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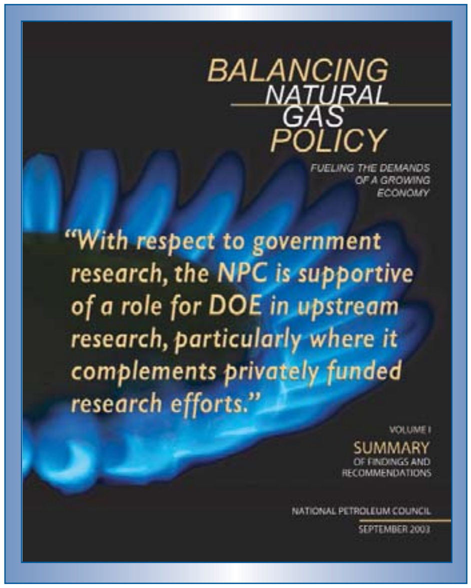
Commentary

Minimizing Risk, Maximizing Cooperation

The June issue of the Society of Petroleum Engineers' *Journal of Petroleum Technology (JPT)* included a summary of a panel discussion JPT hosted last March on the topic: *Funding and Uptake of New Upstream Technology*. Prepared by panel moderator Ali Daneshy of Daneshy Consultants and *JPT* editor John Donnelly, the article summarized what nine panelists identified as the existing practices and key issues related to development funding and acceptance of new technology within the exploration and production industry. The panelists included high-ranking technology managers from four major producers and three major service companies.

The authors first note what is widely acknowledged to be the current state of technology research and development (R&D) in our industry. Responsibility for funding and deployment has shifted from the major producers to the major service companies, but the industry is struggling to reconcile pressure for short-term profitability with the need for longer-term, higher-risk R&D investments that can lead to step-change advancements. The panelists agreed the way out of this dilemma lies in cooperation among producers and service companies for mutual benefit, and that this cooperation can take place via a number of mechanisms such as one-on-one partnerships, consortia and ad hoc agreements, among others. Their conclusion is that cooperation among competitors, and collaboration among technology developers and users helps minimize the risks involved in developing and applying new technology. They also conclude the industry needs new R&D funding mechanisms that also will help mitigate risk.

The U.S. Department of Energy, through the National Energy Technology Laboratory (NETL), helps foster R&D collaboration by providing targeted funding that can help minimize R&D risks. Using inputs collected from industry experts, academic researchers and in-house analysis, NETL crafts targeted research



programs that focus on technologies needed to meet expected domestic demand for fossil fuels. Particular emphasis is placed on technologies where NETL funding can make a difference by advancing a collaborative effort that might not otherwise occur. While the relatively modest investments the NETL makes are not generally sufficient to single-handedly power the development of a new technology, tool or product, it can have an impact beyond its size when the group helps minimize risk and facilitate cooperation. As an example, the NETL and Gas Technology Institute funding during the 1970s and 1980s helped provide the basic understanding of the unconventional resources now relied upon to meet natural gas demand – coalbed methane, tight gas sands and fractured organic shales. Resource assessments, field experiments and technology demonstrations the NETL and GTI funded helped get producers and service companies working together on the problems of developing a resource previously considered uneconomic.

Currently, the NETL is working to repeat this process in other areas where reducing the risks of R&D investments and facilitating collaborative efforts can lead to similarly big payoffs for U.S. energy security and the domestic economy. For example, by helping fund the characterization and testing of methane hydrate accumulations in the Gulf of Mexico and Alaska, the NETL is advancing the development of technologies that could play important roles in offshore drilling safety and domestic gas supply security. Producers, service companies and researchers at universities and national laboratories are cooperating to investigate ways to locate and potentially produce natural gas from hydrates. This sort of multi-decade investment would never meet the short-term criteria of today's financial markets, yet could provide the tools needed to safely add gas reserves in 2025.

Similarly, the NETL's funding of DeepTrek projects is helping leverage industry efforts to develop the tools needed to find and efficiently produce gas from formations below 15,000ft. The data transmission tools, electronic components and drilling enhancements being developed under this program would generally be considered high-risk investments by individual companies. However, with partial support from the NETL, these same companies find it feasible to team together to tackle these technology challenges that must be overcome to meet the gas demand projected during the next two decades.

The real risk is that the business shifts of the past 20 years and the pressures of today's marketplace will delay or prevent the introduction of new technology needed for future growth. This would lead to lost opportunities for the domestic exploration and production industry and accelerated growth in dependence on foreign sources of energy for the U.S. economy.

The *JPT* panel agreed the discussion was part of a very essential dialogue within the oil and gas industry. Hopefully, the spirit of cooperation reflected in the panel's work will lead to innovative ways to keep the stream of technology solutions flowing. ✧

The Editors

Assessing Technology Needs of "Sub-Economic" Natural Gas Resources: Phase II—the Anadarko and Uinta Basins

By Kelly K. Rose and Ray M. Boswell,
U.S. Department of Energy/National Energy Technology Laboratory;
and Ashley S.B. Douds, James A. Pancake and H.R. Pratt III,
EG&G

Demand for natural gas in the United States continues to grow and is predicted to exceed 30 Tcf/year by the year 2025, an increase of 25% over current demand.

During the past 15 years, drilling for natural gas targets in the United States has more than doubled, while the rate of domestic natural gas production has leveled off and remains nearly flat (Figure 1). One particularly significant economic and technical impediment to increasing the domestic natural gas supply facing producers is the growing need to tap complex, deep and unconventional resources to replace reserves. Despite recent progress in the exploration and production (E&P) of unconventional plays, additional technological advances are needed to significantly expand their economic viability.

The National Petroleum Council (NPC) in 1999 and 2003 recommended the federal government place a high priority on research and development (R&D) that improves the technical and economic recoverability of unconventional natural gas targets. Responding to these and other recommendations, the Strategic Center for Natural Gas and Oil, at the U.S. Department of Energy's National Energy Technology Laboratory (NETL), implements a portfolio of R&D projects designed to enable and accelerate the transition of sub-economic resources into economically-recoverable resources and ultimately reserves.

To help identify R&D approaches with the most promise for expanding resource recoverability, the NETL launched a comprehensive program in 2001 to assess the long-term sustainability of the domestic natural gas supply in the United States. A significant part of this program is the detailed gas-in-place (GIP) characterizations of key basins conducted by the NETL researchers. These resource assessments enable the modeling of the potential changes in economic and technical recoverability of marginal gas resources resulting from different technology advances and policy scenarios. This approach helps the NETL identify the R&D requirements needed to provide incremental technology advances that steadily increase the recoverability of the known resource base, as well as technological "leaps forward" that result in the addition of vast resources previously unknown, overlooked or undervalued.

NETL resource assessments

Industry, academia and government commonly conduct resource assessments to improve their understanding of the recoverability of the nation's natural gas resource base. Historically, these resource assessments have produced a static view of a resource that, in reality, is highly

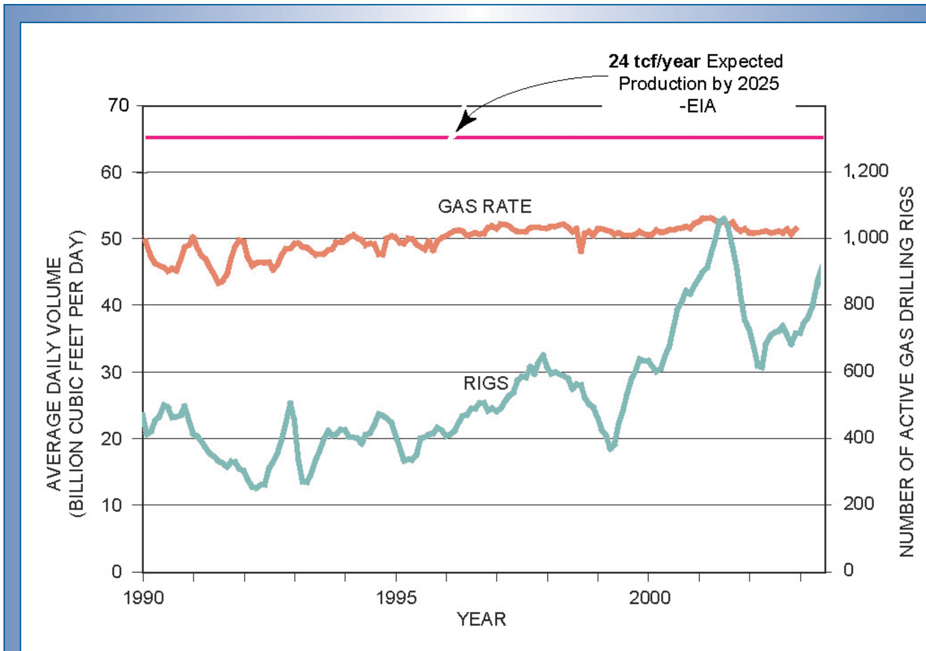


Figure 1. This 1990 graph shows trends of daily domestic gas production (orange) and the number of active gas drilling rigs (teal). (Sources: Energy and Environmental Analysis Inc., GSR and Baker Hughes)

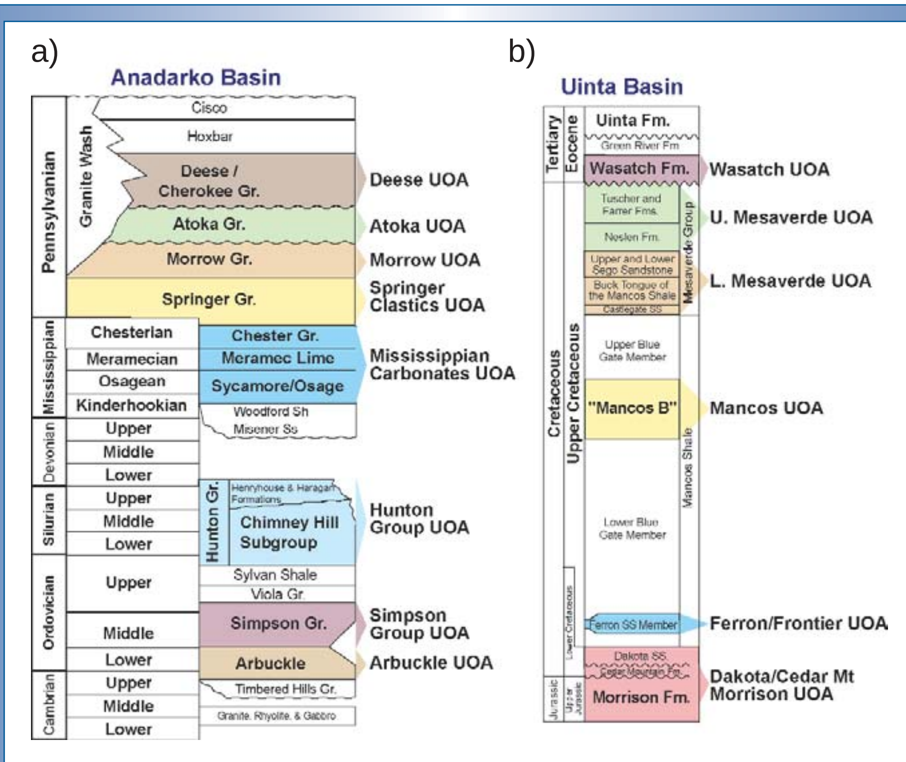


Figure 2. Generalized stratigraphic columns illustrating the stratigraphy included in each of the units of analysis examined in the a) deep Anadarko Basin and b) Uinta Basin gas resource assessments.

dynamic. By design, assessments of technically recoverable resources provide a conservative estimate of potential future resources and exclude vast portions of the nation's in-place resource base. However, it is these excluded resources that future producers will need to review to meet growing demands for natural gas. A recent example that illustrates this reclassification of previously unaccounted gas resources is coalbed methane, which was deemed not technically-recoverable 20 years ago, but now accounts for more than 10% of U.S. natural gas reserves.

The NETL is not interested in producing additional assessments that result in "most-likely" estimates of future technically or economically recoverable resources. Instead, the organization creates detailed GIP characterizations not biased by past or present technology and policy limitations. These assessments are then utilized by in-house computer models to produce unique estimates of future technically or economically recoverable resource volumes for a variety of alternative future technology and policy scenarios, many of which may be considered unlikely at the present.

Phase one of this assessment work, completed in the spring of 2003, assessed the gas resources of the Greater Green River (GGR) and Wind River (WR) basins in Wyoming and Colorado, and were discussed in a Summer 2002 *GasTIPS* article. Phase two examines the natural gas resources of the Uinta and Anadarko basins and is scheduled for completion during the fall of 2004. While much of the approach and methodology for these assessments remains the same, there are aspects of each assessment tailored specifically to the data and technical needs of each basin.

Study area selection and UOAs

Recently published reports and studies have emphasized the significant natural gas resource base of the low-permeability formations in the Rocky Mountain region. As a result, these resources are significant targets and a primary focus of the NETL's R&D program. The importance of these basins is reflected by those initially selected for analysis, including the GGR, WR and Uinta basins. Recent E&P trends also have documented a growing need to tap gas resources in low-permeability and deep formations such as those found within the deep Anadarko Basin. The assessment of the deep Anadarko Basin provided an ideal opportunity to characterize and model the specific advanced technology requirements these high temperature, traditionally higher cost, deeper targets often require.

Once the target basins for phase two were identified, the NETL assessment team reviewed published literature and industry-related data to help identify those strata in each basin that encompass the majority of each basin's under-utilized "deep," unconventional or otherwise sub-economic gas resources. The assessment team then considered regional geology, completion practices, the needs of the NETL models, and time and resource constraints to finalize the selection of each unit of analysis (UOA). These are bundled packets of resource, similar to the concept of a play, that exist in a common geologic condition and are appropriate to characterize within the model as the target of individual wells.

As part of the team's review of the Anadarko Basin, it was recognized that most formations had significant shallow production histories. However, technological constraints have significantly limited the successful exploration, drilling and production of formations at depths greater than 10,000ft measured depth (MD). Therefore, the assessment was limited to areas where each UOA occurred at drilling depths of 10,000ft and greater.

In the deep Anadarko Basin, eight UOAs were chosen for assessment: Deese; Atoka; Morrow; Springer, which is comprised of the Springer clastic facies only; Mississippian, which contains the Springer, Chesterian, Mermecian and Osagean series carbonate facies; Hunton; Simpson; and Arbuckle (Figure 2a).

It is important to note that two additional UOAs, the Granite Wash and the Woodford Shale, were identified as having significant natural gas resource potential. However, given the unique geologic characteristics and assessment requirements of these strata, they were not included in this phase of the study, but have been identified as targets for future analysis.

Geographically, the deep Anadarko Basin study area lies primarily in south central Oklahoma, extending slightly into the Texas panhandle region. The northwestern extent of the study area changes to correspond with the 10,000-ft MD cut off for each UOA. The southern boundary for each UOA corresponds to the structural features of the Wichita Mountain uplift, and erosional and/or structural features related to the Nemaha uplift (Figure 3a) truncate the eastern boundary.

In the Uinta Basin, E&P dominantly has focused upon existing fields and on-trend play extensions. Consequently, much of the deeper Uinta Basin remains relatively unexplored, while significant parts of the shallow Uinta in-place gas resource have been by-passed in favor of more technically and economically desirable targets. UOAs from this basin occur within the Unita structural basin of northern Utah and extend eastward to the Douglas Creek Arch of western Colorado. Uinta UOA boundaries were determined based on a combination of factors including location of outcrops, gas-oil ratio (GOR) trends and shallowest production recorded (Figure 3b).

Detailed reviews of the historical production and basin stratigraphy were completed to select and define the Uinta Basin UOAs. As a result of these analyses, six UOAs were selected for assessment: Wasatch, which includes only the gas-producing interval of the Wasatch Formation; Upper Mesaverde, which consists of the Tuscher, Farrer and Neslen formations; Lower Mesaverde, which contains Sego and Castlegate sandstones; Mancos; Ferron; and Dakota/Cedar Mountain/ Morrison (Figure 2b).

Three UOAs required additional analyses to appropriately constrain and define them. For the Wasatch UOA, GOR calculations conducted using reported production values from the Wasatch Formation throughout the basin were used to exclude dominantly oil-producing areas. In the Mesaverde Group, distinct stratigraphic and petrophysical differences between the upper and lower halves of the group were observed on well logs throughout the basin. If assessed together, the petrophysical differences between these halves would produce distorted average volumetric parameters that poorly represented the Mesaverde as a whole. Therefore, the group was divided into the Upper Mesaverde UOA and the Lower Mesaverde UOA.

Volumetric databases

The goal of each assessment is to produce a detailed, disaggregated database of volumetric characteristics for each UOA that will be utilized by the NETL models for future R&D planning efforts. The general process followed in the development of these datasets for each UOA is briefly described below; however, more detailed discussions of this process are available in the final report publications for each basin.

To characterize and understand the occurrence and distribution of each UOA's lithofacies, hundreds of well log suites were loop-correlated throughout each basin. In addition to the major UOA boundaries, individual sandstone and limestone correlations also were made to ensure the consistency of the broader UOA correlations, and assist mapping and cross-section interpretations. For each UOA, net thickness, potential pay thickness and drilling mid-point/structure maps were constructed (Figure 4). A series of stratigraphic and structural cross-sections (Figure 5) were developed across each basin to illustrate the regional distribution and lithologic nature of each UOA.

Well log suites were analyzed to determine key geologic and engineering parameters for each UOA, including drilling, mid-point depth, "potential pay" thickness, average porosity, v-shale and average resistivity. The goal was to obtain data at a one-well-per-township-area grid scale, but for the older formations, and in the deepest portions of both basins where well penetrations are scarce, this level of data density was not always obtainable. Data collection techniques and analyses also were adjusted to ensure data accuracy and accommodate for differences in lithologies, such as limestones vs. sandstones. Average porosities were determined from the analysis of recent vintage-compensated, density-neutron and bulk-density logs, while net thickness, average resistivity, v-shale and drilling mid-point depth data were obtained from resistivity and gamma ray logs.

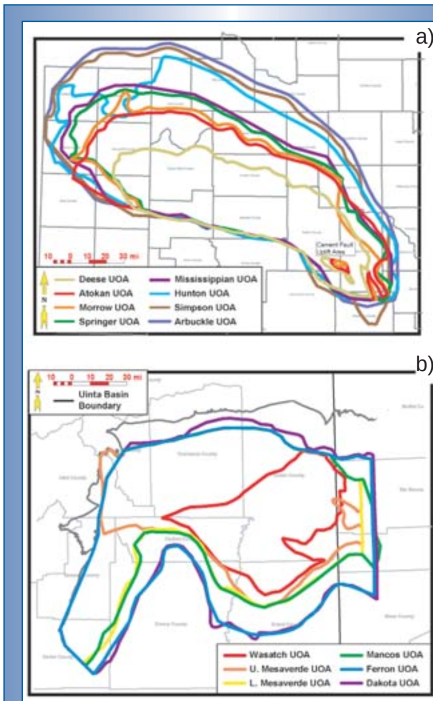


Figure 3. These maps illustrate the geographic limits of each unit of analysis's assessment area in the a) Anadarko Basin and b) Uinta Basin.

Published water resistivity (Rw) databases from the United States Geological Survey (USGS), Society of Petroleum Engineers and the Rocky Mountain Formation Water Database were standardized and used to obtain water saturations for each UOA. Simondoux's equation was utilized for shaley-sandstone reservoirs while limestone and clean

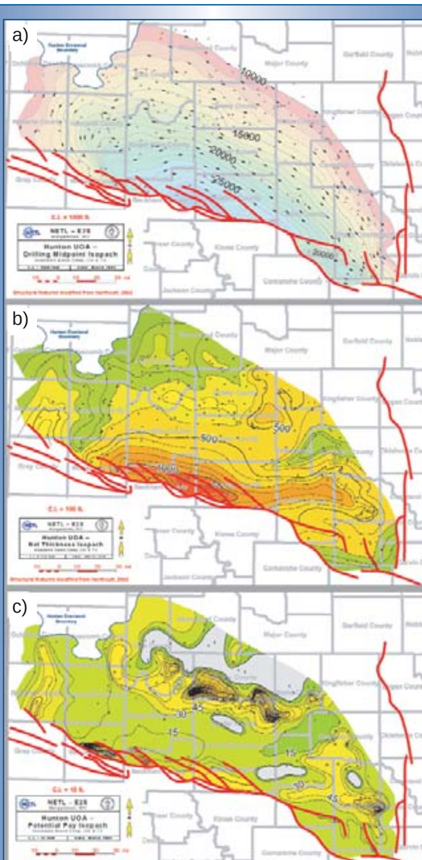


Figure 4. Shown above are example maps from the Hunton unit of analysis (UOA) in the Anadarko Basin. Similar maps were constructed for each UOA in the Anadarko and Uinta basins. (a) depth to drilling mid-point map for the Hunton UOA, Contour Interval (C.I.) = 1,000ft, (b) net thickness map from the Hunton UOA, C.I. = 100ft, and (c) "potential pay" thickness map from the Hunton UOA, C.I. = 15ft.

sandstone water saturations were calculated using Archie. In the Anadarko Basin, each well in the Rw database for a given UOA was used to calculate individual water saturations at that well's corresponding drilling mid-point depth. For cells that did not contain direct Rw data, the temperature-corrected water resistivities were then plotted geographically and extrapolated regionally via contoured interpretations. Water resistivities in the Uinta Basin were determined by averaging temperature-corrected water resistivities data within a township for each UOA. Townships without Rw data were assigned a value based on the average of all Rw values within the same depth range (1,000-ft intervals).

The volumetric parameter potential pay thickness warrants further discussion to differentiate from industry's use of "pay." The term is traditionally equated with the thickness of an interval expected to produce under economic circumstances. Geologists are accustomed to establishing practical reservoir or field-specific cut-offs for porosity (for example 6% or 8%) and water saturation (commonly 60%) when determining pay. However, the goal of these assessments is to create resource descriptions that allow the models to determine what segment of the total resource might be pay as far as 20 years into the future, under cost/technology scenarios very different from what exists. Therefore, aggressive cut-offs of 4% porosity for clastics, 2% porosity for carbonates and 70% water saturation (Sw) were used in defining potential pay in both basins, with the understanding that under most technology/cost conditions, the models will not consider much of this low quality resource to be viable.

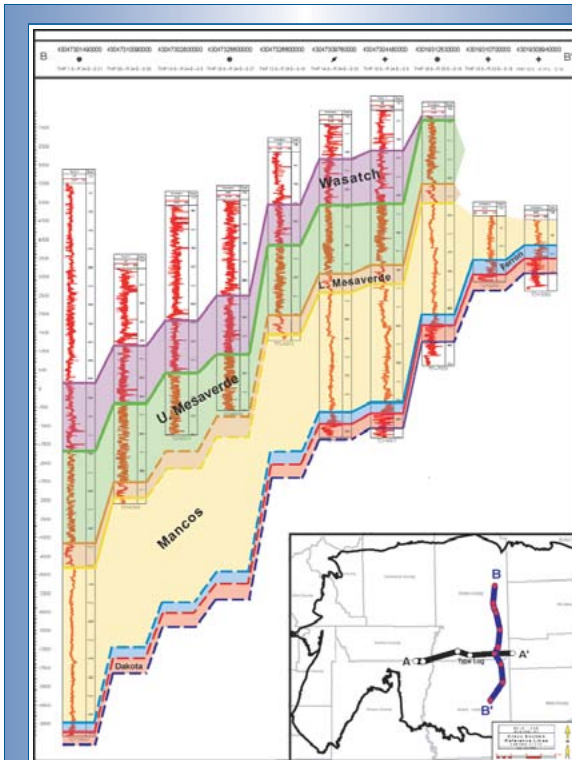


Figure 5. Example structural cross section from the Uinta Basin is shown above.

Temperature gradients for each grid cell in the Anadarko Basin were extrapolated and assigned using temperature gradient contour maps. These maps were produced, as a part of this study, by using temperature gradient data from Cheung (1975) and bottomhole temperatures (BHT) collected from well logs. For the Texas portions of the study, area BHT data were collected and corrected with Cheung's BHT correcton curves. For the Oklahoma portion of the Anadarko Basin, Cheung produced one dataset for the normally pressured rocks and one for the overpressured intervals within the basin. Two temperature gradient contour maps were produced from these data – one for the normally pressured interval and one for the overpressured section. The overpressured section of the study area is of limited geographic and stratigraphic extent, therefore, these data were only utilitzed for intervals where overpressuring was identified.

In the Uinta Basin, average temperature gradient data was collected from the IHS Energy database, corrected BHT well log measurements and the USGS temperature data. Average temperature gradients were then contoured throughout the basin to determine values in undrilled areas. Final temperature gradients compared favorably with published values for the Uinta Basin from the USGS.

Pressure data were collected from Oklahoma State's "Pressure Data on the Anadarko Basin" Web site, the IHS Energy database and the USGS. In both basins, the pressure information consisted of pressure measurements and gradients for specific formations from a variety of sources such as drill stem tests and wireline formation tests. These data were plotted geographically and used to generate average pressure gradients for townships with more than

	Anadarko Basin UOAs							
	Deese	Atokan	Morrow	Springer	Mississippian	Hunton	Simpson	Arbuckle
Area (thousands of acres)	2,650	1,509	3,672	4,328	2,340	3,773	9,007	6,285
Avg. Thickness (ft.)	105	81	93	131	359	41	152	77
Avg. Porosity (%)	7.6	8.3	6.2	8.7	4.0	4.2	8.3	5.5
Avg. Water Saturation (%)	49	47	41	16	55	48	41	48
Avg. Drilling Depth (ft.)	12,710	13,695	14,475	16,072	14,068	16,704	16,581	19,475
Avg. Pressure (psi)	6,747	7,437	8,834	10,026	7,148	7,278	6,819	9,097
Avg. Temperature (°F)	152	167	288	339	178	207	207	241
Avg. Z-Factor	1.14	1.19	1.28	1.36	1.16	1.17	1.13	1.25
In-place Resource (TCF)	181	102	188	609	260	52	931	207
Resource below 15,000' (TCF)	10	35	87	484	126	29	536	186

	Uinta Basin UOAs					
	Wasatch	U.Mesaverde	L.Mesaverde	Mancos	Ferron	Dakota
Area (thousands of acres)	1,616	4,382	5,210	5,581	4,496	5,838
Avg. Thickness (ft.)	158	713	107	77	47	38
Avg. Porosity (%)	10.3	7.8	7.1	5.9	6.7	7.9
Avg. Water Saturation (%)	42	43	47	62	62	58
Avg. Drilling Depth (ft.)	4,257	10,146	10,958	11,605	13,828	11,981
Avg. Pressure (psi)	2,131	5,157	5,529	5,834	6,972	5,938
Avg. Temperature (°F)	147	247	264	279	320	304
Avg. Z-Factor	0.87	1.06	1.09	1.10	1.17	1.12
In-place Resource (TCF)	90	1,188	192	104	75	70
Resource below 15,000' (TCF)	N/A	147	45	21	13	17

Table 1. Preliminary gas-in-place values and average volumetric parameters shown are calculated for each unit of analysis assessed in the Anadarko and Uinta basins.

one data point. These gradients were then gridded across each UOA and combined with drilling mid-point depths to generate pressure profiles for each grid cell and compared with published pressure gradients to assess their validity.

The final reservoir parameter required for the model dataset is an estimation of the total effective permeability (TEP) for each potential well location in each UOA. This effort is under development for both basins. To date, permeability data have been obtained from reported core perms and detailed production/decline curve and log character analyses conducted by Advanced Resources International. Final TEP distribution in each township will reflect the histogram distribution of permeability data calculated from the analysis.

Data collected for each UOA are used to create a detailed, geographically and stratigraphically disaggregated database of volumetric parameters. The comprehensive and compartmentalized nature of this new dataset helps capture the natural variation in drilling, depth, porosity, water saturation, pressure, temperature and permeability for each UOA. Gas-in-place volumes for each UOA in both basins were calculated using this data. The NETL modelers will utilize the database to determine the relative success of future technologies in economically accessing this gas resource base.

Calculations and values

Gas-in-place values and average volumetric parameters were calculated for each UOA in both basins. The previously collected volumetric data were gridded at the township scale across the basin for each UOA. Z factor values, a volumetric parameter that describes the compressibility of natural gas under specific temperatures and pressures, were calculated using the gridded pressure and temperature values and a gas gravity value of 0.6 for each UOA.

These parameters were used to calculate the GIP value for each grid cell in each UOA. Grid cells with water saturations above 70%, or porosities less than 4% for clastics or 2% for carbonates, were eliminated from the GIP calculation as were areas of significant historical production. Grid cells with remaining GIP values were summed to determine the total GIP for each UOA. Using this methodology, geographically and stratigraphically disaggregated GIP volumes were calculated for each UOA (Table 1).

Continuing and future work

The deep Anadarko and Uinta basins' resource assessments have an anticipated completion date for early fall 2004 and will conclude with the publication of a detailed final report. This report will be made freely available on the NETL Web site at *www.netl.doe.gov* through the "publications" link.

The data from these studies will be used internally by the NETL analytical models to determine what portion of the GIP resource is technically and economically recoverable under a variety of technology/cost scenarios. The results of these models will be used with other available reports and studies to determine what technologies and policies will have the greatest impact on reassuring the viability of the U.S. natural gas resource base for decades to come. It is anticipated that additional basins will be chosen for resource characterization and assessment of marginal and subeconomic gas resources upon completion of the current work. ✧

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Better Characterization of Unconventional Gas Reservoirs

By Carrie Decker,
Gas Technology Institute

To reduce the time and cost of reservoir characterization, identify key parameters that affect production and streamline the characterization workflow to focus on those parameters.

Reservoir characterization was given high or top priority for all regions when operators and research providers discussed the key research and development (R&D) needs for unconventional gas-producing basins across the United States in 2002. These regions included the San Juan Basin, the Permian Basin, the southern Mid-continent, West Virginia and the Rocky Mountains.

Successful reservoir characterization results in guidelines for reducing the risk in siting new wells, applying optimal completion and stimulation technologies, and recovering bypassed gas because of compartmentalization and prior production. Most commonly, "reservoir characterization" is used to describe the integration of geological, geophysical and production data and analyses to characterize reservoir properties in three dimensions.

However, the available data for reservoir characterization vary dramatically from field to field, the specific objectives that need to be met may differ, and a myriad of paths and any number of technologies can be used to get from the input to the objectives. At its most complex, reservoir characterization can become a costly and time-consuming task. For many operators in unconventional gas-producing areas, time and money are at a premium, so reservoir characterization becomes an under-used tool.

To reduce time and cost associated with characterizing unconventional gas-producing reservoirs, it helps to identify key parameters that most dramatically affect production and streamline the reservoir characterization workflow to focus on these parameters. Past studies have helped determine key parameters for different unconventional gas reservoir types, including fractured gas shales, coalbed methane, tight gas sands and deep gas (15,000ft). From published studies, it has become apparent a different set of parameters controls production for each different reservoir types. With continuing study, and the understanding that unconventional gas reservoir characterization needs differ from those for conventional gas, the lists of key parameters can be refined.

Parameters

Fractured gas shale—Key parameters affecting production from fractured gas shale include:

- drainage area size, shape and orientation;
- fracture vs. matrix porosity;
- permeability;
- anisotropy;
- fracture length, spacing and conductivity;
- relationship between natural and induced hydraulic fractures; and
- mechanical properties.

Of these, natural fracture characteristics dominate production control. Since individual fractures may be limited in lateral and vertical extent, multiple fracture sets, forming a three-dimensional permeability network, are important for good production. In some fields (like in some Devonian shales), lithologic variations do not seem to significantly impact production. Gas porosity and kerogen content, however, may contribute to productivity.

Coalbed methane—For most coalbed methane, regardless of geographic area, the key parameters are:

- drainage area, thickness of producing zone(s);

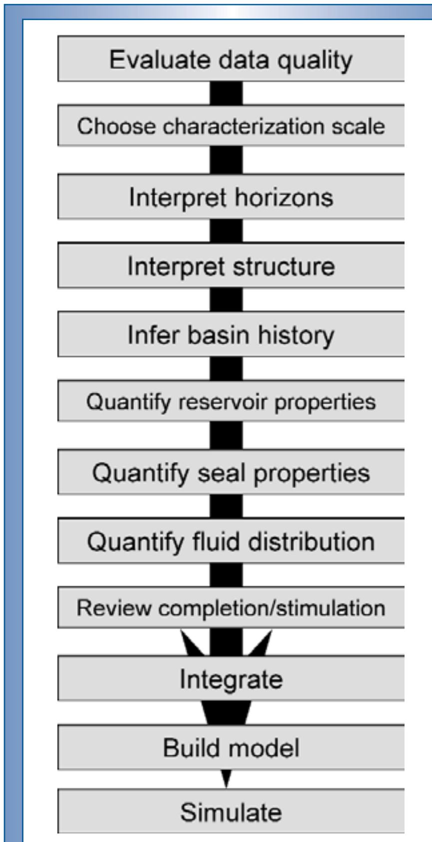

Figure 1. A generalized reservoir characterization workflow.

- coal depositional environment and rank, which may correspond to structural trends;
- cleat porosity;
- radial permeability;
- stress state, which coupled with cleat orientation, may indicate a preferred direction for permeability or may influence fracture treatment design;
- sorption characteristics;
- gas properties; and
- hydrodynamics.

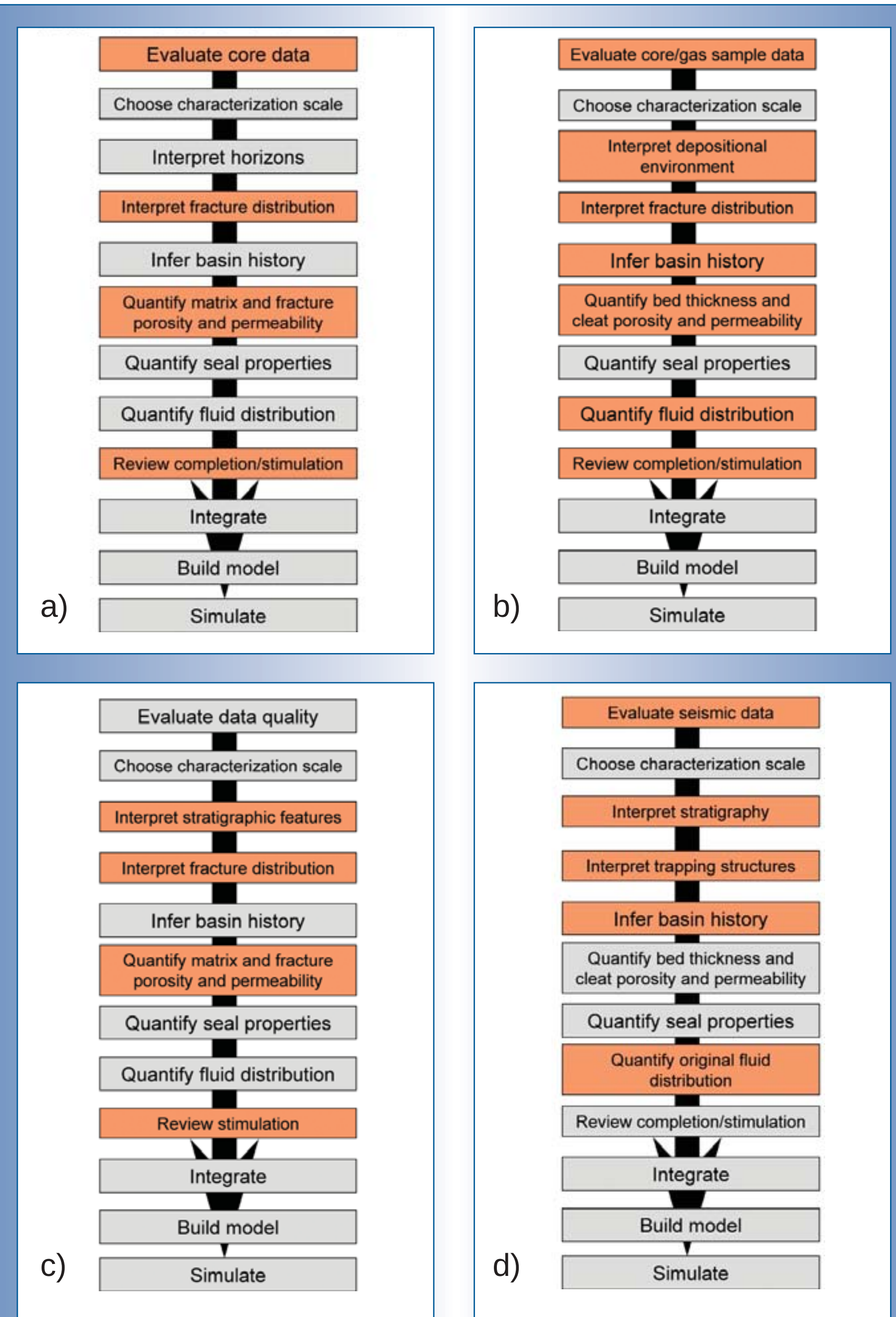

Figure 2. Reservoir characterization workflows for four unconventional gas types – fractured gas shale (a), coalbed methane (b), tight gas sand (c) and deep gas (d). Steps that focus on key parameters for each unconventional gas type are highlighted in orange.

Correct evaluation of gas-in-place—This may be calculated from gas content, which may be correctly predicted by depth for a given coal rank. Correct prediction of gas content from depth may depend on understanding the complex geologic history for a given basin. Measurement of gas content may be problematic; there is a growing concern existing measurements often under-estimate the resource.

Association with tight gas, fractured shales—The idea of treating these groups of associated unconventional gas types as a package that can be jointly considered a resource, and developed with a plan that optimizes exploitation of all types simultaneously, is coming under discussion.

A study that tested the sensitivity of production to several of the parameters listed on the previous page determined that, in a field in the Fruitland coal, the most critical parameters were cleat permeability, gas content and the adsorption isotherm. But, to highlight the complexity of coalbed methane reservoirs, one example from the Rockies shows a variability in absolute cleat permeability from 0.1 millidarcies (md) to 50 md, in gas content from 100 scf/ton to 500 scf/ton and in reservoir pressure from 200 psia to 1,600 psia.

Tight gas sand—The key parameters controlling production are:

- stratigraphy and structure;
- porosity and permeability;
- fracturing parameters: length, spacing, connectivity and anisotropy; and
- mechanical properties.

In the Rockies, channels have not only been shown to be associated with sweet spots in tight sands, but may be linked to elevated natural fracture distribution.

Deep gas—Deep gas (greater than 15,000ft) is different from other unconventional gas types in that it encompasses a range of structural and stratigraphic styles. In the Rockies, compartmentalization of reservoirs and structural traps are important. In the Mid-continent, source availability and local/historical thermal profiles may play a role. Offshore – an area receiving a great deal of attention – stratigraphic traps may play a critical role, and understanding depositional and charge history is critical. Because few wells have been drilled to depths greater than 15,000ft (less than 5% of all wells drilled on the Gulf of Mexico shelf, according to 2001 data), much of the available information draws from seismic data. In all cases, pressure compartmentalization may be an issue.

In general, the key parameters that must be identified for successful reservoir characterization of deep gas include:

- trap type, structure and stratigraphy;
- porosity, permeability and saturation;
- pressure and temperature; and
- charge and gas chemistry.

The workflow

A reasonable generalized reservoir characterization workflow that could be applied to most oil- and gas-producing fields should contain the following steps:

1. Evaluate quality of core, gas sample, well log, seismic, production, well test and/or other data.
2. Choose appropriate vertical and lateral scale for characterization, depending on available data for input and scale of reservoir heterogeneity that has an impact on production.
3. Interpret form of horizons of interest to define reservoir or vertical seal continuity, and determine morphology inherited from original depositional environment, such as fluvial channels.
4. Define structure, particularly where this has an impact on trapping, fracture distribution or compartmentalization.
5. Infer basin deformation and/or thermal history.
6. Quantify, in three dimensions, changes in reservoir thickness, lithology, matrix and fracture porosity, and permeability.
7. Quantify vertical and lateral baffle or seal properties.
8. Review well completion and stimulation strategies.
9. Quantify original and current fluid distribution.
10. Integrate geological, geophysical, and engineering data and analyses.
11. Build geocellular model at appropriate scale.
12. Simulate, matching production history and predict performance.

Having identified the key parameters for an individual unconventional gas reservoir, a generalized reservoir characterization workflow suitable for any reservoir can be modified to "hit the high points" (Figures 1 and 2).

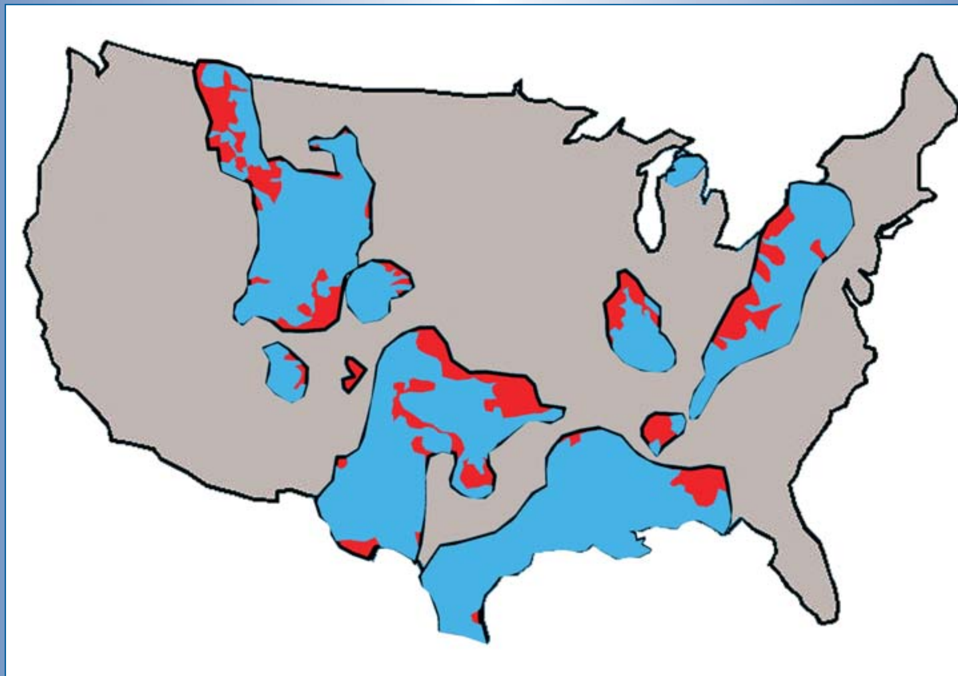

Figure 3. Known or inferred extent of unconventional gas resources (in red), including fractured gas shales, tight sands, coalbed methane and deep onshore gas. Areas of unconventional gas resources covered by existing 2-D or 3-D seismic data (with a density of about 10 lines per county or greater) are shown in blue.

Technologies

New technologies that can be used to enhance reservoir characterization are constantly being developed. Of these, some of the most widely useful are seismic-based. The use of seismic-based technologies goes hand-in-hand with two other R&D needs identified in the development of the 2002 roadmap: reservoir imaging and data mining.

Unfortunately, not all unconventional gas fields are already covered by 2-D or 3-D seismic (Figure 3). Existing data also may not be of sufficient quality to extract the information needed to explore deeper fields or develop complex fields at a finer scale. The acquisition of new seismic data can be cost-prohibitive or logistically challenging in some areas. It is difficult to sell the idea of acquiring new data over a fractured gas shale field, for example, where conventional "bright spot" technology does not work well and where exploration through the drillbit is more cost-effective. As new ways of using seismic data provide more information in more environments, and with an ever-changing economic climate, acquisition of new seismic data may again become attractive.

Seismic-based technologies that meet the needs to characterize key unconventional gas parameters identified above include the following:

- high-frequency seismic, for mapping thin beds;
- crosswell seismic, locally for mapping thin beds – the usefulness of this technology in coal beds is being explored;
- multicomponent seismic, for characterizing fractures and fracture anisotropy;
- time-lapse, for highlighting changes in fluid distribution;
- stochastic fluid modulus inversion (such as FluidPro[SM], see Tools for Improved Reservoir Characterization), for evaluating the reliability of information derived from seismic, and, in certain circumstances, for predicting fluid distribution;

- spectral decomposition (such as InSpect℠, see Tools for Improved Reservoir Characterization) for mapping seismically thin beds, demonstrating changes in bed thickness, identifying stratigraphic features such as channels, and mapping small-scale structures or discontinuities that compartmentalize the reservoir, fluid distribution and changes in reservoir quality.

Conclusions

Key parameters can be identified for different unconventional gas reservoir types that have the most influence on production. The need to quantify these parameters dictates technologies should be used to describe changes in these properties across the reservoir, including between wells, as well as the focused reservoir characterization workflow.

Seismic-based technologies are one of the most rewarding in terms of determining interwell properties in areas where it is economically feasible to collect seismic data. The range of areas over which acquisition of seismic data is worthwhile is growing.

Additional experience will further constrain those parameters that exert the most influence on production and target workflows appropriate for unconventional gas reservoirs.

Targeted workflows optimize time and cost, improving reservoir characterization as a tool for producers.

For more information about this topic, contact Carrie Decker, geophysicist with the Gas Technology Institute, via phone: (281) 873-5050, ext. 28 or e-mail: *carrie.decker@gastechnology.org* ✧

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Tools for Improved Reservoir Characterization

InSpect

This is a wavelet-transform-based spectral decomposition technology that optimizes resolution vertically, laterally and in terms of frequency. By showing improved resolution laterally over conventional seismic data, spectrally decomposed data can be used to interpret small-scale reservoir changes or discontinuities that contribute to compartmentalization. Improved resolution vertically means this technology can be used to deliver useful information about reservoir discontinuities and thickness, even in seismically thin beds (in practical terms, typically down to about 16.4ft). Elevated resolution in the frequency domain has allowed InSpect to be applied successfully in conventional gas reservoirs to detect hydrocarbons.

Gas, for example, illuminates at a higher tuning frequency than brine; attenuation of high frequencies by gas-bearing units also can be interpreted from spectrally decomposed data if the frequency resolution is sufficiently high.

The tuning frequency of a particular reservoir depends not only on thickness and fluid content, but also on rock properties as well. This technology has provided valuable information about changes in reservoir quality when calibrated against well data.

FluidPro

This stochastic fluid modulus inversion is a statistical comparison of real and synthetic seismic attributes, using all known or inferred information about a reservoir unit, to quantify the probability of a particular fluid modulus and fluid density at a given point in the reservoir. It can be used as a risk analysis tool in conventional reservoirs to quantify the uncertainty in finding gas vs. brine, but it is most effectively used to assess the value of seismic attribute data as a hydrocarbon indicator in tighter sands.

An Integrated 3-D Seismic Fracture Interpretation Methodology for Tight Gas Reservoirs

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GeoSpectrum, Inc.

GeoSpectrum, Inc. conducted a tight gas exploration and development study in which a 3-D seismic interpretation method for fractured sandstone reservoirs was established.

The interpretation method is based on a comprehensive reservoir characterization of the Lower Dakota sandstone in a gas-producing unit in Rio Arriba County, NM.

The following reservoir attributes are used:

- **seismic lineament mapping** predicts reservoir fractures in the reservoir section;
- seismic **interval velocity anisotropy** investigates fractured reservoir potential in tight sands up-hole from the main reservoir target;
- a **collocated cokriged clay volume map** for the Lower Dakota, along with additional geologic attributes, screen lead areas defined by regions of "swarming" multi-directional lineaments; and
- a gas-sensitive amplitude variation with offset seismic attribute, near trace stacked phase minus far trace stacked phase, **phase gradient,** is used to further define drill locations having high gas saturation.

A four-well drilling program recently was completed to test the fractured gas reservoir prospects and exploration technology. The nearly 100% success ratio of the drilling program indicates the fracture detection method is ready for commercial application.

Fracture detection methodology

Lower Dakota fractures/seismic lineaments—Reservoir fractures are predicted using multiple azimuth seismic lineament mapping in the reservoir section. A seismic lineament is defined as a linear feature seen in a time or horizon slice through the seismic volume. For lineament mapping, each lineament must be recognizable in more than one seismic attribute volume. Seismic attributes investigated include coherency, amplitude, frequency, phase and acoustic impedance. It has been interpreted that areas having high seismic lineament density with multi-directional lineaments are associated with high fracture density in the reservoir (Figure 1). For the purpose of anonymity, the names of the wells referenced in this paper have been truncated to the last two numerical digits.

The application of azimuth dependent prestack time migration to increase spatial resolution should significantly enhance the ability to accurately map seismic lineaments. Note the concentrated number of lineaments found at **well 28**, one of the most prolific wells in the unit. Borehole breakout indicates present-day maximum horizontal tectonic stress in nearly a north-south direction. This orientation does

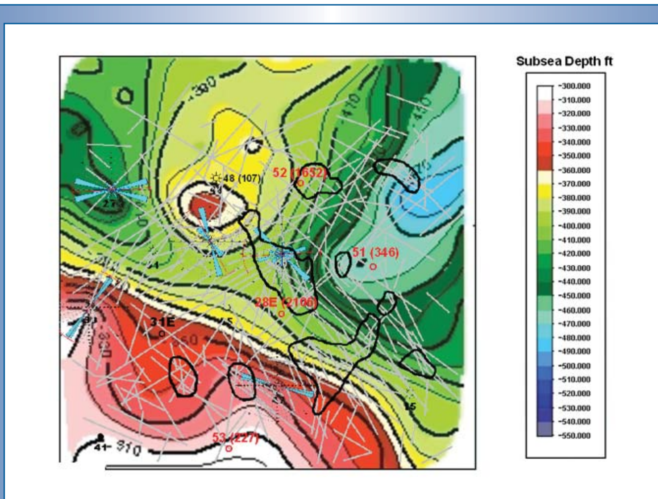

Figure 1. Seismic lineaments (silver lines) superimposed on structure contour map of the Lower Dakota (based on 3-D seismic and unit wells drilled pre-1999). Blue rose diagrams indicate fracture orientation determined from borehole image logs in the Dakota.

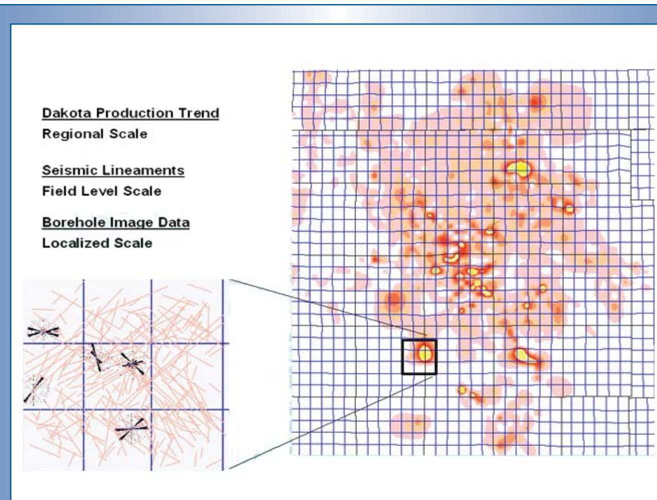

Figure 2. *Dakota production map with inset detailing showing lineaments (pink lines) and rose diagrams (black symbols) indicate fracture orientation from all three scales of data are in agreement showing a classic "fractal-like" dependence of the data. (map courtesy of Charles F. Head, Burlington Resources, 2001)*

not preferentially close any fractures oriented in the northeast or northwest directions. These fracture orientations should be available for fluid or gas flow in the unit. However, borehole breakout data in a well to the southeast and off the map indicates a change in maximum horizontal stress orientation to the northeast.

A number of leads can be distinguished from Figure 1 from the anomalous clusters of multi-directional lineaments. Lower Dakota structure appears to play a strong role in lineament orientation. The swarming effect of many of the seismic lineaments is associated with structural troughs and noses seen in the Lower Dakota corrected seismic structure map.

Figure 2 defines fracture-related reservoir anisotropy on three different scales of data:

- localized scale/rose diagrams show Lower Dakota fracture orientations interpreted from borehole image logs;
- a field-level scale from seismic lineaments; and
- a regional scale from Dakota cumulative production trends.

Inferred fracture orientations from all three scales of data are in agreement showing a classic "fractal-like" dependence of the data at different scales.

Upper Dakota fractures/ interval velocity anisotropy—Seismic **interval velocity anisotropy** is used to investigate reservoir potential up-hole from the main reservoir target. It is interpreted that large interval velocity anisotropy is associated with fracture related anisotropy.

Figure 3 shows a seismic-guided Upper Dakota fracture density map modeled from Dakota fracture counts measured from borehole image logs for five wells. Fracture density mapping is done with collocated cokriging using interval velocity anisotropy (correlation coefficient 0.6). Interval velocity anisotropy is computed as Dix's interval velocity for 145 ± 22.5° azimuth data minus the interval velocity for 55 ± 22.5° azimuth data. The increase in signal:noise ratio obtained by prestack time migration has improved the ability to perform this analysis. Interval velocities were computed for a zone between two strong seismic reflectors, including most of the Upper Dakota from the top of the Lower Cubero to the top of the Green Horn immediately above the Dakota. This analysis is used to infer prospective Upper Dakota fractures.

Fractured reservoir prospects

Lower Dakota clay volume/seismic amplitude AVO attribute—Lead areas defined by regions of swarming multi-directional or intersecting lineaments should be further screened by additional geologic attributes, including reservoir isopach thickness, indicating thicker reservoir section; seismic horizon slices, imaging potentially productive reservoir stratigraphy; a **collocated cokriged clay volume map computed from near trace seismic amplitude** (an amplitude variation with offset – AVO – attribute); and a comprehensive petrophysical analysis of the well data to determine discrete values of clay volume at each well. It has been interpreted that clean/low clay reservoir rock is brittle and likely to be highly fractured when seismic lineaments are present.

In Figure 4, a seismic-guided Lower Dakota clay volume map based on petrophysical analysis of log data from nine wells drilled pre-1999 is shown. Seismic-guided mapping is done with collocated cokriging using the average near trace instantaneous seismic amplitude from a narrow zone (about 3 milliseconds) in the Lower Dakota (measured cross correlation = 0.8). Note that the horizon defining this zone is the same as that used to define the phase gradient AVO attribute described later in this article. The phase gradient and near trace amplitude are AVO attributes. Two distinct rock types are defined by the map: low clay (less than about 13%) shown by hot colors and high clay (greater than about 13%) shown by cooler colors. This article focuses on low clay reservoir and regions of swarming/intersecting lineaments.

In the figure, notice the unique directional distributions for seismic lineaments as a function of rock type, low vs. high clay. Lineaments in the northeast direction are shown in red and in the northwest direction in green. Low clay rocks are associated with lineaments in the northeast direction, and high clay rocks are associated with lineaments in the northwest direction. It is not surprising that the two rock types have differing distributions of lineaments. Their differing strength characteristics, rock fabric, regional geometry or shape of the rock masses and how the two interact with each other during their tectonic stress history control fractures in these two rock masses.

Modeling the state of stress underground using a finite element or finite difference method should test results. One would expect to see an appropriate change in stress trajectory in moving from one rock mass to another that would yield the different fracture distributions.

Note the orientation of fractures inferred from the Upper Dakota interval velocity anisotropy (Figure 3). Most of the values are

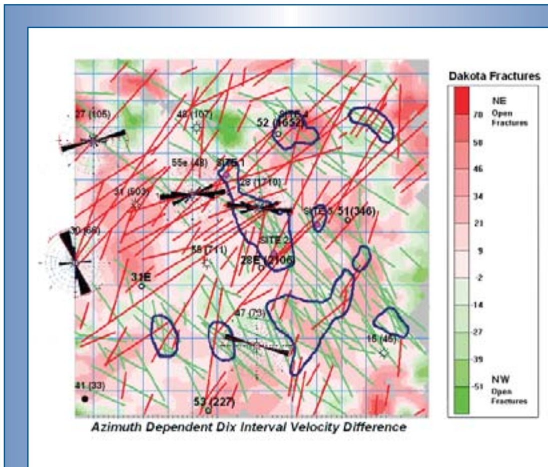

Figure 3. Collocated cokriged Dakota fractures map using seismic interval velocity anisotropy in the Upper Dakota/Green Horn fracture counts from borehole image data measureed in unit wells drilled pre-1999. Black rose diagrams indicate fracture orientations determined from borehole image logs in Upper Dakota.

shaded in red on the map, which may indicate an abundance of northeast trending fractures. If the anisotropy is related to fracture counts, it can be concluded that northwest trending fractures (green) are not as common as northeast trending fractures. Therefore, the distribution of fractures in the Upper Dakota over the study area appears to be more similar to the distribution of seismic lineaments or fractures in the Lower Dakota for the clean low clay rock type (Figure 4). Their differing depositional environments and tectonic history should explain the differences between the Upper and Lower Dakota fracture distributions. The Lower Dakota are non-marine fluvial channel sands, whereas the Upper Dakota are mostly marine shoreline sands. Each of these units should have differing rock types and geometries that effect fracture distributions.

Gas prediction/seismic phase gradient AVO attribute

Gas production data is analyzed using a cross plot showing hydrocarbon pore volume vs. porosity-thickness and the best of 12 months of gas production. Significant or good wells in the study area are distinguished by a gas saturation cut-off of about 33%. There appears to be a random correlation between the best of 12 months of production indicator for the good wells and reservoir volume (porosity-feet), indicating a fracture-controlled reservoir. (In other words, production quality does not increase linearly with reservoir volume.)

A gas-sensitive AVO seismic attribute, near trace stacked phase minus far trace stacked phase, **phase gradient** used to further define drill locations having high gas saturation (correlation coefficient 0.9). The importance of this attribute cannot be understated, as reservoir fractures enhance reservoir permeability and volume, they also may penetrate water-saturated zones and be responsible for the reservoir being water wet and ruined.

Figure 5 shows seismic-guided Lower Dakota gas saturation computed from the phase difference attribute where estimated Lower Dakota clay content is less than roughly 13%. Seismic-guided mapping is done using collocated cokriging and the empirical trend line for low clay reservoir (phase difference vs. gas saturation) from unit wells drilled pre-1999. Gas saturations between about 33% to 60% (determined from petrophysical analysis) define a prospective trend for Lower Dakota fracture-controlled gas production in the unit. The lower end gas cutoff (33%) is interpreted from the cross plot of hydrocarbon pore volume vs. porosity thickness and best of 12 months of production indicator. The high-end gas cutoff (60%) comes from the hydrocarbon pore volume determined for the significant gas-producing unit wells (numbers **28, 55** and **31**).

Two prospective trends that correspond to regional Dakota production are indicated in the northwest and northeast directions. Notice that more favorable gas/AVO attributes are typically found regionally on the updip side of the map. The **well 52** prospect has nearly identical phase difference attributes or a computed "gas saturation" as well 28, indicating similar AVO characteristics. In practice, it is recommended the AVO attributes should be reviewed in the common midpoint offset domain before any prospect is drilled to further confirm the AVO phase gradient mapping. **Well 55E**, which was drilled between the productive wells 31 and 28, is not shown to be prospective, which collaborates with its poor completion results. The fractures at this well may have been responsible for providing a plumbing system for water to get into the Lower Dakota reservoir.

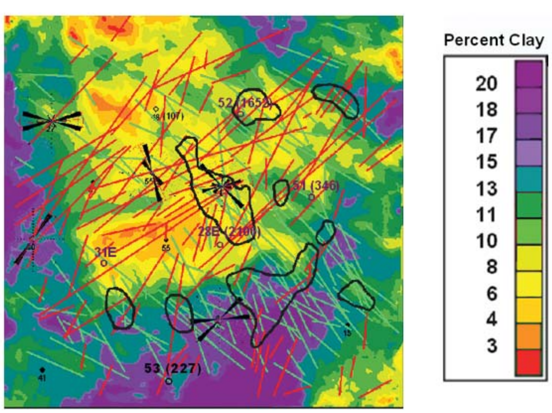

Figure 4. *Collocated cokriged Lower Dakota clay volume from unit wells drilled pre-1999 indicating prospective regions defined by low clay reservoir in areas of swarming/intersecting lineaments associated with low clay (northeast azimuths) and high clay (northwest azimuths).*

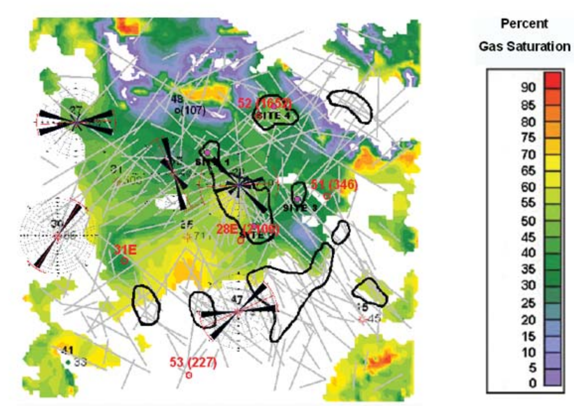

Figure 5. *Collocated cokriged Lower Dakota gas saturation from unit wells drilled pre-1999 showing the well 52 prospect to have nearly the same phase gradient AVO response/gas saturation as well 28 (a significant Lower Dakota gas producer). The phase gradient/computed gas saturation also explains the poor production encountered by well 55E.*

Seismic modeling has not confirmed the empirical relationship of the seismic phase difference attribute and gas saturation. Additional work could be done using full-wave equation AVO modeling to analyze the observed relationship. The gas saturation mapped in Figure 5 should only be used to define prospective trends for gas production, not for actual gas saturation values.

Future work should include evaluation of channel images from horizon slices through the seismic volume near the AVO horizon, which is near the gas. The interpretation should provide important additional information as to the role of channel stratigraphy and trapping mechanism.

In summary, the phase gradient attribute shows all three pre-1999 significant unit wells (numbers 28, 31 and 55) in the Encinal Sand as gas bearing. It explains the poor results of nearby well 55E as gas not being present. Also note the low clay and high clay rock types (good vs. poor reservoir quality) in the Lower Dakota are distinguished in three different seismic attributes that confirm and unify the interpretation:

- near trace seismic amplitude (Figure 4);
- seismic lineament orientation (Figure 4); and
- phase gradient/AVO characteristics (Figure 5).

The gas-sensitive AVO attribute has defined a prospective fairway through the unit in the Lower Dakota sandstone (Figure 5) with successful recent drilling results.

Selected prospects

Overlaying the Lower Dakota phase gradient attribute with the seismic lineament map develops prospects. A prospective fairway is defined where Lower Dakota gas saturation is between 37% to 62% and clay volume is less than 13%. Three prospects (wells 52, **28E** and **31E**) are chosen to drill on swarming/intersecting lineaments in the fairway. Well 52 tests attributes near the northeast edge of the fairway, Well 28E tests attributes near the central region of the trend, and well 31E tests attributes near the southeast edge of the prospective fairway. The fourth prospect, **well 53**, is selected to test a swarm of seismic lineaments close to the southwest/central edge of the 3-D seismic coverage. However, well 53 does not have favorable AVO attributes. The four prospect locations (wells 28E, 31E, 52 and 53) are shown in Figure 5, and are spotted on or near lineaments or intersection points of the lineaments. Note that depending on drilling results, a number of other locations would justify drilling if the reservoir constraints can be relaxed and locations picked based mainly on the phase gradient AVO attribute.

Well No.	Date Completed	Clay Volume (AVO Attribute)	Seismic Lineament Density	Gas Saturation (AVO Attribute)	Seismic Velocity Anisotropy	Initial Production (MCFGPD)
52	01/2004	Low	High	High	High	4000
53	04/2004	High	High	No AVO Attribute	High	Declined to about 230
28E	05/2004	Low	High	High	Low	2100
31E	06/2004	Low	Low	High	Low	850 – 2000 (Estimated)

Table 1. Conclusions/prospect drilling results.

Drilling results

Burlington Resources and Huntington Energy drilled and completed the well 52 prospect in January. The well had an initial potential of nearly 4,000 Mcfg/d and is flowing about 850 Mcfg/d to 900 Mcfg/d (Table 1). The three additional prospects also have been drilled. Well 28E was drilled and completed in May and is producing greater than about 2,100 Mcfg/d, and no significant decline in production has occurred. Well 31E was drilled and completed in June and is expected to produce from roughly 850 Mcfg/d to greater than 2,000 Mcfg/d. Burlington Resources and Huntington Energy recently have laid pipe to the well to sell the gas. The fourth well, No. 53, was drilled and completed in April and initially produced about 2,000 Mcfg/d and is now only producing about 230 Mcfg/d. This well has favorable seismic lineament (fractured) reservoir attributes, however it does not have a good AVO (gas) attribute. Based on Neutron Density log crossover, the well may be producing most of its gas from a different reservoir, the Burro Canyon sandstone, underneath the productive Encinal Sand found in the Lower Dakota wells. It has been predicted that reservoir fractures initially enhanced the gas production in this well, but its rapid decline is caused by the predicted lack of gas in the reservoir.

Conclusions

The three productive unit wells (28, 55 and 31) and the productive new prospect wells (28E, 31E, 52 and 53) completed this year, appear to be predicted with nearly 100% success (Table 1) using the following methodology to explore for Lower Dakota gas:

- locate well in or near alluvial sand channels;
- Lower Dakota clay content less than or equal to roughly 13%;
- AVO attribute indicating phase difference between -15° to -85° (gas saturation about 37% to 62%);
- spot well near intersecting or swarming seismic lineaments; and
- look for up-hole fracture potential using Upper Dakota interval velocity anisotropy.

The authors have interpreted that natural fractures indicated by seismic lineaments have enhanced gas production. The drilling of the prospect wells and the economic discovery of gas in three prospects validates the results of the Phase I, U.S. Department of Energy (DOE) study. These drilling results confirm the value of the applied methodology in detecting commercial and prospective targets in fractured tight gas sands. An automated approach could be developed to apply the technology.

For more information, please contact GeoSpectrum's principal investigator, Dr. James J. Reeves, at (432) 686-8626 ext. 101 or *jreeves@geospectrum.com*, or the DOE technical contract officer, Frances C. Toro at (304) 285-4107 or *frances.toro@netl.doe.gov* ✧

Program Planning and Field Operations Protocols for Coalbed Methane and Shale Gas Reservoirs in Canada

By James A Lee,
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GTI E&P Services Canada

Lessons learned in U.S. and Australian production of gas from coalbeds and shale formations can be used to optimize such operations in Canadian formations of the same kind.

Exploration drilling for unconventional gas targets is complicated, often requiring knowledge about a range of techniques, equipment and engineering methods. To accommodate the unique nature of coalbed methane and shale gas reservoirs, modifications to existing oil and gas drilling techniques often are necessary.

Development of coalbed methane and shale resources in Canada still is in the relatively early stage, and information related to successful exploration procedures is limited. As a result, GTI E&P Services Canada Inc. – an affiliate of Gas Technology Institute (GTI) – compiled guidance on practices and procedures shown successful in the United States and Australia that can be used or adapted to successfully complete drilling programs and produce gas from Canadian coalbed and shale resources.

Well planning

Well planning starts with identification of specific well objectives and ends with a safely drilled well. The process requires the integration of the skills, knowledge and experience of engineers, geologists, geophysicists, accountants and other corporate professionals. It is the task of this drilling team to establish geologic and reservoir objectives, and accomplish them at minimum cost in the safest manner.

The well plan is derived systematically. For example, geological analysis should be established before the undertaking of the coring program, which should be established before the laboratory analysis program is designed (Figure 1).

For any drilling program, the final data required will determine the drilling and sampling methods to use. Luppens, et al (1992) list other factors to consider when designing a drilling and sampling program, including budget constraints, type of subsurface lithologies expected, depth and thickness of the strata sampled and amount of sample required for analysis.

Although obtaining samples may be expensive, the lack of sample information may prove to be even more costly. It is therefore important to design a drilling and sampling program that will cost-effectively gather the optimal amount of data. The same caution applies to gathering desorption data. Because sample recovery often is the most expensive component of the desorption program, it is important to make cost-effective decisions regarding such topics as the type of drilling rig (conventional oil drilling rig or a coring rig) and the procedures used to recover samples.

Cores drilled in unconventional wells are expensive to cut and analyze, particularly within source rocks such as shale, so are not usually taken. More often, wireline logs are used as the primary data source, along with the subsequent well production results.

However, in unconventional reservoirs such as shale, it is important initially to calibrate the shale properties with independent measurements of core samples and then link these properties to the log analyses. These properties and linkages may vary within a basin or from one basin to another, so core samples can be critical to the accurate geological analysis of selected areas.

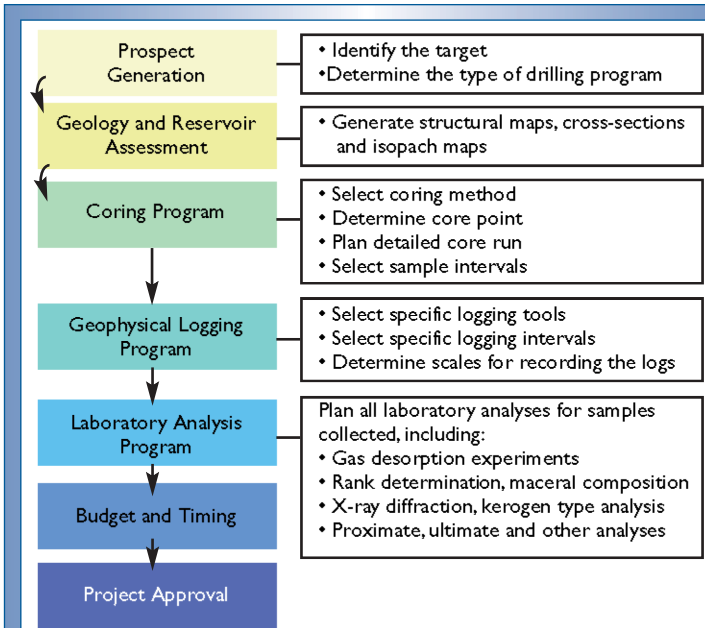

Figure 1. Flow path of well planning for coalbed methane and shale gas reservoirs.

Prospects

The first step in planning a coring and analysis program is identifying specific reservoir targets. Often, these already have been identified from previous exploration programs, but additional targets might be identified during detailed geological assessment.

When working in frontier regions, existing data on coalbed methane or shale gas reservoirs may be limited, and specific coal or shale targets may not have been identified. Therefore, a cursory geological analysis is recommended to identify potential targets. For coal, this may involve examining the geophysical logs from several wells to determine the coal seams in the region that may warrant further investigation.

The type of drilling program conducted depends on the development stage of the unconventional gas resource. This is important because the amount of coring, sampling and analysis required will differ during the various stages of exploration and development.

Exploration—This stage of drilling for unconventional gas targets is conducted as a program specifically dedicated to test unconventional gas targets or as an ancillary one piggybacked on a conventional oil and gas well. In either case, exploration-stage drilling will typically focus on collecting data and quantifying reservoir parameters, such as gas content, coal or shale composition, thermal maturity and reservoir permeability.

However, less flexibility is available if the program is part of a piggyback operation, because the drill rig used and the timing of the program will, in most cases, already have been determined.

Pilot drilling—This program generally is undertaken to test the production characteristics of a reservoir and is conducted after completion of the initial exploration drilling.

Reservoir data such as gas content or coal rank already will have been collected, providing the information necessary to undertake a pilot program. Therefore, a large-scale sampling and analysis program may not be needed during a pilot drilling program. Instead, data may be gathered as confirmation of previously gathered data or to complete a dataset.

Geology and the reservoir

Before beginning any coring program, it is important to understand the geology of the drilling area. Detailed geological maps and cross-sections should be constructed using available well control data. From these maps and cross-sections, stratigraphic and structural information can be analyzed to determine the following:

- depth to zone of interest (coal or shale);
- core points;
- total thickness of the zones;
- number of coal seam or shale intervals likely to be intersected;
- total net thickness of coal or shale;
- lateral continuity of coal seams or shale zones; and
- problematic formations likely to be encountered.

It is important to communicate any information that may affect the drilling process to the drilling engineer or mud engineer during the planning phase.

Coring program

Selecting the coring method is an important part of planning. Coring methods available to operators in Canada include conventional coring, wireline, pressure and sidewall coring. Each method has advantages and disadvantages – for example:

- wireline coring allows retrieval of the core barrel without pulling any of the drillstring out of the hole, reducing core retrieval time compared with conventional coring;
- pressure coring (more costly than conventional or wireline methods) preserves a core sample within a sealed barrel after cutting. This prevents gas loss during core retrieval, which is important for accurate determination of formation gas content; and
- small-diameter sidewall cores, collected perpendicular to the borehole, can be retrieved quickly (using a wireline), but the small sample size usually results in rapid gas loss during retrieval.

Determining the core point—Using the geological maps and cross-sections, the first step is to determine the depth to the top of the interest zone. For coal, the recommended procedure is to plan the core points so coring begins 3ft to 7ft above the coal seam. This minimizes the weight of the rock column above the coal or shale section. How close the core point is planned to the top of the zone should be partly governed by the spacing and quality of the well control data. Tighter well control generally will allow for more detailed geological mapping and modeling.

Factors affecting the selection of core points include the thickness of the zone to be cored and length of core barrel to be used (determined by coring method).

Some operators prefer to locate core points in the field by touch coring. This involves locating a coal seam by drilling until the top of the seam is intersected then beginning the coring process. However, this procedure is not recommended for the following reasons:

- touch coring always will result in the loss of a portion of the coal seam, which may be significant for thinner seams;
- often, the contact between the coal seam and the roof rock above will not be sharp, but rather gradational;
- the drilling break may not be recognized soon enough to prevent drilling through the seam;
- when the coal seam has been intersected, the drillstring is tripped out of the hole and the coring assembly is tripped in to begin the coring process. As the coal seam is partly exposed, the chance for contamination or damage to the coal is increased; and
- having drilled into the coal seam, the portion of the coal exposed to the wellbore may begin desorbing between the time of trip-out and trip-in, affecting the estimate

of gas content for the first cored sample.

Planning the core run—Once the coring method has been chosen and the points established, the following aspects need to be determined:

- total length of core to be cut to sample the zone of interest;
- number of core runs; and
- length of individual core runs (may vary depending on the method).

This information must be communicated to the associated service companies, such as the coring and desorption companies, so the appropriate equipment and supplies will be brought onsite.

Conventional core barrels are typically 30ft or 59ft long, and wireline core barrels are typically 10ft to 25ft long. For collecting coal or shale, 59-ft core runs are not recommended because of an increased chance of core loss or damage. For example, if a coal seam is cut near the top of a 59-ft core run, the weight of the remaining core being pushed into the barrel behind it may jam the core barrel or significantly damage the coal. Alternatively, a coal seam near or at the bottom of the core barrel may be crushed by the weight of the overlying rock column (Figure 2).

Selecting sample intervals—It is important to determine the intervals within each core run to be sampled for desorption or other analyses and estimate the number of samples needed.

This step is critical when planning the desorption program because it allows for accurate cost estimates and helps ensure the appropriate equipment will be brought onsite (such as an adequate number of desorption canisters). By estimating (as accurately as possible) how many samples are to be collected, an accurate laboratory analysis budget also can be produced. A sufficient number of samples must be recovered to provide statistically valid measurements of the different coal or shale zones. Adequate sampling for gas content is especially important because significant variations can occur vertically between different coal seams, vertically within a thick coal seam and laterally within a coal seam.

It is recommended that at least one-third of the vertical reservoir profile be sampled to obtain statistically significant gas content estimates.

When planning a drilling program to collect samples for desorption, especially in frontier regions, a recommended practice is to sample coals with varying ash content, as well as interseam paring material and floor or roof rock. This practice provides a representative sample set that will span the expected density range, from coal though rock. This information helps in modeling gas content vs. density, which is important for accurately modeling the gas-producing zone.

The size of sample collected for desorption depends on the particular canister used. Typically, canisters are designed to hold a core sample about 1ft long. When collecting samples for non-desorption analysis, obtaining 6-in. to about 1ft of coal or shale core will be adequate.

The well site geologist must ensure the coring and sampling program is followed and authorize any changes to the program that may be required as field conditions dictate. For example, the number of samples actually collected in the field may change because of unforeseen circumstances, such as lost core or lost circulation.

Poor core-recovery strategy

Occasionally, repeated poor core recovery will reduce the number of samples that can be collected for desorption evaluation. If several consecutive core runs show total or partial core loss, a plan must be in place to ensure some samples still can be obtained. A recommended practice is to collect drill cuttings during coring, as those returned to the surface can provide a backup source of material for desorption tests.

It is important to note the drill cuttings retrieved might not represent the interval of interest for either reason:

- the core bit may have been grinding up previous lost core; or
- the cuttings likely will be mixed and homogenized as they are returned up the borehole to the surface, if more than one coal seam is present over a short stratigraphic interval.

Upon completion of the drilling and geophysical logging, any lost core intervals should be reconciled against the geophysical log depths. The actual depth interval and length of core lost then can accurately be determined.

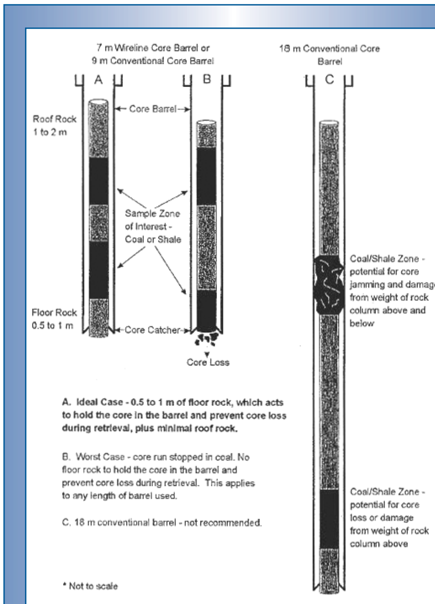

Figure 2. Procedures for core retrieval.

Geophysical logging program

Setting up this program is an important part of the pre-drilling planning. When planning the logging program, discuss the following issues with the geophysical logging company:

- specific suite of logs to run;
- specific intervals to be logged;
- scales at which the logs are recorded; and
- availability of specialty tools.

All wells to be cored or sampled should have geophysical logs run. It is a common practice in the industry that wells drilled adjacent to existing wells (twinned wells) are not geophysically logged as a cost-saving measure. However, assuming the strata being drilled through will remain the same from well to well, even during a short distance, may be erroneous. For example, the thickness and composition of a given coal seam can change significantly over lateral distances as short as tens of feet or meters.

Most logging trucks can stack several tools into a single logging suite, which minimizes the number of logging passes in the hole. This saves time and eliminates the chance of depth discrepancies between logs if run separately. When planning the drilling program, it is recommended the hole be drilled to sufficient depth for logging tools to provide geophysical logs for the lowest zone of interest.

Laboratory analysis program

This program should be planned based on the estimated number of samples to be collected. Consider the availability of any relevant existing data; the types of samples to be collected (partly determined by the types of analyses required); and budget constraints.

It is good practice to review the proposed laboratory analysis program with the laboratory service provider(s) before the drilling program start. Points to consider include:

- how many samples will be analyzed;
- is the laboratory adequately equipped to perform the analysis;
- can the laboratory do the work in the required timeframe; and
- what is the cost of individual analyses.

It is recommended that the proposed program also be reviewed upon completion of the drilling program. Adjustments can be made based on the actual number and types of samples collected.

Reservoir temperature—A common practice in the United States has been to desorb coal samples at ambient surface temperature. However, research at GTI has shown desorption experiments are most accurate when conducted at reservoir temperature. Significant error in lost gas and total gas estimates can result from desorbing samples at ambient surface temperature. The important temperature-related factors affecting the accuracy of lost gas and total gas content estimates are summarized below:

- Gas desorption rates vary with temperature and can affect the volume of gas desorbed during the time required to estimate lost gas content. For example, if early desorption occurs at a temperature greater than reservoir temperature, the estimated lost gas component will be higher than actual, thereby leading to an overestimate of total gas content.
- The gas sorptive capacity of coal is inversely proportional to temperature. Therefore, if the desorption temperature is lower than that of the reservoir, the sorptive capacity of the coal will be higher and the measured gas component will be lower than if it was desorbed at reservoir temperature. The increased sorptive capacity also results in a relative increase in the residual gas component. Conversely, when the desorption temperature is higher than the reservoir temperature, the sorptive capacity of the coal will be lower and the measured gas component will be higher than if it was desorbed at reservoir temperature. This will result in a relative decrease in the residual gas component, which could have an impact on the total gas content if residual gas is not determined.

GTI maintains desorption canisters at reservoir temperature throughout the desorption experiment. However, an alternative method commonly used in Canada and Australia involves conducting early desorption tests at reservoir temperature then heating the samples to twice the temperature. This accelerates desorption, thereby reducing the total time and cost of the experiment. When using this method, residual gas should be determined for all samples to accurately determine the total gas content.

As part of the pre-drilling planning, it is important to estimate the reservoir temperatures of the zones of interest. Typically, reservoir temperatures are estimated using the mean surface temperature and geothermal gradient in the area, using the equation:

$$T_R = Ts + (G \cdot D)$$

where:

T_R = reservoir temperature, ˚C

Ts = mean surface temperature, ˚C

G = geothermal gradient, ˚C per depth interval (typically in m)

(Commonly reported as ˚C /100m, or ˚C /30m)

D = depth, m

In some cases, the reservoir temperature of the planned well can be estimated from the actual formation temperatures recorded in nearby wells. Or, ideally, the actual formation temperatures may have been recorded in a twin well.

The measured temperature of the drilling fluid while circulating can differ from the actual static formation temperature. This is especially true when drilling in winter, as the drill fluid often is heated at the surface to prevent freezing.

Further information

This article is based on *Drilling Program Planning and Field Operations Protocols for Coalbed Methane and Shale Gas Reservoirs in Canada,* report No. GRI-02/0153. That report, which is available through the GTI Web site – *www.gastechnology.org* – provides additional details on each of the topics discussed in this article.

For more information about GTI research on production of methane from coalbed and shale formations, contact Bob Siegfried, associate director for Exploration & Production Research via phone: (847) 768-0969 or e-mail: *bob.siegfried@gastechnology.org* ✧

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Unconventional Gas: Reserve Opportunities and Technology Needs

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Huge resources are awaiting step-change improvements in technology. This is the final in a three-part series.

Unconventional gas resources will play an increasingly vital role in gas supply during the next 20 years to 30 years. This is the theme that has been echoed during the past 5 years through studies by the National Petroleum Council, the Energy Information Administration and others. An underlying theme that also has been emphasized is that technology advances are critical and necessary for unconventional gas to fill this role.

Huge resources of unconventional gas locked up in (mainly) tight gas sands, shales and coalbed methane (CBM) exist throughout the Rocky Mountains, Texas, Oklahoma and the Appalachian Basin. The two previous articles in this series showed how operators are recovering additional reserves through insight and technology. Yet, there are still large hurdles to overcome from a cost and technological improvement standpoint before significant quantities of gas can move through the categories of resource to technically recoverable to economically recoverable (Figure 1). Unconventional resources are known to contain thousands of cubic feet of gas in place; however, less than a few percent of that gas is likely to be economic to produce with current technologies.

Roughly 20 years ago, gas production from tight sands, shales and coals was considered uneconomic. Today, these resources provide 25% of the U.S. gas supply because of the vast knowledge generated by the U.S. Department of Energy (DOE), the Gas Technology Institute and the industry, along with significant technological advances on many fronts. A recent article in the *Oil & Gas Journal* shows many emerging U.S. gas fields are unconventional, including the CBM play in the Powder River Basin (950 MMcf/d), and **Jonah** (750 MMcf/d) and **Pinedale** (400 MMcf/d) in the Greater Green River Basin. Estimated ultimate recovery for these areas range from 10 Tcf in Jonah to nearly 30 Tcf in the Powder River CBM play.

In the first article of this series (Winter 2004), Kuuskraa outlined a suite of technologies necessary for optimizing production and recovery from tight sands (see sidebar). These include natural fracture identification, well logging, multi-zone completion and well testing and analysis. He goes on to discuss how several fields in the Piceance Basin are being drilled on tighter spacing, as low as 20 acres, with 10-acre trials, recovering reserves that may approach 100 Bcf per section.

"With improved core and log data, and a better understanding of lenticular sands…and vertical completion of the full stack of sands…technology could transform a township-sized, basin-centered tight gas field from a 100-Bcf prospect into a major field with multiple Tcf of reserves," according to the article.

A second example Kuuskraa provides shows the evolution of completion practices in the Jonah field. From the early 1990s through today, operators have:

- increased the amount of pay completed, to nearly 100% in some wells;
- increased the number of frac stages, up to 10 or more;
- advanced through the learning curve on frac fluids; and
- increased estimated ultimate recovery from several billion cubic feet per well to 5 Bcf to 10 Bcf per well.

In the second article of this series (Spring 2004), Teufel demonstrated the importance of natural fractures and their associated

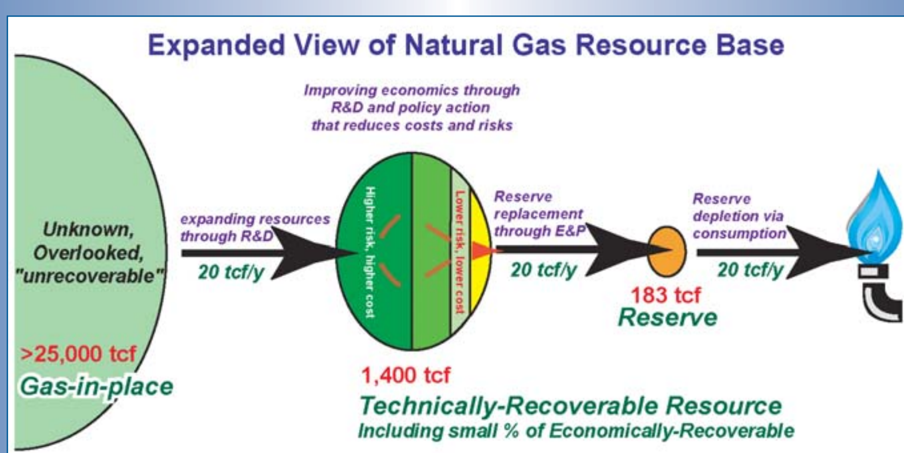

Figure 1. Resource to reserves.

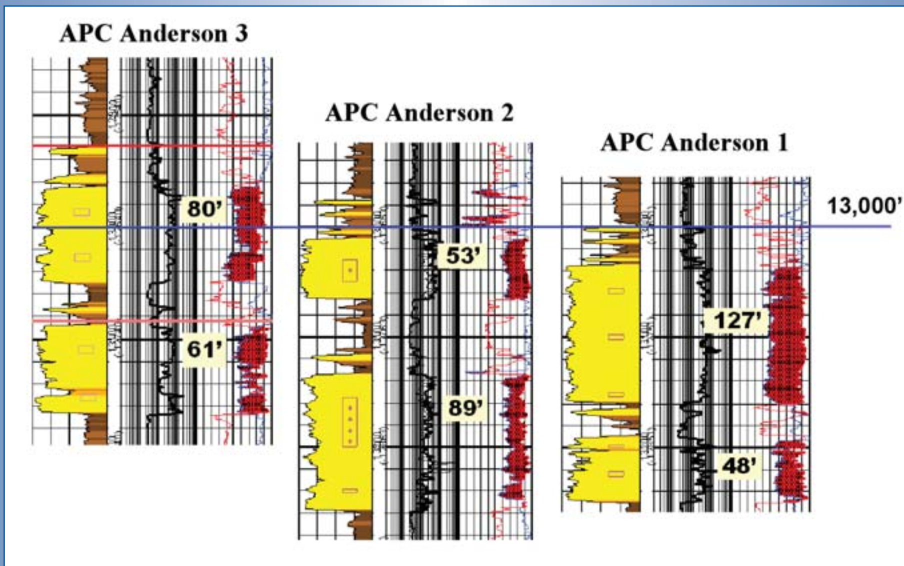

Figure 2. Productive sands in the Bossier: the Bonner (top) and the York (bottom).

anisotropy to infill drilling optimization and recovery in the San Juan Basin, estimating additional reserves of about 8 Tcf for the Mesaverde formation alone if fully developed on 80-acre spacing. Additional details in New Mexico Tech's (NMT) final report show:

- Burlington Resources and BP were granted permission to site new well locations based on drainage area and pattern of previously drilled wells. This was the first approved deviation in the Mesaverde tight gas sandstone reservoirs in the San Juan Basin, and the approval was a direct result of this project; and
- this study has demonstrated a methodology to:
  - – describe reservoir heterogeneities and natural fracture systems;
  - – determine reservoir permeability and permeability anisotropy;
  - – define the elliptical drainage area and recoverable gas for existing wells;
  - – determine the optimal location and number of new in-fill wells to maximize economic recovery; and
  - – forecast the increase in total cumulative gas production from infill drilling.

Resource potential

The resource potential (gas-in-place) of unconventional resources is staggering. Estimates by the United States Geological Survey conducted for the DOE indicated 5,075 Tcf for the Greater Green River (1989), 420 Tcf for the Piceance (1987), 995 Tcf for the Wind River (1996) and 334 Tcf for the Bighorn (1999). Recent reassessments of the Greater Green River and Wind River by the National Energy Technology Laboratory have confirmed these past estimates and provide an unprecedented level of geographic and stratigraphic detail; more than 10,000 uniquely characterized cells that reflect the natural variety of key geological and engineering parameters have been established.

But not all tight sands are created equally. Although these continuous deposits span tens of thousands of acres and have thicknesses up to 5,000ft, any given well can be uneconomical to drill. Why one well recovers 10+ Bcf of gas and its neighboring well 1 Bcf to 2 Bcf or less can only be explained by the great heterogeneity typical of these deposits. Natural fracture networks, porosity and water and gas saturations are important criteria in identifying the correct well location. Economically tying the productive zones to the wellbore via hydraulic fracturing with particular emphasis on non-damaging fluids is essential.

Suite of technologies

Natural fracture identification—3-D seismic technology has been critical to the industry's ability to more accurately resolve details of complex subsurface geology before drilling wells, thereby reducing the number of dry

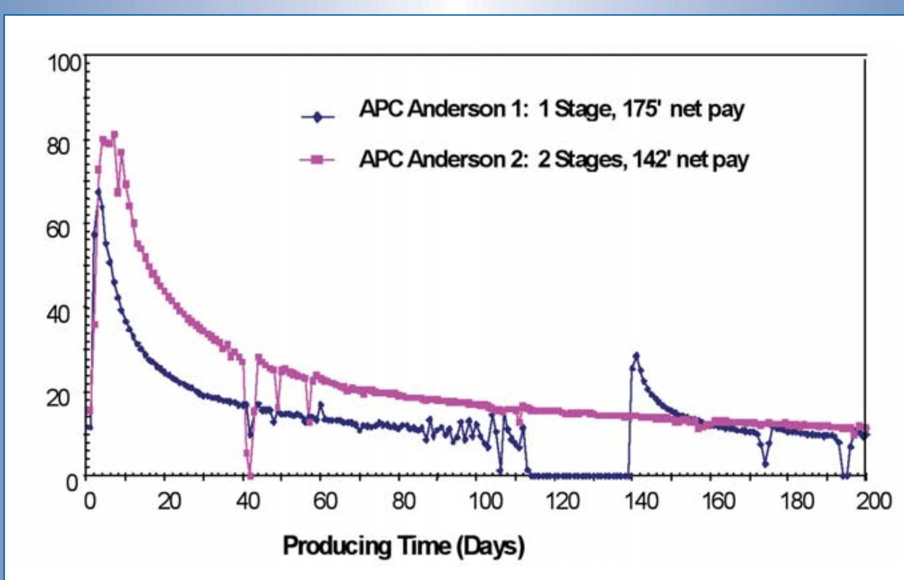

Figure 3. Production response from the two-stage treatment is significantly better than from a single-stage treatment.

holes and optimally placing the wells that are drilled, helping to improve recovery from old and new fields. The DOE has long been at the forefront of technology development for natural fracture identification beginning with six projects that initiated its fracture identification program in 1992. These projects soon led to field verification of several methodologies over existing production and eventually to current projects where well locations have been selected prior to drilling. Two of these projects are highlighted below.

Geospectrum has been working with Burlington Resources Inc. and Huntington Energy LLC, to develop and test a new methodology for siting successful gas wells in fractured Dakota reservoirs in the San Juan Basin. The methodology is based on mapping a suite of seismic and petrophysical attributes at the reservoir scale, in particular:

- seismic lineament intersections;
- interval velocity anisotropy;
- collocated, cokriged clay volume; and
- a gas-sensitive amplitude variation with offset (AVO) attribute based on the phase gradient.

These four attributes were mapped, combined and optimized to select areas of high fracture density and good gas charge in the Canyon Largo unit of the San Juan Basin. Four wells were drilled to validate Geospectrum's site selection methodology, with encouraging results. They all are producing gas at economic rates, and the well with the best AVO attribute also is the best producer in the unit. For more information, please see article *An Integrated 3-D Seismic Fracture Interpretation Methodology for Tight Gas Reservoirs* on page 14.

Lawrence Berkeley National Laboratory has been working closely with ConocoPhillips in an effort to quantify natural fractures in Mesaverde reservoirs in the northwest corner of the San Juan Basin. A 20-sq mile, 3-D surface seismic dataset was reprocessed and analyzed, and VSP and single well seismic, as well as borehole image logs, were collected to image natural fractures at a variety of scales. The surface, VSP, single well and image logs are being incorporated in a state-of-the-art reservoir model, along with petrophysical and production data, in an effort to predict areas of high fracture density. A best practice manual will be published and available early next year.

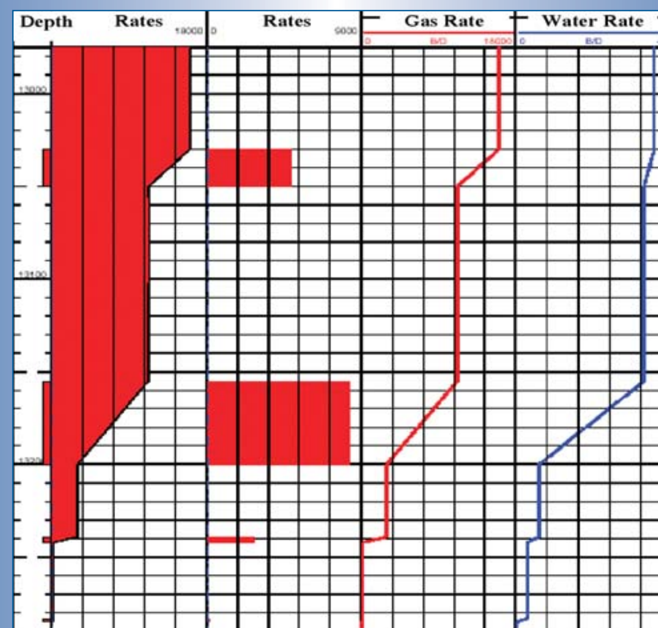

Figure 4. Production logs show both zones were effectively stimulated in the multi-stage fracture treatment.

Although these and other projects have brought researchers closer to successful targeting of natural fracture sweet spots in tight reservoirs, additional technologies are needed to achieve routine, reliable siting of good gas wells in complex settings. Higher resolution seismic tools that allow better sampling density and better recorded frequencies; improved image processing algorithms that move toward full waveform migration; advances in single well seismic and seismic while drilling tools; and data integration packages that optimize the utility of existing production data will contribute to the industry's ability to drill with more certainty in areas where fractures control production.

Well logging—Integrated geologic, petrophysical and engineering teamwork is required to adequately develop these reservoirs. Schlumberger has demonstrated a completion optimization technique (PowerSTIM*) that provides a unique tie between formation properties, hydraulic fracture properties and gas production in the Greater Green River Basin and other basins. Effective reservoir properties, mechanical properties (Young's Modulus and Poisson's Ratio), reservoir pressure and stresses are upscaled, layered and put into a fracture simulator (FracCADE*) for hydraulic fracture design. Hydraulic fractures are staged, designed and customized in each well. The effective fracture properties are combined with the formation properties in a production simulator (ProCADE*) to forecast the initial production of each stage. The efficiency of different fracture fluids and proppants can be simulated, and the economics of each can be evaluated. Published PowerSTIM examples and success stories can be found in Wamsutter with BP and on the Pinedale Anticline with Ultra Resources. The present completion optimization and interpretation technologies are generally restricted to 2-D space and with increased well density; successful reservoir management requires information in space as well as time. The lateral extent, connectivity and pressure of lenticular tight gas reservoirs are equally as important as porosity, saturation and permeability when making completions decisions. More complete determination of formation pressures and 3-D geocellular and predictive modeling will be necessary to successfully optimize completions and manage the overall development of these complex reservoirs. The foundation for all these models

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is reservoir characterization and as such, well logging and interpretation technologies are key to their success.

Well logging in tight gas reservoirs often is restricted to open hole triple-combination-type tools or pulsed neutron devices behind casing. These technologies were developed for interpretation in more porous formations. Tight gas reservoirs are not routinely developed and managed by more advanced well logging technologies for the following reasons and operational challenges that face operators:

- historically slim profit margins;
- tight cost focus of operators;
- poor hole conditions
  - large washouts;
  - ubiquitous tension pulls;
  - poor pad contact; and
  - tool sticking (preventing more than a single logging run); and
- low porosity formation characterization is inadequate in some cases with present tools.

Present technologies being applied to combat these issues include:

- acquisition and splicing of down-logged and up-logged open hole data;
- pressure testing through casing with subsequent plugging;
- acquisition of pressure data via fracture pump-in and mini-fall off analysis;
- production logging;
- utilization of imaging tools to better quantify natural fractures;
- acquisition of dipole sonic data for mechanical Earth modeling to reduce drilling risks;
- hydraulic fracture mapping (passive seismic) to better understand complex fracture geometries; and
- better environmental characterization of logging tools (density in barite muds for example).

The above list represents a wide array of tools that operators are using to reduce operational risk and increase efficiency. As the pace of development increases, what will the future hold:

- crosshole electromagnetic tomography to visualize by-passed pay and sandstone geometries;
- new generation open hole formation testing tools specifically designed to test low porosity/low permeability reservoirs, and
- density behind casing for use when open hole logs are not obtained.

A critically important need is to increase the precision of present open hole logging tools.

These tools may soon be available to operators for use in tight gas reservoirs. With the increase in development, service companies are contributing a significant amount of their research and development budgets to improve the state-of-the-art in logging measurements in low porosity, gas reservoirs. Typical low porosity gas reservoirs are diagenetically complex with clays and gas, both of which affect logging measurements and in many cases, counter to one another. Because of the large vertical sections being completed, small changes in porosity and saturation have dramatically large effects on gas in place calculations; therefore, a critically important need is to increase the precision of present open hole logging tools.

Multi-zone completion**—**Completing and stimulating wells with multiple zones can be accomplished in a single- or multi-stage fracture treatment. A single-stage treatment consists of bullheading the fluids down the casing with no flow control devices to direct fluids into specific zones. This can result in some zones being over-stimulated, while others are starved of fluid and remain un-stimulated, resulting in lower well productivity and bypassing of producible reserves.

Multi-stage treatments can be used to selectively treat zones of interest with frac treatments being designed for each group of sands being stimulated. The need for zonal isolation and the additional time needed for sequential pumping of multiple treatments can add considerable cost. However, this additional cost is usually quickly recovered by the incremental gas production. Multi-zone completions with limited entry, mechanical bridge plugs or packer isolation devices are routine.

A good example of a direct comparison between single- and multi-stage fracture treatments in adjacent wells (**APC Anderson No. 1** and **APC Anderson No. 2**) producing from the same sands is presented by Sharma et. al. as a part of a DOE-funded project.

The wells were drilled in the **Dowdy Ranch** field in East Texas. The APC Anderson No. 1 and No. 2 were drilled on 10-acre spacing for the purpose of having a close offset to compare and for using the No. 1 as an observation well for the micro-seismic work. The APC Anderson No. 1 was completed in one large stage, while the APC Anderson No. 2 was completed in two separate stages down casing for comparison. Figure 2 shows the logs from the wells indicating the location, continuity and thickness of the York and Bonner sands.

The cumulative production of the APC Anderson No. 2 has been 30% greater than that from the APC Anderson No. 1, which had 19% more net pay (Figure 3). With all other factors being the same, it appears that stimulating the Bonner and York in two stages had a large impact on the effectiveness of the treatments, and thus the productivity of the well.

After flowing the well for a little more than a month, the production log results run in the APC Anderson No. 2 are shown in Figure 4. The flow surveys showed that 34% of the production was from the Bonner and 65 % from the York. The shale interval stress tested was contributing the remaining 1%. These percentages matched closely to the percentages of net pay each zone had to the total stimulated interval, indicating that both sands had been effectively stimulated.

In most instances, using multi-zone completions is recommended when sands are separated by shales with a reasonable stress contrast.

Future improvements need to focus on quicker turnaround time and guidelines. Innovative hardware designs that would allow operators to reduce total treatment time for multi-zone completions and better guidelines for assessing when the additional expense of multi-stage treatments are warranted would be useful.

Well testing and analysis —In today's environment of downsizing and meeting next quarter's stock market quota, too little attention is paid to well analysis. There are many diagnostic tools that can help operators analyze a well's performance and then use that information to optimize recovery from future wells, including:

- pressure transient tests;
- hydraulic fracture mapping; and
- production analysis.

In their work for DOE, NMT further developed analytical and numerical procedures and tools for production and well testing analysis of tight-gas reservoirs. These procedures and tools address issues related to estimation of reservoir production/flow characteristics, determination of reservoir permeability anisotropy and well interference, delineation of the drainage volume/area and evaluation of infill well potential. A description of these procedures and tools and their applications are documented in a series of papers presented and published in proceedings of Society of Petroleum Engineers conferences.

Summary

Well down-spacing in many unconventional formations across the United States indicates that many tight gas sands and gas shale resources have the reserves to support closely spaced wells. However, step-change improvements need to be made on all fronts of exploration and production technologies discussed in this series to move these huge resources to the economically recoverable category. For example, a recent *Oil & Gas Journal* article cited that only 10% of the prospective Rockies area had 3-D seismic coverage. With the slim profit margins offered by most of these resources, the application of new tools often is too risky for gas operators. The DOE historically has filled this role through partnerships that help mitigate this risk and will continue to play a vital role in the future. ✧

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Preventing Annular Flow After Cementing in the Shallow Gulf of Mexico

By Dale Doherty, *BJ Services;*
Ed Smalley, *CTES LP;*
and John Aslakson,
W&T Offshore

Cement pulsation can effectively prevent gas flow in the annulus after cementing. This case study focuses on its use in a well in the shallow Gulf of Mexico.

The morning starts with a full cup of steaming coffee in preparation for a quick review of the day's offshore Gulf of Mexico (GOM) morning drilling report. It's important to ensure everything went as planned on the surface casing cement job performed late last night and get back to making hole. Scanning the report, blood pressure rises when the reader sees the words "slight gas flow noted in the conductor/surface pipe annulus within 3 hours following cementing." The reader's eyes rapidly move forward and spot the words "diverter closed" and "platform evacuated" further down the page.

According to the U.S. Minerals Management Service, this type of situation continues to be one of the major causes of well control loss during GOM drilling operations.

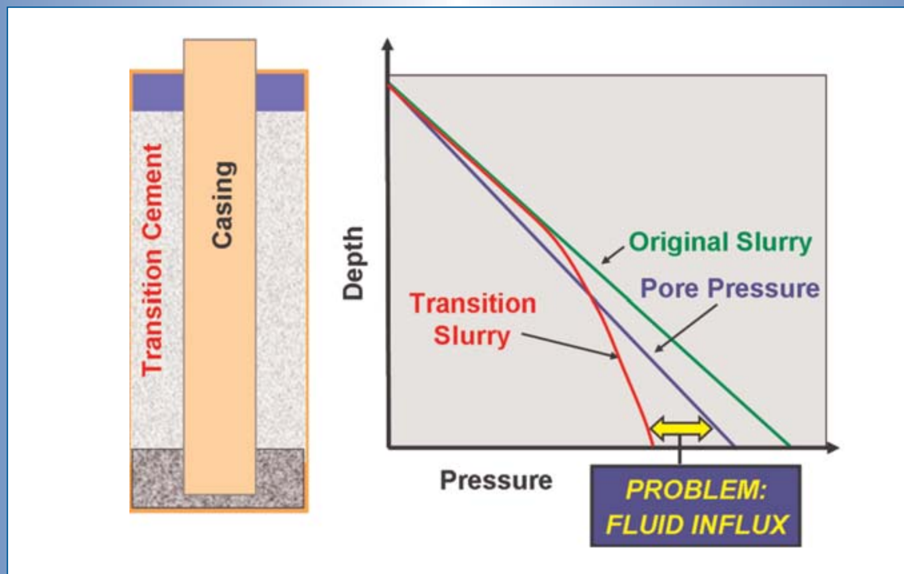

Figure 1. Hydrostatic head reduction during the cement setting process.

In the best case, annular flow after cementing likely will make it necessary to perform a remedial cementing operation at additional cost. On the other end of the spectrum, these incidents can lead to broaching, cratering and fire – situations with which no exploration and production professional wants to be involved.

So what caused this problem? The cement program was designed and executed to perfection. Good cementing practices, including proper mud conditioning casing centralization and movement, were applied. All indicators observed in the field during the cementing operation pointed toward proper mud displacement and expectations of a good cement job.

The root cause of this problem may not be associated with shortcomings in the design or execution in any of the above activities. Annular flow shortly after cementing in the GOM can be significantly impacted by normal gel strength development in the cement slurry and associated loss of hydrostatic pressure on the cement column.

This process starts shortly after the cement is put in place. The cement, through its bond to the casing and formation, begins to develop initial strength to support its weight. Since the result of this action is cumulative over the length of the cement column, a significant reduction in hydrostatic pressure may be experienced in deeper sections of the cement column as it moves through the transition phase.

If certain field conditions are encountered, this loss of hydrostatic head can allow gas migration into the unset cement column. The end result may include creation of a channel to the surface and flow or pressure on the annulus (Figure 1).

Cement pulsation

This relatively simple and inexpensive technique recently was applied successfully in an offshore GOM well (Figure 2) to prevent this loss of hydrostatic pressure and the occurrence of flow/annular casing pressure after cementing. Commercial cement pulsation services, until recently, specifically have been targeted toward land applications. This was done to develop operational history and know-how in preparation for entry into the high-cost operating environment of the offshore market. Cement pulsation has been applied to more than 500 land wells in the United States and Canada. The success rate (defined as no annular pressure after cementing) has been about 95% on wells deviated less than 30°. It successfully has been applied in well depths from 1,900ft to more than 12,000ft. In addition, cement pulsation has helped obtain high-quality cement jobs on wells with lengthy cement columns, some more than 12,000ft in length.

The cement pulsation process encompasses the application of low-intensity pressure pulses to the annulus immediately following the primary cementing operation. As the cement column sets from the bottom to the top, the pressure pulses act to break the gel strength in the unset portion of the column, so hydrostatic pressure is maintained along the length of the unset column and fluid influx is prevented. The compressible volume (CV) of the cement column – the volume of water required to pressurize the annulus as the cement pulse is applied – is monitored during the cement setting process. The cement pulsation operation is deemed complete when the CV stabilizes. A typical pulsation time of 4 hours to 6 hours is sufficient for most slurry designs. No changes to the original cement design are required for application of the cement pulsation technique.

The key elements of the cement pulsation equipment are an air tank, water tank, valve controller and data recorder. The pulsation unit utilizes an air-over-water approach to apply the pulses on the annulus. A large steel-reinforced hose is connected between the cement pulsation unit and the annulus, and the wellbore is initially filled with fluid to the surface (cement, mud or water). Next, the air tank is controlled to apply a pre-set pulse pressure to the water tank for a given period of time. This action applies a water pulse on the annulus. Following the pulse-pressure hold period, the air pressure on the water tank is exhausted to the atmosphere, and the annulus is allowed to relax for a pre-set amount of time before the cycle is repeated.

Figure 2. The cement pulsation unit (center) consists of the black, skid-mounted equipment.

Offshore GOM field operations

W&T Offshore has an active drilling program in the Outer Continental Shelf/South Timbalier **Block 229.** This block is about 40 miles off the Louisiana coast in about 238ft of water. Offset wells in the area had experienced annular casing pressure in less than 18 hours following cementing of the conductor and/or surface pipe. This situation developed in spite of using an appropriate cement job design and while applying good cementing practices in the field, such as pipe movement. The pressure on these offset wells ultimately was eliminated by a remedial cement job.

W&T began to work with their cementing company, BJ Services, to identify a cost-effective solution to this problem. The additional cost of a remedial annular squeeze job could potentially add $150,000 to the final well cost, including rig time and associated costs. Following a review of potential solutions to the annular casing pressure problem, cement pulsation was selected for application on the **ST 229 A5** well.

The construction of this well started with drive pipe set to 750ft. It was then drilled to 1,550ft with a 17½-in. bit, and finally under-reamed to 24-in. The well plan called for 18⅝-in. conductor pipe to be set to 1,550ft with a cement top at 368ft. The conductor pipe cement design called for placement of the following materials during the cementing operation:

Material	Bottom Depth (ft)	Top Depth (ft)	Density (ppg)
Sea Water	31	0	8.4
Spacer	368	31	9.8
Lead Slurry	1,250	368	12.0
Tail Slurry	1,550	1,250	16.4

The lead and tail slurry had a laboratory-tested pump time of 6:00+ hours and 2 hours and 42 min., respectively. It should also be noted the lead slurry had a fluid loss of 26 cc/30 min., and zero free water at a 45° angle.

The lead slurry was designed to control flow after cementing per accepted industry standards of less than 50 cc/30 min. fluid loss and zero free water at a 45° angle. The cement design challenge on the shelf, with respect to shallow gas flow, centers on the control of gas influx as the cement goes through transition.

The transition time refers to the time period when the cement column stops transmitting the full amount of hydrostatic pressure. This occurs when the cement starts to gel and can result in an underbalanced pressure situation.

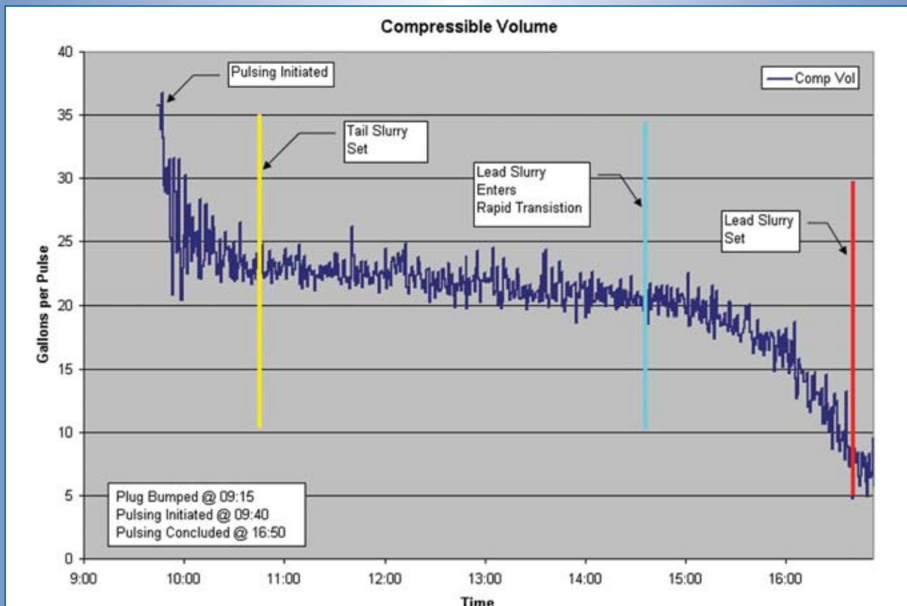

Figure 3. The compressible volume decrease indicates the cement is set.

The mathematical value is 100 lb/100 sq ft to 500 lb/100 sq ft. In other words, cement is no longer liquid at a gel strength value of 100 lb/100sq ft.

Conversely, cement is a solid when it reaches a gel strength value of 500 lb/100 sq ft. At some point between these two gel strength numbers, the hydrostatic pressure of the cement column drops below the pore pressure of the formation. This value is known as the critical gel strength value. The point between the critical gel strength value and 500 lb/100 sq ft is the point where gas or liquids may enter and contaminate the slurry.

In addition to the cement properties that control the influx of gas, application of cement pulsation may shorten this time between the critical gel strength value and the point at which the cement becomes a solid by keeping it in the liquid state longer. It is being considered that each pressure pulse may act upon the setting cement as a mini "hesitation squeeze."

In addition to cement pulsation and slurries designed to control flow after cementing, it is important to note all industry-accepted cementing best practices must still be implemented. In the case of shallow gas, these best practices help ensure successful cement placement in the wellbore. Best practices include but are not limited to:

- proper hole cleaning before pulling out of the hole to run casing;
- proper mud conditioning before the cement job;
- proper spacer type and amount;
- proper centralization;
- pipe movement during the pre-job circulation and cement job; and
- cement and spacer must be displaced into the wellbore at the proper rates.

The use of good primary job cement simulation software, such as BJ Services CmFacts™ program, is critical when modeling any cement-job design. This software will determine at what rates the drilling mud can be displaced most efficiently from the wellbore without exceeding the wellbore's fracture gradient. This software also provides a recommendation for proper centralizer placement. Properly centralized pipe normally has a minimum standoff value of 67%.

This software must be viewed as another component of cementing best practices and is routinely used to help obtain successful cement jobs. The recommended outputs from CmFacts were incorporated into this job design and used to attain optimum mud removal and proper cement placement, allowing cement pulsation to commence on an uncontaminated cement column.

Cement pulsation job design challenge

The cement pulsation job design for this well had to overcome an additional obstacle. This shallow openhole section has a very narrow operating window between the fracture pressure and pore pressure. For normal openhole treating depths greater than about 2,000ft, the low-pressure pulses applied during cement pulsation typically are negligible in relation to the overall pressures experienced at deeper depths in the wellbore.

However, if a 100-psi pulse for example were imparted on shallow sand at a depth of 800ft, that would add an equivalent in excess of 2 ppg to the hydrostatic pressure profile. In light of this constraint, proprietary cement pulsation design software was used to model the minimum surface pulse pressure required to break the gel strength at the total depth of the tail slurry. The modeling indicated a surface pulse pressure of 50psi would be more than sufficient for the job, while staying below the fracture pressure of the shallow gas sand in the openhole portion of the well.

Cementing and pulsation operations

BJ Services commenced the cementing operations at 6:30 a.m., and the cement plug was bumped at 9:15 a.m. Cement returns were observed at the surface during the cementing operation, and the rig crew washed cement from the stack from 9:15 to 9:40 a.m. The annular blowout preventer was subsequently closed to seal the annulus and cement pulsation was initiated.

The well was pulsed with 58psi surface pulses for a little more than 7 hours. The pulse was applied and held on the annulus for 15 seconds, with a 15-second pulse relaxation period following pressure exhaust. Pulse frequency was constant at about 39 seconds during the course of the operation.

The two primary measurements recorded during the pulsation operation included tank water-level (CV) in the pulsation unit tank and total amount of water loss (volume) displaced to the wellbore during the pulsation operation.

The tank water-level measurement is made with a floating ball inside the cement pulsation unit tank. The water loss to the wellbore is measured with a flow meter. A total of a little more than 21 bbl (about 890 gal) of water was lost to the wellbore during this pulsation operation.

Cement setting indicated by cement pulsation data

Following initiation of the cement pulsation operation, the initial CV (water displacement per pulse) was slightly more than 30 gal. The largest magnitude of CV typically occurs at the onset of the cement pulsation operation, as the gel strength along the length of the entire cement column is being sheared. Compressible volume will decrease over time, as the cement column develops sufficient strength to preclude the cement pulsation shearing action at the cement-to-formation/casing interfaces.

About the Technology

The cement pulsation technology was developed with support from Gas Research Institute and was subsequently licensed to two service companies. Commercial cement pulsation services are provided by CTES LP in the United States and Trican Well Services in Canada. Cement pulsation has been applied to more than 500 wells in the United States and Canada. The success rate (defined as no annular pressure after cementing) on wells deviated less than 30° has been about 95%. It has been successfully applied in well depths ranging from 1,900ft to more than 12,000ft. In addition, cement pulsation has helped obtain high-quality cement jobs on wells with lengthy cement columns, some more than 12,000ft in length.

Compressible volume decreased rather rapidly from the start of pulsing until about 10:45 a.m., indicating the tail slurry had developed sufficient strength such that the pulses were unable to continue shearing it (Figure 3). About 420 gal of water were lost to the well during the initial 65 min of pulsing, yielding an average water loss of nearly 6.5 gal/min.

Pulsing continued until 2:40 p.m., with only a slight decline in CV, from about 23 gal/pulse to just above 20 gal/pulse. However, average water loss slowed appreciably during this time. About 390 gal of water were lost to the well during this 235-min period, with an average loss of about 1.7 gal/min during the same period. At this juncture, a cumulative water loss of about 810 gal had been recorded.

At about 2:40 p.m., the CV decreased from just more than 20 gal/pulse to about 5 gal/pulse to 6 gal/pulse by 4:40 p.m., indicating the lead slurry was setting. In addition, the rate of water loss to the wellbore decreased significantly during this time, with a loss of less than 80 gal during this 120-min period (average water loss less than 0.7 gal/min).

The CV stopped decreasing at about 4:40 p.m., indicating the lead slurry was set. Compressible volume had declined to less than 6 gal/pulse by this time, and the cement pulsation operation was deemed complete and was terminated just before 5 p.m.

Success—no annular pressure

The combination of cement pulsation with a sound cement program design and application of proper field cementing practices all worked together to deliver the desired results – a high-quality cement job with no annular pressure or annular flow after cementing. An annular squeeze job and/or loss-of-well control incident was potentially avoided. Finally, data recorded during the pulsation operation indicated setting of the tail and lead slurries.

It is not often that a technical and economic success is obtained on the initial application of a technology in a radically different setting, such as offshore, soft rock. This positive result can in large part be attributed to close coordination among the operator, cementing company and pulsation service company before the operation.

There is still much to learn regarding application of cement pulsation in the shallow GOM environment. That being said, the following important conclusions can be inferred from this case history:

- cement pulsation is another cost-effective tool that can be applied to potentially avoid flow/annular pressure following cementing in the GOM;
- extremely low-pressure pulses can be transmitted to total depth of a cement column;
- cement pulsation data can provide real-time monitoring of the tail and lead slurry setting process; and
- field equipment design is robust and suitable for offshore applications.

Looking to the future, additional offshore candidate wells in the GOM will be sought for application of the cement pulsation technique, so a statistically valid sample of results can be accumulated. There is additional development work to be performed on the cement pulsation job-design software, and there likely is more information to be gleaned from the measurements made during the cement setting process. This information will be incorporated into future cementing programs to provide better job results and reduced well costs.

For more information about this technology, contact in the United States: CTES LP, Ed Smalley, phone: (936) 521-2222, e-mail: *ed.smalley@ctes.com*; or in Canada: Trican Well Services, Dale Dusterhoft, phone: (403) 266-0203, e-mail: *dale.dusterhoft@trican.ca* ✧

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Decision Tools for Natural Gas Industry Planners: Part 1—The Produced Water Management Handbook

By Tom Hayes,
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Gas Technology Institute and BC Technologies, Ltd. have developed several informational products to help energy planners, regulators and producers develop effective and economical strategies for treating and managing produced waters. First of a two-part series.

Development of natural gas reserves – always a complex task – is further complicated by the need to develop produced water management strategies that are economic to implement, satisfy stakeholders and are technically feasible for specific drilling locations. In doing so, gas producers must keep abreast of changing environmental regulations, understand new technologies for treating or disposing of produced water and scrutinize the potential benefits of recycling produced water for beneficial purposes.

The natural gas industry has worked for many years to meet this challenge, balancing energy resource development with environmental and health issues, water and mineral rights, and such stakeholder interests as federal land use and Indian tribal jurisdiction. In addressing these issues, effective produced water management also must be conducted at the lowest possible cost.

This is particularly important to ensure continued development of natural gas reserves in the Rocky Mountain and Central regions of the United States, where additional unique concerns often are raised by individual states.

For energy planners and regulators alike, there is a need for rapid access to accurate and up-to-date information – for each state and basin of interest – regarding key agencies, permits, tribal jurisdictions, regional best practices for produced water management, beneficial-use water guidelines and interwoven rules that affect land use water rights.

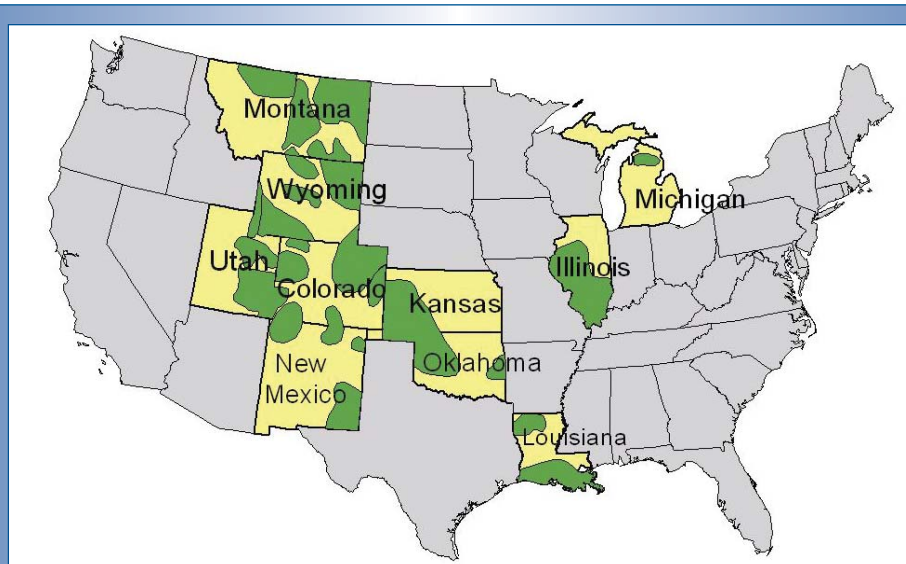

Figure 1. States and basins in the Gas Technology Institute study.

During the past 3 years, the Gas Technology Institute (GTI), in collaboration with BC Technologies, Ltd. (BCT), has developed several informational products that can facilitate the work of governmental and energy industry planners in their development of energy reserves. Three of those products are summarized in Table 1. This article describes the first product, ***The Produced Water Management Handbook.*** The other two products will be described in the Winter 2005 issue of *GasTIPS*.

Produced Water Management Handbook

For energy planners and the regulatory personnel involved in resource management planning, fast access to information that can be used to develop a water management plan is essential. It is difficult for production personnel to find time to keep informed of technology advances and changing regulations. GTI is positioned to serve as a resource and provide produced water management services to the natural gas industry by virtue of its efforts during the past decade to improve produced water management at a variety of locations. The organization also has ability to consider the application of new produced water management technologies. GTI, in collaboration with BCT, has developed a tool that can be used to assist with produced water management decisions. In 2002,

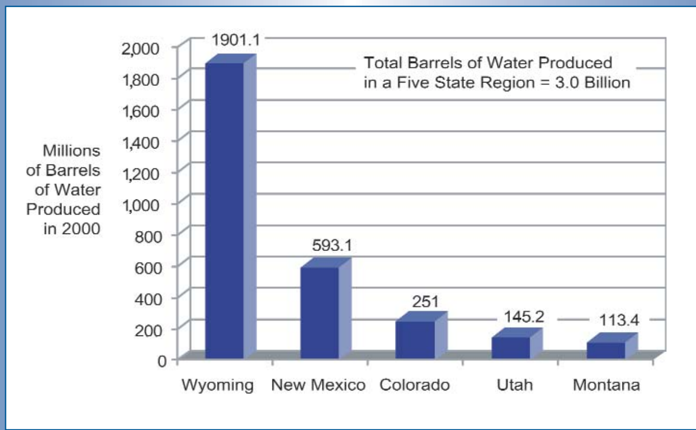

Figure 2. Barrels of produced water generated during oil and gas production in selected Rocky Mountain States. (Based on 2000 data)

GTI published ***The Produced Water Management Handbook,*** which documents produced water management practices used by producers in oil and gas basins throughout the Mid-continent and Rocky Mountain regions of the United States. It also provides information about the federal and state regulatory framework in which those practices exist. Maps and graphs are included to help the reader visualize the impact of each water management strategy by location.

As energy planners deal with the complexities of environmental and water use regulations, they must not only be cognizant of the current situation in each state, but also be aware of future trends and potential changes ahead, especially in the regulatory arena. The purpose of this report is to present a critical review and analysis of produced water practices based on technical, regulatory and economic factors at the local level in each basin of each selected state (Figure 1). The information-gathering approach relied heavily on detailed review of the latest regulations as well as direct interviews with oil and gas producers and regulatory personnel to gather and verify relevant information. More than 200 interviews with field operators in 10 states were included in the surveys. The handbook focuses on the strategies oil and gas producers are using to manage produced water in the selected states and examines the produced water handling, treatment, disposal and beneficial use practices in each of those states. The handbook also identifies how those practices fit into each state's regulatory framework that governs produced water management.

Oil and gas basins in these states were included in the study based on the oil, gas and water production volumes operators reported to state agencies. High volumes of natural gas and produced water were a key consideration for inclusion. A database was developed to identify the oil and gas producers' operating active leases in each basin, as well as to collect data on the volumes of oil, gas and water produced annually at their leases.

Producers who reported large volumes of natural gas and associated water were interviewed by phone regarding the strategies used by their companies for produced water handling, treatment or disposal and reuse. Producers also were asked to discuss the costs and cost factors associated with produced water management at their leases. In some states, where water production statistics were not available, produced water injection volumes were considered and producers with production and injection wells were contacted. About 250 oil and gas operators were interviewed during this project.

Each chapter of the handbook focuses on a different topic associated with produced water management. Chapter 2 examines federal environmental legislation and programs pertaining to produced water disposal such as the Clean Water Act, the Safe Drinking Water Act, the National Pollution Dissemination Elimination System (NPDES) Program and the Underground Injection Control (UIC) Program.

Chapter 3 examines state environmental regulations that apply to produced water management in each of the study states.

Chapter 4 provides a state-by-state look at oil, gas and produced water statistics; localized produced water management practices; and produced water disposal economics.

Chapter 5 addresses produced water han-

Table 1. Decision information for energy planners available from the Gas Technology Institute.

Product Title	Description of Product	Year Completed
Produced Water Management Handbook	*This document examines produced water management and practices in the 10-state region included in the study. It covers current regulations that drive water management decisions and offers location-specific information about produced water disposal costs.*	*2002*
Produced Water Atlas Series	*This atlas series presents maps that convey information on produced water generation and management in the natural gas-producing states of the Rocky Mountains and Mid-continent regions of the United States. The atlases include environmental regulations, oil/gas/water production statistics (year 2000) for basins and key fields, maps locating fields and basins, and produced water management practices of each basin.*	*2002*
Produced Water Decision Tree Model	*This interactive model (available on CD) lets the user select a state (and an oil- and gas-producing basin within a state) to access energy and water production statistics (year 2000), practices for water management, actual water management costs, and state and federal regulations for managing produced water.*	*2002*

Table 2. Produced water handling costs and total disposal costs in the Rocky Mountain Region.

State and Basin	Water Handling Method Reported	Water Handling Charges Reported	Total Handling and Disposal Costs
Colorado			
Denver Basin	Commercial trucking or water gathering system.	—	$1.00/bbl - $1.75/bbl
Las Animas Arch	Combined use of commercial trucking and water gathering system.	$0.40/bbl - $0.65/bbl or $55/hour	$0.50/bbl - $1.50/bbl
Paradox Basin	Water gathering system.	—	$1.33/bbl
Piceance Basin	Combined use of commercial trucking and water gathering system.	—	$0.05/bbl - $0.25/bbl
Sand Wash Basin	Commercial trucking or water gathering system.	—	$1.75/bbl
San Juan Basin	Water gathering system, occasionally commercial water.	—	$0.30/bbl - $1.50/bbl
Montana			
Central MT Uplift	Commercial trucking or water gathering system.	—	$0.05/bbl - $2.00/bbl
Sweetgrass Arch	Water gathering system.	—	$0.05/bbl - $.06/bbl
New Mexico			
San Juan Basin	Water hauling truck and water gathering System.	$0.70/bbl - $3.20/bbl	$0.50/bbl - $4.20/bbl
Utah			
Unita Basin	Commercial trucking or water gathering system.	—	$.05/bbl - $1.00/bbl
Wyoming			
Greater Green River Basin	Generally commercial water hauling service; some pipeline systems.	$0.80/bbl - $1.00/bbl; $80/hour	$0.50/bbl - $5.05/bbl
Powder River Basin	Almost all respondents reported utilizing a water gathering and distribution system.	—	$0.01/bbl - $.80/bbl

dling, and treatment technologies such as reverse osmosis and the freeze-thaw/evaporation (FTE®) process.

Chapter 6 provides conclusions from the research and lists Web sites where the reader can locate online production data or more complete versions of state and federal regulations.

Information in the handbook is based on federal and state environmental regulations that were current in 2002, as well as oil, gas and water production volumes available in 2000. The phone interviews with personnel at oil and gas production companies were conducted between 1998 and 2001. The producers interviewed provided the information about produced water management practices and disposal economics. Their responses represent produced water management practices used in each basin and should be viewed as representative of the produced water management strategies that can be used in a particular basin.

The Produced Water Management Handbook offers overviews of federal regulations on produced water management and helps the reader understand how the state regulations support federal legislation such as the Clean Water Act and the Safe Drinking Water Act. It summarizes state regulations that must be considered during water management planning, such as those that apply to injection wells, evaporation pits and surface discharge operations.

Regulations on other water management options, such as land application and irrigation, are addressed for states that permit such practices. Guidance documents on water management are cited, as are specific forms required for permitting. Information about where to locate electronic versions of required forms and complete copies of the regulations also is supplied.

State-by-state analysis

Chapter 4 of the handbook makes the connection between how much water is actually co-produced during oil and gas production and what it costs per barrel to dispose of it. For example, Figure 2 shows data from the handbook concerning barrels of produced water generated in 2000 during oil and gas production in selected Rocky Mountain states. For each state, the physical placement of the basins, produced water statistics of each basin, and produced water practices and associated costs are presented. A map of the oil- and gas-producing basins in Wyoming and a chart describing produced water volumes managed in each basin

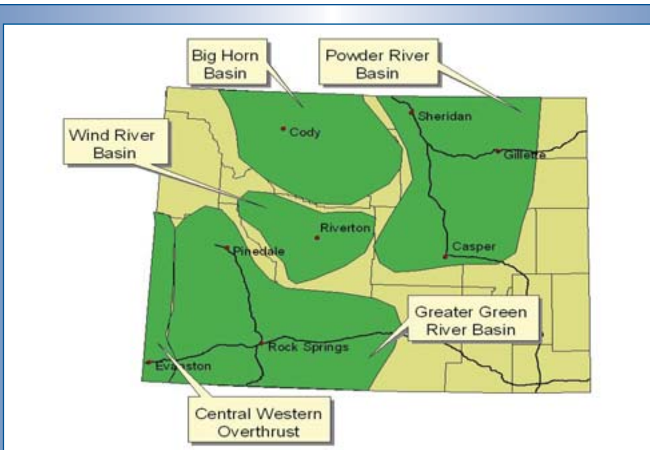

Figure 3. Oil- and gas-producing basins in Wyoming. (Based on production data for 2000)

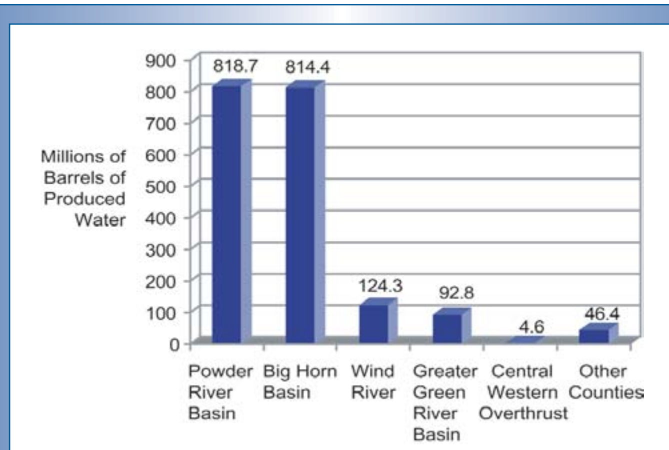

Figure 4. Volumes of produced water generated at selected oil and gas basins in Wyoming in 2000.

Table 3. Produced water handling and total disposal costs in the Mid-continental region.

State and Basin	Water Handling Method Reported	Water Handling Charges Reported	Total Handling and Disposal Costs
Illinois *Illinois Basin*	*Almost all interview respondents reported utilizing water gathering systems; a few reported utilizing commercial water hauling services.*	*$0.50/bbl - $1.50/bbl*	*$0.10/bbl - $1.25/bbl*
Kansas *Anadarko Basin*	*Almost all interview respondents reported utilizing water gathering systems; a few reported utilizing commercial water hauling services.*	*$0.25/bbl*	*$0.075/bbl - $1.30/bbl*
Louisiana *Gulf Coast Region*	*Most interview respondents reported utilizing pipeline systems; a few reported utilizing commercial water hauling services.*	*Not Provided*	*$0.05/bbl - $8.00/bbl*
Arkla Basin	*Most interview respondents reported utilizing pipeline systems.*	*Not Provided*	*$0.25/bbl*
Michigan *Antrim Shale Formation*	*Almost all interview respondents reported utilizing water gathering systems; a few reported utilizing company owned water hauling trucks.*	*$1.00/bbl - $1.50/bbl*	*$0.10/bbl - $1.70/bbl*
Oklahoma *Anadarko Basin*	*Almost all reported utilizing commercial water hauling services; some reported using water gathering systems.*	*$0.25/bbl*	*$0.05/bbl - $2.25/bbl*

are presented in Figures 3 and 4, respectively. Similar maps and charts are presented for all 10 states examined in the handbook.

Environmental regulations

For produced waters not immediately recycled into the hydrocarbon-producing formation, management is subject to regulations at the federal and state levels, though enforcement usually is administered by state agencies. The most applicable features of the regulations are described in the handbook, which gives the energy planner a better picture of the specific requirements for the produced water management options deployed in each of the 10 target states. The handbook also reviews the principal federal laws of The Clean Water Act that forms the basis for the state-administered NPDES permit programs as well as The Safe Drinking Water Act that provides for the creation of the UIC Program, which regulates the Class II injection wells used for the disposal of most produced waters.

More important, however, for each of the 10 states, the handbook gives the energy planner considerable guidance on:

- identification of the areas of compliance and permits required to pursue certain produced water options in each state;
- the specific state agencies that administer the permitting programs associated with produced water management;
- the citation of major sections of state codes that apply to various planning options;
- special requirements that may impact facility location and design; and
- a comprehensive list of Web site addresses where permit application forms and regulatory agencies can be accessed.

Produced water handling and treatment technologies

Current information from producers on produced water handling and disposal practices and associated costs – coupled with statistics on produced water generation – helps energy planners understand the regional magnitude and practical economics of produced water management.

Specifically, the handbook provides a state-by-state look at the water management strategies used in selected basins as reported by producers. Summaries of conventional produced water practices and associated costs in each state (and basin) are presented in Tables 2 and 3 for the Rocky Mountain and Mid-continent regions of the United States, respectively. Special conditions, regulations and factors affecting these costs also are presented for each basin.

In addition to conventional water handling and disposal, the handbook discusses emerging treatment technologies commercially available and being deployed for produced water management. These include downhole water separation for subsurface handling and two above-ground desalinization treatment processes: reverse osmosis and FTE. Each technique is described, including the extent of current use, the appropriate niche, ancillary requirements, the practical challenges encountered, and the potential advantages and disadvantages in implementation. The strengths and limitations of each treatment alternative are discussed.

For example, the practical difficulties of membrane protection are described as well as some process advances that may improve performance. Another example is the discussion of the FTE technology and a description of the specific regions where it would most efficiently operate.

Summary

Produced water management is a major factor in the economic feasibility of oil and gas field development in many areas of the Rocky Mountain and Mid-continent regions of the United States. Energy planners require estimates of not only the production potential of a candidate field, but also the most current information about produced water output, commercial practices for produced water handling and disposal with associated costs, pertinent regulations and other factors that can affect the feasibility of various future management options.

The Produced Water Management Handbook provides this array of information for each basin of the 10 states included in the study, providing considerable insight into the advantages and drawbacks of numerous options in system design and implementation.

For more information about the study that formed the basis of the handbook, contact Tom Hayes, GTI's associate director of environmental engineering via phone: (847) 768-0722 or e-mail: *tom.hayes@gastechnology.org*

The handbook is available on the GTI Web site, *www.gastechnology.org*, as document No. GRI-03/0016. ✧

BRIEFS

The Stripper Well Consortium (SWC) held it's Annual Project Selection Meeting at the end of May in Golden, Colo., where 19 proposed research projects were presented and reviewed for possible SWC funding. Of these, nine proposals were accepted for full funding and one proposal for partial funding. The selected projects are listed in the table. The abstracts for each project can be found on the SWC Web site at *www.energy.psu.edu/swc/projectoverview2004.shtml*

Also at the meeting in Golden, the SWC Executive Council approved a change to the SWC Constitution and By-Laws where a proposing company will no longer be required to be a member of the SWC. Membership to the consortium will still have its benefits. For more information concerning the SWC, please visit its Web site at *www.energy.psu.edu*

Projects selected for funding by SWC in 2004.

Project Topic	Organization
Building and Testing a New Type of Compressor for Stripper Well Production Application	W & W Vacuum Compressors Inc.
Hydraulic Fracture Imaging	Universal Well Services
Advance Technology for Infill and Recompletion Candidate Well Selection	Texas A&M University
Plunger Lift Process Optimization Using a Surface System for Plunger Generated Acoustic Noise Detection and Digital Signal Processing for Wellbore Plunger Location Monitoring	Tubel Technologies Inc.
Resolving Discrepancies in Predicting Critical Rate in Low-Pressure Gas Stripper Wells	Texas Tech University
A New Look at Foam for Unloading Gas Wells	Colorado School of Mines
Design, Construction and Evaluation of An Accurate, Low-Cost Portable Production Tester	Oak Resources
PVT Study of the Interaction of Nitrogen and Crude Oil, Stage II	The Pennsylvania State University
Low Friction Production Tubing for Stripper Gas Wells	Dynacoil
Field testing of the Vortex DXR Retrievable Insert Tool in Conjunction with other Lifting Methods	Votex Flow LLC (partially funded)

EVENTS

▶ SUBSEA HOUSTON 2004

Sept. 16, JW Marriott Houston, Houston
For more information, call (281) 491-5900, e-mail *sandra.gregory@questoffshore.com* or visit *www.subseahouston.com*

▶ SOCIETY OF PETROLEUM ENGINEERS ANNUAL MEETING

Sept. 26–29, Houston
For more information, call (972) 952-9393, or e-mail *spedal@spe.org* or *visit www.spe.org*

▶ EIGHTH ANNUAL MEXICAN ENERGY CONFERENCE

Oct. 28–29, Houston
For more information, call (781) 939-2438 or e-mail *cbireg@cbinet.com*

▶ INTERNATIONAL GAS RESEARCH CONFERENCE 2004

Nov. 1–4, Vancouver, B.C., Canada
Held every 3 years, the International Gas Research Conference (IGRC) is recognized worldwide as the major forum devoted to the exchange of the most recent natural gas research, development and demonstration results. This will mark the ninth presentation of the IGRC. For more information, visit *www.igrc2004.org*

▶ DEVELOPING SENIOR MANAGERS IN THE NEW CENTURY

Nov. 12-14, Edwin L. Cox School of Business, Southern Methodist University, Dallas
For more information, call (214) 758-3890 or (800) 768-6699, e-mail *execdev@mail.cox.smu.edu* or visit *execdev.cox.smu.edu*

▶ NATURAL GAS TECHNOLOGIES 2005: INGENUITY AND INNOVATION

Jan. 30–Feb. 2, 2005, Orlando, Fla.
This is the third Gas Technology Institute-sponsored conference and exhibition designed to showcase new and developing natural gas technologies for use across the entire industry and by gas customers. The conference is to be held at the Wyndham Palace Resort in Orlando. Details at *www.gastechnology.org* ✧

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