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New Albany Shale Gas Project

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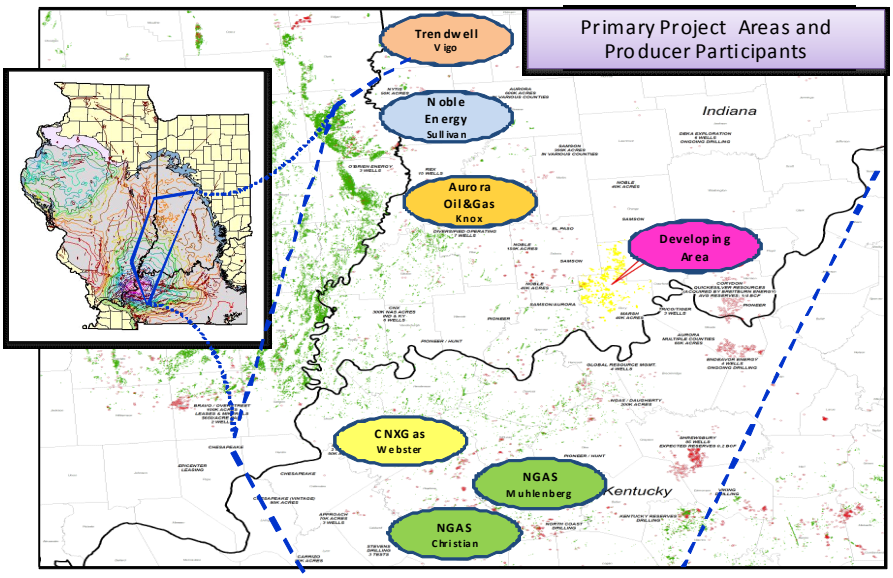

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RPSEA is a non-profit corporation established to help meet the nation's growing need for hydrocarbon resources produced from reservoirs in America; formed by a consortium of premier U.S. energy research universities, industry and independent research organizations. The mission of RPSEA is to provide a stewardship role in ensuring the focused research, development and deployment of safe, environmentally sensitive technology that can effectively deliver hydrocarbons from domestic resources to the citizens of the United States. RPSEA will sharply focus its experience, expertise, and capabilities on meeting the program's objectives: to maximize the value of domestic natural gas and oil resources through new technologies to increase production, and to do so in less expensive, safer and more efficient and environmentally benign ways.

We acknowledge the support of RPSEA for funding the New Albany Shale Gas project. Thanks are also to many producing companies, especially NGAS, CNX, Noble, Aurora, and Trendwell, who contributed data and wells of opportunity for field data acquisition.

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Abstract

PI: Iraj A. Salehi, Gas Technology Institute

Gas Technology Institute (GTI) is engaged in a research and development project aimed at the development of techniques and methods for increasing the success ratio and productivity of New Albany shale gas wells to a level where the otherwise noncommercial wells may become commercial producers. The efforts are funded by Research Partnership to Secure Energy for America (RPSEA) and supported by nine producing companies targeting the development of the New Albany gas shale. Although the project is aimed at the development of New Albany shale gas, results will be applicable to other gas shale formations such as the Marcellus, Woodford, and Mancos as well as other low permeability gas bearing formations.

The New Albany Shale project is an industry cooperative project that combines the application of advanced exploration and development technologies with real-world field data acquisition and field experiments culminating at the actual field testing of results. Nine producing companies and nine research groups are engaged in the project.

The thrust of the work in the first year has been on data gathering from producing companies and public sources and development of the understanding of the New Albany Shale as a source and a reservoir rock and the understanding of flow mechanism and parameters effecting production stimulation. Results have been encouraging and have paved the way for field experiments and research quality data acquisition. At the time of preparation of this report, special logging and coring in the project's first cooperative and drilling of the horizontal section have been completed. Completion of this well including fracture stimulation, microseismic fracture diagnostic survey, and production testing is expected to take another thirty days.

In the present report, we will present a summary of results, a general background covering the purpose and scope of the project, and proceed to reporting detailed progress made on each task.

Summary of Results

Geological Studies

PI: Dr. Steve Laubach and Dr. Julia Gale, Bureau of Economic Geology (BEG)

Focus of geological studies has been on characterization of natural fractures. Specific attention has been paid on determination of the response of sealed natural fractures to hydraulic fracturing. In the course of the year, published fracture characterization data were studied and augmented with fracture description in cores and outcrop for 12 cores from southern Indiana, 1 core from western Kentucky and 4 outcrop locations. Major findings from these studies were:

- Natural fractures are common in the New Albany Shale, but vary in character and have different properties with respect to their effect on gas production.
- There are both opening-mode fractures and faults in core and in outcrop.
- In many cores there is more than one opening-mode fracture set. On the basis of aspect ratio, mineral fill, orientation and whether the fracture has been shortened during sediment compaction, the fracture sets have different origins.
- The majority of fractures observed in core in the Clegg Creek member (the usual gas target) are similar to the demonstrably weak planes present in the Barnett Shale in the Fort Worth Basin (Gale et al. 2007; Gale and Holder, 2008) where calcite mineral fill is only weakly attached to the fracture walls. These fractures are un-deformed, straight-sided, high height to width aspect ratios, and are commonly arranged in en echelon arrays.

- Fractures in the lowest part of the section in the Blocher Member are partly open and have low height to width aspect ratios and irregular fracture walls. They are sealed with dolomite and have residual bitumen and large open vugs.
- The most common sealing cement is calcite, but some samples are sealed by both calcite and quartz. We speculate that quartz cements result in stronger fracture planes because of bonding between wall rock and cement as quartz overgrows broken quartz wall rock grains.
- We tested three samples for subcritical index, fracture toughness, and Youngs modulus. The samples were from cores from Sullivan County, southwestern Indiana. Sample preparation was challenging because the cores are both slant cores and are oblique to bedding. Most of the measurements are considered reliable; stress-strain (2 load/unload cycles per specimen) behavior was consistent, fracture toughness results (three specimens for each core loaded to failure) are consistent, and decay curves for almost all subcritical index tests have good fits to theoretical curves. There are differences in the subcritical indices. The highest subcritical indices were measured in the samples from the two horizons where the apparent fracture intensity is lower. Higher subcritical index generally indicates a more clustered fracture pattern. In a highly clustered pattern the chances of sampling fractures decreases, so that it is quite possible that the lower horizon in the Solsman well (2630 ft) and the core from the Osburn Trust well are fractured, but that the clustering meant the fractures were not sampled.
- The structural grain of the two areas – southern Indiana and western Kentucky – is fundamentally different. Southern Indiana is dominated by the Wabash Valley normal fault system, which is currently active and trends approximately N-S. Western Kentucky is dominated by the E-W trending Rough Creek Graben. The major and minor faults and opening-mode fractures in part reflect this difference. However, preliminary core data suggests that some opening-mode fractures in western Kentucky may not be parallel with the larger faults.
- The present-day in situ stress must be determined on a site-specific basis. The world stress map database suggests a swing in the maximum horizontal stress direction from ENE in southern Indiana to E-W in western Kentucky. The large difference in underlying local structure might have a significant perturbation effect on the far-field stress orientation.

Geochemical Studies

PI: Dr. An Anna Martini, Amherst College, Dr. Jennifer McIntosh, University of Arizona; Matthew Kirk and Julian Damashek, Amherst College; Steven Petsch and Mark Woodworth, University of Massachusetts; Cristina Takacs-Vesbach, University of New Mexico.

Planned geochemical analyses aim at characterization of New Albany gas relative to its biogenic and thermogenic nature and reserve repletion through continuous bacterial generation of methane.

To date 30 core samples, 36 water samples and 30 gas samples have been collected and partly analyzed and the analysis continues. The data has been augmented collected through GRI's Antrim Shale studies. Some key findings from the study follow:

- T-RFLP profiles, essentially DNA "fingerprints", of the archea in samples collected from the New Albany Shale and Illinois basin coalbeds demonstrate that the methanogenic communities in these sources are strikingly similar.
- The isotopic composition of water and gas produced by the Antrim wells sampled has shifted significantly over the last ~15 years. With respect to hydrogen isotopes, the water is 10‰ lighter on average and the methane is 8.5‰ lighter. These findings provide compelling evidence that methane generation has occurred over the last 15 years at a significant rate. It is possible that the same process may be taking place in New Albany shale.

- Biodegradation indices determined for 13 New Albany Shale core samples show that degradation is variable over short vertical distances and suggest that the aromatic hydrocarbon fraction is degraded first, which is similar to what is observed in coal but dissimilar to what is observed during oil degradation.
- Extracted hydrocarbons from New Albany Shale core materials show evidence for increasing biodegradation (e.g. depletion of alkanes) towards the Illinois Basin margin.

Formation Evaluation

PI: Jim Lorenzen, Don Luffel, and Frank Caramanica, ResTech

Log analysis work by ResTech includes the development of advanced methodology for calculation of shale porosity, water and bitumen saturations, free gas saturation and adsorbed gas through correlation with core data. Work also performed by ResTech includes supervision of coring and core analysis including visual inspections and analyses; correlation of core and log data; quality control of porosity; water and bitumen measurements; measurement of matrix permeability, determination of total organic carbon, and adsorbed gas from isotherms.

A review of all available core and log data provided by operating partners was completed along with review of previous GRI studies including the 1999 Producibility Consortium and the GIS Compilation of Gas Potential of the New Albany Shale in the Illinois Basin. From these the following results and observations have been accomplished to date.

- A discrepancy is identified between total gas from canister measurements and the compilation of isotherm adsorbed gas and core measured free gas. This is note in the 1999 Consortium data as well as in the data provided by industry partners. The source of the discrepancy is known to be the presence of heavy components in the gas.
- Using available rotary sidewall and whole core data from two wells, major differences in core measured matrix permeability are noted. It is unclear at this point whether the differences are related to core handling and protocols or reflect actual reservoir character.
- High oil saturations and sub-normal pressure is noted in most of the wells where data is currently available.
- A basic log analysis model for determination of porosity, saturation, shale lithology, total organic carbon, and gas in place has been developed using available core and log data.
- Correlations on a limited basis from logs for geochem parameters TOC, S1, S2, PI, HI, and Ro have been developed.
- Initial work using limited sonic data to computer Young's modulus, Poison's ratio, and calculate isotropic un-calibrated stress profiles has been done.
- Technology transfer was presented at the SPWLA Spring Topical conference in Philadelphia.
- Log data has been normalized in the up-coming project drill well area for approximately 30 wells provided by Ngas.
- Fractures are characterized from the FMI data of the Osburn Trust #1-1H, in Sullivan county, Indiana. Natural fractures both open and partially open exist in conjugate sets with high angle dip. The dip direction is NNW-SSE and the strike is ENE-WSW. Few induced fractures are interpreted.

Reservoir Engineering

PI: Tom Blasingame, Christine Economides, Texas A&M

Regularly spaced production data from New Albany shale are scarce and hence, reservoir engineering studies have been delayed. However, one of the industry partners (NGAS) has started collecting daily production and rate data for use by the project.

Blasingame studied the applicability of Power-Law Exponential decline analysis method for New Albany shale reservoir engineering studies. Application of this method to production data from Joe Hobbs well in Meade County, and DPI 2477 well in Christian County, Kentucky has shown promising results. NGAS has committed to providing daily pressure and rate data that will be used for verification of results from reservoir engineering studies.

In parallel, a new Rate-Normalized Pressure analysis (RNP) technique devised by Ehlig and Economides has been tested on a sample pressure data from a New Albany well (DPI 2477) in Kentucky and shows encouraging results for using this technique in future reservoir engineering studies.

Fracture Modeling

PI: Ahmad Ghassemi, Texas A&M, Steve Wolhart, Pinnacle Technologies

The principal focus of fracture modeling is on prediction of propagation of hydraulic fractures in the presence of sealed and open natural fractures. Work by BEG under geology task and A&M under the modeling task will be augmented to develop a fracture model that satisfies the conditions in New Albany shale and other similar geologic formations.

Work by Ghassemi at A&M has resulted in the successful simulation of hydraulic fracture propagation and its interaction with pre-existing natural fractures. The numerical simulations show that the method effectively captures the salient features of this complex problem. With these developments it is now possible to simulate hydraulic fracture and natural fracture interactions within the framework of poroelasticity. This will be done in the forthcoming months.

Fracture modeling by Pinnacle addresses the design of hydraulic fracture in our planned industry cooperative wells. Hydraulic fracturing of the project's first coop well is scheduled for late August to early September of 2009. Pinnacle, in cooperation with the fracturing service company and NGAS technical staff will design the fracturing schedule.

Fracture Diagnostics

PI: Steve Wolhart, Pinnacle Technologies

The scope of fracture diagnostic work includes microseismic imaging of hydraulic fractures and tiltmeter survey, if technically appropriate and logistically possible. The first survey is scheduled on the 2485-86 well pair is scheduled for early September 2009. Pinnacle has developed the survey design and will be in the field during the fracturing operations.

In addition, Pinnacle has gathered and analyzed geological and reservoir data and information on New Albany shale for use in design of pressure and rate schedule in hydraulic fracturing and fracture mapping of the candidate wells.

Best Practice Analysis

PI: Shahab Mohaghegh, West Virginia University

The initial intent of this task was review the various drilling and completion practices in the New Albany shale play and identify the best practices through correlation of the combined impacts of various parameters on production and economics. In the course of the study, it was realized that enough data to render the proposed method reliable do not exist. However, publicly available production data from the state of Kentucky combined information from outcrops and literature proved to be quite useful for performing a generalized reservoir engineering study.

In addition the history-matched of results of 87 NAS wells were used for performing a novel integrated workflow .In this integrated workflow unlike traditional reservoir simulation and modeling, we do not start from building a geo-cellular model. Top-Down intelligent reservoir modeling(TDIRM) starts by analyzing the production data using traditional reservoir engineering techniques such as Decline Curve Analysis, Type Curve Matching, Single-well History Matching, Volumetric Reserve Estimation and

Recovery Factor. Results from these studies have been very encouraging and the methodology has the promise of providing a tool that may be effectively used for field development planning.

Data Gathering and Cooperative Field Acquisition

- Publicly available data on geology of New Albany shale were gathered and compiled.
- Production data from 250 wells were acquired from Kentucky Geological Survey
- 39 data sets including geological, well logs, and production data were acquired from participating producers
- The first comprehensive field data began in July, 2009 on NGAS well DPI-2485-21 commenced in July 28, 2009. Summary of these activities follow:
- Vertical section of the well was drilled to the bottom of the New Albany Shale formation at 2600' for logging and coring.
    - A 60-foot core in the vertical pilot hole was cut and collected. The core is being studied for lithology and fracture characterization by BEG, petrophysical and geomechnical measurements by CoreLab, and geochemical analysis by Weatherford.
    - A suite of logs including induction log, dipole sonic, and borehole image log and spectral gamma were run and are being nalyzed by ResTech and Weatherford.
    - The following tasks are in progress:
        - Fracture stimulation at six to eight points along the horizontal length of the well DPI-2485-21 will be performed.
        - Plans are underway to perform an offset well (observation well DPI 2486-21) microseismic monitoring by Pinnacle company.
        - The observation well DPI-2486-21 is currently being drilled.
        - A pressure buildup test after stabilizing production will be performed on well DPI-2485-21 and will be analyzed by Texas A&M.

Technology Transfer

GTI staff and the research team presented the following papers at various technical meeting. These papers and presentations were well received by meeting attendees. In fact, the paper by Kent Perry and Iraj Salehi, presented at the 24th World Gas Conference, was recognized as the "best paper" of the conference and the authors were presented with the ***"Best Paper"*** award.

Title	Author	Presented at:	Date
New Albany Shale Gas Project (Featured Article)	Iraj Salehi, Angelica Chiriboga, GTI	HART's Unconventional Natural Gas Report	12/ 2008
Identification of microbial and thermogenic gas components from Upper Devonian black shale cores, Illinois and Michigan basins. (Paper)	Anna M. Martini, Lynn M. Walter, Jennifer C. McIntosh	The American Association of Petroleum Geologists. (AAPG) Bulletin, v. 92, no. 3	3/ 2008
Shale Evaluation, New Albany Example – RPSEA / GTI Project (Presentation)	Don Luffel, Jim Lorenzen, Restech	Spring Topical Conference Petrophysical Evaluation of Un-conventional Reservoirs Philadelphia, PA	3/ 15 – 3/19/ 2009
New Albany Shale Gas Project, An Industry-RPSEA-GTI Cooperative Project (Presentation)	Iraj Salehi, GTI	Spring Topical Conference Petrophysical Evaluation of Un-conventional Reservoirs. Philadelphia, PA	3/15 – 3/19/2009

Title	Author	Presented at:	Date
New Albany Shale Project Project Update (Presentation)	Iraj Salehi, GTI	RPSEA Unconventional Gas Project Review Meeting, Golden, CO	4/15/2009
Implications for development of effective drilling and completion technologies (Presentation)	Julia F. W. Gale, Stephen E. Laubach, Bureau of Economic Geology	RPSEA Unconventional Gas Project Review Meeting, Golden, CO	4/15/2009
New Albany Shale Formation Evaluation (Presentation)	Jim Lorenzen, Restech	RPSEA Unconventional Gas Project Review Meeting, Golden, CO	4/15/2009
Fracture Design & Diagnostics, New Albany Shale Project (Presentation)	Steve Wolhart, Pinnacle	RPSEA Unconventional Gas Project Review Meeting, Golden, CO	4/15, 2009
Analysis of Reservoir Performance in Shale Gas Reservoir Systems (Presentation)	Tom Blasingame, Texas A&M University	RPSEA Unconventional Gas Project Review Meeting, Golden, CO	4/ 15, 2009
Natural Fractures in the New Albany Shale and their importance for shale gas production (Paper)	Julia F. W. Gale, Stephen E. Laubach, Bureau of Economic Geology	International Coalbed and Shale Gas Symposium Tuscaloosa, AL.	5/19 – 5/21/2009
Formation Evaluation: Integrating Core-Geochem-Logs (Presentation)	Jim Lorenzen, Don Luffel, Frank Caramanica	GTI Forum, Chicago, IL.	6/4/2009
Natural fractures in the New Albany Shale and their importance for shale-gas production (Presentation)	Julia F. W. Gale, Stephen E. Laubach, Bureau of Economic Geology	GTI Forum, Chicago, IL.	6/4/2009
Geochemical and microbial investigation of methanogenesis in the Upper Devonian shales (Presentation)	Anna Martini & Matthew Kirk, Amherst College; Stephen Petsch, University of Massachusetts; Jennifer McIntosh, University of Arizona	GTI Forum, Chicago, IL.	6/4/2009
Fracture Design & Simplistic 3-D Parametric Modeling New Albany Shale (Presentation)	Doug Walser, Steve Wolhart, Pinnacle	GTI Forum, Chicago, IL.	6/4/2009
Analysis of Reservoir Performance for Shale Gas Systems**,** RPSEA/GTI Project(Presentation)	Tom Blasingame Department of Petroleum Engineering Texas A&M University	GTI Forum, Chicago, IL.	6/4/2009
New Albany Shale Gas Project A Joint Industry Project Sponsored by the research Partnership to Secure Energy for America (RPSEA) (Paper)	Iraj Salehi, Angelica Chiriboga, GTI	Published by Touch Briefings Exploration & Production. Oil & Gas Volume 7 Issue 1 OTC Edition.	8/2009
Top-Down Intelligent Reservoir Modeling of New Albany Shale (Paper)	A. Kalantari Dahaghi, SPE, S.D. Mohaghegh, SPE, West Virginia University	2009 SPE Eastern Regional Meeting Charleston, West Virginia	9/23–9/25/2009
Economic Impact of Reservoir roperties and Horizontal Well Length and Orientation on Production from Shale Formations, Application to New Albany Shale (Paper)	Kalantari, A., Mohaghegh, D., West Virginia University.	2009 SPE Eastern Regional Meeting. Charleston, West Virginia, USA	9/23–9/25/2009
New Albany Shale Gas Research Project.(Paper)	Kent F. Perry, Iraj Salehi, GTI	World Gas Conference Buenos Aires, Argentina	9/3-9/5/2009

Background

The New Albany Shale formation occurs in Illinois, Indiana, and Kentucky, but to date gas production has been primarily from western Indiana and southwest Kentucky. Figure 1 shows the boundary of the New Albany shale within the Illinois Basin and includes the hydrogen index contours for the most promising areas in the basin. The volumes of in-place and technically recoverable gas in New Albany shale have been estimated to be between 86 and 160 trillion cubic feet (tcf) and 1.9 to 19.2 (tcf) respectively.

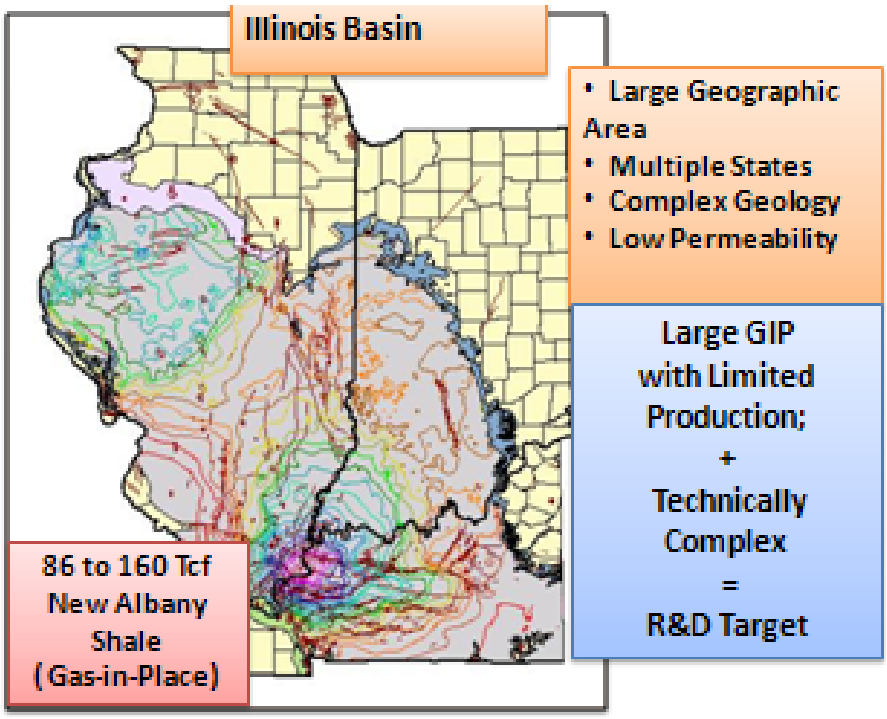


Figure 1. New Albany Shale in the Illinois Basin

The New Albany shale project is a field-based industry cooperative project with producer involvement and support, which combines scientific and technical analyses with field data acquisition, testing, and field validation. Nine producing companies (Atlas America, Aurora Oil and Gas Corporation, Breitburn Energy, CNXGas, Diversified Operating Corp., NGAS, Noble Energy, Rex Energy, and Trendwell Energy Corp.) and nine research organizations (GTI, Texas A&M University, Bureau of Economic Geology (University of Texas), West Virginia University, Amherst College, University of Massachusetts, Pinnacle Technologies, and ResTech) are participating in this project.

GTI has assembled a team of highly qualified experts with outstanding background and experience to implement the project. A comprehensive integrated project plan for geological, geochemical, reservoir engineering, and production stimulation studies and a detailed field data acquisition and testing plan addressing all major issues have been prepared. Figure 2 is a graphical representation of the project structure depicting the flow of information and data between various project elements.

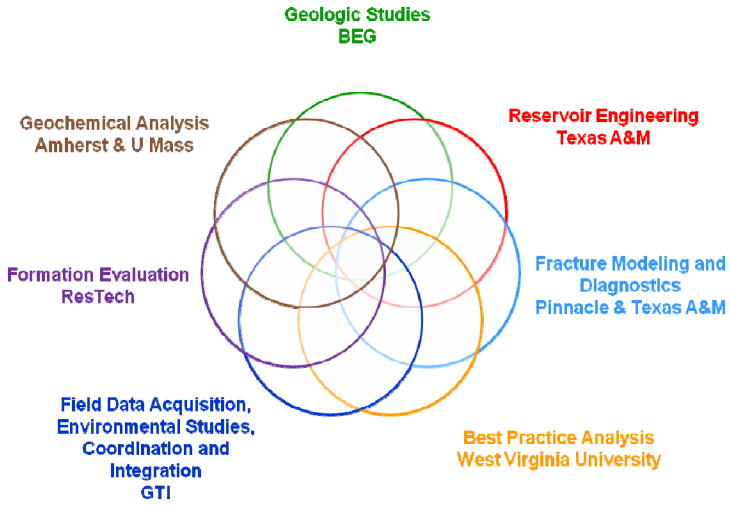


Figure 2. New Albany Gas Shale Project Structure

Table 1. Major Project Elements

Research, Performing Organization, PI	Objective
Geology, BEG, Julia Gale	Characterization of natural fractures in New Albany shale. Interconnection of natural and hydraulic fractures.
Geochemistry, Amherst College, Anna Martini; University of Arizona, Jennifer McIntosh; U Mass, Steve Pitsch	Characterization of New Albany gas relative to source and characterization of methanogene bacteria.
Formation Evaluation, ResTech, Don Luffel & Jim Lorenzen	Development of advanced methodology for calculation of shale porosity, water and bitumen saturations, free and adsorbed gas saturation.
Fracture Modeling, A&M, Ahmad Ghassemi	Development of a numerical model for prediction of hydraulic fracturing in the presence of sealed and open natural fractures.
Fracture Diagnostics, Pinnacle Technologies, Steve Wolhart	Fracture design, Seismic and Tiltmeter fracture diagnostic surveys.
Reservoir Engineering, Texas A&M, Tom Blasingame, Christine Economides	Production data analysis focused on horizontal and hydraulically fractured wells of New Albany Shale.
Best Practice Analysis, West Virginia University, Shahab Mohaghegh	Development of a fractured reservoir model for determination of best drilling and completion methods.
Water Management, GTI, Tom Hayes	Development of database of water use, flow back, and produced water for New Albany Shale.
Data Gathering, Field Testing, GTI, Salehi	
Coordination and Technology Transfer, GTI, Salehi	

As with other shale gas resources, production from the New Albany shale is primarily from natural fractures. However, because of extremely low matrix permeability and limited open natural fractures, commercial production from the New Albany shale may only be achieved by interconnecting the natural fractures through hydraulic fracture stimulations. As such, the primary objectives of this project are to develop techniques and methods for identification and characterization of natural fractures and to develop effective fracture stimulation techniques, leading to commercially acceptable production rate and ultimate recovery. It needs to be mentioned that the New Albany shale is underlain by a water bearing Devonian formation and this geology adds an additional problem for effective hydraulic fracturing, as the fractures should not be allowed to grow into the water bearing zone. A brief description of major elements of the project is given in the remainder of this article.

Geological Studies

Because of the low matrix permeability characteristic of the New Albany shale, natural fractures are the main contributors to flow, and production at a commercial rate can only be achieved by proper placement of horizontal wells relative to dominant fracture orientation. High permeability areas (sweet spots) occur in regions with high fracture intensity. The goal for this task is to characterize the key fracture attributes of orientation, size distribution, intensity, and porosity/occlusion patterns. The work includes application of new techniques to quantify the spatial arrangement of fractures including potential clusters of large open fractures. Key parameters will be assessed through examination of a combination of data types. The most important will be cores, vertical and horizontal well image logs, and drilling and production data. Fracture orientation, intensity, and spatial distribution information will be obtained from core and image log data. Samples will be selected from cores to be made into polished thin sections to examine the mineral fill of the fractures. Scanning electron microscope (SEM) imagery will be also used. At the end of the first year, a suite of fracture attribute characterizations for selected areas will be prepared, which may include maps for attributes such as orientation, and models for attributes such as mineral fill, size distribution and intensity. At this stage, we will identify those attributes with first order control over gas production as a tool for identification of high-potential areas of the basin**.** Dr. Steve Laubach and Dr. Julia Gale of Bureau of Economic Geology (BEG) are the principal investigators for geological studies.

Geochemical Analysis

Hydrocarbon gases contained in the New Albany shale consist of thermogenic gas evolved from thermally matured organic material and biogenic methane resulting from bacterial digestion of carbon compounds. While the evolution of thermogenic methane normally ceases upon uplift of the formation, bacterial activities continue as long as the environment remains amenable to bacterial growth. To arrive at a reliable resource estimate and to identify favorable regions within the basin, a comprehensive geochemical investigation will be performed. Key activities under this task include field data acquisition, including sampling of gas and co-produced water, as well as laboratory tests including gas chromatography and mass spectropy for measurement of total organic content. In addition, the microbial population of the New Albany shale will be determined from water samples. Planned data analysis also includes microbial analysis consisting of DAPI-stained cell counts from individual wells, molecular fingerprinting based on total DNA for community structure, and total RNA to identify active community members. Attempts will be made to isolate and culture novel methanogens to determine rates of methane production. Also, microbial community structure in the New Albany shale will be compared with that of the Antrim Shale to assess whether any observed differences influence production rates and total gas content in the shales. Dr. Anna Martini from Amherst College, Dr. Steven Petsch from University of Massachusetts, and Dr. Jennifer McIntosh from University of Arizona are engaged in geochemical studies of the New Albany shale.

Formation Evaluation

Identification of producing zones in New Albany shale wells and determination of reservoir properties from well logs is a nontrivial problem. Intrinsic physical properties of shale are such that conventional formation evaluation techniques are not applicable,and techniques specific to the New Albany shale must be developed. Emphasis will be placed on borehole imaging, coring, and geochemical techniques as well as seismic imaging where possible. The activities identified for this task include fracture identification from logs such as FMI, CAST and construction of borehole maps of dip projections of fractures within specific distances from boreholes.

Log analysis work includes the development of advanced methodology for calculation of shale porosity, water and bitumen saturations, free gas saturation, and adsorbed gas through correlation with core data. This work is being performed by Mr. Donald Luffel, Mr. Jim Lorenzen, Mr. Jim Jackson, and Dr. Frank Caramanica of ResTech Inc. and includes supervision and quality control of logging, coring and core analysis.

Reservoir Engineering

Pressure buildup tests in horizontal and hydraulically fractured wells can be difficult to interpret because these tests involve many unknown parameters and pressure transient tests require very long durations (*i.e.,* months). Producers need to have a reliable estimate of production to make decisions regarding well completion and to evaluate the financial and operational requirements of the field. Dr. Tom Blasingame and Dr. Christine Economides of Texas A&M will be engaged in designing well testing and interpretation methods for horizontal and hydraulically fractured wells using existing pressure transient models. This task is devoted to the analysis/interpretation of the available pressure transient test data obtained from the gas shales study area as well as new pressure transient data. Production data analysis is focused on production analysis for horizontal and hydraulically fractured wells. In addition, the project plans to develop new pressure transient models for horizontal and fractured wells. The optimum approach is to review existing literature and begin to build a conceptual/mathematical model in the first year. Year 2 will be devoted to the refinement of the model and comparison with observed well behavior.

Fracture Modeling

Commercial production from tight sands and shale formations invariably involves hydraulic fracturing of the formation. Although several hydraulic fracturing simulators have been developed during the last twenty years, none is capable of predicting fracture growth in the presence of natural fractures. In particular, it is necessary to use a model capable of dealing with injection-induced fracture propagation near natural discontinuities such as joints, faults, and bedding planes. The work under this task is focused on the development of knowledge and analytic models for such fractures. Advanced fracture modeling will be carried out by Dr. Ahmad Ghassemi at Texas A&M.

Fracture Design and Fracture Diagnostics

Experts from Pinnacle Technologies will be in charge of design and quality control of fracture stimulations and fracture diagnostic surveys. We anticipate using both tiltmeter and microseismic fracture imaging for independent verification of fracture design as well as monitoring and control of fracture growth. It is absolutely critical to integrate stimulation, production data analysis, and reservoir engineering technologies to successfully evaluate and optimize hydraulic fracturing of unconventional reservoirs. To this end, Pinnacle Technologies will evaluate current completion/stimulation practices in the New Albany Shale, design and perform field experiments to measure hydraulic fracture geometry and evaluate stimulation effectiveness, and integrate the results of field experiments with geologic, geophysical, completion and production data to optimize development of the New Albany shale.

Best Practice Analysis

The intent of best practice analysis is to compile drilling, completion, fracture stimulation, and production and create a comprehensive database that reflects the range of practices in the New Albany shale. Once

the database is populated with data from a statistically significant number of wells, a series of objective numerical analyses based on fuzzy logic and artificial intelligence techniques will be carried out to determine the optimal combination of operational parameters that result in the most favorable production instances. This task will be performed by Dr. Shahab Mohaghegh from West Virginia University.

Upon completion of these analyses, GTI shall compare and verify the results with hard data from the field and augment the data driven results with engineering driven conclusions to arrive at field-verified best practices for drilling and completion of New Albany shale wells.

Environmental and Water Management Studies

The shift of New Albany shale gas from an emerging to an existing resource category entails drilling and completion of thousands of wells, establishment of gathering systems, processing plants, compressor stations, and so forth. Subsequent to determination of substantial producible reserve and upon identification of technically effective and economically optimal development technologies, determination of environmental impacts of these operations and facilities in terms of water requirement and waste management is an imperative. In addition, water resources to meet the needs of the upstream and downstream operations must be identified and a prudent water management scheme be designed. Dr. Thomas Hayes of GTI will be undertaking these studies during the latter stages of the project.

Field Data Acquisition and Verification, Coordination, and Technology Transfer

The prerequisite of success for a field-based project is the acquisition of reliable data and timely testing of results so that dependable data are provided for analytic work and designs. Procedures are checked in the field and modified based on test results. The New Albany Shale project includes extensive field data acquisition and testing including sampling, coring, logging, hydraulic fracturing, fracture diagnostics, and production logging. Specifically, two production logging, two hydraulic fracturing experiments, and four fracture diagnostic surveys are planned. GTI will coordinate and manage all field data acquisition and field testing while research contractors design and supervise the operations.

In a multifaceted field-based research, prudent coordination, and open communication are of essence. GTI will be responsible for coordination of the efforts of individual team members to ensure that each team member is aware of the results of other team members and incorporates those results into their own analyses. Preparation of clear and comprehensive reports will be used to extend the technology beyond the limited individuals and companies, expanding the information to other applicable regions. In the New Albany shale project, all independent research organizations will prepare a stand-alone detailed report describing the scientific bases and results from their work. The work of the various contributors will be used to develop an integrated analysis of the factors controlling economic production in the New Albany Shale, which will be captured in Best Practices recommendations. All project reports will be compiled in a complete summary volume available in electronic format from RPSEA and GTI.

Geology

PI: Dr. Steve Laubach,Dr. Julia Gale, Bureau of Economic Geology (BEG)

Objectives

The objectives of the study are to characterize the natural fractures in the New Albany Shale in the Illinois Basin, and to assess their relevance for natural gas production. Our focus is on the thermogenic part of the play, in southern Indiana and western Kentucky and on whether the sealed natural fractures that are present represent weak planes that reactivate during hydraulic fracture treatments. The possibility of permeability enhancement through open natural fractures is investigated.
These objectives were met through the following tasks:

1. Synthesize published fracture characterization data and augment with fracture description in cores and outcrop for 12 cores from southern Indiana, 1 core from western Kentucky and 4 outcrop locations.
2. Qualitative assessment of the tensile strength of natural fracture planes.
3. Measurement of the subcritical crack index (SCI) of core samples with the aim of understanding fracture spatial distribution and how fracture patterns differ from one layer to the next.
4. Consideration of the relative orientation of S_{Hmax} and natural fractures, and whether this geometry is favorable for reactivation.
5. Assessment of whether part of the fracture population is open and would enhance permeability in the reservoir.

Summary of Results

- Natural fractures are common in the New Albany Shale, but vary in character and have different properties with respect to their effect on gas production.
- There are both opening-mode fractures and faults in core and in outcrop.
- In many cores there is more than one opening-mode fracture set. On the basis of aspect ratio, mineral fill, orientation and whether the fracture has been shortened during sediment compaction, the fracture sets have different origins.
- The majority of fractures observed in core in the Clegg Creek member (the usual gas target) are similar to the demonstrably weak planes present in the Barnett Shale in the Fort Worth Basin (Gale et al. 2007; Gale and Holder, 2008) where calcite mineral fill is only weakly attached to the fracture walls. These fractures are undeformed, straight-sided, high height to width aspect ratios, and are commonly arranged in en echelon arrays.
- Fractures in the lowest part of the section in the Blocher Member are partly open and have low height to width aspect ratios and irregular fracture walls. They are sealed with dolomite and have residual bitumen and large open vugs.
- The most common sealing cement is calcite, but some samples are sealed by both calcite and quartz. We speculate that quartz cements result in stronger fracture planes because of bonding between wall rock and cement as quartz overgrows broken quartz wall rock grains.
- We tested three samples for subcritical index, fracture toughness, and Youngs modulus. The samples were from cores from Sullivan County, southwestern Indiana. Sample preparation was challenging because the cores are both slant cores and are oblique to bedding. Most of the measurements are considered reliable; stress-strain (2 load/unload cycles per specimen) behavior was consistent, fracture toughness results (three specimens for each core loaded to failure) are consistent, and decay curves for almost all subcritical index tests have good fits to theoretical curves. There are differences in the subcritical indices. The highest subcritical indices were measured in the samples from the two horizons where the apparent fracture intensity is lower. Higher subcritical index generally indicates a more clustered fracture pattern. In a highly clustered pattern the chances of sampling fractures decreases, so that it is quite possible that the lower horizon in the Solsman well (2630 ft) and the core from the Osburn Trust well are fractured, but that the clustering meant the fractures were not sampled.
- The structural grain of the two areas – southern Indiana and western Kentucky – is fundamentally different. Southern Indiana is dominated by the Wabash Valley normal fault system, which is currently active and trends approximately N-S. Western Kentucky is dominated by the E-W trending Rough Creek Graben. The major and minor faults and opening-mode fractures in part reflect this difference. However, preliminary core data suggests that some opening-mode fractures in western Kentucky may not be parallel with the larger faults.

- The present-day in situ stress must be determined on a site-specific basis. The world stress map database suggests a swing in the maximum horizontal stress direction from ENE in southern Indiana to E-W in western Kentucky. The large difference in underlying local structure might have a significant perturbation effect on the far-field stress orientation.

Outcrop studies

Much work has previously been published on outcrops of the New Albany Shale in the Illinois Basin and across the Cincinnati Arch into the Appalachian Basin. The stratigraphy of the New Albany Shale is well constrained and key locations are described in a field guide by Schieber and Lazar (2004) (Fig. 1). We used the locations described in the guide, together with a few other locations to examine the New Albany Shale at outcrop. There is also published work on fractures at the surface of the Illinois Basin (Carr, 1981; Ault 1989; Curtis, 2002; Comer et al., 2006) (Fig. 2). Most of the fractures in these studies are barren joint systems (Fig. 3). One of the best exposures of these regional joint patterns occurs on the Indiana bank of the Ohio River at New Albany (Fig. 3). The dominant joint set trends ENE, individual fractures extending several hundreds of feet. A secondary set trends almost orthogonal to the dominant set, but abutting relationships suggest they are broadly coeval. Both joint sets are steeply dipping and have no mineralization on the joint surfaces although there are various oxide stains on the surfaces. Joint properties were also described by Comer et al. (2006) and we did not repeat this work.

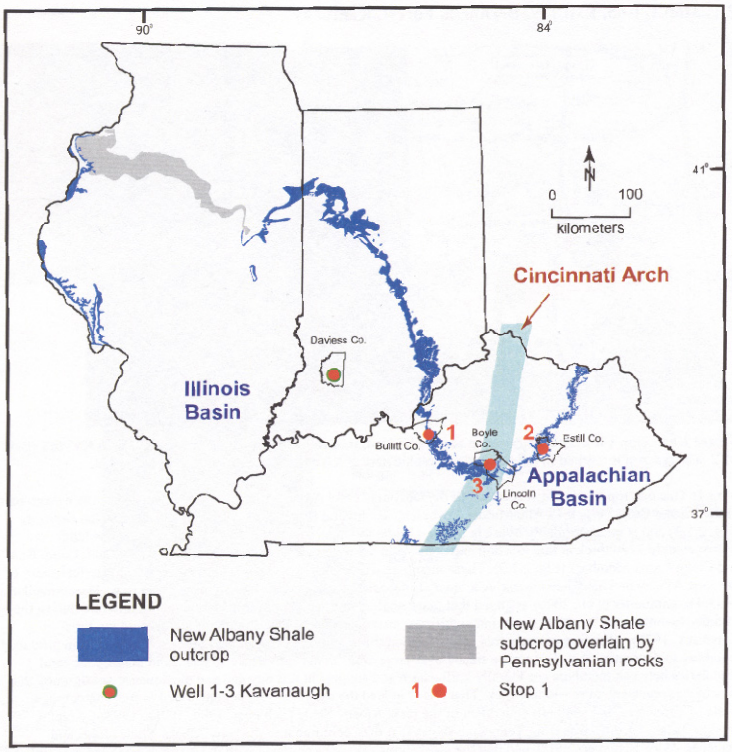


Figure 1. Map showing New Albany Shale outcrop and stops described in Schieber and Lazar (2004). These stops were used as the basis for the initial field visit because the stratigraphic members are well constrained at these locations. The Kavanaugh core is described in the guide but we did not view it.

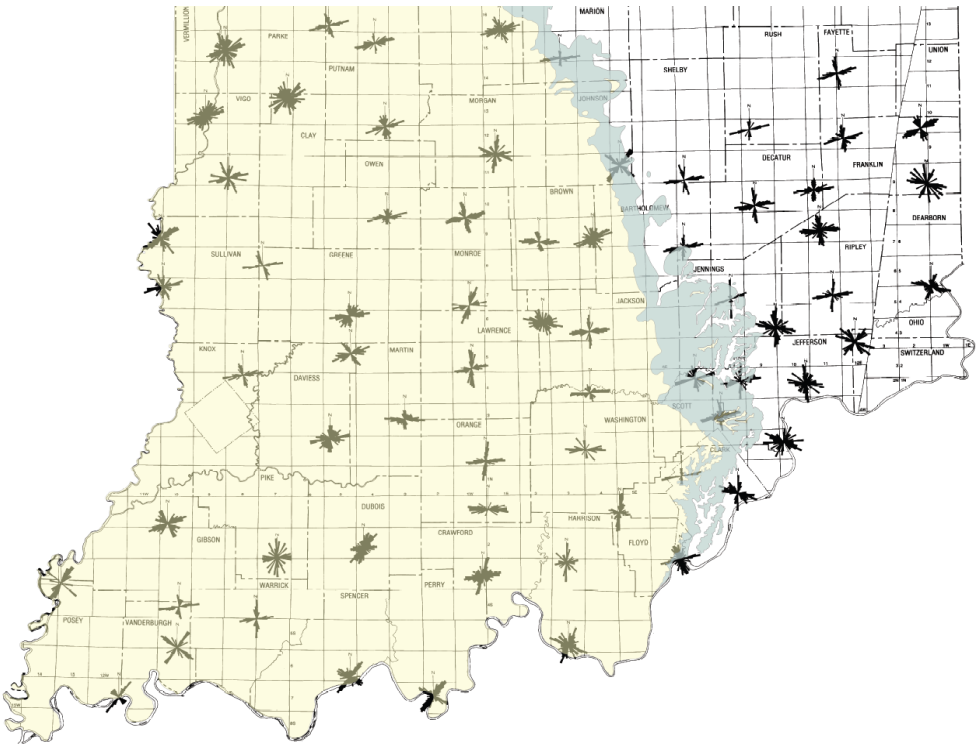


Figure 2. Map of joint orientations in bedrock in the southern Illinois Basin. Map from Comer et al. (2006) after Ault (1989).

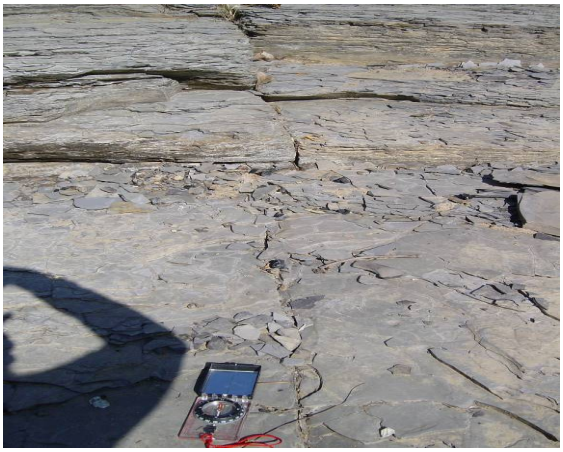
For the shallow biogenic part of the New Albany Shale play it is possible that these orientations are representative of the fracture system in the subsurface. But for the deeper, thermogenic part of the play the subsurface fractures do not necessarily follow the surface orientations (Comer, 2006). The dominant joint orientation is subparallel to present day maximum horizontal stress (Fig. 4). It is likely that the barren joint sets reflect this stress regime, and are the result of fracturing during uplift. The barren fractures in core that we did observe were interpreted as being induced fractures on the basis of petal centerline geometries, and the observation that they do not have the iron oxide staining that is ubiquitous in outcrop. We contend that natural fractures in the subsurface would contain cement or solid bitumen residue. The exception to this would be fractures growing as a result of recent fault movement along the Wabash Valley Fault System (Fig. 4), which would grow parallel to S_{Hmax}. Recent fractures would likely be barren because there would have been insufficient time for cements to accumulate.

Compacted fibrous quartz-dolomite-bitumen veins in the Blocher Member are described in the Schieber and Lazar (2004) field guide for their Stops 1 and 3 (Fig. 5a). We measured a bedding parallel scanline for these fractures at Stop 3 (Fig. 5b). The veins are very wide relative to their height, and commonly contain bitumen in vuggy openings, termed geodes by other workers. We did not observe these large veins at Stop 2 or in the cores. However, in the outcrops and cores we did observe smaller fractures, confined to pyrite-rich layers that also show compaction structures, and that provide support structures for the bedding and compaction fabric, which is deflected down on either side of the fracture (Fig. 6). We do not know at this stage if these small fractures are related in any way to the large fractures. We collected samples of each for thin section analysis.

(a)

(b)

(c)



(d)

Figure 3. Barren joints on an outcrop on the north bank of the Ohio River at New Albany. (a) looking west, (b) looking east, (c) secondary joint trending N-S terminates and jumps to the east at a dominant set joint, (d) a short joint in the dominant ENE direction terminates against secondary joints.

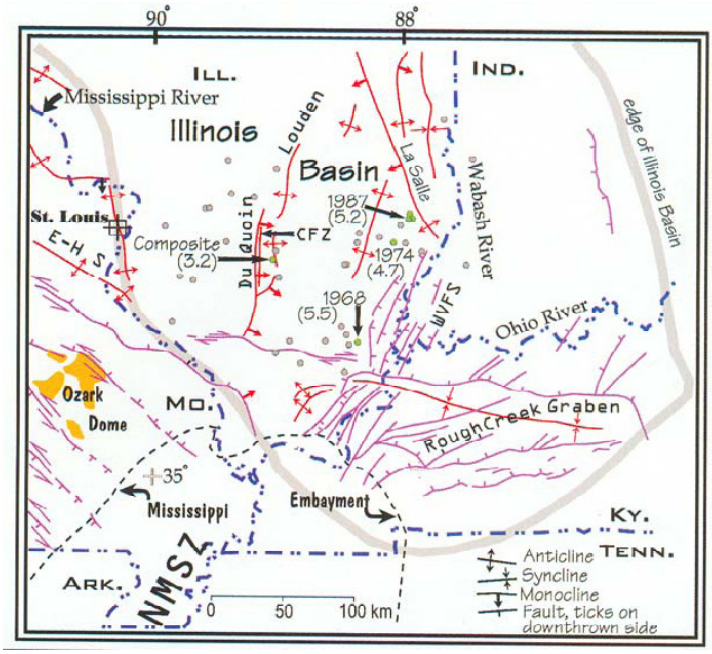
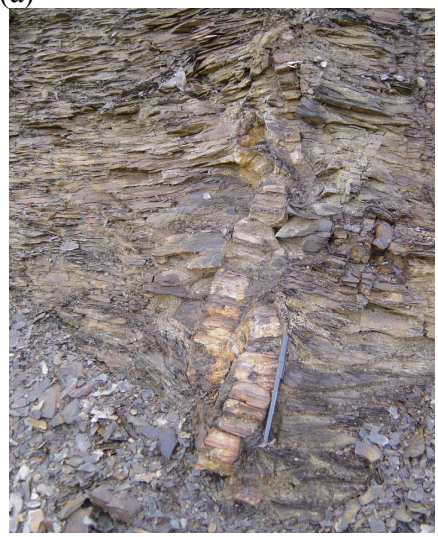


Figure 4. Structure map of the Southern Illinois Basin (from McBride (1999). WVFS = Wabash valley Fault System; NMSZ = New Madrid Seismic Zone; CFZ = Centralia Fault Zone. Earthquake epicenters for body-wave magnitude >3.0 for 1960-1995 are shown. The April 18, 2008 event is shown by the star.

(a)



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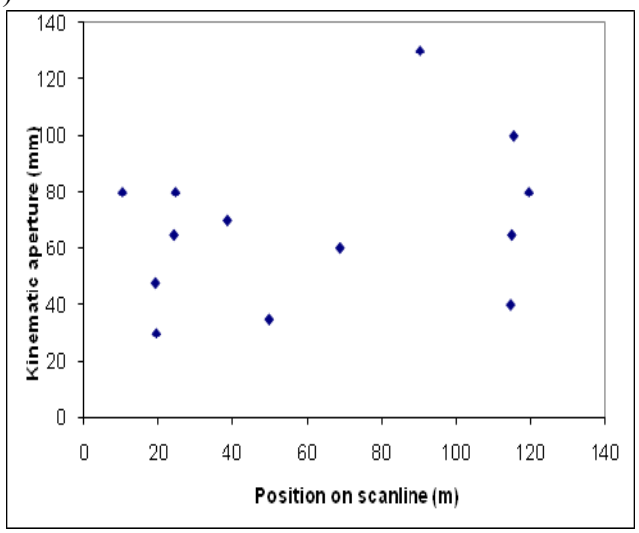

Figure 5. (a) Folded quartz-dolomite vein at Stop 1. (b) Scanline parallel to road cut at Stop 3. Veins are clustered and are up to 14 cm wide.

It is unlikely that these large veins will affect production as they seem to be mostly confined to the Blocher Member, which is well below the usually targeted Clegg Creek Member. The exception is the vein seen at Stop 1, which extends up into the Camp Run Member. However, our observations so far are restricted to a very few outcrops. Vertical cores may not sample them as they are spaced several meters apart. They are worth further study, however, because they record fluid conditions at an early point in the burial of the New Albany Shale. We have sampled them and will make an SEM-based thin-section analysis. The smaller veins are apparently more widespread, but because they are confined to pyrite layers

may not affect production significantly. However, arrays of small veins can act as mechanical discontinuities for hydraulic fractures causing the hydraulic fractures to split or be deflected.

In the underlying limestone and the very base of the Blocher Member there is a second set of filled fractures. These are networks or en echelon arrays and are calcite filled (Fig. 7). These are not compacted and we interpret them to be later than the dolomite-quartz filled veins described above.

(a) (b)

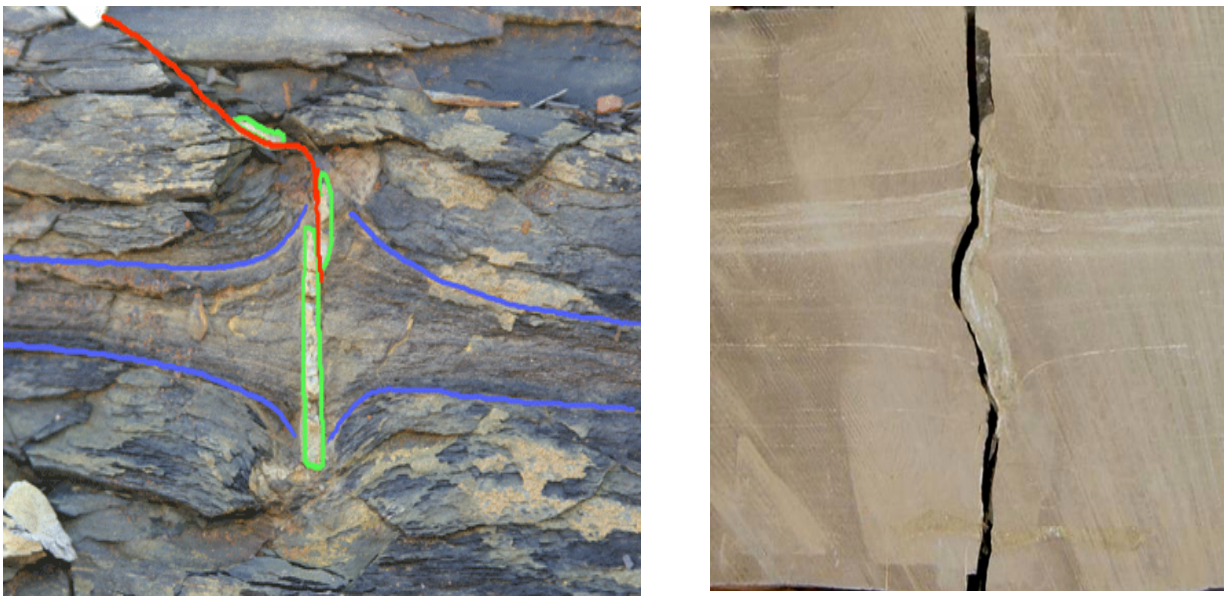

Figure 6. Small, early, compacted veins, fill likely dolomite. (a) Outcrop example at Stop 3. (b) Example from core at 2,804 ft. Height of fractures approximately 3 cm.

(a) (b)

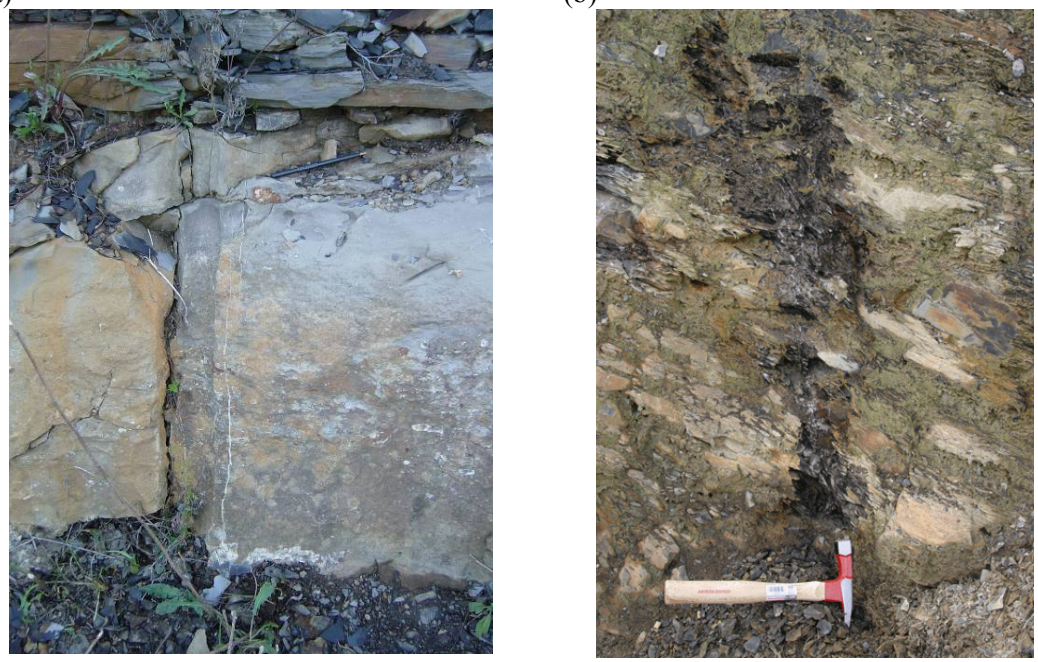

Figure 7. Narrow, calcite-filled fractures in (a) underlying Devonian limestone at Stop 3, (b) the Blocher Member at Stop 1.

Core studies

In the cores we observed several examples of steep, sealed, or partly sealed fractures (Fig. 8a, b). Some of them have smeared cement fill and have been interpreted as faults (Fig. 8c). These sets are likely to important either for enhancing permeability or as influences over hydraulic fracture propagation and will investigated during the next phase of the study. Cores at Indiana Survey Core Repository examined and sampled were:

- Diversified Operating McAtee et al. S26-IV, Pike Co. (5 samples)
- Anschutz Corp. No. 16-19 Voelkel, Dubois Co.
- Energy Resources of Indiana No. 1 Phegley Farms Inc., Sullivan Co. (2 samples)
- Texas Gas Trans. Corp. No. 5 Pittman, Sullivan Co.
- Texas Gas Trans. Corp. No. 4 Peterson et al., Sullivan Co.
- Texas Gas Trans. Corp. No. 3 Peterson et al., Sullivan Co.
- IGS SDH No. 180 Rothrock, Harrison Co.
- IGS SDH No. 181 Deaton, Harrison Co.
- IGS SDH No. 360 Don McRae, Clark Co. (1 sample)
- Texas Eastern Trans Corp. No. 7, Jackson Co.

(a)

(b)

©

Figure 8. (a) Steep, narrow sealed fracture, (b) multiphase cement, (c) sheared cement on fracture surface.

In addition to the above observations we examined two cores from Noble Energy from Sullivan County. These were:

1) Solsman 1-32H, Sullivan Co
2) Osburn Trust 1-11H, Sullivan Co

Fractures in the Solsman 1-32H, Sullivan Co are numerous in the top part of the core but are absent in the bottom part of the core (Fig. 9). This could reflect a real difference in fracture intensity in different mechanical layers or could be the result of a sampling bias of a clustered distribution (Fig. 10). Samples were taken for subcritical crack index measurement at 2558 ft and 2631 ft to determine whether clustering is likely (see results below).

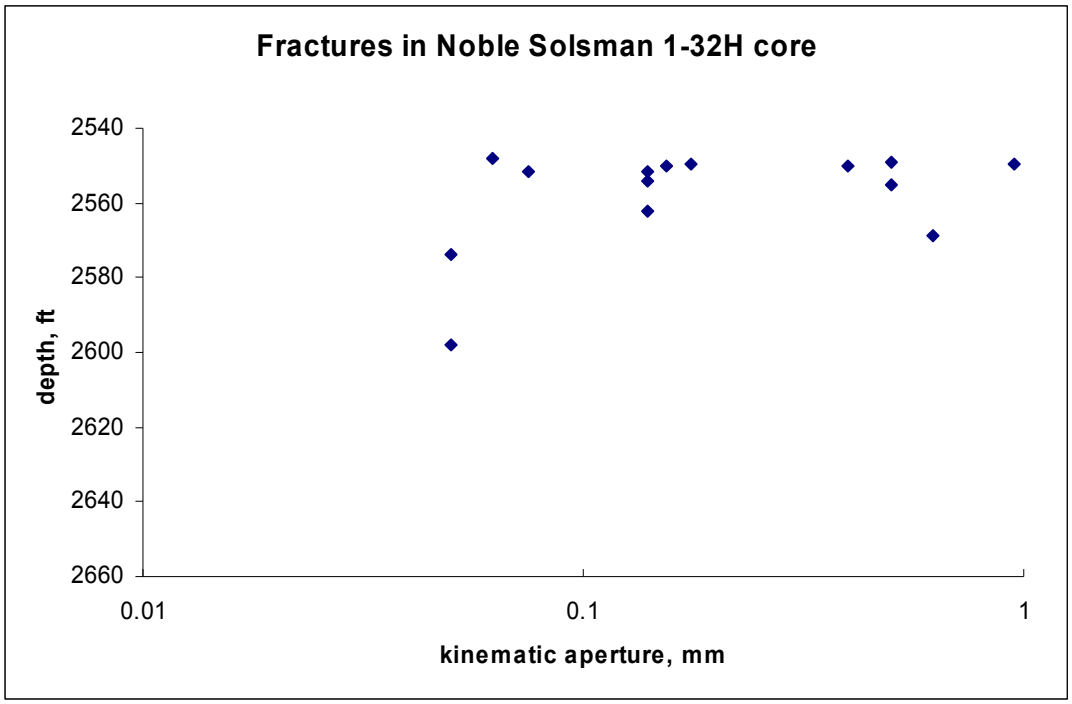

Figure 9. Fracture aperture sizes plotted against depth in the Noble Solsman 1-32H core

The natural fractures that are present are at a high angle to bedding and are sealed with calcite cement, which forms an extremely weak bond, commonly detaching from both fracture walls (Fig. 10a). The fractures mostly cross the core entirely so their height is unconstrained. Several examples have a stepped geometry, which is a commonly observed morphology in other shales (Fig. 10b).

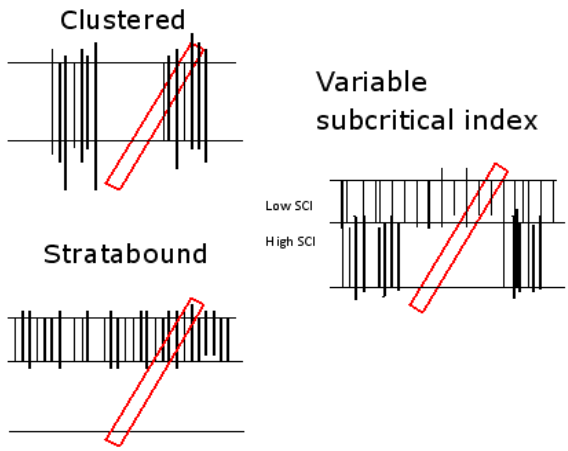

Figure 10. Sketches of possible fracture geometries leading to the same apparent distribution as shown in Fig. 8. In the example shown with variable subcritical index, the lower layer has a higher index, with a more clustered fracture pattern, whereas the upper layer has a lower index and a more evenly spaced fracture pattern. Mechanical layer thickness also controls fracture spacing, with evenly spaced fractures spaced proportionally, but not necessarily equal to, mechanical layer thickness.

(a) (b)

Figure 11. Photographs of natural fractures in the Noble Solsman 1-32H core. (a) Calcite cement sliver detaching from both fracture walls at 2568.8 ft. (b) En echelon stepped fracture planes at 2549 ft, which are mostly calcite cemented although the cement has detached from the fracture wall in places.

There are very few fractures in the Osburn Trust 1-11H core. However, this could be a sampling artifact also (c.f. Fig. 10). Core orientation data for the Osburn Trust 1-11H suggests the few natural fractures in the Osburn Trust core are oriented WNW. At 2543 ft the principal scribe line is oriented at 269.9° and a subvertical fracture trends 15° clockwise from it looking downhole, hence the fracture trends 285°. The fractures are at a high angle to bedding, are stepped and are sealed with calcite. Both the cores from

Sullivan County are slant cores and there are numerous partings along bedding. Bedding-parallel partings are all regarded as being due to stress relaxation. None have cement along them.

During the 3rd project quarter the emphasis of the project changed from southern Indiana to western Kentucky. A new fracture evaluation commenced with a focus on Christian County in anticipation that a well experiment will take place there in summer 2009. The natural fracture pattern and in situ stress field are likely to be different from that in southern Indiana, because the two areas have markedly different structure. The wells in Sullivan and Pike Counties in southern Indiana are close to the Wabash Valley Fault System, a currently active normal fault system trending NNE-SSW. Christian County in western Kentucky is close to the E-W trending Rough Creek Graben, which is not currently active. Maps of faults in the Christian County area dominantly trend E-W, although some linking faults have other trends.

Miller and Johnson's (1979) study on a cored well in Christian County (Orbit Gas Co J. Ray Clark No. 1) showed the dominant natural fracture trend is NW-SE, which does not match with the general trend of the faults, but could be local to that well. Our group strongly recommends that for the experimental well a whole diameter oriented core is taken together with an image log so that site specific information on the natural fracture system may be gained.

Subcritical crack index, fracture toughness and Young's modulus tests

Three samples were selected for subcritical crack index testing: Two from the Noble Solsman 1-32H core; NS-2558, a 6-inch long sample from a horizon that has abundant natural fractures (the samples were selected to be free of fractures); 2- NS-2630, a 4-inch long sample from a horizon where no fractures were observed, and 3- One from the Osburn Trust 1-11H well OT-528, a 3-inch long sample.

Sample preparation was challenging because the cores are both slant cores. For samples OT-2528 and NS-2630 the samples were cut parallel to bedding planes, by mounting the cores at an angle in the saw. The NS-2630 sample was particularly difficult to cut because of bedding plane weaknesses. The NS-2558 sample was cut perpendicular to the core axis so the slices showed some lines of failure along bedding, but several specimens were prepared between these weaknesses, which held together well and gave good decay curves. Most of the measurements were robust; stress-strain (2 load/unload cycles per specimen) behavior was consistent, fracture toughness results (three specimens for each core loaded to failure) are consistent, and decay curves for almost all subcritical index tests have good fits to theoretical curves.

The subcritical index value as well as Young's modulus and the fracture toughness are summarized in table 1.

Table 1: Summary of subcritical index values and relative fracture strength.

Core	E(Mpsi) 1	2	3	4	Avg	SCI 1	2	3	Avg	K_{IC} (MPa-sqrt m)	Comments
OT- 2528 ft											
3A						42	46		**44**		bedding within test

											area
4B	2.4	2.8	3	3.2	**3.0**	64	82	76	**74**	**1.8**	
8B	2.2	2.5	2.5	2.6	**2.5**	88	159	62	**103**	**1.5**	small decay, ragged fit
5B	2.5	3	2.8	2.9	**2.9**	59	93	76	**76**	**1.6**	
5A	1.7	2	2	2.6	**2.2**						
6A	2.5	3.5	2.9	3.4	**3.3**						
6B	2.3	2.7	2.5	2.9	**2.7**						
7A	2.8	3.6	2.9	3.5	**3.3**						
7B	2.4	2.8	2.6	2.8	**2.7**						
8A	2.7	3.5	3.1	3.4	**3.3**						
9A	3.2	4.5	3.5	3.5	**3.8**						
9B	3.2	3.9	3.5	3.7	**3.7**						
NS-2630.6 ft											
3B	2.4	2.8	3	3.2	**3.0**						
4	3.3	3.1	3.3	3.1	**3.2**	58	66	75	**66**	**1.4**	
1A	4.3	4.4	4.5	4.7	**4.5**	70	73	92	**78**	**1.3**	
2A						71	76	88	**78**		Bump on C1
1B						40			**40**	**1.7**	Questionable (good fit)
NS-2558 ft											
4A	3.2	3	3.2	3	**3.1**						
10A	2.4	2.2	2.4	2.2	**2.3**					**0.9**	

8A	2.3	2.4	2.8	2.9	**2.7**					**0.8**	
10B						27			**27**		
9B						34			**34**		
6B						57	41		**49**		Bumpy on C2
5B										**1.0**	

Results

In general the subcritical indices for OT-2528 and NS-2630 are moderate, from 66 to 103, compared to other shale values (discounting the low values with poor specimens or questionable tests). Other shales we have tested normally have a subcritical index well above 100 and commonly in the 200 to 300 range (ambient air conditions). The shallower sample from the Solsman core NS-2558 has a much lower subcritical index with measurements of 27 and 34, (discounting the irregular load decay test). The Young's modulus for all samples lies between 2.2 and 4.5 Mpsi. These are comparable with the lower values for measurements of Barnett Shale (Gale and Holder, 2008). The fracture toughness is 0.8 to 1.0 MPa-sqrt(m) for NS-2558 tests but ranges between 1.3 and 1.8 MPa-sqrt(m) for the other two samples.

The higher subcritical indices were measured in the samples from the two horizons where the apparent fracture intensity is lower. Higher subcritical index generally indicates a more clustered fracture pattern. In a highly clustered pattern the chances of sampling fractures decreases, so that it is quite possible that the lower horizon in the Solsman well (2630 ft) and the core from the Osburn Trust well are fractured, but that the clustering has meant the fractures were not sampled (Fig. 10). The fracture toughness for the NS-2558 horizon is substantially lower than for the other samples.

The test provides results for these shale samples in their current state. We need to assess whether this could also be representative of the subcritical index *at the time of fracturing*.

At this stage we do not have enough information about the way that subcritical index in shales changes with composition and differing diagenesis. The measured subcritical crack indices might be close to those prevailing at the time of fracturing for the steep sealed sets, but may not be valid for the dolomite-filled fractures that predate some compaction.

In order to use these results in prediction of fracture patterns they would need to be incorporated in a geomechanical model, which includes measured parameters such as strain and mechanical layer thickness (estimated for the time of fracturing). In general, low indices indicate a less strongly clustered fracture pattern, possibly with even spacing of larger fractures at or below the mechanical layer thickness. Intermediate indices tend to have more even spacing at or above the mechanical layer thickness.

Year Two Planned Work

1. Collection of core, and fracture characterization from the well experiment planned for August 2009.
2. Petrography and petrogenesis of all sampled fracture cements.
3. Analysis of fluid inclusions using polished thin sections and SEM-based cathodoluminescence imagery.

4. Assessment of the intensity and spatial distribution of natural fractures through a geomechanical modeling approach, using the subcritical crack index values obtained during Phase 1 of the project, and further tests on samples from the western Kentucky area of interest.
5. Quantitative assessment of sealed fracture strength with tensile bending test.
6. Communication of fracture characteristics to other team members (Ahmad Ghassemi, Texas A&M) for incorporation in the modeling of the interaction of hydraulic and natural fractures.

Technology Transfer

Presentations were made at RPSEA forums and project review meetings as follows:

- April 14th in Golden, Colorado, project review meeting
- May 19th Tuscaloosa, Alabama, RPSEA forum
- June 4th Chicago, Illinois, RPSEA forum

We submitted a paper to the 2009 International Coalbed and Shale Gas Symposium, Tuscaloosa, AL, entitled "Natural fractures in the New Albany Shale and their importance for shale-gas production".

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Geochemistry

PI: Anna Martini, Amherst College

Co-PI's: Jennifer McIntosh, University of Arizona; Matthew Kirk and Julian Damashek, Amherst College; Steven Petsch and Mark Woodworth, University of Massachusetts; Cristina Takacs-Vesbach, University of New Mexico.

Project Participants

- **Anna Martini** (Amherst College) – Prof. Martini is lead PI on this project and coordinates all research activities with Co-PI's, graduate students, undergraduate research assistants, and collaborators.
- **Matthew Kirk and Julian Damashek** (Amherst College) – Dr. Kirk is a post-doctoral researcher whose tasks include both microbial community and geochemical analyses for Illinois and Michigan Basin samples. Kirk coordinated field sampling and analysis in the Michigan Basin and is coordinating the second field sampling campaign for the Illinois Basin, which will occur in July 2009. Mr. Damashek is a recent graduate of Amherst College with a degree in Biology and will be responsible for much of the microbial community analysis from Illinois Basin samples. Damashek will also perform major ion and trace element analyses on water samples from the New Albany Shale collected during 2009.

- **Jennifer McIntosh and Melissa Schlegel** (Univ. Arizona) – Dr. McIntosh collaborates with us on all aspects of this project. Ms. Schlegel is a 2nd yr Ph.D. student in Dr. McIntosh's research group. Results of this study will form the basis of her dissertation - specifically, the impacts of Pleistocene glaciation on freshwater recharge into the Illinois Basin and generation of microbial methane in organic-rich shale and coal formations. Schlegel coordinated the first field sampling campaigns and will participate in this July's final major sampling trip. McIntosh and Schlegel are also responsible for most of the major chemical water and gas analyses.

- **Steven Petsch and Mark Woodworth** (Univ. Mass.-Amherst)– Drs. Petsch and Woodworth are analyzing coal and shale core materials as well as oil samples for evidence of microbial degradation.

- **Cristina Takacs-Vesbach** (Univ. New Mexico) – Dr. Takacs-Vesbach is collaborating with us on molecular and phylogenetic analysis of microbial communities.

Major Research Activities

- McIntosh and Schlegel completed three major sampling campaigns in January, June, and July/August 2008 to collect formation waters, natural gas, and microbial cellular materials from New Albany Shale wells across the Illinois Basin. Forty-two New Albany Shale methane wells were sampled in total. In addition, ~30 shale core materials were collected from the Illinois and Indiana State Geological Surveys. Table 1 summarizes the samples collected and laboratory analyses completed/and in progress.
- Kirk completed T-RFLP analysis of microbial samples from the New Albany Shale wells and Illinois Basin coal wells. Statistical analysis of these results is currently in progress.

- Woodworth and Petsch completed a biodegradation indices analysis of 13 shale samples from three cores.

- Kirk and Martini completed a sampling campaign in January 2009 to collect formation waters, natural gas, and microbial cellular materials from eight Antrim Shale wells in the northern producing trend of the Michigan Basin. These wells had previously been sampled by Martini and others in the early to mid 1990s. They were re-sampled for this study to examine how natural gas production has affected the composition of water and gas over time. Field station records corresponding to each well were also gathered. With the exception of some microbial analyses, the analysis of the samples is complete. Data interpretation and writing are currently in progress.

Table 1. Inventory of Samples Collected and Analyzed From New Albany Shale Wells in the Illinois Basin

Type of sample (# of samples)	Analysis	Lab	Primary people responsible for analyses
Water (36)	Anions	UA/Amherst	McIntosh/Schlegel/Kirk/Damashek
	Major cations	UA/Amherst	McIntosh/Schlegel/Kirk/Damashek
	Trace elements	Amherst College	Kirk/Damashek
	$\Delta^{13}C_{DIC}$, $\Delta^{18}Q$ ΔD_{H2O}, $\Delta^{34}S_{SO4}$	UA	McIntosh/Schlegel
	Acetate	USGS	McIntosh/Schlegel
	DOC, TDN, TP	UA	McIntosh/Schlegel
Gas (30)	Gas Composition	Isotech	McIntosh/Schlegel/Kirk
	$\Delta^{13}C_{CO2}$, $\Delta^{13}C_{CH4}$, ΔD_{CH4}	Isotech	McIntosh/Schlegel/Kirk
Core (30)	Extractable Hydrocarbons	UMass-Amherst	Petsch/Kirk/Schlegel/McIntosh
	Culture microbes from core	Amherst College	Kirk/McIntosh/Schlegel

Microbes (36)	DNA and cell counts	UMass-Amherst	Kirk/Damashek
	RNA – to be collected	Amherst College	Kirk/Damashek
	Cultures – to be collected	Amherst College	Kirk/Damashek

*All of these samples have been collected and analyzed *(except where marked in italics)*.

Major Findings to Date

- Chloride versus $\Delta^{18}O$ relations of New Albany Shale formation waters indicates mixing of saline brines at depth in the Illinois Basin with two freshwater sources: 1) dilute meteoric waters with $\Delta^{18}O$ values similar to modern precipitation (-7.5 to -4.5‰), and 2) dilute meteoric waters with relatively low ^{18}O values indicative of mixing with Pleistocene glacial meltwaters (<-12‰). Stable isotope records of speleothems, ostracods, and wood cellulose indicate that throughout most of the last 250,000 years $\Delta^{18}O$ values of precipitation were between -10 to -5‰, consistent with our measured values for dilute waters at depth in the Illinois Basin. Waters depleted in ^{18}O were likely recharged during periods of ice cover.
- The geometry of aquifer systems along the northeastern Illinois Basin margin played a major role in the extent of subglacial recharge to deep saline aquifers. The Silurian-Devonian carbonates are exposed in a wide swath across the basin margin; salinity gradients and hydrologic modeling suggest that these carbonate aquifers were major drains for glacial meltwaters. The Cambrian-Ordovician aquifer system received limited recharge, likely due to the presence of the Maquoketa Shale confining unit overlying the aquifer at the surface.
- Stable isotopes of produced gases coupled to formation waters helps to delineate the mechanism and timing of gas generation. There is an ~65-70‰ depletion in ^{13}C of CH_4, relative to the precursor CO_2 in the New Albany Shale wells in the Illinois Basin. In addition, there is a linear correlation between the ΔD values of co-produced formation waters and CH_4. Isotope mass-balance modeling results confirm that these isotopic shifts can be produced by coupled acetate fermentation and CO_2-reduction. The lowest $\Delta^{13}C$ values for CO_2 and CH_4 are found in the shallow glacial drift (-14 to 8‰ and -80 to -68‰, respectively), where the permeable aquifers are a relatively open system, rapidly flushed by modern recharge. In contrast, the deep Upper Devonian shales have relatively positive $\Delta^{13}C$ values for CO_2 and CH_4 (6 to 20‰ and -56 to -50‰, respectively), indicating that methane has been generated over relatively long time scales (at least since the Late Pleistocene) in a closed hydrologic system.
- Counts of microbial cells from filtered New Albany Shale waters are within the same order of magnitude as the Antrim Shale in the Michigan Basin (an economic microbial gas play).
- Acetate concentrations in shale formation waters throughout the Illinois Basin show that acetoclastic methanogenesis is inhibited at salinities greater than ~500 mM Cl^-. Formation water chemistries are being coupled to DNA, RNA, and culturing experiments to characterize the microbial populations responsible for organic matter degradation and methane generation.
- T-RFLP profiles, essentially DNA "fingerprints", of the archea in samples collected from the New Albany Shale and Illinois basin coalbeds demonstrate that the methanogenic community in these sources are strikingly similar and appear to be dominated primarily by two populations. Statistical analyses that examine the composition of these communities and how that composition relates to environmental factors such as water chemistry will allow us to examine the controls on community composition.
- Extracted hydrocarbons from New Albany Shale core materials show evidence for increasing biodegradation (e.g. depletion of alkanes) towards the Illinois Basin margin. Additional analyses of core materials (including the new core being taken later this month) will be coupled with extractable

hydrocarbons from formation waters and bioreactor experiments to determine key substrates and byproducts of methanogenesis.

- Biodegradation indices determined for 13 New Albany Shale core samples show that degradation is variable over short vertical distances and suggest that the aromatic hydrocarbon fraction is degraded first, which is similar to what is observed in coal but dissimilar to what is observed during oil degradation.
- Field station data gathered for Antrim natural gas wells show considerable declines in water and gas production. Both water and gas production peaked within five years after the wells came online. Water production currently ranges from 0.2 to 15% of peak levels and gas production ranges from 7 to 60% of peak levels. As gas production has declined, its carbon dioxide content has steadily increased, today accounting for as much as 23% of the gas produced from the wells sampled. This increase is expected as CO2 is more strongly adsorbed into the organic matter so as pressure drops the relative percentage of CO2 in the gas will grow.
- The isotopic composition of water and gas produced by the Antrim wells sampled has shifted significantly over the last ~15 years. With respect to hydrogen isotopes, the water is 10‰ lighter on average and the methane is 8.5‰ lighter. These findings provide compelling evidence that methane generation has occurred over the last 15 years at a significant rate. This interpretation is supported by direct analysis of the microbial community. Carbon dioxide reducing methanogenic microorganisms dominated the archeal community.
- The concentration of sulfate has increased considerably in the Antrim wells sampled. The average sulfate concentration observed in samples gathered in 2009 was 300 µm. Samples from the early 1990s typically had undetectable sulfate content. This result shows that groundwater pumping to produce natural gas is causing groundwater to seep into the Antrim, perhaps from the underlying Traverse Limestone, a relatively permeable unit known to contain gypsum horizons. This influx of sulfate may ultimately allow sulfate reducing microorganisms to largely displace methanogenic microorganisms in the Antrim, thereby causing methane formation to cease. The results of analysis of the bacterial community suggest that this may already be the case. The dominant group of bacteria observed was sulfate reducers, which accounted for about 30% of the community.

Upcoming focus

- July 19 to 26, 2009 sampling trip by Kirk, Damashek, and Schlegel that will include the following producers' wells: NGAS, CNX, Atlas, Global GeoData. These are the only remaining producers from which no samples were gathered during the 2008 field campaigns.
- Finish geochemical analysis and continue molecular work for New Albany Shale samples.
- Continue biodegradation analysis of New Albany Shale core material.
- Integrate production history with the growing geochemical database.

Published Abstracts & Presentations of Results

Schlegel, M., McIntosh, J., Person, M., Balletine, C., Zheng, Z. (2008) Investigating the source and timing of freshwater recharge into saline aquifers in the glaciated Illinois Basin. Goldschmidt Conference.

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Publications Resulting From Research

Published and Submitted Papers: None to date

Papers "In preparation" - to be submitted within the next 12 months:

Kirk *et al.* (in prep.) The rate of methanogenesis in a fractured shale natural gas reservoir. *To be submitted to Nature Geosciences*

Schlegel, M.E., Bates, B., Kirk, M., McIntosh, J.C., Martini, A.M. (*in prep*) Activity and extent of CO_2 and acetate utilizing methanogenesis in organic-rich aquifers within the Illinois Basin, USA. *To be submitted to Chemical Geology.*

Formation Evaluation

Principle Manager: Mr. Jim Lorenzen, Res Tech Inc.

PI: Mr. Don Luffel, Mr. Frank Caramanica, Mr.Jim Lorenzen , Res Tech Inc.

Objectives

The objective is the integration of core, electric log, and image measurements to develop advanced methodology that allows determination of the gas in place, shale formation characterization, and through the identification of fracture species and orientation the delineation and effective completion of the highest productivity intervals of the New Albany shale.

Technical Perspective

Identification of producing zones in New Albany shale wells and determination of reservoir properties from well logs is a nontrivial problem. Intrinsic physical properties of shale are such that conventional formation techniques are not applicable to shale. As such, techniques specific to New Albany shale must be developed. Emphasis will be placed on borehole imaging, coring, and geochemical techniques. The activities identified for this task include fracture identification from logs such as FMI and construction of borehole maps of dip projections of fractures within specific distances from borehole.

Log analysis work to be performed by ResTech includes the development of advanced methodology for calculation of shale porosity, water and bitumen saturations, free gas saturation and adsorbed gas through correlation with core data. Work also performed by ResTech includes supervision of coring and core analysis including visual inspections and analyses; correlation of core and log data; quality control of porosity; water and bitumen measurements; measurement of matrix permeability, determination of total organic carbon, and adsorbed gas from isotherms.

Results

A review of all available core and log data provided by operating partners was completed along with review of previous GRI studies including the 1999 Producibility Consortium and the GIS Compilation of Gas Potential of the New Albany Shale in the Illinois Basin. From these the following results and observations have been accomplished to date.

- A discrepancy is identified between total gas from canister measurements and the compilation of isotherm adsorbed gas and core measured free gas. This is note in the 1999 Consortium data as

well as in the data provided by industry partners. The source of the discrepancy is known to be the presence of heavy components in the gas.

- Using available rotary sidewall and whole core data from two wells, major differences in core measured matrix permeability are noted. It is unclear at this point whether the differences are related to core handling and protocols or reflect actual reservoir character.
- High oil saturations and sub-normal pressure is noted in most of the wells where data is currently available.
- A basic log analysis model for determination of porosity, saturation, shale lithology, total organic carbon, and gas in place has been developed using available core and log data.
- Correlations on a limited basis from logs for geochem parameters TOC, S1, S2, PI, HI, and Ro have been developed.
- Initial work using limited sonic data to computer Young's modulus, Poison's ratio, and calculate isotropic un-calibrated stress profiles has been done.
- Technology transfer was presented at the SPWLA Spring Topical conference in Philadelphia.
- Log data has been normalized in the up-coming project drill well area for approximately 30 wells provided by Ngas.
- Fractures are characterized from the FMI data of the Osburn Trust #1-1H, in Sullivan county, Indiana. Natural fractures both open and partially open exist in conjugate sets with high angle dip. The dip direction is NNW-SSE and the strike is ENE-WSW. Few induced fractures are interpreted.

Introduction

In August of 2008 the New Albany Shale Gas study began with the Kick-off meeting and gathering of existing data from previous work and wells provided by the operating industry partners of the project. The objective of the formation evaluation is develop advanced methodology for the determination of lithology, porosity, saturation, free and adsorbed gas content (GIP), total organic carbon (TOC), and matrix permeability in the New Albany shale. Additionally, quality control core procedures, reporting, and tests as they relate to determining the characterization of the shale. This includes porosity, saturations, matrix permeability, isotherm adsorbed gas, canister gas, gas composition and geochemistry. Also, fractures both natural and induced are to be characterized for dip, strike, density, and connectivity from any available image log data. All of this is to be done to optimize completions and production from the New Albany shale resource. Table 1 shows data reviewed and incorporated into year one work. Figure 1 is a cut down map of the basin grossly displaying the location of these data and Christian county, Kentucky where the planned drill wells for Ngas are located.

Table 1:Previous Data

Data	Acquisition Period
Producibility consortium	February 1999
Three (3) wells logs and core –W. Ky.	Circa 1970s
Two (2) wells logs and core – Sullivan county, IN., Noble Energy	April 2007
CNX well logs and RSWC (25) W. KY.	August 2007
Two (2) wells log, core, gas analysis—Vigo County, IN, Trendwell	December 2007 – February 2008
Thirty (30) wells – logs –Christian county , Ky., Ngas	2007-2008 acquisition, received into project (March 2009)

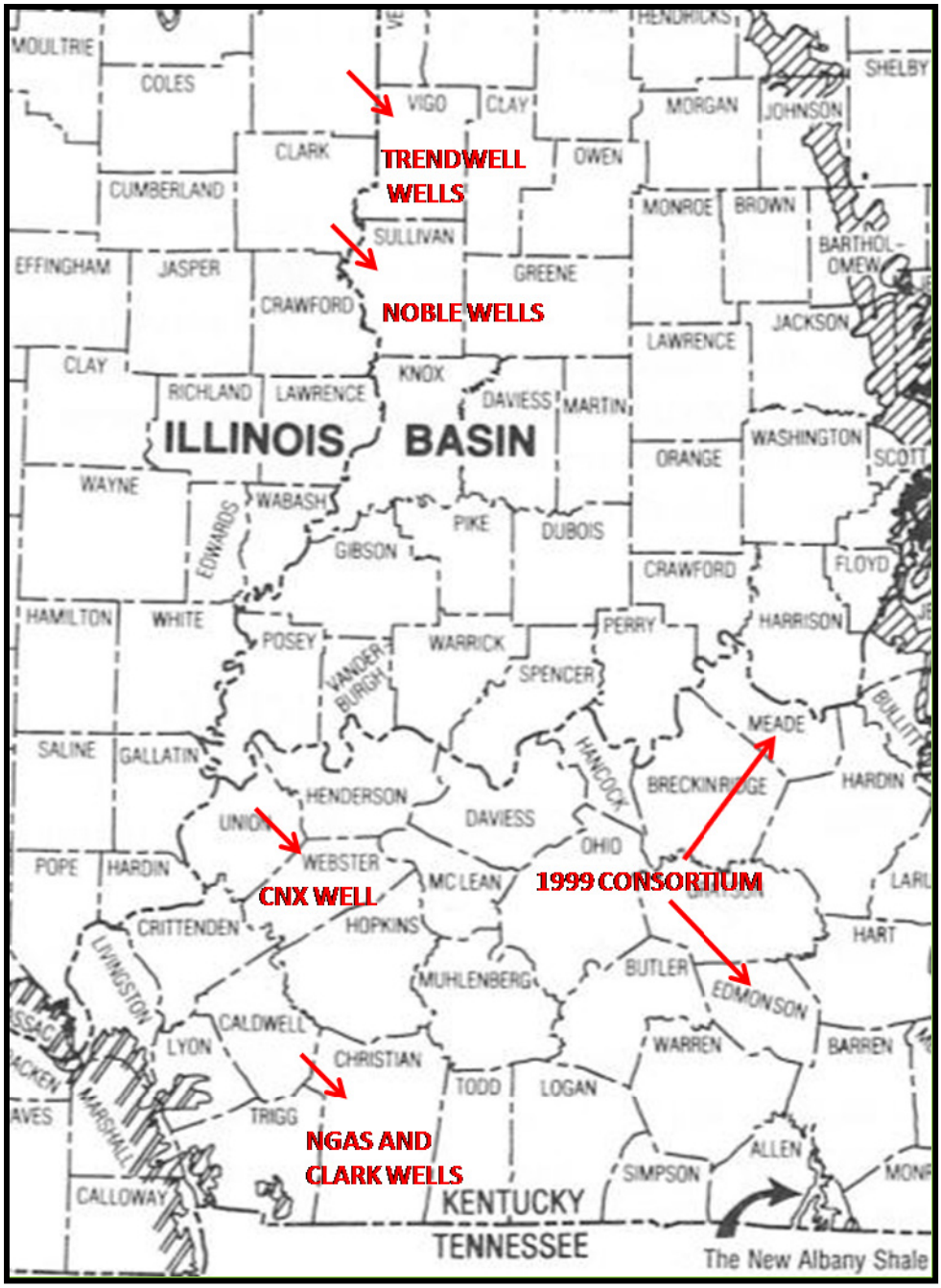


Figure 1. – Location of previous wells –New Albany shale study. Upcoming drill wells will be in Christian county, Kentucky for Ngas

The approach for characterization of the resource is to use the available core to determine porosity, saturations (oil, gas, and water), matrix permeability, adsorbed gas from isotherms, and total gas with gas composition from canister measurements. Additionally x-ray diffraction results provide the basic constituent shale components. Geochemistry done on core samples will define total organic carbon (TOC), parameters S1, S2, production index PI, and S3, which related to the hydrocarbon generated, the potential for additional generation and the oxygen content. Also Tmax, vitrinite reflectance (Ro), and hydrogen and oxygen indices (HI, OI) which relate largely to maturity will be determined.

Log analysis and petrophysical modeling combines the core results with the recorded log data to determine the lithological make-up of the New Albany, kerogen, pyrite, quartz, clay, carbonate, and porosity. The porosity and saturations then calibrated to core with the adsorbed gas from isotherms results provide the break out of calculated free gas, so that gas in place (GIP) both free and adsorbed can be estimated. Also, from geochem results, log based correlation for the determination of TOC, S1, S2, HI, Ro, and PI are developed.

With limited sonic data initial work to determine mechanical properties, Poisson's ratio, Young's modulus, and isotropic stress are calculated in the CNX well in Webster county, Kentucky. At this point, no opportunity to calibration to measured results has been available, and no data are available for corrections for potential anisotropy.

Initial fracture characterization is presented for the Noble Energy, Osburn Trust #1-1H well in Sullivan County, Indiana. These type results along with matrix permeability will be critical to ultimately tying the petrophysical models to the production simulation and producibility of New Albany completions.

In the July-August 2009 time frame Ngas Resources Inc. with drill, core, log, complete, and fracture stimulate a well in Christian County, Ky. Table 2 show the proposed coring, Table 3 the logging program. Year two work will use these data and results to refine and finalize our formation evaluation.

Table 2: Recommendation and Costs for Wellsite Handling and Lab Analyses for Conventional NAB Cores from NGAS Well

	Core and Samples	Cost	Wellsite, Lab Analyses, Comments
1. Coring			***Armstrong Tool L.L.C.***
Core, ft	60	13,392	Price quote to NGAS for coring equipment without inner sleeve.
Add inner sleeve		3,000	Est price to include aluminum inner sleeve.
Sub		***16,392***	
2.Wellsite Core Handling & Canister Cores			***Recommend Weatherford (WFT/Ticora)***
Field personnel and travel		12,202	One engr and one tech at wellsite with truck lab from/to Denver.
Desorption of canister cores at wellsite	3	6,140	Labor, adjacent cores preserved, lab meast's, field report
Rest of core handled at wellsite and transported		2,638	Preserve rest of core in 3' sleeves and truck to Core Lab.
Sub		***20,980***	
3. Completion of Lab Canisters, Isotherms			***Recommend Weatherford (WFT/Ticora Denver Lab).***
Canister cores	3	3,271	Photos, gas compositions, core lithology, TOC, density, archived
Methane isotherm	1	2,205	Compare canister gas comp and contents.

Gas Isotope Analysis for Thermo/BioGenic	1	1,230	C-13 isotopes from 3 different desorption compositions
Professional Services		1,275	Interpret data and construct Tables and Graphs
Sub		***7,981***	
4. Lab Core Analyses			***Recommend Core Lab (GRI Protocol)***
Gamma Ray, Core handling, slabbing, photos	Approx 55'	5,100	For BEG to study whole core for frac's, azimuths, bedding, etc
Shale analysis - Phi, Sw, So	5	4,250	
Permeability, Km	5	500	
Mineralology	3	1,500	For refining log analysis.
Sub		***11,350***	
5. Geochem Analyses			***Recommend Weatherford Humble Geochem***
TOC, Rock Eval	10	900	Samples (about 10 gm) from blend of core spls above.
Vitrinite with microscope	1	165	
Report		1,120	
Sub		***2,185***	
TOTAL		***$42,496***	**Coring costs not included.**

Table 3: Logging Program – Ngas Well

Weatherford Wireline Services
Induction – Density-Neutron
Spectral Gamma Ray
Compact Micro-imager
Full Array Sonic

Core Analysis

Review of available core data from previous studies and wells was undertaken in year one. These data consisted of the core plugs from conventional core taken in 3 wells in Western Kentucky in the 1970's, core data that were part of the producibility consortium (1999), conventional core from two Noble Energy wells in Sullivan county, Indiana (2006), twenty five sidewall rotary core taken in the CNX well in Webster county, Kentucky (2007), and conventional core from two Trendwell Energy wells in Vigo county, Indiana (late 2007). As a whole these data are used to define:

- Porosity, water, oil, and gas saturation
- Matrix permeability
- Constituent components of the shale lithology
- Total organic carbon, and geochem parameters S1, S2, S3, Ro, HI, OI, PI, and Tmax.
- Adsorbed gas from isotherms

- Estimate of total gas and gas composition from canister samples

One key observation from these data results is that the total gas content from canisters often conflicts with high adsorbed gas content from isotherm data. This is not unheard of as the core companies that perform isotherm measurements do so using pure methane only and are aware that heavy components in the gas will cause the isotherm result to be too high, but it should be brought forward that this appears to be common in the New Albany of the Illinois basin. Figure 2 below is an example of canister gas content from a well in Indiana. The first example of this conflict is observed in the 1999 Producibility Consortium and displayed in Figure 3 below.

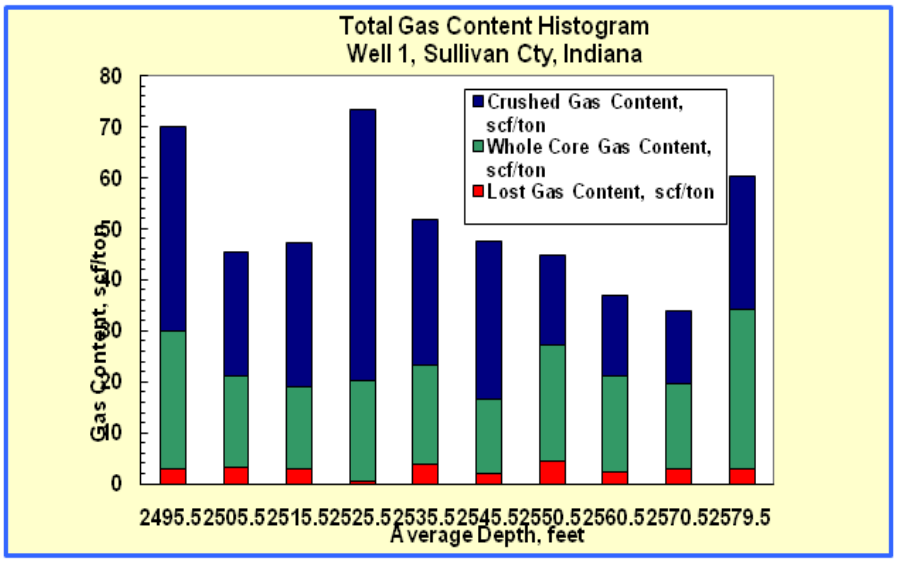


Figure 2: Canister gas—Lost gas, Whole core gas, and Crushed gas combine to estimate total gas content.

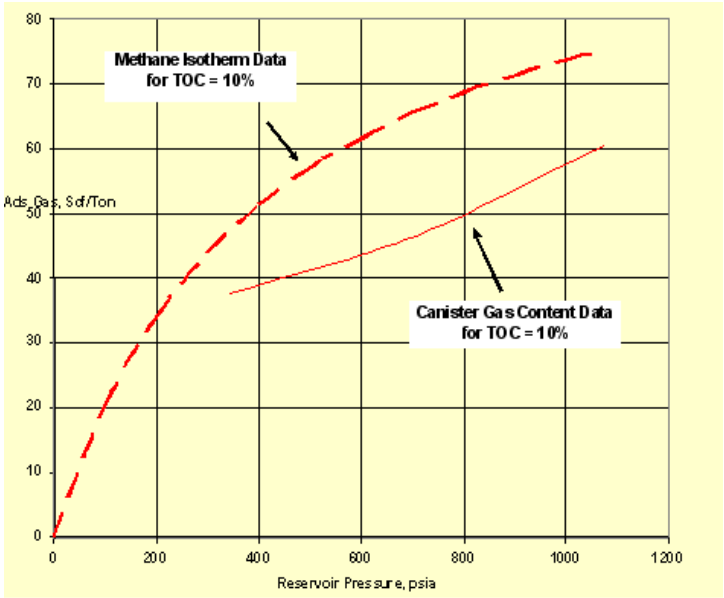


Figure 3 – Isotherm versus canister total gas-Producibility Consortium, 1999. Heavy components in the gas cause the adsorbed gas content to be too high.

The data in Figure 3 are from Edmondson and Meade counties, Kentucky. Figure 4 shows a similar phenomenon when comparing canister gas and isotherm results from the Noble Energy wells in Sullivan County, Indiana.

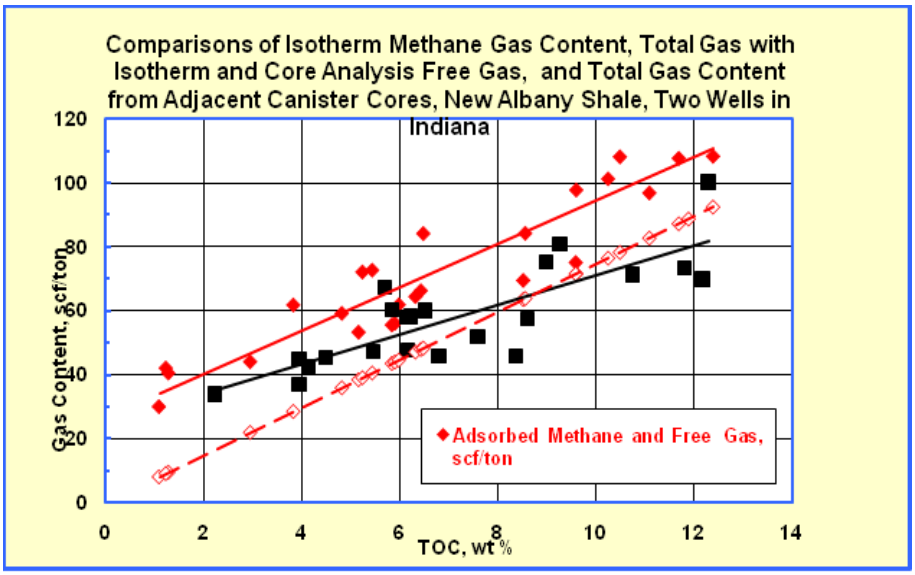


Figure 4: Total canister gas versus adsorbed plus free gas using core data.

The variation and heavy components of the gas are illustrated in Table 4 below. This table compares the Ngas –Daugherty Petroleum data to data from the Producibility Consortium.

Table 4: Estimates of Gas Composition in NAB in Western Kentucky
Daugherty Petroleum

Well	C1 %	C2 %	C3 %	iC4 %	nC4 %	N2 %	CO2 %	Est Gas Grav
DPI 67	90.18	3.59	0.18	0.04	0.02	5.66	0.34	0.60
DPI 71	86.57	5.03	0.96	0.08	0.03	6.90	0.18	0.62
DPI 77	84.39	3.43	0.25	0.05	0.03	11.56	0.27	0.62
DPI 78	87.86	3.97	0.37	0.06	0.02	7.29	0.35	0.61
DPI 79	87.12	3.68	0.36	0.05	0.05	8.39	0.34	0.61
Ave	**87.22**	**3.94**	**0.42**	**0.06**	**0.03**	**7.96**	**0.30**	**0.61**

Tomes, Letha #2 Well, Edmondson, KY from NAB Producibility Consortium, February 1999
22 Rotary SWC Cores with Meas't of Gas Content w/Canister
11 of the Cores were then Crushed and Gas Compositions Meas'd w/Chromatography

Table 4, Continued

Depth	Fm	C1 %	C2 %	C3 %	iC4 %	nC4 %	N2 %	CO2 %	Est Gas Grav
1,576	Clegg Cr	54.51	23.96	15.89	0.84	3.69	0.33	0.00	0.88

1,591	Clegg Cr	59.66	22.80	12.20	0.40	2.14	2.41	0.00	0.82
1,598	Clegg Cr	58.02	22.86	12.69	0.49	2.40	2.99	0.00	0.84
1,612	Clegg Cr	53.49	22.64	16.36	0.90	4.77	0.30	0.00	0.89
1,632	Morgan/ Camp	55.30	23.18	15.69	0.79	3.78	0.18	0.00	0.88
1,650	Morgan/ Camp	57.40	23.56	14.49	0.62	3.32	0.73	0.00	0.87
1,669	Morgan/ Camp	52.39	20.67	18.26	1.17	5.41	0.07	0.00	0.91
1,684	Morgan/ Camp	56.52	20.56	16.48	0.84	4.21	0.00	0.00	0.88
1,701	Selmier	43.97	22.00	22.34	1.62	7.28	0.00	0.00	0.99
1,719	Blocher	49.08	20.37	20.51	1.41	6.35	0.00	0.00	0.95
1,730	Blocher	50.64	21.00	19.91	1.21	5.47	0.00	0.00	0.93
Ave		**50.05**	**20.98**	**19.81**	**1.27**	**5.83**	**0.00**	**0.00**	**0.94**

Gohl #4 Well, Meade, KY from NAB Producibility Consortium, February 1999
20 Rotary SWC Cores with Meas't of Gas Content w/Canister
10 of the Cores were then Crushed and Gas Compositions Meas'd w/Chromatography

Depth	Fm	C1 %	C2 %	C3 %	iC4 %	nC4 %	N2 %	CO2 %	Est Gas Grav
937	Clegg Cr	92.42	0.97	0.65	0.23	0.12	0.00	5.55	0.62
939	Clegg Cr	90.22	0.96	0.65	0.28	0.04	0.00	7.35	0.64
942	Clegg Cr	86.29	1.69	2.47	0.35	1.02	0.00	7.96	0.68
947	Clegg Cr	55.00	6.23	11.98	0.81	3.26	17.06	5.01	0.87
955	Clegg Cr	86.38	0.82	0.83	0.61	0.62	0.00	10.23	0.68
Ave		82.06	2.13	3.32	0.46	1.01	3.41	7.22	0.70
958	Clegg Cr	53.32	5.43	10.60	0.86	3.45	17.57	8.01	0.89
971	Morgan/ Camp	31.23	16.12	14.32	1.07	4.98	30.58	0.00	0.97

982	Morgan/ Camp	43.05	20.23	17.25	1.22	5.44	11.30	0.00	0.95
1,002	Blocher	43.05	16.02	12.68	0.96	4.34	15.73	5.99	0.94
1,009	Blocher	54.22	18.52	12.91	1.06	4.05	0.00	8.01	0.91
Ave		**44.97**	**15.26**	**13.55**	**1.03**	**4.45**	**15.04**	**4.40**	0.93

Some work in year two of the project will look at any potential there may be for creation of a pseudo isotherm that corrects for the observed discrepancy, or at least attempt to predict where there is potential for over –estimating adsorbed gas.

In spite of this concern, isotherm results are still the most direct way to estimate adsorbed gas and this is a key component to determining total gas when canister data is not available or not trustworthy. As such isotherm data is used in both the Indiana and Western Kentucky areas to estimate adsorbed gas content and is combined with free gas determined from either the core or log based model to delineate total gas in place. Figure 5 displays the isotherm results from the 1999 Consortium fields (Maple Corners and Shrewsbury), the Indiana data, and the Western Kentucky results. All data has been normalize to ten (10% by weight) per cent TOC. The volume equation shown in the figure is for western Kentucky.

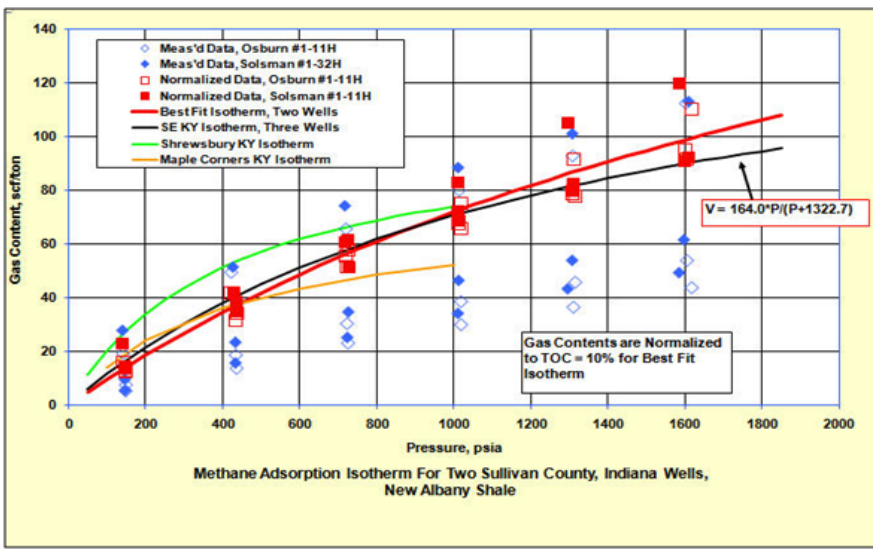


Figure 5 – Core isotherm data results Western Kentucky and Indiana.

In addition to gas content and composition core data provides us with the basis for lithology modeling using XRD results, Table 5 is such an example from the CNX Gas well BF -001 in Webster County, Kentucky. In this case there are 5 groups of rotary sidewall cores; the analysis is performed by TerraTek.

Table 5 Example XRD results

X-RAY DIFFRACTION DATA - Whole Rock and Clay Mineralogy (Weight%)
CNX Gas- BF-001

TerraTek Project No. 810337 Preliminary Results 16 May 2007

WHOLE ROCK MINERALOGY

SAMPLE ID	G1	G2	G3	G4	G5
DEPTH (FT)	3941.8	3981.3	4034.8	4177.2	4293.2
QUARTZ	45	43	36	29	32
K-FELDSPAR	6	4	8	4	9
PLAGIOCLASE	6	6	5	5	6
CALCITE	0	0	0	2	12
SIDERITE	0	0	0	2	0
DOLOMITE	5	3	2	5	14
PYRITE	4	9	4	3	3
FLUORAPATITE	0	0	1	0	1
BARITE*	0	0	0	0	0
TOTAL NON-CLAY	66	65	57	49	77
ILLITE/SMECTITE (I/S)	10	10	11	14	8
ILLITE+MICA	24	25	32	34	16
KAOLINITE	0	0	0	1	0
CHLORITE	0	0	1	3	0
TOTAL CLAY	34	35	43	51	24
GRAND TOTAL	100	100	100	100	100

*barite- traces of drilling mud contamination

The chief constituent make up of the New Albany shale is similar to the Appalachian Devonian shale analyzed extensively in the late 1980's and early 1990's by GRI.

Added to the whole rock mineralogy, we need to determine total organic carbon (TOC wt %) as this relates to the volume of kerogen and the hydrocarbon generative history and potential of the resource. These results are generally given as part of the Rock Eval pyrolysis, which also includes the geochem parameters. Table 6 shows an example of those type of data.

Table 6

								Core Lab Meas	RTI** Calc'd				RTI Calc'd from Calc'd Ro	RTI Calc'd from Meas'd Ro					
County	State	Well	Depth	TOC	S1	S2	S3	Rhob		Tmax	Calc.	Meas.	Kero	Kero	HI	OI	S2/S3	S1/TOC	PI
			(ft.)					gm/cc	% BVO	(°C)	%Ro	%Ro	Dens	Dens					
Crittenden	KY	#1 Frazer	1585.7	8.31	1.45	19.45	0.28	2.423	0.39	448	0.9	0.64	1.278	1.186	234	3	69	17	0.1
Crittenden	KY	#1 Frazer	1711.8	5.15	1.49	7.98	0.22	2.56	0.42	450	0.94		1.291		155	4	36	29	0.2
Crittenden	KY	#1 Frazer	1920.2	5.39	2.02	9.52	0.25	2.487	0.56	454	1.01		1.316		177	5	38	37	0.2
Christian	KY	#1 Clark	2188.7	6.67	3.72	47.73	0.31	2.409	1	444	0.83		1.253		716	5	154	56	0.1
Christian	KY	#1 Clark	2244.7	9.89	5.88	54.81	0.31	2.384	1.56	436	0.69		1.203		554	3	177	59	0.1
Christian	KY	#1 Clark	2284.3	13.31	7.14	76.3	0.3	2.219	1.76	445	0.85	0.55	1.259	1.155	573	2	254	54	0.1

The table above was originally compiled by Humble Geochem with blue columns added by ResTech, and is presented as part of ResTech's cost share courtesy of Global Exploration Consultants. Some observations made from these results are:

- Ro (vitrinite reflectance) calculated and measured ranges from 0.55 to 1.01 which is typical for all data of this sort we have reviewed and put the New Albany in the Type II to Type II-III kerogen range, largely in the oil window.
- TOC is comparatively high in the 5-13 wt % range
- Calculated kerogen density is 1.20 – 1.316 g/cc
- The relatively low PI (production index) indicates that the generative potential of the samples is still high.
- Note – attempts to correlate S1 to core oil saturation have been ineffective to date.

With the data results above and core measured porosity, water, oil, and gas saturations we can begin to determine the bulk volumes associated with the component parts and formulate our approach to the determination of gas in place. Simply stated, within the pore space we need to account for the bulk volume water (BVW), the bulk volume of bitumen and oil (BVO), the bulk volume adsorbed gas (BVG_ADS), and the bulk volume free gas BVG_F. This concept, which is not applied in any other approach is illustrated from core in Figure 6.

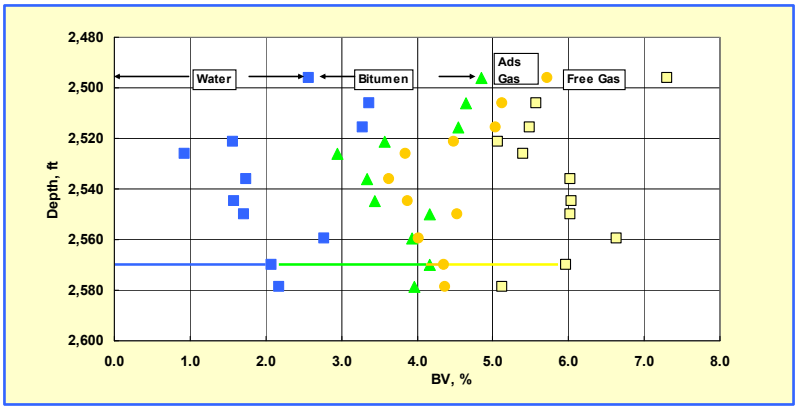


Figure 6 –To determine free gas from a log base model the bulk volume water, bitumen/oil and bulk volume adsorbed gas is calibrated back to core. This approach to enhancing the free gas determination is unique to this study.

Lastly, the core data we have reviewed to date have provided two looks at core measured matrix permeability. One analysis performed by Terra Tek on rotary sidewall core from Webster County, Kentucky, indicates matrix permeability approaching 100 micro-Darcies, while results from Core Lab from conventional core in Sullivan County, Indiana show perm only approaching 1.0 micro-Darcy. These data are somewhat conflicting and the reason at this point is unknown. Both labs claim to be performing matrix permeability measurements as put forward in ground breaking protocols developed by GRI (Don Luffel et al) in the early to mid-1990's. Figure 7 displays these two results.

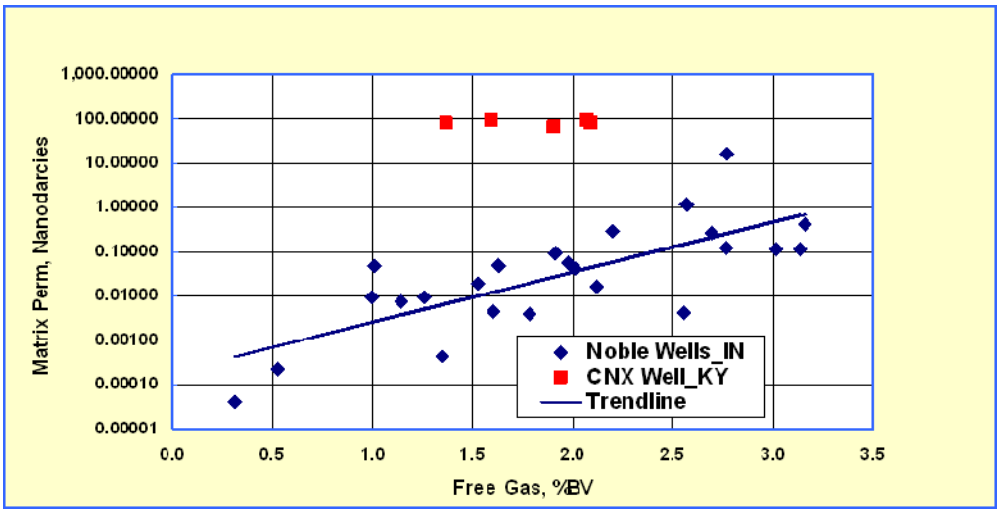


Figure 7: Matrix permeability as measured from sidewall core by TerraTek (Red), Webster County, Kentucky, and as measured by Core Lab (Blue) from conventional core in Sullivan County, Indiana (2 wells). Both labs using GRI protocols as far as can be determined.

From the available core data some additional observations are:

- Oil saturations in the New Albany can be considerably high as reported in core ranging from 30-70%.
- Reported porosity is generally in the 6-12% range
- Combining isotherm and free gas saturation from core indicates that free gas accounts for approximately 30% of the total gas (or hydrocarbon). This is variable and remember there may be some concerns regarding the adsorbed gas content from isotherms
- Core tends to support low bulk volume water.
- S1 has been ineffective so far as a correlation to oil saturation.

Petrophysical Analysis

The petrophysical approach is to use the core data to build log based models that allow the determination of the following.

- Lithology of the shale
- Porosity and water saturation
- Oil and gas saturation
- Matrix permeability
- Total organic carbon and other geochem parameters
- Free, adsorbed, and total gas content
- Geomechanical properties –Young's modulus, Poisson's ratio, stress
- Optimize logging and coring programs
- Natural and induced fracture characterization (from image logs)
- Integration of the log based models with producibility

Figure 8 diagrams the general approach for total gas content but the concept applies to all the points above. Within the first year's effort inroads have been made on all the points listed with the exception of the integration to producibility, this will come as the study culminates.

In the following sections of the report the current models and correlations are presented, however this is a work in progress and information acquired from the up-coming Ngas well to be drilled in late July – August 2009 will impact the final model results. Also, correlations and models may need to be adjusted, changed, or recalibrated as you move about within the basin.

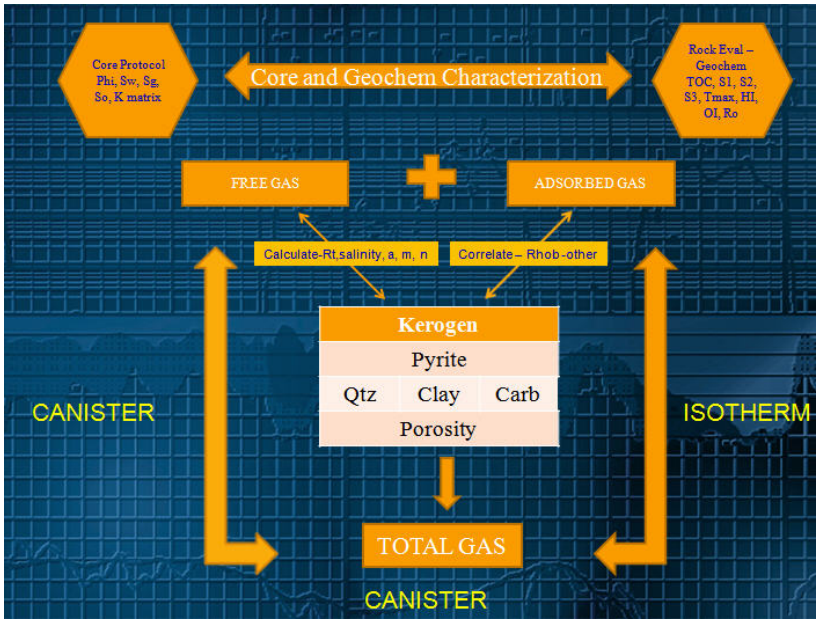


Figure 8 – Generalize concept diagram of how core, geochem, and log data are brought together in a log based petrophysical model.

Lithology and Porosity

The constituent components of the New Albany shale as defined by XRD data (see Table 5 as an example) are quartz, clay (predominantly illite), and lesser amounts of pyrite, carbonates (limestone and dolomite), and feldspar-plagioclase. Additionally there is organic material in the form of kerogen and of course porosity.

Kerogen volume is important because it is related to the TOC and also because of its effects on the logging tool response. In initial work done by GRI in the Devonian shale of the Appalachian basin, the kerogen volume is related to uranium yield as given by a natural gamma ray spectroscopy tool shown in Figure 9.

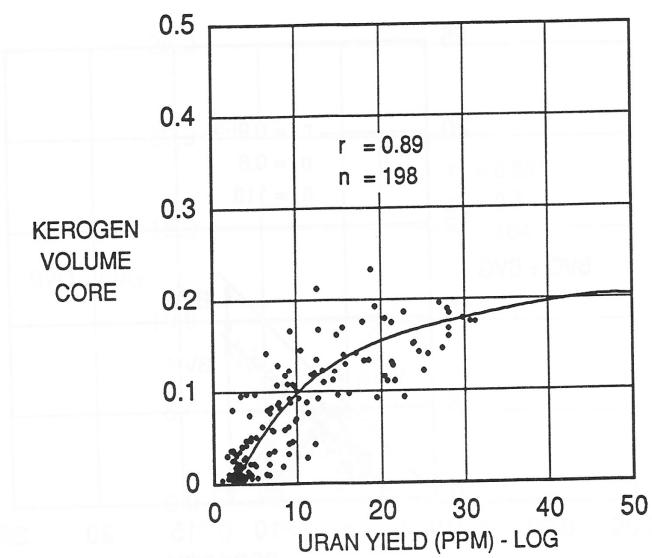


Figure 9 – Appalachian Devonian shale, kerogen volume related to uranium yield.

The equation from Figure 9 is:

Vk=2.89*U-0.178*U^2+(6.24*10^-3)*U^3-(1.11*10^-4)*U^4+(7.7*10^-7)*U^5-6.08 ……(1)

Where: Vk=volume fraction of kerogen (%)

U =Uranium yield (ppm)

Kerogen volume may also be determined from TOC and bulk density. In most shale it is observed that TOC correlates well with bulk density, this is true in the New Albany. Figure 10 shows a correlation from Western Kentucky well data (it will be somewhat different in other areas such as Indiana) of rhob versus TOC.

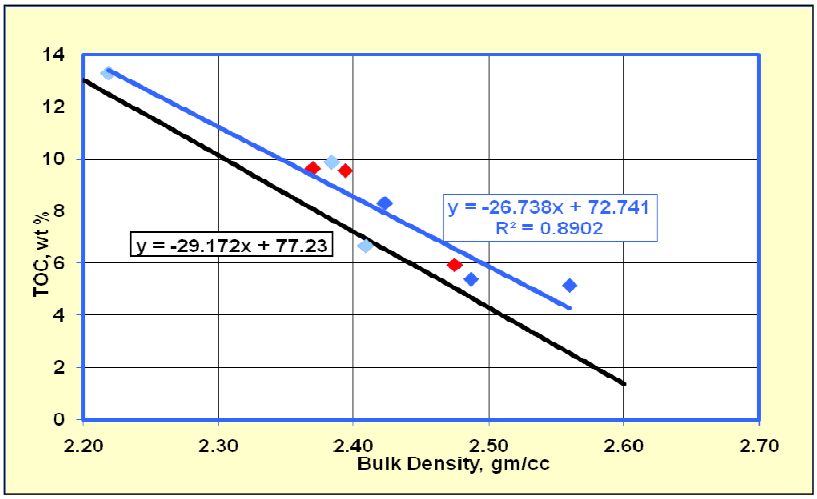


Figure 10 –Bulk density versus TOC from Western Kentucky wells – New Albany shale. Blue is all wells, black is from Shrewbury and Maple Corners Fields from 1999 Consortium.

From GRI report GRI-95/0496 appendix B, the equation for kerogen volume is given by:

Vk=[(TOC-S1*Cs1)/Ck]*Rhob/RhoK ……..(2)

Where:

- TOC is total organic carbon
- S1 is free oil
- Cs1 is carbon in the free oil (0.87)
- Ck is carbon in the kerogen (0.77)
- Rhob is bulk density
- Rhok is kerogen density

Using this equation and calculating kerogen volume from rock eval TOC and pyrolysis for three New Albany shale wells results in Figure 11 which gives a correlation of kerogen volume to bulk density.

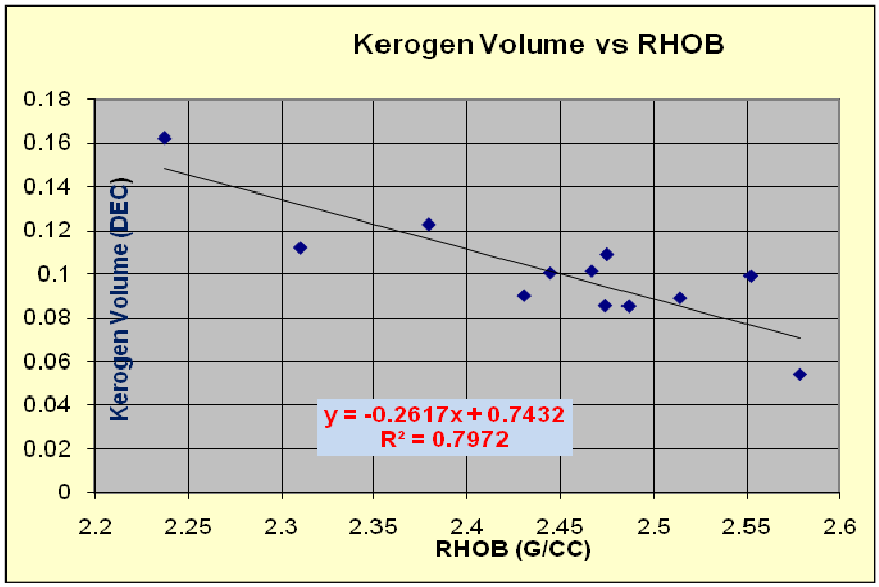


Figure 11 –Kerogen volume correlated to bulk density.

Pyrite volume is generally determined using a correlation to volumetric photoelectric cross-section (Uma) if available or it is assumed as a per centage of kerogen volume. The Uma equation is given by:

VPYR = 2.32*UMA-18.69 ……(3)
VPYR=Volume of pyrite (%)

Total clay volume is correlated with TOC and given by:

Tclay=0.2169*TOC^2-7.2187*TOC+72.784 (rsqrd=0.68) ……(4)

Tclay= total clay volume (%)

The three volumes for kerogen, pyrite, and total clay are then input along with log inputs of density, neutron, Uma, and sonic with appropriate end point response to a multi-linear equation solver to determine the final volumes of quartz, limestone, dolomite, and porosity. The number of inputs available, limits the solved for constituents, and generally the feldspars and plagioclase have been lumped into the quartz volume.

Water Saturation

The water saturation to this point in the modeling has been determined using Dual Water and calibration to core saturation results. This has been done due to large uncertainty with salinity and electrical properties (a, m, and n). These parameters have been adjusted to match core results and are given by:

Salinity connate water = 31,000 ppm NaCl

Salinity bound water = 8000 ppm NaCl

a= 1

m=2

n=1.7 +Vkero (from previous GRI work in the Devonian shale Appalachian)

Adsorbed Gas, Free Gas, and Oil Saturation

The adsorbed gas content is calculated from the isotherms (see Figure 5) and given by the equation:

Ads_Gas=(164.0*P/(P+1322.7))*TOC/10 ……(5)

Where:

Ads_Gas	= Adsorbed gas content (scf/ton)
P	= Pressure (Western Ky. is subnormal, gradient 0.33 psi/ft)
164	= Langmuir Volume
1322.7	= Langmuir Pressure
TOC/10	= Data is normalize to 10% total organic carbon

Core samples report oil saturation in some of the New Albany to range from 30-70%. This oil takes up space and must be accounted for when determining free gas. Efforts to breakout oil saturation using the geochem reported S1 have failed to date. Continued work will need to be done in year two of the project. The oil saturation is therefore being assumed at 50% based on core. This will be revised in the upcoming Ngas drill well. The free gas saturation and associated bulk volume free gas is then backed out as is illustrated in Figure 6 and represented in the following equation.

BVG_F = 1-BVW-BVO-BV_ADGAS …….(6)

Where:

BVG_F	= Bulk volume free gas
BVW	= Bulk volume water
BVO	= Bulk volume oil
BV_ADGAS	= Bulk volume adsorbed gas

The calculation of BV_ADGAS is done by first calculating shale volume, getting shale density from log or core and assuming a liquid methane density of 0.9 g/cc. Accounting for adsorbed gas in the process of determining free gas is unique to this study.

Figures 12 and 13 respectively show log analysis results from Webster County, Kentucky , the CNX well and from Christian County, the Orbit Clark well. Note core results shown in the CNX well and the impact of the oil saturation on total gas in place in the Clark well. Adsorbed gas and free gas are calculated and then a cumulative total gas is presented on the far right track in both plots.

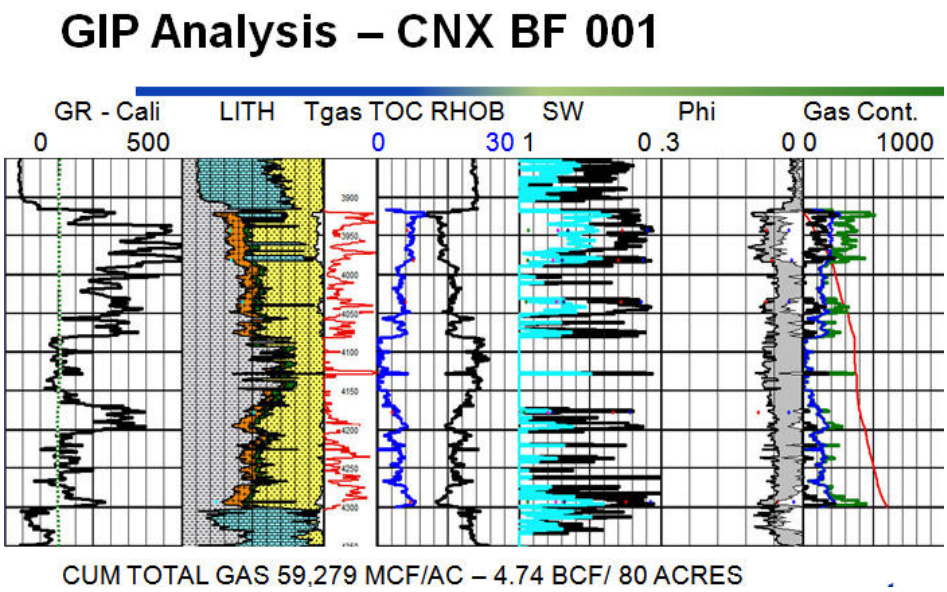


Figure 12 –Gas is in Mcf/acft (0-1000) and the Cum gas (red curve) is in Mcf/ac scaled 0-100,000

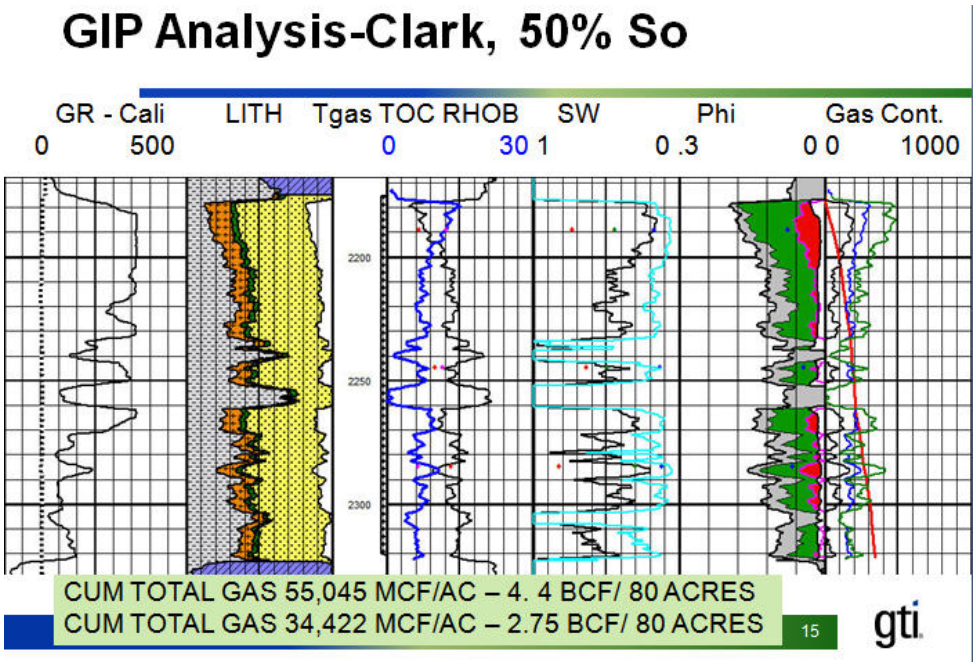


Figure 13—Note the impact of 50% oil saturation on the gas in place result. Gas and Cum gas scales are the same as Figure 12.

Geochemical Properties

Based upon the Rock Eval pyrolysis analyses available a number of correlation are made such that a geochem log can be derived from log inputs specific to the Vigo County, Indiana area. These data are limited at this point but we will expand this based on the Ngas data acquired in Western Kentucky. Figure 14 displays the results from the correlations. Note there is good agreement with the core.

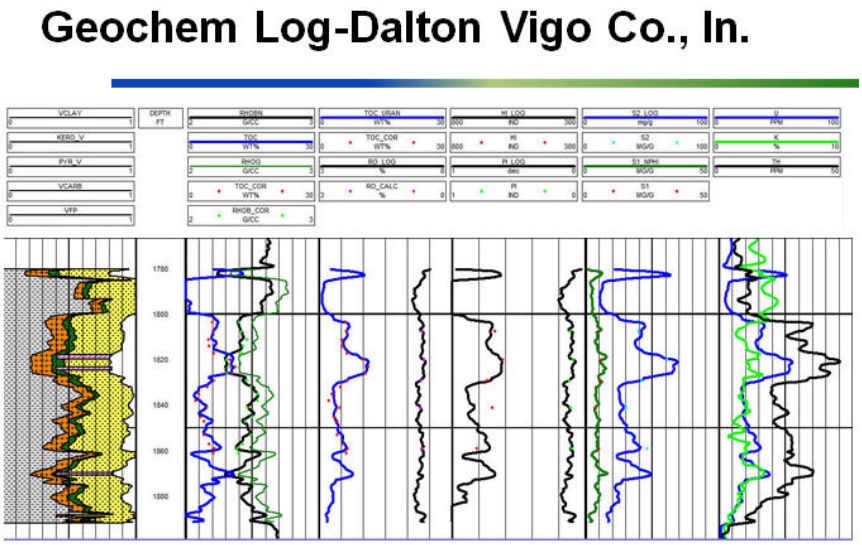


Figure 14—A geochem log derived from correlation of Rock eval – pyrolysis results in Vigo County, Indiana. The correlations used to generate the plot above are shown below in Figures 15-17.

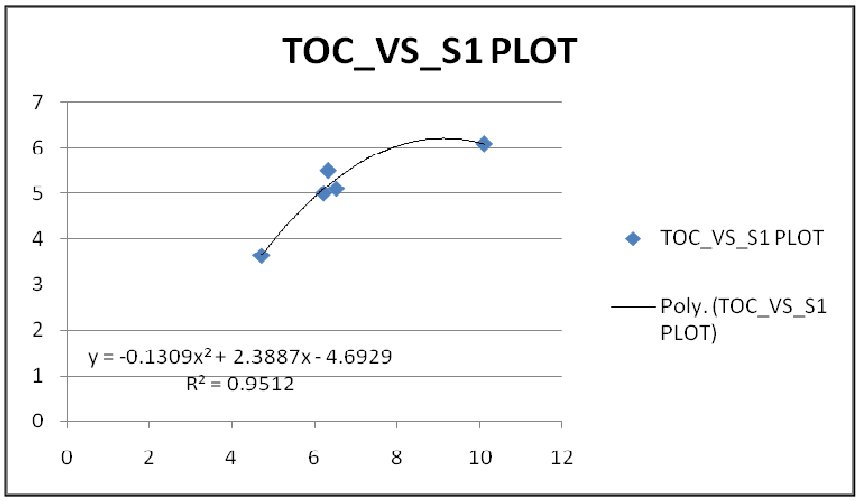


Figure 15—TOC in the x-axis and S1 in the Y axis. S1 is related to the bitumen/oil that has been generated.

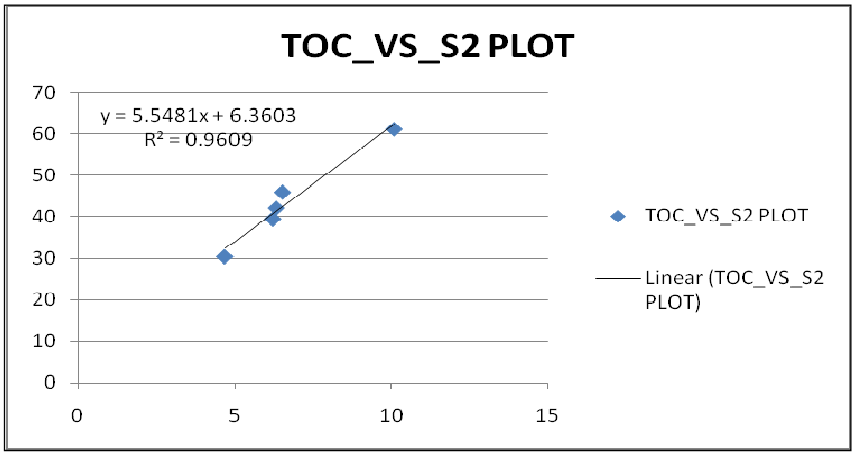


Figure 16—S2 related to the remaining generative capacity of the shale is plotted in the Y axis versus TOC in the X axis.

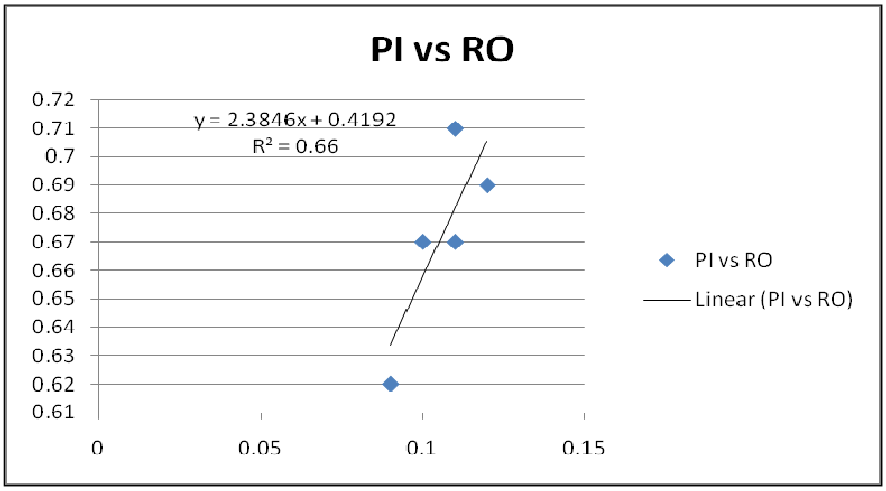


Figure 17 – PI the production index is plotted in the X-axis against Ro, the vitrinite reflectance in the Y axis.

From values of S1 and S2 you can compute values for PI, HI, and OI (see Table 6).

Stress Profiles

Limited dipole sonic data are available for calculation of mechanical properties such as Young's modulus, Poisson's ratio, and resulting closure stress and "brittleness". Results of the single case from the CNX well are shown in Figure 18. The closure stress is un-calibrated and there is no available data to allow correction for potential anisotropy. The closure stress was calculated in the same manner as put forth by Holditch and Voneiff. Brittleness is calculated as presented by Grieser et al, Halliburton in SPE 115258. Additional work should to be done in year two, if the data are available.

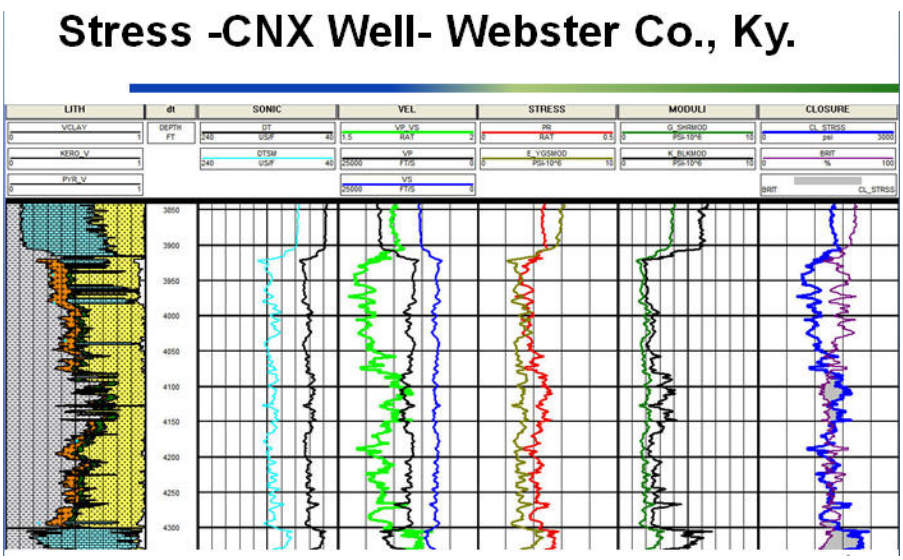


Figure 18—Closure stress (blue curve far right) plotted against "brittleness". Theoretically the gray shading might represent frac boundaries but the model is currently not calibrated.

Image Analysis –Fracture Characterization

The only image log data available to date is from the Noble Energy well, Osburn Trust #1-1H in Sullivan County, Indiana. Preliminary results from this analysis indicate a conjugate set of largely partially open natural fractures dipping NNW-SSE and having strike of ENE-WSW. These fractures are generally very

high angle. Figure 19-22 display these results. More work delineating the fracture character in Western Kentucky will be undertaken using the Compact Micro-Imager that is to be run in the Ngas well (late July-August 2009).

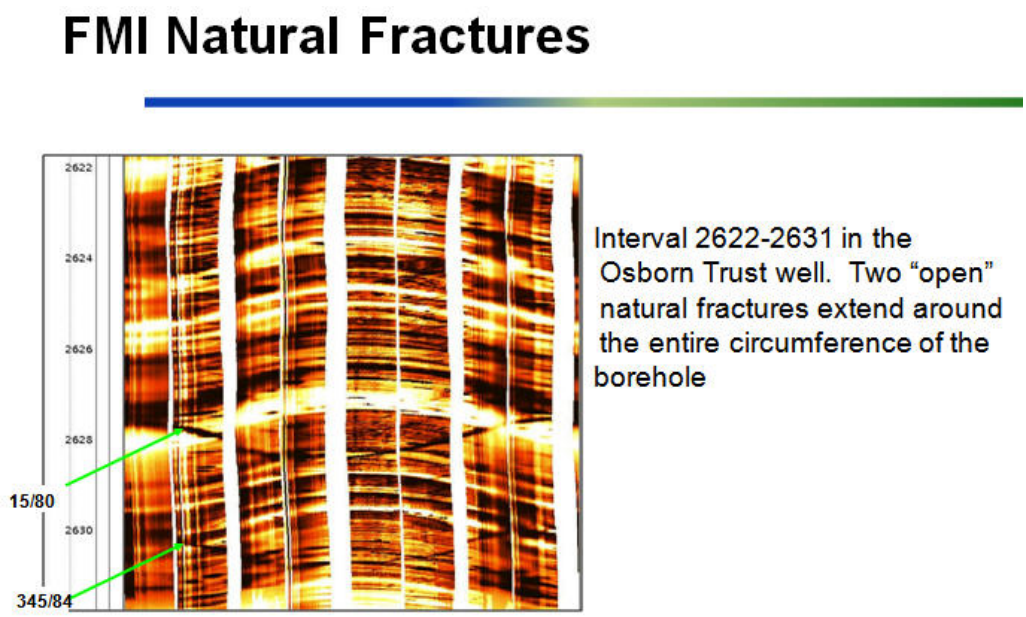


Figure 19—FMI image showing two open natural fractures with 80 and 84 degree dip each within 15 degrees of North

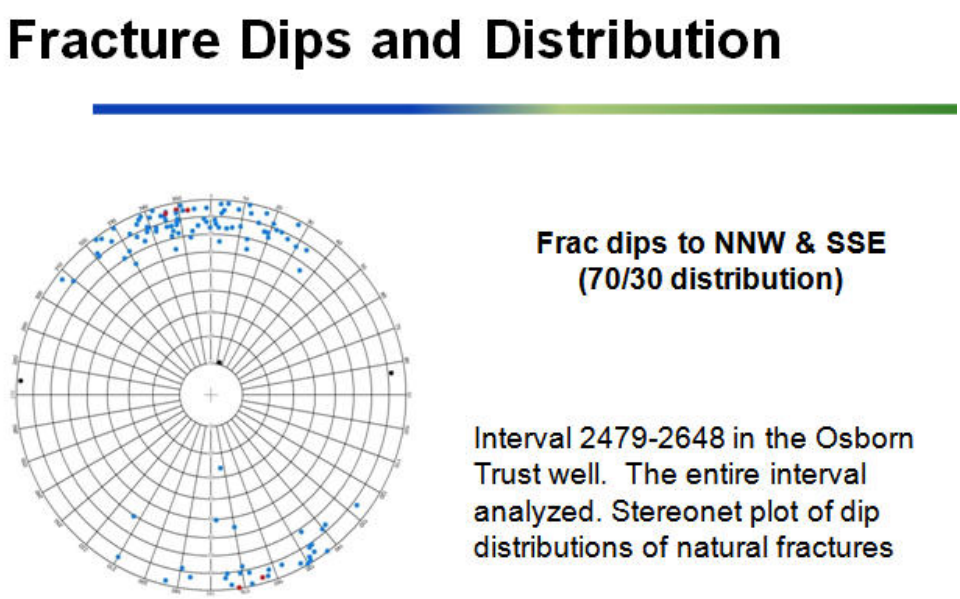


Figure 20 – Stereonet of fracture dip and distribution – note two E-W dipping induced fracture interpreted.

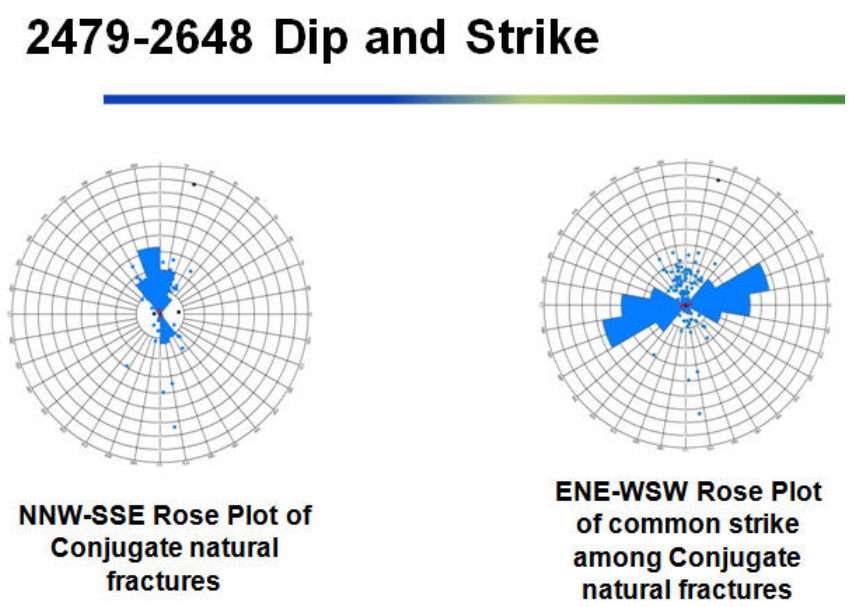


Figure 21—Fracture Dip and Strike natural fractures – Osburn Trust #1-1H

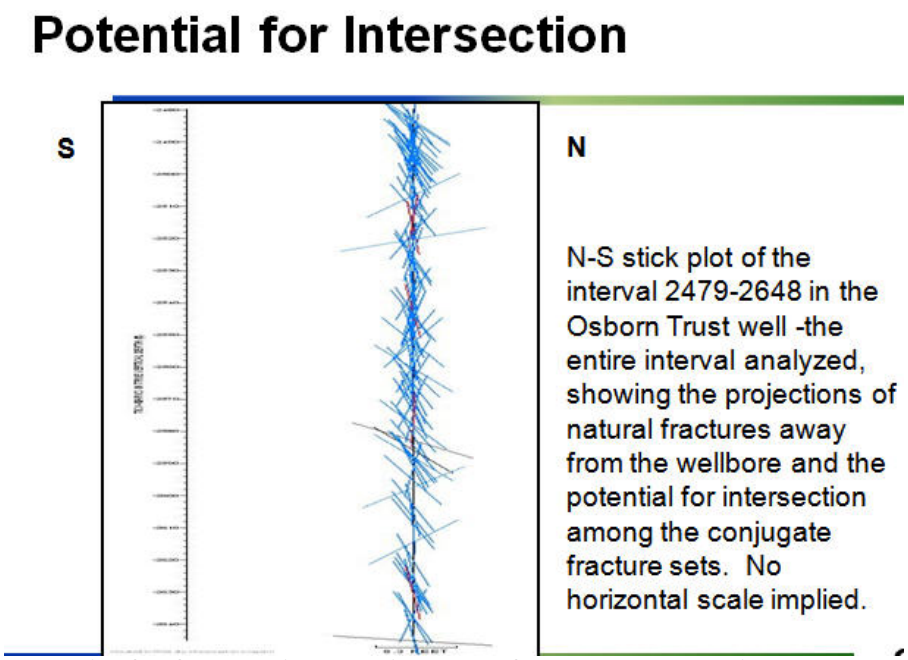


Figure 22—Potential for fracture intersection away from the wellbore is present here. Plots of this type may aid us in modeling fracture density for simulation and completion.

In making interpretations of data, our employees and consultants will give the customer the benefit of their best judgment, but since all interpretations are based on inferences from electrical or other measurements, we cannot, and we do not guarantee the accuracy of the correctness of an interpretation. We shall not be liable or responsible for any loss, cost, damages, or expenses whatsoever incurred or sustained by the customer resulting from any interpretation made by any of our employees or consultants.

Reservoir Engineering/Reservoir Performance

As a summary of work to date, we provide a complete production analysis of the Daugherty Petroleum Well DPI-2477 in Christian Co., KY. The data for this case were provided by Daugherty Petroleum (aka NGAS), a partner in this project. The production history for this case is provided in **Fig. 1**, where we note a complete rate history, but an intermittent wellbore pressure history. From our enquires to Daugherty Petroleum we found that the pressure data were not taken continuously towards the end of the given history as the well "went to line pressure" — so we simply created a pressure history that approximated the traverse to "line pressure," and we believe that this is a reasonable approximation of the actually wellbore pressure history.

According to the drilling, completion, and well stimulation records provided for this well — a lateral section of approximately 3000 ft was created and 8 (eight) separate fracture stimulation treatments were applied (only nitrogen was used as a stimulation fluid, and no proppant was used). This treatment suggests that we will observe the signature for a horizontal borehole, possibly the influence of the fractures, although it is expected that the hydraulic fractures will be of low conductivity. This is the base model for our analysis.

Model-Based Analysis

The model-based matching results for this analysis are provided in the table below

Figure	Reservoir Model	Model Type	Boundary	G (BSCF)	k (md)	L_{well} (ft)	x_f (ft)	F_{cD} (---)
Fig. 2	Horizontal Well (No Fracture)	Analytical	5x1 Rectangle	0.515	0.019	3000	N/A	N/A
Fig. 3	Horizontal Well (No Fracture)	Numerical	11.4x1 Rectangle	0.146	0.019	3000	N/A	N/A
Fig. 4	Horizontal Well (With 8 Fractures)	Analytical	Infinite-Acting	N/A	0.019	1350	200	3.42

In **Fig. 2** (*Analytical* Solution for a Horizontal Well in a Bounded Rectangle, No Fractures), we note that the pressure and flowrate history are matched reasonably well, the estimated gas-in-place (0.515 BSCF) is a somewhat subjective estimate, and should be considered to be an "order of magnitude" type of estimate. The specified horizontal well length was fixed at 3000 ft, the "matching" process centered on the size of the rectangular boundary. In **Fig. 3** (*Numerical* Solution for a Horizontal Well in a Bounded Rectangle, No Fractures), we obtained a very good match of the performance data — although the rate and pressure matches at intermediate and late times are a bit overestimated, we elected not to reduce the size of the rectangular boundary further in order to improve the match. We believe that the gas-in-place estimate of 0.146 BSCF is a "lower bound," and represents only the *contacted-gas-in-place* during the time of this production sequence.

The final case considered is that of **Fig. 4** (*Analytical* Solution for a Horizontal Well in an Infinite-Acting Homogeneous Reservoir with Multiple Transverse (Vertical) Fractures). This case provides (by far) the

best match of the well performance data, and should be considered the most likely scenario. The only significant assumption made in this analysis was to reduce the horizontal well length from 3000 ft to 1350 ft as a means of obtaining a "best fit" of the data. The most used in this case represents *transient flow only*.

Simplified (Compound Linear Flow) Analysis

While less "rigorous" than the model-based analyses, we would like to put forth the concept of "compound linear flow" as validated by the use of the *Solution for a Horizontal Well in an Infinite-Acting Homogeneous Reservoir with Multiple Transverse* (*Vertical*) *Fractures* (results shown in **Fig. 4**). In **Fig. 5** we provide the schematic of the horizontal well with transverse vertical fractures proposed by van Kruysdijk and Dullaert [1989] to represent the compound linear flow regime. In **Fig. 6** we provide the computed productivity index versus time on a log-log plot — the straight-line portion of the trend (at "late" times) most likely confirms the concept of "compound linear flow" — which validates that this well is still producing in the transient flow regime.

Reserves Analysis using Power-Law Exponential Rate Decline Model

The "power-law exponential" rate decline model is introduced as a mechanism to analyze/forecast the reserves of tight gas/shale gas wells by Ilk *et al* [2008]. While this model is empirical, it has been shown that this relation is very flexible to model transient, transition and boundary-dominated flow regimes encountered during production and yield robust reserve estimates. In **Fig. 7** we provide the "*q-D-b*" plot for this well and present the application of the power-law exponential rate model. This relation suggests a maximum cumulative gas production estimate between 0.35-0.62 BSCF.

Figure	Forecast Model	Model Type	$G_{p_max_upper}$ (BSCF)	$G_{p_max_lower}$ (BSCF)
Fig. 7	Power-Law Exponential	Empirical	0.62	0.35

Future Work

Daugherty Petroleum has agreed to provide numerous cases of production data for their New Albany Shale assets (approximately 25 wells were drilled in the last 2 years, but only a few of these are horizontal wells (less than 5)). We will continue our work on the analysis of production data as well as attempt to verify "unique" features for the performance of horizontal well completions in the New Albany Shale.

Acknowledgements

All of the model-based analyses in this work were performed using the software package *Ecrin*, by Kappa Engineering — and the academic license of this software for Texas A&M University is gratefully acknowledged.

References

Ecrin (2009) Kappa Engineering (www.kappaeng.com).

Ilk, D., Perego, A.D., Rushing, J.A., and Blasingame, T.A. 2008. Exponential vs. Hyperbolic Decline in Tight Gas Sands — Understanding the Origin and Implications for Reserve Estimates Using Arps' Decline Curves. Paper SPE 116731 presented at the SPE Annual Technical Conference and Exhibition, Denver, Colorado, 21-24 September.

van Kruysdijk, C.P.J.W. and Dullaert, G.M. 1989. A Boundary Element Solution of the Transient Pressure Response of Multiply Fractured Horizontal Wells. Paper presented at the 2nd European Conference on the Mathematics of Oil Recovery, Cambridge, England.

Illustrations

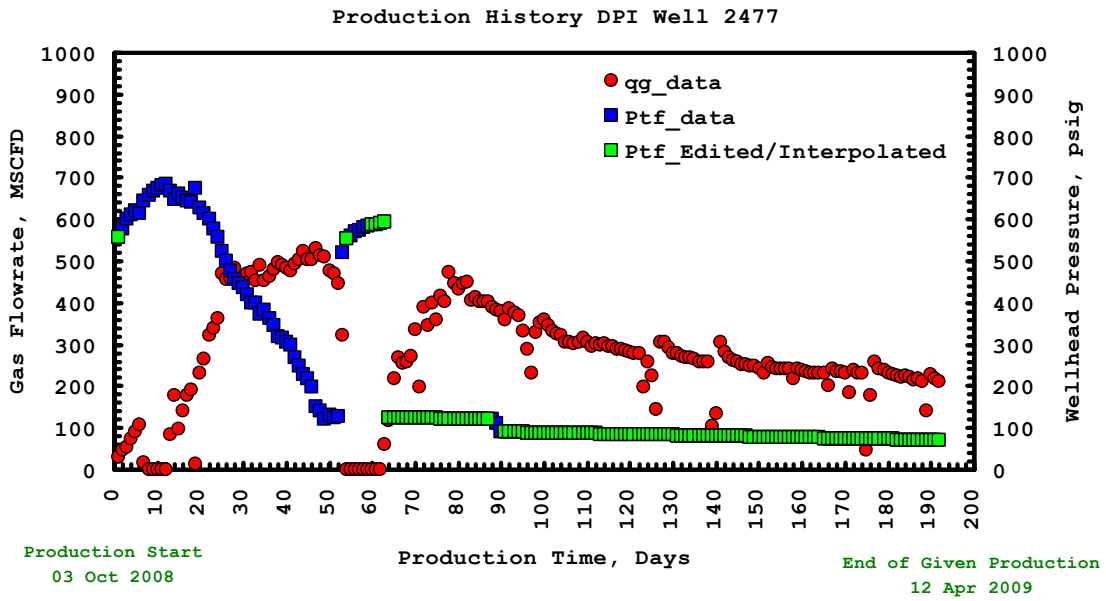


Figure 1: Daugherty Petroleum Well DPI-2477 in Christian Co., KY — Production history plot. Not the sections of edited and interpolated data.

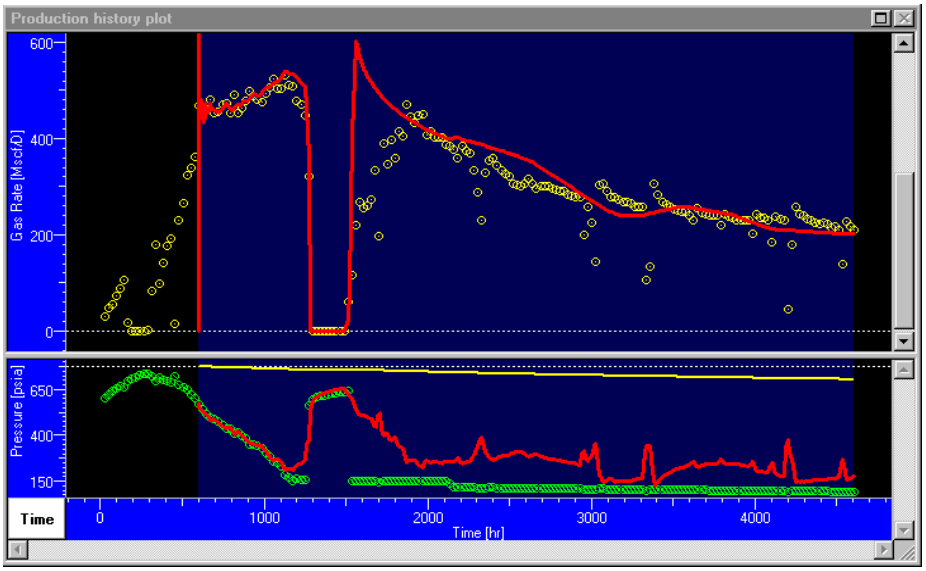


Figure 2: Daugherty Petroleum Well DPI-2477 in Christian Co., KY — Production rate and pressure history match using a horizontal well (analytical solution) with a 5x1 rectangular reservoir boundary. No fractures are included.

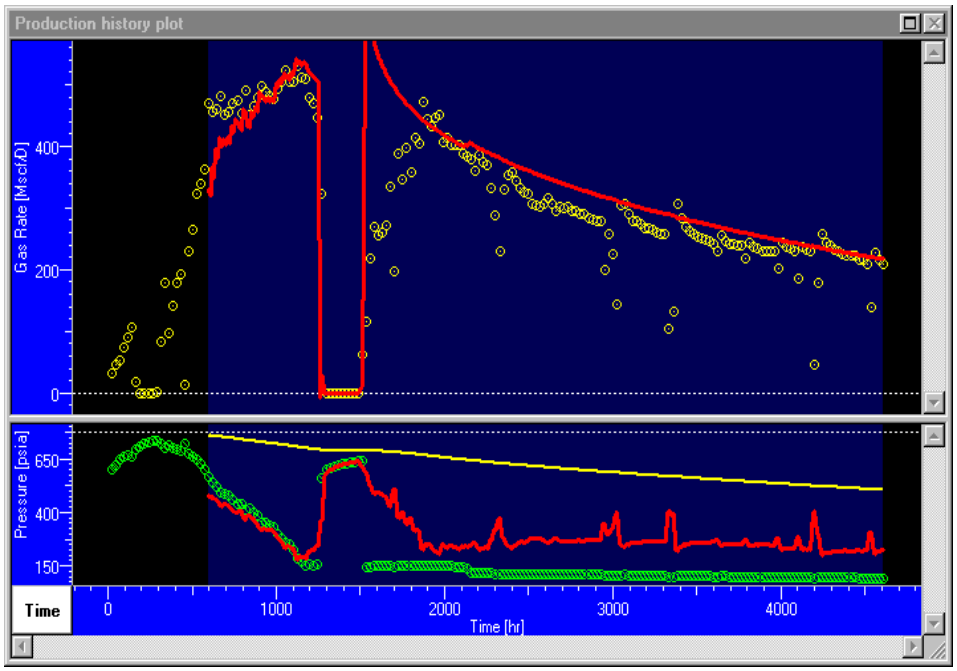


Figure 3: Daugherty Petroleum Well DPI-2477 in Christian Co., KY — Production rate and pressure history match using a horizontal well (numerical solution) with an 11.4x1 rectangular reservoir boundary. No fractures are included.

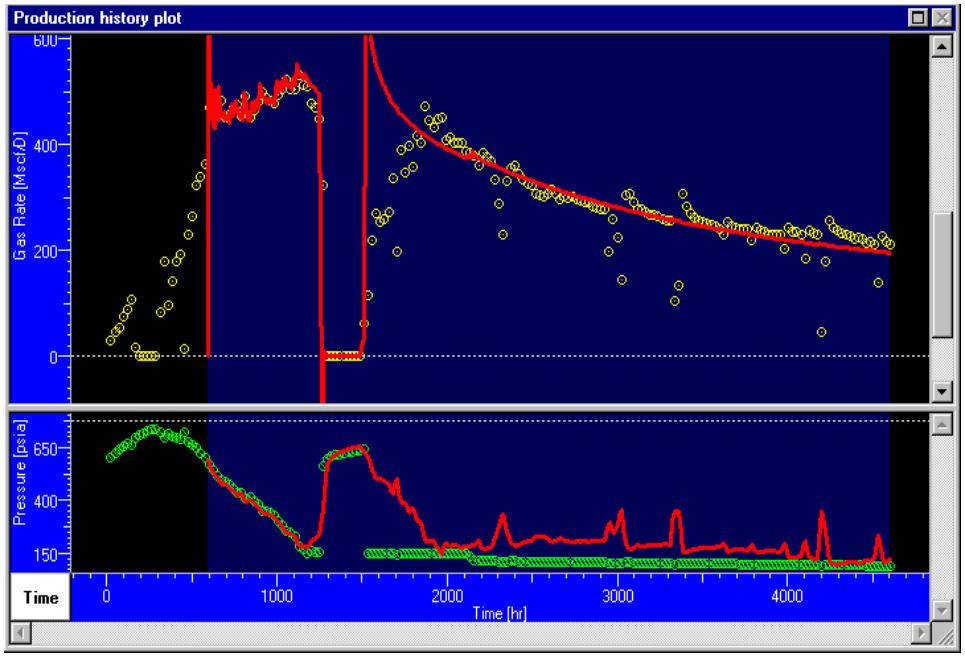


Figure 4: Daugherty Petroleum Well DPI-2477 in Christian Co., KY — Production rate and pressure history match using a horizontal well (analytical solution) with 8 *transverse* (hydraulic) fractures — infinite-acting homogeneous reservoir.

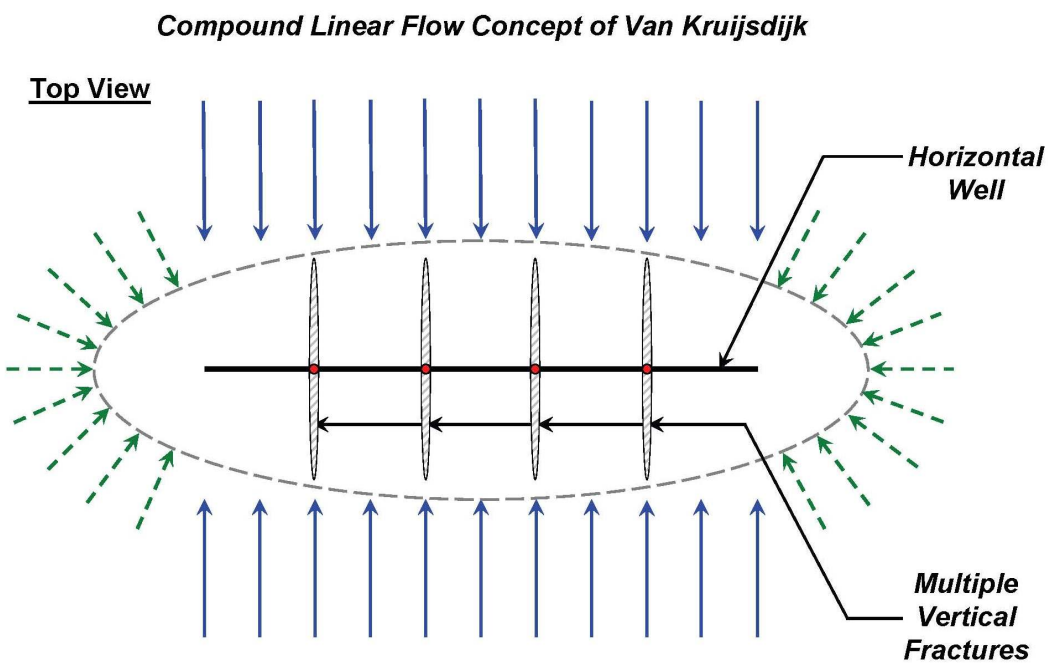


Figure 5: Schematic Plot: Compound linear flow concept of van Kruijsdijk and Dullaert [1989].

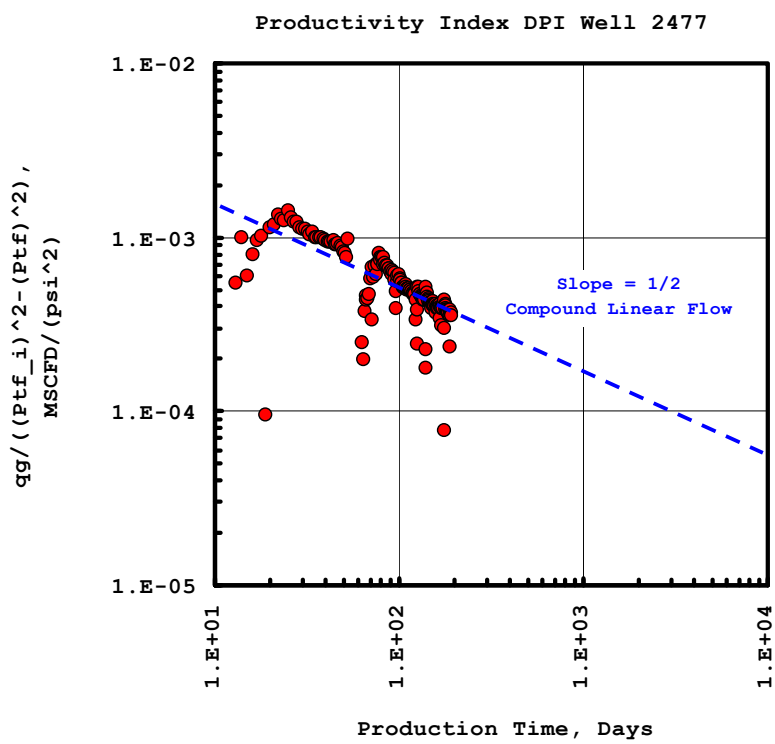


Figure 6: Daugherty Petroleum Well DPI-2477 in Christian Co., KY — Productivity Index Plot. Note the presence of "late-time" linear flow — most likely the "compound linear flow" regime as proposed by van Kruysdijk and Dullaert [1989].

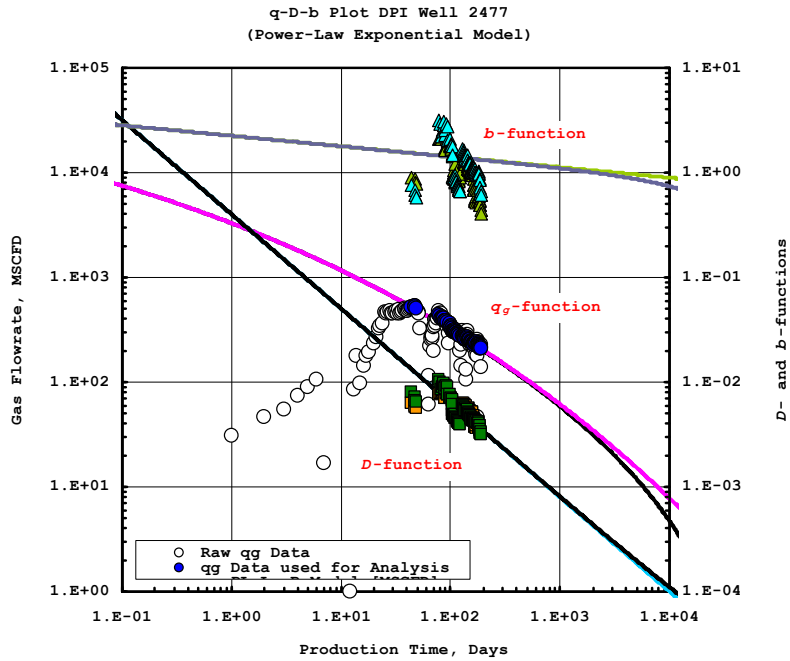


Figure 7: Daugherty Petroleum Well DPI-2477 in Christian Co., KY — "*q-D-b*" Plot. "Power-Law Exponential" rate decline model indicates the maximum cumulative gas production is in the range of 0.35-0.62 BSCF.

Pressure Transient Analysis

Recent work at Texas A&M University has shown promise for unified analysis of pressure transient and production data. The approach is to combine analysis of a selected pressure buildup with long term production data processed as rate normalized pressure. The rationale for this approach is the observation that neither pressure buildup data nor production data on their own can provide a complete view of the well and reservoir performance. Pressure buildup transients can provide insights about the well completion and heterogeneity near the well, but the depth of investigation for the pressure buildup analysis is limited by the duration of time the well is shut in and by the formation diffusivity, which is a function of mobility divided by the porosity-compressibility product. Also, pressure buildup transients are distorted by superposition in time, particularly as the elapsed time during shut in is increased. Production data are difficult to analyze because normal well operations frequently result in fluctuations in rate that mask the trends that may reveal well and reservoir properties of interest. However, for obvious reasons, most of the data recorded for any well are production data. Methods that can get useful information from production data offer potential for characterizing the effective completion geometry for horizontal and/or massively hydraulic fractured wells, as well as for characterizing well drainage limits and geometries.

Production data for Well DPI 2477 are shown in Fig. 1. Pressure and rate data have been recorded on a daily basis for a period of 58 days. After 6 days on production, the well was shut in for 4 days (period highlighted in the figure); and after one year on production, the well was again shut in. Pressures were recorded at the surface. Using the procedure described in Ehlig-Economides, et al (2009), data from the first buildup test were combined with production data processed as rate-normalized pressure (RNP). The two responses in combination were back integrated to give the virtual drawdown response shown in figure 2.

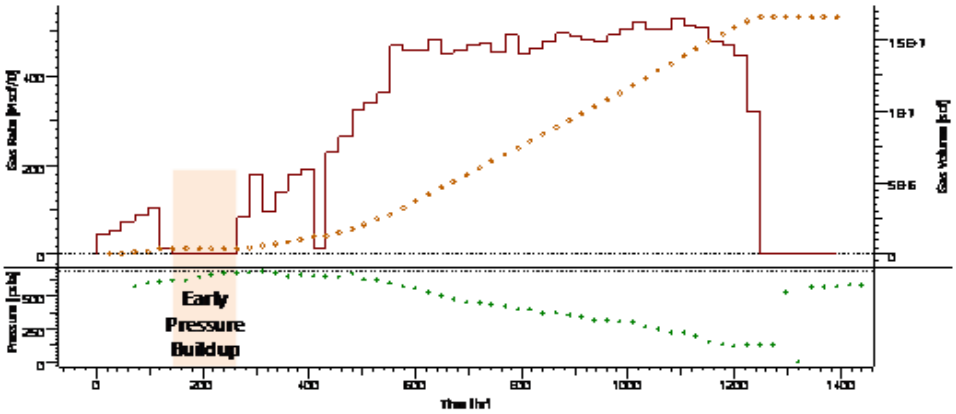


Figure 1: Pressure and rate data for Well DPI 2477

This approach is new. The RNP processing indicated in Ehlig-Economides et al (2009) is different from what is currently done in commercial software and leads to a much more coherent result. However, with only daily data for the buildup and only 58 days on production, it is not yet possible to offer a unique model for the data. The model shown in Fig. 2 is only conceptual. Because we know the well was horizontal and hydraulically fractured, we have selected a hydraulic fracture model for the virtual drawdown. Models do not exist in commercial software for the drawdown response of parallel transverse fractures in a horizontal well, and model development was not included as a deliverable for this project. However, Fig. 3 justifies the single hydraulic fracture as an approximate starting point. Basically, the concept is to model the set of transverse fractures acting as a group like a single long infinite conductivity hydraulic fracture. This model has permeability of about 0.6 microdarcies and an effective fracture length of 2800 ft.

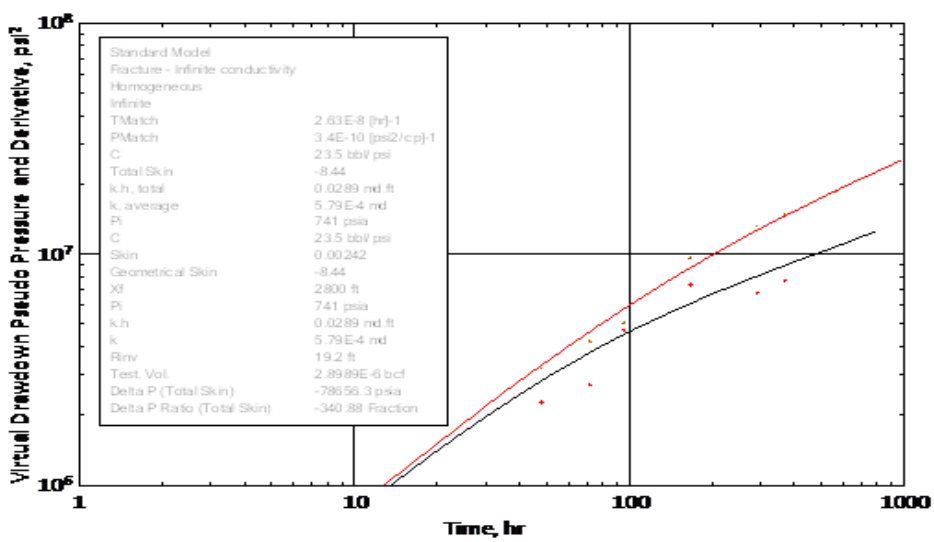


Figure 2: Virtual drawdown response using combined buildup and rate-normalized pressure, with model and parameters shown in the insert

Although these results are preliminary, they are encouraging, and they suggest something about data acquisition. First, if the gauge can be equipped to record data at a higher data rate when the well is shut in, buildup data may offer more detail about flow near the well. Second, we can continue to monitor this well to see whether the response continues to reflect primarily linear flow. The RNP analysis technique works even as the well goes on rate decline. As long as the linear flow response prevails, we cannot be sure of the reservoir permeability. At 0.6 microdarcies, it would appear that microfractures must provide permeability because shale permeability without microfractures would very likely be less. Depending on the permeability and the effective fracture length, the data may stay in a linear flow trend for the productive life of the well.

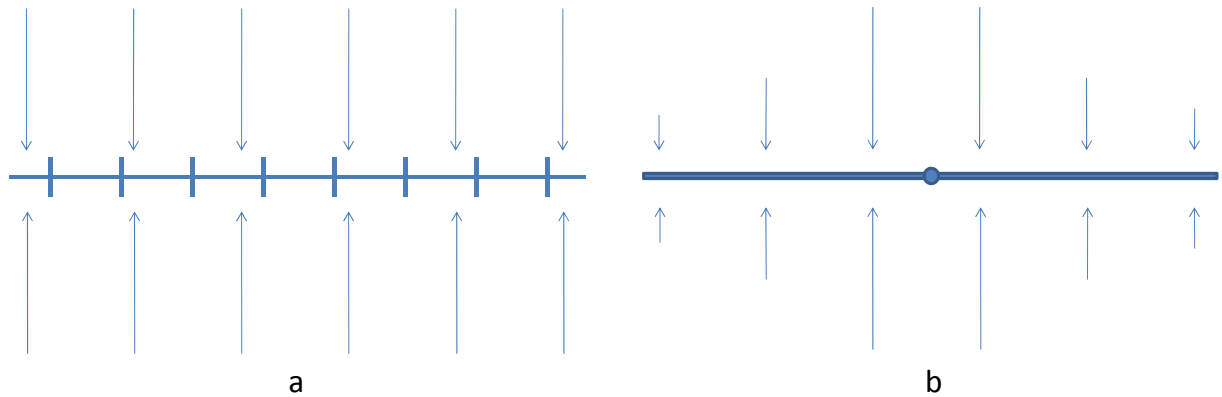


Figure 3: The horizontal well with 8 transverse fractures (a) is modeled like a hydraulic fracture with 1400 ft half length (b). The difference is that the transverse fractures enhance well productivity along the entire well length,while massive hydraulic fracture would probably have lower conductivity. Hence, the stream lines are shown with lower flow contribution near the fracture tips.

Fracture Modeling

PI: Ahmad Ghassemi, Texas A&M, Department of Petroleum Engineering

I. Analysis of Reservoir Response to Stimulation by Hydraulic Fracturing

1. Structural Permeability

When injecting into a well or a hydraulic fracture, the pore pressure effects on the sliding of joints and rock mass failure are of interest. The joint response can be analyzed and used to create a structural permeability diagrams that show the ΔP required to reactivate fabrics of different orientations. Also, by considering the stress and pore pressure distribution around a hydraulic fracture the extent of the rock mass failure can be estimated to estimate the stimulated reservoir volume. In this part of the report we describe both techniques, the first approach is applied to predict the pore pressure change, ΔP, required to reactivate fabrics of different orientation in the well J Ray Clark in Christian County, KY. The second method is applied to data from stimulation of Barnett shale to illustrate its potential.

1.1 The Sliding of joints with injection into a well

To determine the slip of joints, a failure criterion is employed. There are many failure criteria for the sliding of jointed rock masses. In this work we use the Mohr-Coulomb failure criterion :

$$|\tau| = c + \sigma_n' \tan\phi' \quad (1)$$

in which τ is the shear stress on the joint plane, c (in some references given by τ_s) is the shear strength or cohesive strength or cohesion of that joint, σ_n' is the effective normal stress (σ_n-p), on the joint and ϕ' is the joint friction angle, and sometimes $\tan\phi'$ can be replaced by μ, the coefficient of friction. The above criterion can be used to study the effects of increasing pore pressure on rock failure by generating a structural permeability diagram that shows ΔP required to joints of different orientations (Mildren *et al*. 2002; Nelson *et al*. 2007). It can be seen in Fig. 1 from Nelson *et al*. 2007, the structure permeability diagram is set up based on the dip angle δ and the angle from north to the dip direction of the joints φ (clockwise positive). Here, the dip angle refers to the angle between the joint plane and the horizontal plane; and the dip direction is really vertical to the strike of the joint.

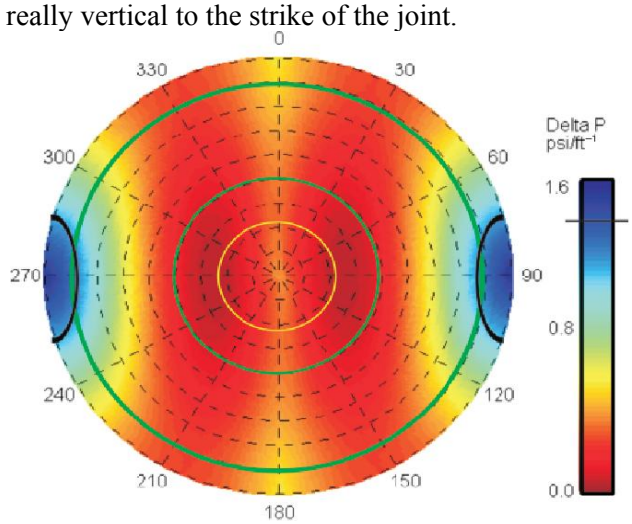


Fig.1 Structural permeability diagram for the Cooper Basin (Nelson *et al*. 2007).

To obtain this structural permeability diagram for a given stress state in the formation, all possible joint orientations are the direction cosines of the principal stresses are first found using the known dip angle and dip direction angle. To do so, first the direction cosines of the normal to the weakness plane with respect to the 3 principal stress directions ($\square_H$, $\square_h$, $\square_v$) should be found. To do this we use the expressions in Goodman (1989) for finding the direction cosines (d_x, d_y, d_z) for the normal relative to the X, Y and Z coordinates (by setting the principal stress directions to ($\square_H$ =X, $\square_h$ =Y, $\square_v$ =Z). However, instead of using the dip angle (δ) and the dip direction (φ), Goodman used the rise angle and the angle of the horizontal projection of the normal to the joint from the X-axis (counterclockwise). The relations between those angles are easily found and used to modify the expression in Goodman. By setting $\square_H$, $\square_h$, $\square_v$ to the $\square_1$ $\square_2$, $\square_3$ as appropriate, the calculation provide the direction cosines with respect to the principal stresses. Rearranging Eqn (1), yields the expression for the required pore pressure to reactivate the joint plane:

$$P = \sigma_n + (c - \tau) / \mu \quad (2)$$

Then the *effective treating pressure*, ΔP, is given by:

$$\Delta P = P - P_p \quad (3)$$

in which P_p is the original in situ pore pressure.

We have developed a model to calculate the effective treating pressure for activating all possible joint orientations for a given in-situ stress and pore pressure. The model automatically generates a structural permeability diagram. To verify the calculations, the model is first applied to the special case given by Nelson *et al.* (2007) for the Cooper Basin stimulation experiment (Figure 1).

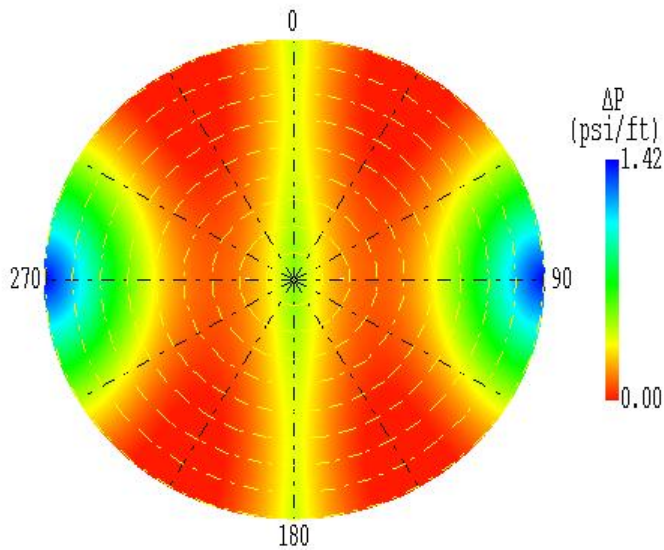


Fig.2. Structural permeability diagram generated in this study. It shows orientations of joints that may be reactivated during stimulation in Cooper Basin.

Table 1. Parameters used for Cooper Basin (Nelson *et al.* 2007) .

$\sigma_{H\max}$ (psi/ft)	1.85	E-W direction
$\sigma_{H\min}$ (psi/ft)	0.84	N-S direction
σ_V (psi/ft)	0.95	Vertical
P_p (psi/ft)	0.433	
μ	0.6	Tensile negligible
H (ft)	9800	

Table 2. Otway Basin Data from Mildren *et al.* (2005).

$\sigma_{H\max}$ (MPa/km)	37.1	156 º N
$\sigma_{H\min}$ (MPa/km)	16.1	Normal to $\sigma_{H\max}$
σ_V (MPa/km)	22.4	Vertical
P_p (MPa/km)	9.8	
M	0.8	Tensile negligible
H (km)	3	

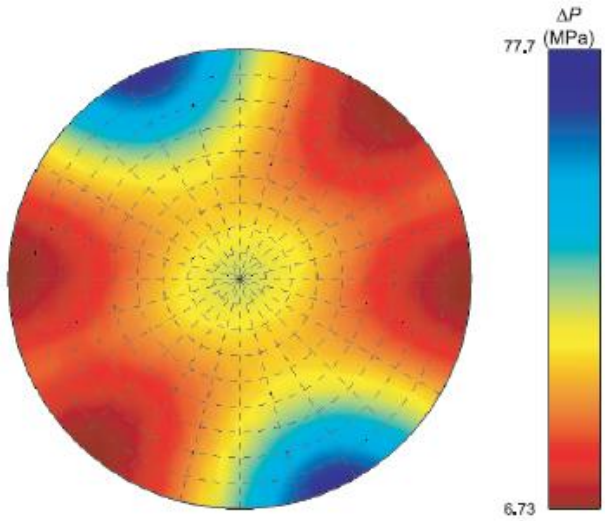


Fig. 3 Structural permeability diagram for Otway Basin (Mildren *et al*. 2005)

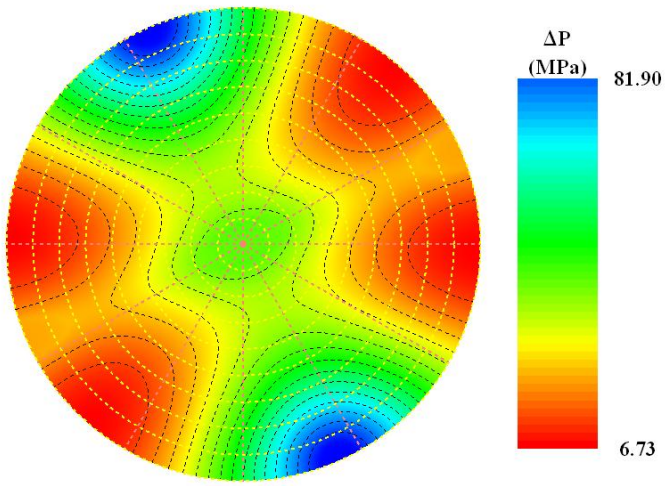


Fig. 4 Calculated structural permeability diagram for Otway Basin.

By comparing Fig.9 with Fig.8, generally good agreement is observed. In order to further verify the results, we simulated the data of Mildren *et al*., 2005. The structural permeability maps are shown in Figures 3 and 4. Minor difference can be attributed to uncertainty in the input data used.

1.1.1 Stimulation New Albany Shale (J. Ray Clark well)

The structural permeability diagram showing the orientations of geological weaknesses that may be reactivated during fracture stimulation treatments at high treating pressures in the New Albany Shale is plotted as in the following figures. According to the data from J Ray Clark well in Christian County, KY, we assume that the principal stresses are σ_1=2500 psi (vertical), σ_2=2200 psi (East horizontal), σ_3=2000 psi, and pore pressure P_p=1800 psi with μ=0.6, and cohesion zero. As shown in Fig.5, the maximum required effective treating pressures are located in areas with low dip angles, and the minimum required effective treating pressures are located in the areas with dip angles around 50º-70º and dip directions between -30º N and 30º N, 150º N and 210º N.

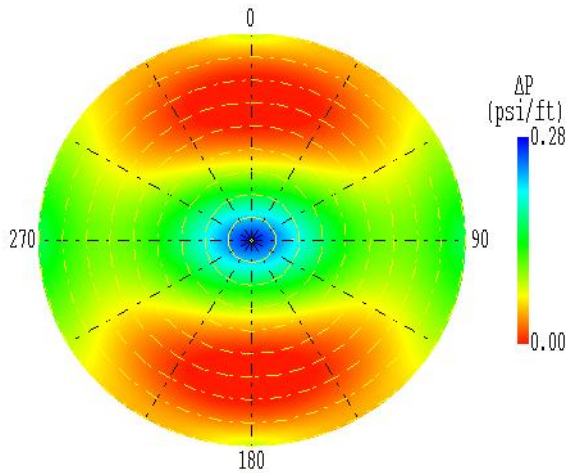


Fig.5 Structural Permeability Diagram for New Albany Shale (μ =0.6)

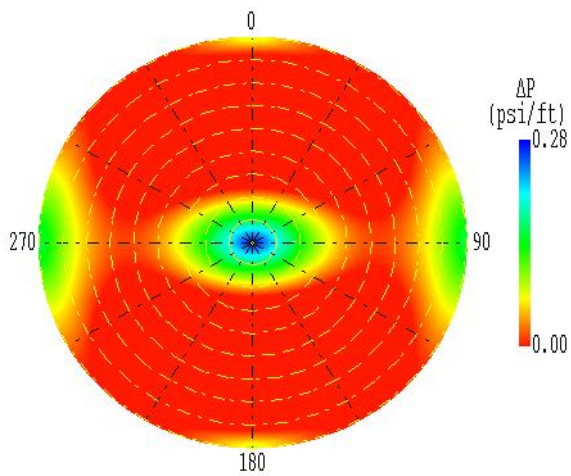


Fig.6 Structural Permeability Diagram for New Albany Shale (μ =0.3)

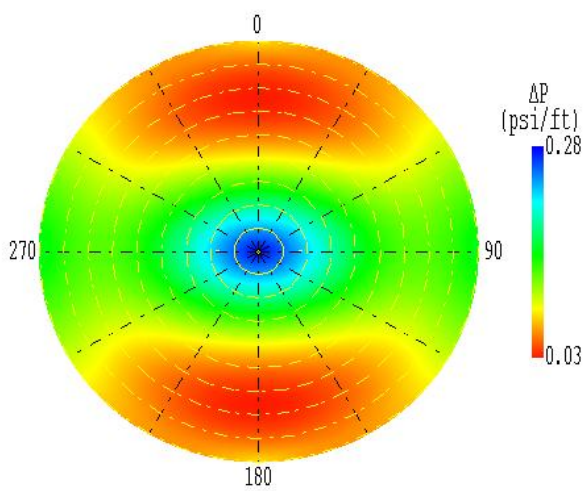


Fig.7 Structural Permeability Diagram for New Albany Shale (μ =0.9)

Fig. 6, and 7 show the sensitivity analysis of the results to the friction coefficient of joints. It can be seen that with the increase of friction coefficient, the failure of certain joints require larger effective treating pressures. This underscores the necessity of rock data for accurate prediction of stimulation requirements and outcomes.

2. Injection into a hydraulic fracture: stimulated volume

In previous Section, we studied the sliding of joints during injection into a well. In this part, we will consider the failure of rock mass around a hydraulic fracture. Shear failure of the formation occurs outside a hydraulic fracture and is caused by pore-pressure and stress perturbations. This can have a significant impact on permeability around a hydraulic fracture, and therefore on production. In this work, the pore pressure distribution after hydraulic fracturing is calculated and the failure of rock in the reservoir is studied by employing the Mohr Coulomb failure criterion. Then, the enhanced permeability of the formation is estimated by matching the failed reservoir volume and the volume of the microseismic cloud, using injection permeability as the matching parameter. To verify the method used for the prediction of failed reservoir volume, the parameters from the Barnett shale case study of Palmer *et al.* (2007) are used.

2.1. Pore pressure needed to cause rock mass failure

There are many other criteria for the failure of rock masses, such as Mohr-Coulomb criterion, Drucker–Prager yield criterion (1952), Bieniawski criterion (1974), Hoek and Brown criterion (1980), and Ramamurthy's criterion. Palmer, *et al.* 2007, used Drucker–Prager yield criterion (Drucker and Prager, 1952). However, in this study we use the Mohr-Coulomb failure criterion (Eqn. 1) which can be expressed in terms of effective principal stresses as to give the peak effective principal stress:

$$\sigma_1' = q_u + \sigma_3' \tan(45 + \phi'/2) \quad \text{.....} \quad (5)$$

In which $q_u = 2c\tan(45 + \phi'/2)$. Equation (5) can be solving for pore pressure needed to cause failure of a rock mass that in initially in a state of stress defined by σ_1 and σ_3 ::

$$p_w = \sigma_3 - \frac{(\sigma_1 - \sigma_3) - q_u}{\tan^2(45 + \phi'/2) - 1} \quad \text{.....} \quad (6)$$

Also, an approach similar to the previous Section might be used to determine a structural permeability map for regions surrounding the hydraulic fracture.

2.1.1. Pore pressure distribution around fracture

The pore pressure increase in the reservoir can be approximated by a 1D pressure transient away from the central fracture plane (Muskat, 1946):

$$p(y,t) = p_r + (p_f - p_r)[1 - erf(fy/\sqrt{t})] \quad \text{.....} \quad (7)$$

where $f = \phi\mu c_t / [(10.54 \times 10^{-4})k]$. However, similar to Warpinski and Teufel (1987) we use the expression for the pressure in an infinite joint:

$$p(y,t) = p_f - (p_f - p_r)(y/y_f) \quad \text{.....} \quad (8)$$

where p_f is the average pressure in the hydraulic fracture over the entire treatment time and p_r is the original reservoir pore pressure. y_f is the location of the fluid front (Koning, 1985):

$$y_f = 1.5\sqrt{\frac{kt}{\phi\mu c_t}} \quad \text{.....} \quad (9)$$

Figure 8 shows the pore pressure distribution around a hydraulic fracture in Barnett Shale (Table 3) and assuming the fracturing net pressure is 900 psi. It can be seen that the pore pressure distribution is elliptically decreasing from the bottom-hole pressure at the fracture surface to the original reservoir pore pressure at far field.

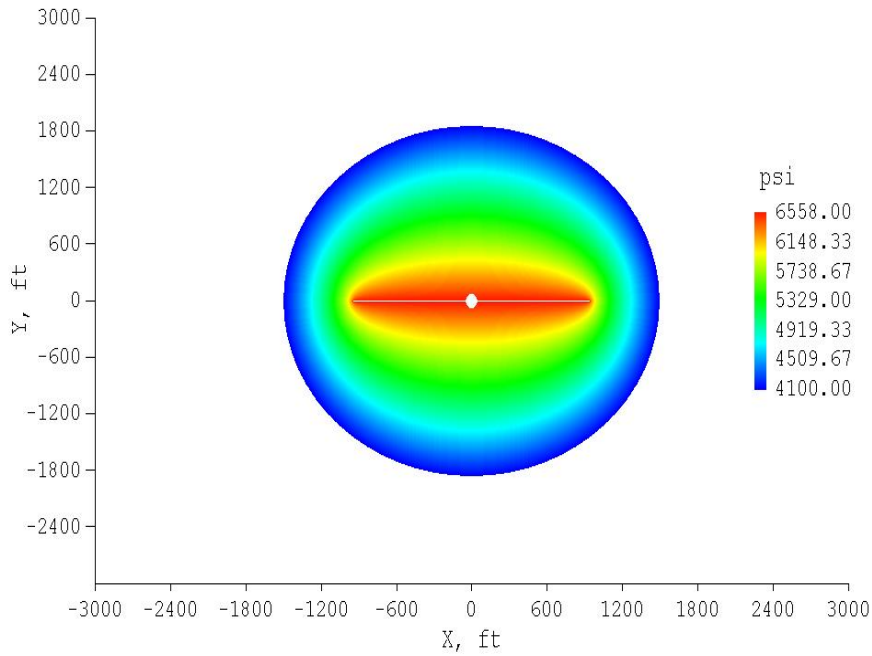


Fig. 8. Pore Pressure Distribution around Fracture.

Table.4. Barnett shale stimulation parameters (Palmer *et al.* 2007).

In situ Stresses	
Depth	8200 ft
Min in situ stress, S_h	5658 psi (= 0.69 psi/ft)
Max in situ stress, S_H	6286 psi (Sh/SH = 0.9)
Overburden, S_v	8200 psi (= 1 psi/ft)
Reservoir pressure, P_o	4100 psi (= 0.50 psi/ft)
Barnett Shale properties	
Friction angle	31 deg
Cohesion	100 psi
Modulus	3.00E6 psi
Poisson's ratio	0.25
Fracture Porosity $\varphi = \varphi_o*(K/K_o)$^(1/3)	Ko = 0.03 mD; φo = 0.1%
Bulk compressibility	3.69E-06 (1/psi)

Water viscosity at res. temp.	0.3 cp
Injection permeability, K	Determined by matching the FRV trendlines
Fracture Treatment Parameters	
Frac half height, H_f	200 ft
Frac half length, X_f	1000 ft
Pumping time, T	9 hours
Fracturing pressure, P_f	100-900 Psi
Fracturing rate	70 bpm
Fracture fluid volume	800,000-1,000,000 gal

2.2 Prediction of enhanced permeability

The methodology of predicting the permeability in the failed region around a fracture is based on the following trial and error procedure (e.e, Palmer, *et al.* 2007):

- use the pressure transient profile at shut in and using a guesses value for permeability, K
- for a selected net fracture pressure (in the range 0 to 900 psi), predict the failed rock volume (FRV)
- vary K until FRV matches the particular trendline of the stimulated reservoir volume from induced seismcity at the given net fracturing pressures

Assuming that (i) the failed distance is uniform along the fracture height, (ii) stresses are uniform in the reservoir, and (iii) considering the position of the pore pressure contour small enough not to cause joint slip as the boundary of the failure zone, the failed rock volume can be estimated by:

$$FRV = \pi y_d x_d h \quad \text{.....} \quad (10)$$

where y_d is the failed distance, and x_d is the failed distance in X direction, and h is assumed equal to the fracture height H_f (Figure 9).

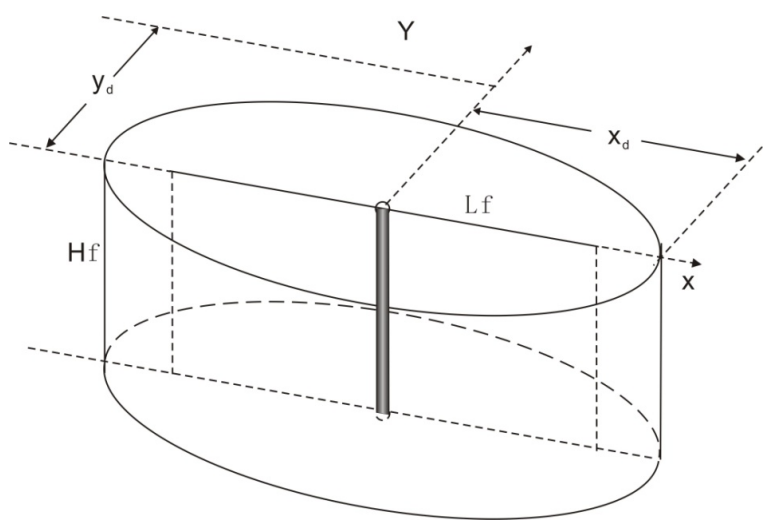


Fig.9.1 Estimation method for failed reservoir volume (for vertical well)

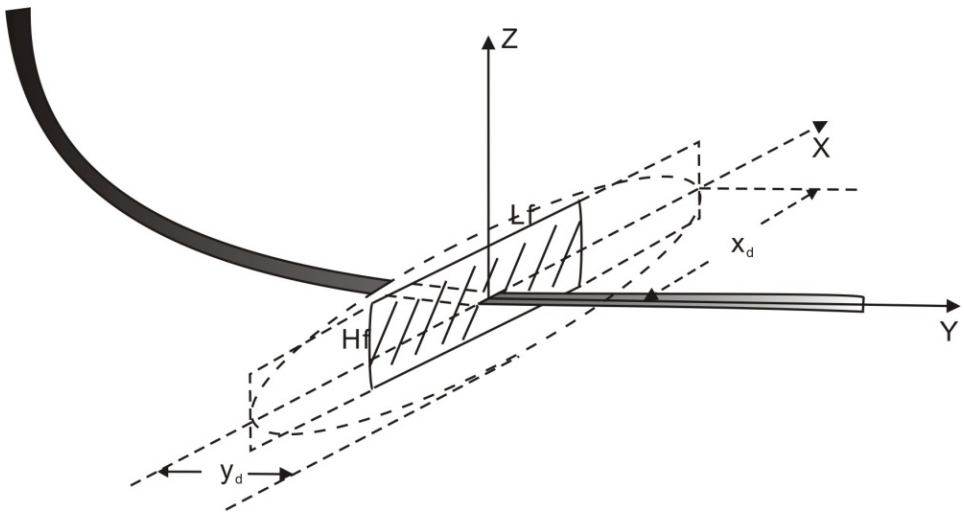


Fig.9.2 Estimation method for failed reservoir volume (for horizontal well)

This approach is applied to the stimulation data of Table 3 for the Barnett Shale. The calculated failed distance normal to the fracture surface is plotted in Fig. 10. Knowing the failed distance, the failed reservoir volume is then determined and the enhanced permeability calculated (Fig. 11). Fig. 12 and 13 show the results of Palmer; comparison shows that there is reasonably good agreement.

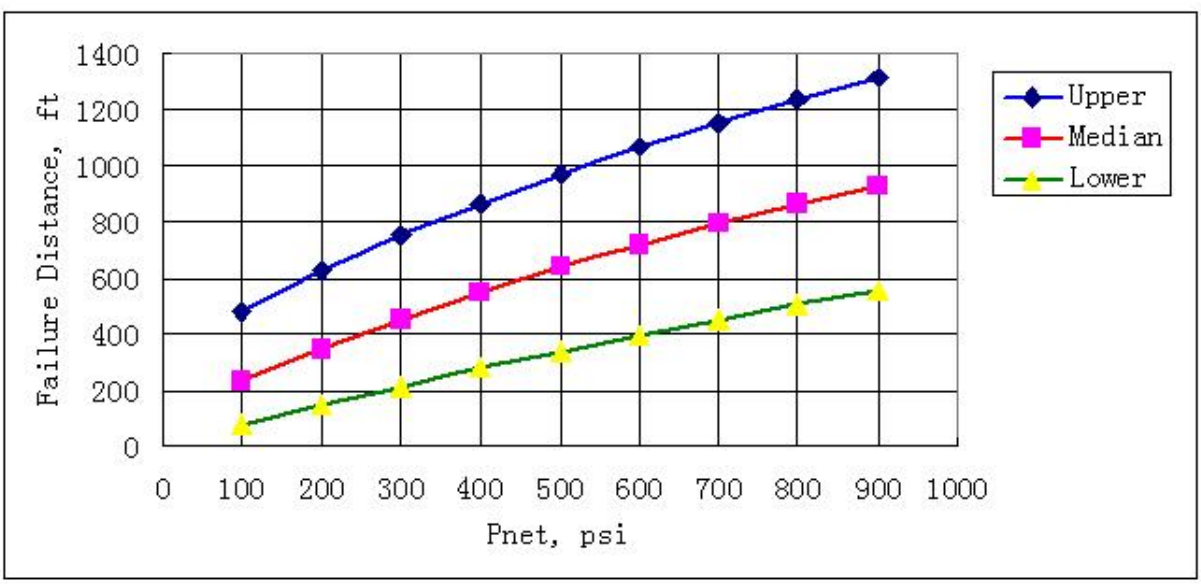


Fig.10 Estimated failed distance normal to the fracture surface.

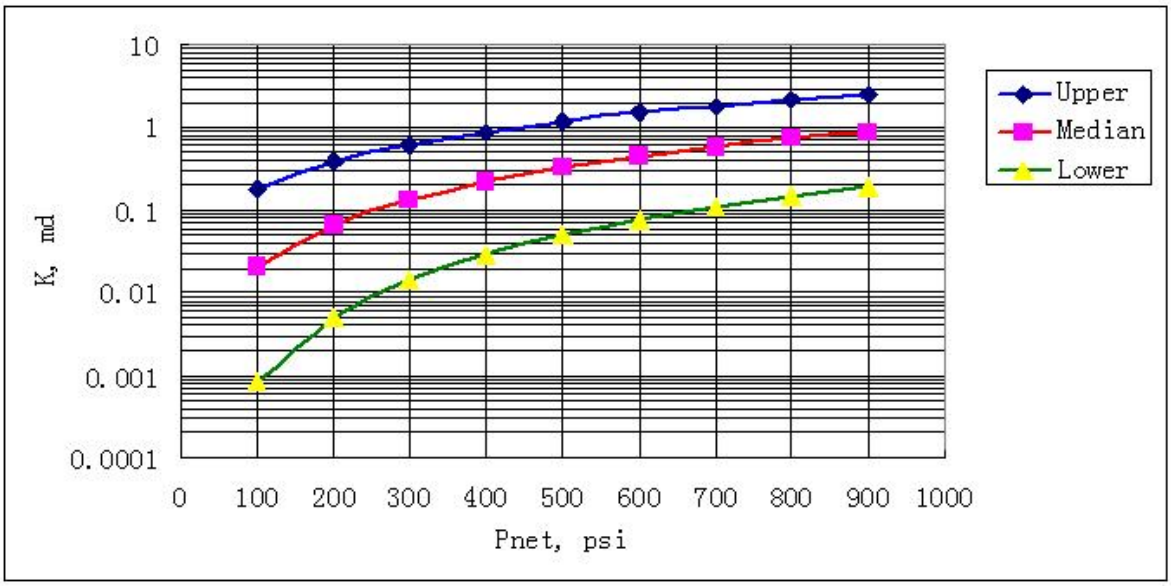


Fig.11. Calculated enhanced permeability for Barnett Shale.

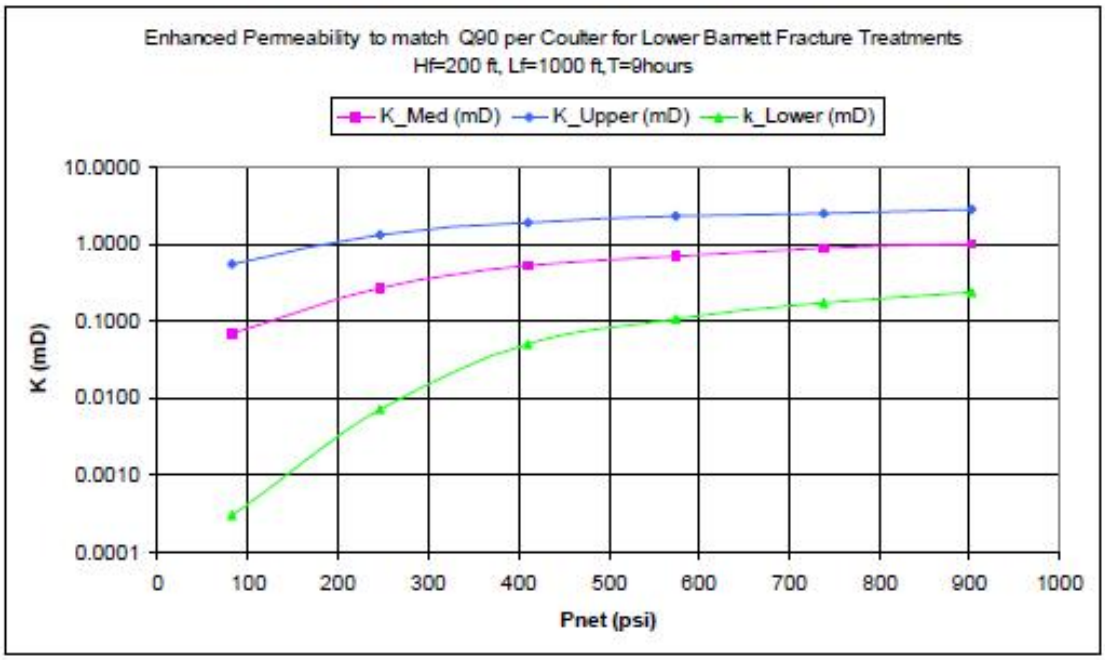


Fig.12 Enhanced permeability during injection to match FRV for lower Barnett Shale fracture treatments (Palmer, *et al.*, 2007).

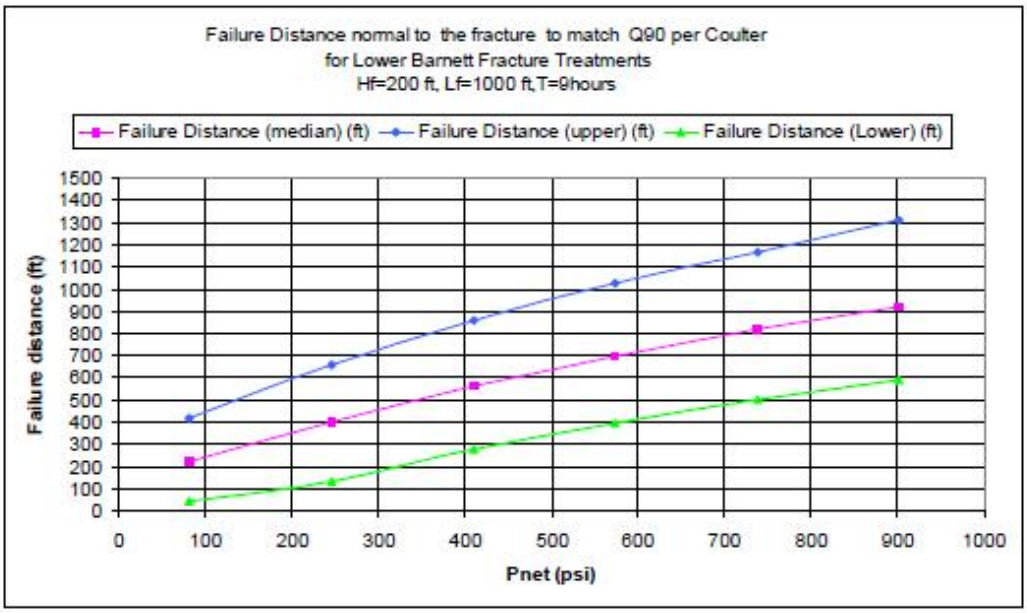


Fig.13 Failure distance normal to central fracture face to match FRV for lower Barnett Shale fracture treatments (Palmer, *et al.*, 2007)

It is also possible to generate a structural permeability diagram for the region around a hydraulic fracture in Barnett Shale. Assuming the maximum in situ horizontal stress is in E-W direction, the results shown in Figure 14. It can be seen that the effective treating pressures required to reactivate the joints ranges from 0.06 psi/ft to 0.50 psi/ft. The joints with small dip and strike in E-W direction are more difficult to reactivate.

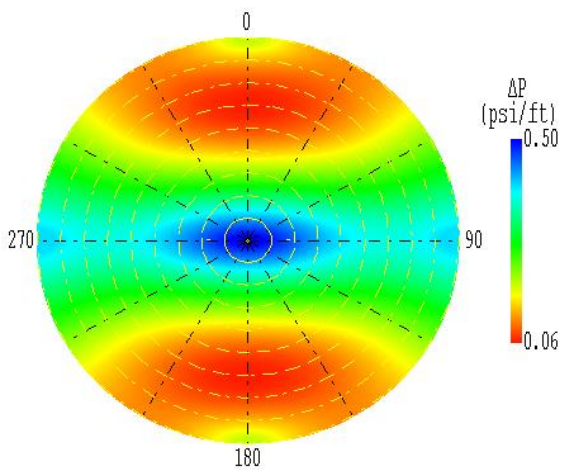


Fig.14. Structural permeability diagram at treating pressures in Barnett Shale.

Conclusions

In this part of the work, we have simulated the slip of joints around injection wells to generate a structural permeability diagram. A number of examples have been presented for the Cooper Basin and the New Albany Shale. In addition, we have developed a method to study the joint slip and rock mass failure around a hydraulic fracture to estimate the extent of the failed rock volume and the resulting permeability enhancement. Exampel simulations for the Barnett Shale show good agreement with literature. If the in

situ stresses, injection conditions, joint orientations, and the trendline of stimulated reservoir volume of the New are known, the stimulation outcome of the New Albany Shale can also be studied.

II. Modeling Hydraulic Fracture/Natural Fracture Interaction

A virtual multidimensional internal bond (VMIB) model has been used to simulate the propagation of hydraulic fractures using the finite element method. The VMIB is formulated within the framework of the virtual internal bond theory (VIB) that considers a solid as randomized material particles in the micro scale, and derives the macro constitutive relation from the cohesive law between the material particles with an implicit fracture criterion. The hydraulic pressure is applied using a new scheme that enables simulation of hydraulically-driven cracks. The model is applied to study hydraulic fracture propagation in the presence of a natural fracture. It is found that although, the in-situ stress ratio is the dominant factor governing the propagation direction, a natural fault can also strongly influence the hydraulic fracture behavior. This influence is conditioned by the shear stiffness of the fault and the distance to the original hydraulic fracture. The model results show that when the fault is strong in shear, its impact on hydraulic fracture trajectory is weak and the hydraulic fracture will likely penetrate the fault. For a weak fault, however, the fracture tends to be arrested at the natural fault. The distance between the fault and the hydraulic fracture is also important; the fault influence increases with decreasing distance.

1. Hydraulic Fracture and Natural Fracture Interactions

Often, there are natural fractures or fault on the path of a hydraulically-induced fracture, particularly when stimulating geothermal reservoirs and unconventional petroleum resources. The behavior of the hydraulic fracture near a discontinuity is of concern in effective reservoir stimulation, as natural discontinuities influence the propagation of hydraulic fracture [1, 2]. To study this influence, the problem of a hydraulically-driven crack in the vicinity of a natural fracture is considered next (Fig.1). The joint or fault length is ten times that of the hydraulic fracture. The distance between the hydraulic fracture and the fault is d . The angle contained by the fault and fracture is β. The horizontal and vertical in-situ stress are σ_x and σ_y , respectively. We performed a number of simulations to study the effect of the in-situ stress ratio, the distance d , the contained angle β and the shear stiffness of fault slip on fracture propagation.

1.1 Effect of the Fault Shear Stiffness

For a given stress state, whether the fault slips or not depends on the fault shear stiffness. When the shear stiffness is low, the fault walls are likely to slip under the stress disturbance induced by the hydraulic fracture opening and propagation. In turn, the fracture slip also affects the hydraulic fracture behavior (Figure 1). To study the effect of fault slip different fault shear stiffness values were considered while the normal stiffness was set at $K_n = 10^9$:

Case 1: $\beta = 60^\circ$; $d = 1.0L$; $K_s = 1.0\times10^3$

Case 2: $\beta = 60^\circ$; $d = 1.0L$; $K_s = 1.0\times10^8$

Case 3: $\beta = 60^\circ$; $d = 2.5L$; $K_s = 1.0\times10^3$

Case 4: $\beta = 60^\circ$; $d = 2.5L$; $K_s = 1.0\times10^8$

The simulated results are shown in Fig.2-Fig.5. It can be seen that the fracture propagation pattern for $K_s = 1.0\times10^3$ (Fig.2b) is quite different from that for $K_s = 1.0\times10^8$ (Fig.3b). In Fig.3b, the fracture follows a straight path while in Fig.2b the fracture propagates incline to its original path. Comparing part (b) of Figures 2-3b shows that when a natural fault is present, the fracture propagation pattern for the case of $K_s = 1.0\times10^8$ (Fig.3b) is consistent with the general tendency of propagation in the absence of a

natural fault. This indicates that a weak fault has considerable influence on the hydraulic fracture behavior. The influence can be attributed to mutual stress disturbances caused by the applied pressure in the HF (which the fault to slip), and the slip of weak fault (which caused the HF to turn). A more pronounce influence of fault shear stiffness can be observed in Fig.2-3c.

However, the influence of shear stiffness is conditioned by other factors. For example, the in-situ stress ratio impacts the extent of this. From Fig.2-3a, it can be seen that the influence of fault stiffness becomes weaker in an isotropic in-situ stress environment. The distance of fault and hydraulic fracture is another factor which impacts the influence of fault shear stiffness. When the distance between the fault and the hydraulic fracture is widened, the influence of the fault shear stiffness decreases, as shown in Fig.4-5. Another feature worth noting is that the hydraulic fracture can penetrate the fault when the fault is sufficiently strong as Fig.3, while no penetration is observed in the case of a weak fault (Fig.2). These results are consistent with those of Blanton [3], Cook and Underwood [4], and Kosheleve and Ghassemi [5].

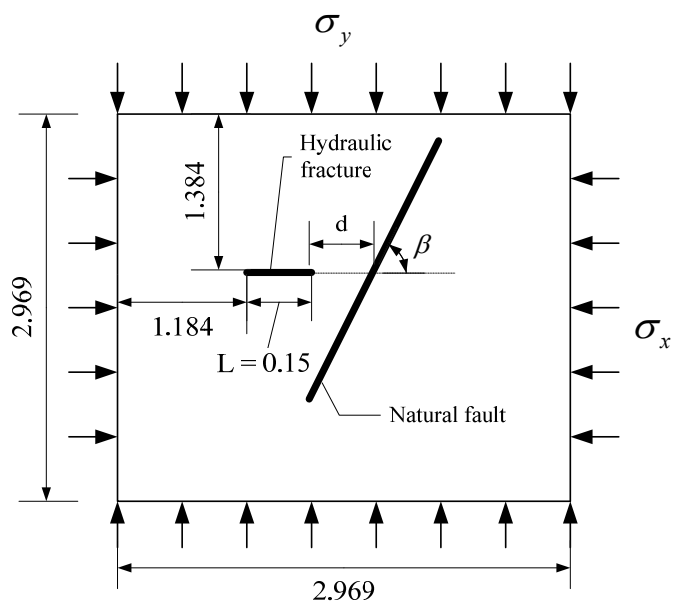


Fig.1 Simulation object for natural and hydraulic fracture interaction.

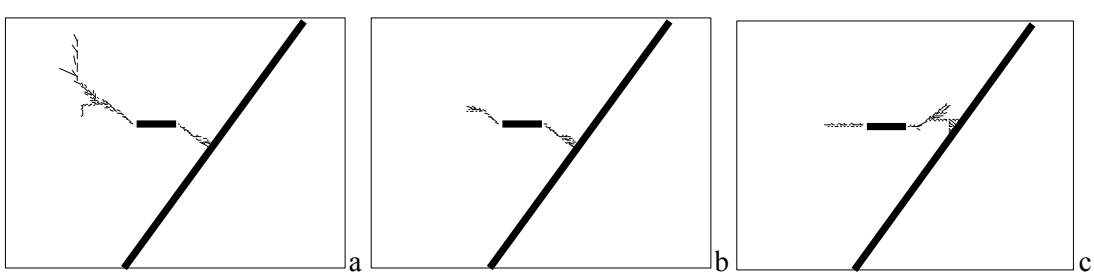
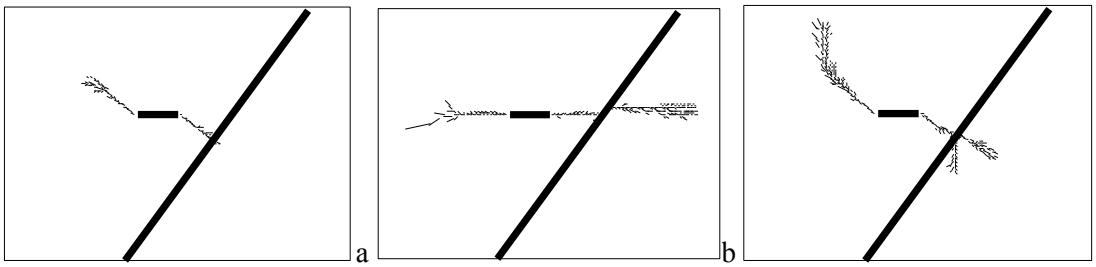


Fig.2 Simulation results of Case 1: (a) $\sigma_x/\sigma_y = 1.0/1.0$ **; (b)** $\sigma_x/\sigma_y = 2.0/1.0$ **; (c)** $\sigma_x/\sigma_y = 1.0/2.0$ **.**



cFig.3 Simulation results of Case 2: (a) $\sigma_x/\sigma_y = 1.0/1.0$; (b) $\sigma_x/\sigma_y = 2.0/1.0$; (c) $\sigma_x/\sigma_y = 1.0/2.0$.

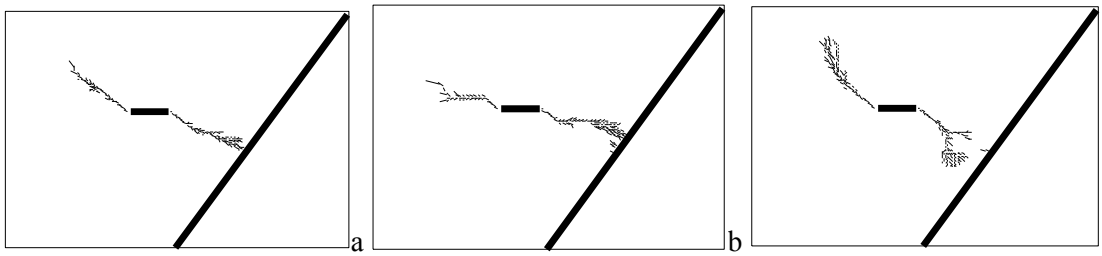
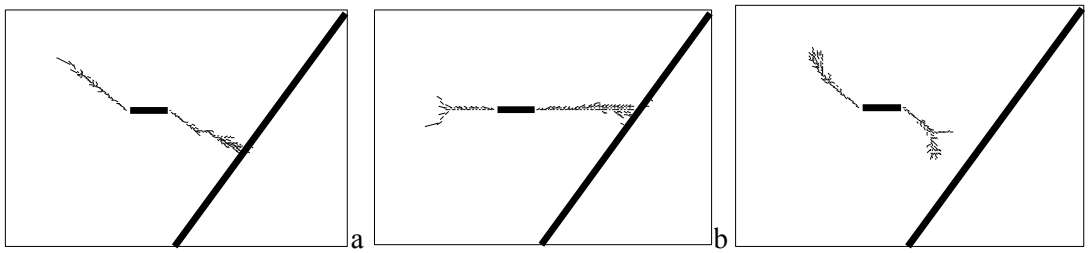


Fig.4 Simulation results of Case 3: (a) $\sigma_x/\sigma_y = 1.0/1.0$; (b) $\sigma_x/\sigma_y = 2.0/1.0$; (c) $\sigma_x/\sigma_y = 1.0/2.0$.



cFig.5 Simulation results of Case 4: (a) $\sigma_x/\sigma_y = 1.0/1.0$; (b) $\sigma_x/\sigma_y = 2.0/1.0$; (c) $\sigma_x/\sigma_y = 1.0/2.0$.

2. Numerical simulation for hydraulic fracture propagation in poroelastic rock

The fracture propagation in porous rock mass is influenced by the coupling between the process of rock deformation and pore pressure diffusion. To consider this coupling, Biot consolidation theory is used. In this part of the work we have combined VMIB with Biot consolidation theory to allow modeling hydraulic fracture propagation in poroelastic rock.

To validate the computation method for the hydraulic-pressure-induced additive node forces, here two examples are presented. Fig.6 shows an infinite domain containing a wellbore. Take a narrow strip of this infinite domain as the analysis object. This strip is equivalent to the combination problem of the two following loading scheme:

- ***Model I*:** only stress $\sigma_n = p^*$ is applied on the top surface. The pore pressure on the top surface is zeros, i.e. $p = 0.0$. The actual boundary conditions on the top surface is: $\sigma_n = p^*$ and $P_{ore} = 0.0$.
- ***Model II*:** only pore pressure $P_{ore} = p^*$ is applied on the top surface. The actual boundary conditions on the top surface is: $\sigma_n = -\alpha p^*$ and $P_{ore} = p^*$.

To make the two-dimensional problem shown in Fig.6 equivalent to the one-dimensional problem, the lateral displacement of this column is restricted, shown as Fig.7b. The top surface is drained. The other surfaces are undrained. The material is assumed to be linear elastic, the Young's modulus $E = 1.0 \times 10^9$ Pa; Poisson ratio $\nu = 0.2$; $\alpha = 1.0$; $k/\mu = 1.0 \times 10^{-10}$ m/sec; Biot's Modulus: $M = 1.0 \times 10^9$ Pa.

The comparison between the theoretical and the numerical results for ***Model I*** and ***Model II*** are respectively shown in Fig.8 and Fig.9. From Fig.8a it is seen that when a stress is applied to the top, it initially subsides with increasing time and then approaches a fixed value. During this consolidation process, the pore pressure at the bottom gradually decreases with the time increasing, finally approaching to zero, shown as Fig.8b. For ***Model II*** where a only pore pressure applied, the top surface moves up so that the simulation object expands as shown as Fig.8. There is good agreement between the numerical and theoretical prediction as shown in Both Fig.8 and Fig.9.
We next consider a hydraulic fracture (HF) problem in which fluid is injected into a wellbore at the rate of $1.4 \times 10^{-3}\ m^3/s$. The in-situ stress is $\sigma_x = 2.5$ MPa and $\sigma_y = 1.0$ MPa. The HF propagation process is shown as Fig. 10; it can be seen that the fracture initiates at the wellbore and propagates forwards along the direction of the maximum in-situ stress. Fig.11a shows the deformed mesh configuration, from which it is seen that a fracture forms in the horizontal direction. The pore pressure distribution is shown in Fig.11b.

Fig.12 shows the wellbore pressure variation with time. It is seen that the pressure starts from it assumed zero value in the well. After the wellbore is filled up, the HP increases with time reaching its peak value and then drop and levels off. From Fig.12 it is also found that the peak hydraulic pressure is different for different injection rates. The lower the injection rate, the lower peak hydraulic pressure, in agrees with the lab and field observations.

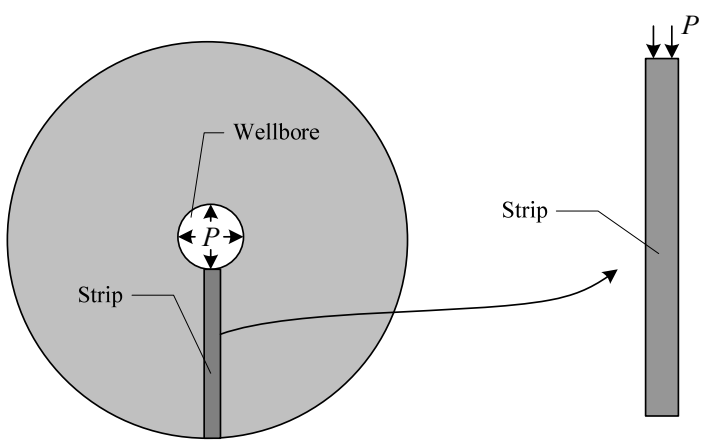


Fig.6. Idealized concept of hydraulic fracture problem.

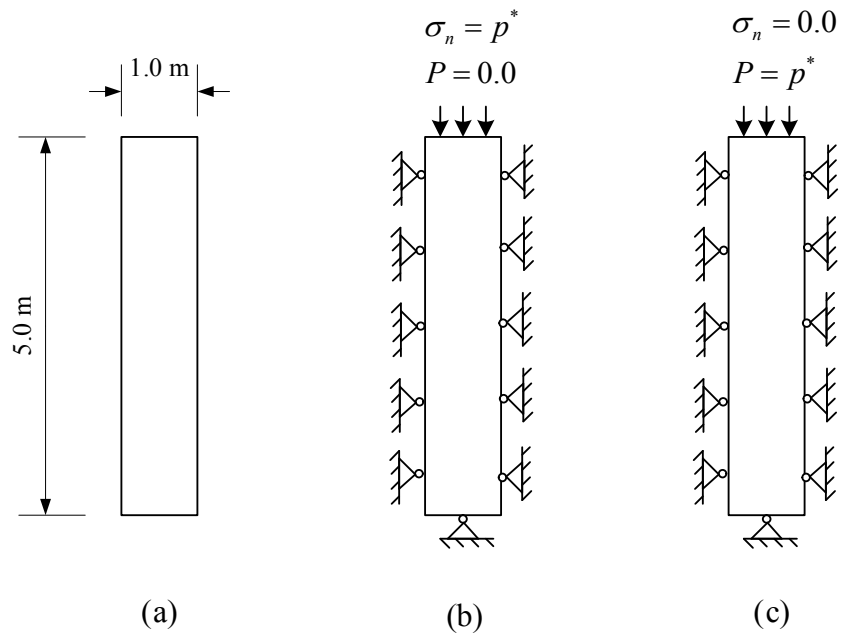
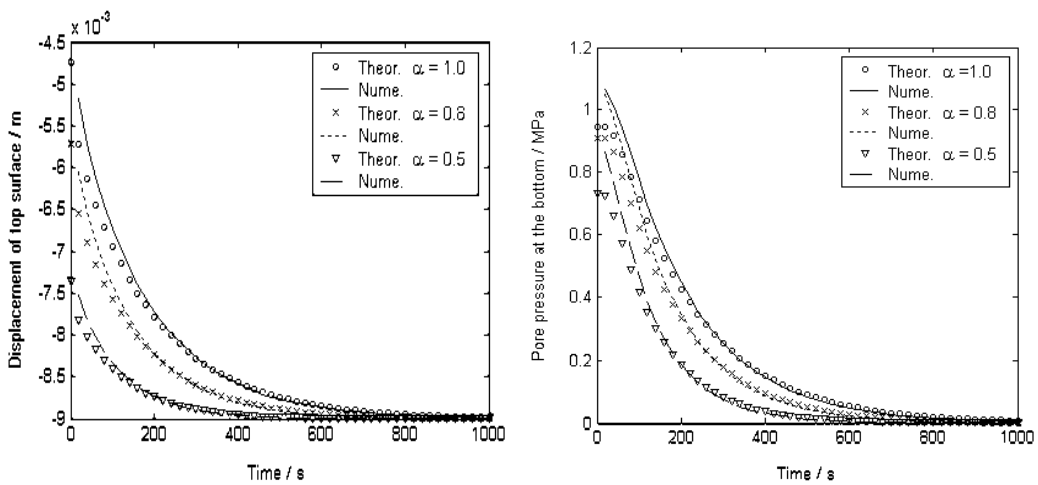
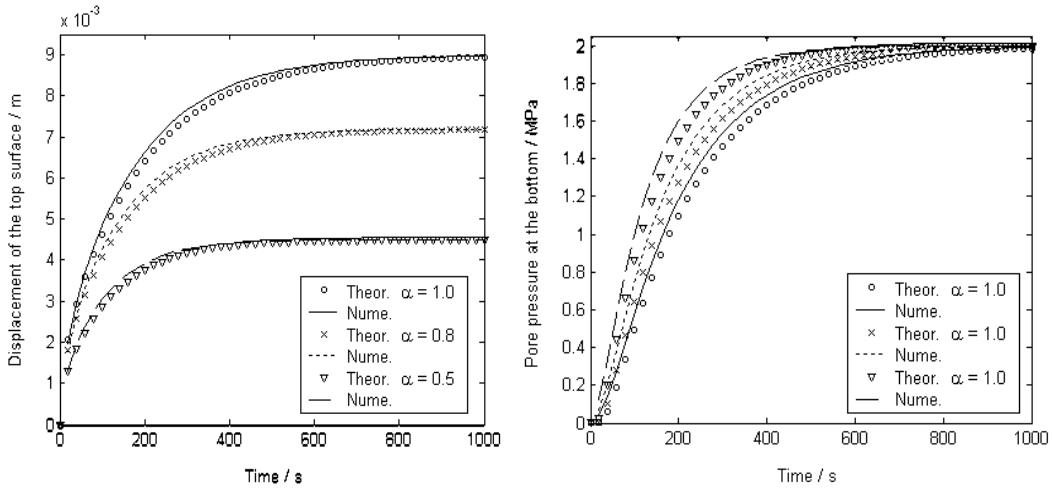


Fig.7. One-dimensional consolidation problem (a) Dimension of specimen; (b) Model I where on the top surface only normal stress σ_n is applied and the pore pressure P is zeros; (c) Model II, where on the top surface only the pore pressure P is applied and the normal stress σ_n is zeros. In both Model I and Model II, the top surface is drained, but the other three boundaries are undrained.



(a) (b)

Fig.8. Comparison between the theoretical and the numerical result for Model I (a) Displacement of the top surface V.S. time; (b) Pore pressure at the bottom V.S. time.



(a) (b)

Fig.9. Comparison between the theoretical and the numerical result for Model II (a) Displacement of the top surface V.S. time; (b) Pore pressure at the bottom V.S. time.

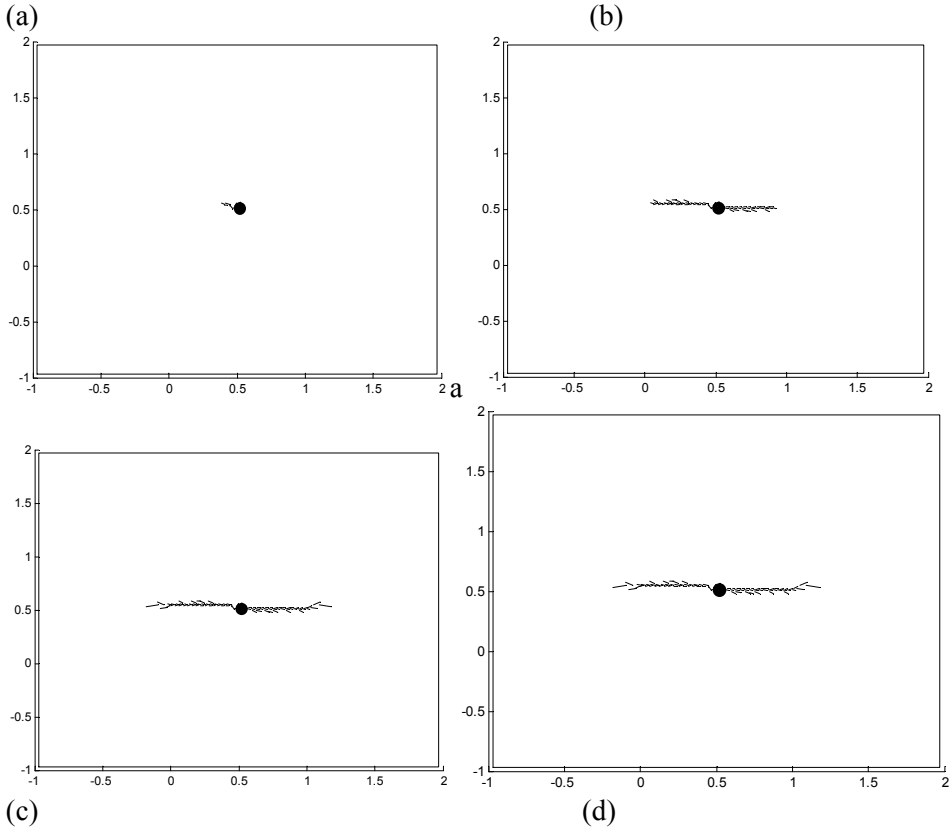
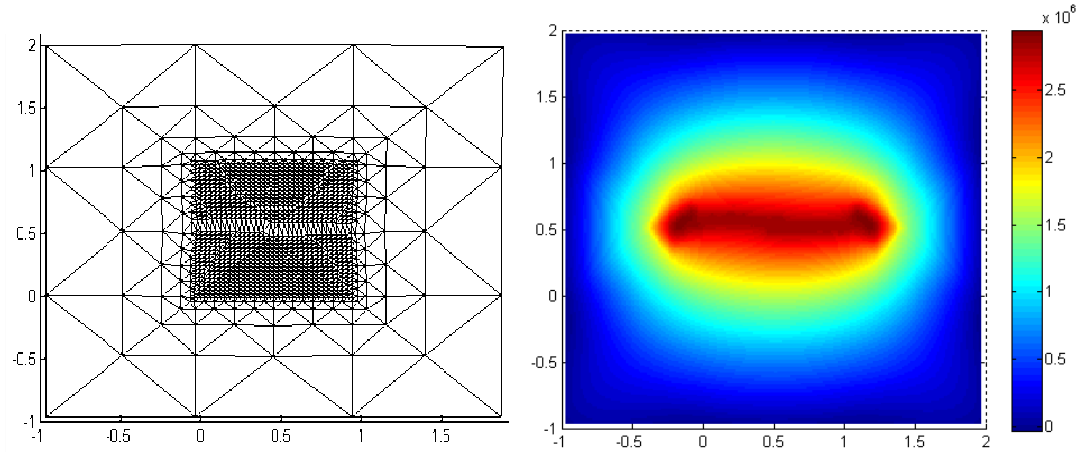
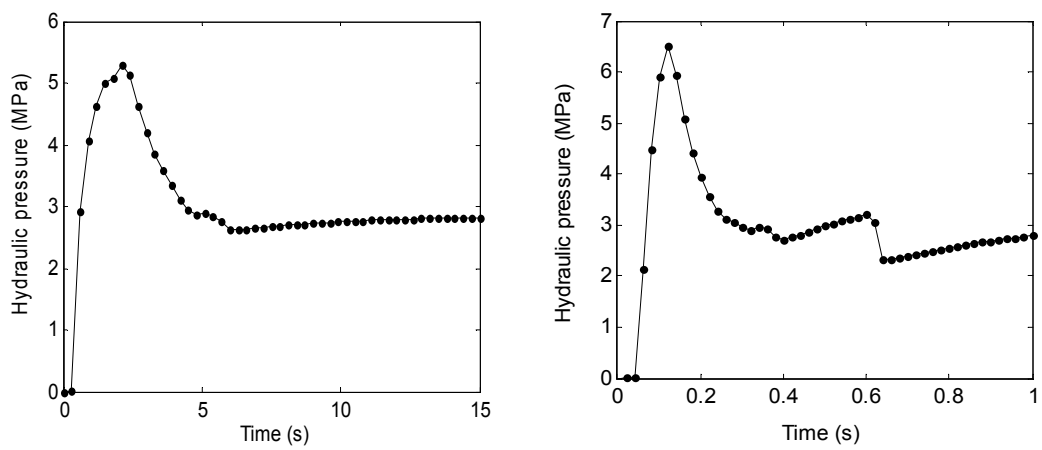


Fig.10. Hydraulic fracture propagation (a) t = 6.3 s; (b) t = 11.7 s; (c) t = 18s; (d) t = 30s. (Injection rate is $1.4\times10^{-3}\ m^3/s$. The pore pressure along the outer boundary is zero. The in-situ stress is $\sigma_x = 2.5$ MPa and $\sigma_y = 1.0$ MPa.



(a) (b)

Fig.11. Simulation results of the injection rate $1.4\times10^{-3}\ m^3/s$ at t = 30s (a) Deformed mesh configuration; (b) Pore pressure distribution.



(a) (b)

Fig.12. Hydraulic pressure in the injection wellbore (a) Injection rate $1.4\times10^{-3}\ m^3/s$; (b) Injection rate $5.0\times10^{-3}\ m^3/s$

Conclusions

In this Section we have results of simulating hydraulic fracture propagation and its interaction with pre-existing natural fractures within the framework of the VIB FEM. The numerical simulations show that the method effectively captures the salient features of this complex problem. Simulating hydraulic fracture propagation with and without a natural fault has shown that in-situ stress is a dominant factor that affects the propagation direction of hydraulic fractures: the hydraulic fracture always tends to propagate along the maximum compressive stress direction. In addition to the in-situ stress, pre-existing natural fractures

can significantly impact hydraulic fracture propagation. The fault influence is conditioned by its shear stiffness, its inclination, and its distance to the hydraulic fracture. When the shear stiffness of the fault is strong enough, the hydraulic fracture can penetrate the fault and propagate continuously. However, when the shear stiffness of the fault is low, the hydraulic fracture is arrested at the fault. The influence of the fault is diminished as the angle between the natural fault and the hydraulic fracture decreases, or when the distance to the hydraulic fracture increases.

In addition, we have further developed the VMIB method to allow simulation of fracture propagation in porous rock mass. Comparison with analytical solutions has been used to verify the model. The simulation results suggest that the breakdown hydraulic pressure increases with the injection rate. With these developments it is now possible to simulate hydraulic fracture and natural fracture interactions within the framework of poroelasticity. This will be done in the forthcoming months.

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Analysis Of Reservoir Response To Stimulation By Hydraulic Fracturing: Structural Permeability

When injection into a well, the pore pressure effects on the sliding of joints are of interest. A structural permeability diagram can be used to show the ΔP required to reactivate fabrics of different orientations. Finally, we have applied this method to predict the pore pressure change, ΔP, required to reactivate fabrics of different orientation in the well J Ray Clark in Christian County, KY.

The structural permeability diagram showing the orientations of geological weaknesses that may be reactivated during fracture stimulation treatments at high treating pressures in the New Albany Shale is plotted as in the following figures. According to the data from J Ray Clark well in Christian County, KY, we assume that the principal stresses are σ_1 =2500 psi (vertical), σ_2 =2200 psi (East horizontal), σ_3 =2000 psi, and pore pressure P_p=1800 psi with μ =0.6, and cohesion zero.

As shown in Fig.1, the maximum required effective treating pressures are located in areas with low dip angles, and the minimum required effective treating pressures are located in the areas with dip angles around 50º-70º and dip directions between -30º N and 30º N, 150º N and 210º N.

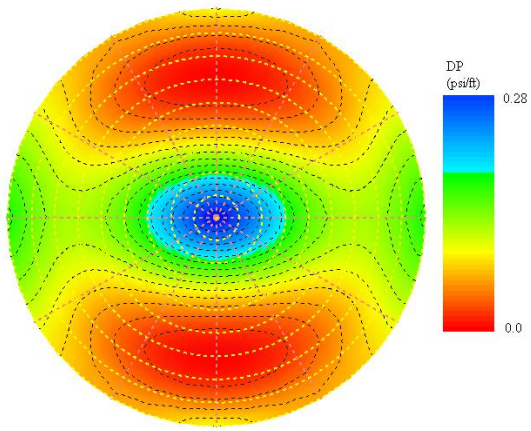


Fig.1 Structural Permeability Diagram for New Albany Shale (μ =0.6).

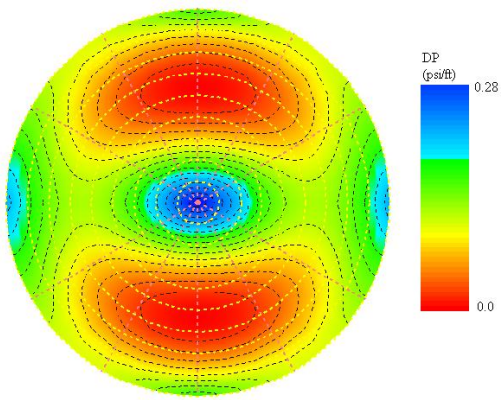


Fig.2 Structural Permeability Diagram for New Albany Shale (μ =0.3).

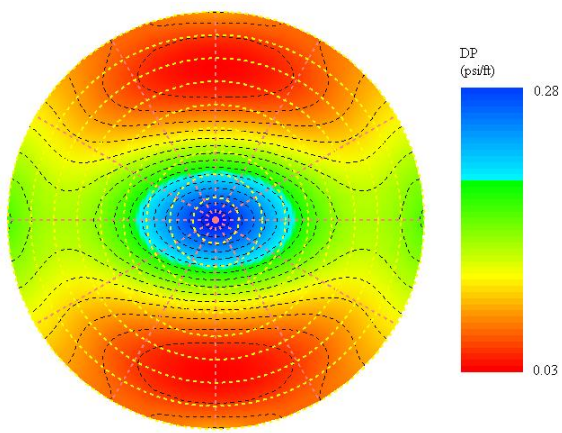


Fig.3 Structural Permeability Diagram for New Albany Shale (μ =0.9)

Fig.1, 2, and 3 show the sensitivity analysis on friction coefficient. From the comparing between them, we can see that with the increase of friction coefficient, the failure of certain joints require larger effective treating pressures.

Fracture Diagnostics

Pinnacle is pleased to submit this annual report of progress on GTI Project 20747 relating to work performed during the first year of the proposed two-year duration of GTI's Subcontract 07122-16, a portion of the Department of Energy Prime Contract DE-AC26-07NT42677. Pinnacle's portion of this project was two-fold: first, to provide consulting services with respect to 3-D parametric modeling and design of New Albany Shale stimulation treatments, and then second, to provide fracture mapping services as appropriate to GTI and its industry partners. The summary below covers two basic phases of the project, and is current to the date of this submission.

Phase I: Data Gathering and Literature Review

Work performed in the second and third quarters of 2008, and the first quarter of 2009 revealed a number of points:

1. Existing geological, petrophysical, and geochemical literature pertaining to the New Abany Shale is extensive. There is substantially more information of this nature than exists for most domestic shale plays.
2. Literature with respect to completion engineering, reservoir engineering, and operational issues for wells targeting the New Albany Shale is extremely limited.
3. Published information with respect to fracture mapping operations in the New Albany Shale is nonexistent, primarily due to leasing and confidentiality issues involving the parties that have performed and purchased fracture mapping services. Pinnacle has been involved in some of these mapping activities, and while specifics of these operations cannot be revealed, some generalized conclusions were drawn from the overall experience in multiple portions of the play, and are presented here. Each time a conclusion of this nature is made, it is footnoted with a (†) that indicates that the statement or conclusion is not associated with previously available [public] information, but is culled from either industry experience or conversations with industry participants.
4. Most fiscally successful domestic shale plays have been stimulated with large volumes of water, low volumes of additives, and relatively low concentrations of small-diameter proppant, at high pump rates. There is evidence, especially in the lower-pressure portions of the New Albany Shale, that these techniques may not be applicable in this formation†. Geological and geochemical literature universally supports the presence of potentially commercial quantities of mobile gaseous hydrocarbons through wide swaths of the play, if techniques can be developed to extract them. The inference, then, is that stimulation processes involving large volumes of water may not (at least at this point in time) be a short-term solution, and that alternate process(es) must be focused on.
5. Though there are specific wells in specific portions of the play with enough natural fracturing that hydraulic fracturing is not necessary to commercially complete, the vast majority of properties do and will require hydraulic fracturing.
6. More is known about New Albany Shale completion practices and fracture geometries in Kentucky and Indiana than in Illinois†.
7. 2,000 – 5,000 bbl slickwater fracs have been mapped in the play, and result in network half lengths X_f of between 750 and 1,100 ft†.

8. There may be significant variability in fracture half-lengths associated with treatments containing N_2[†].
9. Uncemented liners may have some difficulty achieving good stimulated coverage along the wellbore[†].
10. Cemented liners may be associated with extreme operational difficulty in terms of pumpability of fluids[†].
11. Total Stimulated Reservoir volume is important in terms of the magnitude of the early production profile.
12. Horizontal wells may, on average, outperform vertical wells in terms of total D&C cost/ft^3 of hydrocarbon recovered[†].

Phase I - Fracture mapping efforts

A New Albany Shale fracture mapping project on a horizontal well and potential industry partner were identified. Offset microseismic was eliminated as a possibility, due to lack of suitable observation well(s)s. A surface tiltmeter array was designed and proposed, but difficulties associated with surface ownership and terrain precluded its use, and the effort was terminated.

Phase I – Fracture modeling efforts

As part of the review process, proprietary microseismic data was examined. Because these mapping efforts could not be shared in a public format, it was decided to create some "typical" 3-D parametric modeling runs that demonstrated approximate geometry that could be expected if similar treatments in similar lithological settings were pumped. These models utilized simple 3-layer constructions, and were not intended to be utilized to forecast future completion work in the New Albany Shale, but simply portray approximations of observed geometry.

Phase II - fracture 3-D parametric modeling and completion process review

By the end of the 1st Quarter of 2009, sufficient log evaluation by another GTI subcontractor had been completed in the Haley's Mill Field in Christian County, KY to take a closer look at the utilization of logging tool response to develop lithological layering for 3-D parametric stimulation modeling.

During the process of reviewing area fracture mapping results[†], it became evident that sometimes induced fractures appeared to be relatively simple, and sometimes looked more like shale "networks" that are observed in other domestic shale plays. Often, these networks are composed of multiple parallel and oblique or orthogonal networks of natural and/or induced fractures. 3-dimensional parametric stimulation models simulate the geometry of simple, bi-wing induced fractures, so it was concluded that the only cases where 3-D parametric modeling would be applicable would be cases where it was known that induced fractures were relatively "simple". A number of attempts have been made by other researchers to develop workarounds to this problem utilizing existing software packages, but reasonable, stable, or duplicatable solutions have not been made public. At least four (and maybe more) corporate or other entities are in various stages of development and commercialization of software that could possibly simulate the geometry of fracture networks with multiple parallel and/or oblique or orthogonal fractures, when the frequency of such fractures can be estimated or calibrated to an existing fracture mapping effort. One of the GTI subcontractors for this project is now involved in this effort.

In other domestic shale plays, it has been noted that the most successful wells exhibit relatively large induced or naturally fractured networks, with the inference that the better production was associated with the higher degree of fracture surface area exposed to the reservoir. It follows that the effort described below to develop adequate 3-D parametric modeling techniques will only apply to those cases where fracturing is simple, the degree of networking is low, and therefore the relative degree of fracture face exposed to the reservoir is low.

Several logs from New Albany Shale penetrations in Christian County, KY were looked at by the primary GTI logging interpretation contractor. One log, in particular, from the Orbit Gas Co. J Ray Clark No. 1, was analyzed, and the single [measured] sonic channel was combined with industry-accepted routines to develop reasonable values for both shear and compressional velocities in lithologies in and above the New Albany shale. Utilizing these channels, values for Young's modulus, Poisson's ratio and stress were calculated by the contractor (again, using industry-accepted equations), and these values were utilized to develop lithological layering for a series of 3-D parametric modeling runs. As has been observed previously by multiple researchers and industry engineering participants in other shales[†], the calculated stress within the New Albany shale was higher than the boundary lithologies. The result was similar to what has been noted in other areas – a fundamental instability in the modeling result. This occurs frequently when the perforated interval lies within a layer or series of layers in which the calculated stress is higher than the boundaries.

A method was proposed by which more realistic, and stable 3-D parametric modeling might be accomplished in the New Albany Shale for cases where induced fracturing is relatively simple. This method relies on utilizing gamma ray, photoelectric constant, and [calculated] effective porosity in conjunction with known area fracture gradients or closure stresses, and/or calibrating with fracture mapping efforts, when available. Examples were constructed for the case of straight nitrogen fracturing treatments.

A second review of current completion techniques and processes was undertaken[†]. The inapplicability of large waterfracs from the perspective of production response was verified[†]. A number of operators have experimented for several years with both foam fracs and straight nitrogen fracturing treatments[†]. It appears as if there is a consensus that for the shallowest and lowest pressure properties, straight N_2 treatments have outperformed foam[†]. For moderate-depth and normally pressured properties, there does not appear to be a consensus as to whether foam is any better or worse than straight nitrogen[†]. However, it is clear that operators who were regularly utilizing one or the other have ceased drilling and completing New Albany Shale wells in the current low commodity price environment [in place at the time of this report], suggesting that medium-depth completions may be less cost-effective, or may yield less scf/ton to early production than shallower properties where drilling activity is still active.

A limited amount of experimentation has taken place with ultra high nitrogen-to-liquid ratios; in which +96-quality mists are pumped ultra low quantities of small diameter low-specific gravity proppants[†], but production results were not available at the time of this report.

Phase II - Fracture mapping efforts

A potential fracture mapping project was identified with an industry partner, and plans are underway to perform offset well microseismic monitoring of a multi-stage completion in a proposed Daugherty Petroleum Inc. DPI No. 2485-21 horizontal lateral, listening from two offset observation wellbores. It is expected that the completion and fracture mapping effort will be performed in the third quarter of 2009.

The stimulation will consist of 100% nitrogen; common for the area, and appropriate for those situations where it has repeatedly been shown that introducing water into the completion fluid causes difficulty with both load recovery and early production response.

A map view of the proposed setup is shown in **Figure 1**. Initially, an array of 12 geophones will be deployed in the vertical DPI No. 2426-21, straddling the New Albany Shale, and listening to microseismic activity along the toe-most extremes of the DPI No. 2485-21 horizontal lateral. The completion is scheduled to be an open-hole packer arrangement of nine stages total, with continuous pumping until the 4th or 5th stage has been completed. A shut-down about half-way through the process will allow the pumping service provider to restock nitrogen, and during that time interval, the tools will be pulled out of the DPI No. 2426-21 and placed into the vertical portion of the DPI No. 2486-21 (a twin horizontal with trajectory opposite that of the DPI No. 2485-21). Microseismic events emanating from the last 4 – 5 stages (closest to the lateral heel) will then be monitored from this new position.

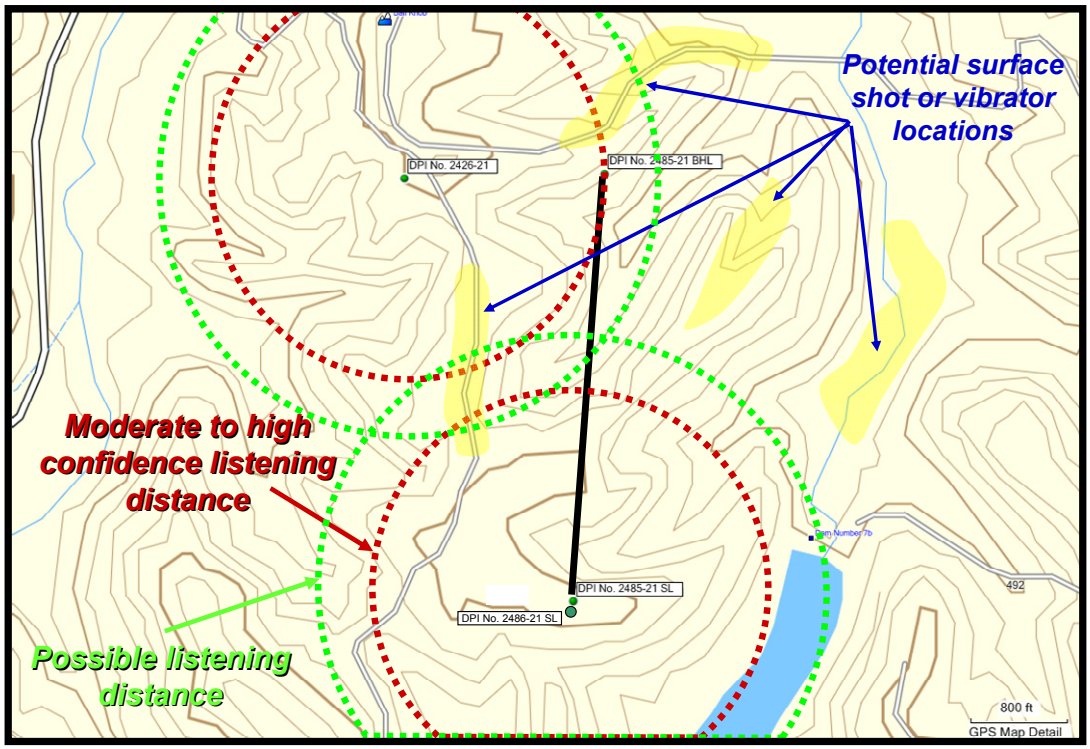


Figure 1. Proposed setup for microseismic monitoring effort

During the shut-in period, pressure will be monitored for evidence of closure. A 3-D parametric calibrated model will then be developed (if the fracture network is simple enough), whereby the final simulation matches both observed net pressure and microseismic response.

This statement is based not on publically available literature, but is derived from industry experience and/or conversations with industry participants.

Best Practice Analysis

West Virginia University

Executive Summary

Although the New Albany Shale of the Illinois Basin has been estimated to contain approximately 86 TCF of natural gas in place, the full development of this potentially large resource has not yet occurred. The intent of this study is to reassess the potential of New Albany shale using a novel integrated workflow, which incorporates field production data and well logs using a series of traditional reservoir engineering analyses with artificial intelligence & data mining techniques. The model developed using this technology is a full filed model and its objective is to predict future reservoir/well performance in order to recommend field development strategies.

In the first part of this report, the impact of different reservoir characteristics such as matrix porosity, matrix permeability, initial reservoir pressure and pay thickness as well as the length and the orientation of horizontal wells on gas production in New Albany Shale have been presented.
The study was conducted using a publicly available numerical model, specifically developed to simulate gas production from naturally fractured reservoirs.

The study focuses on several New Albany Shale wells in Western Kentucky. Production from these wells is analyzed and history matched. During the history matching process, natural fracture length, density and orientations as well as fracture bedding of the New Albany Shale are modeled using information found in

the literature and outcrops and by performing sensitivity analysis on key reservoir and fracture parameters.

Sensitivity analysis is performed to identify the impact of reservoir characteristics and natural fracture aperture, density and length on gas production.

In second part the history-matched of results 87 NAS wells has been used for performing a novel integrated workflow .In this integrated workflow unlike traditional reservoir simulation and modeling, we do not start from building a geo-cellular model. Top-Down intelligent reservoir modeling(TDIRM) starts by analyzing the production data using traditional reservoir engineering techniques such as Decline Curve Analysis, Type Curve Matching, Single-well History Matching, Volumetric Reserve Estimation and Recovery Factor. These analyses are performed on individual wells in a multi-well New Albany Shale gas reservoir in Western Kentucky that has a reasonable production history. Data driven techniques are used to develop single-well predictive models from the production history and the well logs (and any other available geologic and petrophysical data).

Upon completion of the abovementioned analyses a large database is generated .This database includes a large number of spatio-temporal snap shots of reservoir behavior. Artificial intelligence and data mining techniques are used to fuse all these information into a cohesive reservoir model. The reservoir model is calibrated (history matched) using the production history of the most recent set of wells that have been drilled in the field. The calibrated reservoir model is utilized for predictive purposes to identify the most effective field development strategies including locations of infill wells, remaining reserves, and under-performer wells. Capabilities of this new technique, ease of use and much shorter development and analysis time are demonstrated as compared to the traditional simulation and modeling.

Introduction

The New Albany Shale is predominantly an organic-rich brownish-black and grayish-black shale that is present in the subsurface throughout the Illinois Basin. The total gas content of the New Albany Shale (Devonian and Mississippian) in the Illinois Basin (Figure 2) has been estimated to be 86 trillion cubic feet (TCF) (Bookout, 1980). Although the New Albany Shale has produced commercial quantities of gas for more than 100 years from many fields in southern Indiana and western Kentucky, only a small fraction of its potential has been realized (Consortium, 1994).

The Shale is shallow, biogenic and thermogenic that lie at depth of 600-5,000 feet and are 100-200+ feet thick. Natural fractures are believed to provide the effective reservoirs permeability in these zones and gas is stored both as free gas in fractures and as absorbed gas on kerogen and clay surfaces.(Rexenergy Corp).

Figure 1. Illinois Basin Map (Smith Oil Group, Inc.)

The New Albany Shale has great potential for natural gas reserves. Gas-in-place (GIP) measures from 8 bcfg/square mile to 20 or more bcfg/square mile, depending on locations and depths.

Unlike many other shale plays, the New Albany Shale in the Illinois Basin has a continuous 100 foot thick pay zone of shale, capped by a very thick, dense, gray-green shale (Borden Shale). Prior to 1994, over 600 New Albany Shale wells had been produced commercially in the Illinois Basin. In the New Albany Shale, a well commonly produces water along with the gas. It was learned in the early 1900's that a simple open-hole completion in the very top of the shale, would yield commercial gas wells that would last for many years, in spite of producing some water with the gas. Vertical fractures in the shale fed the gas flow at the top of the shale. The potential of these wells was seldom realized, as the production systems for handling the water were limited. Today, we have the ability to deal with the water cost effectively and as a result can keep the water produced off from the shale allowing better rates of gas production. Utilizing the success of horizontal drilling, modern water production systems, and low-pressure gas gathering systems, long-term production of natural gas can be achieved (Oil- Gas News).

Current recovery of the black shale gas in vertical wells is estimated typically at 15% to 20% of GIP from the black shale. On a well-to-well basis, this recovery varies depending on the natural fracture intensity associated with each well bore. The opportunity to exploit these shale gas reserves is big. Production volumes from the black shale are related mostly to our ability to desorb gas from the shale. Removing the hydrodynamic trap on the shale is the key to producing shale gas. The lower the producing pressure of the well bore, the greater its capacity to produce gas.

Simple, low-cost vertical wells are delivering good returns on investment to several operators in the play. Horizontal drilling with only 1,000 feet of lateral wellbore, has demonstrated from a producing horizontal well to produce long-term, stable gas flow. Other horizontal test wells drilled recently under joint ventures have also confirmed the excellent production potential of the shale. Commercial production from wells is projected for 40 years or more. Due to the vertical nature of natural fractures/jointing through the shale, horizontal drilling is expected to have the best overall return on investment (Oil- Gas News).

Part 1: New Albany Shale Natural Fracture Network Modeling and Simulation

The modeling of fluid flow through fractured formations can be based on deterministic, stochastic or fractal formulations of flow paths and matrix volumes. Deterministic models, however, are generally unable to effectively describe many naturally fractured formations with respect to the distributions of flow path length, flow path connectivity, and matrix block size and shape.

NFFLOW™ is a numerical model for naturally fractured gas reservoirs (Developed by NETL/DOE) that permits the modeling of irregular flow paths mimicking the complex system of interconnected natural fractures in such reservoirs. This type of natural fracture reservoir simulation permits a more accurate and realistic representation of fractured porous media when modeling fluid flow compared to the traditional deterministic formulations. The NFFLOW™ simulator is a single-phase (dry-gas), two-dimensional numerical model that solves fluid flow equations in the matrix and fracture domains sequentially for wells located in a bounded naturally fractured reservoir. The mathematical model “decouples” fluid flow in fractures and matrix, and solves a one-dimensional unsteady state flow problem in the matrix domain to compute the volumetric flow rates from matrix into fractures and wellbores.(6)

FRACGEN™, the fracture network generator (Developed by NETL/DOE), implements four Boolean models of increasing complexity through a Monte Carlo process that samples fitted statistical distributions for various network attributes of each fracture set. Three models account for hierarchical relations among fracture sets, and two generate fracture swarming. Termination/intersection frequencies may be controlled implicitly or explicitly. (6)

In this study FRACGEN/NFFLOW is being used to model gas production from New Albany shale. New Albany shale reservoir contains high-angled (vertical or nearly so) orthogonal natural fractures with non-uniform spacing that are open to unimpeded flow. The predominant fracture system is oriented east-

west with spacing between joints estimated to average five feet based on outcrop studies (Figure 3) and production simulations. Based on this information, it was concluded that increases in performance could be achieved with a horizontally drilled well compared to a vertically drilled well in the same reservoir.

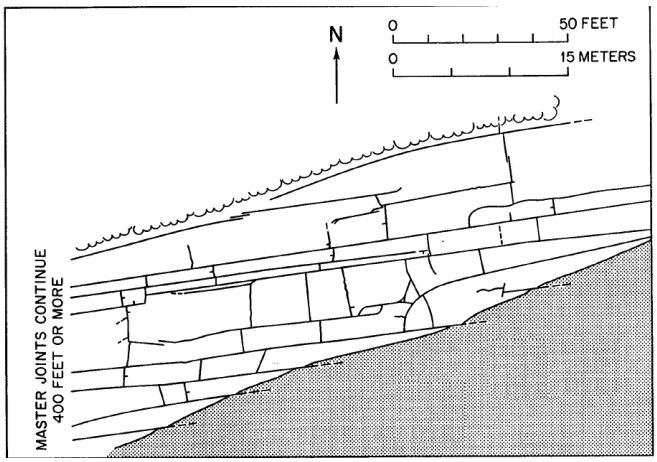


Figure 2. Schematic showing outcrop fracture features of the New Albany shale (7)

Fractures in a core of the New Albany Shale from the Energy Resources of Indiana No. 1 Phegley Farms Inc. well in Sullivan County, Indiana, were described by Kalyoncu and others (1979)(8). Twenty-one fractures were described over an interval of 104 feet. They were mainly vertical, but some had dips as low as 80 degrees. The strike of the fractures was predominantly northwest-southeast and a small secondary mode trended slightly to the north of east-west. (9)

Joint orientations in outcrops of the New Albany Shale in Indiana are parallel to this secondary east-west trend of fractures in the Phegley Farms core. (10)Fractures in a core of the New Albany Shale from the Orbit No. 1 Clark well in Christian County, Kentucky, were described by Miller and Johnson (1979)(9). Natural fractures were regular planar sub vertical features striking northwest-southeast. They generally were filled with calcite, or less commonly with pyrite, and had apertures as great as 3.0 millimeters (0.0098 ft). In the vertical plane, these fractures were commonly continuous for 1 or 2 feet, succeeded by sub parallel fractures offset from each other at their terminations(9).

There is a decrease in fracture from the top of the New Albany shale to the lower members. The Clegg Creek member is clearly contains the most fractures, both natural and induced. The Blocher member typically shows half the number of natural fractures when compared to the clegg creek (8).Therefore the Clegg Creek member contains the most natural fractures with fracture frequency decreasing down section.

Because of the problem that we had during this study to access fracture detection tools like image logs, seismic or any other tools that can be used for fracture identification and characterization, the abovementioned fracture distribution characteristics has been used to build a base fracture network model in FracGen and the flow modeling was performed in NFflow. The Fracture network characteristics used for the base model and the reservoir parameters that have been used for history matching (in NFflow) are shown in Tables 1 and 2.

Results of this model are compared with the production from a well producing from the New Albany Shale as shown in (Figure 4). Meanwhile, because only last 9 years of production history was available, our production modeling (and eventually the history match) included reservoir behavior from the well completion to the last available production date.

The fracture network of the base model (model providing the best history match) consists of 4sets of fractures. Three of the sets are defined in order to generate the major fracture patterns that mostly

contribute to flow (the orientation of those fractures are E 95° W, E97° W and E 90°) and the remaining set are defined in order to generate the bedding.

Table 1. Fracture network properties (Base model)

	Fracture Properties	Fracture Length(ft)	Fracture Aperture(ft)	Fracture Density(ft/ft$^{2)}$	Major Fracture orientation
Major fracture generator	Set 1	2-400	0.0098	0.00003	E 95° W
	Set 2	2-400	0.0098	0.00003	E 97°W
	Set 3	5-400	0.0098	0.000003	E 90°
Bedding generator	Set 4	400-1000	0.00025	0.00003	E 24° N

Generations of fracture sets are based on two different models. Model 1 generates randomly located fractures, although the connectivity controls can be used to produce various degrees of clustering, including unintended clustering. Model 2 generates fracture swarms (elongated clusters), whereby the swarms are randomly located and can overlap.

Table 2. The input variable for single well history matching

Matrix Permeability (md)	Matrix Porosity (%)	Initial Pressure (psi)	Thickness (ft)	A (Acres)
0.0000822	0.05	700	100	320

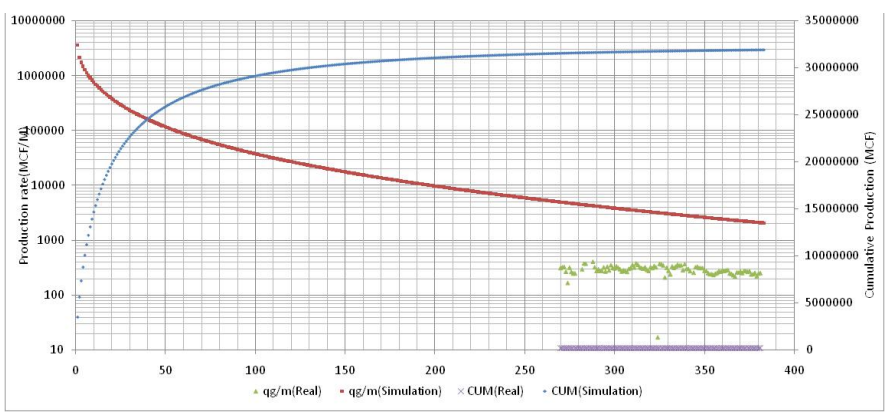


Figure 4. Simulation result examples for one history-matched New Albany Shale Gas well

The 9 years production data of a well which is completed in New Albany shale, western Kentucky has been used to verify the built fracture network and perform history matching. Figure 4 shows production rates and cumulative production from the well in green and purple dots, respectively while modeled production rate and cumulative production are shown as red and blue profiles. This figure shows that the base model has significantly overestimated the production from this well. According to the well completion report (11) the initial rate after the stimulation at July 1973 is around146 MCF/day while the

model results start at 127,830 MCF/day and declines to more than 70 MCF/day in about last nine years of production.

To match the production from the New Albany Shale with the FracGen/NFflow simulator, sensitivity analysis was performed on fracture network properties (Fracture Aperture, Length, and Density) and reservoir properties (Pi, φ_m, Km, and h) in order to make the best estimation of NAS natural fracture network pattern.

Sensitivity Analysis on Reservoir and Fracture Properties

The objective of sensitivity analysis is to study the impact of different parameter and identify the factors that have the most contribution to flow.

To investigate the effect of different reservoir and fracture property on flow behavior, several studies were performed. The approach used for this analysis, starts by building the fracture network model based on the available information in literature (in FracGen). After performing the sensitivity analysis, the fracture network and reservoir properties of base model are tuned in order to match the observed production for each of the gas wells in New Albany shale.

As shown in Figure 5 through**Error! Reference source not found.**, sensitivity analysis is performed, with the purpose of scrutinizing the influence of Initial reservoir pressure, matrix porosity, matrix permeability, net pay thickness and aperture reduction factor on flow behavior.

Aperture reduction factor is a term that has been defined as a parameter that can be used in order to shrink the hydraulic apertures of the fractures nearby the well and/or the entire drainage area of the well to further improve the history matched model. Alternatively, the fracture apertures can remain unchanged (reduction factor = 1.0).The process of reducing the aperture is a trial and- error process until the best possible match with production data or well test data is obtained for each of one or more networks.

As illustrated on Figure 9, which represent the comparison of the influence of reservoir and fracture properties on flow rate based on the sensitivity analysis results, the key parameters that have substantial effect on production behavior are initial reservoir pressure pay thickness and aperture reduction factor (ARF).

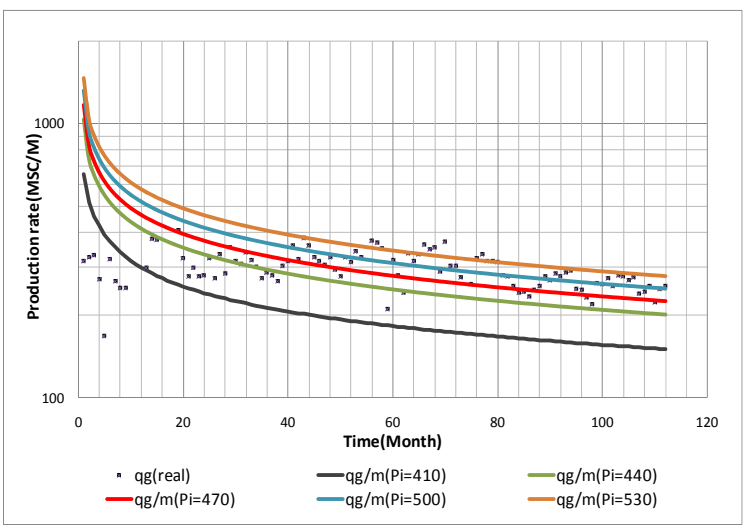


Figure 5- Sensitivity analysis on initial reservoir pressure (Monthly gas production)

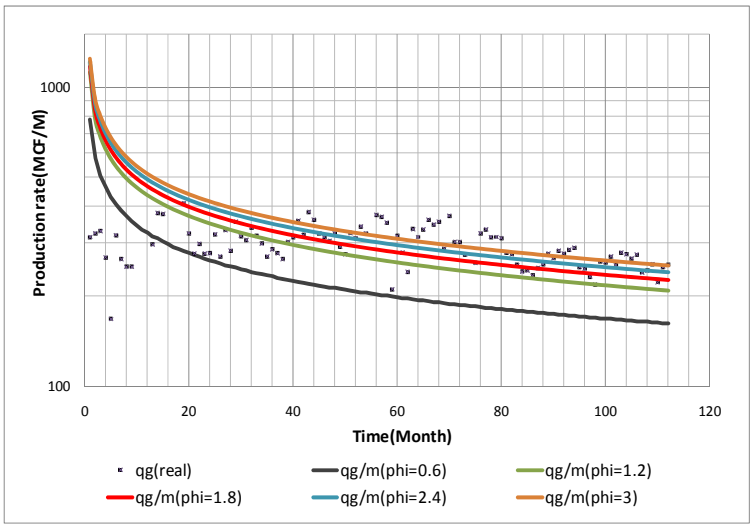


Figure 6. Sensitivity analysis on matrix porosity (Monthly gas production)

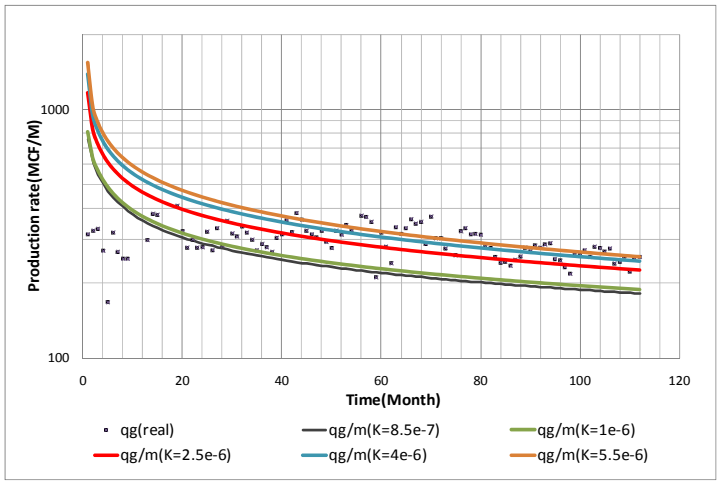


Figure 7. Sensitivity analysis on matrix permeability (Monthly gas production)

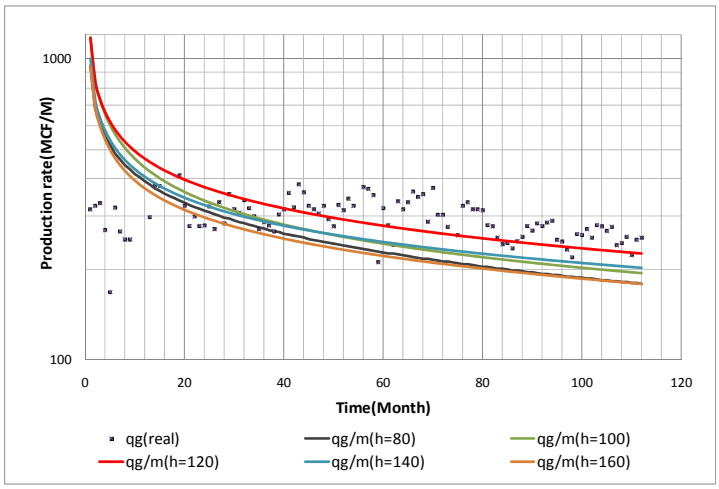


Figure 3. Sensitivity analysis on pay thickness (Monthly gas production)

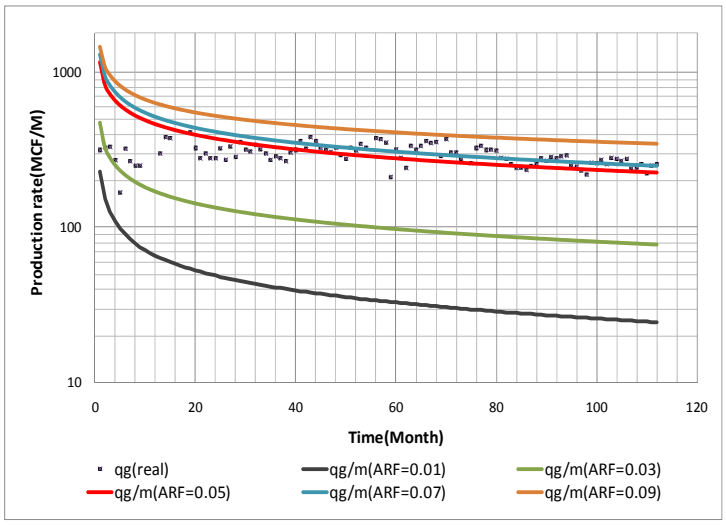


Figure 4. Sensitivity analysis on Aperture reduction factor (Monthly gas production)

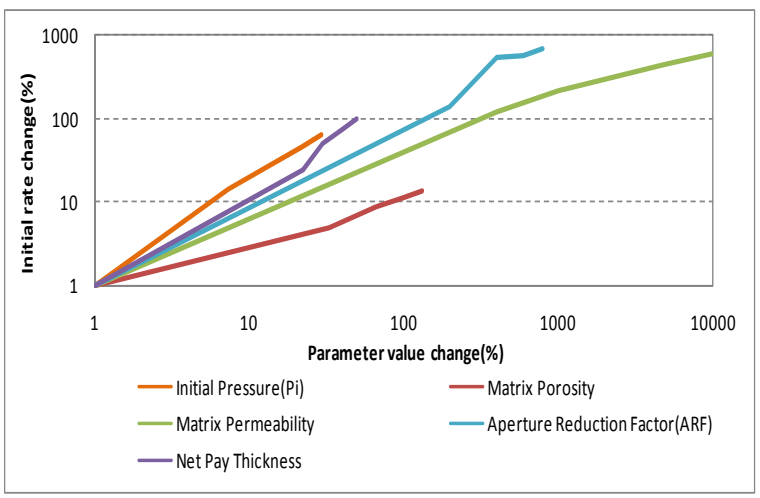


Figure 5. Sensitivity analysis - Effect of reservoir and fracture properties variation on initial gas rate

In the next part of this study, we intend to understand the effect of fracture length and density on production and reservoir behavior. Reservoir properties (h, φm, Km, Pi), fracture orientation, inner cluster fracture length & density, fractures aperture and bedding properties were assumed to remain unchanged. Therefore, the only parameters that have been changed are fracture length ad density.

Hence, sensitivity analysis was performed for values of fracture length and density. Table 3 represents the suggested values for fracture length and density for one of fracture set.

Table 3. Multiple values for fracture length and density

Density	Very Short (LVS)	Short (LS)	Average (LA)	Long (LL)	Very Long (LVL)
Very High (DVH)	D: e-4 L: 1-150	D: e-4 L: 1.5-200	D: e-4 L: 2-250	D: e-4 L: 3.5-325	D: e-4 L: 5-400
High (DH)	D: 8 e-5 L: 1-150	D: 8 e-5 L: 1.5-200	D: 8 e-5 L: 2-250	D: 8 e-5 L: 3.5-325	D: 8 e-5 L: 5-400
Medium (DM)	D: 6 e-5 L: 1-150	D: 6 e-5 L: 1.5-200	D: 6 e-5 L: 2-250	D: 6 e-5 L: 3.5-325	D: 6 e-5 L: 5-400
Low (DL)	D: 4 e-5 L: 1-150	D: 4 e-5 L: 1.5-200	D: 4 e-5 L: 2-250	D: 4 e-5 L: 3.5-325	D: 4 e-5 L: 5-400
Very Low (DVL)	D: 2 e-5 L: 1-150	D: 2e-5 L: 1.5-200	D: 2e-5 L: 2-250	D: 2e-5 L: 3.5-325	D: 2e-5 L: 5-400

Length

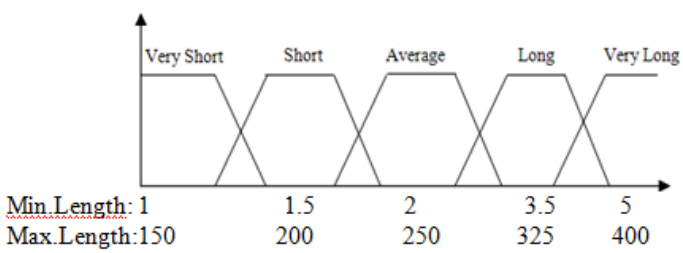


Figure 11 . Fuzzy sets of Fracture Length

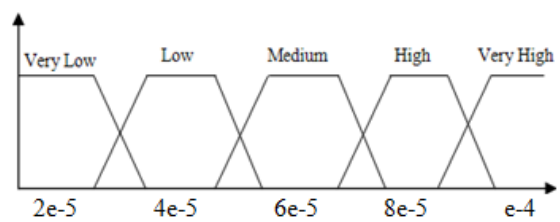


Figure 12. Fuzzy sets of Fracture Density

Through Figure 17 demonstrate the results of sensitivity analysis based on fuzzy values of fracture length and fracture network density. The production data was available for just a part of well's life so the complete production profile has been generated and initial rate after stimulation has been used to verify the predicted initial rate.

According to sensitivity analysis results, with increasing fracture length or fracture density the production will be increased. In the case that fracture length and/or density are low the fracture intersection will be decreased significantly, as a result some part of the reservoir will not be depleted, so the only way to put those parts of reservoir on production is performing some sort of stimulation (hydraulic fracturing).

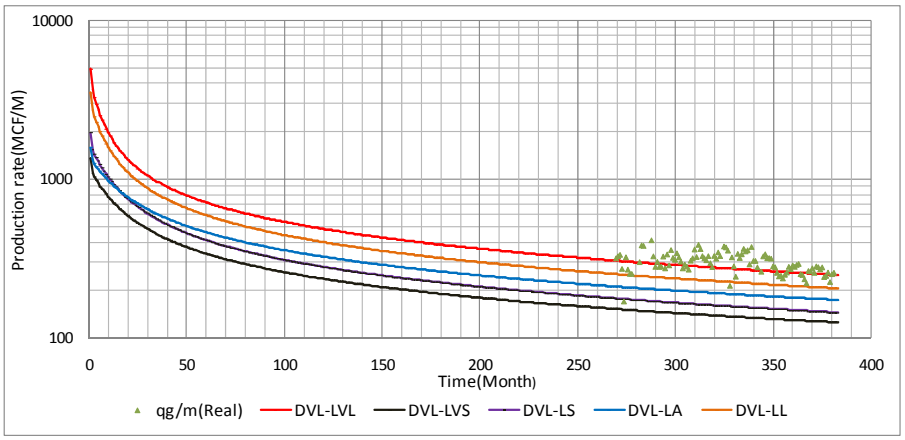


Figure 13. Sensitivity analysis results (Monthly gas production) (Very low fracture network density with variable length)

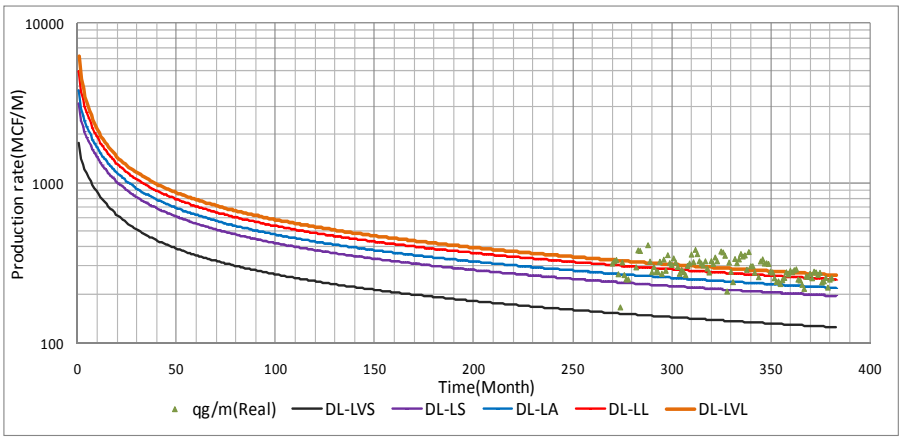


Figure 14. Sensitivity analysis results (Monthly gas production) (Low fracture network density with variable length)

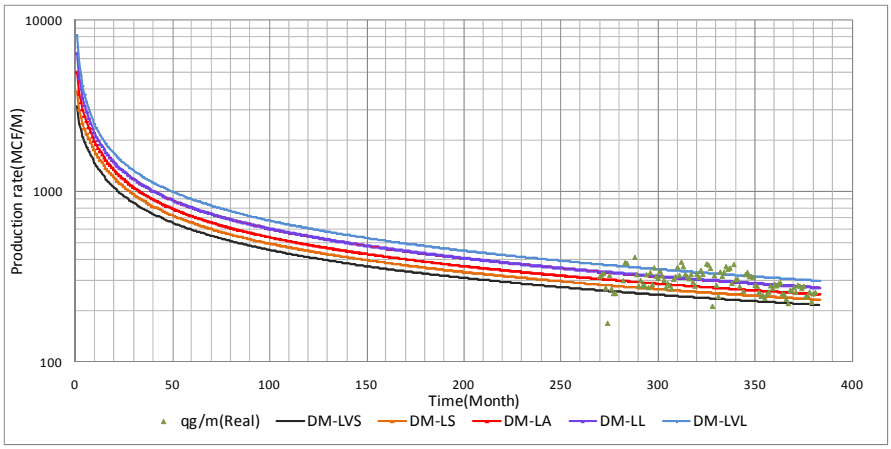


Figure 15. Sensitivity analysis results (Monthly gas production) (Medium fracture network density with variable length

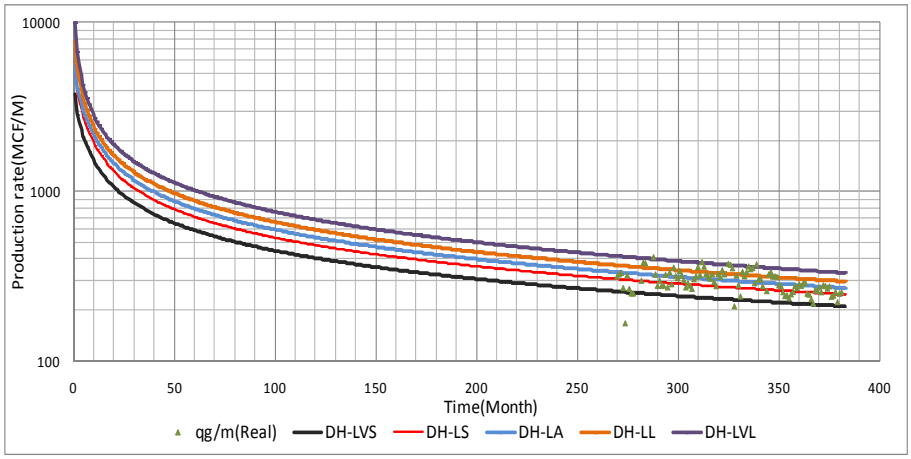


Figure 16. Sensitivity analysis results (Monthly gas production) (High fracture network density with variable length)

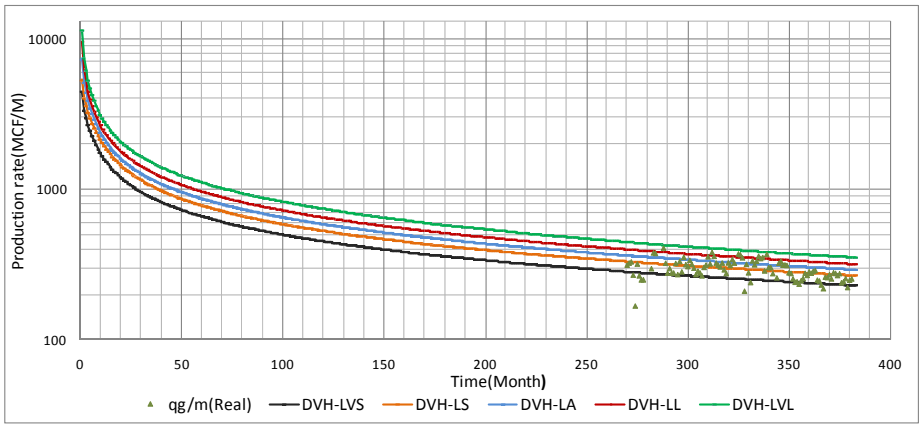


Figure 17. Sensitivity analysis results (Monthly gas production) (Very high fracture network density with variable length)

History Matched Model

Upon completion of the sensitivity, analysis and careful study of the impact of different parameters on production a new set of parameters were identified. This new set was used in the model. The result is shown in Figure 18.

According to the well completion report (10), the initial rate after the stimulation at July 1973 is 146 MCF/Day. The history matched model results in an initial production rate of 141 MCF/Day, which shows the reliability of fracture network and history matched model.Figure 18 shows production rates and cumulative production from the well in green and purple dots, respectively while modeled production rate and cumulative production are shown as red and blue profiles.

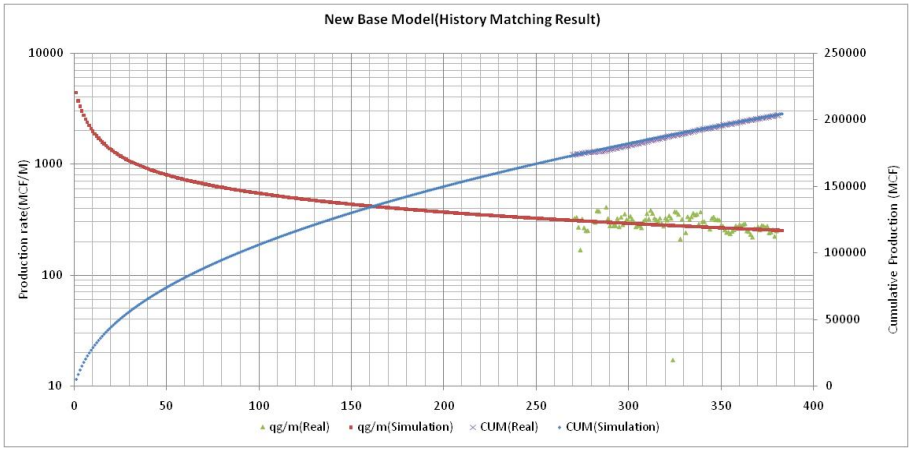


Figure18. Single well history matching result, after changing the key

The final values of input parameters that are used in simulation (final history matching) are illustrated in Table 4.

Table 4. Shows the input parameters for single well history matching (Best match)

Matrix Permeability (md)	Matrix Porosity (%)	Initial Pressure (psi)	Thickness (ft)	A (Acres)	Aperture reduction factor(ARF)
1.5E-7	2.2	500	100	320	0.056

Fracture network characteristics used for the history-matched model are shown in Table 5 and the fracture network distribution for the base model is illustrated in Figure 19..

Table 5. Fracture network properties (History matched model)

	Fracture Properties	Fracture Length(ft)	Fracture Aperture(ft)	Fracture Density	Major Fracture orientation
Major fracture generator	Set 1	2-200	0.00055	0.00006	E 95° W
	Set 2	2-200	0.0004	0.00006	E 97°W
Bedding generator	Set 3	5-200	0.0004	0.000009	E 90°
	Set 4	400-1000	0.00025	0.00002	E 24° N

As shown in Table 1 and Table 5, the fracture network properties has been modified in order to get better history match is fracture aperture values.

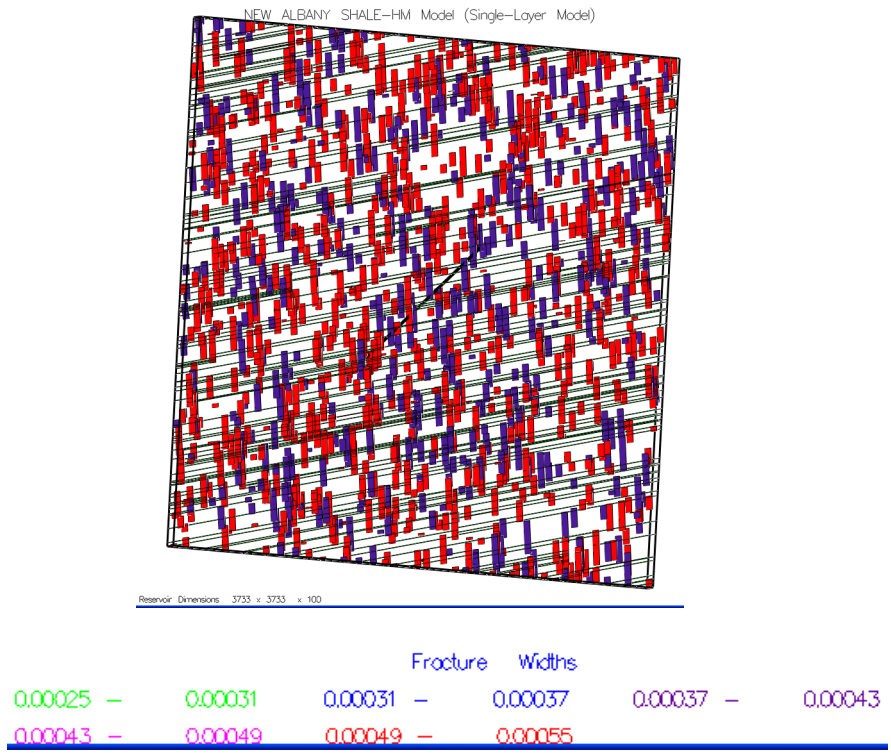


Figure 19. The well and fracture intersection for the history matched model (Based on 320 acre spacing)

Effect of lateral orientation on well productivity

In order to understand the impact of the orientation of horizontal wells on gas production in New Albany Shale the fracture network and reservoir properties are assumed to be the same for all the models to see the effect of different well orientations in horizontal plane (not Z-direction) on production and well performance. Figure 21 shows the history match results based on different well orientations in horizontal plane (0, 30,45,60,75 and 90 degree).The result of this study shows that the history-matched models of different well orientation in X-Y plane have only slight difference in production profile(Qi, Di and b). Therefore, horizontal well orientation has not substantial effect on well performance (Table 6).

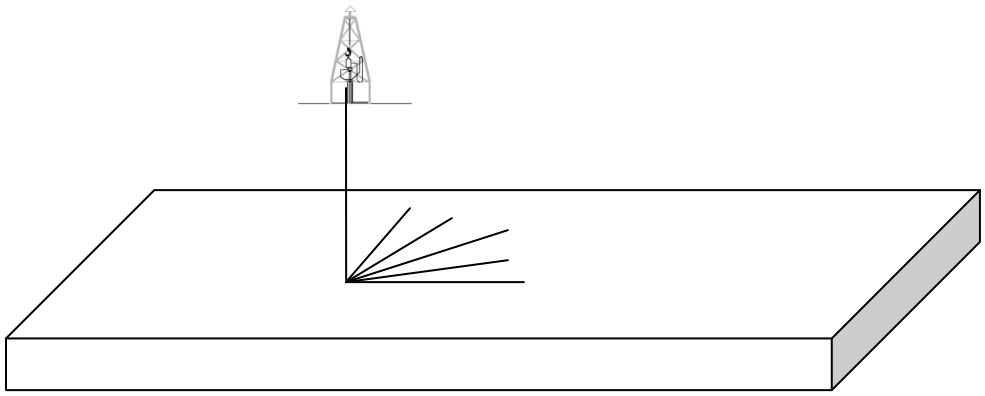


Figure 20. Horizontal well orientations in Y direction (0, 30, 45, 60, and 90 degrees)

Table 6. Initial rates based on different well orientation-History matched model

Well Orientation (degree)	Q_i (MCF/day)
0	140.13
30	140.24
45	140.56
60	140.76
75	141.19
90	140.01

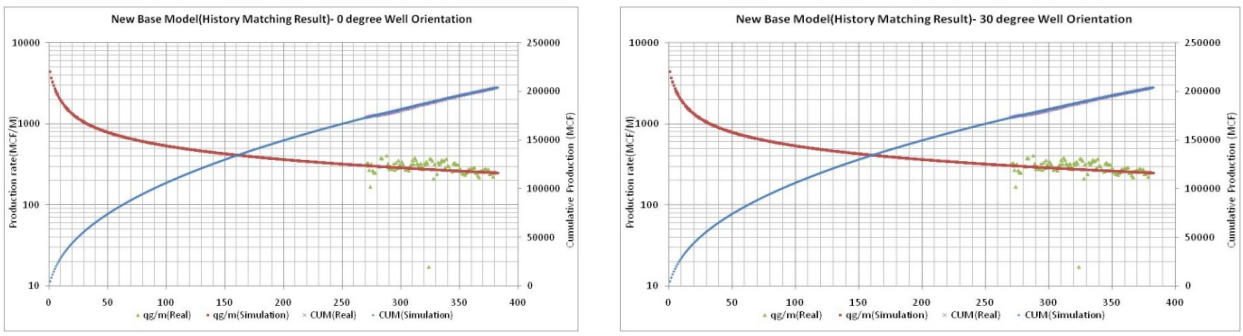


Figure 21. Single well history matching result-Zero and 30-degree well orientation (From left to right)

Part 2: Top-Down Intelligent Reservoir Modeling of New Albany Shale

Traditional Reservoir Simulation & Modeling

Reservoir simulation is the industry standard tool to understand the reservoir behavior and predict future performance. It is used in all phases of field development in the oil and gas industry. In order to predict reservoir performance, a series of models of reservoir process are constructed which yield information about the complex phenomena accompanying different recovery methods.

Full field reservoir simulation models which has been built by integration of static and dynamic measurements into the reservoir model have become the major source of information for analysis, prediction and decision making. Traditional reservoir simulation and modeling is a bottom-up approach that starts with building a geo-cellular model of the reservoir. Using modeling and geo-statistical manipulation of the data the geo-cellular model is populated with the best available petrophysical and geophysical information at the time of development. Engineering fluid flow principles are then added and solved numerically in order to generate a dynamic reservoir model. Figure 22 shows the Conventional reservoir simulation workflow (A bottom-up approach).

Usually, the full field model is calibrated using historic pressure and production data in a process referred to as "history matching." Once the full field subsurface reservoir model has been successfully calibrated, it is used to predict future reservoir production under a series of potential scenarios, such as drilling new wells, injecting various fluids or stimulation.

For economical and technical point of view, building a complex geological model, which serves as the foundation of the reservoir simulation model, needs a significant investment (time and money).On the other hand, the history matching process itself can be very time consuming and frustrating. This is due to

uncertainty about the reservoir, and the fact that a history match can usually be achieved through various configurations - a set of unique and distinctly different simulation models (which all condition to input data) can produce the same history match. How do we know which one is correct? (12)

Despite aforementioned issues, conventional reservoir simulation and modeling is a well understood technology that usually works well in the hand of an experienced team of engineers and geoscientists.

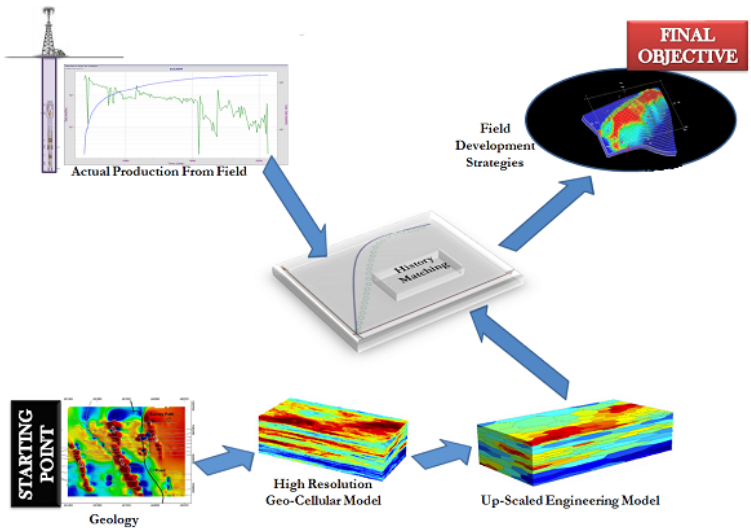


Figure 22. Conventional Reservoir Simulation &Modeling-A Bottom-Up Approach

Top-Down Intelligent Reservoir Modeling (TDIRM) as an Alternate/Complement to Conventional Reservoir Modeling Techniques

TDIRM can be used as an alternative for short-term reservoir modeling and/or as a complementary method for long term, reservoir behavior modeling.

Top-Down Intelligent Reservoir Modeling approaches the reservoir simulation and modeling from reverse standpoint by attempting to make an insight into reservoir by starting with actual field measurements (well production history). The production history is augmented by core, log, well test, and seismic data in order to increase the accuracy of the Top-Down modeling technique. Although not intended as a substitute for the conventional reservoir simulation of large, complex fields, this unique approach to reservoir modeling can be used as an alternative (at a fraction of the cost) to traditional reservoir simulation and modeling in cases where performing conventional modeling is cost and man-power prohibitive specially for independent producer of mature fields. In cases where a conventional model of a reservoir already exists, Top-Down modeling should be considered a compliment to the conventional technique, to provide an independent look at the data coming from the reservoir/wells for optimum development strategy and recovery enhancement.

Top-Down Intelligent Reservoir Modeling starts with well-known reservoir engineering techniques such as Decline Curve Analysis, Type Curve Matching, and History Matching using single well numerical reservoir simulation, Volumetric Reserve Estimation, and calculation of Recovery Factors. Using statistical techniques, multiple Production Indicators (First 3, 6, and 9 month cumulative production as well as 1, 3, 5, and 10-year cumulative oil, gas and water production and Gas Oil Ratio and Water Cut) are calculated. These analyses and statistics generate a large volume of data and information that are spatio-temporal snap shots of reservoir behavior. This large volume of data is processed using the state-

of-the-art in artificial intelligence and data mining (neural modeling (13), genetic optimization (14), and fuzzy pattern recognition (15)) in order to generate a complete and cohesive model of the entire reservoir. This is accomplished by using a set of discrete modeling techniques to generate production related predictive models of well behavior, followed by intelligent models that integrate the discrete models into a cohesive picture and model of the reservoir as a whole, using a continuous fuzzy pattern recognition algorithm.

The Top-Down Intelligent Reservoir Model is calibrated using the most recent set of wells that have been drilled in the field. The calibrated model is then used for field development strategies and reservoir management to improve and enhance hydrocarbon recovery. Figure 23 shows the Top down intelligent reservoir modeling workflow.

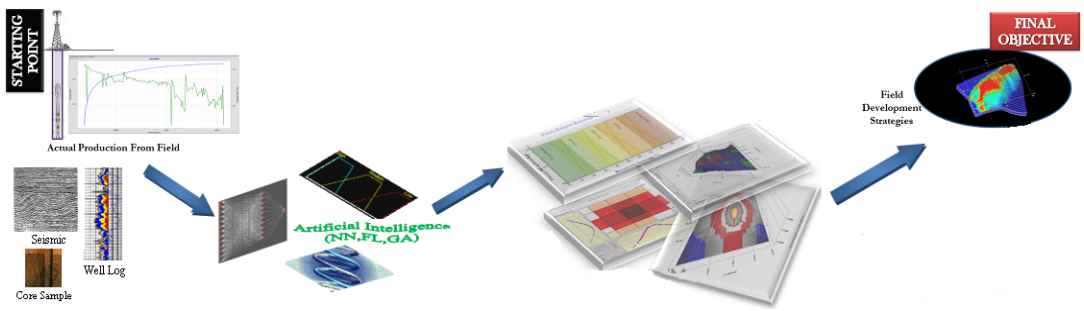


Figure 23. Top-down Intelligent Reservoir Modeling Workflow

Top-Down Modeling Methodology-Conceptual Approach

Top-Down Modeling is a well-designed integration of state-of-the-art in Artificial Intelligence & Data Mining (AI&DM) with solid reservoir engineering techniques and principles. It provides a unique perspective of the field and the reservoir using actual measurements. It provides qualitatively accurate reservoir characteristics that can play a key role in making important and strategic field development decisions. A brief summary of several components of this approach to reservoir modeling and management has been followed:

1. **Decline Curve Analysis:** Conventional hyperbolic decline curve analysis is performed on oil, gas and water production data of all the wells. Intelligent Decline Curve Analysis is used to model some production data such as GOR and Water Cut that does not usually exhibit a positive but rather a negative decline.
2. **Type Curve Matching:** Using the appropriate type curves, production data from all wells are analyzed. Special techniques are used to remove the inherent subjectivity associated with type curve matching process.
3. **History Matching:** History matching is performed on all individual wells using a single well radial numerical simulation model.
4. **Production Statistics:** General statistics are generated based on the available production data such as 3, 6, 9 months cumulative production and one, three, five and ten years cumulative productions. Similar data is generated for Gas Oil Ratio and water cut.
5. **Volumetric Reserve Estimation:** Using Voronoi graph theory in conjunction with well logs, estimated ultimate drainage area and volumetric reserves are estimated for each well, individually.
6. **Recovery Factor Calculation:** Using the results of Decline Curve analysis and Volumetric Reserve Estimation, a well-based Recovery Factor is calculated for all wells, individually. A

field-wide Recovery Factor is also calculated. This would be an item that will be optimized in the consequent steps of the analysis.

7. **Discrete Predictive Modeling:** Results of the abovementioned analyses are a wealth of data and information that are generated based on individual wells. This information is indicative of reservoir/well behavior at specific time and space throughout the life of the reservoir. Using AI&DM techniques discrete, intelligent, predictive models are developed based on the large amount of data and information that has been generated. The predictive models represent all aspects of reservoir characteristics that have been analyzed.
8. **Continuous Predictive Modeling:** Using two-dimensional Fuzzy Pattern Recognition (FPR) technology, discrete predictive models are fused into a cohesive full-field reservoir model that is capable of providing a tool for integrated reservoir management.
9. **Model Calibration:** The full field model is calibrated based on classifying the reservoir into "most" to "least" prolific areas, prior to be used in the predictive mode. This is done using the latest drilled wells in the field. This practice is an analogy of history matching of the conventional reservoir simulation models. The calibrated model can then be used in predictive mode for field development strategies.
10. **Field Development Strategies:** Performing economic analysis, while taking into account the uncertainties associated with decision making, multiple field development strategies are examined in order to identify the optimum set of operations that would result in recovery enhancement. This process includes identification of remaining reserves, sweet spots for infill drilling as well as under-performer wells.

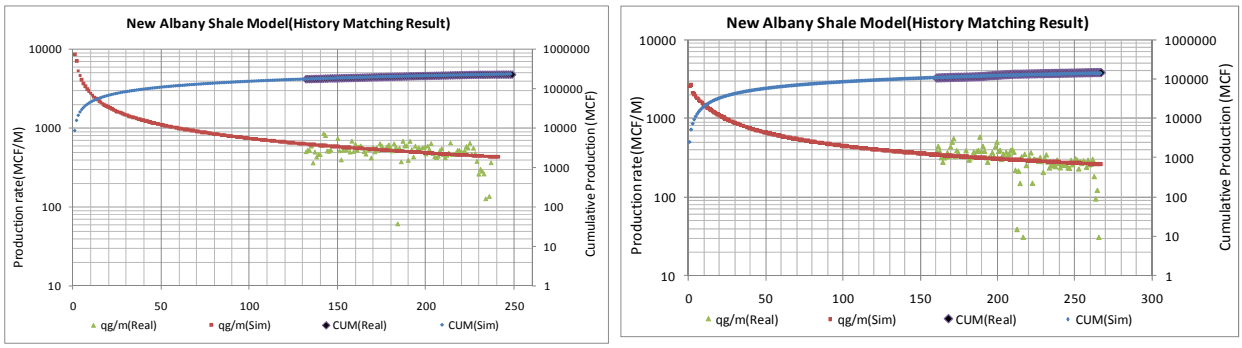
Data Preparation Procedure

Location and monthly production rate data for all wells and well logs (not necessary for all wells) are the minimum data requirement for the Top-Down modeling. Although gas has been produced from the New Albany Shale in the Illinois Basin for more than a century, available gas production data are sparse. Production data for the older wells were either never recorded or have not been preserved. Moreover, information about recent production is difficult to obtain. The New Albany shale data for 87 wells in Western Kentucky region was extracted from Kentucky geological survey and prepared for the analysis.

Because only last 6-9 years of production history was available for the wells mentioned above, a unique natural fracture network modeling and simulation (FracGen/NFFlow) was performed in order to generate (through history matching) a relatively complete production profile for each of the 87 wells. The complete production profiles were generated using FracGen/NFFlow for the 87 wells. These production profiles were used to perform Top-Down Intelligent Reservoir Modeling (TDIRM) for the New Albany Shale gas reservoir.

Figure 24 illustrates an example of generating the complete production profile for two of the NAS wells. In this figure, the green and black dots represent the actual production rates and cumulative production data collected from the Kentucky Geological Survey while the red and blue lines represent the history matched production rate and cumulative production profiles.

In this study, FracGen/NFFlow numerical simulator has been used to model natural fracture network and simulate a single gas well in New Albany shale.



(A) (B)

Figure 24. Simulation result examples for two history-matched New Albany Shale Gas wells (Out of 87 wells)

Results and Discussion

Figure 26 represent the location of wells being studies in Western Kentucky. To enhance the resolution of the study area, the wells being analyzed were divided into 2 clusters of 55(Case1) and 32(Case 2) wells. Both cases were analyzed during this study.

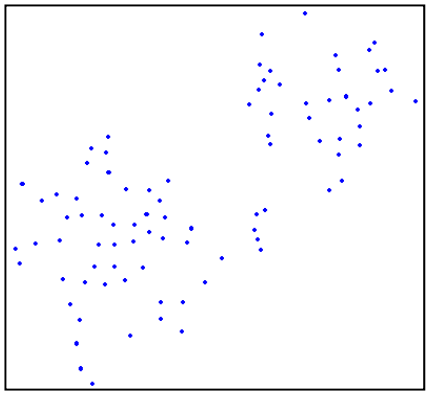


Figure 25. Location of under-study NAS gas wells

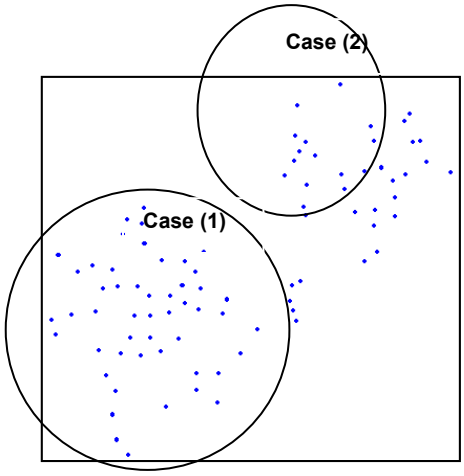


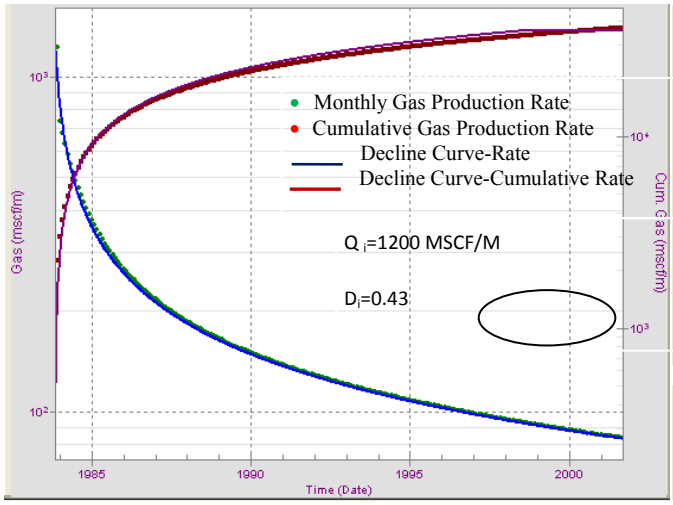
Figure 26. Two clusters of NAS wells for analysis (Case 1&2)

Case 1

The Top-Down Intelligent Reservoir Modeling (TDIRM) begins by plotting production rate and cumulative production versus time on a semi-log scale. An automatic optimization routine based on genetic algorithms identifies the best decline curve for the given well, as both the rate versus time and the cumulative production versus time are simultaneously matched. This is demonstrated in Figure 27 for one of the NAS gas wells. Initial production rate Qi, initial decline rate Di, and hyperbolic exponent b are automatically identified. Additionally, the 30-year EUR is calculated. The information that results from the decline curve analysis is then passed to a type curve matching (TCM) procedure.

The appropriate type curves for the reservoir and fluid that is being investigated are selected. The type curves developed by Cox et al. (1995) have been used for the analysis of low-permeability shale gas reservoirs assuming constant bottom-hole pressure.

The type curve matching (TCM) has been performed by plotting the production profile using decline curve analysis results rather than the actual production data in order to minimize the subjectivity of the type curve matching. Performing decline curve and type curve analyses is an iterative process.



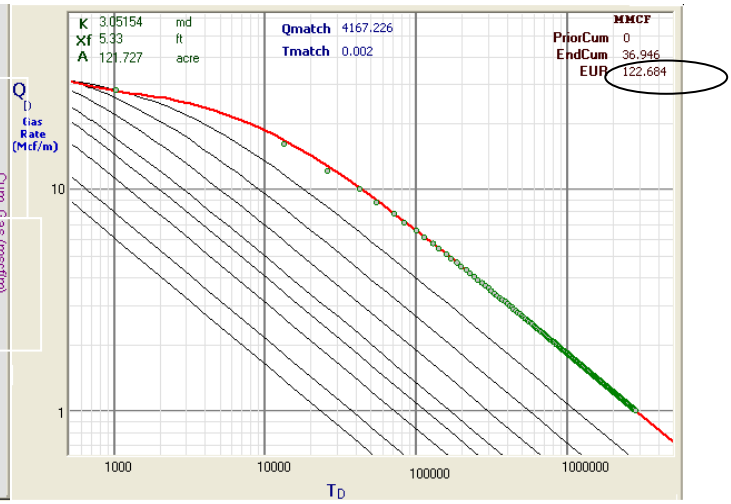


Figure 27. Decline curve analysis sample for one of NAS Gas wells

Figure 28.Type curve matching sample for one of NAS Gas wells

While following this procedure, we should always keep an eye on the 30 years EUR value calculated by these two methods as a controlling yardstick. These values should be reasonably close.

The third step of TDIRM is numerical reservoir simulation using a single-well, radial numerical simulator. During history matching the production data, all of the information generated from the DCA and TCM is used to achieve an acceptable match. Decline curve analysis, type curve matching, and single well history matching are an iterative process. Figure 29 represent the qualitative comparison between the result of history matching process and decline curve analysis.

Once the individual analysis for all of the wells in the field is completed, the following information for all the wells in the field is available: initial flow rate (Qi), initial decline rate (Di), hyperbolic exponent (b), permeability (k), drainage area (A), fracture half length (X_f), and 30 Year EUR. Figure 29 shows the well locations, followed by identification of boundary and the Voronoi grids for all the wells in the analysis for case 1.

Using the results of Decline Curve analysis and Volumetric Reserve Estimation, a well-based Recovery Factor is calculated for all wells, individually. A field-wide Recovery Factor is also calculated. Figure 31illustrates the calculate recovery factory of 17.47 % for one of the wells and Field recovery factor of 23.58%.

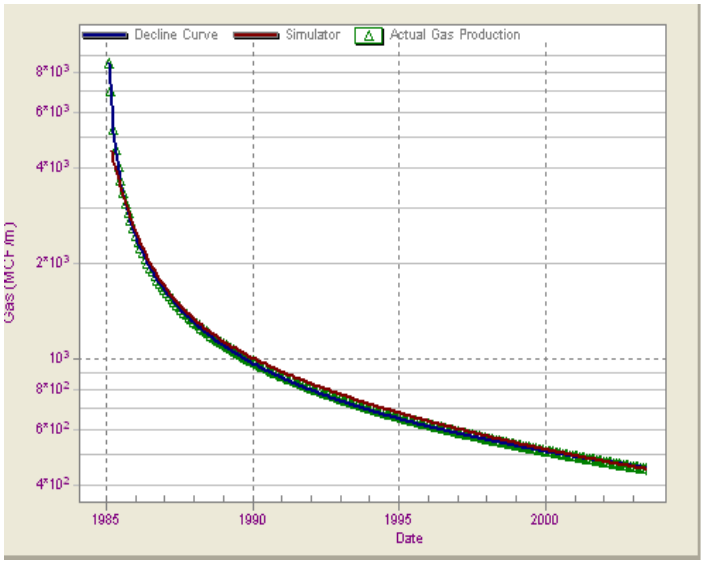


Figure 29.History matching results in comparison with DCA for one of the wells

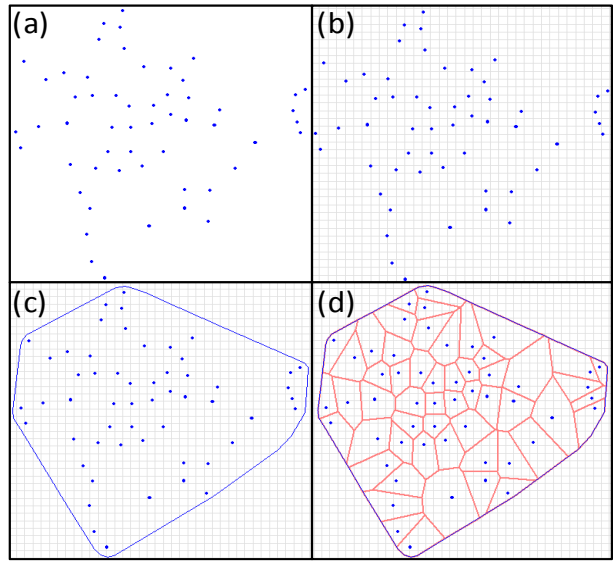


Figure 30.Generating the Voronoi cells for 55 NAS wells (Case 1)

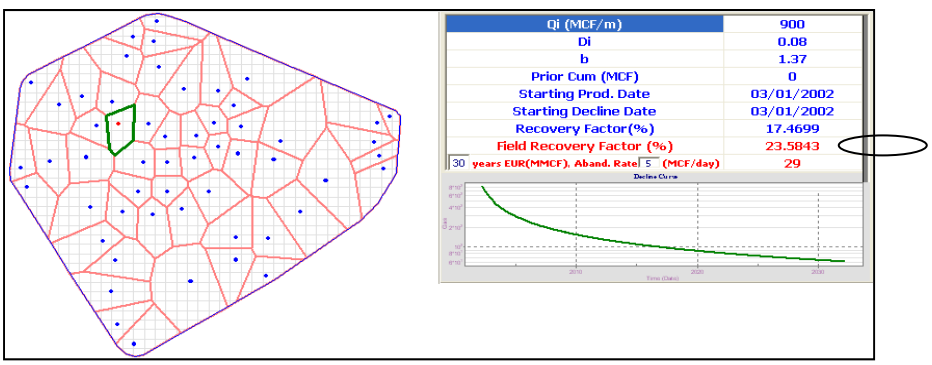


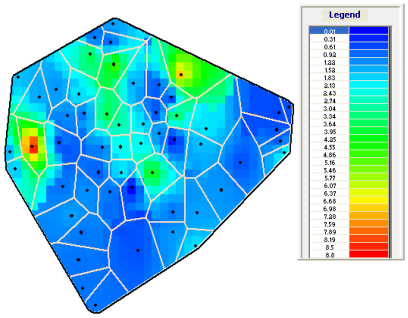
Figure 31. Calculated recovery factor for individual wells as well as field recovery factor

Once the Decline Curve Analysis and other steps mentioned above were completed, discrete, intelligent, predictive models are developed for the reservoir (production) attributes such as, first 3, 6, 9 month and 1, 3, 5, 10 years of cumulative production, decline curve information (Qi, Di and b), EUR, Fracture half length, matrix and total porosity, matrix and total permeability, net pay thickness, Initial gas in place, and well recovery factor. These sets of discrete, intelligent models are then integrated using continuous fuzzy pattern recognition in order to arrive at a cohesive model of the reservoir as a whole.

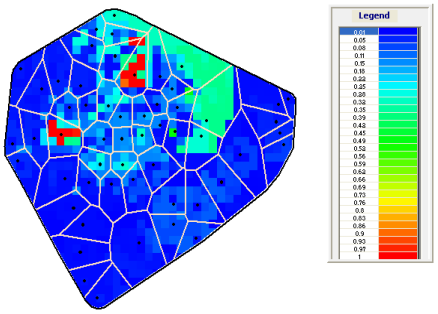
Using geostatistics a high level earth model is built. As part of the out comes of the high level earth model some of the two dimentsional maps of characteristics of the field such as porosity, permeability, and Initial Gas In Place distribution are shown in Figure 32 and Figure 33. Another part of Top-Down, Intelligent Reservoir Modeling (TDIRM) includes analysis of flow and production pattern characteristics usin fuzzy pattern recognition as shown in Figure 34 and Figure 35.

Upon completion of these analyses a rather complete spatio-temporal picture of the fluid flow in the reservoir emerges. The maps that are generated through these processes develop a sereis of visual guidelines that can help engineers and geo-scientist analyze reservoir behavior as a function of time and make decisions on field development strategies. Furthermore, optimum infill locations, examininig

different infill scenarios and identifying potential remaining reserves based on each scenario and identifying underperformer wells are among tangible results that can be concluded from such analyses.

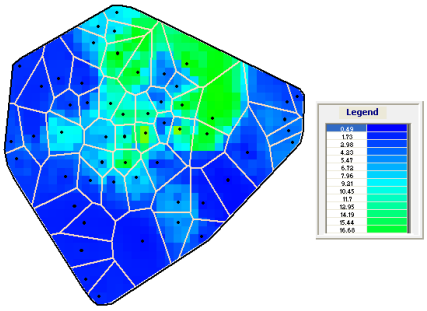


Matrix porosity (From simulation)

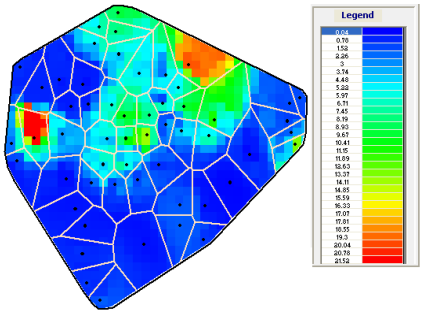


Matrix Permeability ((md)*10^-6) (From simulation)

Figure 32. Results of discrete predictive modeling showing the distribution of matrix porosity, and matrix permeability for the entire field (From left to right)



Total Permeability (From type curve)



Initial gas in place (IGIP)

Figure 33. Results of discrete predictive modeling showing the distribution of total permeability from type curve and initial gas in place for the entire field (From left to right)

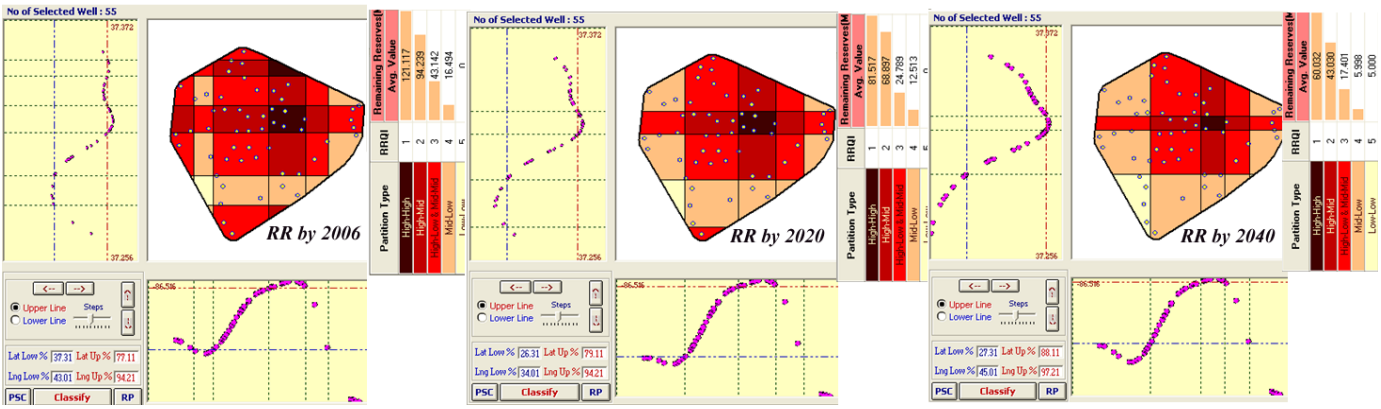
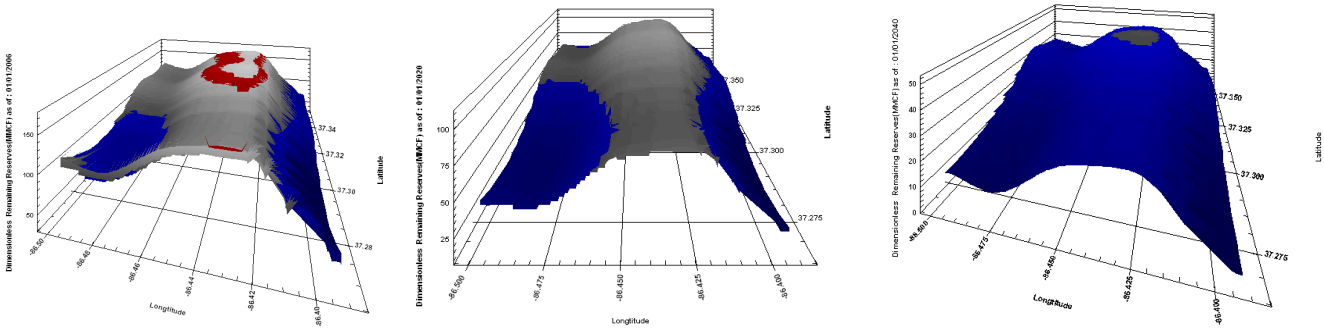


Figure 34. Results of Fuzzy Pattern Recognition showing the sweet spots in the field for the remaining reserve (MMCF) as of 2006, 2020 and 2040



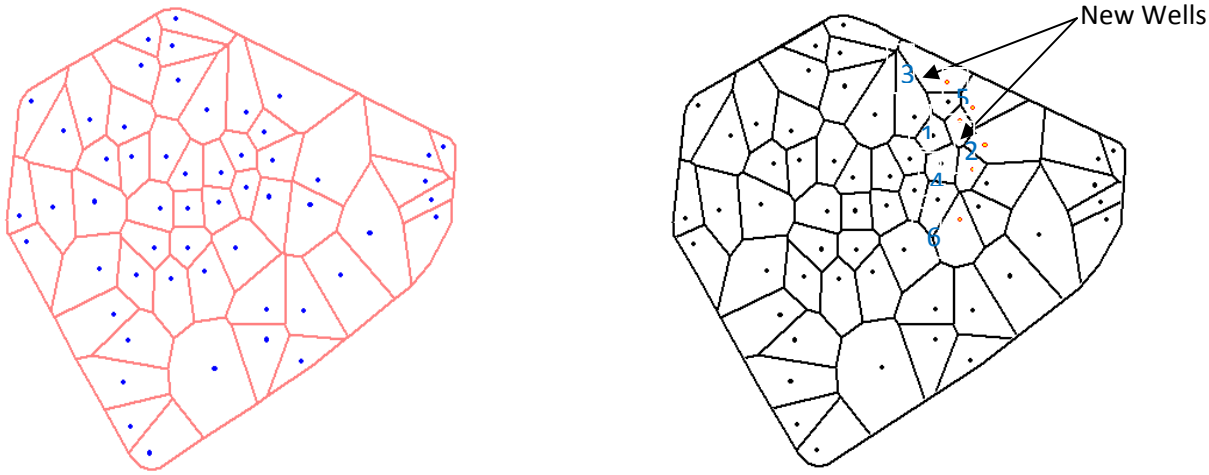
Remaining Reserve, by 2006 Remaining Reserve, by 2020 Remaining Reserve, by 2040

Figure 35. Remaining reserve as a function of time

The remaining reserve as of year 2006,2020 and 2040 has been shown in Figure 34 and Figure 35. In the two dimensional maps (Figure 34) reservoir is delineated with Relative Reservori Quality Index (RRQI) being the Remaining Reserves. The delineation shown in this figure are indicated by colors. Higher quality regions (regions with high values of Remaining Reserves) are shown in darker colors and as the average value of Remaining Reserves reduces in each region, the color becomes increasing ly lighter. The difference between these three figures shows the depletion in the reservoir and identifies the parts of the field that still have potential for more recovery.

Based on the results of predictive modeling and fuzzy pattern recognition, the best spots for drilling new wells were decided. The permeability is a key parameter that plays an important role in fluid production from the reservoir. Thereby having high initial production rate in the locations which have high permeability makes sense. Another important factor while making decision about the infill drilling locations is remaining reserves. It defines the amount of the stored fluid in the reservoir. Having both the remaining reserves and permeability, results in high storage and flow capacity. Thus, the potential spots for infill drilling can be selected, based on these parameters. Although these two parameters have considerable effect on deciding the new well locations, other parameters such as forcasted EUR for 30 years, matrix porosity,initial gas in place and also fracture half length have been taken into account.

According to these analyses, six new wells were proposed to be drilled in the reservoir. Locations of these new wells are shown in Figure 36. This figure also illustrates the change of drainage area ofter placement of new wells.



Voronoi Grid Cells Before New Wells Placement

Voronoi Grid Cells After New Wells Placement

Figure 36. Proposed infill drilling locations and drainage area before and after placement of new wells (From left to right)

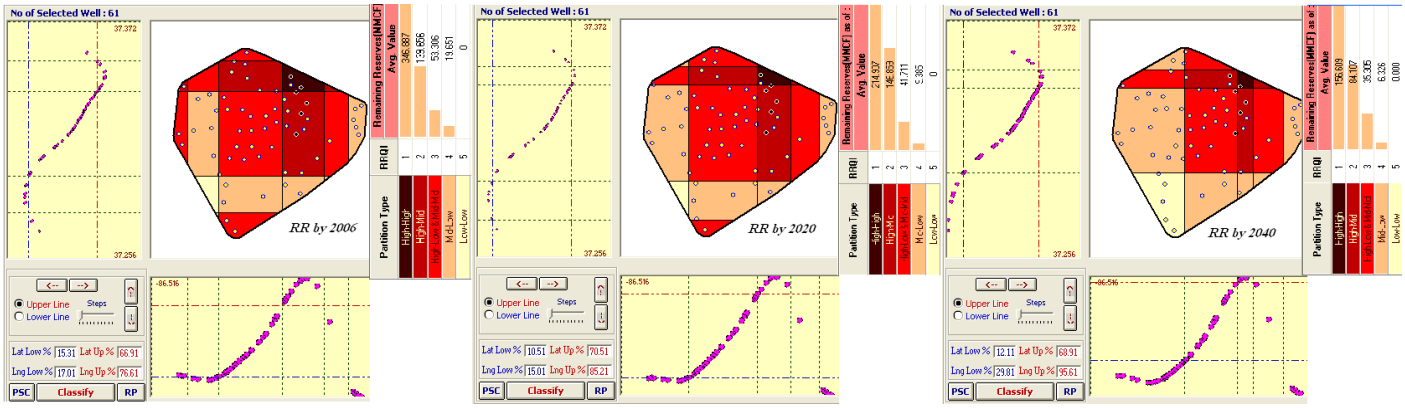
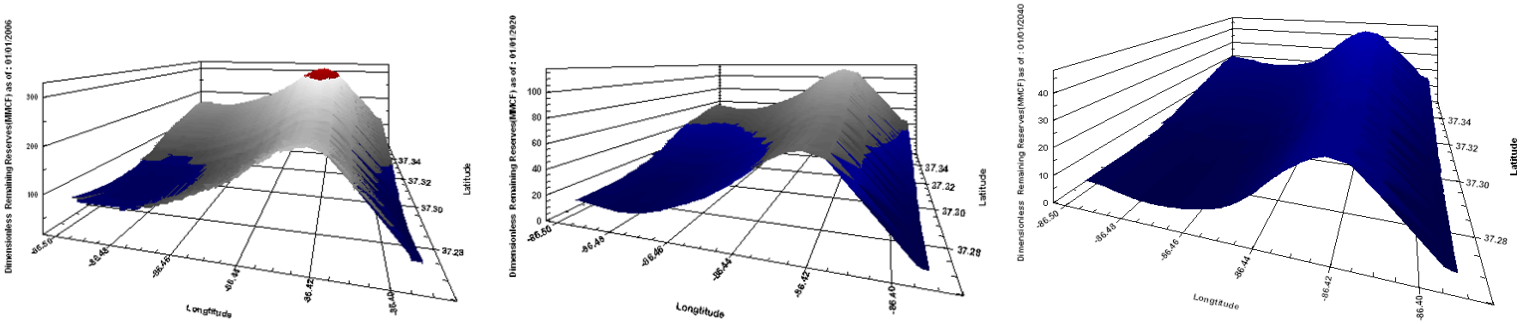


Figure 37. Results of Fuzzy Pattern Recognition showing the sweet spots in the field for the remaining reserve (MMCF) as of 2006, 2020 and 2040 (After drilling 6 extra wells)



Remaining Reserve, by 2006

Remaining Reserve, by 2020

Remaining Reserve, by 2040

Figure 38. Remaining reserve as a function of time (After drilling 6 extra wells)

Figure 37 and Figure 38 illustrates remaining reserve as of year 2006,2020 and 2040 when those 6 new wells are added to the model. New wells identified in the analyses are shown in Figure 36. By selecting new wells at different locations and repeating the analyses shown in Figure 38 (observing reservoir depletion as a function of their decision on where to place new wells), engineers and geo-scientits can identify the best locations in the field that would provide the best production profiles and that satidfies their economic objectives.

Economic Analyses

The economic analyses were carried out for new infiil drilling liocations. Figure 39 demonstrates the details of economic analysis for one of proposed infill locations.The gas price that has been used in analysis was obtained from Energy Information Administriation (Official Energy Statistics from the U.S. Government) and the the vertical well cost has been estimated around $200,000 (David Wagman). The value of other parameters which are used in economic analysis are based on our best guess. The predicted Net Present Value(NPV) for each new well is listed in Table 7.

Table7. NPV for New infill drilling location

Well ID	NPV for 5 Years(USD)
1	87,054.53
2	102,207.01
3	134,870.31
4	86,170.17
5	124,827.53
6	93,311.03
Average	**104,740.10**

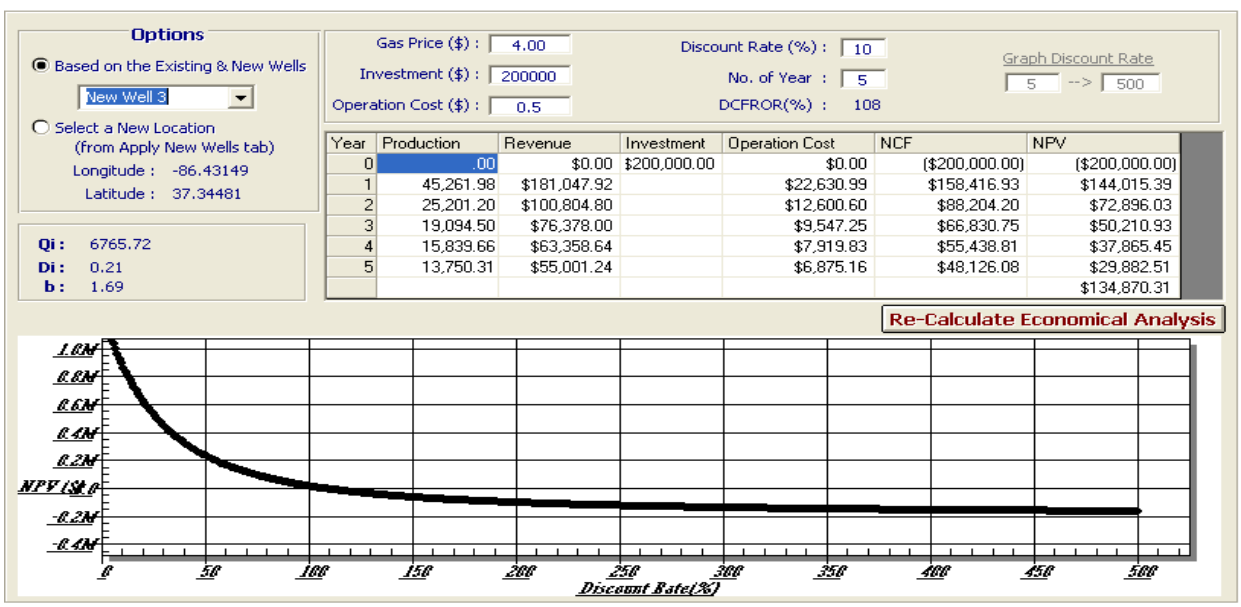


Figure 39. Economic analysis result for new well#3.

Model Calibration and Validation

One of the steps that are taken upon building the Top-Down, Intelligent Reservoir Model (TDIRM) is to calibrate and validate the model. To calibrate the Top-Down models about 10 % of wells for are removed from the analyses. This constitutes removal of 6 wells from the analysis. The models are developed using the remaining 49 wells. The objective is to make sure that the Top-Down model can predict the 1 year cumulative production for these removed wells (blind data set). The results are shown in Table 8 and Figure 40.

For example in Table 8, four Relative Reservoir Quality Indices (RRQI) are shown as well as the model results that indicates the prediction for the blind/validation wells. As indicated in this table the Top-Down model predicted that the average 1 year cumulative production for wells drilled in the RRQI "1" (the darkest areas in Figure 40 will be more than 31.98 MMSCF. One well in RRQI "1" is removed and the average 1 year cumulative production for this well was 35.06 MMSCF **(correct prediction)**.

Furthermore, the Top-Down model predicted that the average 1 year cumulative production for well in the RRQI "2" will be between 16.9 and 31.98 MMSCF. As shown in Table 8, there was 1 well drilled in RRQI "2" and the average 1 year cumulative production for this well was 26.13 MMSCF **(correct prediction)**.

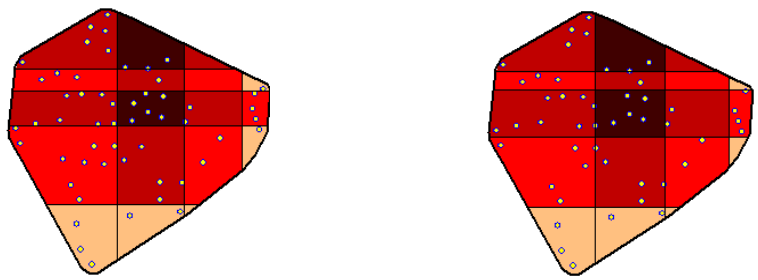
For RRQI "3" the Top-Down model over-estimates the result slightly. It predicted that the average 1 year cumulative production for wells drilled in the RRQI "3" will be between 8.45 and 16.9 MMSCF while the 1 well drilled in RRQI "2" had an average 1 year cumulative production of 18.5 MMSCF.

The Top-Down model predicted that the average 1 year cum. for one well drilled in the RRQI "4" will be between 7.69 and 8.45 MMSCF and it turned out to be 8 MMSCF **(correct prediction)**.

The same methodology has been performed for the second case.

Table 8. Results of Top-Down modeling (Case 1)

1 Year Cumulative Production(MSCF)					
	Model Results			Removed Wells	
RRQI	More Than	&	Less than	Average 1 Yr Cum	No. of Wells
1	31,980.55			35,062.77	1
2	16,894.13	&	31,980.55	26,130.53	2
3	8,447.53	&	16,894.13	18,553.57	2
4	7,686.24	&	8,447.53	8,006.76	1
			7,686.24	Total	6



1 Year Cumulative Production (55Wells) 1 Year Cumulative Production (49 Wells)

Figure 40. Results of Fuzzy Pattern Recognition showing the sweet spots in the field for the 1 Year cum for 55 wells (left) and 1Year cum. Production for 49 wells (right).(Case 1)

Case 2-The same analysis explained in the preceding section has been carried out for second case as well.

The generated field model besed on result of disceret intelligent modeling and fuzzy pattern recognition can be used to estimate the reserves, determine optimum infill drilling locations, follow fluid flow and depletion, verify remaining reserves,and detect underperforming wells (Figure 45 through Figure 49).

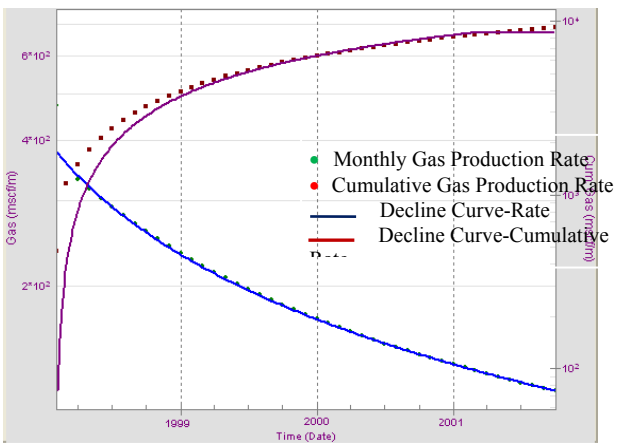


Figure 41. DCA sample for one of NAS Gas wells

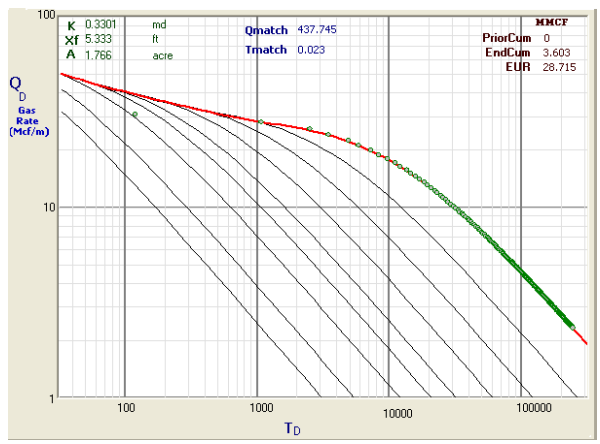


Figure 42. TCM sample for one NAS Gas wells

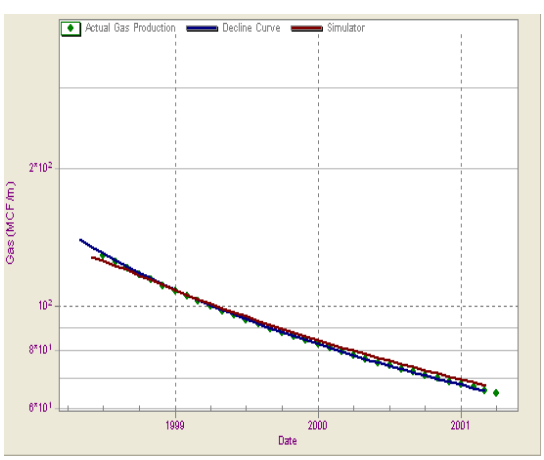


Figure 43. HM results in comparison with DCA

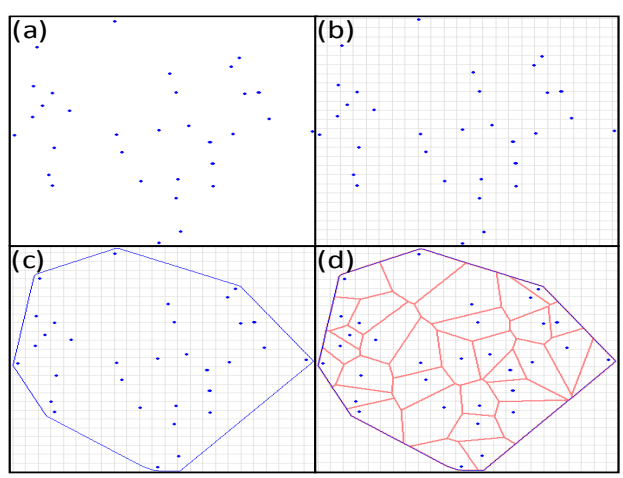
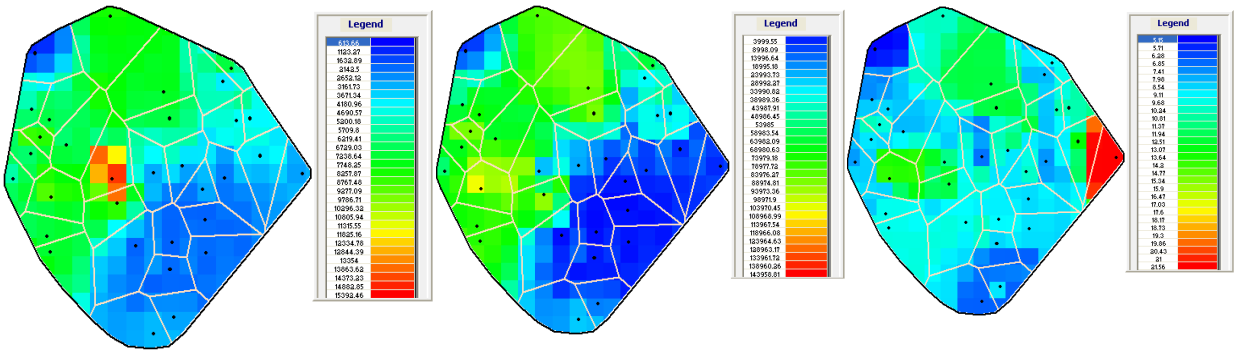


Figure 44. Generating the Voronoi cells for 32 NAS wells (Case 2)



3 Month Cumulative Production 5 Years Cumulative Production Fracture half-length

Figure 45. Results of discrete predictive modeling showing the distribution of first 3 months, 5 year cum. Production and fracture half length for the entire field (From left to right)

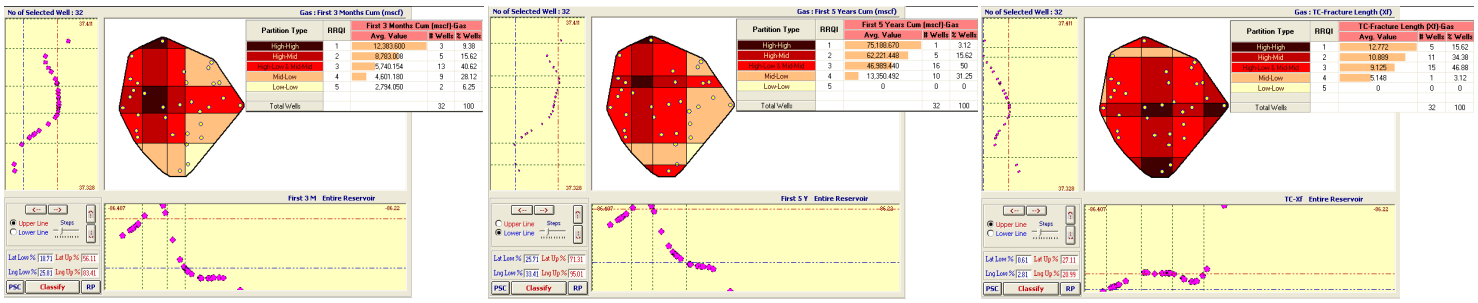
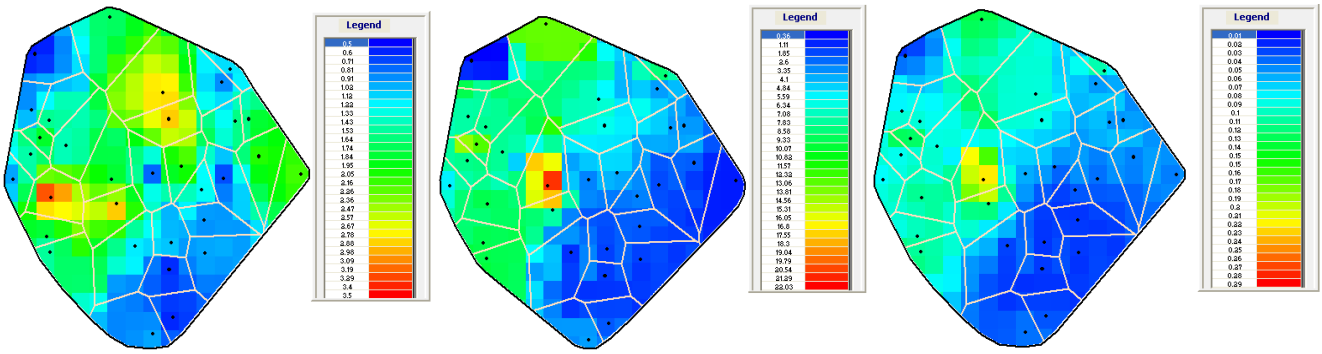


Figure 46. Results of Fuzzy Pattern Recognition showing the sweet spots in the field for the first 3 months, 5-year cum. Production, and the fracture half-length (From left to right)



Matrix porosity Total Permeability (TC) Matrix Permeability ((md)*10^-6)

Figure 47. Results of discrete predictive modeling showing the distribution of total porosity, matrix porosity, and net pay thickness for the entire field (From left to right)

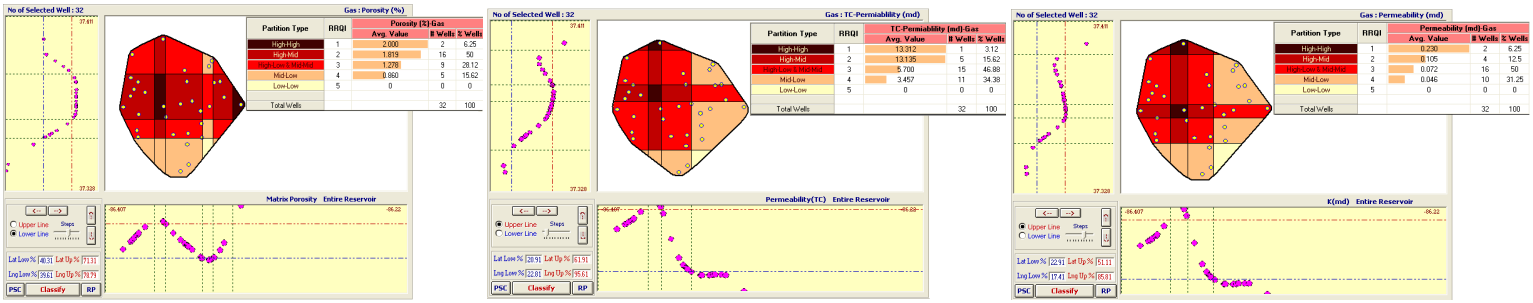
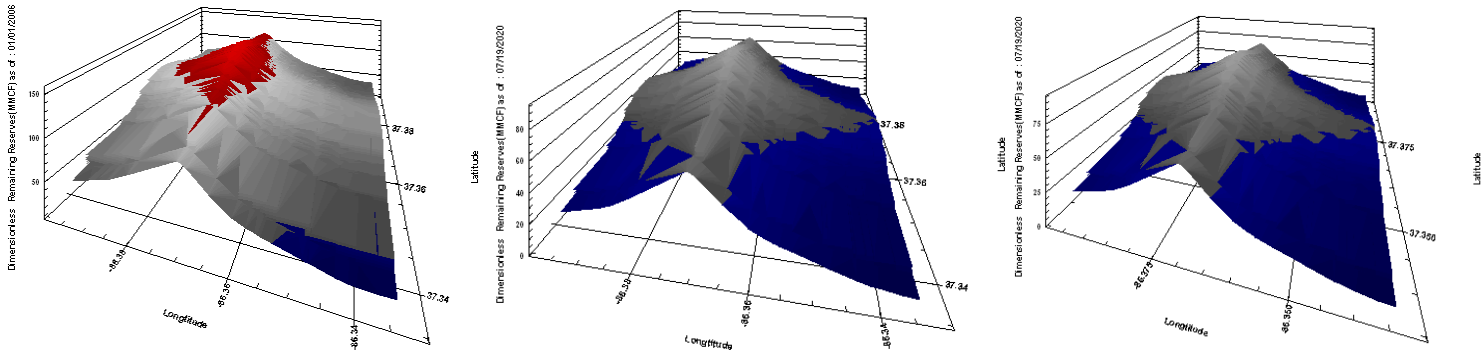


Figure 48. Results of Fuzzy Pattern Recognition showing the sweet spots in the field for the matrix porosity and total permeability from type curve and matrix permeability (From left to right)



Remaining Reserve, by 2006 Remaining Reserve, by 2020 Remaining Reserve, by 2040

Figure 49. Remaining reserve as a function of time

The remaining reserve as of year 2006,2020 and 2040 has been shown in Figure 49. The difference between these three figures shows the depletion in the reservoir and identifies the parts of the field that still have potential for more recovery.

Model Calibration and Validation

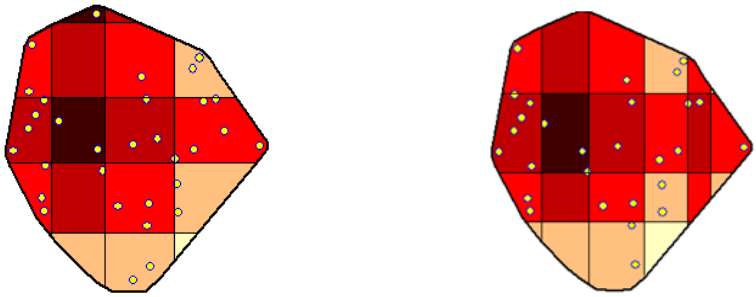
The same methodology has been performed for the second case.(Table 9 and Figure 50). For example in table 1 the four Relative Reservoir Quality Indices (RRQI) are shown as well as the model results that indicates the prediction for the blind/validation wells. As indicated in this table the Top-Down model predicted that the average 1 year cumulative production for wells drilled in the RRQI "1" (the darkest areas in Figure 50) will be more than 29.56 MMSCF. One well in RRQI "1" is removed and the average 1 year cumulative production for this well was 32.39 MMSCF. **(correct prediction)** Furthermore, the Top-Down model predicted that the average 1 year cumulative production for well in the RRQI "2" will be between 18.37 and 20.93 MMSCF. As shown in there was 1 well drilled in RRQI "2" and the average 1 year cumulative production for this well was 22.33 MMSCF .**(correct prediction)**

For RRQI "3" the Top-Down model predicted that the average 1 year cumulative production for wells drilled in the RRQI "3" will be between 12.92 and 18.37 MMSCF . The 1 well drilled in RRQI "2" had an average 1 year cumulative production of 14.49 MMSCF. **(correct prediction)**

The Top-Down model predicted that the average 1 year cum. for one well drilled in the RRQI "4" will be between 10.04 and 12.92 MMSCF and it turned out to be 11.5 MMSCF. **(correct prediction)** The same methodology has been performed for the second case.

Table 9. Results of Top-Down modeling (Case 2)

1 Year Cumulative Production(MSCF)					
	Model Results			Removed Wells	
RRQI	More Than	&	Less than	Average 1 Yr Cum	No. of Wells
1	29,559.87			32,391.21	1
2	18,371.65	&	20,937.61	22,332.96	1
3	12,924.83	&	18,371.65	14,492.04	1
4	10,043.96	&	12,924.83	11,507.91	1
			10,043.96	Total	4



1 Year Cumulative Production (32Wells) 1 Year Cumulative Production (28 Wells)

Figure 50. Results of Fuzzy Pattern Recognition showing the sweet spots in the field for the 1Year cum for 32 wells (left) and 1Year cum. Production for 28 wells (right).(Case 2)

Conclusion

In the first part of this study, natural fractures in the New Albany Shale were characterized by a comprehensive review of literature. Sensitivity analysis was performed on key reservoir and fracture parameters such as (write the names here). The orientation of natural fractures in New Albany Shale wells are EW and NNW-SSE and a minor ENE-SWS. Majority of natural fractures are vertical through there appears a minor set that dip between 55 to 75 degree.

A fracture network based on best available information and data was developed in FracGen. NFflow was used for fluid flow modeling based on the FracGen model. Reservoir characteristics and fracture properties were modified systematically until a reasonable history match was achieved for all the wells being studied.

The fracture model like any other geological model has a degree of uncertainty and can be updated by using additional information from fracture detection log, seismic and core analysis and any other tools

that help to characterize fracture properties in order to building the more accurate model that represents the fracture network distribution of New Albany Shale.
This new workflow can be performed on the other types of Unconventional resources such as other shale plays and tight gas reservoirs.

In the second part a relatively new reservoir modeling technology has been applied to New Albany Shale. This relatively new modeling technology, Top-Down, Intelligent Reservoir modeling (TDIRM) incorporates Artificial Intelligent and Data Mining techniques such as data driven Neural network modeling and fuzzy pattern recognition in conjunction with solid reservoir engineering analyses in order to combine single well analyses into a cohesive full field model.
Top-Down intelligent reservoir modeling allows the reservoir engineer to plan and evaluate future development options for the reservoir and continuously updated the model that has been developed as new wells are drilled and more production data and well logs become available.

One of the most important advantages of Top-Down intelligent reservoir modeling is its ease of development. It is designed so that an engineer or a geologist will be able to comfortably develop a Top-Down model in a relatively short period of time with minimum amount of data (only monthly production data and some well logs are enough to start modeling). This new technique can be performed on the other types of shale and tight gas sand (Unconventional resources) as well as conventional reservoirs (Oil and Gas).

Our Studies have shown that Intelligent Top-Down Reservoir Modeling holds much promise and can open new door for developing reservoir models using field measurement data.

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Field Data Acquisition

Industry Cooperative Data Acquisition and Tests

The key of success for a field-based project is the acquisition of reliable data and appropriate testing of results so that reliable data are provided for analytic work and designs. The first full-scale field data acquisition commenced in July on NGAS well DPI-2485-21 located in Christian County, Kentucky. At this time, the following tasks have been completed:

- Drilling of well DPI-2485-21 commenced in July 28, 2009.
- Vertical section of the well was drilled to the bottom of the New Albany Shale formation at 2600' for logging and coring.
- A 60-foot core in the vertical pilot hole was cut and collected. The core is being studied for lithology and fracture characterization by BEG, petrophysical and geomechnical measurements by CoreLab, and geochemical analysis by Weatherford.
- A suite of logs including induction log, dipole sonic, and borehole image log and spectral gamma were run and subsequently analyzed by ResTech and Weatherford.

The following tasks are in progress:

- Fracture stimulation at six to eight points along the horizontal length of the well DPI-2485-21 will be performed.
- Plans are underway to perform an offset well (observation well DPI 2486-21) microseismic monitoring by Pinnacle company.
- The observation well DPI-2486-21 is currently being drilled.
- A pressure buildup test after stabilizing production will be performed on well DPI-2485-21 and will be analyzed by Texas A&M.

In addition, A RVSP (Reverse Vertical Seismic Profile) was proposed and completed in November 2008 on well BF-001 CNX. The purpose of this test was to acquire the degree of the porosity and the orientation of the natural fractures. Results from this survey are presented in Appendix 1.

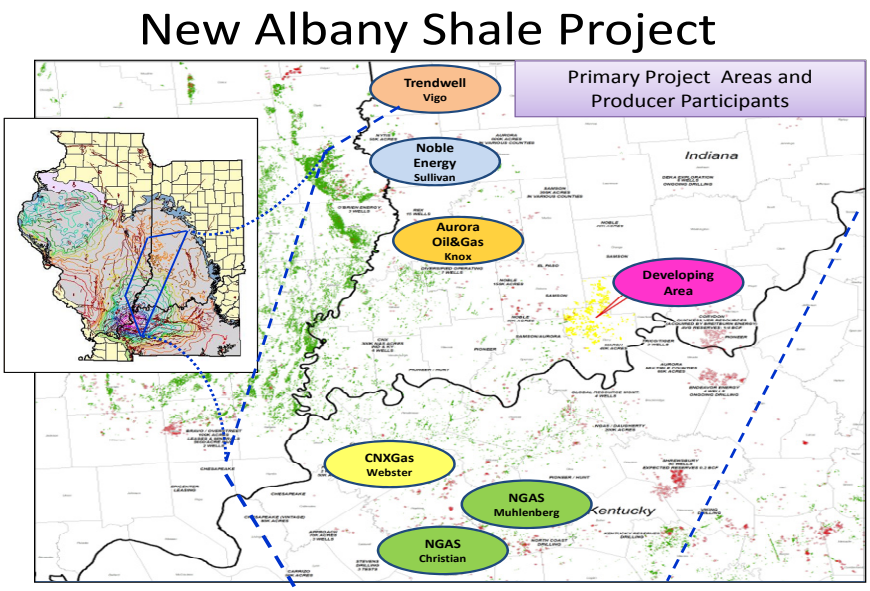
A Surface tiltmeter array- hydraulic fracture orientation was also designed and proposed on well DPI-2471-21 NGAS in March 2009 but the effort was terminated due difficulties associated with surface right of ways.

Other data Acquisition Tasks

A total of 39 data sets (See table for more details) has been acquired and distributed from producing members in Indiana and Kentucky. (See map for location).

COMPANY	# DATA SET
Aurora	1 Set
CNX	1 Set
NGAs	33 Sets
Noble Energy	2 Sets
Trendwell	2 Sets

Most of data sets include logs, production data, rock analysis, plats, gas analysis, drilling reports, some photos, permits reports and some other important information. Also access to HPDI database on over 250 wells in Kentucky has been established. GTI, along with all research subcontractors participated in this effort.



Technology Transfer

GTI staff and members of the research team presented the following papers at various technical meetings. Copies of papers and presentations are included as appendices to this report.

Title	Author	Presented at:	Date
New Albany Shale Gas Project (Featured Article)	Iraj Salehi, Angelica Chiriboga, GTI	HART's Unconventional Natural Gas Report	12/ 2008
Identification of microbial and thermogenic gas components from Upper Devonian black shale cores, Illinois and Michigan basins. (Paper)	Anna M. Martini, Lynn M. Walter, Jennifer C. McIntosh	The American Association of Petroleum Geologists. (AAPG) Bulletin, v. 92, no. 3	3/ 2008
Shale Evaluation, New Albany Example – RPSEA / GTI Project (Presentation)	Don Luffel, Jim Lorenzen, Restech	Spring Topical Conference Petrophysical Evaluation of Un-conventional Reservoirs Philadelphia, PA	3/ 15 – 3/19/ 2009
New Albany Shale Gas Project, An Industry-RPSEA-GTI Cooperative	Iraj Salehi, GTI	Spring Topical Conference Petrophysical	3/15 – 3/19/2009

Project (Presentation)		Evaluation of Un-conventional Reservoirs. Philadelphia, PA	
New Albany Shale Project Project Update (Presentation)	Iraj Salehi, GTI	RPSEA Unconventional Gas Project Review Meeting, Golden, CO	4/15/2009
Implications for development of effective drilling and completion technologies (Presentation)	Julia F. W. Gale, Stephen E. Laubach, Bureau of Economic Geology	RPSEA Unconventional Gas Project Review Meeting, Golden, CO	4/15/2009
New Albany Shale Formation Evaluation (Presentation)	Jim Lorenzen, Restech	RPSEA Unconventional Gas Project Review Meeting, Golden, CO	4/15/2009
Fracture Design & Diagnostics, New Albany Shale Project (Presentation)	Steve Wolhart, Pinnacle	RPSEA Unconventional Gas Project Review Meeting, Golden, CO	4/15, 2009
Analysis of Reservoir Performance in Shale Gas Reservoir Systems (Presentation)	Tom Blasingame, Texas A&M University	RPSEA Unconventional Gas Project Review Meeting, Golden, CO	4/ 15, 2009
Natural Fractures in the New Albany Shale and their importance for shale gas production (Paper)	Julia F. W. Gale, Stephen E. Laubach, Bureau of Economic Geology	International Coalbed and Shale Gas Symposium Tuscaloosa, AL.	5/19 – 5/21/2009
Formation Evaluation: Integrating Core-Geochem-Logs (Presentation)	Jim Lorenzen, Don Luffel, Frank Caramanica	GTI Forum, Chicago, IL.	6/4/2009
Natural fractures in the New Albany Shale and their importance for shale-gas production (Presentation)	Julia F. W. Gale, Stephen E. Laubach, Bureau of Economic Geology	GTI Forum, Chicago, IL.	6/4/2009
Geochemical and microbial investigation of methanogenesis in the Upper Devonian shales (Presentation)	Anna Martini & Matthew Kirk, Amherst College; Stephen Petsch, University of Massachusetts; Jennifer McIntosh, University of Arizona	GTI Forum, Chicago, IL.	6/4/2009
Fracture Design & Simplistic 3-D Parametric Modeling New Albany Shale (Presentation)	Doug Walser, Steve Wolhart, Pinnacle	GTI Forum, Chicago, IL.	6/4/2009
Analysis of Reservoir Performance for Shale Gas Systems**,** RPSEA/GTI Project(Presentation)	Tom Blasingame Department of Petroleum Engineering Texas A&M University	GTI Forum, Chicago, IL.	6/4/2009
New Albany Shale Gas Project A Joint Industry Project Sponsored by the research Partnership to Secure Energy for America (RPSEA) (Paper)	Iraj Salehi, Angelica Chiriboga, GTI	Published by Touch Briefings Exploration & Production. Oil & Gas Volume 7 Issue 1 OTC Edition.	8/2009
Top-Down Intelligent Reservoir Modeling of New Albany Shale (Paper)	A. Kalantari Dahaghi, SPE, S.D. Mohaghegh, SPE, West Virginia University	2009 SPE Eastern Regional Meeting Charleston, West Virginia	9/23–9/25/2009
Economic Impact of Reservoir roperties and Horizontal Well Length and Orientation on Production from Shale Formations, Application to New Albany Shale (Paper)	Kalantari, A., Mohaghegh, D., West Virginia University.	2009 SPE Eastern Regional Meeting. Charleston, West Virginia, USA	9/23–9/25/2009
New Albany Shale Gas Research Project.(Paper)	Kent F. Perry, Iraj Salehi, GTI	World Gas Conference Buenos Aires, Argentina	9/3-9/5/2009

Appendices

Appendix 1, CNX/GTI New Albany Shale RVSP, October 2008

Appendix 2, Salehi, "New Albany Shale Gas Project; A Joint Industry Project Sponsored by Research Partnership to Secure Energy for America (RPSEA)", December 2008 issue of Exploration and Production News Letter by Hart Energy.

Appendix 3, Salehi, "New Albany Shale Gas Project; A Joint Industry Project Sponsored by Research Partnership to Secure Energy for America (RPSEA)", International Oil and Gas Review, 2009, volume 7.

Appendix 4, Gale, "Natural fractures in the New Albany Shale and their importance for shale gas production" @009 International Coalbed and Shale Gas Symposium, Tuscaloosa, Alabama.

Appendix 5, Mohaghegh, "Economic Impact of Reservoir Properties and Horizontal Well Length and Orientation on Production from Shale Formations, Application to New Albany Shale", submitted and accepted for 2009 SPE Eastern Regional Meeting.

Appendix 6, Mohaghegh, "Top-Down Intelligent Reservoir Modeling of New Albany Shale", in preparation for 2009 SPE Eastern Regional Meeting.

Appendix 7, Anna M. Martini, Lynn M. Walter and Jennifer C. McIntosh , "Identification of microbial and thermogenic gas components from Upper Devonian black shale cores, Illinois and Michigan basins".

Appendix 8, Kent Perry and Iraj Salehi,"*New Albany Shale Gas Research Project*".

Appendix 9, Spring Tropical Conference, Philadelphia, PA, March 2009, presented by GTI staff and members of the research team.(Presentation slides.

Appendix 10, RPSEA review meeting, Denver, April 14, 2009, presented by GTI staff and members of the research team. (Presentation slides.

Appendix 11, RPSEA/GTI forum, Chicago, June 4, 2009, presented by GTI staff and members of the research team.