGS Seismic Survey" should more properly have read "1998 CMRET/USGS Seismic Survey." CMRET stands for the Center for Marine Resources and Environmental Technology at the University of Mississippi, which kindly brought this to our attention. Our apologies for the omission.

Assessing Technology Needs of "Sub-Economic" Gas Resources in Rocky Mountain Basins

By Ray M. Boswell, Ashley S.B. Douds
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Kathy R. Bruner, Kelly K. Rose
and James A. Pancake
EG&G Services
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Advanced Resources International

The Department of Energy has undertaken a new program of detailed, gas-in-place resource assessments to support the identification of the most promising R&D opportunities.

The goal of the Department of Energy's (DOE's) natural gas program is to assure the long-term sustainability of affordable domestic natural gas supply through steady expansion of the nation's economically-recoverable gas resource base. To do this, the National Energy Technology Laboratory's Strategic Center for Natural Gas (NETL-SCNG) implements a portfolio of R&D projects designed to enable and accelerate the transition of sub-economic resources into recoverable resources and, ultimately, into reserves. To support this effort, NETL has undertaken a coordinated program combining technology modeling, industry tracking, and resource assessment (Figure 1).

This article describes the work undertaken to supply this effort with specially-tailored assessments of the marginally-economic and sub-economic resources that are a prime target of DOE-supported technologies. Phase I, now nearing completion, has focused on vast low-permeability and deep gas resources of the Greater Green River (GGRB) and Wind River (WRB) basins of Wyoming. This report provides an overview of the ongoing effort. A more detailed report will be posted on NETL's website (www.netl.doe.gov) in the Fall of 2002.

Broad Resource Base is Disaggregated

This work differs from previous studies in that it conducts detailed log-based regional resource assessment within a gas-in-place framework. Detail is provided through the analysis of hundreds of well log suites to produce datasets that capture the natural variety in key geologic and engineering parameters such as depth, pay thickness, porosity, pressure, and water saturation. This disaggregation of the resource into numerous, uniquely-described segments is vital to allowing NETL computer models to sensitively probe the "response" of the resource to individual R&D cases. In addition, the detailed geographic dissaggregation of the resource will provide an improved means to assess the impact of various federal land access and environmental policies on future supplies.

The effort uses a gas-in-place approach that attempts to describe resources without reference to economic or technical viability. Other, less inclusive characterizations, such as the

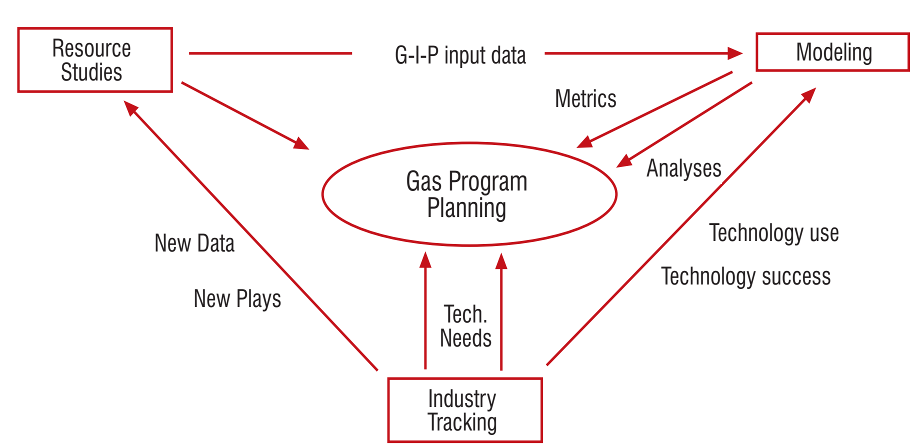


Figure 1: Schematic of SCNG's Integrated Approach for Planning R&D

Table 1: United States Geological Survey Assessments of Resources for GGRB and WRB

Greater Green River Basin			Wind River Basin		
Play	GIP ('89)	Tech. Rec. ('95)	Play	GIP ('96)	Tech. Rec. ('95)
Ft. Union	96	1	Ft. Union	101	Not Assessed
Fox Hills/Lance	707	10	Lance	365	Not Assessed
Lewis	610	19	Meeteetsee	124	Not Assessed
Mesaverde	3,347	52	Mesaverde	193	Not Assessed
Frontier-Cloverly	307	37	Frontier	151	Not Assessed
Total	**5,063**	**119**	**TOTAL**	**995**	**Not Assessed**

United States Geological Survey's National Assessment of technically-recoverable resources, are not suitable for technology modeling as they presuppose what might be recoverable in the future. Because history has shown that it is very easy to underestimate what technology can accomplish (see sidebar on the topic of "Resource Growth" at end of article), we have attempted to characterize as much of the remaining gas-in-place as possible. This will allow DOE's Gas Exploration and Production Team to probe the full resource base, looking for opportunities to continue past successes where dramatic technology advance has allowed vast resources previously viewed as "unrecoverable" (such as coalbed methane and gas shales) to be added to the nation's resource base.

Initial Study Areas: The Greater Green River (GGRB) and Wind River (WRB) Basins

It is well established that the basins of the Rocky Mountain region hold large quantities of natural gas in low-permeability formations. From 1987 to the present, the United States Geological Survey (USGS) has worked with NETL to raise industry awareness of the vast resources of the Piceance-Uinta (419 tcf), Greater Green River (5,063 tcf), Wind River (995 tcf), and Big Horn (335 tcf) basins. Yet, despite the enormous potential, many took the view that the vast majority of these resources were too widely disseminated and tightly held to ever be recoverable. This viewpoint was supported in 1995, when the USGS reported as part of its National Assessment that the technically-recoverable resource in the low-permeability plays of the Greater Green River basin was roughly 137 tcf (Table 1). Resources in the Wind River basin were similarly assessed to hold 995 tcf of gas in-place but were not included in the USGS 1995 National Assessment. In effect, roughly 98 percent of the 6000 tcf of gas believed to exist within the Greater Green and Wind River basins was deemed "not technically recoverable." To better constrain the potential of this resource, and to assist in identifying those technologies that may unlock this potential, these two basins were selected as the targets for Phase I of this effort.

Units of Analysis

For both basins, well log information was collected with the goal of obtaining quality log suites from one or more of the deepest wells in each township. To ensure the dataset was not biased to higher quality reservoirs, well productivity was not considered. Based on the USGS's previous work, the team began with the section from the Cretaceous Lance/Fox Hills formations through the Mississippian Madison Limestone in the GGRB, and the interval from the Lower Fort Union Formation to the Tensleep Sandstone in the WRB. The team then considered regional geology, industry completion practice, the needs of NETL's analytical models, and time and resource constraints, to finalize the selection of "units of analysis" or UOAs. (Figure 2).

Determination of Volumetric Parameters

Each UOA was correlated in loop fashion to establish the occurrence and distribution of lithofacies (Figure 3). Correlations and sandstone thickness mapping were generally accomplished

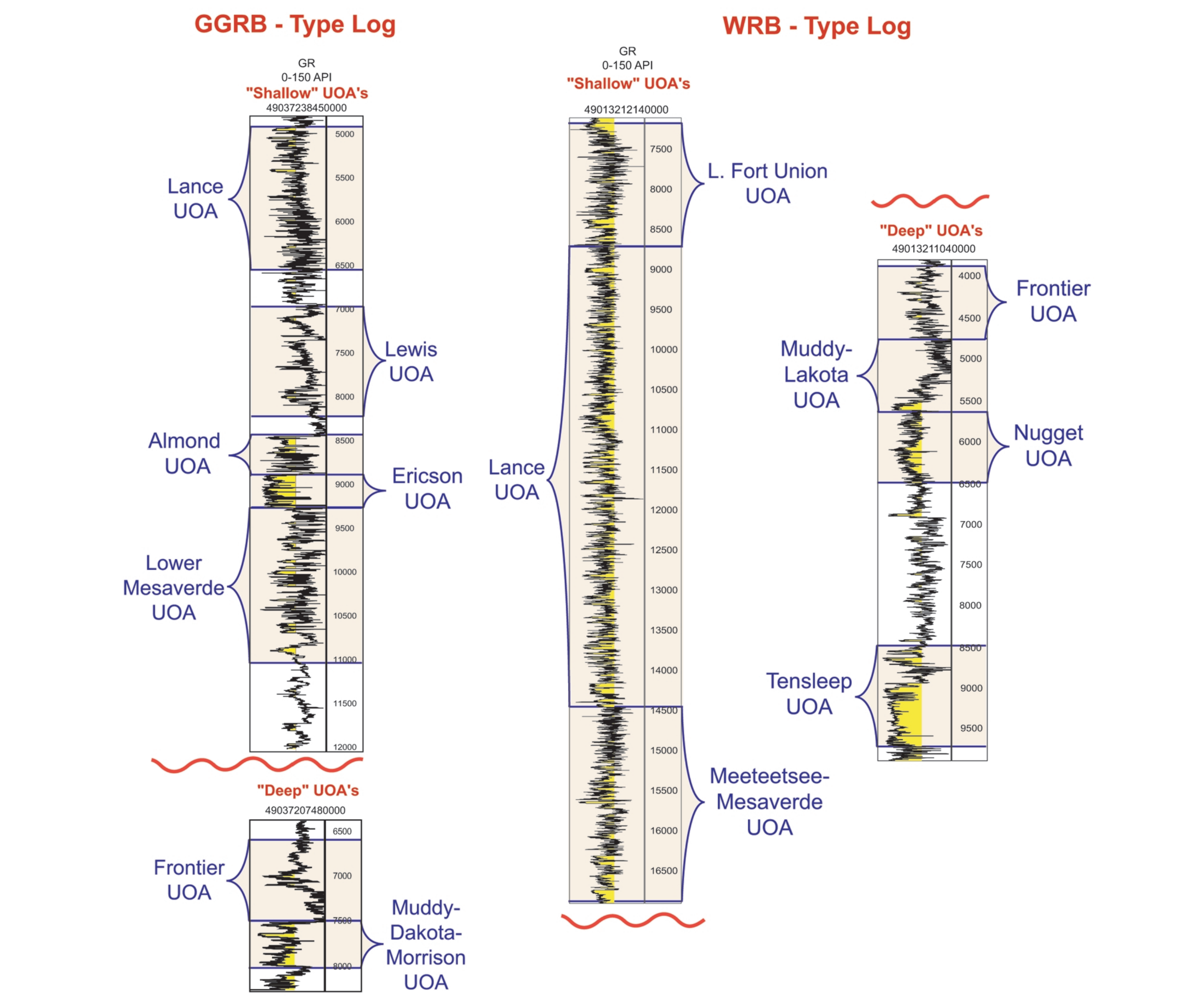


Figure 2: Type Logs Indicating 14 Units of Analysis (UOAs) in the GGRB and WRB

on a UOA-level (Figure 4); however, where appropriate and possible (primarily in marine and marginal-marine intervals), correlations were accomplished on a sand-body level (see Figures 3 and 5).

Well log suites were analyzed to provide drilling depth to unit mid-point (Figure 6) and average volumetric parameters across the UOA. Volumetric parameters include average porosity, water saturation, pressure, temperature, and thickness of potential pay. Average porosities were determined almost exclusively from recent vintage compensated density-neutron logs. Saturations were calculated using shaley-sand corrections (Simondoux) based on log-based determinations of shale volume (V_{sh}) and shale resistivity (R_{sh}), and regional estimates of formation water resistivity (R_w). These characterizations will be revisited once ongoing NETL studies to sample and analyze Rocky Mountain region formation waters provide better R_w data. Pressure and temperature at the play mid-point were determined from drilling depth and township average gradients based on information obtained from logs and from commercial databases (e.g., *IHS Energy Data*).

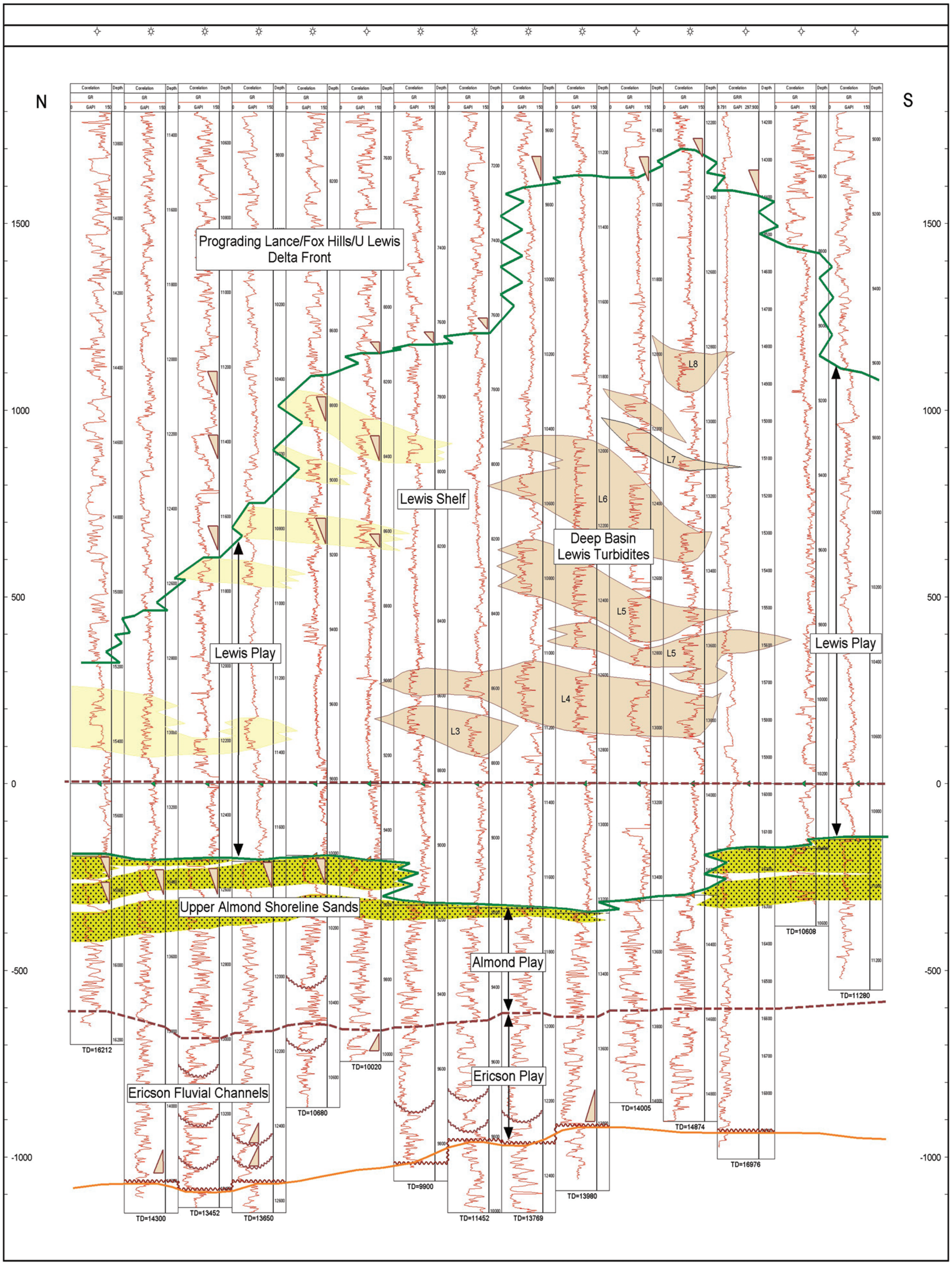


Figure 3: North-South Stratigraphic Cross-Section of the Lewis, Almond, and Ericson UOAs in the Eastern Greater Green River Basin.

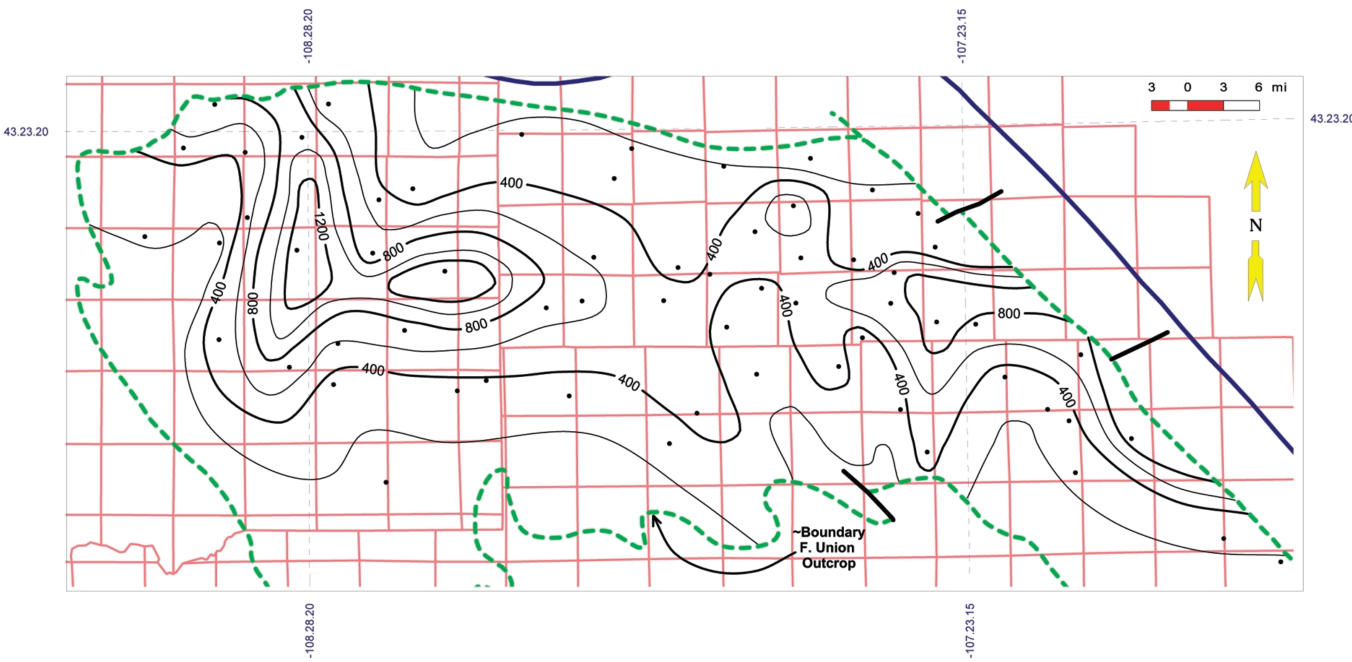


Figure 4: Isolith Map of Sandstone Within the Fort Union UOA, Wind River Basin

The volumetric parameter called "potential pay" thickness bears further discussion. The term "pay" is usually equated with the thickness of an interval that is expected to produce under current circumstances. Geologists are accustomed to establishing practical reservoir or field-specific porosity (for example 6 or 8 percent) and water saturation (commonly 60 percent) cut-offs in determining pay. However, the goal to create resource descriptions that allow the models to determine what segment of the total resource might be pay as much as 20 years into the future under cost/ technology scenarios that are very different from what currently exists. Therefore, aggressive cut-offs of 4 percent porosity and 70 percent S_w were used in defining "potential pay" with the understanding that under most technology/cost conditions, the models may not consider much of this low-quality resource to be viable.

Despite efforts to create detailed and disaggregated datasets, it remained necessary to average variable parameters across large vertical sections. For many units of analysis, this averaging did not create any major difficulties, as parameters such as porosity and saturation were often fairly consistent within a unit. However, for the upper Mesaverde "Almond" unit, the presence of the high-quality marginal-marine "Upper Almond" sandstones within the same unit with numerous lower-quality "Main Almond" units presented a problem. The solution was to prepare separate characterizations of the "best" and "rest" within that unit. Included within the "best" category are zones that, in the team's judgment, would be most likely to be completed (commonly those marked by density-neutron cross-over). Although the models do not currently have the capacity to utilize this distinction, modifications are being planned that will allow more accurate modeling of the standard industry practice of high-grading zones within a play for completion.

Permeability Analyses

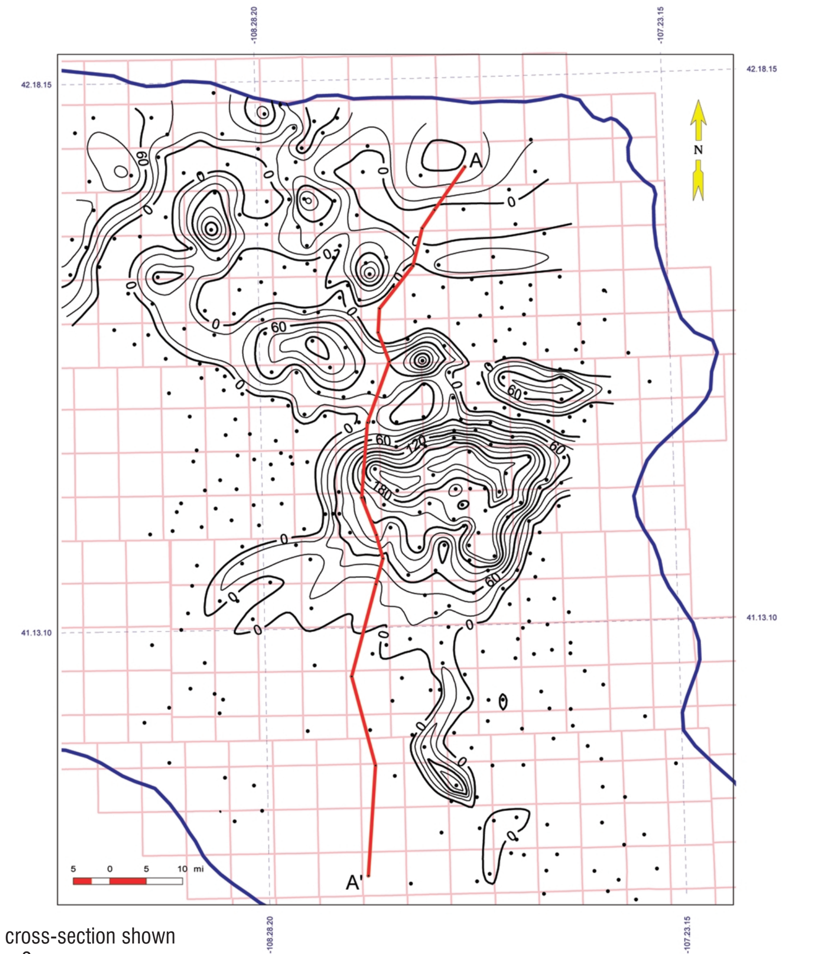
The final element in providing datasets to model the future economics and productivity of these resources is an estimation of permeability. First, an estimate of total permeability was generated through the detailed analysis of the productivity and log character for 10-20 calibration fields per unit of analysis. A statistically representative "type" well was chosen for each calibration field. Log based porosity, thickness and saturation for each "type" well was used to constrain gas-in-place for a decline curve analysis. Production data were analyzed using a Fetkovich-style type curve approach to define the bulk producing permeability around the wellbore. Existing porosity-permeability relationships were used to constrain the expected matrix contribution to the bulk system. The difference between expected matrix permeability and the bulk system permeability was ascribed to the presence or absence of a fracture permeability overprint in the reservoir (calibration field). The estimates for incremental fracture-related permeability in each calibration field were then correlated to the corresponding structural complexity as determined through analysis of aeromagnetic, gravity, and other satellite imagery data (Figure 7). From these correlations, estimates of areally variable matrix and fracture permeability contributions were generated, as appropriate, for each cell of each UOA.

Geographic Dissaggregation

To provide the needed geographic disaggregation of the resource, each unit of analysis is divided into cells on the scale of townships (deeper units) or quarter townships (shallower units). Well-log-based estimates for each volumetric parameter were gridded to provide interpolations for each grid cell. For example, for a deep unit of analysis that covers 80 townships, the datasets will consist of 80 uniquely-characterized reservoirs - each 1 township in size. Lastly, the available remaining acreage within each cell for of each unit of analysis was determined by removal of all grid cells from which at least a quarter of the available acreage has been drilled. This approach produces a conservative estimate of remaining resources.

Results and Products

The primary result of this work has been the construction of detailed and disaggregated resource characterizations for major gas accumulations in the GGRB and WRB that will allow meaningful analyses of the relative impact of alternative future technology,



A-A' is cross-section shown in Figure 3

Figure 5: Isopach Map of Lewis-4 Sandstone

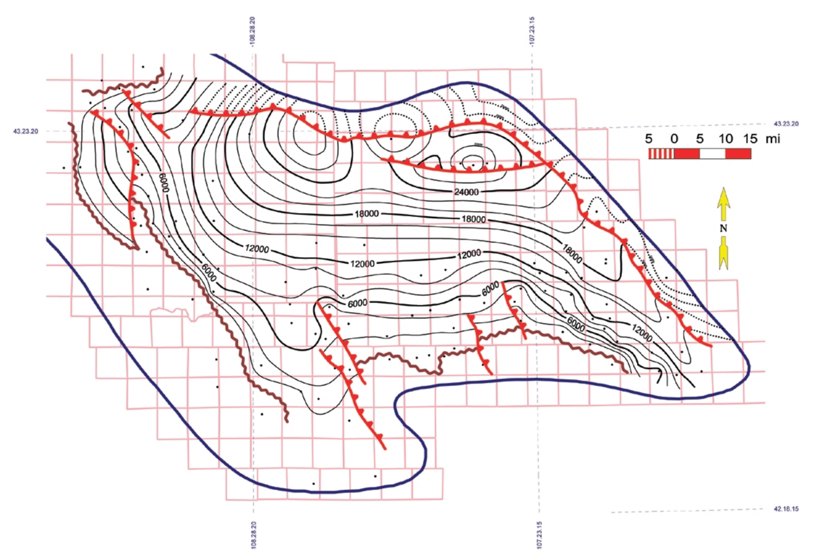


Figure 6: Drilling Depth map for the Frontier UOA, Wind River Basin (Depth is to the mid-point of the UOA)

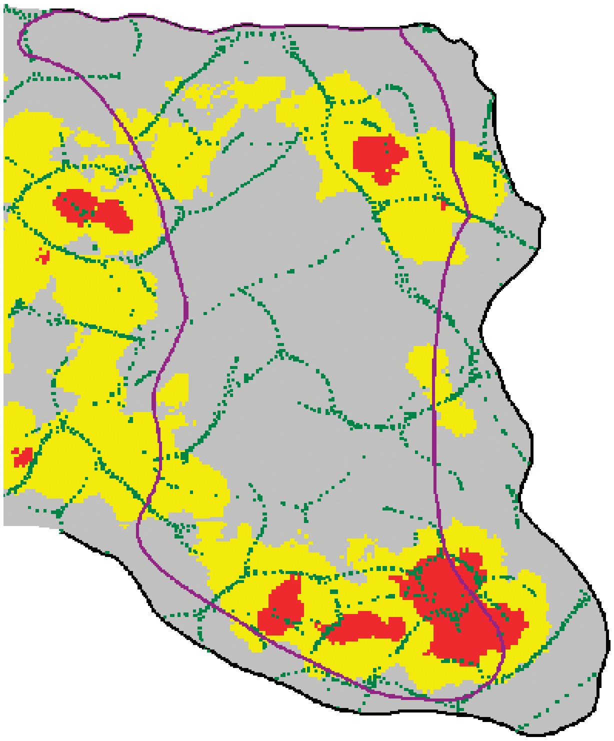


Figure 7: Structural Complexity Map for the Lewis UOA in the Eastern GGRB

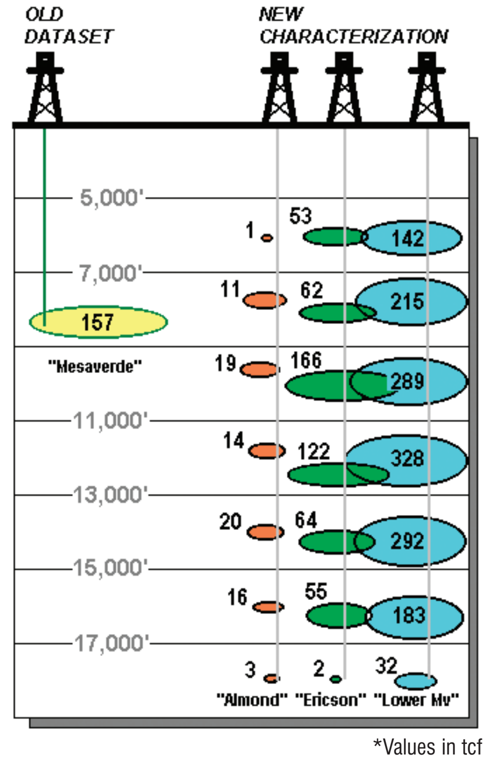


Figure 8: Analytical Methodology Provides More Detailed Resource Information

cost, and policy scenarios. This new dataset, by compartmentalizing the resource both geographically and vertically, contains many unique packets of resource that capture the natural variation in drilling depth, porosity, water saturation, pressure, temperature, and permeability (see Figure 8).

Table 2 summarizes the preliminary resource characterizations for the various plays. These data provide average values (with the exception of the acreage and gas volume totals) for key volumetric parameters that vary within 500 to 4000 individually-characterized, 4-square-mile-sized cells. For example, for the Lewis UOA, cell-level values for potential pay thickness vary from 0 to 699 feet with an average of 100 feet; depth varies from 5,000 to 17,600 feet with an average of 10,211 feet.

Given this database, NETL will now assess the impact of technology on roughly 3,013 tcf of marginal and sub-economic resource in the GGRB. Roughly half this resource resides within the sandstones of the lower Mesaverde UOA. Nearly one-quarter of the total GGRB resource (711 tcf) lies below 15,000 feet drilling depth. For the Wind River basin, 1,332 tcf of gas, with 533 tcf below 15,000 feet, have been characterized. Roughly half of this resource occurs in the thick sandstone packages of the Lance and Meeteetsee/ Mesaverde UOAs. The total appraised resource of 4,345 tcf represents a significant expansion of NETL's modeling capacity - previous datasets contained only 257 tcf in comparable formations across both basins.

These results provide our preliminary estimate of the gas-in-place in sandstones of the target formations with the exclusion of: (1) deposits above 5,000 feet of drilling depth; (2) areas already tapped by production, (3) areas likely to hold oil instead of gas — primarily an issue for the deeper WRB UOAs; (4) areas which calculate with water saturations in excess of 70 percent; and (5) gas in zones with porosities less than 4 percent as determined from logs. For the WRB Frontier, Muddy-Lakota, and Nugget UOAs, no gas resources above 13,000 feet were included. For the WRB Tensleep UOA, the cut-off to exclude likely oil accumulations was set at 15,000 feet. Also, as new and better information on R_w values is obtained, significant alterations in potential pay thickness and gas volume could occur.

The results obtained for the WRB are in close agreement with those provided by the USGS in 1996. For the

Table 2: Preliminary Results of Assessment for GGRB and WRB

GGRB Gas Resource: 3,013 Tcf / Deep Gas Resource: 711 Tcf	GREATER GREEN RIVER BASIN UOAs					
	LEWIS	ALMOND	ERICSON	L. MSVD	FRONTIER	DAKOTA
Total Area (Acres)	3,891,200	6,097,920	7,782,400	8,125,440	11,258,880	10,749,440
Avg. Thickness (ft.)	100	44	173	369	47	52
Avg. Porosity (%)	7%	9%	9%	8%	8%	8%
Avg. Water Sat. (%)	56%	60%	47%	53%	43%	40%
Avg. Depth (ft.)	10,211	9,615	10,663	10,767	15,472	15,670
Avg. Pressure (psi)	5,428	5,075	5,488	5,559	10,186	10,415
Avg. Temperature (oF)	223	214	226	223	255	257
Avg. Z-Factor	1.05	1.03	1.06	1.06	1.39	1.4
Total Resource (tcf)	132	87	528	1,481	368	417
Deep Resource (tcf below 15,000')	10	3	60	214	198	226

WRB Gas Resource: 1,332 Tcf / Deep Gas Resource: 533 Tcf	WIND RIVER BASIN UOAs						
	FORT UNION	LANCE	MEET/MSVD	FRONTIER	MUDDY +	NUGGET	TENSLEEP
Total Area (Acres)	1,103,360	1,354,240	1,546,240	1,525,760	1,672,960	1,681,920	1,246,720
Avg. Thickness (ft.)	441	512	461	91	34	76	285
Avg. Porosity (%)	10%	9%	8%	6%	6%	5%	6%
Avg. Water Sat. (%)	57%	51%	43%	46%	45%	47%	22%
Avg. Depth (ft.)	8,110	10,117	11,991	18,191	18,423	19,485	20,458
Avg. Pressure (psi)	3,627	5,104	6,933	12,420	12,559	13,444	14,184
Avg. Temperature (oF)	189	222	252	351	355	372	387
Avg. Z-Factor	0.94	1.03	1.16	1.52	1.52	1.57	1.61
Total Resource (tcf)	180	322	374	74	30	76	276
Deep Resource (tcf below 15,000')	0	2	109	62	23	61	276

GGRB, perhaps the most significant difference is a substantial reduction in pay thickness for the Lewis and Lower Mesaverde plays. For the deeper Frontier and Dakota plays in the GGRB, we have calculated larger gas volumes due primarily to higher assessed porosity.

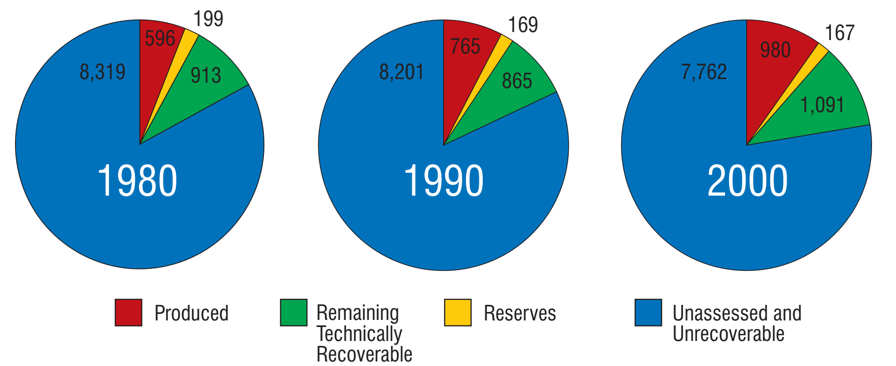
Next Steps

Our analyses indicate that approximately 4,345 Tcf of potentially accessible gas exists in-place in the

America's Growing Gas Resource: Can the Trend Continue?

Over the past two decades, the nation has produced roughly 390 tcf of gas. Over the same period, the amount of technically-recoverable gas thought to remain has grown by roughly 10 percent (from 1,112 tcf to 1,258 tcf based on estimates of the Potential Gas Committee). In short, we have more gas left now than we did 20 years ago!

The reasons for this remarkable record of resource growth are a series of quantum leaps forward in both technology and information that have allowed the nation to access previously overlooked or undervalued resources. Examples include coal-bed methane, gas shales, and tight sandstones. Once considered permanently "unrecoverable", these sources now represent roughly 25 percent of the nation's gas supply.



*Remaining recoverable estimates taken from reports of the Potential Gas Committee – for illustrative purposes, graphs assume a total domestic in-place resource of 10,000 tcf.

How long can resource growth continue? There is no question that it must continue in order to assure the vast and diverse resource bank that will enable production rates to keep pace with rising demand. However, the gas remaining in the ground is located in deeper, more geologically complex, and in general, more technically challenging places. Compounded by declining industry investment in gas supply R&D, it will be difficult to sustain past trends. Clearly, future resource growth will depend heavily on DOE's success in developing new tools and information that will unlock more of the nation's "unrecoverable" resource.

subject intervals of the Greater Green River and Wind River basins. In the coming months, this resource characterization will be subjected to intense analysis using NETL's analytical models. These analyses will focus on determining the recoverability profile (the proportion of the resource that is the technically- and economically-recoverable) under a variety of technology/cost scenarios. These data will be used internally by DOE planners to support project selection and other programmatic activities. In addition, the data will be closely compared to information recently gathered by DOE on federal land access restrictions to more accurately quantify the impacted resource under both current and potential future technology/cost/policy conditions. In August 2002, NETL will kick off Phase II of this effort, consisting of similar resource characterization studies of the marginal and sub-economic resources of the Anadarko (Oklahoma) and Uinta (Utah) basins. ■

For more information on the status of this project, contact James Ammer, NETL Project Manager for Natural Gas Supply and Storage, at 304-285-4383 or at james.ammer@nelt.doe.gov/.

Desalination of Produced Water Using Reverse Osmosis

By Graciela Morales and
Maria Barrufet
Texas A&M University

Increasing volumes of produced water, regional scarcity of fresh water, and the improvement of reverse osmosis technology are prompting researchers to look at the potential for desalination of produced water.

Many oil and gas wells, particularly those in mature fields, produce large amounts of brine along with the hydrocarbons. Disposing of the brine can be costly, due to its composition and large volume. For example, in the Permian Basin of West Texas and New Mexico more than 490 million gallons of water per day are produced and re-injected. The prospect of many millions of barrels of produced water from coalbed methane wells planned for the Powder River Basin has complicated development of that resource.

Historically, the oil and gas industry has not promoted on-site water desalination. The re-injection or surface discharge alternatives were much less costly and there was little demand for the water. However, growing demand for fresh water in many areas and the development of lower-cost technologies for removing contaminants from water are beginning to provide compelling arguments for desalination of produced brine.

The *Texas Water Resources Institute* (TWRI) at *Texas A&M University* (TAMU) currently is supporting a multidisciplinary program, led by the Department of Petroleum Engineering to develop technologies to treat produced water and make it safe for use in agriculture and wildlife habitat restoration. The aim of the TAMU project is the development of small-scale, modular, transportable units capable of treating relatively small amounts of brine inexpensively. The team will utilize new technology in solids and oil removal and advances in remote process control to create units exhibiting low maintenance and high reliability in the field. These small scale units will utilize nanofiltration (NF) and reverse osmosis (RO) to remove contaminants from oilfield brines produced with oil and gas.

Similar pressure-driven membrane filtration equipment installations are widely used in desalination of brackish water and seawater and compete successfully with traditional thermal desalination operations. However, if RO is to assume a more prominent role in produced water treatment, there is a need for sound engineering designs adaptable to modular operations.

As one portion of this effort, the TAMU team has developed a static model using parametric curves to allow scale-up of an integrated RO system. They are also developing a dynamic model that will be the basis for a control system and automatic operation. This article provides some basic background on RO systems in general, along with a brief description of the static model developed by the TAMU team.

RO Desalination Process

A typical RO water treatment system includes two primary process elements: a pretreatment subsystem and the actual RO unit (Figure 1). Feed water quality determines the amount and type of pretreatment necessary to make RO economical, and as such is the limiting factor of most RO systems in operation today. Membrane surfaces are prone to fouling by particulate matter, inorganic scales (e.g. carbonate and sulfates salts of alkaline earth metals), oxides and hydroxides of aluminum and iron, organic material (e.g. humic, tannic, etc.) and biological material (e.g. bacteria, fungi, algae).

A typical pretreatment unit consists of a sand filter, an activated carbon filter and a depth cartridge filter. The sand filter is used to remove larger impurities, however, sand filters can clog quite quickly and the relative coarseness of sand allows many smaller impurities to pass through. (Osmonics, 1992).

The activated carbon filter absorbs low molecular weight organics and reduces the amount of chlorine or other halogens, but does not remove any salts. This absorption process takes time, so service rates are limited to a maximum of about 5 gpm/ft. The accumulation of solids can require backwashing, however this can result in loss of the relatively fragile activated carbon material. Over a period of months to years, the adsorption capacity of the carbon diminishes, requiring replacement or reactivation, a process not easily accomplished in the field. These filters may also need to be changed periodically to avoid bacterial growth. Hydrocyclones, coalescing media, and organoclay materials may also be used for the removal of oil in the pretreatment portion of these systems.

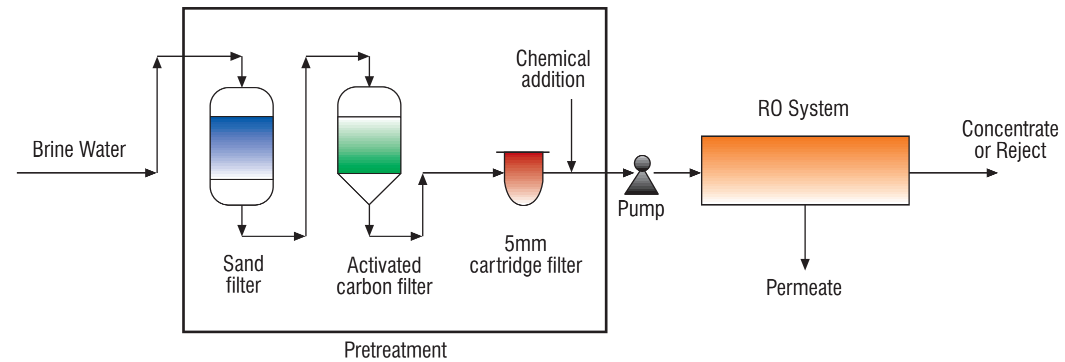


Figure 1: Schematic of a Typical RO Treatment System

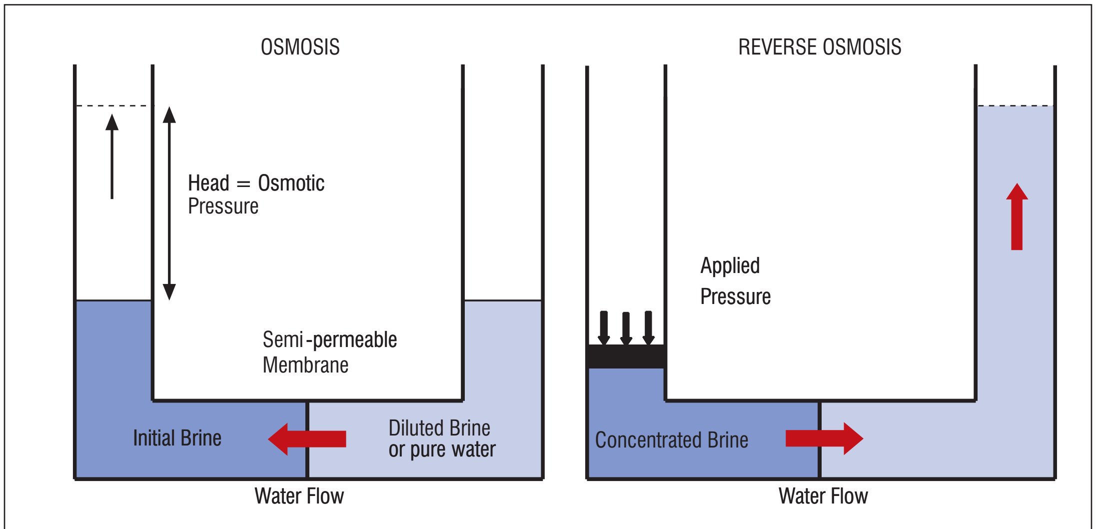


Figure 2: Schematic of Osmosis and Reverse Osmosis

In the depth cartridge filter, remaining particles (in the 1 to 100 micron range) are trapped in the complex openings of a filter material constructed of cotton, cellulose, synthetic yarns or “blown” microfiber such as polypropylene. These filters have a lower density on the outside and progressively higher density toward the inside wall. The effect of this graded density is to trap coarser particles toward the outside of the wall and the finer particles toward the inner wall. These filters are often disposable. As particles accumulate, the pressure drop across the filter increases and when the pressure difference between filter inlet and outlet has increased by 5 – 10 psi relative to the starting point, the filter is backwashed or replaced.

After pre-treatment to remove suspended particles, the incoming water is pressurized with a pump to exceed the osmotic pressure (typically 200-400 psi, depending on the RO system and the contaminants). A portion of the water (permeate) diffuses through the RO membrane leaving dissolved salts and other contaminants behind with the remaining water. This “reject” or “concentrate” is drawn off as waste. RO removes virtually all organic compounds and up to 99 percent of inorganic ions.

RO membrane fouling is a complex phenomenon involving the deposition of materials on the membrane surface rather than plugging of the system. Scaling of RO membrane surfaces is caused by the precipitation of sparingly soluble salts from the concentrated brine (especially $CaCO_3$ and $BaSO_4$). A number of chemicals may be added to prevent membrane fouling. For example, sulfuric or hydrochloric acid is employed to reduce pH and prevent $CaCO_3$ precipitation. Sulfuric acid, while safer and less expensive than HCl, will increase the content of sulfate ions in the feed water and consequently the risk of $CaSO_4$ precipitation. The addition of polyphosphates or, more recently, polycarboxylates is employed for preventing $CaSO_4$ scaling.

Chlorination, either continuous or at intervals, is a common pre-treatment method for preventing the growth of bacteria and algae that may cause fouling in the system or degradation of cellulose acetate membranes. The amount of chlorine required is determined by the amount of organic matter in the feed water and by the water temperature.

Reverse Osmosis

Osmosis, an integral part of the functioning of all living cells, is a phenomenon in which a liquid (water in this case) passes through a semi-permeable membrane from a relatively dilute solution toward a more concentrated solution. This flow produces a measurable pressure, termed osmotic pressure. If, however, pressure is applied to the more concentrated solution that exceeds the osmotic pressure, water flows through the membrane from the more concentrated solution to the dilute solution (Figure 2). This process, reverse osmosis, results in two streams of water: one relatively large volume with a low concentration of dissolved impurities (permeate), and one relatively small volume with a high concentration (reject).

Osmotic pressure, and thus the trans-membrane pressure required to overcome it, is a function of contaminant component molecular weight and concentration. For example, the osmotic pressure for a 2 percent by volume sodium chloride stream is 250 psi, while the pressure for a 10 percent potassium chloride solution is 965 psi.

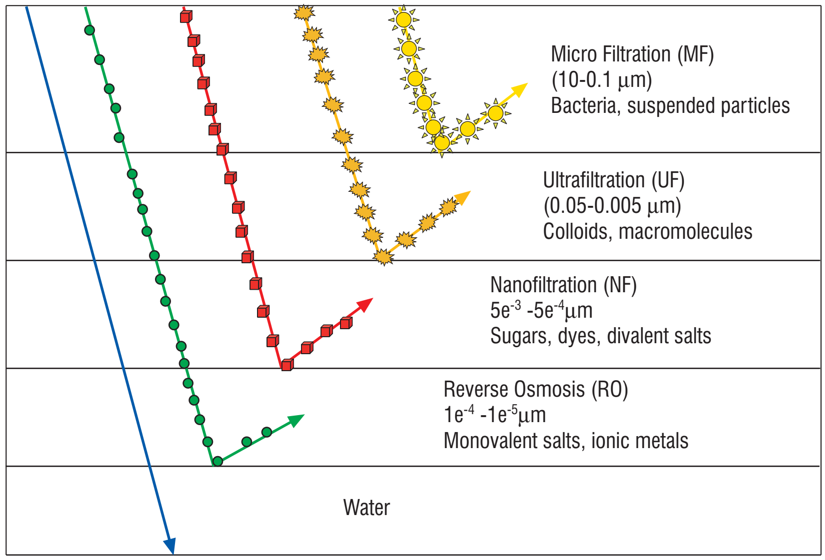


Figure 3: Pressure Driven Separation Processes

RO Membranes

During the last two decades significant advances have been made in the development and application of microfiltration (MF), ultrafiltration (UF), nanofiltration (NF) and reverse osmosis (RO) processes. MF membranes reject suspended particles only, UF membranes reject suspended particles and high molecular weight compounds, NF membranes also reject low molecular weight compounds, and RO membranes also reject ions (Figure 3).

The membrane itself must be physically strong in order to stand up to high osmotic pressure. Over 100 different materials are used to make RO membranes, however the two most commonly used membranes are made from cellulose acetate (CA) and polyamide thin film composite (TFC). These may come in spiral, tubular hollow fiber, plate and frame, or proprietary configurations. Hollow fiber and flat sheet are the most commonly used RO membrane configurations. Hollow fiber membrane is extruded like fishing line with a hole in the center to create a tiny (100 to 200 micron) hollow fiber strand. Flat sheet membrane, a continuous sheet rolled up like a large paper towel roll, is used in spiral wound (SW) configurations (Figure 4).

Table 1: Comparison of Hollow Fiber and Spiral Wound Membranes

Membrane	Advantages	Disadvantages
Hollow Fiber	High membrane surface area to volume ratio	Sensitive to fouling by colloidal materials
	High recovery in individual RO unit	Limited number of membrane materials and manufacturers
	Easy to troubleshoot	
	Easy to change bundles in the field	
Spiral Wound	Good resistance to fouling	Moderate membrane surface area
	Easy to clean	Difficult to achieve high recovery
	Variety of membrane materials and manufacturers	

Although hollow fiber RO elements provide more surface area, they are more prone to fouling (Table 1). The characteristics and performance of these membranes differ as well (Table 2) (Amjad Z., *et al*, 1998).

Spiral membrane elements are loaded in a serial configuration in a pressure vessel (1 to 7 membranes per pressure vessel) and tubular membrane elements are loaded in a parallel configuration in a pressure vessel (1 to hundreds of elements pre pressure vessel). Multiple pressure vessels may be connected in a serial or parallel flow path.

If the product flux decreases to unacceptable values (typically >10% decrease) due to membrane fouling, the membrane must be cleaned. The cleaning method and frequency depend on the type of foulant and the membrane's chemical resistance. Generally, it is easier to clean a membrane that is slightly fouled. Cleaning methods include mechanical cleaning (i.e. direct osmosis, flushing with high velocity water, ultrasonic, sponge ball or brush cleaning, air sparging, etc.), chemical cleaning (use of chemical agents), or a combination of both.

Table 2: Comparison of Cellulose Acetate and Thin Film Composite Membrane

Parameter	Cellulose Acetate (CA)	Thin Film Composite (TFC)
Operating pressure (psi)	410 to 600	200 to 500
Operating temperature (°F)	32 to 86	32 to 113
Operating pH	4 to 6.5	2 to 11
Membrane degradation potential	Hydrolyzes at low & high pHs	Stable over broad pH range
Permeate flux (gfd)	5 to 18	10 to 205
Salt rejection (%)	70 to 95	97 to 99
Stability to free chlorine	Stable to low (<1 ppm) levels	Attacked by low levels (>0.1 ppm)
Resistance to biofouling	Relatively high resistance	Low resistance
Manufacturer	Several	Several
Cost	Lower	50 to 100% more

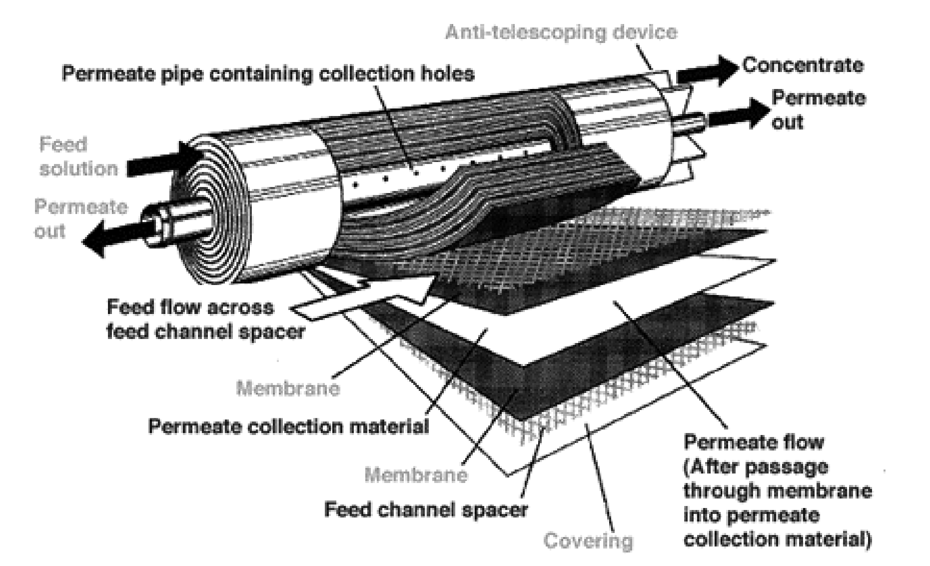


Figure 4: Spiral Wound (SW) Membrane Configuration

TAMU Sizing Model

The TAMU research team has developed a set of theoretically grounded parametric curves (Figure 5) that enable a designer to quickly arrive at an optimal RO unit size and operating scenario by following an iterative procedure. Primary inputs for the procedure include: feed water ionic composition, salinity, temperature, and pressure. These are used to calculate several intermediate parameters which are embedded in the equations plotted in Figure 5. By assuming a delta pressure (ΔP) and desired permeate flow rate (qP), one obtains a value for membrane area (A_m) from the left axis of the chart. Using this value, and assuming a value for membrane length/area ratio (L/A), one determines a value for feed flow rate (qF) from the right axis. This value may be too large exceeding the amount of feed water available. This value is then checked against a tolerance range and if it is not within tolerance, the procedure is repeated by changing either the proposed value of L/A or ΔP, and iterating. The procedure ends when the feed flow (qF) is within expected values, resulting in values for permeate flow rate, membrane area, and membrane length/area ratio that correspond to a particular feed rate. Following this procedure one can observe that, as might be expected, membrane area increases when increasing the brine concentration for a given permeate flow rate. *(Note: A comprehensive description of the theoretical basis used to develop these parametric equations, as well as an example of their application, is available from the author.)*

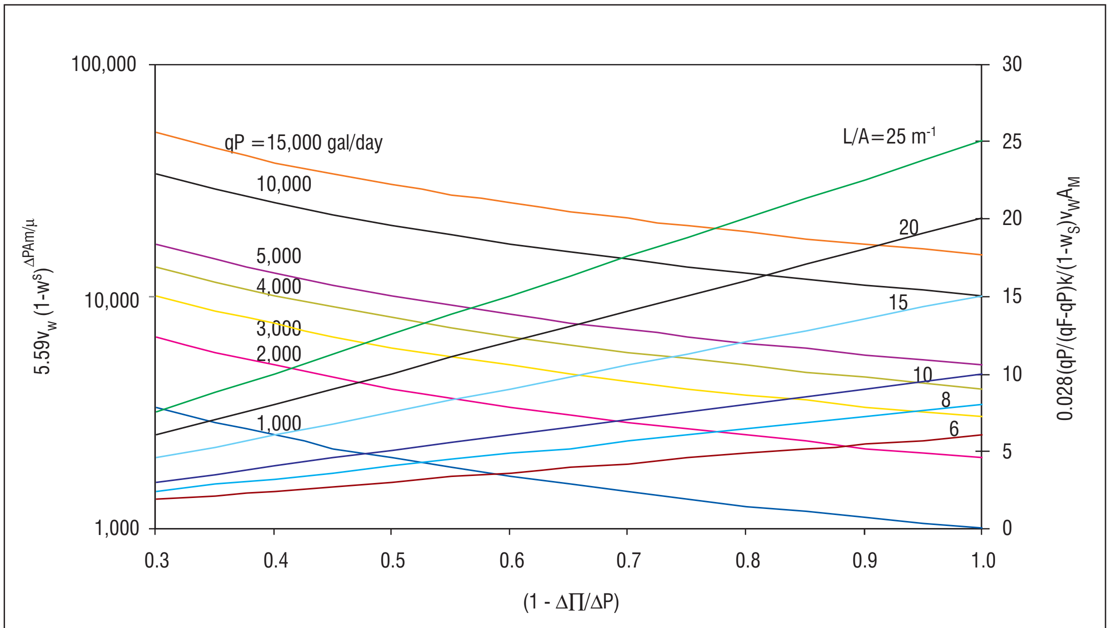


Figure 5: Parametric Equation Based Sizing Model

Ongoing RO Research

In addition to the development of this set of parametric curves, the research effort currently underway includes:

- Evaluation of different RO membrane configurations for various membrane types,
- Investigation of the effects of operating conditions (pressure, temperature and brine composition) on RO membrane flux,
- Experimental determination of the best diffusivity model,
- Investigation of the effects of temperature and composition on osmotic pressure, and
- Completion of a sensitivity analysis across a range for three key variables: salt concentration and types of salts up to 200,000 ppm); temperature (100 to 200°F) and pressure (220 to 2,000 psi).

During the past two years the TAMU team has identified and tested a hybrid system consisting of pretreatment methods, inexpensive centrifugation technologies and ceramic/polymeric RO membranes. Preliminary results indicate that the brine treatment is feasible and can be done simply and economically. The research team has been working closely with *PCI Membrane Systems* and *Somicon A.G.*, who have redesigned their commercial membrane modules by changing membrane coating methods, polymer combinations and membrane element configurations. In addition *PCI* and *Somicon* developed new low fouling NF and RO membrane materials and low cost module geometries.

Using specifically formulated membrane modules, actual process water tests were completed at the university incorporating state-of-the-art pre-treatment technologies that included organo-clays, inexpensive and selective centrifuges and microfiltration systems. The test results show that the treated wastewater quality is equal or better than that of tap water. ■

For additional information on the status of this work or to become involved in industry efforts to support this research contact the author, Dr. Maria Barrufet, at 979-845-0314, or via e-mail at barrufet@spindletop.tamu.edu. Or members of this research team: Dr. Sefa Koseoglu at s-koseoglu@tamu.edu (membranes); Dr. Graciela Morales at gmorales@ciunsa.edu.ar (diffusión models); or Mr. David Burnet at burnett@gpri.org (regulatory aspects).

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Flow Assurance: Understanding and Controlling Natural Gas Hydrate

By Dr. Ram Sivaraman
Gas Technology Institute

Gas Technology Institute has a new facility providing state-of-the-art technologies for developing hydrate management measures.

Natural gas hydrate is formed when methane molecules—the primary component of natural gas—are trapped in a microscopic cage of water molecules. Naturally formed hydrate material is found in abundance worldwide, at or beneath the seafloor and in permafrost zones onshore (see related article in the Spring 2002 GasTIPS). Because natural gas (methane) hydrate contains methane in concentrations up to 160 times its volume, the substance could be a promising new energy resource if cost-effective production methods can be devised.

However, of more immediate concern to the natural gas industry is the fact that methane hydrate also can form within pipelines under certain pressure and temperature conditions, forming a solid or semi-solid mass that can slow or completely block gas flow. While the problem is particularly serious for producers moving gas from offshore wells to onshore processing facilities, methane hydrate also can be found in many other elements of the nation's network of gas storage facilities and transmission pipelines.

Clearing hydrate-plugged lines is an expensive and time-consuming task that can take as long as several weeks. Experts estimate that controlling and preventing hydrate formation—what the industry calls "flow assurance"—costs more than $100 million annually. DeepStar, a consortium of companies focused on Gulf of Mexico deepwater development technology issues, has concluded that replacement of hydrate-plugged lines in deepwater environments costs one million dollars per mile on average. For this reason, there is a growing interest in gaining a better understanding of the mechanisms that trigger hydrate formation in pipelines, so that flow assurance costs can be reduced. Gas Technology Institute (GTI) has built a state-of-the-art facility for developing this understanding.

Conditions for Methane Hydrate Formation

As a rough rule of thumb, methane hydrate will form in a natural gas system if free water is available, the temperature is 39°F or lower, and the pressure is greater than 166 psig. However, methane hydrate can also form at higher temperatures (even above 70°F) if the pressure is high enough (2900 psig or above). There are six classic methods for preventing hydrate formation:

- Remove water from the system (the best protection)
- Keep the system operating temperature above the hydrate formation threshold
- Keep the system operating pressure below the hydrate formation threshold
- Inject an inhibitor – methanol or monoethylene glycol – to effectively decrease the hydrate formation temperature below the system operating temperature
- Add kinetic inhibitors (low-molecular-weight polymers) that bond with the hydrate surface, delaying crystal growth for a period of time that is longer than the residence time of free water in the system, and
- Add anti-agglomerants that prevent the aggregation of hydrate crystals by dispersing the free water as droplets suspended within entrained oil or condensate.

The choice of which (or which combination) of these methods to employ depends on a number of factors, including the configuration of the system, the range of temperatures and pressures expected over the operating life, the relative volumes of gas, water and hydrocarbon liquids involved, and a number of cost considerations.

Understanding the nature of hydrate formation is critical to making the best choice. Where and how does methane hydrate first form in the pipeline? How can it be easily detected? How can it best be removed or prevented from forming? Researchers around the world are trying to find answers to these questions.

Hydrate Management Research at GTI

At its facilities near Chicago, Illinois, GTI has assembled a state-of-the-art laboratory, operated by an expert research team that is uniquely equipped to study methane hydrate. The GTI methane hydrate management program offers a range of instrumentation, hardware, and analytical tools for the study of hydrate at the microscopic and macroscopic level, both in the laboratory and in the field.

GTI has invested about $1.5 million in its Flow Assurance Facility, establishing three unique laboratories: the Laser Imaging Laboratory; the Acoustic Resonance Spectrometry Laboratory; and the Calorimetry Laboratory. Through its flow assurance research program, GTI can:

- Evaluate gas hydrate phase transitions
- Evaluate the effect of low-dosage inhibitors on hydrate control
- Develop improved understanding of hydrate nucleation induction times and growth-rate mechanism
- Evaluate the impact of drilling fluids on hydrate formation and dissociation
- Assist the chemical industry in the development of new anti-agglomerants and kinetic inhibitors for hydrate control, and
- Conduct full-scale field-testing in the a special hydrate test flow loop facility in Colorado.

A number of new technologies

Figure 1: GTI Laser Imaging System

Figure 2: High-Pressure Visual Cell Assembly

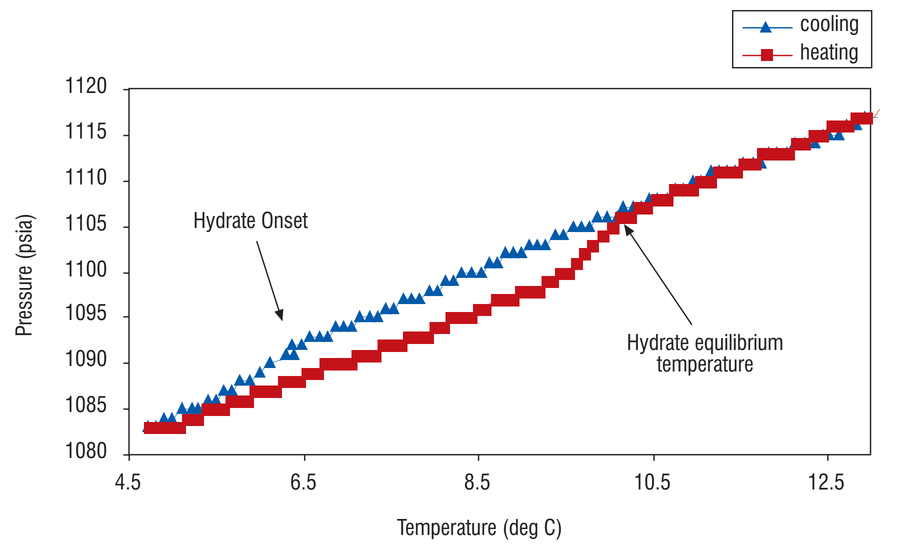


Figure 3: Hysteresis of Methane Hydrate Formation and Dissociation

Figure 4: Laser Image of Pure Methane Hydrate

have been brought to bear on the problem. Each of these is briefly highlighted below.

Laser Imaging Technology

Laser imaging technology allows engineers and scientists to observe and analyze rapid hydrate formation and dissociation processes in slow motion. This leads to powerful insights and quantitative data that are valuable for developmental research.

A laser emitting very short pulses is used to illuminate a high-pressure sapphire cell. The laser light acts as a very-short-duration strobe lamp for a high-speed digital camera, capturing the rapid action of hydrate formation and dissociation in the cell in a series of freeze-frames and removing any motion blur. A screen behind the windows of the cell diffuses the lighting. This allows researchers to actually view the size and shape of the evolving hydrate crystals.

The complete laser imaging system is shown in Figure 1. An air-cooled solid-state diode laser, operating with a peak power of 200W at a wavelength of 808nm and a pulse energy up to 20mJ, is coupled with a high-resolution digital imaging camera capable of capturing images at up to 10,000 frames per second. The system also includes a diffuser, a motion recorder, a controller, computers to monitor and store data, and a videocassette recorder to record the imaging events in the sapphire cell. The system can operate at pressures up to 1500 psia and temperatures from 100°C to –40°C.

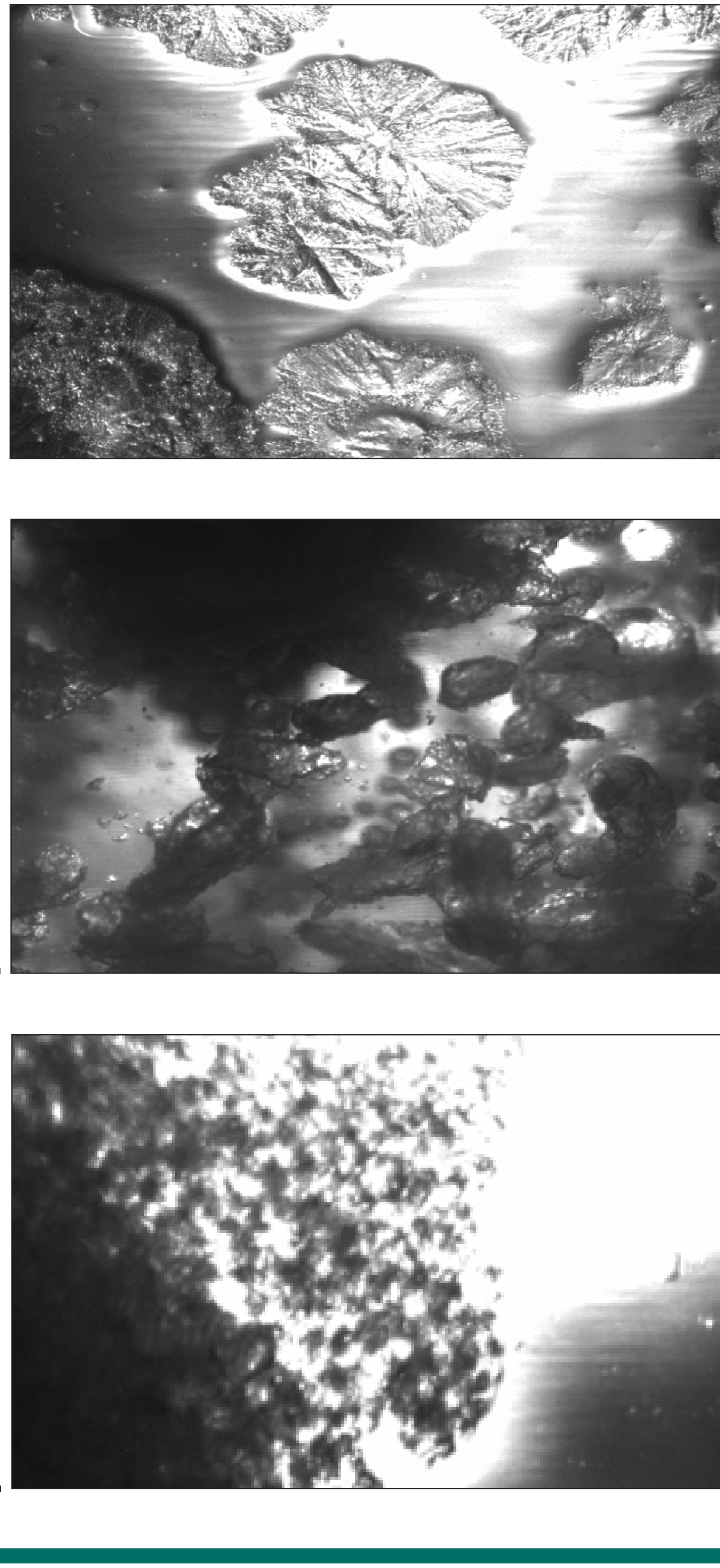
Application of Laser Imaging to Flow Assurance

In one experiment to evaluate hydrate formation, pure methane gas was charged to 1130 psia in the high-pressure sapphire cell of the laser imaging system. Through a custommade, high-pressure syringe assembly, a known amount of water was added to the methane. A powerful magnetic stirrer mixed the mixture continuously.

The temperature of the high-pressure visual cell (Figure 2) was lowered from 20°C to 4°C at a rate of 0.1°C/min.
A chiller was used to cool and heat the cell at programmed rates with proportional-integral-derivative (PID) control. The pressure and temperature in the cell were measured simultaneously using a digital pressure sensor and thermocouple, respectively.

Very short pulses from a solid-state laser illuminated the high-pressure sapphire hydrate cell. The high-resolution digital imaging camera was used to record the imaging events while a high-speed computer was used to control the system and to collect and process data on pressure, temperature, and time as well as the images. Temperature and pressure measurements were tracked in real time and graphics software was used to update and display temperature and pressure data versus time, and pressure versus temperature.

Hydrate formation and dissociation were monitored in real time. As shown in Figure 3, the onset of hydrate formation occurred at 6.38°C. The heating run started at 4.5°C and continued at the same rate (0.1°C per minute) as the cooling run. During the heating cycle, the hydrate completely dissociated (the crystals disappeared) at the hydrate equilibrium temperature (9.98°C). Above that temperature, pressure traces for the cooling and heating runs overlapped. Images of the process were captured during the heating and cooling cycle at a rate of 40 frames per second using the high-resolution, high-speed digital imaging camera, and then were digitally processed.



A.

B.

C.

Fig. 5: Laser Images of Hydrate in Presence of: A. Methanol Inhibitor, B. Condensate, C. Anti-Agglomerant and Condensate

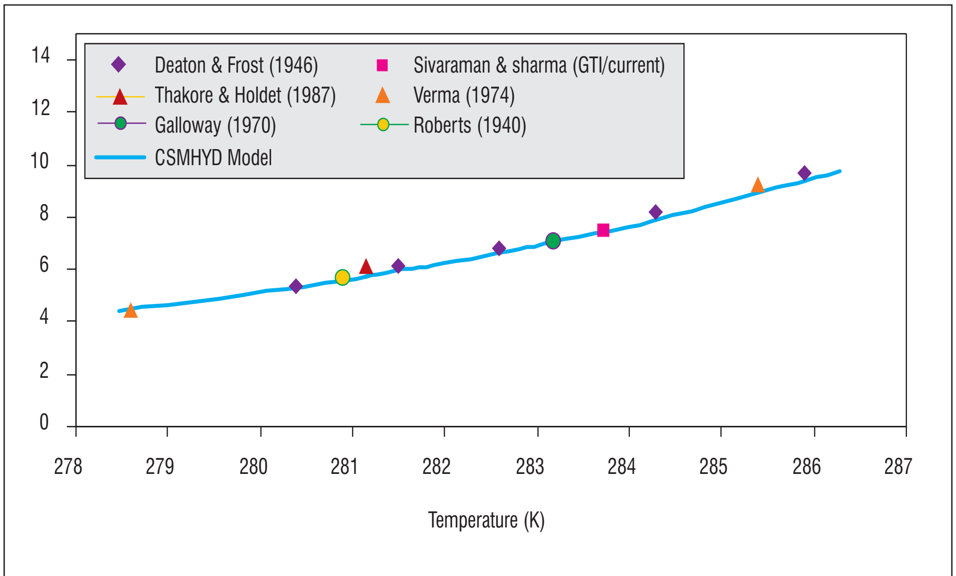


Figure 6: Comparison of GTI Lab Data with Data from Literature and Model for Pure Methane Hydrate

Figure 4 shows an image (1mm x 1 mm) of hydrate crystals during formation.

Laser imaging can also be used to evaluate the influence of methanol (the most common thermodynamic hydrate inhibitor), condensate, or low dosages of anti-agglomerants on methane hydrate. As shown in Figure 5 the size and shape of crystals change considerably in the presence of these substances.

Current studies also confirmed the suspicion that certain drilling fluids promote hydrate formation, under-scoring the need to screen drilling fluids before their application in deepwater environments.

A close comparison of the current results with the literature data and the CSMHYD hydrate model developed by E. Dendy Sloan, at the Colorado School of Mines, shows good agreement (Figure 6).

Acoustic Resonance Spectrometer

The acoustic resonance spectrometer used at GTI works on the principle of Rayleigh's theory of sound and Ferris's solution for the scalar Helmholtz equation for a spherical cavity. The heart of the system is a 25mm diameter sphere that has two transducers mounted at 45°angles. One transmits acoustic waves through the natural gas mixture in the sphere and the other receives the wave fronts that have picked up the phase or transitional changes in the mixture at different pressures and temperatures.

During the phase transition of a fluid, there is a significant change in sonic speed. Because frequency is directly proportional to sonic speed, one observes the same changes in frequency. When hydrate formation occurs, or at the hydrate equilibrium temperature, the radial frequency signals undergo a large change that can be measured in real time.

The GTI acoustic resonance spectrometer is an important tool for the following hydrate research:

- Precise detection and measurement of hydrate equilibration temperatures, hysteresis of growth, decomposition and kinetics
- Automated collection of large volumes of information about hydrate growth
- Analysis of hydrate formation in dark and murky fluids that render conventional optical techniques useless
- Study of the effect of various drilling fluids on hydrate dissociation (a major safety issue is the stability of the ocean floor during drilling when methane hydrate is present in the sediment), and
- Study of the influence of low-dosage (parts-per-million level) inhibitors on methane hydrate.

The device is cooled by liquid nitrogen with heat exchange coils, fins and a double-walled, stainless steel vacuum jacket. This allows better temperature control and lower heat loss. The temperature control, scanning of the radial modes of the frequency spectrum, and data acquisition are computer-controlled. A platinum resistance thermometer is used for accurate temperature measurements and a digital pressure sensor is used for absolute pressure measurements. Temperature and pressure measurements and radial mode frequencies were monitored in real time and recorded by the computer.

Differential Scanning Calorimeter

For calorimetry the GTI flow assurance facility employs a Mettler Toledo DSC821 System with a robotic arm auto-sampler that can analyze 35 samples in one loading. The DSC is a valuable tool for probing the impact of inhibitors on natural gas hydrates at low dosage levels. Use of such inhibitors could save gas producers millions of dollars by providing alternatives to toxic methanol or other chemicals whose over-usage could pose safety or environmental problems. The system also can be used to screen different inhibitors in the market for their efficiency. Time-temperature transformation (TTT) profiles can be constructed from isothermal DSC data, yielding valuable information not currently available about complex hydrate nucleation and growth mechanisms. Results can provide heat flow versus reference temperature data, with heats of fusion and crystallization resolving ice and hydrates distinctly.

Other Capabilities

Other key instruments in the GTI hydrate flow assurance facility are a Perkin Elmer gas chromatograph (Auto System GC ARNEL) and a Dionex high-pressure liquid chromatograph (HPLC) for gas and chemical inhibitor analysis. A Perkin Elmer System 2000 Fourier Transform Infrared (FTIR) Spectrometer also has been added for use in hydrate characterization research. The GTI facility also is equipped with a Malvern Mastersizer 2000 System for analyzing particle distribution in emulsions and suspensions. It can detect particles in the range from 0.02 μm to 2000 μm.

Field Testing and Future Plans

GTI and its partner, the Colorado Engineering Experimental Station Inc. (CEESI) – a leader in field testing, flow measurement and calibration – plan to build a 100-foot-tall, 4-inch-diameter vertical riser near Fort Collins, Colorado. Researchers could then use laser-imaging technology to track concentrations of inhibitors as they move through the vertical risers during shut-in and start-up operations.

GTI and CEESI have also submitted a proposal to the Department of Energy for a research program to help resolve hydrate formation problems that occur when natural gas is transferred from underground storage to a pipeline system. During this transfer, the high-pressure, rapid-withdrawal conditions can trigger hydrate formation, which can choke off valves and halt operations. If the project is approved, work will begin by yearend 2002.

The Flow Assurance Facility at GTI's headquarters near Chicago is unique because it provides all the tools needed for hydrate research in one place, and because its equipment for laser imaging, acoustic spectroscopy, and calorimetry are fully dedicated to hydrate research. The addition of these new capabilities is especially timely, in view of industry's increased interest in methane hydrate over the past several years and the awareness that more investment is needed in basic and applied research on critical hydrate issues. Testing carried out over the next several years at GTI's laboratories will help answer many significant questions about hydrate formation and its impact on flow assurance. GTI's vision is to make the three labs that comprise the Flow Assurance Facility the equivalent of a national laboratory – a center for excellence in hydrate research. ■

For more information on the capabilities of the GTI facility described above, contact Dr. Ram Sivaraman, Manager, GTI Hydrates Flow Assurance Facility and Projects, at 847-768-0998) or at alwarappa.sivaraman @gastechnology.org.

The Use of Spectral Decomposition as a Hydrocarbon Indicator

By John P. Castagna and Shengjie Sun
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A new spectral decomposition method utilizing wavelet transforms reveals seismic direct hydrocarbon indicators that are not obvious on conventional stacked seismic data. The method can be applied to existing seismic datasets as a low-cost post-processing step.

Two years ago, the Gas Technology Institute awarded a research contract to Fusion Geophysical to investigate the use of wavelet transform-based seismic attributes for gas detection. The proposed idea was that wavelet transforms could be used to obtain frequency spectra with high temporal resolution and without the windowing problems associated with traditional Fourier analysis. The question to be answered was: Can such improved spectral analysis of seismic data reveal hydrocarbon indications that are not apparent on conventional seismic data or that are not resolved using Fourier-based spectral decomposition methods? Our investigations indicate that the answer to this question is a resounding "yes!" By performing a number of case studies, we have identified three distinct spectral hydrocarbon indicators that are best revealed by proper spectral decomposition. These are: (1) abnormal seismic attenuation (2) low frequency shadows associated with hydrocarbon related bright spots, and (3) differences in "tuning" frequency between gas and brine sands. The purpose of this article is to briefly describe the spectral decomposition method that we use, to provide illustrative examples of spectral hydrocarbon indicators, and to discuss how these can be used in a practical manner for exploration applications.

Wavelet Transform Based Spectral Decomposition

Once one accepts the notion that a seismogram can be represented as a superposition of wavelets, it follows immediately that the frequency spectrum of that seismogram must be a superposition of the frequency spectra of the wavelets. Thus, once a seismogram has been decomposed into constituent wavelets, a time versus frequency analysis (spectral decomposition) can readily be constructed by weighted superposition of wavelet spectra as a function of record time. Notably, such an approach to time-frequency analysis requires no windowing and no use of the Fourier transform if an appropriate wavelet dictionary (set of wavelets) is utilized. Consequently, the method has excellent time resolution and eliminates "Gibbs phenomena" and other undesirable effects of windowing such as spectral notches caused by multiple seismic reflection events occurring within the analysis window. We refer to our wavelet transform based spectral decomposition technique as Enhanced Spectral Processing (ESP) in order to call attention to the fact that processing applications of the method go well beyond hydrocarbon indication.

Figure 1 compares ESP and the Short-Time Window Fourier Transform (STFT) for a synthetic waveform. ESP better defines the frequency content for each discrete event, especially for the composite signals. Note that multiple arrivals occurring in close proximity cause "ribs" and other pronounced spectral notches in the STFT. Note also, that for ESP, the spectral energy for any particular arrival is spread out in time only for the duration of the arrival, whereas for the STFT the spectral energy is spread out over the length of the analysis window, irrespective of the actual time duration of the event. The ESP spectrum clearly resolves arrivals closely spaced in time, whereas the STFT cannot temporally resolve any features shorter than the window length.

Seismic Attenuation

It is well established that gas-filled reservoirs exhibit higher frequency-dependent seismic attenuation than similar rock fully-saturated with brine. What is not well established is how to validly measure this attenuation using surface seismic reflection measurements. A naïve approach is to presume that the slope of the ratio of frequency spectra for two time windows is directly

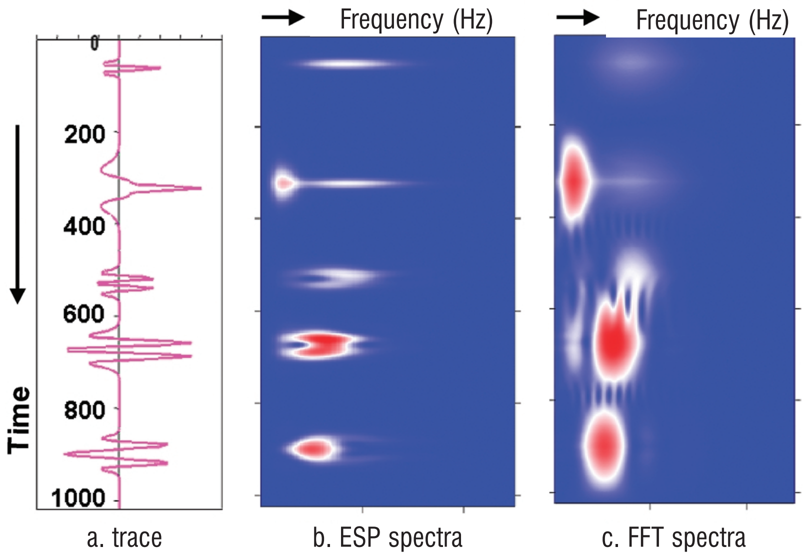

**Figure 1. a. Synthetic Trace for Modeling Study
b. ESP Time-Frequency Spectrum of the Synthetic Trace.
c. STFT Time-Frequency Spectrum of the Synthetic Trace.**

related to the attenuation coefficient. This is what most commercial "energy absorption" procedures try to do. The fundamental problem with this approach is that spectral notches, caused by local reflectivity, dramatically bias the spectral ratio, thereby inhibiting valid attenuation measurement. As evident in Figure 1 however, it is clear that the ESP method, by better separating events in time, is also freer of spectral distortions caused by the occurrence of multiple reflecting interfaces occurring in close temporal proximity.

Furthermore, any processing method that relies on regression or other automated procedures to calculate an attribute (such as Q) is subject to breaking down as necessary assumptions (such as the appropriate frequency band over which to measure the attenuation) are not necessarily conducive to characterization by simple predefined rules. It is more robust to directly compute attribute sections that require no assumptions and rely on the interpreter to observe abnormal attenuation. One simple method of doing this is to display the spectral decomposition results as seismic sections representing instantaneous amplitude at specific frequencies. To obverse frequency dependent attenuation, the interpreter simply looks for amplitudes that are lower on a high frequency section than on the corresponding low frequency section. Thus, as displayed in Figure 2, the instantaneous amplitude sections at frequencies of 30 Hz and 60 Hz over a known gas reservoir readily reveal that reflections below the reservoir top are dramatically more attenuated at high frequencies (60 Hz) than at low frequencies (30 Hz). To the contrary, the reservoir top and overlying reflectors do not experience preferential high attenuation at high frequencies as the seismic travel paths for these reflections do not go through gas-saturated rock.

Experience indicates that such attenuation is usually only readily observable for reservoirs of thicknesses sufficient (1) to accumulate significant attenuation as the seismic energy propagates down and up through reservoir and (2) to avoid complications due to interference of top and base reflections. Sometimes, frequency-dependent attenuation can be observed in a thin reservoir if the reservoir rock frame is extremely unconsolidated.

Low Frequency Shadows

The use of low frequency shadows as hydrocarbon indicators is nearly as old

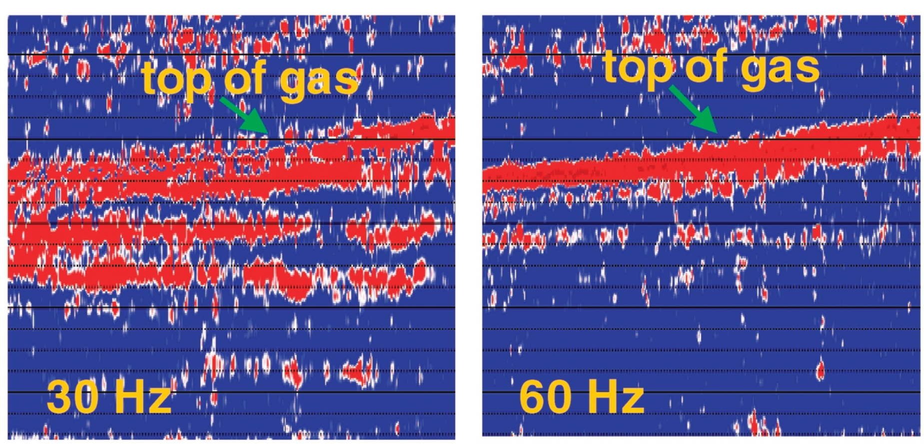

Figure 2. Comparison of ESP Instantaneous Amplitudes Over a Gas Sandstone Reservoir at 30 and 60 Hz.

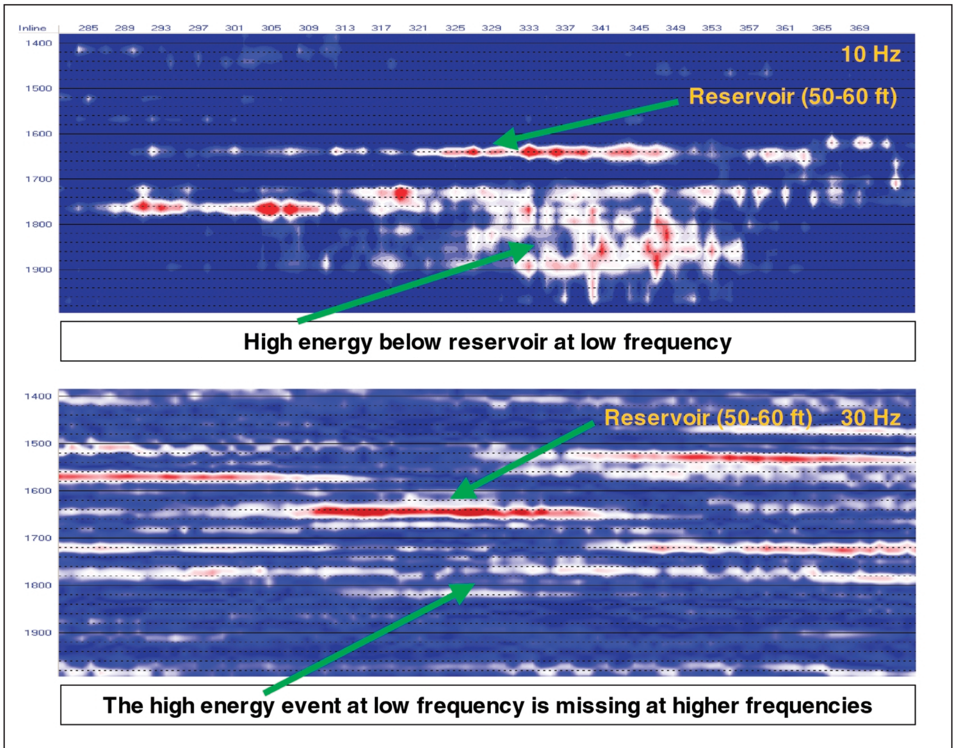

Figure 3. ESP Instantaneous Amplitude Seismic Sections From a Thin Gulf of Mexico Reservoir at 10 and 30 Hz

as bright spot detection. The shadows are usually erroneously presumed to be due to abnormal high frequency attenuation. Our investigations suggest that these shadows are often in fact related to additional energy occurring at low frequencies, rather than preferential attenuation of higher frequencies. One possible explanation is that these are locally converted shear waves that have traveled mostly as P-waves and thus arrive slightly after the true primary event.

On a broad-band stacked seismic section, such shadows are often not apparent to the naked eye, but as illustrated in Figures 3 and 4 for two different Gulf of Mexico reservoirs, shadows are difficult to miss on ESP instantaneous amplitude sections. Notice that the strong shadow seen on the 9 Hz section is nearly absent on the 18 Hz section.

Preferential Illumination

The frequency content of a broad-band stack of seismic data is essentially an accident of nature resulting from the interplay of acquisition, earth filtering, and data processing, and is not necessarily optimized to reveal information about a particular target. This leads to the obvious question: Why should the seismic amplitudes and other attributes that we use in seismic interpretation be those derived from this accidental dominant frequency? The prevalent idea of a "tuning thickness", the thickness at which a reservoir is preferentially illuminated at a given dominant frequency, is an archaic concept when viewed from the perspective of having an ESP dataset. Since single

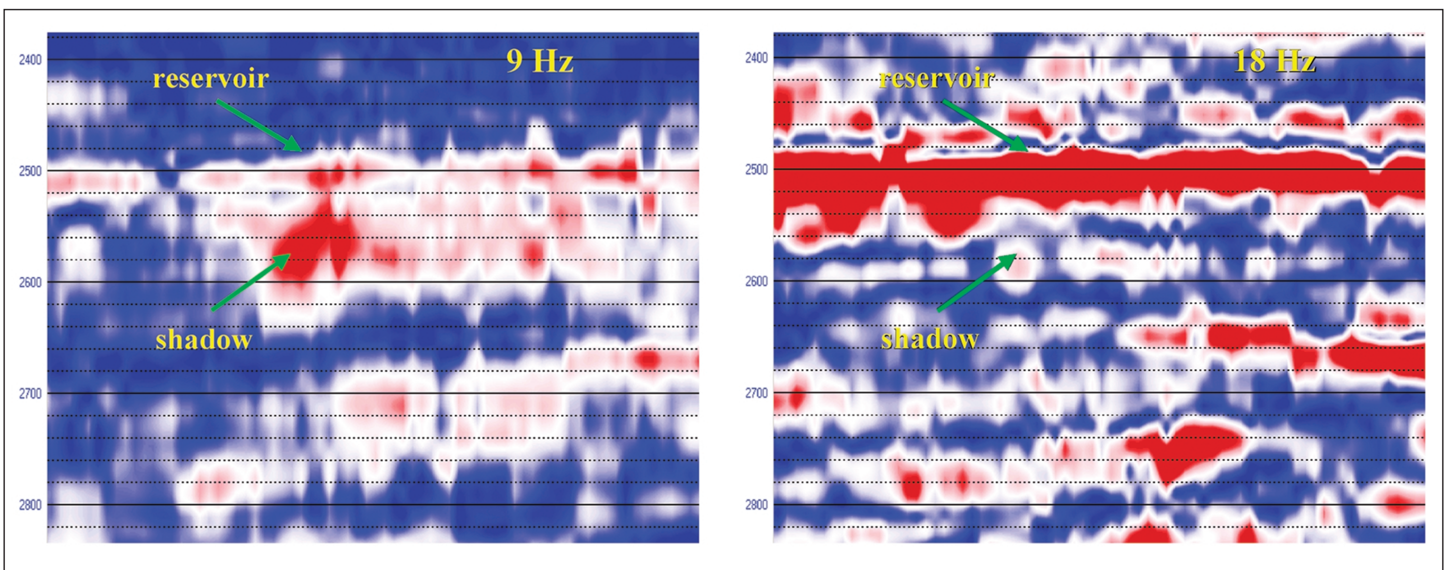

Figure 4: ESP Instantaneous Amplitude Sections at 9 and 18 Hz for Another Gulf of Mexico Reservoir

frequency seismic volumes can be obtained over any range of frequencies permitted by signal-to-noise ratio, there is no one tuning thickness. Rather, there is a “tuning frequency” at which the target is preferentially illuminated. This idea leads to several interpretive insights. First of all, for a layer of constant thickness, the tuning frequency will be different for brine and gas saturated rock and the tuning frequency itself can be mapped as a hydrocarbon indicator. Secondly, by observing how amplitudes change with frequency for thin reservoirs, one can readily see thickness changes that otherwise would not be apparent. For example, in Figure 3, the maximum reservoir amplitude shifts from right to left as the frequency changes from 10 Hz to 30 Hz as a result of the reservoir thinning to the left.

Discussion

ESP time-frequency analysis has much better resolution than conventional spectral decomposition. The ESP spectral attribute can potentially be used to directly detect hydrocarbons for gas reservoirs using high frequency attenuation anomalies, and/or low frequency shadows. The ESP technique can also be used to detect amplitude anomalies at given frequencies for thin reservoirs that are not as apparent on conventional broad-band seismic sections. We believe these potential applications of ESP will help us to improve upstream performance by reducing drilling uncertainties, helping to unravel complex variability in reservoir heterogeneity and thickness, and predicting physical reservoir properties. Although our particular spectral decomposition method is computationally intensive, it can be applied to existing seismic datasets at minimal cost. The major hurdle for routine use of this technology is in training and education of seismic interpreters and in providing appropriate visualization and analysis tools needed to handle the multiple volumes of data that can be produced. ■

This research is supported by the Gas Technology Institute, Fusion Geophysical, and the OU Geophysical Reservoir Characterization Consortium. For more information contact the authors, John P. Castagna, Director, Institute for Exploration and Development Geosciences, 405-325-6679, castagna@ou.edu; and Robert W. Siegfried, Associate Director Earth Sciences, Gas Technology Institute, 847-768-0969, robert.siegfried@gastechnology.org.

A Quantum Leap in Borehole Seismic Imaging

By Dr. Bjorn N.P. Paulsson
P/GSI
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DOE/NETL

A new 400-level downhole receiver array yields ultra-high resolution VSP and crosswell images that promise significant enhancement in interwell characterization capability.

Paulsson Geophysical Inc. (P/GSI), working with the Strategic Center for Natural Gas, is pushing borehole seismic imaging to a new level, with a recently constructed, 400-level, 3-component, ultra-high resolution borehole recording system. The receiver array has 5 times as many geophones and yields 4 times the image resolution compared to currently available vertical seismic profiling (VSP) systems.

The 400-level system represents a huge step forward in VSP and crosswell imaging technology. Small geologic features on the scale of 10 to 20 feet (3 - 6 m), that can control hydrocarbon accumulations on the reservoir level, were previously only identifiable within the near-well-bore area via electrical logging techniques. With this new system, these same features can be imaged quickly and accurately at significant distances away from a single well-bore or in the intervening region between adjacent wells.

The Leap from 80 to 400 Levels

P/GSI,s 80-level array, which was the predecessor to the new 400-level array, has served industry as the top-of-the-line VSP recording technology for the past 4 years. Current VSP systems are not universally used, primarily because of time and borehole constraints. However, when there is a need for high-resolution seismic and surface seismic is incapable of providing the definition needed, VSP can be very valuable (see sidebar). The development of a capability to economically acquire massive 3D VSP seismic will help to widen the applicability of this approach.

The 400-level array, with its 3 channels at each level, records 1200 seismic traces simultaneously. During a single survey, this translates into a rapid flood of p- and s-wave data that get transmitted to the surface for data processing, data analysis, and interpretation. P/GSI has modified and upgraded their processing and imaging software to easily handle this huge volume of data. Once the data is recorded, images can be produced in real time while in the field, or ansmitted back to the lab for processing.

Figure 1: Geophone Pod Ready to Deploy

Development of Vertical Seismic Profiling (VSP) Technology

Placing a geophone in a well and recording data from a surface source was first tried in the early 1930s (Stewart,1984). It was quickly realized that this "well shooting" would deliver a wealth of information. These well surveys were run with one geophone in the well and, usually, with just one component (vertical). Although useful they were time consuming. This type of survey was soon followed by check shot surveys designed to obtain interval velocities in order to provide accurate velocity information for surface seismic reflection. These were also one-level-at-a-time surveys, with wide spacing between the levels.

By the early 1950s, variations of VSP data processing grew to include looking at bed dip and reflectivity. Various individuals started looking at later arrivals and noticed reflections that could be traced back to the beds that caused them. As the technology evolved, many of the techniques for processing surface data were applied to VSP data, inferring such properties as anisotropy, heterogeneity and much more. In the 1980s it became clear that three component recording was useful for inferring fracture properties. In all of these applications, in order to optimize the data processing it is necessary to have the full wave field, preservation of true amplitude and/or better wavelength spacing of the receiver points over the range of interest.

Although a very useful technique, VSP is still not used as widely as surface seismic. One obvious reason is that a borehole or well with the appropriate diameter through the zone of interest is needed. Another reason is that it has been time consuming, resulting in added costs not only for acquisition but also associated with removing a well from production and pulling tubing. Until the early 1980s it was rare that more than one level at a time was recorded. About this time several vendors introduced multilevel systems, first with five levels and ultimately expanding to nine.

During the late 1980s and early 1990s it was common to find most vendors still offering five to ten levels of recording. The only alternative was to lower strings of hydrophones into the well to record many levels at a time. This was not totally satisfactory for several reasons: particle motion was not recovered (only pressure), only fluid filled wells could be used, and in some cases the lack of clamping resulted in lost sensitivity. As 3-D surface seismic became more widely used in the 1990s it became clear that VSP systems had not kept up with surface seismic systems. While 3-D VSP's were run, they were often much more expensive per trace than surface seismic data collection. Outside of the P/GSI 80 level array, the majority of current systems are still less than twenty levels, with most being in the twelve to sixteen level range (with the exception of one twenty four level system). If VSP is to realize its full potential it must become competitive in both cost and value to 3-D surface seismic.

The ultimate goal of the 3D VSP method is to create a high resolution depth image of the reservoir around the borehole. The move from 20 to 80 to 400 geophones opens up a whole new area in reservoir geophysics, and allows operators to answer difficult interpretation questions that have been virtually impossible to get to in the past. P/GSI is poised to finally push the 3D VSP method into mainstream use within the oil and gas community.

Recent Application

A massive 3D VSP incorporating four of the five cables (320 of the 400 recording levels) in 4 wells, was carried out in *BP Exploration's* Milne Point Field on Alaska's North Slope this past March with excellent results (Sullivan *et al.*, 2002). Field development depends on multilateral completions in a 30 foot thick zone with numerous small throw (20-30 foot) faults that are not observable from conventional surface seismic. The reservoir is at a depth of approximately 4000 feet within the Schrader Bluff formation, a Tertiary marginal marine sandstone.

Vintage surface seismic 3D acquired to image the deeper Ivishak formation has very low fold (4-6) at the shallower Schrader Bluff interval, as well as considerable statics problems due to the highly variable permafrost zone. The inability to locate faults or local structural dip resulted in several sidetracks while attempting to drill long multilaterals as part of a 14 multilateral development program. A VSP was determined to be the most practical method for obtaining the inter-well geologic detail needed to complete the drilling program without additional problems.

The VSP approach was chosen because it could provide extremely high fold data and placement of geophones below the permafrost reduced the static and velocity problems. To improve the

Figure 2: Photo of Milne Point Experiment

areal coverage beyond what a single well would provide, four wells were drilled and fitted with 80 three-component geophone pods at 50 foot spacing, the tool length totaling 4000 feet (Figure 1). This arrangement provided 320 receiver positions without having to move arrays or repeat any source positions (a "massive" VSP).

Since the field is developed from a single pad, the location of the VSP wells had to be optimized for lateral coverage and increased frequency content (Figure 2). The central (vertical) well had geophone locations from near surface to several hundred feet above the reservoir while the other 3 wells projected out from the pad at deviations of up to 75 degrees. The geophone arrays in the deviated wells were placed below the permafrost zone at 2000 feet tvdss. Placement of the geophone arrays and source positions were determined by pre-survey modeling of the of the fold coverage.

The survey, shot over 5 days with 3232 vibration points and totaling over 3 million traces, resulted in stacked data with frequencies up to 120 Hz and a central peak frequency of 50-60 Hz near the edge of the survey. Reflections at reservoir level were recorded at offsets up to 7000 ft from the vertical well. The 50 ft receiver spacing interval allowed a close match of the velocities at the vertical well location, the only well with comprehensive wireline logs.

The 3D VSP successfully provided a high frequency, high fold image over the Schrader Bluff development area. Drilling underway during the summer of 2002 will test the accuracy of this survey. In the future, *P/GSI* hopes to deploy the entire 400-level system in other areas where detailed reservoir imaging is essential.

Improvement Over Existing Technology

The impact of 400 level clamped receiver array technology for natural gas production can best be understood if it is compared with the current status of downhole seismic receivers. Beside *P/GSI's* 80 level array, the general industry state-of-the-art in downhole receiver array technology from the large geophysical service companies is represented by several different 5 to16 level 3C clamped receiver arrays. These arrays can only collect a small fraction of the seismic data needed for high resolution reservoir imaging - especially for the higher frequencies possible in borehole seismology that require fine spatial sampling not to be aliased. The available commercial downhole receiver arrays include *Schlumberger's* 5 level clamped array, the *Baker Atlas* 13 level array and *OYO's* 16 level array. Even with *P/GSI's* current 80 level array a compromise must be made between large spatial imaging aperture, achieved by placing the receiver array high in the borehole, and recording the best possible data achieved by placing the array low at the reservoir depth. A 400 level array will allow operators to simultaneously achieve both objectives without shooting each shot point several times.

Potential Economic Impact

A commercially available 400 level 3C borehole seismic receiver array will make it possible to economically map high permeability zones and monitor production in heterogeneous and fractured reservoirs with a resolution in the range of 10 to 20 ft (3 - 6 m). Applications could include 9C cross well seismic techniques between wells spaced up to 6,000 feet or more apart, or the 9C 3D VSP technique to any known reservoir depth. In the cross well configuration operators could record 10 times higher seismic frequencies and by using the 9C 3D VSP technique, 2 to 5 times higher frequencies than what is possible using surface to surface seismology. Large 3C borehole seismic arrays will allow recording of both P and S wave data that together provide information on the location, size and preferred direction of fractures and fracture zones in the reservoir, information key to determining directional permeability of fractured reservoirs. As gas producers develop tighter, more geologically complex reservoirs, and look for better ways to locate unproduced gas hidden in existing reservoirs, this capability will find greater and greater application. ■

For questions related to this system or to obtain more information about the research program sponsored by SCNG/NETL, contact Bjorn Paulsson, President of P/GSI, at 562-697-9711 or via e-mail at bjorn.paulsson @paulsson.com

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Formation Testing and Sampling Through Casing

By Troy Fields and Gretchen Gillis
Schlumberger Oilfield Services
Brian Ritchie
Devon Canada Corporation
and Robert Siegfried
Gas Technology Institute

A unique wireline testing tool drills through casing, cement and formation rock to measure reservoir pressures and collect fluid samples, then plugs the holes it drills.

Reservoir pressure is one of the key properties that engineers, geologists and petrophysicists use to estimate both reserves and productivity of productive zones. It can be measured in several ways in uncased boreholes: wireline formation testers (FT) and openhole drillstem tests (DST) are two options. When the risks of sticking tools or pipe appear prohibitive, operators may choose to run casing and forgo openhole pressure measurements. In this situation the ability to sample fluids and test pressures in cased holes can become critical.

Determining pressure and fluid type in formations behind casing in older wells is also important. Data from cased wellbores help operators plan infill wells, monitor the progress of secondary-recovery operations, and identify portions of a field that may remain undepleted due to an inaccurate geological characterization of the reservoir.

In the past, the alternatives for gathering such data in cased holes required perforating the casing, performing a test between packing elements, and then squeezing off the perforations. This time-consuming operation was expensive and risky. The Cased Hole Dynamics Tester (CHDT) device is the first tool designed to penetrate casing, measure reservoir pressure, sample formation fluids and plug the test holes in a single trip. Schlumberger and the Gas Technology Institute (GTI) developed the CHDT tool jointly as part of a GTI initiative to develop new ways to evaluate cased gas wells.

Limitations of Tools for Testing Cased Wells

In the 1980s Schlumberger modified their RFT Repeat Formation Tester tool to perforate steel casing with a shaped charge, meeting the need to acquire fluid samples and pressure measurements in cased holes. After testing and removal of the Cased Hole RFT tool from the well, the perforation tunnel is covered by a patch, a plug or a cement-squeeze operation. This tool has some limitations: there is no measurement of fluid properties prior to collecting a sample, there is no pressure-drawdown control once the sample-chamber valve is opened, achieving a high-quality seal of the perforation may be difficult and time-consuming, and perforation entry-hole burrs on the casing wall can impede future operations.

The CHDT tool overcomes the limitations of the Cased Hole RFT tool. It is capable of drilling up to six precise sampling tunnels per trip, acquire multiple formation pressures, retrieve high-quality formation-fluid samples and restore pressure integrity (i.e., plug the holes it drills), in a single, cost-effective operation. The tool can be conveyed on wireline, on drillpipe or with a tractor.

An important aspect of CHDT tool application is having a good understanding of the nature of the near-wellbore zone. If cement-bond quality is poor, communication between zones might affect test results. Knowing the condition of the casing and the location of external casing hardware, such as centralizers, also is important. Casing and cement thickness and rock type all affect the ease and speed of drilling the individual test holes.

How the CHDT Tool Operates

The CHDT tool first is run to the target depth. Anchor shoes push the tool packer against the casing to provide a seal between the inner surface of the casing and the tool (Figure 1). A packer-seal test ensures that a seal is properly established before drilling into the casing.

After the seal is verified, a hybrid bit on a flexible drill shaft starts to drill. The drilling mechanism is hydraulically isolated from the borehole; the drill-bit position and pressure of the fluid surrounding the drill bit are monitored at surface. The fluid around the drill bit may be completion fluid, such as brine, or oil-base or water-base drilling fluid.

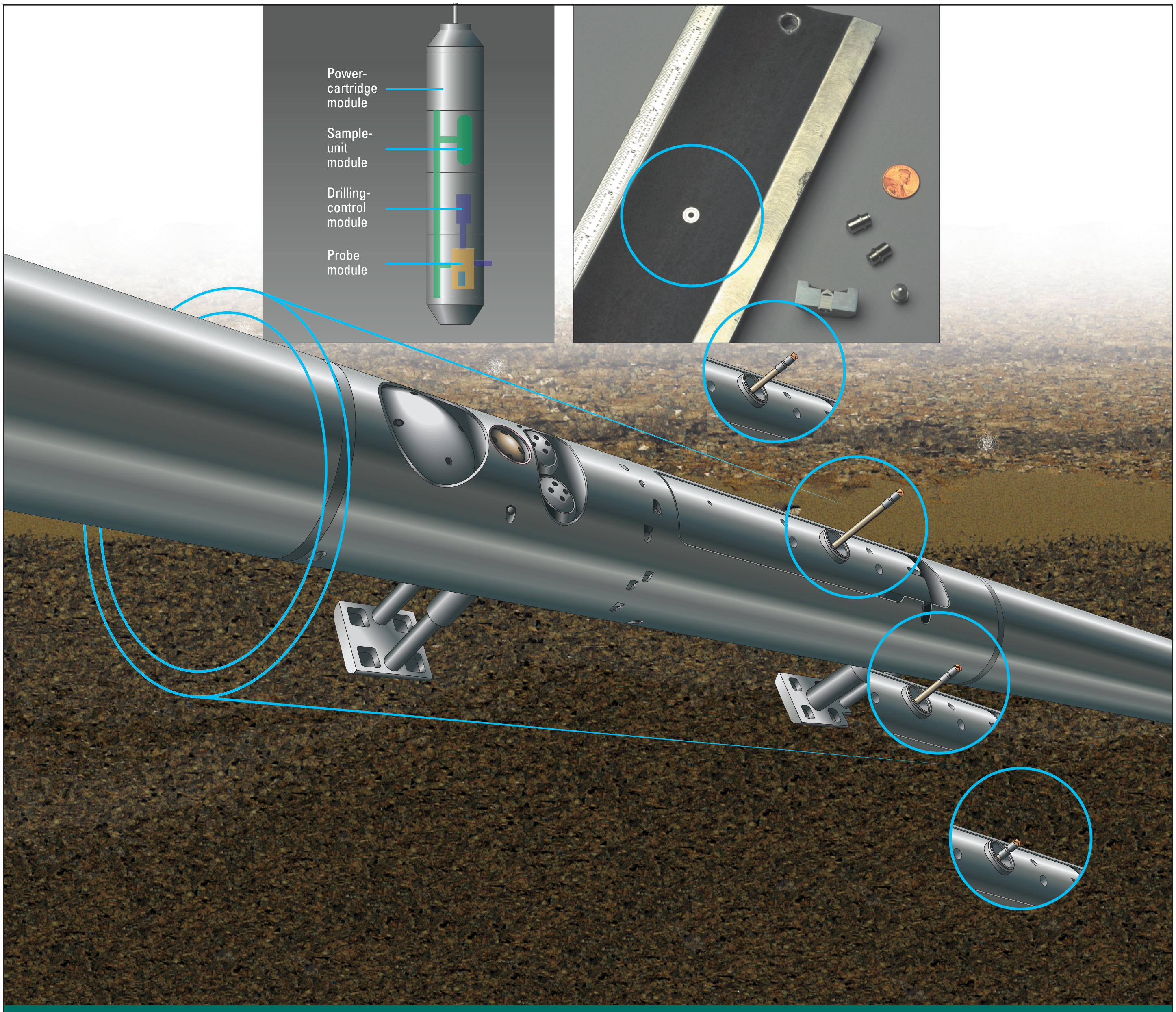

Figure 1: The Cased Hole Dynamics Tester (Courtesy of *Oilfield Review*)

As the drill bit advances through the casing into the cement sheath, small pressure variations result from volumetric and pore pressure changes within the cement. As drilling continues, cleaning cycles remove debris from the tunnel, enhancing drilling performance and reducing bit torque.

Reducing the pressure of the fluid surrounding the bit prior to drilling enhances the pressure response when communication is established with the formation, which makes detection of the response easier. Once the bit encounters the formation, the measured pressure stabilizes at reservoir conditions and drilling stops. The tool can drill up to 6 in. (15 cm) from the internal surface of the casing. Extending the drilled tunnel deeper into the formation increases the flow area for evaluating low-permeability formations.

For drawdown analysis, the CHDT tool can perform multiple pretests at various rates with volumes up to 6 in.^{3} (100 cm^3). Performing multiple pretests at different penetration depths can detect the presence of a microannulus and ensure that formation-pressure measurements are repeatable.

CHDT samples are collected when suitable communication is established between the tool and the formation. The tool monitors resistivity for fluid typing and can be combined with the Optical Fluid Analyzer (OFA), Live Fluid

Analyzer (LFA) and pumpout modules from the Modular Formation Dynamics Tester (MDT) tool for advanced fluid typing and contamination monitoring.

The CHDT tool can incorporate 1-gal (3.8-L) H_2S-rated sample chambers suitable in most 5 ½-in. casing. The external diameter of sample chambers in the MDT tool is 4 ½ in., limiting deployments combined with that tool to wells with 7-in. or larger casing. With the MDT tool however, sample chamber options include a number of combinations of chambers from 250 cm^3 to 22.7-L.

After pressure testing and sampling a particular target, the CHDT tool inserts a corrosion-resistant Monel plug to seal the hole drilled in the casing (Figure 2). This metal-to-metal seal restores pressure integrity to the casing and is rated to a differential pressure of 10,000 psi (69 MPa). The change in original internal casing diameter after the plug is set is only 0.03 in. (0.8 mm), and even this enlargement can be removed without reducing the pressure rating of the plug.

Optimizing Reservoir Development in Alberta

Recently, a carbonate reservoir in a mature Alberta gas field was evaluated with the CHDT tool. The Dunvegan Debolt reservoir comprises 800 ft (240 m) of interbedded limestone, dolostone, shale and anhydrite. Production comes from 15 dolostone zones that typically have less than 30 ft (10 m) of vertical separation. All gas zones are completed at the same time, and production is commingled; historical well pressure data represent an average value of all producing zones in a well.

The Dunvegan field, discovered in the 1960s and developed in the 1970s, is approximately 50 percent depleted. A key challenge in all subsequent infill-drilling programs is to optimize

Figure 2: CHDT Drilled Hole and Plug (Courtesy of *Oilfield Review*)

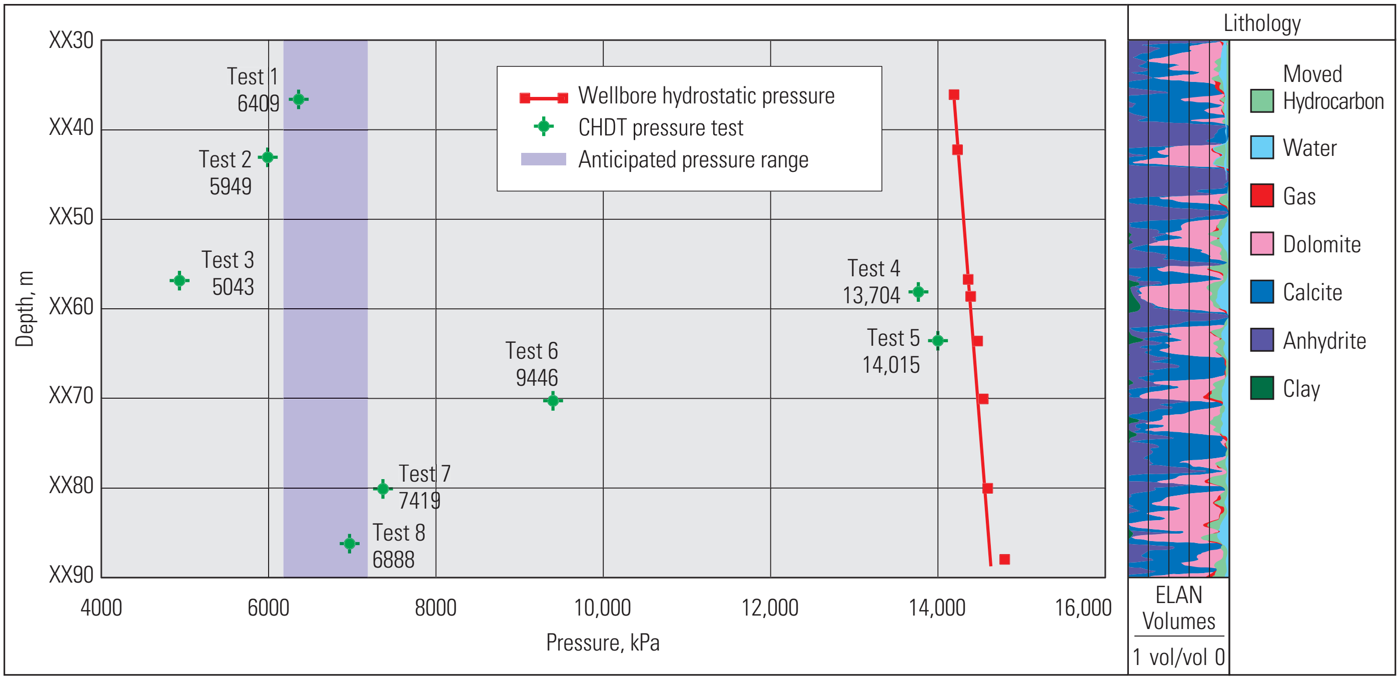

Figure 3: Plot of Pressure vs Depth for Well 7-3 (Courtesy of *Oilfield Review*)

infill-well locations. Currently, infill locations are selected on the basis of predicted pressure or depletion rate, so knowing the pressure of each zone is valuable to the operator, *Anderson Exploration Ltd.*, now *Devon Canada Corporation.*

After drilling Well 7-3 during its 2001 infill-drilling program in the Dunvegan field, *Devon* decided to measure pressure in eight zones using the CHDT device. Unlike their openhole counterparts, cased-hole devices like the CHDT tool can be run from a crane or service rig and do not require having a drilling rig on standby, which means that acquiring the CHDT data is economically practical in this mature field.

Prior to running the tool in the hole, the team reviewed CBT and USI logs to assess cement quality and confirmed that the zones to be tested were isolated from each other. Pressure measurements from eight zones were acquired in two wireline descents of the CHDT tool. The measurements demonstrated that six of the eight zones in the infill well consisted of reservoir-quality rock; the other two intervals (Tests 4 and 5) were inconclusive because the zones were relatively tight or possibly supercharged.

The composition of the gas in the field was well-known, so there was no incentive to acquire samples. Since all of the potentially productive zones in the well would be perforated after CHDT testing, successful plugging was not a crucial aspect of this job. Nonetheless, all of the holes were plugged successfully.

The pressure data revealed that one zone (Test 3) was more depleted than Devon suspected, suggesting drainage by another nearby well (Figure 3). Another zone (Test 6) had a higher-than-expected pressure. Formation-pressure measurements (green symbols in Figure 3) from eight zones in Well 7-3 indicate various stages of depletion in the reservoir. Pressure measurements were expected to fall in the zone shaded in lavender. The red line shows wellbore hydrostatic pressure. Tests 4 and 5 were likely influenced by the tight nature of the formation, or might be supercharged. Expected reservoir pressure is shown in the shaded area and clearly demonstrates a depleted interval in Test 3 and higher-than-expected pressure in Test 6. Incorporating these results into the field model has led to new opportunities for optimizing well placement as the infill-drilling program proceeds.

The value of CHDT data in the Dunvegan field is high for several reasons. *Devon* can incorporate the new data quickly and improve its infill-drilling operations immediately rather waiting until the end of a drilling campaign. The company saves about C$1 million each time it avoids drilling an unnecessary well. Because the CHDT tool acquired the necessary data while minimizing cost and risk, it is likely to become a standard component of Dunvegan well evaluations in the future.

CHDT Reliability

The CHDT tool has been operational for more than one year, including a rigorous field-testing stage during which it demonstrated its capabilities in a number of challenging environments. CHDT data, along with other through-casing formation evaluation now available (nuclear and acoustic porosity, resistivity, rock mechanical properties, lithology, elemental analysis and borehole seismic measurements) allow operators to obtain data in new wells where logging-while-drilling or openhole logs are unavailable or inadequate, and also to assess bypassed pay or monitor reservoirs in older wells. Restoring the pressure integrity of the casing after CHDT operations eliminates the costs and rig time associated with conventional plug-setting runs, cement-squeeze operations, pressure tests and scraper runs. The CHDT tool, even at this early stage in its use, has a 93 percent success rate for plugging holes. This means that remedial action such as isolation with a bridge plug, installation of a casing patch or cement-squeeze operations, may be necessary only 7 percent of the time.

The CHDT tool gives operators a number of important capabilities, not the least of which is a way to more accurately understand how well geologically complex gas reservoirs are being depleted. Applications for this tool should only expand as producers continue to search for ways to optimally produce the reserves they have already discovered. ■

This article has been adapted from an article by Keith Burgess et al. in the Spring 2002 issue of Schlumberger Oilfield Review. CHDT (Cased Hole Dynamics Tester), LFA (Live Fluid Analyzer), MDT (Modular Formation Dynamics Tester) OFA (Optical Fluid Analyzer) and USI (UltraSonic Imager), are marks of Schlumberger. Monel is a mark of Inco Alloys International, Inc. for more information on this tool contact Troy Fields at 281-285-8013 or at tfields@sugar-land.oilfield.slb.com.

Field Tests Support Reliability of Membrane Gas/Liquid Contactor Gas Dehydration System

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Suzanne I. King
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New field test data support the reliability of using gas-liquid membranes to reduce the space and weight requirements of dehydration units.

The application of permeable membranes to gas processing problems holds some of the greatest potential for enabling dramatic reductions in the size, complexity and cost of the equipment required to prepare natural gas for the pipeline. These advances will be needed as the demand for natural gas pushes producers to tap poorer quality, more remote resources, making smaller, cheaper, more efficient gas treating equipment a prerequisite for monetizing what might otherwise be stranded gas.

Development History

Since 1992, *Kværner Process Systems* (KPS) has been working on the development of a process for removal of CO_2 from both gas turbine exhaust and natural gas. The development of a permeable membrane gas-liquid contactor has been funded through two consortia, one focusing on the contactor's application to exhaust gas and the other on its application to natural gas treatment. GTI has been a member and major funder of the natural gas consortium, along with *BP Exploration, Statoil, Norsk Hydro, Saga Petroleum, Mobil North Sea, A/S Norske Shell, Norske Conoco A/S,* and *Chevron Research and Technology*. In addition, GTI has operated field tests for the consortium at the *Shell/Tejas Gas* Fandango test site in Texas to confirm theoretical and laboratory predictions of the contactor's performance (Falk-Pedersen, 2000).

Through continued work on this project, *KPS* and its technology partners have established basic knowledge of the membrane gas/liquid contactor and the possibility for process optimization when membrane gas/liquid contactors are used. In this effort, *W.L. Gore & Associates GmbH (GORE),* manufactures the membranes, *SGL Carbon Group (SGL)* constructs the membrane modules, and *Ottestad Breathing Systems a.s. (OBS)* manufactures the membrane protection system. Together with Gas Technology Institute (GTI), they are proving the technology through field tests.

This article provides an update on the results of a field test carried out during November and December 2001 at the *Duke Energy Field Services (DUKE)* Marla Compressor Station northeast of Denver Colorado (King *et al.*, 2002). The results of a second round of testing at the site are currently being analyzed.

Advantages of Membrane Contactors

The most widely used process for separation of acid gases (CO_2 and H_2S) and water vapor from natural gas is absorption using an appropriate chemical solvent. In a typical absorption process, the gas enters the bottom of an absorber column and flows upward in counter-current contact with the aqueous solvent solution. The column contains bubble trays or packing material designed to provide for the greatest possible degree of contact between gas and solvent as the solvent absorbs the contaminants on its way down. The height of an absorber column is dictated by the required purity of the gas leaving at the top, while the diameter is dictated by the maximum allowable gas velocity before the gas starts to entrain the liquid. Large flow rates with high levels of contaminants make for large absorbers.

The overall absorption process remains the same when a gas-liquid membrane contactor is used in place of a conventional column. The sour (wet) gas enters the contactor, where it is separated from the lean solvent solution by a membrane that is highly permeable to the component for which removal is desired (e.g., CO_2 or water). The contaminant diffuses through the membrane into the lean amine solution where it is chemically absorbed (Figure 1). Because the membrane provides a large contacting area, a highly selective separation can be achieved through a suitable choice of the absorption liquid. The major driving force for the separation is absorption into the liquid, not partial pressure differential. This is different from a gas/gas membrane approach, which relies on the membrane alone to separate contaminants from the sour gas stream.

Advantages of a gas-liquid absorption membrane over conventional contacting equipment include: four to five times higher packing density; greater flexibility with respect to flow rates (liquid to gas ratios) and solvent selection; elimination of foaming, channeling, entrainment and flooding; higher turndown ratio; insensitivity to motion and flexibility regarding unit orientation (important offshore and on floating structures); and a significant savings in weight and space requirements (70-75 percent weight reduction and 65 percent space reduction in major components, also important at remote and offshore locations).

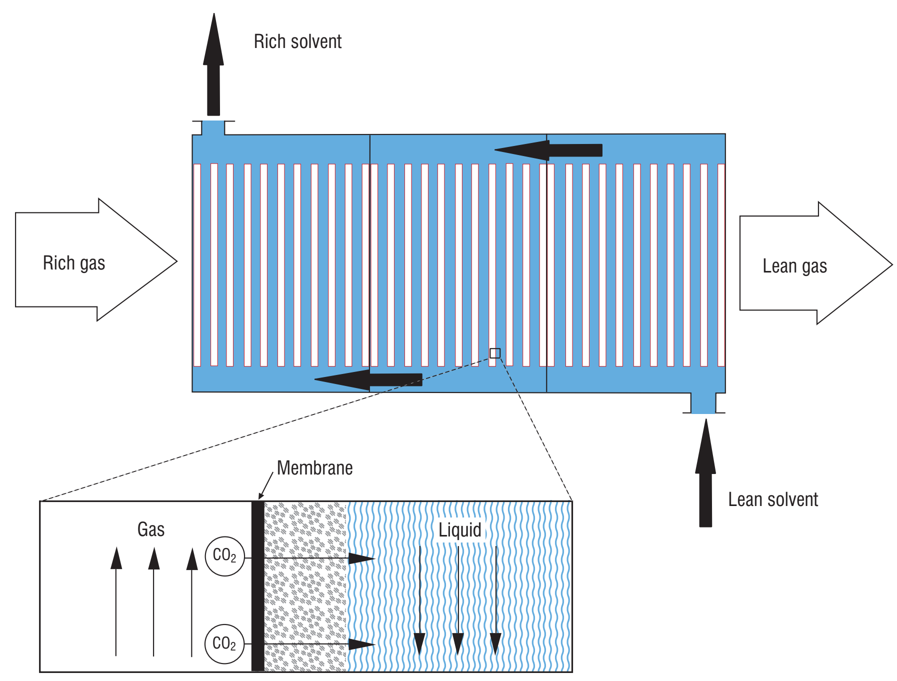


Figure 1: Schematic Illustrating the Use of a Gas-Liquid Membrane Contactor

Design Offers Flexibility in Smaller Package

When using a membrane gas-liquid contactor, more freedom is allowed in the sizing of the membrane module-containing pressure vessel. Higher gas velocities may be tolerated since flooding is impossible. Also, the liquid does not have to "wet" a specific packing area since it is already constrained inside the membrane tubes. This makes it possible to use smaller diameter columns, which significantly reduces the required wall thickness and thereby the weight of the vessel (pressure vessel wall thickness is proportional to the square of the vessel diameter).

To accommodate the high operating pressure, the membrane modules are housed in pressure vessels that can be oriented either horizontally or vertically to suit the overall plant layout. The multiple pressure vessel arrangement allows single bank service/maintenance without requiring a plant shutdown. Increases in feed gas contaminant content and/or feed gas flow rate can easily be handled by adding the required number of additional membrane contactor vessels, provided excess handling capacity is built in for the rest of the system.

Marla Site Details

The *DUKE* Marla Compressor Station collects gas from approximately 350 wells, compresses the gas from 100 to 950 psig, and dehydrates it before it is sent to a second plant for liquids recovery. The gas is rich, containing about 12 percent ethane, 5 percent propane, 4 percent butane plus, 2.5 percent carbon dioxide and 200-300 ppm BTEX.

A series of tests were run between November 17 and December 15, 2001, using a trailer-mounted membrane contactor dehydration (TEG) unit (Figure 2). The unit was a stand-alone system incorporating membrane contactors, a membrane protection system, instrumentation, and a conventional regeneration system.

Gas flow during the test ranged from 0.5 to 0.85 MMscfd at approximately 950 psig, water saturated (between 30 and 70 lbs/MMscf), at a temperature between 80 and 100 degrees F.

The goals for the test were straightforward:

- Meet a 7 lbs /MMscfd pipeline water content specification,
- Reduce BTEX co-absorption in TEG,
- Demonstrate stable operation, and
- Verify the accuracy of process simulation software.

Marla Test Results

The first goal was met. The dry gas was well below the specification, averaging 2 to 5 lb/MMscf.

Figure 2: Skid-Mounted Membrane Unit Installed at Marla Station

A specially coated membrane unit was tested as part of the program, to see if a selective membrane layer could retain the BTEX in the gas stream. Glycol dehydrators are a major source of BTEX emissions by the gas industry and regulations are requiring controls to mitigate these emissions. The results of the test showed that measured co-absorption with the membrane contactor was less than what would have been expected under the same circumstances with a conventional absorber. The reductions varied with the compound: benzene absorption was reduced 2.6 percent, toluene 9.3 percent, ethylbenzene 8.5 percent, and xylenes 6.8 percent. While encouraging, this result is not sufficient to satisfy Clean Air Act Amendment requirements.

The third goal was also realized. Stable operations were achieved during the 432 hours (18 days) of testing. The membrane protection system proved reliable over large gas and liquid pressure fluctuations.

The process simulation model correctly predicted operational trends. A comparison of the simulation model output with actual moisture measurements shows that they track well, but that the simulator is conservative (Figure 3). A second prediction, based on *GRI-GlyCalc* (v.3.0) software for predicting equilibrium water contents for experimental operating conditions, also tracks the actual measurements, although slightly low. Incorporating the *GlyCalc* equilibrium model into the simulation software should result in a better predictive tool.

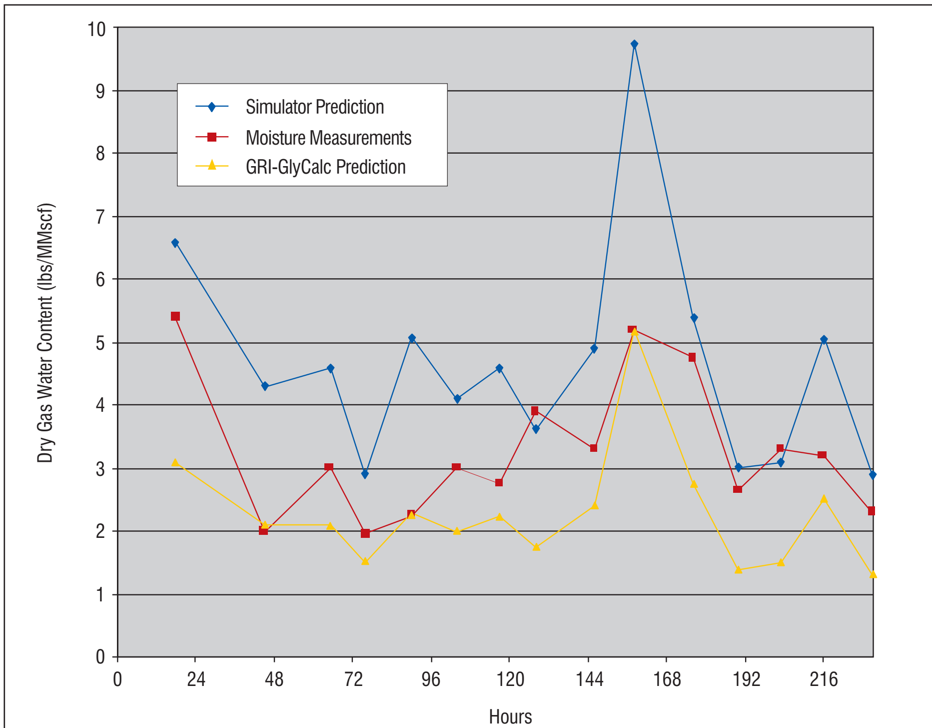


Figure 3: Comparison of Actual and Simulated Dry Gas Water Content Data

Problems Encountered

The major operational problem during testing was the need to maintain the lean glycol temperature 10 to 15 degrees above the wet gas temperature to prevent condensation within the membrane unit. This would not normally be a problem with a commercial-sized unit, but the small diameter tubing running from the regenerator to the membrane vessels on the skid-mounted prototype had much higher heat losses than expected. Accordingly, the glycol flow rate had to be maintined near the pump maximum, resulting in higher glycol to water removed ratios than planned (4 to 15 gallons TEG/lb water removed, versus 3 to 5 gallons).

Also, glycol purity was lower than expected (97.9 weight percent TEG versus an expected 98.5 percent). Stripping gas was used in the second set of tests to increase the lean glycol concentration and allow higher gas flowrates for a given glycol rate. Finally, the flow rate during the test was lower than anticipated due to a piping problem related to the feed tie-in. This was also corrected for the second test program.

Next Steps

A second program of testing at the Marla station was carried out during the spring of 2002 to test the unit at higher gas throughputs and higher purity lean glycol. The results of this testing campaign are still being analyzed, but look promising. They will be the topic of a future *GasTIPS* article.

The next step in the development of the technology is construction and installation of the first demo/prototype unit. GTI, *Chevron Research and Technology,* and the US Department of Energy are currently seeking interested parties to participate in that program. ■

For more information on the results of these field tests contact Howard Meyer, Principal Project Manager, Gas Processing at 847/768-0955, or via e-mail at howard.meyer @gastechnology.org

References

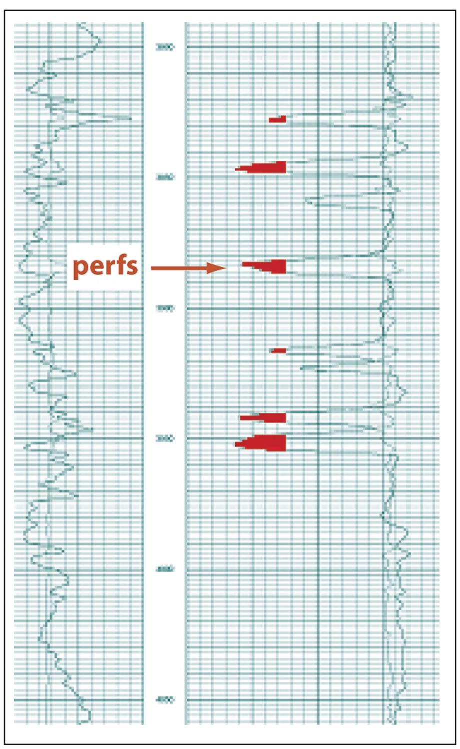
King, S.I. et al., 2002. "Membrane Gas/Liquid Contactors for Natural Gas Dehydration," presented at the 52nd Annual Laurance Reid Gas Conditioning Conference, Norman, OK, February 24-27.

Falk-Pedersen, O., Dannstrom, H., 2000. "A Gas-Liquid Membrane Contactor for Natural Gas Treatment," GasTIPS, Volume 6, Number 1, Winter issue, pgs. 4-9.

New PRODUCTS, SERVICES & OPPORTUNITIES

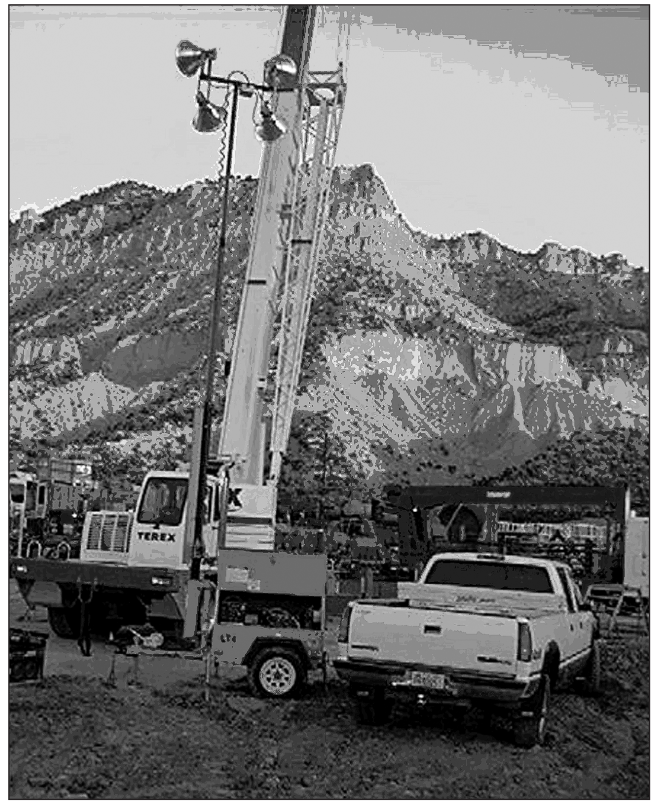
Tiltmeter Fracture Diagnostics Applied to Coalbed Methane

Pinnacle Technologies has been providing downhole tiltmeter mapping services commercially since 1997 in offset monitor wells to directly measure fracture geometry on hundreds of fracture treatments (see *GasTIPS,* Fall 2001 issue). *Pinnacle* partnered with *Halliburton Energy Services* in 2000 to migrate this technology to the treatment well, so fracture height and width could be directly measured during pumping in the treatment well itself. This eliminates the need to shut in production on monitor wells and allows tiltmeter mapping technology to be used in areas where well spacing is not conducive to mapping from an offset wellbore.



Log showing coal sequence

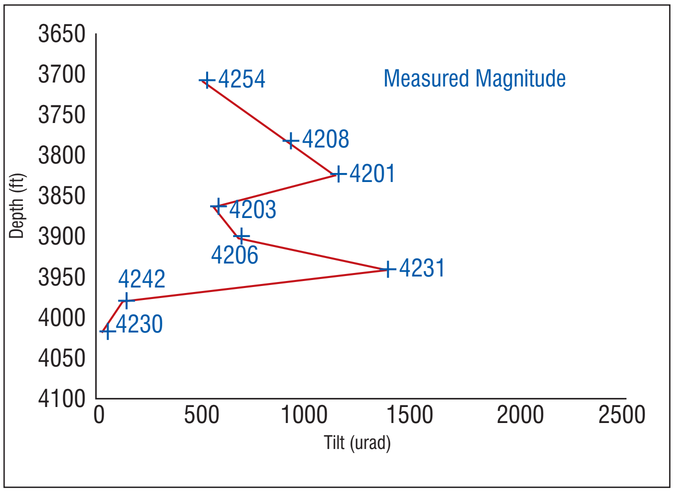
Earlier this year, *Anadarko Petroleum* investigated the feasibility of reducing the number of fracture stimulation treatments in the Helper Field, southeast of Salt Lake City, Utah. The standard industry practice for the past five years in the Helper Field has been to stimulate coals in multiple stages in order to ensure that all zones were adequately stimulated. This field contains multiple sand and shale sequences between coal beds so multi-staging has been the preferred way to ensure complete coverage of the large gross interval. The primary target in the Helper Field is a series of Ferron coal seams interspersed with tight gas sands that are found over a 250 foot interval.



Well site in the Helper Field

Anadarko investigated the use of a "limited-interval" perforating technique, whereby a short set of perforations is placed in the center of a group of coal seams and a single fracturing treatment is pumped covering an entire sequence of several hundred feet of coals, tight sands and shales. This limited interval technique can have obvious advantages: cost savings due to eliminating one or more fracturing stages, a reduction in the number and complexity of hydraulic fractures due to multiple initiation points, and potentially better stimulation of the tight gas sands which intersperse the coals. However, covering large gross intervals with a single fracture treatment can be difficult when the lithology is widely variable such as is found in many coalbed plays. A way was needed to determine if the treatment was covering the entire interval.

The solution was to employ *Pinnacle's* Treatment Well Tiltmeters on a large mini-frac treatment to measure fracture height growth in real-time and determine if the limited-interval technique allowed for coverage of the entire gross pay interval. A typical



Measurements No. 4201 and No. 4231 identify fracture height

density log (see figure) shows the series of five coal seams that were fractured in a single stage.

The tilt response during pumping (see figure) indicates a fracture that has its top at 3780 ± 30 ft and its fracture bottom at 3960 ± 30 ft. These results indicate that the fracture has a total height of 180 feet and covers all of the coal seams from the single stage, point-source completion (2 ft of perforations), supporting the conclusion that adequate fracture height is being created to cover large pay intervals through a single, small, perforated interval.

Subsequent other treatments with a slightly larger "limited interval" perforating strategy successfully stimulated the entire interval in a single stage. Production from these subsequent treatments proved to be as good as or slightly better than neighboring wells that had been fractured using multiple stages, but with a cost savings of $35,000 to $50,000 per well.

Opportunities to Reduce Methane Emissions to be Highlighted at Workshop

The 9th Annual Natural Gas STAR Workshop will be held October 28-30, 2002 at the Houston InterContinental in Houston, TX. The Annual Implementation Workshop provides STAR partners with an opportunity to obtain information about the most current, cost-effective emission reduction technologies and practices, exchange ideas with other STAR partners, and learn about new STAR Program activities and initiatives. It also provides an opportunity for companies interested in joining the program to learn more about it.

The Natural Gas STAR Program is a voluntary partnership between EPA and the natural gas industry, focused on identifying and implementing cost-effective technologies and practices to reduce emissions of methane, a potent greenhouse gas. In 2000, STAR industry partners reduced methane emissions from unit operations and equipment leaks by 34 billion cubic feet (Bcf). At a gas value of $3.00 per thousand cubic feet, these gas savings are worth approximately $102 million.

The program has more than 90 partners across all of the major sectors of the gas industry-production, processing, transmission, and distribution. Currently, the program's production sector partners represent 40 percent of domestic gas production, and the transmission and distribution partners represent 77 percent of transmissions mileage and 51 percent of distribution service connections. The program's partnership with gas processing companies, which was launched in 2000, already represents nearly 60 percent of industry throughput.

For more information on the Gas STAR Program, call Program Manager Carolyn Henderson at 202-564-2318 or visit the program's website at http://www.epa.gov/gasstar/.

Deep Trek to Develop Technology to Tap Gas Supplies Below 15,000 Feet

Although most of the gas produced in the continental United States already comes from below 5,000 feet, as demand for natural gas increases tapping reservoirs at depths of 15,000 feet or more will have to become more common. To help develop the high-tech drilling tools the industry will need to tackle these deeper reservoirs, NETL has begun "Project Deep Trek" with the goal of developing a cost-effective, "smart" drilling system tough enough to withstand the extreme conditions of deep reservoirs.

The agency is initially funding the initiative at $10.4 million and is currently soliciting cost-share proposals from industry. Proposing organizations will have two opportunities to respond. Selected organizations that have already submitted a pre-application proposal (due by April 11) have been asked to submit a more detailed, comprehensive application by May 30. For organizations that missed the first deadline, a second opportunity will come before November 30, when another set of pre-applications (a mini-proposal no longer than seven pages) will be due. After review of these pre-applications, NETL will request comprehensive applications from selected applicants by January 13, 2003.

The department will fund three phases of Deep Trek research and development: feasibility and concept definition (Phase I), prototype development or research, development and testing (Phase II), and field/system demonstration and commercialization (Phase III). Technologies need not go through all three levels of development if they already have completed several years of research. For instance, technologies that are proved to be feasible may be eligible for phases II and III. Others that are more mature may bypass phases I and II and qualify for a field demonstration. No phase is planned to last longer than four years. Private partners must contribute a minimum of 20 percent for Phase I projects, 35 percent for Phase II, and 50 percent for Phase III.

Technologies likely to be pursued under the Deep Trek project include low-friction, wear-resistant materials and coatings, advanced sensors and monitoring systems, advanced drilling and completion systems, and new bit technology that could be integrated into a high-performance, "smart" system. The new system must operate in extreme temperatures (more than 347° F) and pressures (greater than 10,000 pounds per square inch). For specific information about the solicitation and the IIPS, contact Kelly McDonald, Contract Specialist, at (304) 285-4113, or via e-mail at kelly.mcdonald@ netl.doe.gov. The solicitation (Number DE-PS26-02NT41434-0) can be read and downloaded at http://www.netl. doe.gov/business/solicit/index.html.

GTI Pipeline Coatings Facility Mimics Real-World Conditions

GTI's Pipeline Coatings Facility in Des Plaines, Illinois was built last year to address the pipeline industry's need for a testing facility that could compare corrosion resistance performance of a large number of commercial coatings under a wide range of conditions, consistently and objectively. In May, 2002, GTI inaugurated the facility with the launch of a multi-year project to test a variety of coatings on numerous types and sizes of pipes buried in a variety of soils, at both ambient and elevated temperatures. This work is being funded by a consortium of more than 25 pipeline companies, coating manufacturers and utilities.

The results will be compiled into a database which operators will be able to use to match an appropriate coating with known pipe size, soil type/ conditions and service temperatures. Specific information will be developed on costs per joint, time to apply a system, equipment needs and special requirements, as well as quantitative ASTM and other test data (e.g., adhesion, peel, hardness, impact resistance, abrasion resistance, etc.) According to GTI Materials Scientist Dan Ersoy, manager of the project, "No easy, scientifically sound way to determine the optimal coating for each pipe and field condition exists. This research will provide the industry with a knowledge base no one pipeline or coating company could develop on their own." In addition to a "pipe farm" where pipe joints are buried under controlled conditions, there is also a state-of-the-art testing facility for performing a wide range of both standard and specialized pipe performance and strength tests.

Other GTI laboratories nearby are involved in a wide array of gas industry research, including other pipeline-related investigations. One of these involves the testing of a capsicum-based inhibitor of microbial corrosion (capsicum is the active ingredient in chili peppers).

New PUBLICATIONS

Exploring for Anomalously Pressured Gas Accumulations

A GTI report titled *"A New Approach to Exploring for Anomalously Pressured Gas Accumulations: The Key to Unlocking Huge Unconventional Gas Resources"* describes the *Innovative Discovery Technology* (IDT) strategy for the exploration and exploitation of anomalously pressured gas assets. Key elements include interpretation of gas distribution, gas migration conduits, reservoir gas content, microfracture swarm distribution, and linear fault orientation. This GTI research provides industry with an improved diagnostic technique that will substantially reduce risk and increase profitability in the exploitation of anomalously pressured gas assets.

The improved economics of developing "basin-center" gas accumulations in the Rocky Mountain Laramide Basins is expected to increase reserves and production from these accumulations. This 21-page report is available online at www.gastechnology.org for $60 (Member Price $35) under the publication code GRI-02/0120.

Pressure Regimes in Sedimentary Basins and Their Prediction

This brand new addition to the AAPG Memoir Series (No. 76) is an outgrowth of an international forum sponsored by the Houston chapter of the American Association of Drilling Engineers. Experts in pore-pressure prediction from the geologic, geophysical, reservoir, and drilling communities were brought together to share the state of the art from each discipline. The 19 chapters in this volume are organized into three groups: (1) rock physics and pore pressure theory, (2) pore pressure and fracture gradient prediction in different geologic environments and, (3) a variety of topics ranging from geophysics to drilling technology. This 238-page hardbound book by Alan R. Huffman and Glenn L. Bowers will interest pore-pressure interpreters, basin modelers, explorationists, drilling engineers, and rock physicists. Buy it online at http://www.aapg.org (List Price $74, AAPG Member Price $54).

Conference Proceedings Available Online

Last May, the Strategic Center for Natural Gas (SCNG), in partnership with the Gas Technology Institute (GTI), convened *"Natural Gas Technology - Investment in a Healthy U.S. Energy Future"*, in Houston, Texas. The conference provided a forum for the US gas industry to comment on what the future holds for the natural gas market and what technologies and policies are needed to get there. Presentations by the following speakers are available online (at www.fetc.doe.gov/scng/index.html): Rita Bajura, Director, National Energy Technology Laboratory; John Riordan, President, Gas Technology Institute; Scott Tinker, Director, Bureau of Economic Geology UT-Austin; Chris Mottershead, Technology Vice President, BP Amoco; Raoul LeBlanc, Manager, Strategic Planning Department, Anadarko Petroleum; and others. SCNG and GTI are working together to convene another new conference and exhibition entitled *"Natural Gas Technologies - What's New and What's Next"* in Orlando, Florida this coming September.

Hart Publications Launches New Magazine for Pipeline and Natural Gas Industry

Hart Publications has launched a new magazine, *Pipeline and Gas Technology*, for the worldwide pipeline construction, maintenance and rehabilitation business sectors. *GasTIPS* readers can obtain a complementary subscription by filling out and faxing in the form on the following page.

Underbalanced Completions: A Technology Review

This CD-ROM introduces the basic principles and practices of underbalanced well construction applications. It extends concepts developed previously in the Underbalanced Drilling Manual (published by Gas Research Institute) to include initial well completions, live interventions, and workovers. The CD presents key inflow performance relationships that are vital to planning a successful completions program. It also provides practical guidelines for completion fluids, cementing, perforating, and completion design and operations. Multilateral wells and well servicing considerations are also covered. Document number GRI-00/0178.1. Price $95 to GTI members; $125 to nonmembers. Order from GTI Document Fulfillment Center, 1520 Hubbard Drive, Batavia, IL 60510; phone 630-406-5900; E-mail fillit@compuserve.com.

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   - ❑ (85) Executive Management *(CEO, President, VP, Partner, Director, etc.)*
   - ❑ (86) Management other than Engineering or Executive
   - ❑ (87) Consulting
   - ❑ (88) Purchasing
   - ❑ (59) Other

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   - ❑ (94) Pipeline Contractor or Subcontractor
   - ❑ (95) Engineering and Construction
   - ❑ (96) Engineering
   - ❑ (97) Water/Slurry Lines
   - ❑ (98) Product Lines
   - ❑ (99) Consulting/Design Engineer
   - ❑ (59) Other

Signature: ____________________

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FAX to PipeLine and Gas Technology at 1-847-647-0830

CALENDAR

Information related to workshops, short courses, and other industry meetings.

2002

August 14 - 16

Coalbed Methane Reservoir Engineering Short Course, Morgantown, WV.
This course two and one-half day course is being sponsored by GTI, TICORA Geosciences, Inc., Intelligent Solutions Inc., WVU and the PTTC. The program will be held at West Virginia University. For more information or to register before August 9, contact 304-293-7682, ext 3405,or e-mail Shahab@wvu.edu.

August 27 - 29

AAPEX - Prospect and Property Expo, Houston, TX.
American Association of Petroleum Geologists (AAPG), Phone: 800-364-2274 or 918-584-2555. Fax: 918-560-2684. Email: postmaster@aapg.org. Internet: www.aapg.org/.

September 8 - 11

AAPG Rocky Mountain Section Meeting, Laramie, WY.
American Association of Petroleum Geologists (AAPG), Phone: 800-364-2274 or 918-584-2555. Fax: 918-560-2684. Email: postmaster@aapg.org. Internet: www.aapg.org/.

September 19 - 20

7th Annual Deepwater Technologies & Developments Conference, Houston, TX.
This Strategic Research Institute conference will take place at the Renaissance Hotel. Topics include new technologies, future developments, and current strategies for maintaining production and performance/reliability of current deepwater equipment. Specific topics include: flow assurance, subsea processing, deepwater site investigations, use of improved seismic data, water/oil separation in deepwater fields, pipeline route surveys, and ROV technology. For more info contact 1-888-666-8514, or 646-336-7030, or visit www.srinstitute.com/cr229.

September 30 - October 1

CBM Water Management Strategies Seminar, Jackson Hole, WY.
This Strategic Research Institute seminar will be held at the Snake River Lodge. Topics include concerns over CBM water interactions with the environment, as well as cover water treatment, water disposal issues, regulation requirements and technological improvements. Register online at www.srinstitute.com or call 1-800-599-4950 for more information.

October 1

Innovative Gas Exploration Concepts Workshop, Denver, CO.
One day workshop at the Denver Marriott Center sponsored by RMAG and PTTC. Includes speakers on topics such as: Bossier gas play, Bennett Shale play, gas generation and maturation, Albuquerque basin, low perm shallow Canadian gas, exploration for biogenic gas and geophysical approaches to gas exploration in the Rockies. For more information call 303-273-3107.

September 29 - October 2

SPE Annual Technical Conference and Exhibition, San Antonio, TX.
Society of Petroleum Engineers (SPE), Phone: 972-952-9353. Fax: 972-952-9435. Email: bwright@spe.org. Internet: www.spe.org/.

September 29 - October 2

GTI Technology Transfer Conference, Wyndham Palace Resort Hotel, Orlando, FL.
Gas Technology Institute (GTI), Phone: 847-768-0500; 847-768-0832. Fax: 847-768-0501. Email: feingold@igt.org. Internet: www.igt.org or www.gastechnology.org/. New annual conference and exhibition cosponsored by the Strategic Center for Natural Gas of the U.S. Department of Energy's National Energy Technology Laboratory.

October 6 - 11

SEG Annual Meeting and International Exposition, Salt Lake City, UT.
For more information or to register phone 918-497-5500, Fax: 918-497-5557 or e-mail meeting@seg.org. Program available on the Internet at www.seg.org.

October 23 - 25

4th Annual Unconventional Gas and Coalbed Methane Conference, Calgary, Alberta.
Sponsored by PTAC and the Canadian Coalbed Methane Forum. Conatct Kerri Markle at 403-218-7711.

October 28 - 30

North American Gas Strategies Conference, Calgary, Alberta
Annual gas strategies conference sponsored by Ziff Energy Group. Contact: Paula Arnold at (403) 234-4279 or at gasconference@ziffenergy.com/.

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