

Fracture Research and Application Consortium (FRAC)

The University of Texas at Austin

<http://www.beg.utexas.edu/frac>

Prospectus 2011

The Fracture Research and Application Consortium (FRAC) engages in fundamental and applied research toward the successful characterization, prediction, and simulation of naturally and artificially fractured reservoirs. A key aspect of the program investigates mechanical and chemical fracture processes and interactions over a range of scales. The goal is improved prediction of the geometry, spatial distribution, and hydraulic properties of subseismic-scale structural heterogeneities and their influence on fluid migration, production and injection.

Fractures and faults have worldwide importance because of their influence on successful extraction of resources. Many faults and fractures are difficult or impossible to characterize adequately using currently available technology. Consequently, reservoirs that contain fractures have been intractable to describe and interpret effectively, posing serious challenges for exploration, development, and accurate reservoir simulation and reservoir management. More accurate prediction and characterization of fractures holds great potential for improving production by increasing the success and efficiency of exploration and recovery processes.

Scope of the Project

The scope of this project includes measurement, interpretation, prediction, and simulation of natural and induced fractures. The project

- creates and tests new methods of measuring attributes of reservoir-scale fractures, particularly as fluid conduits and barriers;
- extrapolates structural attributes to the reservoir scale through rigorous mathematical techniques and help build accurate and useful 3-D models for the interwell region and develops procedures to do so;
- develops the capability to accurately predict reservoir-scale deformation using geomechanical, structural, diagenetic, and linked geomechanical/diagenetic models;
- improves the usefulness of seismic response as an indicator of reservoir-scale structure by developing seismic methods and providing methods of calibrating and verifying seismic fracture detection methods;
- designs new ways to incorporate geological and geophysical information into reservoir simulation and verify the accuracy of the simulation, and
- examines hydraulic fracture propagation from vertical and horizontal wells in naturally fractured reservoirs from experimental and numerical modeling perspectives.

The aims of this project are both fundamental and practical—to improve prediction and diagnosis of natural-fracture attributes in hydrocarbon reservoirs, accurately simulate their influence on production, and assess fractured reservoir response to stimulation operations (such as hydraulic fracturing). New analytical methods will lead to more realistic characterization of fractured and faulted reservoir rocks. These methods will produce data that can enhance well-test and seismic interpretations and that can readily be used in reservoir simulators.

Testing diagnostic and predictive approaches is an integral part of the research. Our requirement is that new methods must ultimately be cost effective. Testing of diagnostic and predictive approaches developed from outcrop, core, and well-test studies is generally carried out in areas of interest to member companies.

Our results are applicable to many types of fractured rocks. Ongoing studies include work on shales, sandstones, and carbonate rocks in both the subsurface and in outcrop.

Research Staff

Our research team comprises staff of the Bureau of Economic Geology (BEG), and the Departments of Petroleum & Geosystems Engineering (PGE) and Geological Sciences (DGS), The University of Texas at Austin. This group of petroleum engineers, geophysicists, and geologists applies a wide range of techniques, including geomechanical modeling, rock property testing, quantitative structural geology, microstructural and structural diagenetic analysis, fluid-flow simulation, and geophysical modeling.

Dr. Stephen E. Laubach (BEG), *Structure and diagenesis*

Dr. Jon E. Olson (PGE), *Petroleum engineering, geomechanical modeling; hydraulic fracture in naturally fractured rock*

Dr. Randy Marrett (DGS), *Quantitative analysis, structural geology*

Dr. Peter Eichhubl (BEG), *Brittle deformation and diagenesis*

Dr. Julia F. W. Gale (BEG), *Structural geology; shale systems*

Dr. Jon Holder (PGE), *Rock property testing, rock physics*

Dr. Andras Fall (BEG), *Fluid inclusion analysis*

Dr. Tobias Weisenberger (BEG), *Geochemistry, fracture petrology*

Dr. Sergey Fomel (BEG), *Geophysics*

Dr. Rob Reed (BEG), *Microstructural imaging, structural geology*

Mr. John Hooker (BEG), *Microfracture interpretation, structural geology*

Ms. Hyein Ahn (BEG), *Microstructural imaging & interpretation*

Collaborators

Dr. Rob Lander and Dr. Linda Bonnell, Geocosm, *quantitative diagenetic modeling of fracture development*

Students

Graduate student training is an integral part of the consortium program. Graduate students, and some undergraduates, obtain degrees in Petroleum & Geosystems Engineering, Geological Sciences, and the Energy & Earth Resources cross disciplinary engineering and economics program.

Current and Planned Research: Subsurface Fractures

Each year we combine industry input with our own ongoing research plans to develop a set of key geological and engineering research topics. The research outline and time table is discussed at the Annual Research Meeting, but member input is welcome at any time.

Core and Field-Scale Characterization and Prediction

Fractures in Shale-Gas Reservoirs

Our overarching goals are to seek unifying principles that govern the development and properties of fractures in shale-gas plays with the aim of improving systematic fracture prediction & characterization. We hope to accomplish this using a structural diagenesis approach, making use of principles discovered in tight gas sands and dolostones.

The research plan for shale-gas studies focuses on two aspects:

- 1) Understanding the origins and attributes of natural fracture systems in shales

Natural fractures can form in shales at many different times during burial and uplift. The mechanical properties that control natural fracture attributes can be markedly different for different fracture sets, depending on their timing relative to diagenesis. Each fracture type must be placed in context of burial and tectonic history of the basin in which they are forming. We are using our understanding of the linked chemical and mechanical processes gained from studies in sandstones and carbonates to adopt the same approach in shales. The details of the diagenetic processes are different in shale but the principle of interdependence of chemical and mechanical processes is common to all rock types.

- 2) Understanding the interaction of hydraulic fracture treatments with natural fractures

The traditional idea that it is the open fractures in a fractured reservoir that are important for production must be modified when dealing with shale-gas reservoirs. Gale et al. (2007) showed how interaction of hydraulic fractures with sealed natural fractures is an important consideration. We are currently undertaking geomechanical modeling of these interactions both at the individual fracture interaction scale using XFEM techniques, and also at the interwellbore scale using *JOINTS* (in house software developed by Jon Olson and available to FRAC members). The interaction may serve to increase the effectiveness of the hydraulic fracture network, or could work against it. Natural fracture attributes such as fracture intensity and spacing, orientation with respect to S_{Hmax} , and strength of the fracture plane will influence the interaction.

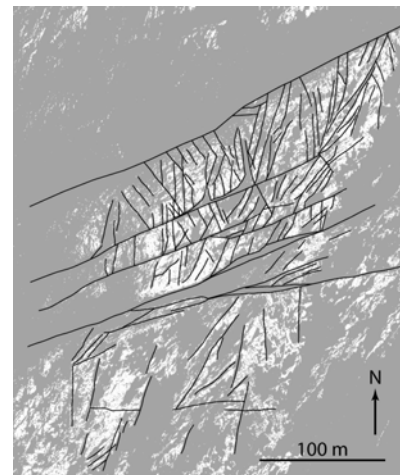


We aim to build a comprehensive library of examples through further case by case study.

In 2009-2010 we focused on the New Albany Shale. In 2010 we began a new effort on the **Marcellus Shale**, which will continue through 2011. A summary of the research plan is on the Reports page. A new effort in 2011 will address fracture formation in organic-rich mudstone of the **Monterey Formation**, coastal California.

Targeting Reservoir Potential in Deep, Low Permeability Sandstones

A key to unlocking the natural gas resource for the future global energy economy lies in successfully targeting effective reservoir rocks in low-porosity, low-saturation, fractured, and heterogeneous rock systems. This research is designed to create a robust, accurate, and testable procedure for predicting variations in porosity and permeability in deep, tight sandstones. A unique aspect is that rock mass predictions will explicitly include effects of fractures by combining an innovative numerical model for predicting sandstone porosity and permeability, new models for predicting rock mechanical properties through time and space, and a successful computational model for predicting fracture growth patterns. In deep, nonconventional plays, better predictions are key to locating and producing hydrocarbons economically. Our research will provide new geologic system models and exploration concepts that will help find new and overlooked fairways for oil and gas production. Better interwell characterization



will also allow for improved reservoir management, leading to maximum economic recovery of hydrocarbon resources.

This project employs novel **seismic diffraction** techniques to image fault and fracture systems that are below seismic resolution using conventional seismic techniques. These techniques are currently being tested by modeling synthetic seismic responses to outcrop-generated fault and fracture patterns obtained from field sites that share fundamental characteristics with producing subsurface reservoirs. Starting in 2010/11, we test these techniques using an industry seismic data set from the Piceance Basin, Colorado. The seismic component of this project integrates with core fracture scaling research in the Piceance Basin, and with field-based outcrop analog studies elsewhere.

A new effort in 2011 focuses on carbonate cementation in naturally fractured tight-gas sandstones. Core observations have consistently shown that late carbonate cements can destroy fracture porosity and permeability. This research addresses where and when late carbonate cements occur, what geochemical reactions lead to carbonate cementation, and how these carbonate cements can be predicted based on stratigraphic, structural, and tectonic information that may be available prior to drilling. For 2011, this effort is focused on the Mesaverde Group of the Piceance Basin.

Predicting Fracture Porosity Evolution in Sandstone: Chemical-Mechanical Feedback

The goal of this research is to develop an understanding of how fracture growth and diagenetic alteration interact to systematically create and destroy fracture porosity. Our initial objective is a key link between mechanical and chemical processes in opening fractures. Specifically, a new theory of quartz cementation postulates that the rate-limiting step for quartz cementation is precipitation, with supply and transport being of secondary importance. We test the hypotheses that this cementation process governs evolution of (1) fracture porosity and (2) fracture growth velocity (the subcritical crack index), which, in turn, controls many aspects of fracture pattern development. Despite the important influence of fracture systems on fluid flow, our understanding of the properties of these systems and how they evolve in sedimentary basins is exceedingly meager, owing in part to formidable challenges in collecting meaningful samples of fracture patterns. A practical benefit of our fundamental research is that it will lead to predictions of linked structural and diagenetic attributes, therefore potentially increasing the range of samples that provide meaningful fracture information.

High temperatures and reactive fluids in sedimentary basins dictate that interplay and feedback between mechanical and geochemical processes could significantly influence evolving rock and fracture properties. Moreover, microstructure observations demonstrate that fracturing and diagenesis are linked processes in a wide range of formations, basins, and tectonic settings. Yet we lack fundamental understanding of how these processes are linked. Until we understand how these processes are linked we cannot hope to develop truly predictive models of fracture systems.

We are studying mechanical and diagenetic feedback loops using new models of cementation, improved measurement methods of key mechanical properties, advanced fracture-mechanics-based fracture growth modeling, and high-resolution cement and microstructure quantification. This cross-disciplinary research will result in a fundamental advance in our understanding of how the diversity of natural fracture patterns evolves and better predictions of fracture pattern attributes in the subsurface where sparse sampling is the rule.

Trap-Scale Initiative

The project is a multidisciplinary research effort in analysis of fracture patterns at the trap scale. The study will use outcrop and subsurface data from both siliciclastic and carbonate systems. Among the issues to be addressed:

- Fracture intensity patterns on and off structure.

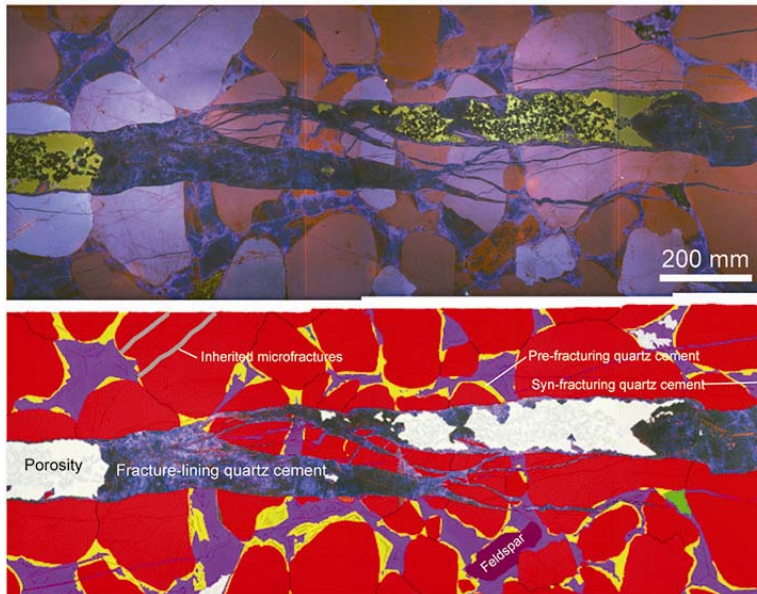
- Fracture style, intensity, and porosity preservation variation with structural position and burial history.
- Fracture intensity and fracture spatial arrangements at scales ranging from thin section to trap scale.

Fracture intensity and fracture patterns will be studied in the context of high resolution data on fold geometry on outcrop analogs and horizontal core data. The aim is to use this data to guide studies of fracture seismic response.

Surrogate Methods

This research aims to provide methods to acquire site-specific fracture information at user-specified levels of completeness and to yield results even without measuring elusive, difficult-to-sample large fractures (Laubach, 1997; Marrett and others, 1999; Gale, 2002; Laubach, 2003).

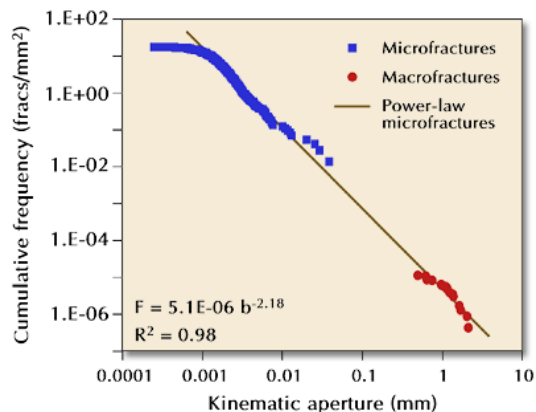
We continue to investigate surrogate methods to obtain accurate, site-specific information on fracture intensity, spatial distribution, and fracture porosity preservation. Our automated SEM-based system for collection of microstructural



data has allowed us to collect large, statistically meaningful datasets to test and improve these methods. These datasets are also used as a key tool for calibrating seismic fracture characterization methods. We are seeking funding leveraged by FRAC support to further our efforts in seismic fracture detection methodologies. The greater volume of data afforded by an automated system has allowed us to apply new insights into fracture spatial scaling. The goals of this part of the FRAC program can be summarized as follows:

- Testing quantitative scaling and fracture quality information for exploration mapping and horizontal well placement, orientation, and length.
- Calibrating seismic response to extract more information on fracture attributes.
- Constraining and validating fracture mechanics-based predictive models.
- Improving fractured reservoir simulation.

Fundamental studies of fracture formation and closure help put fracture observations in a rigorous theoretical framework. This study is aimed at matching the wealth of new empirical evidence on fracture attributes with fundamental understanding of the processes that produce these fracture patterns. This will help extrapolation of observations to unsampled areas and prediction of fracture attributes.



The aim is to derive predictions of fracture attributes from pre-drill data such as basin models, diagenetic history modeling, and predictions of rock types based on stratigraphic interpretations. Studies are needed that combine diagenetic and mechanical modeling with rigorous structural and geochemical descriptions of fracture networks. Carefully designed rock-property tests are required and are being carried out in our laboratory to link key parameters in mechanical models (for example, subcritical crack index) with diagenetic parameters that evolve in a systematic way during burial (for example, quartz cement volume and pore pressure; dolomitization; hydrocarbon maturation).

A key aspect of these studies is creation of predictive structural models that can be tested with the types of observations readily available to industry. These studies explicitly take account of fracture-size scaling.

Fracture-Charge History Mapping

This effort correlates the timing and spatial distribution of fracture opening with hydrocarbon migration and charge on a reservoir to basin scale. This core and outcrop-based approach employs detailed **fluid inclusion compositional analyses and thermometry** of fracture cements with microstructural fracture opening reconstructions and basin modeling in an effort to date the timing of fracture opening and to reconstruct the fluid compositional evolution of the reservoir. We are in the process of applying these techniques on the reservoir to basin scale to

- map out areas and stratigraphic intervals of high fracture opening strain;
- constrain the timing of fracture opening relative to the hydrocarbon maturation and porosity evolution of the matrix;
- assess spatial variations in saturation state within the reservoir.

Fracture-charge history maps are designed to aid in the development of tight-gas resource plays. Current efforts are under way in the Piceance basin of Colorado, the East Texas basin, and the Canadian Rocky Mountain fold and thrust belt. East Texas results have been summarized in Becker et al. (2010).

Deformation Bands and Compaction Localization

Deformation bands are planar structures accommodating shear, compaction, or dilation in sand and porous sandstone. Deformation bands typically occur in sets and are preferentially cemented over the host rock, thus forming baffles to fluid flow and imparting a permeability anisotropy to clastic reservoirs. In production settings, it is believed that deformation bands can result in a directional reservoir response not unlike that of fractured reservoirs. Past research has focused on deformation bands in depositionally mature eolian sediment. Research in 2011 will address localization of compaction and shear into deformation bands in sediment of varying size and shape distribution.

Fault Deformation Processes and Flow Properties

Faults may act as reservoir seals and preferred flow conduits depending on a variety of parameters, including fault rock properties and their spatial distribution within a fault zone, loading conditions, and slip history. Current research focuses on the effect of faults on the focusing of CO₂ leakage from underground storage reservoirs. We investigate the structural and diagenetic interactions in a natural CO₂ system in eastern Utah as an analog for the long-term (10,000 yr) behavior of anthropogenic CO₂ reservoirs. For 2011, diagenetic research will focus on fault and fracture processes in caprock (top seal) units. Other aspects include pore-scale models of CO₂ flow in carbonate cemented sandstone, and field-scale numerical models of flow-fault interactions.

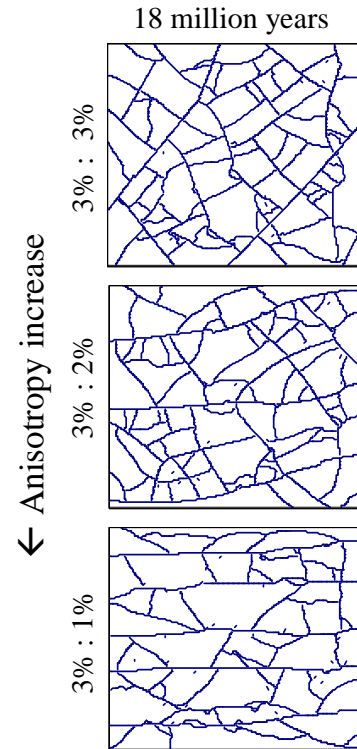
Numerical Simulations and Prediction

JOINTS Modeling of Fracture Network Evolution

Direct characterization of natural fracture network attributes such as length, spacing, aperture, orientation and intensity in most reservoirs is difficult. The problem stems mostly from the low probability of intersecting vertical fractures with vertical wellbores. Even if fractures do intersect the wellbore they are rarely abundant enough to give a good representation of fracture geometry.

Our JOINTS geomechanical model is part of our effort pursuing indirect, physics-based fracture characterization. This process-oriented approach can provide a theoretical basis for deciding what types of fracture attribute distributions are physically reasonable, and how attributes such as length, spacing and aperture are inter-related. The current model is pseudo-3d in nature, but we are developing a **fully 3d model** to better address multi-layer and fracture/fault interaction problems. The objective of the study is to improve geomechanical fracture network modeling by examining the micro-mechanics of the fracturing process (focused on subcritical crack growth) and by quantifying diagenetic controls on fracture growth parameters.

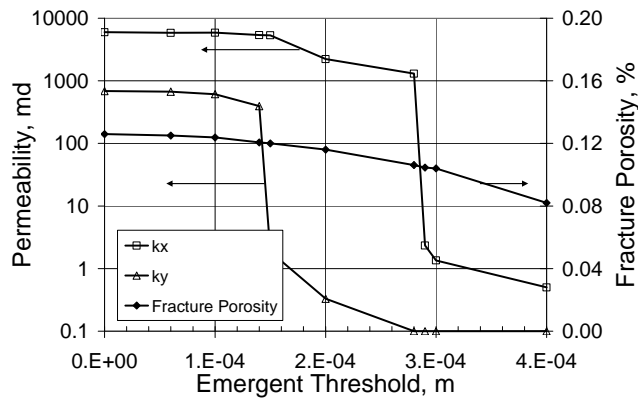
A key element of the geomechanics approach is the recognition that natural fracture propagation is dominated by stress corrosion cracking (subcritical crack growth), a process that is sensitive to rock fracture properties as well as environmental conditions. Variations in subcritical parameters exert a fundamental control on fracture pattern geometry. For a given strain event, the subcritical index can control the amount of



clustering of the fracture spacing as well as the ultimate fracture intensity.

The spatial organization of a fracture pattern has a primary impact on fluid flow, but we also include the equally important influence of fracture diagenesis on porosity and permeability predictions. We have developed an efficient algorithm to directly assess the flow properties of JOINTS generated fracture patterns with the capability to incorporate varying degrees of syn-kinematic and post-kinematic cement.

Fracture Permeability Assessment



Complex Hydraulic Fracture Development Modeling

Recent activity, primarily in gas shales, has indicated that hydraulic fractures can be significantly influenced by interaction with natural fractures, and planar symmetric bi-wing induced fracture geometry is not an adequate representation of field experience. We are using the JOINTS model to do multi-frac, pseudo-3d simulation of hydraulic fracture propagation from horizontal wells, and are developing a fully 3d version to address more general fracture/wellbore geometries.

Leveraged Research

The Fracture Research and Application Consortium leverages industry support through grants from Federal and State funding sources. Currently, the U.S. Department of Energy supports our efforts on understanding the evolution of fracture systems. These studies will continue during 2011. Our research has also been supported by a major initiative grant from the Geology Foundation, John A. and Katherine G. Jackson School of Geosciences.

Participation and Technology Transfer

Membership

Companies participate in this Industrial Associates program through an annual subscription. Research results are shared equally among supporting companies at annual review meetings and through our private web site. New members are welcome to join at any time.

Website

Our private Website is an important part of our information transfer strategy. The private side of the project Website is extensive and frequently updated. <http://www.beg.utexas.edu/frac/>

Mentoring and Case Studies

Interaction with the technical staff of our sponsoring companies allows us to test our concepts and methods on real problems while assisting sponsors in developing new reserves. Sponsors are encouraged to contact us with projects that could be mutually beneficial.

Meetings and Workshops

The annual Research Meeting is generally held sometime between late spring and early fall and typically has an associated field trip. The 2011 meeting is being planned for California in late fall, with a field trip to the Monterey. This meeting will be combined with an Applications Workshop which involves teaching of fundamental aspects of fractured reservoirs, methods, software, practical exercises using case study data, etc. In addition, we can meet individually with Members either in Austin or at Members offices to discuss or review case studies or to provide background briefings or training for staff.

During the year, there are various other single-issue technical meetings scheduled in Austin or Houston that Members are welcome to attend. These meetings are announced on the private web site.

Selected FRAC Papers

A 48 m.y. history of fracture opening, temperature, and fluid pressure: Cretaceous Travis Peak Formation, East Texas basin. Becker, S. P., Eichhubl, P., Laubach, S. E., Reed, R. M., Lander, R. H., and Bodnar, R. J., 2010, Geological Society of America Bulletin, vol. 122, no. 7/8, p. 1081-1093.

Natural fracture characterization in tight gas sandstones: Integrating mechanics and diagenesis.

Olson, J. E., Laubach, S. E., and Lander, R. H., 2009, AAPG Bulletin, v. 93, no. 11, p. 1535-1549.

Fracture diagenesis and producibility in tight gas sandstones, Laubach, S.E. Olson, J.E. and Eichhubl, P., 2009, in Carr, T., D'Agostino, T. Ambrose, W., Pashin, J, and Rosen, N.C., eds., Unconventional Energy Resources: Making the Unconventional Conventional, 29th Annual GCSSEPM Foundation Bob F. Perkins Research Conference, on CD, p. 483- 499.

Mechanical and fracture stratigraphy. Laubach, S. E., Olson, J. E, and Gross, M. R., 2009, AAPG Bulletin, v. 93, no. 11, p. 1413-1426.

Laurentian paleostress trajectories and ephemeral fracture permeability, Cambrian Eriboll Formation sandstones west of the Moine thrust zone, northwest Scotland. Laubach, S.E. and Diaz-Tushman, K., 2009, Journal of the Geological Society (London), v. 166, part 2, p. 349-362.

Structural and diagenetic control of fluid migration and cementation along the Moab Fault, Utah. Eichhubl, P., Davatzes, N.C., Becker, S.P., 2009, AAPG Bulletin, v. 93, no. 5, p. 653-681.

Aperture-size scaling variations in a low-strain opening-mode fracture set, Cozette Sandstone, Colorado, Hooker, J.N., Gale, J.F.W., Gomez, L.A., Laubach, S.E., Marrett, R., Reed, R.M., 2009, Journal of Structural Geology (2009), v. 31, p. 707-718.

Natural fractures in the New Albany Shale and their importance for shale-gas production: Gale, J.F., and Laubach, S.E., 2009, 2009 International Coalbed & Shale Gas Symposium.

- The effect of mineralization on the ratio of normal to tangential compliance of fractures.** Sayers, C.M., Dahi Taleghani, A. and Adachi, J., 2009, *Geophysical Prospecting*, v 57, no. 3, p. 439-446.
- Late opening-mode fractures in karst-brecciated dolostones of the Lower Ordovician Ellenburger Group, West Texas: recognition, characterization, and implications for fluid flow** Gale, J. F. W., and Gomez, L. A., 2007, *AAPG Bulletin*, v. 91, p. 1005–1023.
- Natural fractures in the Barnett Shale and their importance for hydraulic fracture treatments** Gale, J. F. W., Reed, R. M., and Holder, Jon, 2007, *AAPG Bulletin*, v. 91, no. 4, p. 603–622.
- Obtaining fracture information for low-permeability (tight) gas sandstones from sidewall cores** Laubach, S. E., and Gale, J. F. W., 2006, *Journal of Petroleum Geology*, v. 29, no. 2, p. 147–158.
- Modeling coupled fracture-matrix flow in geomechanically simulated fracture networks:** Philip, Z.G., Jennings, J.W., Olson, J.E., Laubach, S.E., and Holder, J., 2005, *Society of Petroleum Engineers Reservoir Evaluation & Engineering*, v. 8, no. 4.
- Are open fractures necessarily aligned with maximum horizontal stress?** Laubach, S. E., Olson, J. E., and Gale, J. F. W. 2004, *Earth & Planetary Science Letters*, v. 222, no. 1, p. 191-195.
- Coevolution of crack-seal texture and fracture porosity in sedimentary rocks: cathodoluminescence observations of regional fractures:** Laubach, S. E., Reed, R. M., Olson, J. E., Lander, R. H., and Bonnell, L. M., 2004, *Journal of Structural Geology*, v. 26, no. 5, p. 967-982.
- Sublinear scaling of fracture aperture versus length: an exception or the rule?:** Olson, J.E., 2003, *Journal of Geophysical Research* v. 108, no. B9, 2413, doi:10.1029/2001JB000419.
- Practical approaches to identifying sealed and open fractures:** Laubach, S.E., 2003, *AAPG Bulletin*, v. 87, No. 4, (April 2003), 561-579.
- Specifying lengths of horizontal wells in fractured reservoirs:** Gale, J.F.W., 2002, *Society of Petroleum Engineers Reservoir Evaluation and Engineering*, v. 5, no. 3, p. 266-272.
- Estimation of fracture orientation and relative intensity using azimuthal variation of P-wave AVO responses and oriented core data in the Tacata Field, Venezuela,** Montoya, P., Fisher, W., Marrett, R., and Tatham, R., 2002, *SEG Expanded Abstracts, 2002, AVO2 Case History Section*, Salt Lake City, 261-264.
- Genesis and controls of reservoir-scale carbonate deformation, Monterrey salient, Mexico:** Marrett, R., ed., 2001, *The University of Texas at Austin, Bureau of Economic Geology, Guidebook 28*.
- Experimental determination of subcritical crack growth parameters in sedimentary rock:** Holder, J., Olson, J.E., and Philip, Z., 2001, *Geophysical Research Letters*, v. 28, No. 4, 599-602.
- Constraining the spatial distribution of fracture networks in naturally fractured reservoirs using fracture mechanics and core measurements,** Olson, J. E., Holder, J., Qiu, Y. and Rijken, M., 2001, 2001 SPE Annual Technical Conference and Exhibition, New Orleans, LA, Sept. 30 – Oct. 3.
- Brittle deformation in sandstone diagenesis as revealed by scanned cathodoluminescence imaging with application to characterization of fractured reservoirs:** Milliken, K.L., and Laubach, S.E., 2000, Chapter 9, *Cathodoluminescence in Geosciences*, New York, Springer Verlag, 225-243.
- Power-law scaling of natural fractures in rock:** Marrett, R., Ortega, O.O., and Kelsey, C., 1999, *Geology*, v. 27, 799- 802.
- Aggregate properties of fracture populations:** Marrett, R., 1996, *Journal of Structural Geology*, v. 18, No. 2/3, 169-178.

Members

Current FRAC membership is listed on the web site: <http://www.beg.utexas.edu/frac/sponsors.php>

Contact Information

Steve Laubach — Phone: (512) 471-6303 or (512) 471-1534 (BEG Operator)
E-mail: steve.laubach@beg.utexas.edu

Julia Gale — Phone: (512) 232-7957 or (512) 471-1534 (BEG Operator)
E-mail: julia.gale@beg.utexas.edu

Jon Olson — Phone: (512) 471-7375 (Department of Petroleum and Geosystems Engineering)
E-mail: jolson@mail.utexas.edu

Peter Eichhubl — Phone: (512) 475 8829 or (512) 471-1534 (BEG Operator)
E-mail: peter.eichhubl@beg.utexas.edu

Eric Potter — Phone: (512) 471-7090 (Bureau of Economic Geology)
E-mail: eric.potter@beg.utexas.edu