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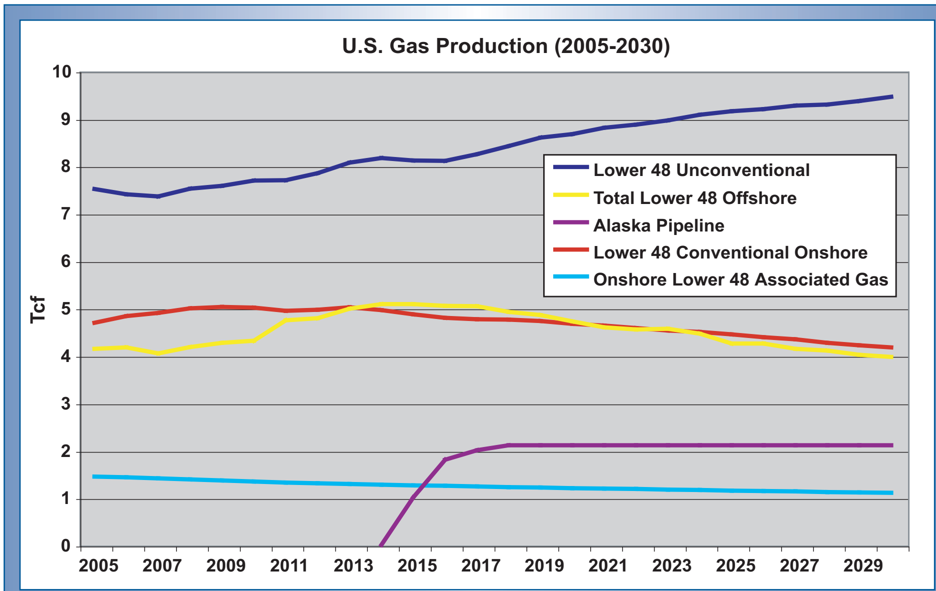
Commentary

Future U.S. Gas Supply Relies on an Unconventional "Pipeline"



Source: EIA Annual Energy Outlook 2006

The most recent Annual Energy Outlook, produced by the Energy Information Administration (EIA) and published in February, reiterates several points about North American natural gas that have been highlighted in earlier versions of the document. For example, new natural gas discoveries are expected to be deeper and more expensive to develop. Also, as onshore conventional natural gas production plateaus and then declines (from 4.7 Tcf last year to 4.2 Tcf in 2030), incremental production will come primarily from unconventional gas reservoirs, including coalbed methane, deep tight sandstones and gas shales. Production from these types of reservoirs is projected to increase from 7.5 Tcf last year to 9.5 Tcf in 2030; a 27% increase. Other natural gas resources will provide important contributions as well, but their impact will become less important as time goes by. For example, deepwater Gulf of Mexico gas production will peak at 3.2 Tcf in 2014 and then decline, while shallow water Gulf of Mexico gas will continue to decline from 2.4 Tcf in 2004 to 1.8 Tcf in 2030.

One exception is the abrupt addition of Alaskan gas, which is projected by EIA to begin flowing through a yet-to-be-built pipeline in 2015, rising to 2.1 Tcf by 2018 and extending on beyond 2030. The pipeline was in the news recently, as the state of Alaska reached a tentative agreement with ExxonMobil, BP and ConocoPhillips to begin the process of making the line a reality. The 2015 start-up date for the pipeline could be considered optimistic, however. The companies involved have so far committed to initiate a multi-year design phase, and a number of political issues will need to be worked out, including obtaining the necessary environmental, right-of-way and construction permits from U.S. and Canadian authorities. Currently, there is no steel mill capable of manufacturing the 3,600 miles of 52-in. pipe the line will require. The pipeline's eventual cost, estimated at $20 billion 5 years ago, is expected to be between $25 billion and $30 billion.

If the pipeline's construction and start-up were to be delayed, filling the gap between domestic supply and demand will require more imports of liquefied natural gas (LNG), a supply option that could be more expensive for U.S. consumers. The importance of continuing to find and produce deep gas and other unconventional gas resources in the lower 48 states remains as great as ever.

This issue of *GasTIPS* includes two articles that focus on efforts to accelerate the development of technologies to accomplish that goal. One describes work to establish a baseline of performance data for drillbits and advanced drilling fluids operating under the high-pressure conditions that exist at greater depths. Results from this research have highlighted opportunities for improvements in both. A second article describes field tests of a unique system for linking bottom-of-the-drillstring equipment with the surface through electromagnetic telemetry. This approach could dramatically improve the capability of measurement-while-drilling systems operating in increasingly deeper environments.

Both of these projects are part of the National Energy Technology Laboratory's Deep Trek program, which supports development of new technologies that promise to significantly reduce deep drilling costs.

A third article in this issue deals indirectly with unconventional gas; a discussion of the Gas Technology Institute's efforts to improve the ability to site and monitor carbon dioxide (CO_2) sequestration projects with coal fields. Eventually, CO_2 injection into coals could help produce additional gas while reducing the volume of greenhouse gas emissions. ✧

The Editors

Seismic Imaging for Site Selection and Monitoring of Carbon Dioxide Sequestration Part 2—Laboratory Studies

By I.A. Salehi, S. Gowelly and S. Batarseh, *Gas Technology Institute*

Laboratory measurement of changes in seismic wave velocity show an addition of a gaseous phase in water-saturated coal samples. Editor's note: This is the second in a two-part series.

Gas Technology Institute (GTI), with support from Illinois Clean Coal Institute and cooperation of Illinois State Geological Survey (ISGS), designed and implemented a comprehensive research project to determine the viability of seismic techniques for site selection and monitoring of carbon dioxide (CO_2) sequestration in Illinois coals. This article summarizes results from the project.

As with all greenhouse gas sequestration processes involving injection of greenhouse gases into geologic formations, safety and permanency of the processes require the injected gas to remain within the target zone with no possibility of contaminating water supplies, leaking to unintended zones or eventually escaping back into the atmosphere. Diligent site selection and attentive monitoring are crucial prerequisites for success. Specifically, the host coal seams must be continuous, extend over a large area, occur in structurally closed geometry, and be free of faults and displacements.

Advanced seismic technology has been proven successful in providing detailed subsurface images of conventional oil and gas reservoirs as well as thicker coal seams. However, Illinois coal seams are shallow and thin, with the thickness rarely exceeding 10ft. The first objective of this project was to establish viability of seismic imaging of the thin coal seams in Illinois. This issue was investigated in a series of seismic data acquisitions including surface seismic, vertical seismic profiling and cross-well seismic imaging. The data proved that thin coal seams could reliably be mapped by properly designed seismic surveys. Results of seismic work were discussed in the Fall 2005 issue of *GasTIPS*.

The second objective was to verify viability of the time-lapsed (4-D) seismic technique as a monitoring tool for potential CO_2 sequestration projects in coal seams of Illinois. Although 4-D seismic has proven successful in monitoring gas movements in conventional reservoirs, because of the intrinsic properties of coal seams, it is not known whether the technique is viable for mapping the gas front in coals. In pursuing this objective, a number of elaborate laboratory measurements of acoustic velocity in gas and water-saturated coal samples were carried out. Measurement results showed the magnitude of velocity changes from addition of a gas phase into water-saturated coal is large enough to render the time-lapsed seismic imaging useful for monitoring the position of the injected gas front.

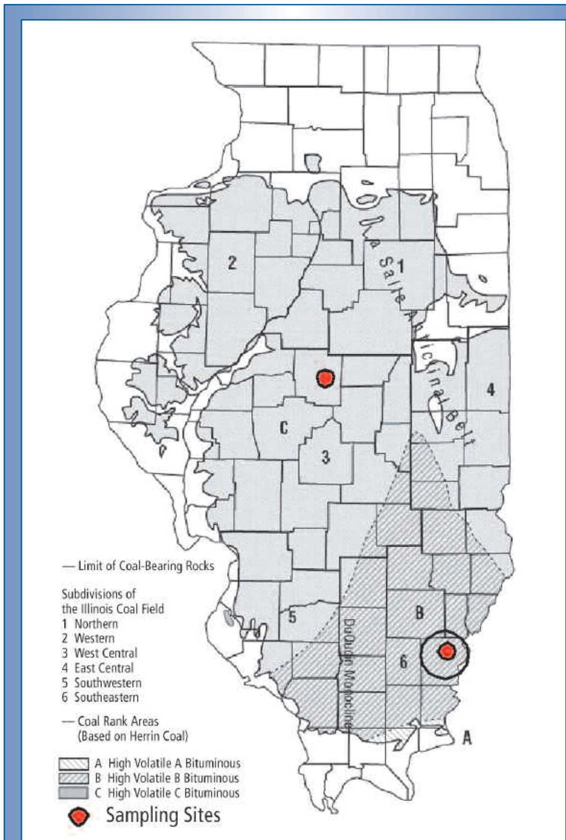


Figure 1. Location map for sampling sites and ISGS pilot site (Open circle).

Motivation

A significant challenge in geological sequestration is to map and monitor the CO_2 in the subsurface thin coal reservoir, assuring the CO_2 is safely contained within the intended zone. It has been well established that the addition of a gas phase into non-gas-bearing sediments causes a measurable decrease in seismic velocity, thus analysis of the two consecutive surveys provides a direct measure of the movement of the gas/liquid contact during the elapsed time. This phenomenon has given birth to 4-D seismic that is used for gas cap monitoring in many petroleum fields as a matter of routine. In the case of coal, however, two issues are not as clear. First, because of the intrinsic properties of coal (low density and high compressibility), it is not certain that the magnitude of velocity change would be large enough to be reliably detectable. Second, not all coals are the same, and their elastic properties vary over a long range, therefore, viability of 4-D seismic technology for specific coal deposits must be determined before embarking on the expensive and time consuming 4-D seismic surveys. GTI's laboratory measurements were focused on Illinois coals with specific attention to the Davis seam in southern Illinois, which is the target of the ISGS pilot project (Figure 1).

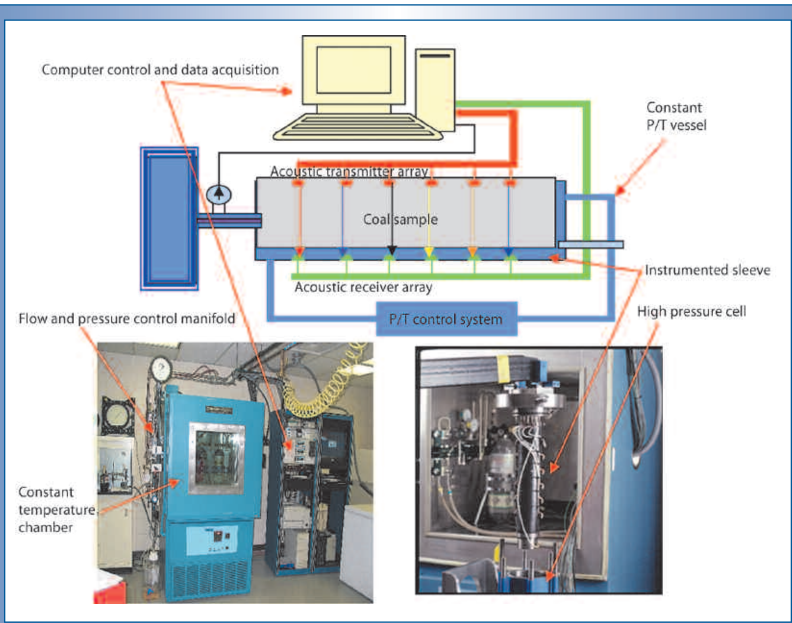


Figure 2. Exhibits the laboratory set up for measurement of acoustic velocity under controlled pressure and temperature conditions.

Experimental procedure

Laboratory measurements of coal's physical properties are difficult and time consuming primarily because of coal's high friability and low matrix permeability, and the pressure dependency of compressional wave velocity. Samples used for the experiments were taken from blocks of coal collected from two coalmines, one in Southern Illinois near the ISGS site and one in central Illinois near Springfield. These blocks contained numerous natural fractures most of which were filled with calcite with various degree of purity. Twenty cylindrical $2\frac{3}{4}$-in. by $13\frac{1}{2}$-in. samples were cut from these blocks. Nearly half the samples were cored parallel and the other half normal to the dominant fracture system.

In these experiments, the sample is placed inside a viton sleeve that houses two orthogonal arrays of matched transducers functioning as source/receiver pairs. The sleeve is capped at both ends with blocks that house signal input/output connections and flow ports allowing flow from either end of the sleeve. The assembly is then placed inside a high-pressure reaction cell, which is placed inside a constant temperature chamber. Gas injection into the space between the instrumented sleeve and the inner wall of the cell provides the confining pressure that can be externally regulated and maintained at the desired level. Using the external and internal manifolds, gas or liquid can be injected into the core while recording continues (Figure 2).

Laboratory studies were focused on measuring changes in acoustic velocity resulting from the addition of a gas phase into water-saturated coal samples. In cases where high friability of the coal prevented cutting sufficient cores to the desired length, the test apparatus was reconfigured to accommodate shorter (5-in.) cores. In the reconfigured setup, two additional pairs of transducers were added for simultaneous measurements in two orthogonal directions without extraction and reinsertion of the core (Figure 3).

Laboratory results

The dilemma is that while "good" samples for laboratory measurements have to be solid and free of fractures, such specimens are by no means representative of large bodies of coal. To overcome these difficulties, experiments must be repeated multiple times on different samples to arrive at some meaningful average values. GTI developed in excess of 140 data points for coal samples from two Illinois coalmines. A summary of results for 20 samples is shown in Table 1.

These measurements showed acoustic velocity changes that resulted from injection of a gas phase into water-saturated coal samples and thus, validate the feasibility of time-lapsed seismic surveys for monitoring CO_2 sequestration in coal. Please note that in all cases, compressional wave velocity for water-saturated samples is higher than that for the same sample with gas saturation.

Figure 4 is a graphic representation of the data in Table 1, which also shows the pressure dependency of the acoustic velocity for

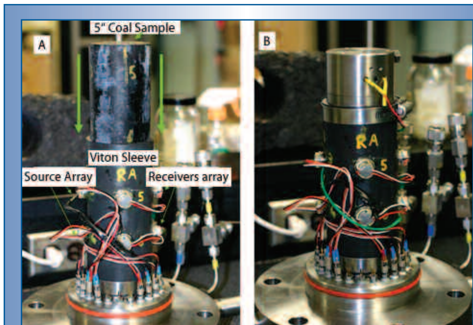


Figure 3. Transversely instrumented sleeve

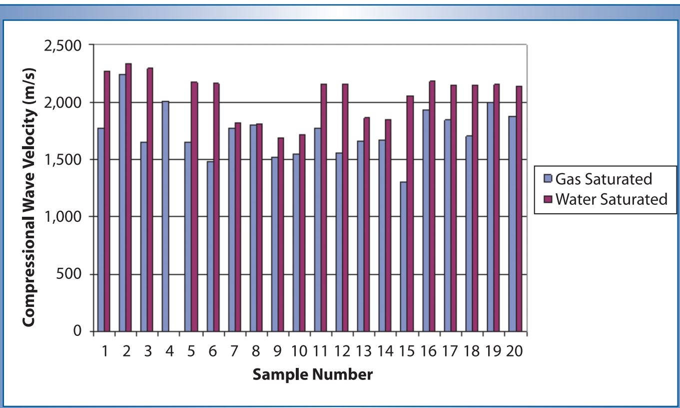


Figure 4. Graphic representation of information in Table 1

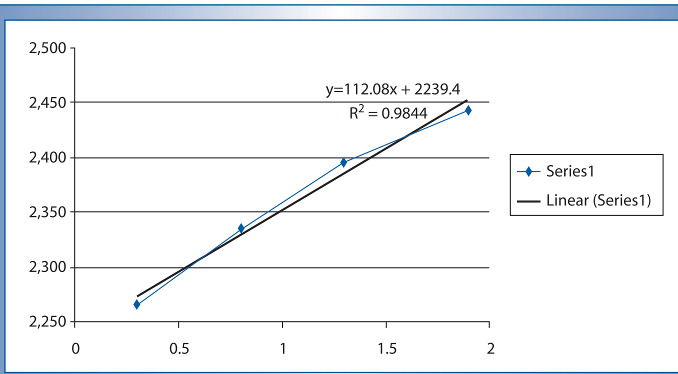


Figure 5. In many cases, the relationship between acoustic velocity and pressure dependency is almost linear.

all samples. In many cases, this relationship is almost perfectly linear (Figure 5). However, it was not possible to establish an analytical relationship between velocity and confining pressure for cases of highly fractured coal samples.

Conclusions and recommendations

Combining the results from field seismic surveys described in part one (*GasTIPS* Vol. 11, No. 4) and laboratory measurements described here, the following conclusions can be drawn:

- The resolution is low, between 10-Hz and 50-Hz bandwidth, and results from surface seismic surveys are not reliable.
- High-resolution imaging is possible between 10-Hz and 200-Hz bandwidth, and surface seismic data would be reliable for mapping of the "coal seam packages" as a whole.
- The use of impulsive sources for surface seismic surveys is strongly recommended.
- Vertical seismic profiling surveys (between 10-Hz and 300-Hz bandwidth) enhance the resolution.
- Under geologic conditions similar to those at the ISGS pilot site, position of the injected or evolved gas can only be imaged at higher frequencies through cross-well seismic applications.
- Laboratory measurements proved that changes in acoustic properties of coal resulting from the addition of a gas phase into the cleat and pore spaces is substantial and, therefore, seismic monitoring of the injected CO_2 would be quite feasible. Furthermore, monitoring of methane production from coal seams of Illinois appears to be quite practical and can be used as means for determination of the high permeability trends and development of de-watering and production well patterns. ✧

Table 1. Compressional wave velocity under gas and water saturation

Sample Number	Confining Pressure (Mpa)	P Travel Time in µs (Gas Saturated)	P Travel Time in µs (Water Saturated)	Vp @ Gas Saturation on (m/s)	Vp @ Water Saturation on (m/s)
1	3.9	39.45	30.79	1,771	2,269
2	1.9	31.14	29.95	2,243	2,332
3	2.9	42.19	30.5	1,656	2,290
4	2.9	34.83		2,005	
5	2.9	42.35	32.13	1,649	2,174
6	2.9	47.14	32.25	1,482	2,166
7	3.9	39.38	38.44	1,774	1,817
8	3.9	38.9	38.56	1,796	1,811
9	3.9	46.1	41.46	1,515	1,685
10	3.9	45.16	40.72	1,547	1,715
11	3.9	39.33	32.49	1,776	2,150
12	2.9	44.87	32.4	1,557	2,156
13	2.9	42.08	37.56	1,660	1,860
14	2.9	41.87	37.88	1,668	1,844
15	2.9	53.43	34.02	1,307	2,053
16	2.9	36.19	32.02	1,930	2,181
17	2.9	37.94	32.52	1,841	2,148
18	1.9	40.97	32.52	1,705	2,148
19	2.9	34.89	32.43	2,002	2,154
20	2.9	37.28	32.72	1,874	2,135

Acknowledgements

The authors wish to express their acknowledgments to the Illinois Clean Coal Institute and GTI for their financial support, and to Dr. Robert Finley and Dr. David Mores of the ISGS for their technical support and contributions. Thanks also to Jim Cantrell of Royal Drilling Co. for his valuable logistical and operational support and to Z-Seis for its coordination of the fieldwork and contribution of a second cross-well survey at no charge.

Risk Reduction in Gas Reservoir Exploration Using Joint Seismic-EM Inversion

By Yoram Rubin, G. Michael Hoversten, Zhangshuan Hou and Jinsong Chen, *University of California, Berkeley*

A method for identification of gas saturation in deep ocean oil-gas reservoirs, which combines data obtained from seismic with electromagnetic surveys, is presented. Researchers from the University of California, Berkeley, and Lawrence Berkeley National Lab test their ideas using synthetic and real-life data from the Troll Gas Province in the North Sea and prove the potential for significant exploration risk reduction.

The prediction of reservoir parameters such as gas or oil saturation or both from geophysical data is the goal of most geophysical surveys performed in the context of hydrocarbon exploration and production. Interpretation of geophysical data is rarely a trivial task, but is particularly challenging in the case of gas exploration.

Current seismic imaging technology cannot accurately discriminate between economic and non-economic concentrations of gas. This is primarily because of the insensitivity of acoustic (V_p) and shear (V_s) wave velocities to gas saturation. According to Gassmann's equations, a gas sand with 1% gas saturation can have the same V_p/V_s as a commercial accumulation of gas.

In recent years, the focus of oil-related geophysical exploration has been on using time-lapse seismic data for predicting changes in pressure and fluid saturation. Predictions of changes in pore pressure can be done when there is only oil saturation (S_o) and water saturation (S_w). The presence of gas complicates the problem by introducing a third independent variable, the gas saturation (S_g). In the case of a reservoir with an oil-water-gas mix, the determination of gas saturation is inherently non-unique.

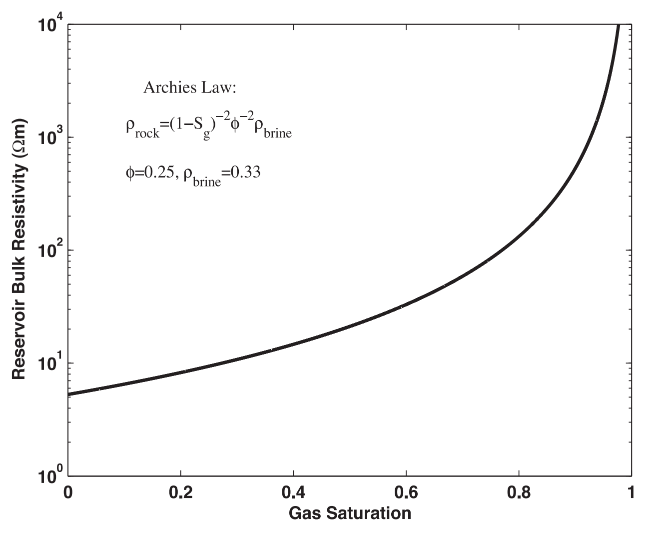


Figure 1. Reservoir bulk resistivity as a function of gas saturation (S_g). Porosity = 25%

Seismic technology can provide two critical pieces of information needed for the ultimate estimation of gas saturation: the physical location of the reservoir unit, to within a few percent of the true values; and the porosity of the reservoir unit.

In contrast to the insensitivity of seismic attributes such as V_p/V_s, AVO slope and intercept or acoustic-shear impedance to gas saturation, the electrical resistivity of reservoir rocks is highly sensitive to S_g, through the link to water saturation. This sensitivity can be seen using Archie's law, which has been demonstrated to accurately describe the electrical resistivity of sedimentary rocks. Figure 1 shows the bulk resistivity (R_{bulk}) as a function of S_g=(1–S_w) for a reservoir having 25% porosity and brine salinity of 0.07 ppm. The relationship between R_{bulk} and S_g has the advantage of displaying the steepest slope in rock bulk resistivity R_{bulk} in the S_g range from 0.5 to 1.0, where the division between economic and non-economic S_g usually occurs.

The means of estimating R_{bulk} have recently become available through the use of electromagnetic (EM) sounding systems. Recently, attention has been focused on the use of controlled-source electromagnetic (CSEM) systems in direct detection/mapping of hydrocarbon. A marine CSEM system consists of a ship-towed electric dipole source and a number of seafloor deployed recording instruments capable of recording orthogonal electric fields. During the past few years, a number of contractors have begun offering marine CSEM data on a commercial basis.

The relative strengths of seismic and CSEM technologies suggest they can complement each other. Combining the two types of data should improve fluid saturation estimates in a joint inversion, since they provide different and complementary images of the geology. This is not a new idea, and studies along this line were reported, such as Hoversten et al.,

2003. This article develops a new systematic approach for application and illustrates the benefits of joint amplitude vs. angle (AVA) and CSEM inversion for estimating gas saturation and porosity.

A strategy for marine natural gas exploration

Several challenges need to be addressed before joint AVA-CSEM inversion can become routine: (a) different types of data, as well as data obtained from different sources, are characterized by different error levels, which are not always known prior to the inversion. Thus, methods are needed for modeling such errors with minimum bias, while assigning proper weight to the different data; (b) deterministic inversion – one which assumes unknown parameters can be uniquely defined – is in general an ill-posed mathematical problem because of non-uniqueness and instability of the inverse problem. This in turn suggests that inversion formulated in a stochastic framework – one which views the unknown parameters as random variables, in a statistical sense – may be more robust than traditional deterministic approaches, and must be formulated rigorously; and (c) prior information is available, in many cases, to constrain the inversion in reservoirs. Such data may be available, for example, from geologically similar formations, but its incorporation into stochastic inversion requires answering questions such as what relative weight the prior information should be assigned compared with direct measurements, and what would be a rational approach for incorporating prior information into a stochastic framework for inversion.

Data used for inversion

Seismic data used for this study are the pre-stacked seismic time series at several incident angles along depth, typically representing two-way travel times. After appropriate seismic processing, including amplitude recovery, we will assume the seismic attenuations in the earth above the target interval (the overburden) have been accounted for and can be neglected in the seismic modeling. We can choose to invert seismic V_p and V_s and density in the zones outside the reservoir, and invert gas saturation and porosity within the reservoir.

Marine EM data used in this study include the amplitudes and phases of the recorded electrical field from many receivers on the seafloor. The EM amplitudes and phases, along with the applied current and transmitter locations, are recorded as time series, which are then averaged to produce in-phase and out-of-phase electric field. Those data are the responses to the electrical conductivity in the space that includes seawater, overburden above the gas reservoir, gas reservoir and bedrock below the reservoir.

Inversion approach

Designating the inversion target parameters as random variables offers a rational way of modeling the uncertainty because of measurement errors, data scarcity and spatial variability. We represent the inversion target parameters by a vector m the composition of which can change between reservoirs, but in general it contains saturation of various layers, porosities, resistivities, etc. To account for parameter uncertainty, m is viewed as a realization of a random vector M which is characterized by a p-variate probability distribution function (pdf), $f(m)$, where p is the number of parameters in M. Our inversion approach is based on Bayes' Theorem

$$f(m) \propto f(d^*|m,I)\, f(m|I),$$

that identifies $f(m)$, known as the posterior (or a-posteriori) pdf, as a function proportional to the product of a prior (or a-priori) pdf, $f(m|I)$, and a likelihood function, $f(d^*|m,I)$. The symbols to the right of the vertical bar denote information, given or assumed. The prior pdf, $f(m|I)$, summarizes, in a statistical form, the information available on the parameters vector M prior to the EM and seismic surveys. It represents the probability of M to assume the set of values m, given prior information I, consisting of information such as expertise gained in other parts of the reservoir, relevant borehole information, as well as information and expertise borrowed from other, geologically-similar formations. There can be many physically plausible combinations to m, and $f(m|I)$ assigns to each of them a different probability according to how realistic or unrealistic it is, in light of I. This opens the door for subjectivity, which can be detrimental. One of the challenges in using priors is minimizing the subjectivity associated with its formulation. Our approach is to select the prior pdf that minimizes the subjectivity using entropy-based measures of information. We refer to this approach as minimum relative entropy (MRE). The likelihood function, $f(d^*|m,I)$, represents the probability of observing the data vector, d^*, which includes data obtained from the EM and seismic survey, given m and I. It provides the means for updating the prior pdf with new information gleaned from d^*. The likelihood function maps the prior into the posterior pdf: it assigns larger probabilities to those m that make observing d^* more probable, and smaller probabilities to those m that make observing d^* less probable.

Application I. Synthetic data

To illustrate the performances of the individual and combined inversion of seismic and EM data, we constructed a simple model (Figure 2) from which we generated the synthetic seismic and EM datasets, assuming the rock properties to be known. The gas saturation values (S_g) and porosities (ϕ) of the layers are shown from top to bottom, in Table 1.

The synthetic AVA is sampled 80 times at

Table 1. The gas saturation values and porosities of the layers from top to bottom

Target Layer	S_g	ϕ
1	0.10	0.15
2	0.95	0.25
3	0.40	0.15
4	0.90	0.10
5	0.10	0.05

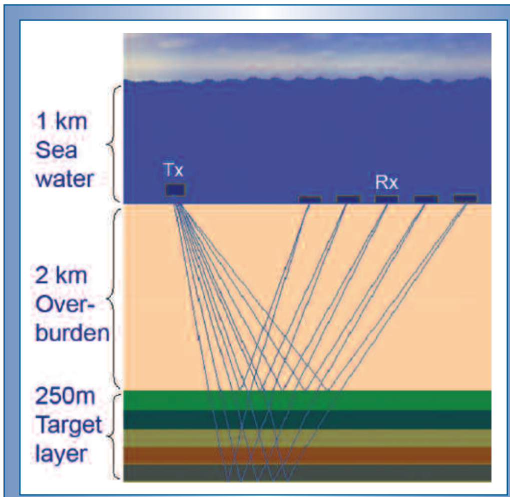


Figure 2. This schematic represents the domain investigated in the synthetic study.

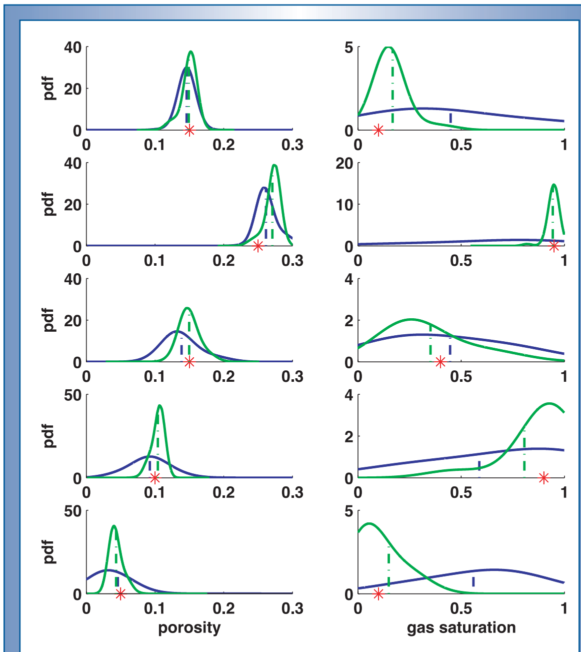


Figure 3. This graph shows the estimated porosity and gas saturation using seismic data only inversion (blue lines) and joint inversion (green lines). The true values are represented by red star symbols, and the solid lines represent the posterior probability distribution function obtained from inversion. The dash-dotted lines represent the posterior means.

2ms for five incident angles. The synthetic EM data includes the amplitude and phase of the measured electric field at frequencies 0.25 Hz, 0.75 Hz and 1.25 Hz, for 15 source-receiver offsets. Gaussian random noise was added starting with 10% noise for the first angle and increasing up to 30% for the far angle. Similarly, 10% Gaussian noise was added to the electric fields at the near offsets, increasing to 30% for the maximum offset.

Figure 3 (blue lines) shows the results from a seismic-only inversion. The results are given in the form of the pdfs of the target statistics. The mode of a pdf is the most likely estimate, and the mean of the distribution is another acceptable estimate. When an estimate is accompanied by a widely spread pdf, there is only limited confidence in it. On the other hand, narrower pdfs, with well-defined modes, indicate high confidence in the estimates.

Figure 3 (blue lines) shows that porosity estimates are quite accurate, with the associated uncertainty increasing with depth. The gas saturation estimates, on the other hand, are poor, as expected.

Results obtained after augmenting the seismic data with EM synthetic data are shown as green lines in Figure 3. The joint inversion provides better estimates of gas saturation at all layers. Although the uncertainty levels for the bottom layers are still not small, the modes of the pdfs are close to the true values, thus all gas-rich or water-rich layers are well identified through the maximum likelihood estimates. As stated above, up to 30% noise is introduced into both measurements and forward model responses, and large predictive bounds are not unexpected.

Application II. Troll field study

In this section, we apply our MRE-based Bayesian approach to the Troll field site in the North Sea. At the study site, hydrocarbon-filled sands occur at a depth of about 1,400m below sea level. The well log from a nearby borehole shows a predominantly oil zone between 1,544.5-m and 1,557.5-m depth. The Bayesian model for this application was developed based on the geometry shown in Figure 4. We divided the reservoir into 16 layers, each of which having a thickness of 20m. The unknowns are S_w, S_g, S_o, and ϕ for each of these target layers. For seismic AVA data inversion, we also consider V_p, V_s and bulk density ρ at each of the five layers above and the one layer below the reservoir as unknowns, with each layer having a thickness of 20m. For the EM data inversion, we divided the reservoir overburden (including seawater) into 13 layers, based on resistivity logs from a nearby well, and considered the electrical conductivity of each layer as unknown.

In practice, information on the reservoir parameters is available, for example, in the form of bounds and/or expectation values (prior means), which can be obtained from the site geology or from other sites explored in this province. With only information about the bounds, the priors assume uniform distributions. Given information about the bounds as well as the prior means, the priors take the form of truncated exponential distributions, based on MRE theory.

We performed inversions using seismic AVA data and EM data individually, as well as a joint inversion using both types of data. The results shown (figures 5 and 6) are for AVA-only and joint AVA-EM respectively, using truncated exponential priors.

By comparing the results from seismic only inversion (Figure 5) to the joint inversion (Figure 6), we can see that the joint inversion improved the predictions of the target parameters, leading to much narrower predictive intervals, especially for the gas saturation estimates at the bottom layers. The predictions obtained for the water and oil saturations are closer to the well log observations.

Compared with the results generated using uniform priors, the predictive intervals of almost all the target parameters are narrower, and the estimated posterior modes are

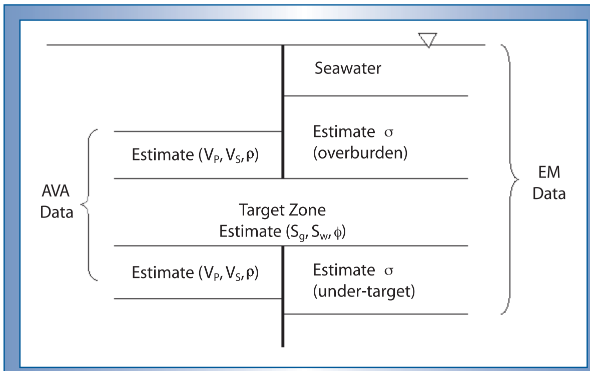


Figure 4. This schematic map shows the inversion domain.

closer to the well-log values. These results are expected, since more information is included when using bounds and means priors compared with the case where only uniform bounds are available.

The seismic and EM observations and the model responses calculated using the posterior modes of the parameters from joint inversion are plotted in figures 7 and 8, respectively. The figures show that the model responses match the observations well.

Discussion and conclusions

We proposed here an MRE-Bayesian approach for joint seismic and EM inversion. Our results using synthetic data indicate that joint inversion based on seismic and EM data improves our capability to identify and confirm the locations of gas-rich layers. Incorporation of EM data in the inversion is useful in improving predicted gas saturations. The approach is also applied to field data at Troll field in the North Sea. Results show the benefits of including EM data with seismic data in the inversion. Compared with any individual inversion using seismic or EM data, the joint inversion gives predictions that are generally closer to well logs and yields narrower predictive intervals.

The advantage of formulating the inverse problem in a stochastic framework is manifested in the statistics of the target parameters. Instead of the usual single-valued estimation provided by deterministic approaches, we obtain a probability distribution, which allows computing mean, mode and confidence intervals and is useful for a rational evaluation of uncertainty and risk. Moreover, the MRE-Bayesian framework improves estimation results when incorporating informative priors.

We made several important assumptions in the study. We assumed a one-dimensional layered model can represent the earth. This assumption may be inappropriate for high frequency EM datasets at large offsets, since higher frequency EM responses are more easily affected by three-dimensional structures of the earth. For seismic data inversion, we assumed the effects of multiples and waveform spreading can be neglected. We also assumed the rock physics model parameters developed from the well logs nearby are true for our study site. These assumptions can be relaxed by increasing the complexity of the seismic and EM models. For example, we can use one-dimensional elastic seismic calculation with waveform spreading, mode-conversions and all multiples; or we can consider quasi-two-dimensional, two-dimensional or even three-dimensional forward models.

The limitations described above notwithstanding, we have shown that combining CSEM with seismic data through joint inversion significantly reduced the risk of making an error when trying to identify gas-rich layers. We continue to pursue this topic. For more information, please email *rubin@newton.berkeley.edu* ✧

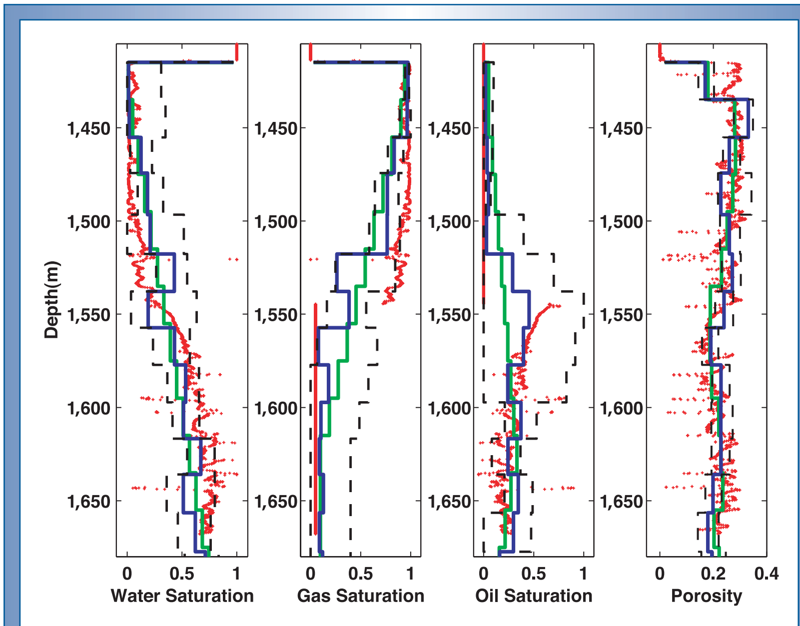


Figure 5. This graphic shows an inversion using only seismic data with information about prior means. Red crosses represent well log values, green lines are the prior means, blue lines are the estimated posterior modes, and black lines represent 99% predictive intervals.

Acknowledgements

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We are grateful to Statoil for supplying the CSEM data over Troll and to EMGS and Shell for their contributions of data and consultations. In particular, we thank Tage Rosten of Statoil, Jaap Mondt and Maren Kleemeyer of Shell and Rune Mittet of EMGS. In addition, we thank the Troll partners (Norsk Hydro, Statoil, Petoro, Norske Shell, Total and ConocoPhillips) for permission to publish this work.

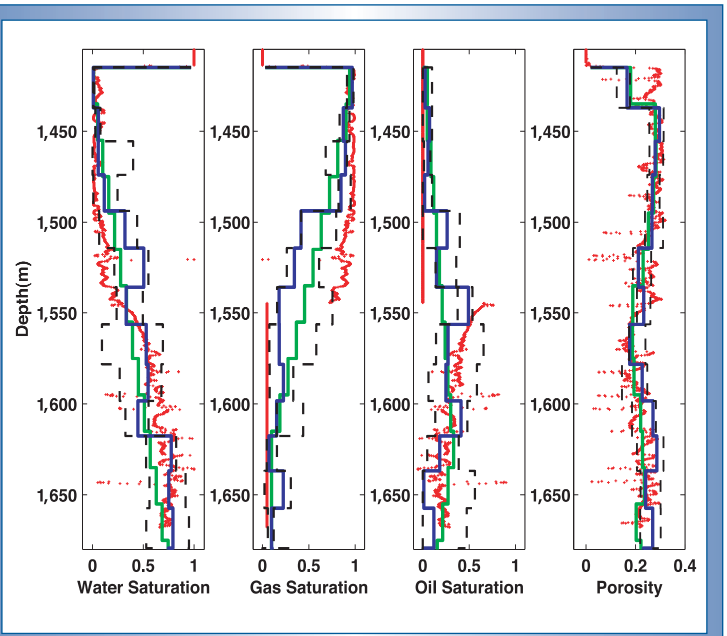

Figure 6. This graphic is a joint inversion using seismic and electromagnetic data, with information about prior means. Red crosses represent well log values, green lines represent the prior means, blue lines represent the estimated posterior modes, and black lines represent 99% predictive intervals.

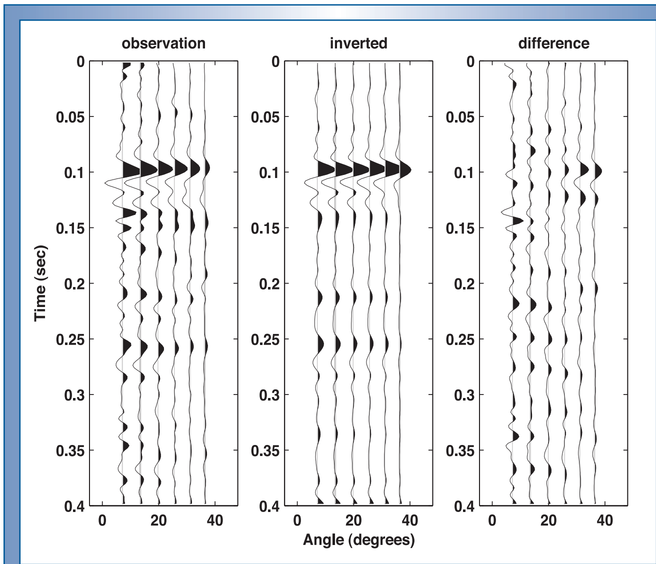

Figure 7. The above graphic shows observed seismic amplitude vs. angle (AVA) gather (left panel), calculated AVA data from seismic only inversion (middle panel) and the difference between observed and calculated AVA data (right panel). Zero time corresponds to the top of the seismic inversion zone 100m above the reservoir. The top and base of the gas reservoir are at 0.1 seconds and 0.37 seconds.

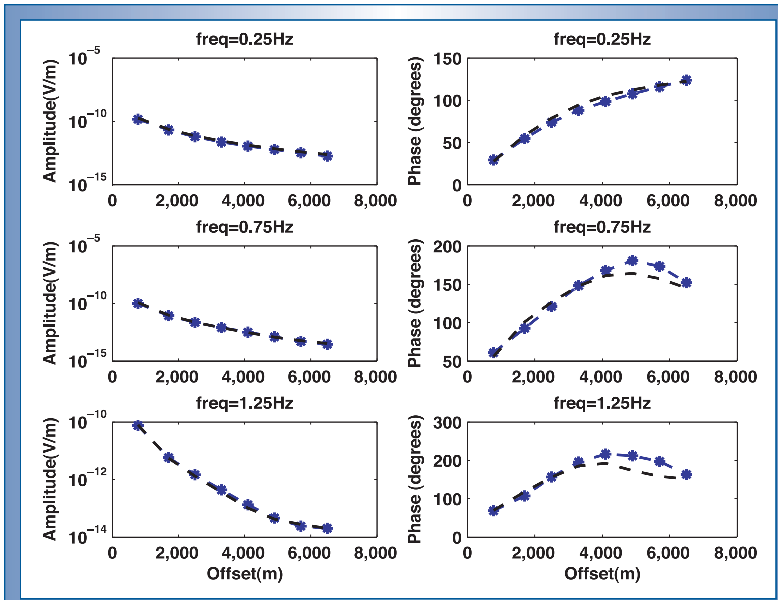

Figure 8. The above graphic shows observed controlled source electromagnetic data and calculated data from joint inversion. The blue lines represent the field data, black lines represent the calculated data.

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Optimization Model for Design and Planning: Uncertainty of Offshore Gas Field Infrastructures

By Vikas Goel, *ExxonMobil Upstream Research Co.*; and Ignacio E. Grossmann, *Carnegie Mellon University*

In a project sponsored by the ExxonMobil Upstream Research Co. and the Gas Research Institute under an RPSEA grant, the authors developed an advanced optimization model that accounts for uncertainties in the sizes and deliverabilities of fields in the design and planning of offshore gas-producing sites.

Oil and gas exploration and production is a highly capital-intensive industry. Each project in this industry typically lasts between 10 and 30 years or more and can be worth in excess of $1 billion. With such high investments and profits, it is not surprising many decisions involve large expenditures. For instance, leasing a drilling rig typically costs $1 million per day. Since projects are characterized by long time horizons, the investment decisions have long-term impact. For such capital-intensive projects, there is a clear need for developing systematic optimization tools that can aid in the decision-making process.

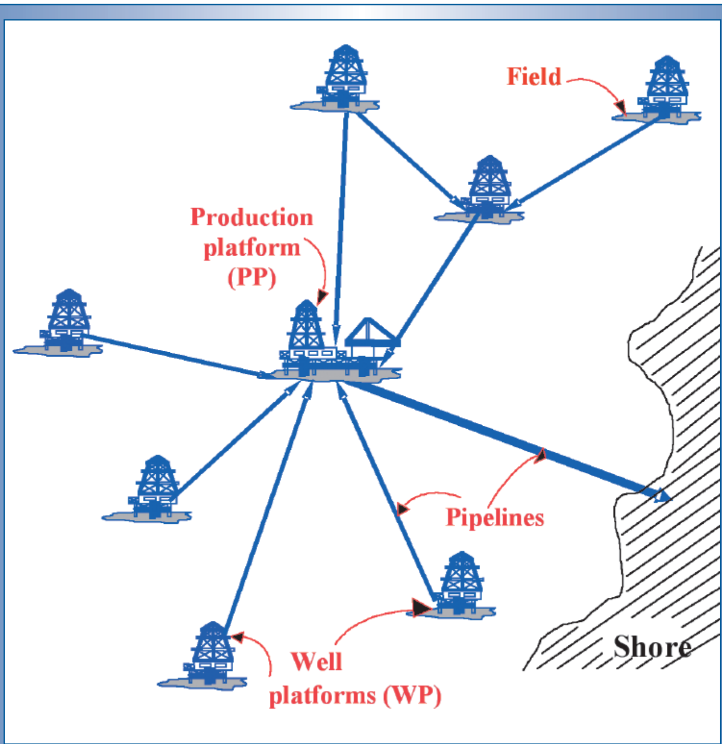

Figure 1. A typical offshore gas production site.

Most of the available literature that deals with planning of oil and gas field infrastructures uses a deterministic approach (see Van den Heever et al. (2001) for a review). However, a major challenge lies in the fact that decision-makers in this industry have to contend with a great deal of uncertainty. One of the most important sources of uncertainty is the quality of reserves. The existence of oil and gas at an offshore site is indicated by seismic surveys and preliminary exploration tests. However, the actual amount of oil or gas in these reserves and the efficacy of extracting these remain largely uncertain until after the investments have been performed. Hence, the effect of these uncertainties must be taken into account when formulating the decision policy. Goel and Grossmann (2004) present a review of literature that deals with uncertainty in these problems. Most of the past work deals with simplified cases, where the investment or operation decisions are assumed to be fixed, or the problem includes only one field.

In this article, the specific problem described is a stochastic optimization model by Goel and Grossmann (2004) for the design and planning of an offshore gas-producing site with a number of reserves of gas or fields. Major sources of uncertainty considered for the unexplored fields are their sizes and deliverabilities. We assume that discrete probability distribution functions for these uncertainties are given. The optimization objective selected is the maximization of the expected net present value (NPV) of the project.

Description of offshore gas field infrastructure

An offshore gas production site has a number of reservoirs of gas, known as fields. The typical infrastructure at an offshore site includes well platforms, production platforms and connecting pipelines (Figure 1). To extract gas from a field, a dedicated well platform has to be installed at the field. Each well platform is connected to another well platform, or to a production platform, through pipelines. Gas produced at all well platforms is sent to the production platforms and from there to the shore through this network of pipelines. During an offshore gas production project, investment and operation decisions have to be made. Investment decisions include selecting where and when to install the well platforms and production platforms, the capacities of these platforms and the pipeline connections to be constructed. Operation decisions include determining the production profiles for the different fields over time.

One of the most important sources of uncertainty is the quality of reserves. The existence of oil and gas at an offshore site is indicated by seismic surveys and preliminary exploration tests. However, the actual amount of oil or gas in these reserves, and the efficacy of extracting these, remain largely uncertain until after the investments have been performed. Hence, the effect of these uncertainties must be taken into account when formulating the decision policy.

Uncertainty and scenario trees

Based on the dependence of the stochastic process on the decisions, Jonsbraten [23] classifies uncertainty in planning problems into two categories: project exogenous uncertainty and project endogenous uncertainty. Problems where the stochastic process is independent of the project decisions are said to possess project exogenous uncertainty. For these problems, the scenario tree is fixed and does not depend on the decisions. For example, Figure 2 shows a scenario tree for a problem with three time periods and two random variables. Both uncertainties have two possible realizations, (high) and (low). The uncertainty of the first random variable is resolved at the end of the first time period, while the uncertainty of the second random variable is resolved at the end of the second time period. The scenario tree in Figure 2 is based on the assumption that uncertainty in each random variable is resolved at a pre-determined time, and this time, or the realizations of these random variables, is not affected by the project decisions. The uncertainty in gas price in a planning problem similar to the one described here is an example of project exogenous uncertainty.

Problems where the project decisions influence the stochastic process are said to possess project endogenous uncertainty. A gas production-planning problem with uncertainty in gas reserves is included in this category, because the uncertainty in gas reserves of a field is resolved in principle only if, and when, exploration or investment is done at the field. If no action is taken, the uncertainty in the field does not resolve at all. For problems with project endogenous uncertainty, the scenario tree is decision-dependent. This leads to significant challenges in defining a model because, traditionally, the stochastic programming literature has relied on the assumption of fixed scenario trees like the one in Figure 2. Consider an example with two uncertain fields, A and B, and four time periods. The sizes of these fields are uncertain and each has two possible realizations, *H* (high) and *L* (low).

We consider two investment policies. Investment policy I suggests we install a well platform at field A in t=1. If the size of A is found to be low, then we install a well platform at field B in t=2. On the other hand, if the size of field A is found to be high, we postpone the installation of the well platform at field B to t=3. Investment policy II suggests the well platform at field A be installed in t=2 and the well platform at field B be installed in t=3, irrespective of the size of field A. Since the uncertainty in a field is resolved only when a well platform is installed at that field, the scenario trees for the two investment policies are shown in Figure 3. Thus, the shape of the scenario tree depends upon when we invest in the uncertain fields.

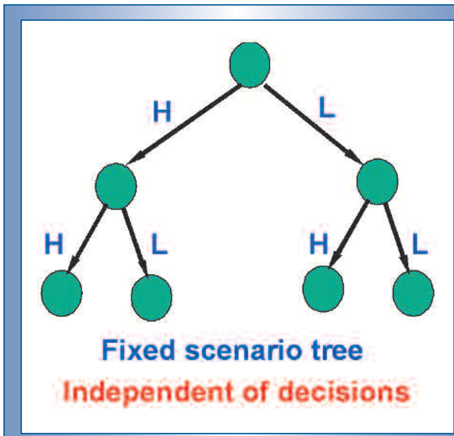

Figure 2. A fixed scenario tree for a problem with project exogenous uncertainty.

Problem definition

To develop a mathematical optimization model for the planning of offshore gas field infrastructure, it was assumed that a set of gas fields has been identified at the offshore

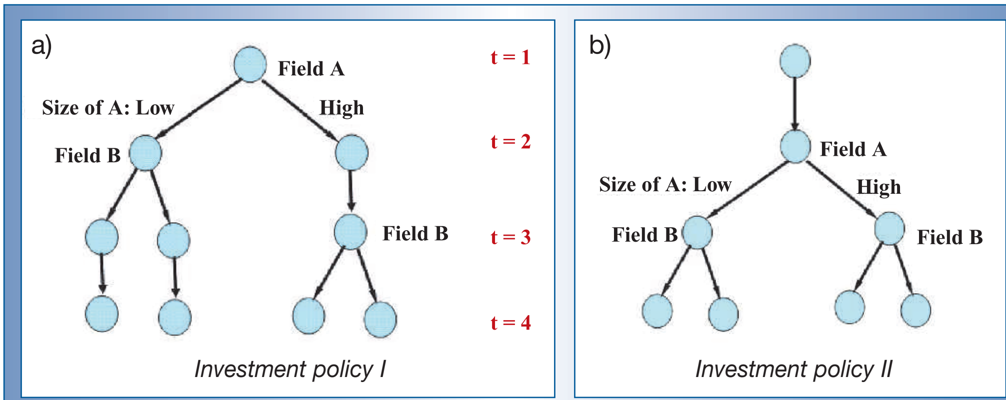

Figure 3. Decision-dependent scenario trees

site under consideration. Based on the accuracy of estimates of their gas reserves, these fields are classified into two categories: certain and uncertain. Fields for which estimates of gas reserves are known accurately are classified as certain. The rest of the fields, gas reserves of which are relatively uncertain, are classified as uncertain.

Some or all of these fields have to be exploited for gas over a project horizon of T years, which is discretized into T time periods of 1 year each. To produce gas from a field, a dedicated well platform needs to be installed at the field. Potential pipeline connections from the well platform at each field and potential locations for the production platforms are given. Investment decisions for the project include selecting at which fields and in which periods well platforms should be installed, at what locations and in which periods production platforms should be installed, the capacities of well platforms and production platforms and the pipeline connections to be installed. If more than one out-going pipeline connections from a well platform are possible, exactly one has to be selected. Operation decisions include determining the production rates of each field for each time period.

It is assumed that investments are instantaneous and take place at the beginning of a time period, while operation takes place throughout the entire time period. Also, investments in a well platform at any field, in a PP or pipeline can only occur once in the entire time horizon. Thus, the capacity of any platform cannot be expanded once it has been installed. Moreover, once installed, each of these units exists for the remaining part of the project horizon.

The gas reserves of a field are characterized by the size and deliverability of the field. The size of a field refers to the total amount of gas that can be recovered from the field, while the deliverability of a field at any time is the maximum rate of gas production that can be obtained from the field. The deliverability of a field is highest (initial deliverability) when no gas has been recovered from the field and decreases with increase in cumulative production from the field. When the cumulative production from the field equals the size of the field, the deliverability reduces to zero and hence, no more gas can be produced from the field. In our work, we have assumed the deliverability of a field decreases linearly with the increase in cumulative production from the field. Thus, we assume a linear reservoir model (Figure 4). In reality, reservoir behavior is characterized by a complex system of partial differential equations commonly used for reservoir simulation. In the planning process, simplified algebraic models frequently approximate this behavior. For the sake of simplicity, we have used a linear model to approximate the reservoir behavior.

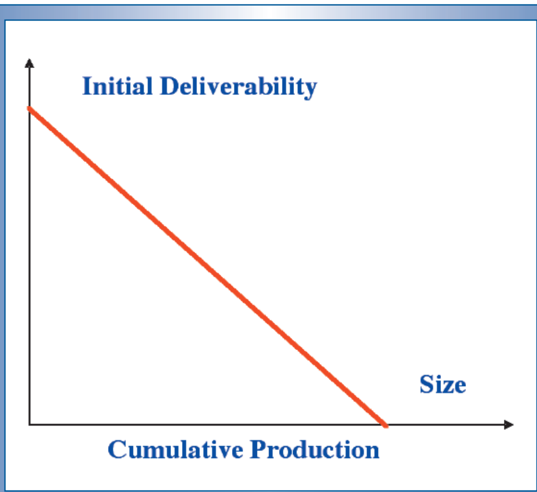

Figure 4. Linear Reservoir Model

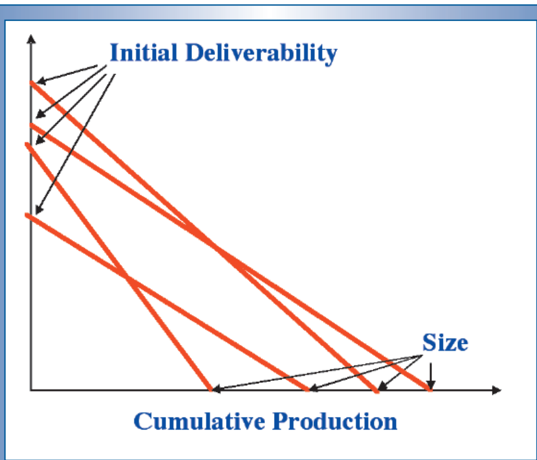

Figure 5. This shows the representation of uncertainty in size and initial deliverability of a field.

All future possibilities are represented by a set of scenarios, where each scenario is a combination of the sizes and initial deliverabilities of the uncertain fields, and has a given probability. The objective is to find decisions that maximize the expected net present value (ENPV) of the project. Figure 5 shows the 16 scenarios associated with a problem with one uncertain field and four discrete probabilities each for the size and the initial deliverability of this field.

For the development of the stochastic optimization model, it is assumed all uncertainty in a field is resolved completely as soon as a well platform is installed at the field; i.e., the size and initial deliverability of the field are known deterministically once a well platform is installed at the field. Thus, investment at uncertain fields reduces the uncertainty. This dependence of the resolution of uncertainty on the investment decisions implies the scenario tree is not unique and depends on the investment decisions as discussed above. Another implication of this feature is that depending on when investments at the uncertain fields are made, the uncertainty resolves over the entire project horizon. Since investment and operation decisions are spread over the project horizon, we consider recourse in investment and operation decisions (i.e., in both integer and continuous variables).

Outline of model

For the proposed stochastic mixed-integer programming model, the project horizon is discretized into time periods and each of the above decisions has to be made for every period. Discrete decisions regarding which well platforms, production platforms and pipelines are to be installed, and when, are represented by binary (0-1) variables, while capacities of platforms and all operation related decisions are represented by continuous variables. This combination of discrete and continuous variables, along with the linear reservoir model of Figure 4 that governs the gas production for a field, leads to a mixed integer linear programming model with the objective of maximizing the NPV. By taking into account the uncertainties as well as the variable structure of the scenario tree, the model takes the form of a multistage stochastic programming model. Special solution algorithms were developed for this problem (decomposition and Lagrangean branch and bound method) that are described in Goel and Grossmann (2004, 2006).

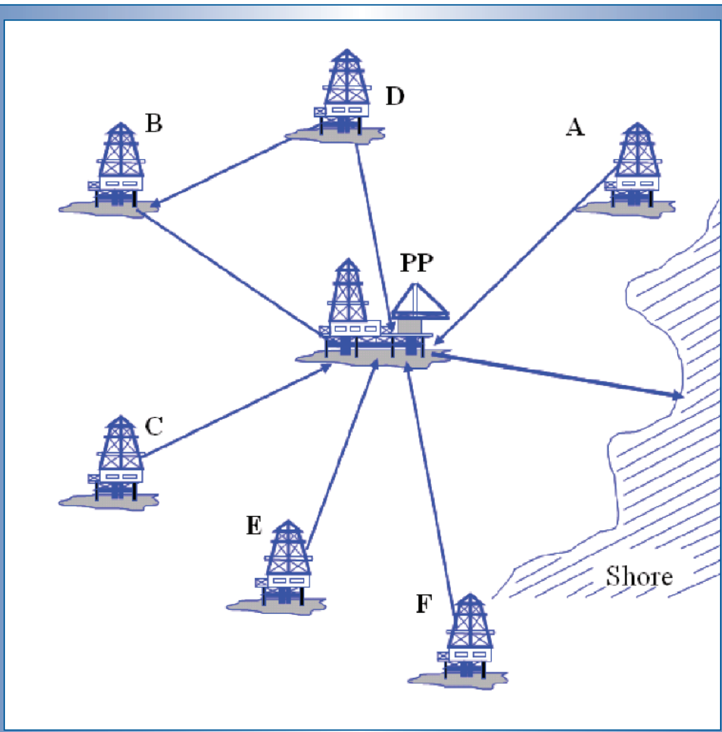

Figure 6. Superstructure for 'Illustration' information

Illustration

The problem under consideration is the investment and operational planning for an offshore site with six fields, denoted by the letters A-F, and one production platform (Figure 6). The project horizon is 15 years (15 time periods). Field F is uncertain while fields A-E are certain. For ease of illustration, we assume only the size of field F is uncertain, and that it has three possible realizations, represented by *L*, *M* (medium) and *H*. The problem thus has three scenarios. The initial deliverabilities (in Mscf/d) and sizes (in Bscf) of the fields, along with the probabilities of the respective sizes for field F, are shown in Table 1.

A deterministic approach to solving this problem consists in solving the expected value problem where mean (or expected) values for the size of field F are assumed. The solution of this problem proposes that the production platform, and the well platforms at the fields A, B, C and F be installed in year 1, while investments at fields E and D be made in years 5 and 7 respectively. The uncertainty in the size of field F would be resolved as soon as the well platform is installed at this field. The model would then be resolved to find the optimal future decisions (recourse), given that investments in the first year have been fixed using the solution of the expected value problem. The investment years for the platforms in each scenario proposed by the solutions thus obtained, along with the investment decisions for year 1 obtained from the solution of this approach, and the associated NPV for each scenario are given in Table 2. The ENPV of this solution over the three scenarios is $94.56 million. Note that scenarios 1, 2 and 3 correspond to low, medium and high sizes, respectively, for field F.

Using the proposed stochastic programming model, we obtain a solution with ENPV = $99.55 million. This solution proposes that the production platform and well platforms at fields A, B, C and E be installed in year 1, while the well platform at uncertain field F be installed in year 5. Investments at field D are proposed to be made in years 6 or 7 depending on the size of field F. The proposed investments, along with the NPV for each scenario are given in Table 3. Thus, the "value of the stochastic solution" is $4.99 million.

The large difference in ENPV obtained from the two approaches can qualitatively be explained as follows. Each investment decision leads to high costs and hence has a strong impact on the NPV. By assuming a

Table 2. Deterministic solution (with recourse) for 'Illustration'

Scenario	1	2	3
Year 1	*A, B, C, F, PP*		
Year 3	*E*	*-*	*-*
Year 5	*-*	*E*	*E*
Year 6	*D*	*-*	*-*
Year 7	*-*	*D*	*-*
Year 8	*-*	*-*	*D*
NPV ($ million)	*-24.18*	*117.26*	*183.03*
ENPV ($ million)	*94.56*		

Table 1. Field properties for 'Illustration'

	A	B	C	D	E	F					
						Low	p^{Low}	*Med*	$p^{Med.}$	*High*	p^{High}
Size (Bscf)	*400*	*400*	*350*	*200*	*290*	*130*	*0.3*	*300*	*0.4*	*470*	*0.3*
Initial Deliverability (Mscf/d)	*130*	*200*	*100*	*100*	*130*	*130*					

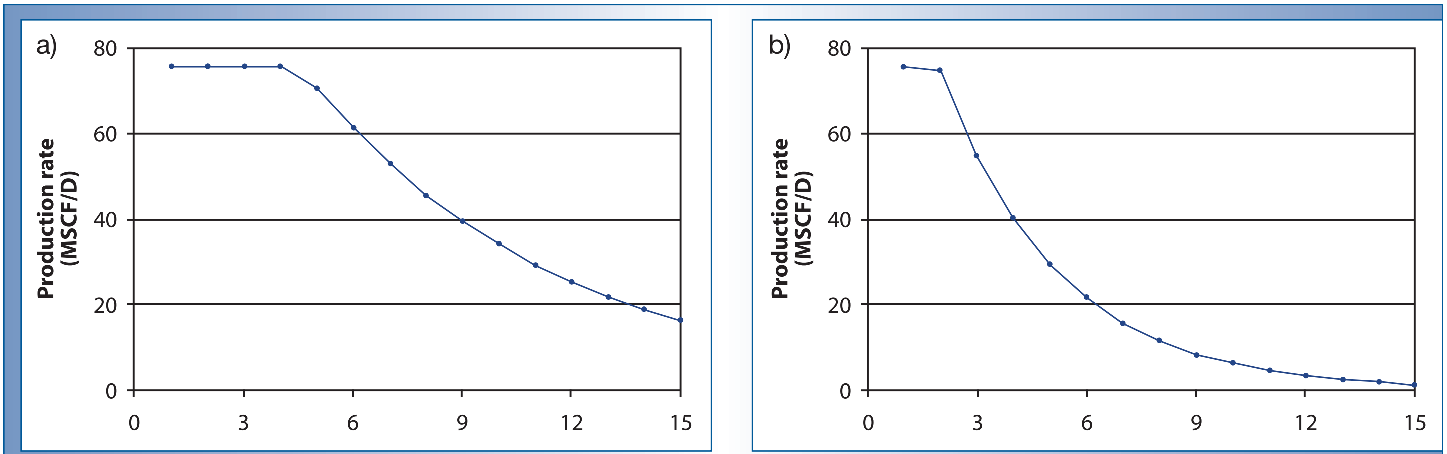

Figure 7. Production profile of field F for deterministic solution (a) predicted assuming mean size for field F: production plateau = 4 years (b) actual production rate if field F has low size: production plateau = 2 years

mean value for the size of field F, the deterministic approach assumes that field F would produce to full capacity for 4 years (as shown in Figure 7; proposed well platform capacity for field F = 76 Mscf/d). At the beginning of year 5, when the production plateau for field F ends, a well platform would be installed at field E to offset the reduction in total production rate. However, if the size of field F turns out to be low (scenario 1), then as shown in Figure 7, field F can produce to full capacity for 2 years only and the investment at field E has to be done earlier, in year 3 (Table 2). This investment, which is worth $111 million, leads to a significant reduction in NPV for this scenario. On the other hand, the proposed solution proposes investment only in the certain fields in year 1, thereby ensuring no more investments have to be made until year 5 (Table 3). Hence the large difference in NPV for the two solutions in scenario 1.

Table 3. Proposed solution for 'Illustration'

Scenario	1	2	3
Year 1	A, B, C, E, PP		
Year 5	F		
Year 6	D	-	-
Year 7	-	D	D
NPV ($ million)	15.73	115.97	161.48
ENPV ($ million)	99.55		

For such capital-intensive projects, there is a clear need for developing systematic optimization tools that can aid in the decision-making process.

The investment decisions and the NPV of the two solutions in scenario 2 are similar. In scenario 3, the deterministic solution is able to delay investment in field D compared with the proposed solution and hence lead to a higher NPV. However, this difference cannot offset the larger difference in NPVs in scenario 1. Note that aside from the difference in ENPV, the proposed solution leads to a positive NPV in all scenarios, whereas the deterministic solution results in a large negative NPV in scenario 1 (tables 2 and 3).

Solution to problems involving a larger number uncertain fields can be found in Goel and Grossmann (2004). ✧

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Improved Modeling of Bedded Salt Cavern Stability

By Kerry DeVries, *Respec*

Cavern stability is a crucial consideration for the design and development of storage caverns in salt formations. Stability issues limit cavern size, spacing and operating pressure range. These issues are often evaluated by geomechanical studies, which are typically performed when a new cavern is developed or an existing cavern is converted to natural gas storage.

The primary outcome of any geomechanical study is the determination of an operating pressure range during natural gas storage that will ensure cavern stability and provide acceptable system performance.

A constraint that often limits the minimum gas pressure in a storage cavern is the potential for salt dilation. Salt dilation (the volume increase associated with the formation and growth of microcracks) occurs when the difference between the gas pressure inside a cavern and the *in situ* stress of the surrounding salt becomes too large. When the dilation in the salt becomes severe enough to initiate macrofracturing, rock falls may occur that damage the hanging string(s) or even cause the roof to collapse. Because salt dilation enhances the permeability, increases the porosity and reduces the load-bearing capability, an accurate criterion for predicting the onset of salt dilation is critical during geomechanical assessments of cavern stability. Respec was funded by the U.S. Department of Energy's National Energy Technology Laboratory (NETL) to advance the current technology used to assess the stability of natural gas storage in bedded salt formations. The purpose of the research was to develop a criterion to predict the onset of salt dilation more accurately and apply the criterion in a geomechanical modeling effort to determine the minimum allowable gas pressure for caverns in a bedded salt formation.

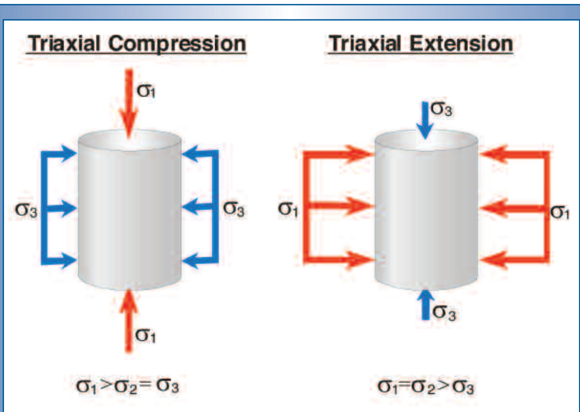

Figure 1. Illustration of triaxial compression and triaxial extension tests performed on circular cylindrical specimens.

Bedded vs. domal salt cavern design

Different criteria are not necessary for defining the onset of salt dilation for domal and bedded salt; however, the nature of the two formations often dictates the necessity for different cavern designs. Bedded salt formations occur in varying thicknesses, and other interbedded sedimentary rock types are always present. The relatively thin nature of the salt beds and local presence of interbedded nonsalt strata present problems unique to bedded salt storage.

Salt domes provide massive quantities of salt real estate, which provides significant cavern design flexibility. Storage caverns are typically cylindrically shaped and taller than they are wide in salt domes. Controlled solution-mining results in a domed roof, which is favorable from a mechanical stability standpoint, and caverns can be placed so that a significant amount of salt is present between the roof and the top of the dome.

The height of a bedded salt cavern depends on the thickness of the salt bed(s). This forces the diameter of a bedded salt cavern to be greater than its height to obtain sufficient storage volume. The bedded salt cavern configuration is less desirable from a rock mechanics standpoint because of large roof spans. The domed roof and massive layer of salt between the cavern roof and the next significant stratigraphic layer in salt dome caverns is impossible to obtain in bedded salt formations because of the relatively thin nature of the salt beds.

States of stress around caverns

The structural stability of caverns in bedded salt depends on the strength and deformation characteristics of the salt and nonsalt beds surrounding and overlying the cavern. Even with this information, problems may still arise because the state-of-the-art in salt mechanics has not advanced to the point of establishing a full understanding of salt response at all possible states of stress. This is important for salt storage caverns because varying states of stress exist around the caverns.

Three principal stresses can be used to define the state of stress at a point in an isotropic body. The maximum (σ_1) and minimum (σ_3) principal stresses lie on a plane and are always perpendicular to each other and oriented in directions for which the shear stresses are zero. The other principal stress, the intermediate principal stress (σ_2), lies between the maximum and minimum princi-

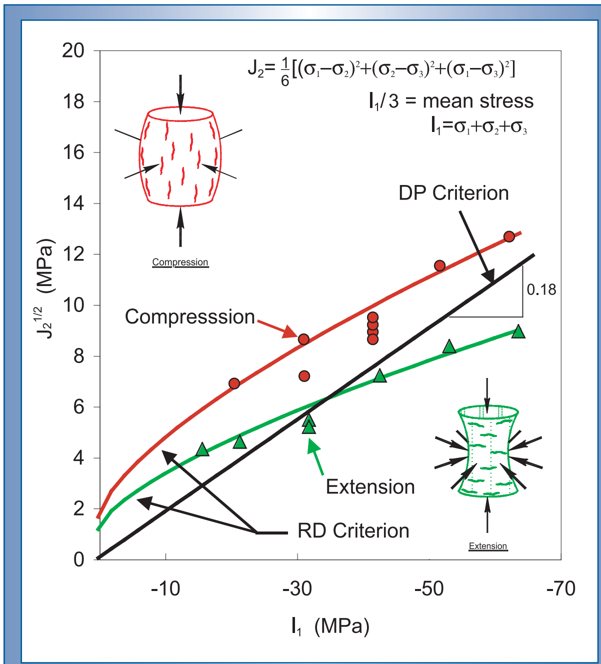

Figure 2. Comparison of the original and newly developed dilation criteria with laboratory tests data.

pal stresses or is equal to the minimum or maximum principal stress. If the intermediate principal stress is equal to the minimum principal stress, this state of stress is referred to as triaxial compression, where tension is assumed to be positive. Similarly, the state of stress is called triaxial extension if the intermediate principal stress is equal to the maximum principal stress. The relationship of the intermediate principal stress to the minimum and maximum principal stress can be expressed in terms of another stress invariant termed the Lode angle. The Lode angle (ψ) varies from 30° at triaxial compression to –30° at triaxial extension. The state of stress in the salt surrounding the cavern varies from triaxial compression to triaxial extension. When the cavern pressure is relatively high, the state of stress in much of the salt in the roof is at or near triaxial compression conditions. Conversely, states of stress approaching triaxial extension are predicted in the salt when the cavern is at a low pressure.

Rock is typically weaker in triaxial extension than in triaxial compression. Because triaxial extension states of stress exist in the roofs of bedded salt caverns, it is important to understand the creep and strength characteristics of salt under this state of stress.

Laboratory testing

Standard laboratory rock testing equipment using cylindrical shaped specimens can only subject the test specimen to triaxial compression or triaxial extension states of stress (Figure 1). Nearly all laboratory tests performed to date on rock salt have been performed under triaxial compression conditions. From this single stress point, researchers must extrapolate or generalize the information to all possible (three-dimensional) states of stress to develop constitutive relations that describe the behavior of salt. This generalization has been done without any knowledge of the strength and deformation behavior at stress states other than triaxial compression.

During Respec's project, several laboratory tests were performed on rock salt under triaxial extension states of stress. The purpose of the testing effort was to acquire more data at stress states other than triaxial compression that could be used for developing constitutive models. The tests performed included constant mean stress tests to determine the onset of dilation and long-term constant stress tests to determine the creep characteristics of salt.

Results of the creep tests indicate the steady-state creep rate of salt is essentially the same at triaxial compression and extension states of stress. However, the onset of dilation is about 30% lower under triaxial extension states of stress compared with triaxial compression states of stress (Figure 2). The results also indicate that the dilation limit is nonlinear in the stress space for which the data are plotted and has a nonzero intercept.

Improved design criterion

Rock salt is a viscoplastic material that is difficult to fail under moderate levels of confining pressure. In this context, "fail" is associated with the formation of macroscopic fractures accompanied by a reduction in load-bearing capacity of a test specimen as is typically observed in elastic-brittle types of rocks. Under moderate levels of confining pressure, formation of microcracks during tertiary creep is suppressed or retarded. As a result, the total accumulated strain can be quite large and the time to creep rupture can be significant. Because salt exhibits these characteristics, development of a Mohr-Coulomb envelope, from which the failure strength or factor of safety of an underground structure in salt can be determined, is difficult. Therefore, Respec pioneered the use of a stress-based dilation criterion – Dilation Potential (DP) – for salt cavern design that compares the computed states of stress around a cavern with the stress state that initiates dilation or microfracturing as determined through laboratory tests. The difference between the DP and Mohr-Coulomb criteria resides in the condition or state defined by the criteria and the test methodology used to acquire supporting experimental data. A Mohr-Coulomb criterion describes the maximum shear stress a material can withstand before failure occurs; whereas, the DP criterion describes the maximum shear stress a material can withstand before microfracturing occurs. Standard triaxial compression tests may be used to define a Mohr-Coulomb envelope; whereas, constant mean stress tests are typically used to define the onset of dilation needed for the DP criterion.

As shown in Figure 2, the DP criterion does not include a nonzero intercept, a nonlinear relation for the dilatancy boundary or the effects of Lode angle. For example, the model predicts the same response regardless of stress conditions ranging from triaxial compression to triaxial extension. To address these shortcomings, a new criterion, referred to here as the Respec Dilation Criterion (RD) criterion, was developed based on the experimental evidence of laboratory tests performed under triaxial compression and triaxial extension states of stress. Figure 2 shows that the new dilation criterion fits the triaxial compression and triaxial extension data well. It also shows that the new dilation criterion provides a significant improvement over the linear dilation criterion in its ability to represent the test data.

Impact of new design criterion

Finite element analyses were performed of hypothetical natural gas storage caverns that illustrate the use of the new criterion over a range of conditions expected to exist in bedded salt formations. Estimates for the minimum allowable gas pressure were determined utilizing the RD and the DP criteria. In general, the RD criterion suggests lower minimum gas pressures may be allowed for caverns at shallow depths (less than 800m) compared with that determined by the DP criterion. However, as cavern depth is increased, less conservative estimates for minimum gas pressure are determined by the RD criterion. Figure 3 provides an illustration of the potential for dilation in the salt surrounding a hypothetical cavern at depths of 300m and 1,200m. Here, factor of safety is defined as the ratio of the measure of shear stress that produces dilation according to the dilation criteria to the measure of shear stress predicted in the numerical model. A safety factor of 1.0 is the limit stress state for dilation to occur. Dilation is expected to increase with decreasing factor-of-safety values. For the cavern at a depth of 300m (Figure 3a), the salt is predicted to be less safe along the cavern sidewall using the DP criteria.

Figure 3b is similar, but provides factor-of-safety contours determined from the analyses simulating caverns at a depth of 1,200m below the ground surface. The predicted factor-of-safety results are significantly different for the two criteria at a depth of 1,200m. The RD criterion predicts a significant amount of salt above the cavern mid-height will dilate; whereas the DP criteria does not predict dilation of the salt at this gas pressure. This difference is attributable to the effects of the Lode angle and the nonlinear mean stress dependency of the RD criterion. The dilation limit predicted by the RD criterion for triaxial extension states of stress is greater than that predicted by the DP criterion at low mean stress. As the cavern depth becomes progressively deeper, the mean stress in the salt increases because of the additional overburden. As shown in Figure 2, the dilation limit predicted by the DP criterion becomes greater than that predicted by the RD criterion for triaxial extension states of stress at a mean stress of about −11 MPa (I_1 = −33 MPa).

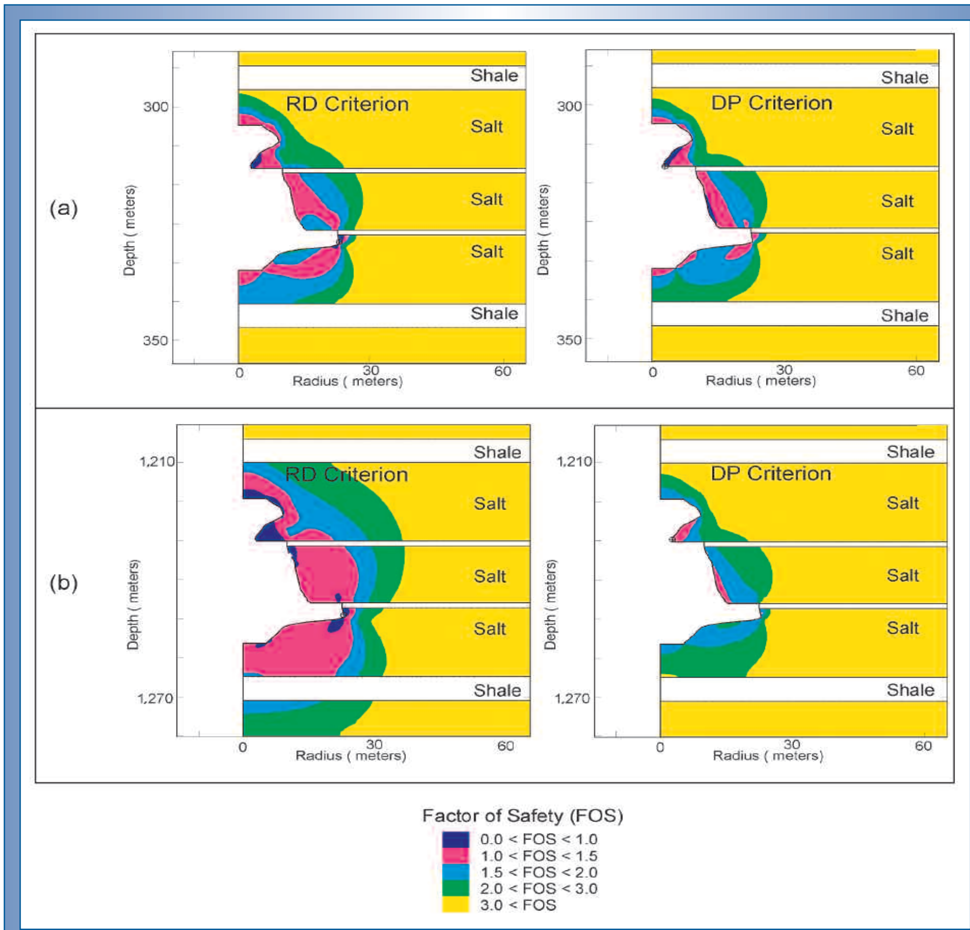

Figure 3. Comparison of factor-of-safety contours using the RD and DP criterion for caverns at a depth of (a) 300m and (b) 1,200m (gas pressure gradient of 0.0068 MPa/m depth at the casing shoe).

Conclusions

The results of numerical analyses confirmed much of the salt surrounding salt caverns approaches a triaxial extension state of stress at relatively low operating pressures. Because of numerous laboratory test confirmations of salt being weaker at triaxial extension states of stress, it is important that salt cavern design criteria capture this aspect of salt behavior. The recently developed RD criterion is capable of predicting this behavior and provides an improved method for evaluating cavern designs and avoiding dilatant states of stress that would be detrimental to the long-term stability of the cavern.

A detailed report of the project to improve the predictive capability of caverns in bedded salt is available on the NETL Web site, *http://www.netl.doe.gov/technologies/oil-gas/publications/Storage/41651_FinalReport.pdf* For more information, contact Kerry L. DeVries at *kerry.devries@respec.com* or (605) 394-6400. ✧

Drilling Advancements Essential to Deep Gas Recovery

By Arnis Judzis, *TerraTek;*
Gary Collins, *ConocoPhillips;*
and Tim Grant, *National Energy Technology Laboratory*

Natural gas has long been emphasized, for its efficiency and low emissions, as the fuel of choice for heating and electrical generation. Although this has increased demand, the need to meet it with increased supplies has been left by the wayside.

With the increase in demand, the world's energy mix is moving toward gas, and North America is now in a position where it cannot meet current needs. America may not be able to establish energy independence but has the ability to improve domestic production through deep exploration and development. An important factor in future gas reserve recovery is the cost to drill a well. This cost is dominated by the rate of penetration (ROP) that becomes increasingly important with increasing depth. A primary goal of the National Energy Technology Laboratory (NETL) is to increase future supplies of natural gas with the key ingredient of lower costs, which can be accomplished by improving the technology of drilling and increasing the ROP. This improves the economics of deep exploration and development; increasing drilling activity, production, supply; lowering the cost to the consumer; and improving the economy.

Figure 1. Shown above is a `bottomhole pattern in Carthage marble, also known as Burlington limestone, drilled with a PDC bit at high borehole pressures.

Optimization of Deep Drilling Performance: Development and Benchmark Testing of Advanced Diamond Product Drill Bits & High-Pressure/High-Temperature (HP/HT) Fluids to Significantly Improve Rates of Penetration (NT41657), a project that is part of the NETL's Deep Trek program, was awarded in September 2002. NETL organized a workshop of the same title in 2001. The primary goal of this workshop and program is "…to develop technologies that make it economically feasible to produce deep oil and gas reserves…" and "…will focus on increasing the overall rate of penetration in deep drilling." Bill Shaughnessy of BP presented examples of field data showing that 50% of the time taken to drill a deep well is spent on making the last 10% of the hole. In 1990, Gas Research Institute (now Gas Technology Institute) reported that drilling consumes nearly half the time it takes to drill a well. Tripping is the second largest consumer of rig time, and a common reason to trip out of the well is to change the bit. Together, these two functions account for 70% of rig time. The remaining 30% is split among six other categories. Bit selection and drilling fluids are two decisions any drilling engineer will make in drilling a safe, efficient and ultimately economic well.

TerraTek's proposal to the NETL was to test drillbits and advanced fluids under high-pressure conditions. The first phase in the proposal was to establish a baseline of performance and provide data upon which to make design improvements (Figure 1). The second phase was to establish improvements in design. The third phase of the project is to take the drillbit and drilling fluid improvements to the field for further testing and technology commercialization.

TerraTek has an establish history of testing drillbits in a wellbore simulator under downhole conditions. Operators and service companies have accepted this method of testing bit designs and drilling scenarios under downhole conditions as a means for improving bit designs (Figure 2).

In an earlier project, Drilling Shales at Great Depth, funded by the Drilling Engineering Association (DEA) participants, TerraTek had reached a circulating pressure of 7,500psi. However, to simulate drilling in environments exceeding 15,000ft, the NETL project required circulating pressures between 10,000psi and 12,000psi and confining pressures up to 15,000psi. Engineering upgrades to the drilling simulator were a critical task for this project to progress. The work included upgrading safety equipment, increasing pumping capacity and mud handling capacity of two pumping systems, increasing the ability to handle pump pulsations and sealing high pressures at the pump fluid ends, rotary shaft and swivel.

Hughes Christensen and Baker Hughes Drilling Fluids partnered in the project. Hughes Christensen provided bits and engineering support (Figure 3), and Baker Hughes Drilling Fluids provided drilling fluid and engineering support. Further industry support for Phase I was provided by ConocoPhillips, Marathon, Aramco, BP and Statoil. The DEA, in which the participants of this project are also involved, is providing funding support for this project (DEA project No. 148). All participants have provided data and technical support in developing the test matrix and simulation scenarios to be modeled by these tests.

There are a number of deep productive horizons in several basins in the United States that present deep drilling challenges. The test matrix was based on two of these productive basins. One is the Tuscaloosa trend in southern Louisiana and the other is the Arbuckle play in Oklahoma and Arkansas. The Tuscaloosa trend has a number of productive reservoirs at depths below 20,000ft. It is a clastic reservoir with predominately a sand/shale sequence up hole. Simulating drilling to this horizon utilized an oil-based mud system with Crab Orchard Sandstone and Mancos Shale for drilling samples. The Arbuckle play is a carbonate reservoir with a carbonate, sand/shale sequence up hole. Simulating drilling to this horizon utilized a water-based mud system with Carthage Marble and Crab Orchard Sandstone for drilling samples. A roller-cone bit was run to establish a baseline, and PDC and impregnated diamond bits were utilized for both modeled lithologies. The test matrix for Phase I of the project contained 16 tests, eight for each scenario.

Figure 2. TerraTek full-scale drilling rig with high pressure wellbore simulator

Phase I testing was conducted in late April and early May last year, which was later than planned because upgrading the drilling simulator to operate at higher pressures took more time than anticipated. Another delay in the project was securing a second mud pump. Hughes Christensen leased a second mud pump to the project so flow rates over 300 gpm could be reached in conjunction with circulation pressures in excess of 10,000psi. This is the highest pressure yet attained for any full-scale well drilling simulator. Overall,

Figure 3. Drillbits used for the DeepTrek benchmarking study

all 16 tests were run with but a single flaw, the failure of an O-ring gasket causing a loss of pressure in the drilling simulator during the first test sequence.

The simulated Arbuckle formation of Crab Orchard over Carthage Marble was tested first. The drilling fluid and bit used to perform the first test of the Arbuckle formation combination was water and a seven-blade PDC bit. For subsequent tests, 11-ppg water-base mud was used in combination with four- or seven-bladed PDC bits, or an impregnated bit. A roller cone bit was tested in each of the samples separately to provide a baseline for each rock.

Figure 4. Mancos shale drilled with oil-based mud at high wellbore pressure

The simulated Tuscaloosa formation of Crab Orchard over Mancos Shale (Figure 4) was tested next. The drilling fluid and bit used to perform the first test of the Tuscaloosa formation combination was base oil and a seven-blade PDC bit. Two tests had 12 ppg and the remaining four used 16-ppg oil-based muds. One test in this sequence was run with a borehole pressure of 5,000psi to provide an up-hole scenario of bit performance as well as provide a connection with data collected on earlier tests and those found in the literature. The roller cone bit was not run during this test sequence. Another test was run with a higher flow rate to determine hydraulic effects.

The baseline test for each mud system show high ROPs are possible with a seven-bladed PDC bit before mudding up. After mudding up, drilling tests through hard sandstones show the ROP can drop as much as 80% or 90%. Diamond product bits showed substantial performance improvements over roller cone insert bits in certain tests but not all.

Cutting analysis showed that cuttings generated at high pressure are smaller than anticipated. The smaller size suggests significant re-grinding takes place at high bottom-hole pressures or the cutting mechanism of the bit changes from its primary mode to a grinding mode.

Phase I test results also show there are opportunities for improvements in bit design and "smart" HP/HT drilling fluid design. It's mostly about understanding how confining pressure affects the ability of a drillbit to break the rock. With depth, confining pressure increases and the state of stress in the rock changes. This influences the ability of any specific bit design to break the rock as well as the size of the cutting generated relative to bit design, the ability of the mud to penetrate the fractures induced by drilling and the ability of bit and mud to collectively remove the cuttings from beneath the bit.

With increasing depth, the ability for the bit to perform at penetration rates observed in shallower hole sections is reduced. The drilling fluid characteristics also change with depth. As the drilling fluid returns to the surface, it transitions from an HP/HT environment to lower temperatures and pressures (LTP) and the functions and performance of the drilling fluid becomes increasingly different between the bottom and top of the hole. Recent deep drilling activity has required the use of mud coolers for personnel safety, sharply reducing the temperature of the drilling fluid at the surface. In a deep well, the drilling fluid will continuously transition between HP/HT and LTP environments, which have a dramatic influence on the physical and chemical properties on the mud's constituents. This presents a greater challenge to improving the mud's performance in HP/HT environments than those available for improving bit designs.

Phase I testing established baseline efficiencies for bit and drilling fluid designs used in deep well drilling. Phase II planning, which is currently underway, will examine the potential for bit improvements, such as materials, efficiency and aggressiveness, and also identify the processes that slow deep drilling, such as solids content, weighting materials and base fluid. Design changes influenced by Phase I will be tested in Phase II and hopefully improvements in ROP will be observed, maybe even significant improvements.

The growing emphasis on natural gas use will require advances in drilling that will provide economic access to deep gas reserves. Unlocking more reserves with lower drilling costs will have a long-term benefit for consumers and the economy. This project has already advanced the understanding of drilling at depth under high confining pressures. Testing design improvements in Phase II will further advance the understanding of drilling. As the results of this project filter through the industry, operators and engineers will learn and improve drilling performance. Initial, individual improvements may be small but collective application throughout the industry will accelerate the process. It is believed that within 5 to 7 years, significant improvements in ROP, in conjunction with other technology advancements and possible operational adjustments, will be realized by the industry, one well at a time. This is a continuous and ongoing process. ✧

Deeper, Smarter EM Drilling Technology

By Robert Houston and
Jeffery M. Gablemann, P.E.,
E-Spectrum Technologies

For a number of reasons, primarily noise immunity and signal sensitivity, current electromagnetic telemetry systems are limited by operational depth and geological formation characteristics.

Recent developments in computational power and advanced computer algorithm techniques have produced data fusion technologies that can be employed to create rugged, commercially viable telemetry systems for energy exploration. Electromagnetic (EM) telemetry provides an ideal application area for data fusion methods. Recent testing of a newly developed system has demonstrated that information from multiple independent sources can be fused, in real-time, resulting in a marked increase in the ability to reject ambient environmental noise while extending operational capabilities.

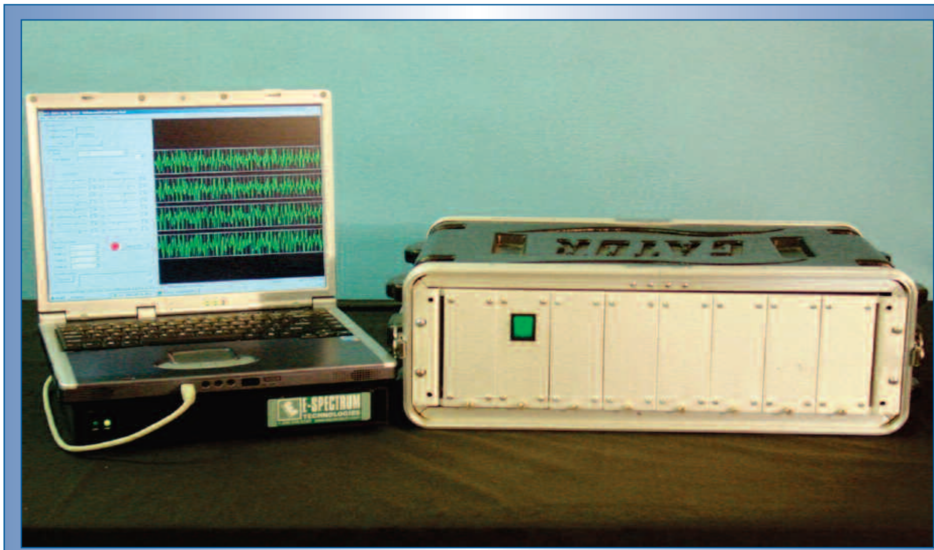

Figure 1. Data fusion receiver hardware platform

Data fusion for EM telemetry

To facilitate the development of high-tech drilling tools that will provide access to increasingly deeper energy resources, the U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory's Deep Trek project has collaborated with San Antonio, Texas-based E-Spectrum Technologies Inc. to develop an innovative two-way EM telemetry system for energy exploration applications. Based on the culmination of 3 years of research and development in the area of advanced EM telemetry communications, E-Spectrum has successfully tested the system in test wells and operational drilling environments with successful results. This data fusion-based EM telemetry system provides an EM tool capability that can benefit onshore and offshore oil and gas exploration operations for conventional and underbalanced drilling applications.

A key element of the new design is a data-fusion receiver, which enhances the system's ability to extract weak telemetry signals originating thousands of feet below the earth's surface. This data-fusion receiver adapts technologies used for interplanetary deep space navigation and missile guidance systems and makes them work in energy exploration applications. Every element of the system's design, from power efficiency to reliability, has been optimized to extend operational depth and improve noise immunity. The data fusion receiver apparatus and algorithms are patent-pending with awards anticipated during the second quarter this year.

Data fusion system development

The data fusion receiver is a key element of the EM telemetry system, with much of the system development focused on perfecting this new technology. Development efforts consisted of two fundamental areas: the development and tuning of the data fusion computer algorithms, and the design and construction of the data fusion receiver hardware platform.

The objective of the data fusion computer algorithm development was to generate and validate a set of innovative signal-processing algorithms that maximize the noise rejection capabilities of a high-sensitivity subterranean communications receiver. Within the context of the energy exploration market, developing a methodology that increases a subterranean telemetry receiver's noise rejection capability works to improve the signal-to-noise ratio resulting in a receiver capable of recovering the extremely weak electromagnetic field signals associated with deep drilling telemetry applications.

The data fusion receiver hardware platform was designed to maximize electronic signal

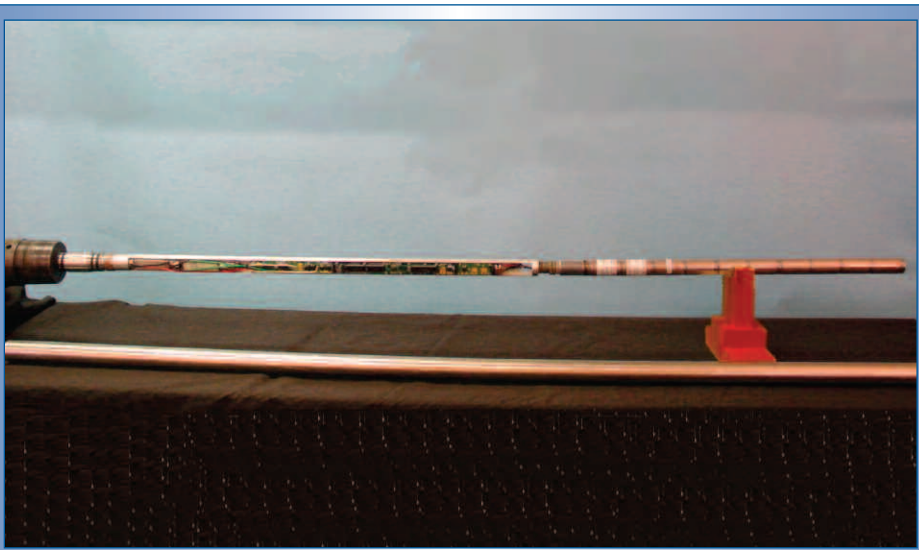

Figure 2. Downhole tool power amplifier and receiver assembly

sensitivity, employing techniques adopted from biomedical sensing devices. It also was critical the data fusion receiver be computationally efficient, rugged and compact to satisfy the requirements of the oil and gas market.

The receiver platform (Figure 1) developed during the Deep Trek project consists of two primary components: an ultra low-noise signal conditioning unit and a Windows-based notebook computer.

The ultra-low noise signal-conditioning unit accommodates up to four electric-field signal channels and up to 12 magnetic-field signal channels for a total of 16 real-time receive-input channels.

A Windows-based, personal computer-architecture computer provides an industry standard platform for digitizing the incoming signal channel. It also provides the run-time processing platform for the data fusion and demodulation engines. The computer also hosts the data fusion receiver's graphical user interface (GUI) application, the primary function of which is to provide the operator-interface for display of the data received from the downhole tool. This data can be real-time information from the tool sensors, such as tool-face information for measurement-while-drilling (MWD) applications; or diagnostic information about the "health" of the tool, such as battery voltages and gap antenna impedance. The GUI application also allows the operator to format downlink commands to the downhole tool to configure the tool for telemetry uplinks or query it for real-time health/diagnostic information. Additional GUI functionality includes the ability to display multiple incoming/receive antenna waveforms, allowing the operator to select any four of the 16 incoming waveforms for real-time display.

The data fusion receiver application also allows the user to save the incoming real-time waveform data to the hard drive to facilitate post-processing analysis of the raw temporal-waveform data. The receiver application also keeps an electronic log of all uplinks received from the tool and all downlinks sent to the tool. This log is time stamped and can be used to facilitate the post-processing of the raw waveform data archived to the hard drive.

High-efficiency PA development

The high-efficiency power amplifier (PA) employs a robust architecture to provide increased power-delivery efficiency in a compact, rugged mechanical package. Increasing transmission efficiency results in a greater transfer of available energy from the transmitter's principal power source to the transmission media. The maximization of energy transfer is especially critical downhole, where the transmitter's principal power source is typically a battery. Efficient coupling of magnetic field energy into the low impedance transmission media present at the PA transmitting antenna results in a maximum amount of field energy remaining at the receive antenna after transit through the earth's strata. Increased field energy at the receive antenna equates to increased recoverable signal amplitude; thus, the overall receiver signal-to-noise ratio is improved resulting in increased operational depth capability.

Two separate high-efficiency PA systems have been developed: a downhole tool power amplifier and a surface power amplifier. The downhole tool PA is compact, rugged and uses a solid-state switched-output driver circuit topology to efficiently convert battery-stored energy into magnetic field energy. For maximum operational flexibility, the downhole PA can be reconfigured while deployed in-hole via a two-way, EM-based, communications link to the surface. Additionally, the downhole tool PA electronic-assembly was sized to fit in a 1¼-in. inside diameter (max) pressure vessel to allow integration into a working drillstring.

The downhole tool PA and receiver assembly consists of printed circuit boards mounted in a rigid backbone. Each circuit board is designed to utilize SOIC components provided by Honeywell. The components are designed for extended temperature range operation to 225°C and are provided in thru-hole style integrated circuit packages.

The power source for the downhole electronic assembly consists of a battery pack constructed from a series of high-temperature (200°C), lithium-thionyl-chloride batteries arranged in an axial configuration (shown in the right-hand portion of Figure 2). The battery pack is assembled with insulators between each cell to prevent shorting during drilling operations and act as mini shock absorbers to absorb vibration. The entire

PA/receiver/battery assembly is contained within a 1¼-in. ID screw-on pressure housing (shown in the foreground of Figure 2).

The downhole tool PA/receiver assembly provides the following capabilities:

- 15 W (max) delivered power: programmable via the EM downlink (eight adjustment settings);
- 2 Hz to 10 Hz adjustable uplink carrier frequency: programmable via the EM downlink (five adjustment settings);
- ability to measure received signal strength of the downlink and report via EM uplink;
- ability to measure gap-antenna impedance and report via EM uplink;
- ability to perform real-time system-health diagnostics and report status via EM uplink; and
- ability to record up to 30 minutes of time domain waveforms from the gap antenna.

The surface power amplifier (Figure 3), housed in a compact ruggedized chassis, allows downlink command-communications with the downhole tool.

Its electronics utilize the same basic solid state, switched output driver circuit topology as the downhole tool PA; however, the surface PA is capable of generating 1,000 Wrms of power to the load. In addition, the surface PA features safety interlocks so power delivery to the load is disabled if an abnormal impedance condition is sensed on the PA outputs. This interlock feature helps protect against the safety hazard caused by broken, loose or improperly connected antenna wires.

The surface PA provides an RS-232 serial communications interface to a laptop or desktop computer so information can be exchanged with the data fusion receiver. The serial communications link is used to relay the operator-downlink command packet to the PA for formatting and subsequent downlink transmission to the downhole tool. The surface PA also performs internal health/diagnostic functions such as measurement of the transmission antenna load impedance and the monitoring of various internal system-health metrics. This data is reported to the data fusion receiver GUI application via the RS-232 serial communications interface.

Field testing

Seven separate field tests have been conducted to validate the Deep Trek data fusion system. Field testing has consisted of two types of test protocols: test-well performance and field-noise recordings. The performance tests were conducted in commercial test well facilities, ranging in maximum depth from 2,000ft to 5,000ft. All test wells were completely cased and topped by fully equipped drilling-rig platforms. The casing in each well was constructed from a ferrous material (steel), which extended the entire length of the structure and strongly attenuated the electromagnetic waves broadcast from inside the bottom of the well to the surface. Testing at a depth of 4,944ft using the lowest possible downhole transmission power setting of less than 1.7 W resulted in consistent successful data transmission in the presence of strong rotational noise. Using industry developed models, this data can be extrapolated to estimate a typical functional operational depth in excess of 13,000ft in the presence of drilling noise.

A field test was conducted in February in a 9,517-ft well being drilled in North Texas. The data fusion receiver was deployed as part of the MWD telemetry support equipment for the top-drive drilling rig being used to drill the well. The receiver was able to decode EM telemetry uplinks from the bottom of the well throughout the 10 days the rig was operational. This operational profile included the successful recovery of uplinks while sliding and drilling. Test results were excellent despite portions of the well including a geological formation (the Lower Barnett) known to be unfavorable to EM transmission.

These field test results show using data fusion technology provides a measurable advantage over existing EM systems and should facilitate the development of high-tech drilling tools that will provide access to increasingly deeper energy resources. E-Spectrum Technologies is seeking industry partners to collaborate in introducing these technologies to energy exploration markets.

For more information about E-Spectrum's EM telemetry or data fusion technologies, contact Jeff Gabelmann at (210) 696-8848 ext. 238, or via email *at jgabelmann@espectech.com* ✧

Figure 3. Surface power amplifier

Next-Generation Compression Technology

By Danny M. Deffenbaugh,
Klaus Brun and Ralph E. Harris,
Southwest Research Institute

To meet growing demands for energy, the U.S. Department of Energy initiated a Natural Gas Infrastructure program with the goal of increasing capacity of the current pipeline infrastructure by 10% and reducing operational costs by 50%.

Under funding from the U.S. Department of Energy's (DOE) Office of Fossil Energy, National Energy Technology Laboratory-Delivery Reliability Program, Southwest Research Institute (SwRI) led an effort in conjunction with the Gas Machinery Research Council (GMRC) to formulate the Advanced Reciprocating Compression Technology (ARCT) research program for the DOE to address this challenge. The objective of the ARCT program is to create the next generation of reciprocating compressor technology to enhance the flexibility, efficiency, reliability and integrity of pipeline operations. The suite of technologies developed during this program will not only provide pipeline operators with improved, affordable choices for new compression, but will also provide innovative solutions that can be retrofitted to existing machines to substantially improve current reciprocating compression.

Figure 1. This slow-speed integral compressor is typical of the class of equipment that accounts for the majority of the U.S. pipeline infrastructure.

Advances in compression technology helped the U.S. gas industry expand during the early 1950s. The original, first-generation (pre-1950) compression technology consisted of many small (500 hp to 750 hp) slow-speed (180 rpm) compressors to move gas from producing regions to markets. To provide the necessary expansion, a developmental second generation (post-1950) of larger, higher-speed machines promised significant reductions in installed costs. As industry installed the first of these machines, they experienced many reliability and operational problems involving flow pulsations and mechanical vibrations that resulted in piping failures.

To address these problems, the pipeline industry in 1952 formed what is now the GMRC, which contracted with SwRI. As a result of this initial collaboration, SwRI developed pulsation control systems that combined acoustic filters and dampers with effective mechanical restraints. SwRI has continuously operated the GMRC pulsation design service for decades, generating royalties that have funded GMRC research since 1955.

This second generation of compression technology has since become known as "slow-speed integral" compression (Figure 1). This equipment has nominally three times the horsepower, running at twice the speed (at less than 300 rpm in the 1,500 hp to 2,500 hp range) of the equipment it replaced. These slow-speed integral machines now form a majority of the U.S. pipeline industry's compression infrastructure.

The promise of dramatic cost reductions has driven the industry toward even higher-speed, larger-horsepower reciprocating compression, powered by efficient, separate, modern gas engines or large electric motors. Within the past few years, the first iteration of this new class of machines has been installed. This third generation of equipment has three times the power of the prior generation and is now running at two to three times the speed (500 rpm to 1,000 rpm; 4,000 hp to 8,000 hp). New vibration and pulsation problems have come with this technology. The pipeline industry faces a technology transition similar to that of 50 years ago. As a few large machines replace many small ones, each must provide a wider flow-rate capacity range with increased reliability. Wider variations in speed complicate pulsation control, and higher speeds have resulted in significant losses in compressor efficiency, contributed to in part by pulsation control and conventional valve technology.

The primary challenges for the slow-speed, integral fleet are limited flexibility, large range of thermal performance, and significant operating and maintenance costs. The primary challenges for the new, high-speed compressors are cylinder nozzle pulsations, mechanical cylinder vibrations, short valve life and even lower thermal efficiency. The goals for next-generation compression are improved flexibility (50% turndown in flow rate), improved efficiency (more than 90%), improved reliability and maintenance (increase valve life by a factor of 10 with half the pressure loss), and improved integrity (vibration levels less than 0.75 in. per second).

The ARCT program has developed many technologies to address these goals. Two particularly significant ones are a tapered nozzle pulsation control device and a semi-active electromagnetic valve.

Pulsation control

The state-of-the-art in pulsation design and control technology has evolved as compressor technology installed by industry has changed. Designs for low-speed compressors are more mature, with fewer critical issues. However, relatively recent high-speed, high-horsepower compressor designs are placing significant challenges on the pulsation control designer (Figure 2).

Cylinder nozzle response represents the single most important challenge to high-horsepower, high-speed, variable-speed units (Figure 3). Significant reductions in unit efficiency and capacity occur through use of pressure drop elements required to control pulsation amplitudes. Technology is required to allow control of the nozzle response without significantly lowering cylinder performance, which is particularly important if compressor flexibility (in turndown ratio) is required or the trend toward higher speed continues.

For high-speed compressors, there is a need to lengthen the cylinder nozzles (to reduce mechanical coupling), raise the reso-

Figure 2. High-speed horsepower compressors are challenging pulsation control designers.

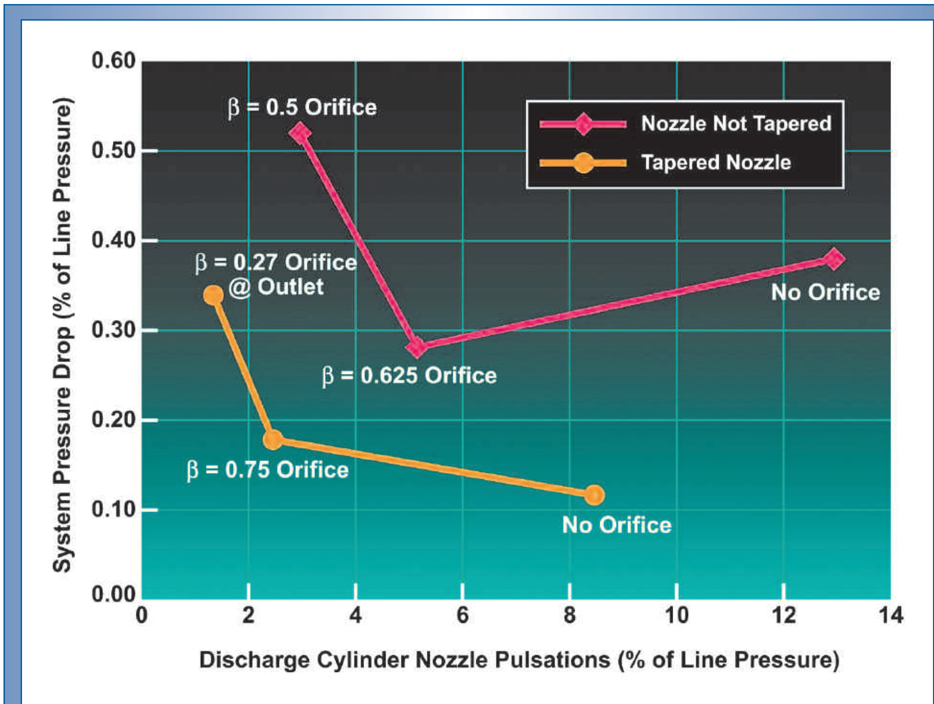

Figure 3. The tapered cylinder nozzle reduces pulsation level and parasitic pressure loss. The top curve shows pulsation response and pressure loss for a standard nozzle while the bottom curve shows the reduced pulsation level and pressure loss for the tapered nozzles.

nance frequency and reduce pulsations at the cylinder nozzle resonance frequency. A concept was formulated to replace conventional, straight compressor cylinder nozzles with tapered cylinder nozzles. The tapered cylinder nozzle concept lowers the effective acoustic resistance, thereby reducing the acoustic reflection, decreasing the resultant pulsation amplitude and pressure loss through the nozzle. Benefits associated with this concept include significant increase in the cylinder nozzle resonant frequency and lower amplitudes of excitation. It also allows for lengthening the cylinder nozzle such that mechanical coupling between the cylinder and the rest of the piping is reduced.

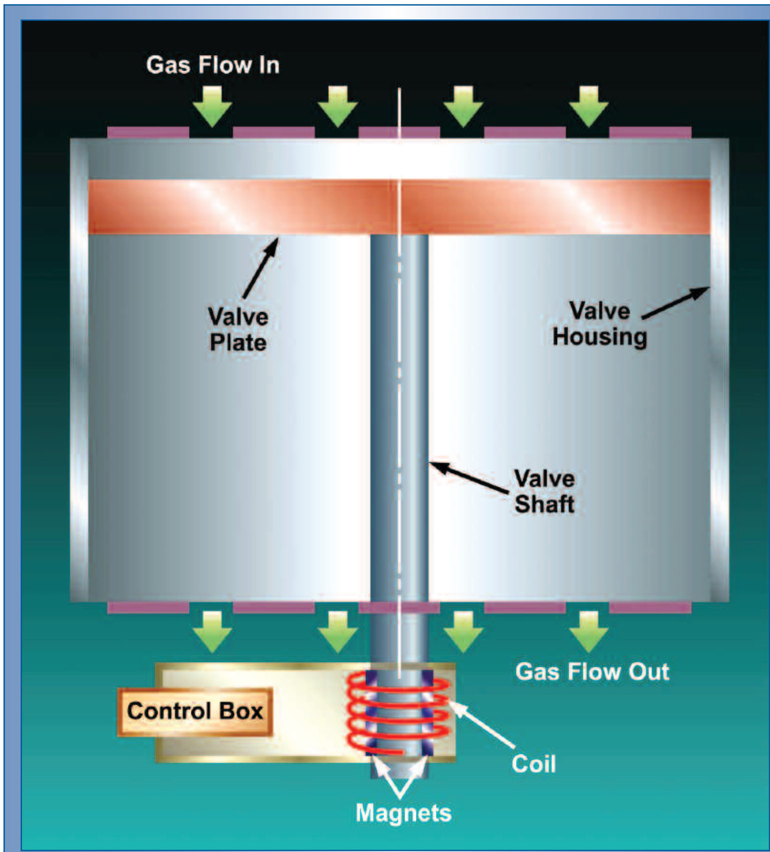

Figure 4. The semi-active electromagnetic plate valve is a relatively simple modification to a standard plate valve, with the addition of a center shaft and speaker voice coil.

Simulation and experimental data of the tapered cylinder nozzle show a significant shift in the cylinder nozzle resonant frequency and reduced amplitude of the cylinder nozzle pulsations. At the same time, the associated thermal efficiency is improved because of the reduced parasitic pressure loss through the nozzles.

Results demonstrated that the cylinder nozzle resonant frequency shifted above the fourth order of running speed or 24 Hz to 26 Hz frequency, which is a 50% increase. The maximum nozzle pulsation amplitudes were reduced by 34% to 35%, and the pressure drop was reduced by one-third. The tapered cylinder nozzle results showed fewer pulsations (below 3% of line pressure) with less pressure drop than would be required in a traditional system with a straight nozzle installed. (The American Petroleum Institute pulsations guideline is 7% of line pressure for these operating conditions.)

The tapered cylinder nozzle has demonstrated the potential to resolve the critical cylinder nozzle problem experienced in modern high-speed compression and may be the needed enabling technology for next-generation compression.

The financial benefit to reducing pressure loss in these nozzles can be realized in terms of improved thermal efficiency or expanding the flow through the station. At a current cost of natural gas of $9 per Tcf, a 6% improvement in overall thermal efficiency would result in a cost savings of $50,000 per year per compressor.

While this technology development has undergone a proof-of-concept experiment, additional development is required before full-scale acceptance by the industry can be expected. Laboratory testing of the technology, along with development of design tools, is under way and will be followed by prototype demonstration in an actual pipeline under realistic conditions. This proven technology can then incorporate in the designs of advanced pulsation control systems.

Compressor valves

The single largest maintenance cost for a reciprocating compressor is compressor valves. Valve failures can primarily be attributed to high-cycle fatigue, sticking of the valve, accumulation of dirt and debris, improper lubrication and liquid slugs in the gas. Valves are designed for an optimal operation point; hence, valve operation is impaired when the operating conditions deviate significantly from the design point. In the traditional compressor valve design, an increase in valve life (reliability) directly relates to a decrease in valve efficiency. This relationship is because of an increase in valve lift (and flow-through area) being limited by the corresponding increase in the valve impact force. Above a certain impact velocity, valve plate failure is attributable to plastic deformation of the valve springs. These springs fail to provide adequate damping for the plate. The design of the valve springs is a weakness in the valves currently in use. A lack of durability and low efficiency of the passive valve design demonstrates the need to control valve motion.

Reducing impact velocity can greatly increase the life of a valve. A new valve concept was developed that could create a soft landing at the valve seat on closing and at the valve guard on opening. The concept is to effectively replace the valve spring with an electromagnetic coil that senses position and provides an opposing force prior to impact. This concept is referred to as a "semi-active electromagnetic plate valve" because it is still activated by gas pressure and only controlled prior to impact. This new valve concept was initially tested using a single-impact shock tube. During this testing, a valve element was coupled to the voice coil of a speaker to provide a variable reaction force. The reaction force applied by the coil was able to measurably reduce the impact velocities of the valve plate. The reduction in impact velocities resulted in a relative life gain of three to 11 times that of a standard valve experiencing the same forces. A full-scale test breadboard was designed and implemented in a reciprocating compressor. The design included a standard valve configuration, with modifications to couple it to an electromagnetic voice coil.

The foundation of the semi-active electromagnetic plate valve is similar to existing plate valves in service today. Only slight modifications are needed to facilitate the addition of the coils. Initial testing showed the valve motion profile becomes rounded, thus reducing the impact velocity. Reduced impact velocities result in a significant increase in valve life, since high cycle fatigue is the primary cause of valve failures. The financial benefit of this valve technology is based on the increased life and the associated reduced maintenance cost for valve change-out. However, the new valve technology will require some additional cost per change-out. If, for example, the valve life improvement is a factor of 10, the increased cost is a factor of two, the current life is a half year, and change-out cost is $30,000, then the overall maintenance cost benefit is calculated to be $240,000 during a 5-year period or a normalized annual savings of $48,000.

The semi-active valve design has proven to be worth further evaluation (Figure 4). By decoupling the lift vs. life relationship, it allows long-life, high-lift valves. This high-lift valve will result in lower pressure drop and higher efficiency. The next step is to reduce the size and complexity of the unit and field-test it in actual pipeline compressors.

Other ARCT developments

During the course of Phase 1 of this project, other successes included 18 additional technology solutions. These technologies have been developed to a proof-of-concept stage. The industry has recommended advancing half of these technologies to the next stage. A conservative estimate for the value of this suite of technologies is $50,000 per installation per year.

Figure 5. A semi-active electromagnetic plate valve breadboard is shown being tested at the ARCT test bed at the SwRI Metering Research Facility.

For the future, solutions are needed for slow-speed and high-speed compression. For slow-speed compression, optimum flow rate turndown will be accomplished with a combination of speed and clearance. Advances in pulsation control will recover capacity lost because of pressure drop. Advances in valves will extend valve life with low-pressure loss penalty. The combination of these technology improvements will provide the potential of 95% thermal efficiency with 3-year valve life and expanded flow rate turndown.

For high-speed compression, optimum flow rate turndown will be accomplished with unit speed. Tapered cylinder nozzles will resolve the nozzle pulsation problem with half the pressure loss and also eliminate cylinder vibration. An additional new technology developed during this program is a tunable side-branch-absorber that addresses the fundamental frequency vibration in the lateral piping over the entire speed range with minimal pressure loss penalty. The semi-active electromagnetic plate valve will extend valve life with half the pressure loss penalty (Figure 5). The combination of these technology improvements will provide the potential of 90% thermal efficiency with 2-year valve life, 50% flow rate turndown and vibrations of less than 0.75 in. per second.

The program has developed sufficient technology solutions to address the current limitations of modern high-speed compression, thus enabling this equipment to meet its full potential. This suite of technologies has the potential to meet the stated objective of creating the next generation of reciprocating compressor technology that provides expanded capacity at reduced operation costs. Fully implemented, this technology can meet the DOE goals of increasing capacity of the current pipeline infrastructure by 10% and reducing operational cost by 50%. ✧

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Briefs

DOE-funded Seismic Tool Guides First Deep Well Through San Andreas Fault

A newly commercialized Department of Energy (DOE)-funded technology developed to aid the exploration and production of natural gas and oil has enabled researchers for the first time to drill through and observe an active portion of California's San Andreas Fault. With the help of new vertical seismic profiling technology, scientists have created an earthquake observatory 2 miles deep in a seismically active section of the fault where earthquakes originate. The technology, developed with DOE funding by Brea, Calif.-based Paulsson Geophysical Services Inc., produces high-resolution, three-dimensional subsurface images. To locate the earthquake-prone portion of the fault, the team used Paulsson's 80-level borehole seismic receiver array, which is essentially a string of instruments for gathering subsurface seismic signals from within a borehole. The array, the world's longest, recorded more than 1,000 earthquakes, including many events too small to detect on conventional seismographs positioned on the ground. More information is available at *http://www.netl.doe.gov/publications/press/2005/tl_seismic_sanandreas.html*

U.S. Department of Energy Announces $2 Million for Methane Hydrate Projects

A total of $2 million in funding to five research projects that will assess the energy potential, safety and environmental aspects of methane hydrate exploration and development were announced. Termed the "ice that burns," methane hydrates are crystalline solids that release a flammable gas when melted. They are considered the Earth's biggest potential source of hydrocarbon energy and could be a key element in meeting natural gas demand in the United States, which is expected to increase nearly 50% by 2025. The total value of the projects is about $3.3 million, with university and science institute partners providing the remaining funds. The selected projects will examine the resource potential, recoverability, safety aspects and climate change questions surrounding methane hydrates. More information is available at *http://www.netl.doe.gov/publications/press/2005/tl_methane_hydrate_awards.html*

DOE-funded Microhole Program Brochure Available

A new brochure is available detailing projects in the DOE Microhole Technology (MHT) Program. The MHT program is developing a promising suite of technologies that enables drilling of wells with casings less than 4½-in. in diameter using coiled tubing drill rigs that are relatively small and easily mobilized. These technologies have the potential to reduce the cost of drilling shallow- and moderate-depth holes for exploration, field development and long-term subsurface monitoring. The MHT program employs a systems approach in that it considers the larger picture and takes into account how factors such as technology, research, risk and the business environment contribute to the overall success or failure of resource development. The MHT Program's potential benefits to the nation include lower drilling costs from reduced materials, labor and support equipment; reduced environmental impact from lower volumes of drilling waste, smaller footprints and lighter equipment; lower exploration risk from low-cost exploration wells; and increased quality and quantity of high resolution, dynamic and continuous reservoir data. This brochure is available at *http://www.netl.doe.gov/technologies/oil-gas/publications/brochures/Microhole2005_Oct.pdf*

Mature Region, Youthful Potential — Oil and Natural Gas Resources in the Appalachian and Illinois Basins

A report developed by the Appalachian and Illinois Basin Directors in cooperation with the Interstate Oil and Gas Compact Commission (IOGCC) and the U.S. Department of Energy's Office of Fossil Energy and National Energy Technology Laboratory is available. The report is intended to serve as a reference source for government and industry decision makers. Making optimal use of available domestic fossil fuel resources is a key to ensuring adequate supplies of energy for American consumers. This imperative has brought renewed focus to the significant oil and natural gas resources still remaining in America's oldest producing areas: the Appalachian and Illinois basins. After more than a century, the Appalachian and Illinois basins still contain at least as much oil and natural gas as have been produced to date. Together, these basins span 10 states – Kentucky, Maryland, New York, Ohio, Pennsylvania, Virginia, West Virginia, Tennessee, Illinois and Indiana. Prospects for future production from the Appalachian and Illinois basins remain promising, despite their maturity. This report is available at *http://www.netl.doe.gov/technologies/oil-gas/publications/AP/AIBasins_L.pdf*

DOE Continues Series of LNG Public Education Forums

The second in a series of Department of Energy (DOE)-sponsored public education forums on liquefied natural gas (LNG) has been scheduled for Tuesday, March 28, at the Liberty Theater in Astoria, Oregon. Joining the DOE in presenting the educational forums will be the U.S. Department of Transportation, U.S. Department of Homeland Security, the Federal Energy Regulatory Commission, coastal state governors and professional groups representing regulatory and safety officials. The Department of Energy's LNG forums are being scheduled in compliance with the National Energy Policy Act of 2005 and aim to initiate constructive dialogue among community members, local, state and federal government leaders. The Energy Information Administration estimates the United States will have to increase imports of LNG by more than 600% in the next 25 years to fulfill America's increasing demand for natural gas. This forum is one step, of many, that will help address and evaluate energy needs, and increase America's energy security. More information is available at *http://www.fe.doe.gov/news/techlines/2006/06013-DOE_Schedules_Oregon_LNG_Forum.html*

Events

SPE / ICoTA Coiled Tubing and Well Intervention Conference and Exhibition

April 4-5, The Woodlands, Texas

AAPG, Annual Convention

April 9-12, Houston. For more information visit: *www.aapg.org*

SPE, Offshore Technology Conference

May 1-4, Houston. For more information visit: *www.otcnet.org*

AAPG Rocky Mountain Section Annual Meeting

June 10-13, Billings, Mo. For more information visit: *www.aapg.org*

SPE, Annual Technical Conference & Exhibition

Sept. 25-27, San Antonio, Texas. For more information *visit: www.spe.org*

SEG, International Exposition & Annual Meeting

Oct. 1-6, New Orleans. For more information visit: *www.seg.org*

AAPG Eastern Section Annual Meeting

Oct. 8-11, 2006, Buffalo, NY. For more information visit: *www.aapg.org*

THREE NEW TRANSMISSION AND DISTRIBUTION REPORTS AVAILABLE

Reports are available detailing the activities and findings of three U.S. Department of Energy Transmission and Distribution program area projects. Carnegie Mellon University reports on the "Wireless Self-powered Visual and NDE Robotic Inspection System for Live Gas Distribution Mains," the Edison Welding Institute reports on "Internal Repair of Pipelines" and Southwest Research Institute reports on "Technologies to Enhance the Operation of Existing Natural Gas Compression Infrastructure—Manifold Design for Controlling Engine Air Balance." These reports are available at *http://www.netl.doe.gov/technologies/oil-gas/ReferenceShelf/index.html#tds*

ROCKY MOUNTAIN BASINS PRODUCED WATER DATABASE

A recently completed U.S. Department of Energy project has resulted in a database containing information on produced water from basins in the Rocky Mountain region. The results of this project may help operators reduce costs, improve production rates and increase the longevity of wells within these basins. *http://www.netl.doe.gov/technologies/oil-gas/Software/database.html#Rocky*

FEASIBILITY STUDY OF DILUTING A WEIGHTED DRILLING FLUID WITH A LOW-DENSITY LIQUID TO CREATE A RISER FLUID FOR A DUAL-DENSITY DRILLING SYSTEM

This report documents an investigation of two dual-density drilling concepts – riser dilution with a low density liquid and riser gas lift – as a potential means to implement a dual-gradient system for simpler, safer and more economic well designs. The report summarizes the experimental work performed to evaluate the feasibility of diluting a high-density mud from the wellbore with a low-density liquid to create a reduced density mud in the riser.

Price: $60
Form: Computer file, 357 KB
Document No.: GRI-04/0176

Order through the Gas Technology Institute Web site "Search" function at *www.gastechnology.org*

IMAGING DEEP GAS PROSPECTS USING MULTICOMPONENT SEISMIC TECHNOLOGY

This report investigates the value of long-offset multicomponent seismic data for studying deep-gas geology across the northern shelf of the Gulf of Mexico (GOM). Long-offset four-component ocean-bottom-cable (4-C OBC) seismic data have been analyzed to determine whether increased source-receiver offsets improve the ability to image deeper geology across the gas-producing areas. The data were processed using source-receiver offsets as large as 10 km. These data represent the largest imaging offsets available for seismic reflection data and should image deeper than conventional seismic reflection data. This information sets new guidelines for deep geology across the GOM basin. The P-SV mode sometimes images to depths of 13 km. Both modes, P-P and P-SV, provide good images of geologic conditions to depths of 9 km, the present deepest depth that most operators wish to drill along the shallow-water, northern shelf of the GOM. The research findings should encourage operators in the GOM basin to integrate long-offset 4-C OBC seismic technology into their prospect evaluations.

Price: $60
Form: Computer file, 7.28 MB
Document No.: GRI-04/0186

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REAL-TIME PORE-PRESSURE PREDICTION AHEAD OF THE BIT

This project evaluates the feasibility of using a new method for predicting formation pore pressures ahead of the bit in real time while the well is being drilled. Pore pressures of formations are one of the big problems facing drillers in exploration areas. The pore pressure, together with fracture gradient, determines the amount of mud weight needed. The new approach estimates the pore pressures of formations before the drillbit drills through them. Surface seismic data, in the vicinity of the well, and real-time logs and check-shot measurements as the well is being drilled, are combined to make a more reliable estimate of velocities ahead of the bit. The predicted velocities are then mapped to pore pressures using an equation or empirical relationship appropriate for the area. The study demonstrated that incorporation of check-shot and well log data significantly improves the velocity estimates ahead of a well. The field data inversion study showed that big improvements could be seen, particularly in gradual changes of velocities that are typically associated with pore-pressure variations in areas like the Gulf of Mexico.

Price: $60
Form: Computer file, 423 KB
Document No.: GRI-04/0208

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