Abstracts

Horizontal TBR core from NYS: Implications for TBR reservoir development and regional tectonics

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Fortuna/Talisman in partnership with DOE and University at Buffalo retrieved the first oriented horizontal core in the Trenton/Black River (T/Br) of the northern Appalachian Basin. The core is nearly perpendicular to a T/Br graben structure in the Southern Tier of New York State. Our core analysis offers a glimpse at sub-seismic features within the graben and allows us to develop a relative timing of phases of strain and mineralization. Over 200 features were measured in the core including: stylolites, veins, vugs, and lithologic contrasts.

Sub-horizontal stylolites are present in the retrieved core. A few dolomite veins occur within these stylolites, and show that the sub-horizontal stylolites were conduits for the passage of mineralizing fluids.

This observation suggests that this fluid phase occurred during a period of unloading. At least two phases of stylolite growth along sub-vertical planes, separated by a phase of dolomite vein growth, may indicate multiple phases of relatively high horizontal stress.

Several sets of veins with varying orientations are recorded in the core. Cross-cutting relationships with other vein sets and with the stylolites place each vein set into a relative time framework. The existence of these temporal relationships demonstrates that mineralization occurred in several phases throughout the tectonic history of the region. Kinematic indicators in some veins, such as rhombochasms with dolomite crystals growing obliquely to the wallrock, indicate that these veins developed during apparent strike-slip conditions. Core-scale interpretation of these features indicates regional scale oblique and strike-slip motion along the regional faults.

Mohawk Valley Exposures as Outcrop Analogs for the T/Br Finger Lakes Play, New York State

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Outcrops of the Cambro-Ordovician section in the Mohawk Valley may be an analog for the subsurface T/Br play in the Finger Lakes (NYS) region of the Appalachian Basin. Dolomitization and faulting commonly occur in the Little Falls region of the Mohawk valley. Slickenlines, drag folds, and outcrop patterns indicate that the northerly-striking faults are dominantly dip-slip. Some WNW-striking faults in the region are short lateral ramps that link northerly trending faults, whereas others appear to extend across the northerly trending faults.

Outcrop analysis of faulting, fracturing, veining, and other mineralization features in the Mohawk Valley show that the faults of the study area have acted as fluid conduits. Along NNE-trending splays of the Little Falls Fault, a significant increase in mineralization features (vugs, veins, incipient breccia, dolomitized limestone) is observed within 200m of the fault. The mineralization events also bear a Mississippi Valley Type (MVT) signature. Along the N-trending Dolgeville Fault, the mineralization zone is more restricted (<100m).

Veins occurring in stratigraphically low units near the Little Falls Fault strike parallel with the fault plane, whereas veins occurring higher in the section near the Dolgeville Fault strike nearly perpendicular to the fault plane. This change in orientation can be related to a tectonic model wherein the faults in earlier Taconic times in this region were extensional, related to stretching of the craton over the peripheral bulge and into the trench, whereas in later Taconic times, the stress field would have rotated in response to the jammed subduction zone.

Direct Detection of Mobile Hydrocarbons – Converted Shear Waves

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Converted shear waves are clearly seen at large offsets in conventional seismic reflection profiling using 3-component seismometers. However, at normal or near normal incidence it is unusual. One such observation where the horizontal component signal was more pronounced than the corresponding vertical component prompted this inquiry. Possible explanations are scattering and anisotropy. A different possibility considered here is the conversion due to lateral motion of fluids in the reservoirs. This lateral motion of fluids induces shearing forces on the matrix due to a combination of viscous drag and pressure differences.

Compressional waves were induced in a slab of aluminum bonded to a Berea sandstone block and reflected waves, both compressional and shear, were recorded for varying offsets. In the first run the rock was dry. In a repeat run the rock was wetted with water. In one of these experiments significant differences between the observed shear wave amplitudes and those predicted by theory were observed.

Another experiment investigated the influence of fluids on the transmitted wave. In this experiment compressional and shear motion in two orthogonal directions were induced on one face of the core sample and for each set-up all three motions were recorded on the opposite face. The data suggests that the converted shear is enhanced by the presence of fluids, in this instance water. These results are preliminary and further work is in the planning stages.

High resolution lithostratigraphy of the Rose Run formation of eastern Ohio using Diffused Spectral Reflectance (DSR).

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The diffuse spectral reflectance technique and other core logging methods have been used extensively on ocean cores since the mid 1980's, proving effective in both paleo-climatological and paleoenvironmental reconstruction. Although DSR has been applied in the study of terrigenous sediments e.g. Galavao and Vitorello (1994), its use in terrestrial settings has remained very limited. I anticipate the reflectance measurements will be able to pick up fine scale changes in lithology based on variability within individual lithofacies at resolution of ~0.5 to 1.0 cm. The objectives of this study are therefore aimed at:

1. Establishing the DSR technique as a proxy for resolving bedding details in lithostratigraphic sequences mm to cm.
2. Using DSR to identify homogeneity in depositional events in order to reconstruct paleodepositional history from data obtained through core measurements.

Tectono-stratigraphic architecture of eastern North America, and geometry of the Central Appalachian Basin, during Middle Paleozoic time.

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The tectono-stratigraphic architecture of eastern North America, and the geometry of the Central Appalachian Basin, during Middle Paleozoic time were controlled dominantly by regional tectonic stresses impinging on the Laurentian continent. Pre-existing Precambrian Proterozoic terranes and Neoproterozoic/Cambrian rifts affected sedimentation and structure throughout the Paleozoic. Significant volumes of clastic and carbonate sediments accumulated during Cambrian time, notably along the Rome Trough trend. Sediment removal across the region during the Late Cambrian/Early Ordovician Sauk unconformity partially masked pre-existing structural features. Middle Ordovician Black River time marked the position of elongate, north-northeast-trending depo-center geometries, which remained throughout the Paleozoic. Black River time was dominated by a broad, stable, shallow-water carbonate ramp along the northwest margin of the basin. Thick, shaley carbonates were deposited along the southeast margin of the ramp, defining the western edge of the Central Appalachian Basin approximately along the western edge of the underlying Rome Trough. Further to the east and southeast, thick shale and clastics accumulated in the Sevier Basin foredeep along the Laurentian continental margin. Craton-wide transgression continued after Black River time with deposition of relatively clean Trenton platform carbonates to the northwest and north, and argillaceous Lexington platform carbonates to the south, thereby marking significant changes in regional tectonics and global paleoclimate. Low-relief carbonate buildups on these extensive platforms surrounded an interplatform sub-basin where brown and black shale of the Utica Shale/Point Pleasant were deposited. Shaley carbonates accumulated in the depo-centers to the east, while further east at the continental margin, an extensive volcanic island system supplied wind-borne sediments to the region. Over time, shaley carbonate deposition in basin depo-centers gave way to shale deposition as continent-wide transgression continued. As the basin subsided during Late Ordovician time, carbonate platforms were completely drowned by Utica Shale and equivalents.

Geological Carbon Sequestration Potential in Devonian Saline Aquifers of the Michigan Basin, USA

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The Michigan basin is an elliptical, Cratonic interior basin extending over approximately 100,000 square miles and consisting of up to 16,000 ft of mostly Paleozoic sedimentary strata. The Midwest Regional Carbon Sequestration Partnership (MRCSP), one of seven regional CO_2 sequestration partnerships funded by the USDOE has concluded an initial (Phase I) geologic assessment of the geological carbon sequestration potential in a seven-state region including the Michigan basin. Substantial sequestration potential was found in the region with the largest potential targets identified in several regional saline aquifer formations. Because of the dramatic increase in density of CO_2 between 1000 and 1500 psi optimal saline aquifer sequestration targets occur at depths in excess of approximately 800m-1000m (2,600ft-3200ft). The late-Early Devonian Sylvania Sandstone and related strata occurs at or just below these depths throughout most of the central Michigan basin and was estimated to contain as much as 15 gigatonnes of CO_2 sequestration potential.

Regional lithologic variations within the Sylvania Sandstone and related strata are known mainly from the analysis of geophysical logs. The Sylvania Sandstone is typically a very porous unit that consists of dolomitic to cherty, fine- to medium-grained, well-sorted and rounded; quartzose sandstone in central and southeastern Lower Michigan but grades into cherty, sandy carbonate to the north and west. The Sylvania, along with the underlying Bois Blanc and Garden Island Formations, overlies the base Kaskaskia unconformity in complex regional stratigraphic relationship and provides substantial regional CO_2 sequestration potential. A USDOE funded, pilot CO_2 injection project has been proposed targeting the Sylvania and related strata in northern Lower Michigan in order to evaluate lithology, petrophysics, and saline aquifer sequestration potential of the Sylvania Sandstone and related strata in this area.

Hydrothermal Dolomite: Occurrence and Mechanisms, Michigan Basin, USA

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Analysis of petroleum producing formations, including the Ordovician Trenton/Black River (T/BR) and St Peter Sandstone (aka "PdC"), and Devonian Dundee Formation, indicates a pervasive overprint of hydrothermal dolomitization in the Michigan basin. Hydrothermal origin of volumetrically significant dolomite is supported by new analytical data including light (relative to initial sea water) oxygen isotopic composition and elevated (relative to inferred ambient burial temperatures) fluid inclusion homogenization temperatures. Mapping and log analysis in the T/BR and Dundee suggest close spatial correlation among gross hydrothermal dolomite reservoir facies (HTDRF) distribution and interpreted, wrench fault-related NW-SE and NE-SW structures.

The T/BR and Dundee are separated by thick, Silurian and Devonian age, salt-bearing formations and other units thought to be too plastic to support brittle fracture. Episodic reactivation of basement wrench faults may have episodically propagated fractures and hydrothermal fluid conduits upwards through the Paleozoic cover rock section. These fracture conduits must have annealed in shale and evaporite sections in geologically short time periods in order to create effective seals for important hydrocarbon accumulations.

Emerging models, incorporating reactivated basement faulting, downward migrating saline formation fluids, and serpentinization of basement peridotite, are intriguing mechanisms for the origin of economically significant HTDRF in the Michigan basin. These mechanisms are consistent with regional structural grain (probably resulting from repeated regional basement wrench fault reactivation); dense, saline formation fluids; and possible Proterozoic mafic and ultramafic crust genetically related to the Mid-Continent rift in the central Michigan basin. Rift-derived, magnesium-rich, high pressure hydrothermal fluids may have been transported through "regional aquifer units" including the St Peter Sandstone and/or other regional aquifers, and delivered through wrench fault related fractures to form HTDR in several carbonate formations throughout the Paleozoic succession.

Northern Vermont and the Noyan, Quebec Natural Gas Prospect: Stratigraphic and Structural Relations

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Quebec lands are under government oil and gas lease at the border of Vermont and New York by Junex, Inc. A seismic line (Q118) 5 km north of the Vermont border spans the autochthonous (west) to para-autochthonous (east) domains bounded by the Tracy Brook and Aston faults. The correlation of this line with the Shell, Saint-Armand ouest No. 1 test well on the east side of Missisquoi Bay in Lake Champlain shows normal faults which extend into Precambrian basement and thrust faults which override some of the normal faults (Sejourne et al., 2003). The Noyan Prospect, located along the line north of Alburg, Vermont, is estimated by the leaseholders (CCNMathews/Junex press release, 2001) to have in situ gas potential of 20.67 Bcf distributed between 5 stratigraphic units to a depth of 3,330 meters: Stony Point, Trenton, Chazy, Beekmantown and Potsdam.

Based on mapping in northern Vermont, the Cambro-Ordovician section is estimated to be 1500 meters thick. Depth to basement is not well constrained but estimated to be less than 2 km in the Champlain Islands. A 1964 American Petrofina test well in South Alburg is consistent with this depth. Seismic data in Quebec shows basement depths of 3 to 4.5 km. An interpreted cross section indicates that depth to basement increases both to the north and east. Thrust faults in Alburg override normal faults in the lower plate which is consistent with the Quebec interpretation. Alternatively, extensional tectonics may have controlled the thin limestone horizon in the Alburg well.

Early Burial History of the Upper Devonian Rhinestreet shale, Western New York State - From Early Diagenesis to Fluid Retention

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Early formed carbonate concretions in the Upper Devonian Rhinestreet shale of western New York State indicate that the organic-rich host sediment accumulated as water-rich flocculated clay. The depositional microfabric of the shale is preserved in strain shadows adjacent to carbonate concretions and within the concretions themselves. Geochemical characteristics of the concretions indicate that they grew by rapid near-uniform precipitation of carbonate cement throughout the concretion body. Thus, the volume percent carbonate in concretion matrix samples - 74 to 93% - is a proxy for the porosity of the host sediment at the time of concretion growth and is consistent with porosities of modern marine clays. The water-rich sediment experienced rapid gravitational compaction and consequent reorientation of platy grains to produce a strongly anisotropic microfabric common to many black shales. The multiple concretion horizons reflect episodic reductions in subsidence rate during burial. Compaction strain measurements conducted on 118 concretions yield an average compaction strain of the Rhinestreet shale of 51.8%, which translates to a paleoporosity of 37.8%, a value markedly higher than that expected for shale normally compacted to the 3.1 km maximum burial depth of the Rhinestreet shale. The calculated paleoporosity of the Rhinestreet shale likely reflects the onset of overpressure at a depth of ~1,100 m, the fluid retention depth, well shy of its maximum burial depth. Early and relatively shallow overpressuring of the Rhinestreet shale likely originated by disequilibrium compaction induced by a marked increase in sedimentation rate in the latter half of the Famennian stage.

Location of dolomitized grainstone reservoirs in the Upper Ordovician Black River and Trenton Limestone Groups in Ontario: a Persian Gulf/West Florida and northern Afghanistan comparison.

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Dolomitized bioclastic grainstones form the main hydrocarbon reservoirs in the Ordovician of Ontario. These are controlled by depositional environment, tectonics and climate. Environmental position on the ramp determined where the contributing organisms lived and what sediments were deposited. Tectonics not only determined the configuration of the ramp and hence where grainstones developed, but also movements on faults which controlled the dolomitization.

By analogy with carbonate ramp models based on modern environments (the most applicable ones being cool Persian Gulf/West Florida models), bioclastic grainstones occur in two main settings: in shallow shelf shoal areas around normal wave base (brachiopod-coralgal), and in deeper shelf areas affected by contour currents (pelmatozoan-bryozoan). The grainstones form the tops of coarsening (and possibly shallowing) upwards cycles (parasequences) within a generally transgressive succession.

By analogy with tectonic models based on Cenozoic collisions (the most applicable one based on the indentation and rotation of Afghanistan by NW India), Ordovician dolomitization and reservoir formation occurred along lateral transtensional and transpressional faults related to collision of the Taconic arc with the Ordovician carbonate ramp. Differential shear can be related to the rheological contrast between the Canadian shield and the areas to the south (with complex basin/plateau structure) - the dividing line roughly running from Anticosti Island down the St Lawrence into southern Ontario and Ohio.

The Ordovician succession in Ontario and New York is now known to be at least partially controlled by synsedimentary tectonics. Such successions, especially in the absence of a reliable chronostratigraphy, should not be automatically assumed to consist of blankets of uniform and easily correlated facies controlled by relative changes of sea-level; nor can simple sequence models be applied to such successions. For example, the differential shelf edge erosion towards the top of the Trenton can plausibly be attributed to the development and uplift of a forebulge during emplacement of Taconic allochthons to the east. In this case, relative sea-level changed divergently in closely adjacent areas lead to incompatible sequence descriptions.

Molecular and isotopic differences between abiogenic hydrocarbons and thermogenic natural gases in the northern Appalachian basin, USA

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Although generation of abiogenic methane by serpentinization or by graphite-water reactions in high-grade metamorphic rocks is well documented, geochemical evidence for abiogenic generation of higher hydrocarbon gases (ethane through pentane) is equivocal. Thermogenic hydrocarbon gases, generated by thermal cracking of sedimentary organic matter or residual crude oil, are progressively enriched in ^{13}C as a function of increasing number of carbon atoms in the molecule. Published analyses of hydrocarbon gases in Precambrian rocks in Canada and South Africa have carbon isotopic compositions that are reversed and interpreted to be diagnostic of gases produced abiogenically by Fischer-Tropsch (F-T) synthesis in crustal rocks. We have documented reversed isotopic compositions in natural gas accumulations in lower Paleozoic reservoirs of the Appalachian basin regionally from central New York and Pennsylvania to eastern Ohio and West Virginia. Although the nominal similarity of isotopic reversals in the gases suggests that abiogenic F-T reactions may have generated some fraction of the gases in the deep basin, the molecular and stable isotope compositions (carbon and hydrogen) show that the Appalachian basin gases do not contain abiogenically synthesized higher hydrocarbons. All the Precambrian gases have extremely light hydrogen isotopic compositions of CH_4 (δ^2H <-300‰) and are depleted in CH_4 (Canada gases C_1/C_{2+} < 10, S. Africa gases C_1/C_{2+} < 60) compared to gases in lower Paleozoic reservoirs of the Appalachian basin (δ^2H (CH_4) > -150‰, C_1/C_{2+} up to 220). New hydrogen isotopic analyses of ethane in Appalachian basin reservoirs clearly demonstrate that these gas accumulations do not contain abiogenically synthesized hydrocarbons.

Models for Integrated Energy and Carbon Dioxide Sequestration Systems

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Fossil fuels will continue as a primary source of energy for the world well into this century. However, it may become necessary to manage anthropogenic CO_2. Sequestering CO_2 in geological reservoirs is one method to safely store carbon, but high cost is a barrier. *Integrated Energy Systems* attempt to address economic constraints by linking agricultural, industrial, energy and sequestration systems. Integrating energy systems result in savings of energy, while avoiding the emissions of carbon dioxide.

One project links agriculture, electrical co-generation, biofuel production (ethanol), and CO_2 enhanced oil recovery. Gas-fired electric generators provide waste heat for ethanol production. High concentration carbon dioxide, a byproduct of fermentation, is sequestered by a miscible enhanced oil recovery project (EOR). This pilot project is being replicated at a commercial scale in Nebraska. A second project captures landfill gas (LFG), which is a product of waste degradation (50 percent methane and 45 percent CO_2), and a significant contributor to greenhouse emissions. Understanding the behavior of LFG in subsurface coal is critical to recovering additional methane (ECBM) while efficiently sequestrating CO_2. A third project involves CO_2 capture from cement kilns. Both the energy generation and calcination processes generate significant CO_2 and waste heat. Linking cement kiln waste heat to ethanol production can generate a high concentration CO_2 emission for value-added sequestration through ECBM.

Efficiencies gained by linking energy and carbon-management systems can enhance economics, increase energy efficiency, and create environmental benefits. Widespread application throughout the US significantly increases energy reserves, benefit industries, and cost-effectively manage carbon.

Oil and Gas Resources Underlying the U.S. Portions of the Great Lakes

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The U.S. Geological Survey (USGS) has allocated the following mean values of undiscovered, technically recoverable oil and gas resources underlying the U.S. portions of the Great Lakes: 312 million barrels of oil (mmbo), 5,229 billion cubic feet of natural gas (bcfg), and 122 million barrels of natural gas liquids. These allocations were estimated from recent USGS assessments of oil and gas resources of the U.S. portions of the Appalachian Basin (2002) and the Michigan Basin (2004). For the U.S. portions of the Great Lakes, the USGS described eight petroleum systems (defined according to petroleum source rocks and associated reservoirs) and 21 reservoir intervals or assessment units (AUs). Thirteen of the AUs are classified as containing conventional accumulations, and eight are classified as containing continuous (unconventional) accumulations. Mean values of the resources are allocated as follows: Most conventional oil resources (179 mmbo) and conventional gas resources (914 bcfg) are allocated to the Silurian Niagara AU in the Michigan Basin, whereas most unconventional gas resources (2,355 bcfg) are allocated to the [Silurian] Clinton-Medina Transitional AU in the Appalachian Basin. In terms of allocation by lake, most conventional oil resources (141 mmbo) and conventional gas resources (721 bcfg) are allocated to Lake Huron, whereas most continuous gas resources (2,408 bcfg) are allocated to Lake Erie. In terms of allocation by State, most conventional oil resources (282 mmbo) and conventional gas resources (1,325 bcfg) are allocated to Michigan, whereas most continuous gas resources (1,536 bcfg) are allocated to Ohio.

The New Albany Shale Gas Play in Southern Indiana

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The New Albany Shale (Devonian and Mississippian) in Indiana is mostly brownish-black organic-rich shale with lesser greenish-gray shale. The formation is 100 to 140 feet thick in southeastern Indiana and dips and thickens to the southwest into the Illinois Basin, where it attains a thickness of 337 feet in Posey County.

Gas production from New Albany Shale began in 1885 and drilling activity continued into the 1930s, when interest waned in favor of more lucrative opportunities elsewhere. Renewed activity, driven by higher gas prices, has been brisk since the mid-1990s, witnessed by the completion of more than 400 productive wells. The majority of these wells were drilled in Harrison County, where production typically occurs at depths from 500 to 1,100 feet and production rates generally range from 20 to 450 MCFGPD. In the past 2 years, Daviess County and surrounding areas have become the focus of New Albany exploration after the El Paso Production No. 2-10 Peterson horizontal discovery well was rumored to have tested 1.3 MMCFGPD at an approximate measured depth of 2,200 feet.

New Albany production is mostly from the organic-rich Clegg Creek Member. Gas compositions (C_1-C_4 and CO_2) and carbon and hydrogen isotopic signatures indicate that both purely thermogenic and mixed thermogenic and biogenic gases are produced from the New Albany. Produced water ranges from brine to water diluted through recharge by modern precipitation; the brine zones contain primarily thermogenic gas and the diluted water zones contain gas of mixed thermogenic and biogenic origin.

Preliminary Subsurface Correlations of the Theresa (Galway) Sandstone Formation in New York State: Implications for Exploration

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Given the recent natural gas discoveries in the Theresa (Bockhahn, Northwood's, Cascade Brook, Gas Fields) and the pervasive shows in wells penetrating this horizon it is important to begin to understand the regional distribution of reservoir quality rocks within the subsurface Theresa (Galway) and the implications for future exploration.

Larry Rickard in his 1973 Publication, Stratigraphy and Structure of the Subsurface Cambrian and Ordovician Carbonates in New York gave some indication of the hydrocarbon potential of the Theresa (Galway). Under *Economic Aspects* he noted that the "pre-(Knox) unconformity sandstone at the top of the Galway-Gatesburg (is) reported to be poorly cemented in some wells" with the obvious implication that friable sand translates into good reservoir.

He also did a yeoman's job of correlating electrical logs across the state and giving us a framework for understanding subsurface stratigraphy of the Cambro-Ordovician in New York; and he did so in 1973, at a time when far fewer wells penetrated the so called "deep section".

That was yesterday, today there are about 925 wells that have penetrated the Trenton or deeper formations in New York with a wealth of attendant log information from which to (literally) draw correlations and conclusions.

The paper emphasizes the Theresa (Galway), and particularly the upper sandy section for its natural gas potential but intervals below this maybe equally prospective.

Use of Pre-existing Coal Mine Maps and Drill Holes for Coal Bed Methane Exploration

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Coal seams in the eastern United States have become a target for coal bed methane (CBM) exploration. CBM has recently been recognized as a viable source of energy. CBM is bonded to coal and emitted from both active and abandoned mines. Coal seams and mines are found throughout the Appalachian Basin, where a long history of mining provides a wealth of geological information. The use of pre-existing mine map and drill-hole data allows for quick means of ascertaining information for CBM exploration. The Office of Surface Mining's National Mine Map Repository is a national clearinghouse for coal mine maps for the entire United States. While this repository is not complete, data available from more than 300,000 mine maps may include: 1) coal seam elevation,
2) coal thickness, 3) coal analysis, 4) structure, 5) location of mining, 6) stratigraphy,
7) coal rank, 8) property ownership, 9) the location of exploration drill-holes and gas wells, and the 10) location of mines. Drill-hole logs and other coal data useful for finding CBM locations, boundaries, and quality are generally obtainable from the various state geological or economic surveys.

Fluid Flow within Fractured Porous Media

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Fractures provide preferential flow paths to subterranean fluid flows. In reservoir scale modeling of geologic flows fractures must be approximated by fairly simple formulations. Often this is accomplished by assuming fractures are parallel plates subjected to an applied pressure gradient. This is known as the cubic law. An induced fracture in Berea sandstone has been digitized to perform numerical flow simulations. A commercially available computational fluid dynamics software package has been used to solve the flow through this model.

Single phase flows have been compared to experimental works in the literature to evaluate the accuracy with which this model can be applied. Common methods of fracture geometry classification are also calculated and compared to experimentally obtained values. Flow through regions of the fracture where the upper and lower fracture

walls meet (zero aperture) are shown to induce a strong channeling effect on the flow.
This model is expanded to include a domain of surrounding porous media through which the flow can travel. The inclusion of a realistic permeability in this media shows that the regions of small and zero apertures contribute to the greatest pressure losses over the fracture length and flow through the porous media is most prevalent in these regions. The flow through the fracture is shown to be the largest contributor to the net flow through the media. From this work, a novel flow relationship is proposed for flow through fractured media.

Two-Phase Flow within Geological Flow Analogies – a Computational Study

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Displacement of a viscous fluid in heterogeneous geological media by a less viscous one does not evacuate 100% of the defending fluid due to capillary and viscous fingering. This is of importance in geological flows that are encountered in secondary oil recovery and carbon dioxide sequestration in saturated brine fields. Hele-Shaw and pore/throat cells are commonly used to study this in the labratory. Numerical simulations of this flow phenomenon with pore-throat models have been prevalent for over two decades. This current work solves the full Navier-Stokes equations of conservation within random pore-throat geometries with varying properties to study the resulting flow properties.

Verification of the solution method is performed by comparison of the model predictions with the available experimental data in the literature. Experimental flows in a pore-throat cell with a known geometrical structure are shown to be in good agreement with the model. Dynamic comparisons to a computational pore-throat model have been shown to be in good agreement as well. There are also additional two-phase immiscible flow patterns that can be identified from the current solutions for which the corresponding laboratory counter part or the pore-throat model predictions are not available. The identification of these flow patterns may allow more accurate modeling of fluid displacement on the reservoir scale.

Advances in Understanding Devonian and Silurian Subcrop Plays in Illinois

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Difficulties in correlating old electric logs coupled with paucity of core and sample material has led to generic naming of pays or mis-correlation of pay zones. This practice may have led to misunderstanding of reservoir geometries and compartments in strata at or near the sub-Kaskaskia unconformity, or bypassed pays. Accurate correlation can be an effective tool in exploring for and exploiting productive facies and reservoir compartments. Case studies will be used to show where multiple pays and missed pays may exist. Cross sections will examine the sub-Kaskaskia unconformity's role in oil play analysis.

Correlation of productive zones at and near the sub-Kaskaskia unconformity has identified areas where generic naming of pays may have led to missed or bypassed pays. For example, both the Middle Devonian Lingle and the Grand Tower producing zones may be present in the same field and contain similar dolomite facies that are productive but are labeled "Devonian" or "Geneva," which can lead to misunderstanding of the nature and distribution of reservoir compartments. In another case study, it appears that production designated as "Devonian" is from at least three distinct Devonian units; the basal Middle Devonian Dutch Creek, and Lower Devonian Clear Creek and Grassy Knob formations. This paper will examine these and other examples that may lead to further field development and discoveries in Illinois, and may be applicable elsewhere.

Structurally-controlled carbonate diagenesis: creation of hydrothermal dolomite and leached limestone reservoirs

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Structurally-controlled carbonate diagenesis, covering the spectrum of hydrothermal dolomite (HTD) to leached limestones, is a field of rapidly growing significance in petroleum exploration. HTD reservoirs, some with associated productive leached limestones, are major producers in the Ordovician, Devonian and Mississippian of North America. Structurally-complex rifted North and South Atlantic margins record similar diagenetic processes and reservoir creation in Jurassic to Cretaceous sections. In Europe and through into the Middle East, Jurassic and Cretaceous hosts, including the world's largest oil and gas fields, show strong structurally-related diagenetic controls on reservoir development and enhancement.

HTD is formed under burial conditions from Mg-charged brines emplaced *via* structural conduits into a carbonate host, typically limestone, at temperature and pressure greater than the **ambient** T and P of the host. Original limestone facies and permeability play a major role in lateral extent of dolomitization, replacement textures, pore type, and pore volume. Transient, short term but high temperature (tTI) hydrothermal events may result in 'forced maturation' of kerogens in this setting.

Extensional and strike-slip (wrench) faults are the preferred structural locations for hydrothermal dolomitization and/or limestone leaching, with a bias toward the upper hanging wall site. The seismic signature for simple dilational or pull-apart sites is a structural 'sag', often with high positive correlation to HTD distribution. Underlying sandstone aquifers, basement highs, and shale top seals and internal aquitards are other variables in localization of HTD facies and solutional porosity.

Rock fabrics in an HTD system record short-term ('instantaneous') shear stress and pore fluid pressure transients. They include dilational 'floating clasts' breccias, rimmed microfractures in shear sets, boxwork vugs and zebra fabrics compartmentalized by shear microfractures, and hydrofracturing of low-permeability hosts. Younger tectonic fracturing may be a critical factor in economic production and high flow rates.

The Knox Group: A Potential Saline Reservoir for Carbon Sequestration in the Eastern Midcontinent

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In the eastern Midcontinent, the Knox Group is divided into the upper (Ordovician) Beekmantown Dolomite and the lower (Cambrian) Copper Ridge Dolomite and their equivalents. The group is composed of several thousand feet of dominantly dense, impervious dolomites that are generally considered, along with the Conasauga Formation, to be the regional seal for carbon sequestration projects in the underlying Mount Simon Sandstone.

The Knox, however, has numerous thin zones of high porosity throughout its vertical extent and could constitute an important sequestration target, especially in those instances where the Mount Simon may be missing or of low permeability. One example of this is in the DuPont waste injection well at Louisville, Ky. Here, 400 feet of Mount Simon proved to be of insufficient injectivity and was abandoned in favor of a highly permeable vuggy dolomite facies in the Copper Ridge. Injectivity tests in the dolomite were as high as 150 gallons per minute, equivalent to injecting about 48 million tonnes of supercritical CO_2 annually.

The extent of porous zones in the Knox is variable, but they are noted throughout much of the interval in Indiana, Kentucky, and Ohio. In this region, several gas storage fields exist in Knox porous zones. Likewise, oil fields along the Cincinnati Arch are developed in Knox breccias, fractures, and paleokarst zones. These scattered porosity zones are usually relatively thin and are confined both above and below by dense carbonates, making them potential carbon sequestration targets, that together have both high permeabilities and confining seals.

An Organized Approach: Challenges Faced By Today's New Engineers In The Petroleum Industry

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Today the knowledge gap between the "seasoned professional" and "new hire" to the petroleum industry has reached a new level of disparity. Due to market trends and job availabilities in prior years, many engineers have been turned away from futures in oil and gas. But with the current global demand for energy at an all time high, companies are now looking for fresh faces to fill their empty seats.

It is not out of the norm for a new engineer to see a dramatic split among his peer group of engineers. Many of those in the industry today have on average 10 to 15 years experience working in the oil and gas industry, which reflects the time of the last major market upswing. The challenge arises in bridging generational as well as technological gaps.

In navigating the new profession, the right questions need to be asked by the young engineer. Nothing can be assumed or taken for granted. No matter what role the engineer holds in the disciplines of drilling, completions, reservoirs, or operations, a level of responsibility must be assigned with clear definitions and expectations.

There is not always the luxury of transition periods, more positions are becoming available each day with a smaller pool of applicants who poses the desired years of experience. This forces companies to fill openings with many candidates fresh from college. This paper will be a guide for today's new engineer with suggestions for how to succeed in this essential global industry.

Black-Shale Source Rocks as Indicators of Paleozoic Tectonic History in the Appalachian Foreland Basin

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In the Appalachian Basin, black shales are common lithologies, ranging in age from Middle Ordovician to Pennsylvanian. Dark coloration suggests greater-than-normal abundances of organic matter, and many of these shales are hydrocarbon source beds, or reservoir rocks when fractured; at various times, moreover, they have also been considered as oil and gas shales or as sources for various radioactive and heavy metals. Organic matter in these shales may comprise as much as 20 % by weight, and the distinctive lithology makes mapping their distribution in time and space relatively easy.

These shales are parts of third- and fourth-order, unconformity-bound cycles that have been interpreted to be flexural, foreland-basin manifestations of distinct episodes of tectonism, called tectophases, during each orogeny. The black shales reflect deposition during rapid, loading-related subsidence in early parts of each tectophase, and hence, track the progress of orogeny in time and space. Included fossils and bentonites, moreover, provide ages for the shales and the related timing of orogenic events. Thirteen black-shale units, representing 13 tectophase cycles during four major orogenies are recorded in the Appalachian Basin. During the Taconian, Salinic, and Acadian, subduction-type orogenies, deeper water, open-marine, black shales were typical, but during the final Alleghanian collisional orogeny, two tectophases are represented by shallow-water, terrestrial or marginal-marine dark shales, reflecting a change in tectonic style and secondary, glacio-eustatic influences. As hydrocarbon source and reservoir rocks, these shales are clearly the product of distinctive tectonic frameworks and histories, and aside from any economic value, they may provide additional controls on the timing and location of those tectonic events.

Albion/Scipio Field, Michigan: What does a detailed look at cores tell us about the reservoir?

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Michigan's only giant oil field, the Albion/Scipio Field, has produced over 125 million barrels of oil and is used as an analog for much of the Trenton-Black River exploration in Eastern North America. Current reservoir models, based on published literature suggest extensive fracturing and brecciation followed by pervasive hydrothermal dolomitization created the field's reservoir architecture. The general impression of this reservoir is one of facies-independent and fabric-destructive processes, especially dolomitization that created the reservoir quality.

Detailed examination of numerous cores from the field and a few outside the field, do show some intervals of extensive fracturing and brecciation along with hydrothermal (saddle) dolomite cement. Many other cores show only limited fracturing and rare saddle dolomite cement. Some of the cores, in the heart of the field, show almost no fracturing although much of the cored interval is dolomitized. Several well cores show interbedded dolomite and limestone with primary facies fabrics and textures very well preserved in both lithologies. Depositional environments can easily be interpreted from most of the core material. These cores show a diverse set of shallow shelf and peritidal facies stacked in multiple cycles through the Black River and Trenton intervals.

It appears from this core study that fracturing and brecciation is very laterally restricted to the proximity of major faults within the field. Wells a short distance from these faults may show little or no fracturing. Dolomitization does, however, extend well beyond the fractured zone. Primary sediment texture and porosity may have provided sufficient fluid pathway to transmit the dolomitizing fluids substantial distance from the major faults.

Characteristics of Carbonate Reservoirs in Kentucky through the Examination of Cores

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Carbonates comprise more than seventy percent of the sedimentary record in Kentucky and have considerable significance and economic and scientific importance. They contain most of the fossil record and provide information that permits reconstruction of past environments. Carbonates serves as reservoir rocks to most of Kentucky's petroleum reservoirs and is host rock for many minerals.

Understanding carbonate reservoirs through the examination of cores is often challenging because of the complexity of carbonate diagenesis. However, this examination provides a better understanding and greater knowledge of those reservoirs and the nature and characteristics of the environments and the depositional history. It also provides a better understanding of the origin and occurrence of hydrocarbons, tectonic setting, diagenesis, paleoclimate, paleogeography, and rock properties of the reservoir.

Carbonates from Kentucky's reservoirs were deposited in a variety of marine environments ranging from tidal flats to reefs to deep marine. They are important oil and gas reservoirs and the most prolific producers of hydrocarbons in Kentucky. The original texture and porosity of the reservoir carbonates are highly variable because of the wide range of environments in which they were formed. Porosity types, texture, fabric, grain composition, and carbonates types vary considerable due to the depositional setting.

Effects of tectonics; fractures and faults, sedimentation, and stratigraphic cycles can be observed in the reservoir cores. In addition, variation in minerals, dissolution features including karst and solution collapse breccias, recognition of patterns, colors, bedding, hydrothermal activity, and compaction can also be observed. Also, the effects of diagenesis including compaction, cementation and dolomitization are recognized.

Combining CO2 sequestration with EOR activities – a synergistic approach for the future: An example from the Michigan Basin

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Increasing domestic oil production by maximizing recovery from known domestic oil fields is an economic and political imperative as U.S. imports of crude oil approach 60% of daily consumption. As part of this effort, CO_2 flooding of reservoirs is a proven and effective means to increase the recovery of oil bypassed during primary production, although often at significant cost due to preparation and transportation of adequate CO_2. At the same time, global and national interest in viable sequestration of anthropogenic CO_2 is also increasing because of its role as a greenhouse gas. Here we report on an example from the Michigan Basin in which CO_2 flood EOR operations and CO_2 sequestration are economically positioned to be combined in a single operation.

Silurian pinnacle reefs in the Michigan Basin have produced over 450 MMBO since the late 1960's. Due to the complex heterogeneity of reef reservoirs, however, primary production averages around 30% with secondary waterflood programs capturing an additional 12% on average. In the northern reef trend, a local source for subsequent CO_2 flooding is readily available as a byproduct of nearby Antrim Shale production. In a single county alone, the annual production of CO_2 separated from Antrim gas is about 20 BCF, a majority of which is vented directly into the atmosphere. The close proximity of high quality CO_2 from several gas processing plants throughout the northern reef trend, a region with over 800 Niagaran reef fields, may provide an economically viable opportunity to combine CO_2 flood EOR with geological carbon sequestration.

New Insight into the Reservoir Architecture of Silurian (Niagaran) Pinnacle Reefs in the Michigan Basin

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Silurian-aged (Niagaran) pinnacle reefs have been productive in the Michigan Basin for over 60 years, but extensive lateral and vertical heterogeneity in the reservoirs may limit primary production to as little as 25%. Enhanced recovery efforts have generally been focused upon horizontal or directional drilling and waterfloods, but the internal reservoir architecture is often poorly understood which leads to marginal economic success in many reefs. Recent detailed facies analysis from core suggests that vertical compartmentalization in some pinnacle reefs is the result of complex facies variability, and that the vertical distribution of these facies can be constrained, and therefore predicted, within a sequence stratigraphic framework.

The sequence stratigraphic framework of the Miller Fox 1-11 reef, Oceana Co., MI, is characterized by a tripartite hierarchy of sequences, high frequency sequences, and cycles. Large-scale sequences (90-120 ft) correspond reasonably well to the commonly accepted "pinnacle reef model" in the Basin which describes an overall shoaling from mud mound to coral-stromatoporoid framework reef, to a restricted marine algal/stromatolitic unit which is ultimately capped with supratidal algal mats and evaporites. Smaller scale high frequency sequences (35-50 ft) and cycles (3-10 ft), however, consisting of shoaling upward packages bounded by low permeability facies, result in the potential for vertical permeability baffles or barriers within the overall "pinnacle reef" complex. Because there is a distinct correlation between various facies types and porosity/permeability values within these higher resolution packages, enhanced understanding of how these facies are distributed should result in more effective primary and enhanced production efforts.

Selected Illinois Basin Lower Paleozoic Cores

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Devonian, Silurian and Ordovician reservoirs account for 7.5% of the petroleum produced in Illinois and while these units represent 50% of the rock volume of the Illinois Basin, only 2% of all exploratory wells drilled have penetrated deep enough to test these rocks. These reservoirs represent a guideline to the potential for Lower Paleozoic production and the opportunity for new exploration targets in the Basin. An Illinois Basin Consortium project funded in part by the U.S. DOE is focusing on existing petroleum reservoirs and the potential for new discoveries in Lower Paleozoic units. This project is designed to compile and present a broad base of information and knowledge needed by independent oil companies to pursue the development of exploration prospects in overlooked, deeper play horizons in the Illinois Basin.

One source of information and data that can benefit the knowledge base of the Basin is drill core. The Illinois State Geological Survey is the repository of rock core that represents over 2 million feet of cored section. Selected carbonate and siliciclastic core including a New Albany Shale core from the Devonian, carbonate core from Silurian reef and non-reef reservoirs, and Ordovician Trenton core will be displayed at the Core Poster Session of the Buffalo Eastern Section AAPG Meeting. Available core analysis and field related information will also be displayed.

Glacial Depositional Patterns: Potential Clues to Basement Faulting in Northwestern Pennsylvania and Adjacent Areas

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Patterns of glacial deposition and post-glacial stream development in NW Pennsylvania suggest that Pleistocene ice flow was influenced directly or indirectly by basement tectonics and Phanerozoic fracturing inherited from Late Precambrian-Early Paleozoic basement movement. Orientations of sets of stratified drift deposits in buried glacial valleys, generally NW-SE, N-S, and E-W, appear related to fracturing associated with deep wrench faulting. The NW-SE set coincides with the orientations of numerous established and suspected faults that have strike-slip components, with relative movement determined from offset of structure axes, discontinuities in depositional patterns, and other features farther to the southeast. Orientation of the N-S and E-W sets probably is related to zones of tension fracturing associated with right- or left-lateral strike-slip movement along the wrench faults. In addition, the extent of mapped maximum glacial advance in NW Pennsylvania coincides closely with the western edge of the Rome trough in NW Pennsylvania. Reactivation or inheritance of trough fracturing occurred intermittently throughout the Phanerozoic. Coincidence of maximum glacial advance with the edge of the Rome trough suggests the trough may have influenced glaciation in NW Pennsylvania by acting as a crustal pivot to slow ice flow, and by conducting crustal heat to the surface where increased ambient temperatures could have impaired ice advancement. I suggest, therefore, that mapped glacial deposits in NW Pennsylvania, as well as in adjacent states, may be useful for predicting the existence of basement faults in advance of more costly remote sensing (e.g., seismic) techniques.

High matrix porosity in a dolomitized Black River reservoir, Clinton County, Kentucky

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Ordovician oil reservoirs in the Black River (High Bridge) Group (Stones River, Murfreesboro of drillers) in south-central Kentucky commonly occur in fractured limestone. High-volume oil producers like the 1990 Syndicated Options No. 9372 Ferguson Brothers well in Clinton County are rare, and predicting these fractured reservoirs remains difficult.

Little reservoir data were obtained when the 9372 well was drilled. Oil production declined rapidly, and the well was later deepened. Subsequent logging revealed two fractured limestone zones. Surprisingly, wells drilled near the 9372 discovery penetrated an unusual zone of high matrix porosity in the lower Black River and Wells Creek. This narrow, linear oil reservoir, penetrated by 12 wells to date, occurs immediately above the Knox unconformity and is oriented northeast-southwest. It is at least 2,400 ft long, 150-200 ft wide and up to 250 ft thick. The zone is characterized by log-derived porosity of up to 30 percent. Neither well samples nor core are available from this interval, but log data indicate the porous interval is dolomitized.

Interpretation of seismic reflection data over the trend indicates it lies above a deep-seated fault zone, suggesting the porosity may be fault-controlled. The zone cuts across a larger structural low mapped at the Knox, Black River, and Devonian Chattanooga Shale levels. The origin of the dolomite and associated porosity may be related to Mississippi Valley-type hydrothermal mineral deposits in south-central Kentucky. The Ferguson trend, which has produced at least 650,000 barrels of oil, indicates the Black River dolomite play extends into south-central Kentucky.

Potential for Geological Carbon Sequestration in the Michigan Basin

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An evaluation of the potential for geological carbon sequestration has been conducted during the past 18 months under the auspices of the Midwest Regional Carbon Sequestration Partnership. This research has identified two types of targets that have significant potential in Michigan.

Oil and gas reservoirs are important because they have natural confining or sealing strata that provide containment for the injected CO2. Additionally, injection of CO2 into oil reservoirs provides an opportunity for enhanced oil recovery through reservoir repressurization and viscosity reduction. CO2 is sequestered during the EOR process even though sequestration is not the main economic motivator. Currently several Silurian reef oil reservoirs are being flooded with CO2 for EOR. It is estimated that about 300,000 tons of CO2 has been sequestered in the last ten years. Other oil-bearing horizons in Michigan include the Devonian Traverse and Dundee limestones and Detroit River Group, Lucas Fm. dolostones and Trenton/Black River reservoirs. Cumulative Michigan historic oil production exceeds 1.2 billion barrels. Widespread development of CO2-based EOR might produce another 150 million barrels of oil from known reservoirs and sequester several hundred million tons of CO2.

A far larger potential target for CO2 sequestration in Michigan is the extensive saline aquifers system in the Basin. The Cambrian, Mt. Simon Sandstone and the Ordovician, St. Peter Sandstone along with the Devonian Sylvania Sandstone are widespread aquifers that contain highly saline brine. Saline aquifers are also present off-structure in the Devonian Traverse, Dundee and Lucas Formations. Carbon sequestration in these saline aquifers is hundreds of times greater than in the oil fields.

Crustal Framework of the Eastern U.S., and Its Influence on Hydrocarbon Development

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Eastern U.S. crust records Neoproterozoic breakup of supercontinent Rodinia, development of a Neoproterozoic to Early Cambrian rift-to-drift sequence, then an early Paleozoic platform. The Middle Ordovician Knox unconformity resulted from withdrawal of the sea from the eastern two thirds of Laurentia. Immediately following renewed inundation of the Appalachian foreland the diachronous Taconian orogeny produced foredeep sedimentation during the Middle (southern) and Late (central) Ordovician. This event was probably related to dynamic loading produced by obduction of volcanic arcs and ophiolites onto the outer margin, producing the foredeep and a peripheral bulge farther west.

The Devonian Acadian (and latest Devonian-early Mississippian Neoacadian) orogeny produced the Devonian Catskill delta, and Devonian shale, which propagated southwest from a source in New England. These events are related to accretion of the Carolina-Avalon terrane to Laurentia. They produced folding and some faulting far into the southern Appalachian foreland, later truncated by the pre-Chattanooga Shale unconformity. Chattanooga Shale and younger Mississippian clastics form the Neoacadian clastic wedge.

The late Mississippian to Permian Alleghanian orogeny uplifted the internal parts of the Appalachians, spreading sediment in a large late Mississippian to Early Permian delta complex from the Appalachian chain into the Midwest. The delta was deformed as Africa collided with North America propagating thrust faults through the crystalline crust and into the foreland. Deposition continued farther west as the eastern foreland was being deformed. These events provide the structural and depositional framework within which Appalachian petroleum systems and hydrocarbon traps developed.

Modeling on the Cheap: Creating a 3D Seismic Velocity Model with Common Software and Free Data

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Geoscientists use reflection seismic data to determine the geometry of the geology of the subsurface. Unfortunately, a seismic section displays in what is essentially an “apples and oranges” set of dimensions. The horizontal (X, Y) dimensions are in distance units (meters, miles, etc.), while depth (Z) units are in time (seconds). To make it even more complicated, the correlation between these terrestrial and temporal units changes depending on lithology, porosity, depth, etc. This not only changes the depth to subsurface targets, but also can change their geometry (dips of anticline limbs, fault planes, etc). This is not a problem for larger, well-funded petroleum exploration companies since the calculations involved in this time-to-depth correlation are included in all high-end seismic interpretation software packages. This software is often financially out of reach for researchers in academia or for smaller independent exploration companies, however.

The computations and data that make up seismic velocity models are relatively simple. With the online availability of scanned images of geophysical well logs in many areas, most geoscientists have all the software they need already on their desktop computer. KGS researchers were able to create a procedure using common spreadsheet and GIS software packages to manipulate stratigraphic well tops and sonic log data into a 3D seismic velocity model. An added advantage of this procedure is that it can be used in reverse, generating expected depths in time of target horizons from nearby well data, even if no sonic log was recorded from that particular well.

Paleozoic Tectonic Effects on Trenton-Black River Hydrothermal Reservoirs

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The preexisting structure of the crystalline basement in eastern North America has influenced the subsequent structural history of later Paleozoic rocks. Past exploration for Trenton-Black River hydrocarbons has shown that basement faulting (often with a wrench component) and structural sags within the Ordovician Trenton and Black River carbonates can indicate the presence of hydrothermal dolomite reservoirs. In many cases, major basement faults have been reactivated by the later Appalachian orogenies, causing deformation of the younger overlying strata. Other basement faults in the area show little or no reactivation, and exhibit no shallow expression in the overlying Paleozoic rocks. Furthermore, since most basement faults did not propagate or otherwise deform any strata younger than the Late Ordovician, it can be inferred that these faults were reactivated only during the Taconic Orogeny.

The orientations of basement faults with respect to the changing regional orogenic stress field through time may be the primary control on what appears to be a selective reactivation history. Although faults oriented perpendicular to the primary tectonic force (σ_1) could be reactivated, the associated compression would tend to destroy porosity and permeability. Without this open path for hydrothermal fluids and hydrocarbons to migrate through, no reservoir would be created. If the preexisting basement fault (or even just a segment along one) was oriented so that the regional tectonic forces produced local transtension, however, this could reactivate the fault in such a way that the permeability of the fault zone would be enhanced, creating conduits for hydrothermal fluids.

Separating the Spiderweb of Faults in the Northern Appalachian Basin of NYS and PA: Grenvillian to Present Fault Activity That Influenced Reservoir Development

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Integration of 11 types of data promote recognition of a complex web of fault systems in the Appalachian Basin of NYS and PA, and demonstrate a nearly continuous reactivation history of these fault systems. This view of an extremely faulted continental basin can serve as a model for developing continental basins, and for the prominent influence of faulting on depositional systems in shallow basins.

Reactivations of the northerly-trending intra-Grenvillian suture and other Grenvillian faults were common throughout the Phanerzoic. Reprocessed proprietary seismic data indicate that the arcuate Phanerozoic Appalachian structural pattern was strongly influenced by an arcuate system of Iapetan opening/Rome Trough faults. Arcuate lineaments (from satellite images) that are coincident with aeromagnetic anomalies support this interpretation. These early arcuate faults controlled (through weakened, fractured rock from fault reactivations) the locations of later faults, including Alleghanian faults (including thrust ramps). Other fault trends (e.g., NW) also have extended faulting histories.

Phaerozoic units have depositional patterns that indicate syndepositional fault control. For example, interplay between the eustatic sea level and reactivation of the arcuate Iapetan-opening fault blocks guided Devonian sandstone deposition.

Generation of Lower Paleozoic Carbonate Reservoirs in the Appalachian Basin of NYS: the Plate Tectonic Connection.

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It is well established that the Trenton/Black River experienced fluid migration and mineralization that resulted in reservoir development in central NYS. Yet, in the Mohawk Valley and western Vermont, older carbonate units exhibit extensive dolomitization. For example, in the Mohawk Valley faulting and dolomitization is prevalent in units of the Cambro-Ordovician Beekmantown, and some of these events are thought to be a separate event from those phases in the Trenton/Black River.

The fault activity for the initial development of the Trenton/Black River is likely Taconic, based on the seismic records that show infilling of the grabens in post Trenton time. Models suggest that both peripheral bulge faulting when the continental plate was under extension, and later faulting when the plate was under collisional compression can account for the faulting of classic Taconic time. But what explains the intra-Beekmantown faulting? That time is known from Vermont to be the time of initiation of subduction. We suggest that initiation of subduction processes promoted deep faulting in the leading edge of the continental plate, as well as at the site of subduction initiation.

In western NYS the Silurian Lockport Formation is pervasively dolomitized with MVT deposits. The dolomitization/MVT deposits probably are related to active faulting that penetrated the basement during development of the Silurian Appalachian basin. This faulting and basin development may be related to ridge subduction beneath Laurentia.

The Devonian Onondaga and Tully were not dolomitized—possibly because of changed stratigraphic/structural conditions, including the Silurian salt blanket below and the black shales above.

Geochemical Assessment of Unconventional Shale and Tight Gas Sands Plays

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Pre-lease and pre-drill assessment of resource plays requires a detailed understanding of the hydrocarbon system. Geological information and knowledge must be combined with geochemical characteristics to assess the likelihood of commerciality. Geological and geochemical reconnaissance requires evaluation of publicly available information and also requires further evaluation of nearby outcrop or well samples, whether archived cuttings or cores, well head or production gases, or oils.

The first step in assessing unconventional plays is to determine the gas type, i.e., whether the gas is biogenic or thermogenic. Biogenic gas plays will have low initial flow rates, but long-lived production of low calorific gas. Unconventional thermogenic gas systems will yield varying flow rates depending on the system type (shale or tight gas sand), and organic richness and thermal maturity of the shale source rock. In such tight shales or sands, flow rates are restricted by the presence of even low levels of oil saturation. Unconventional thermogenic gas production may be developed from early mature or highly mature shales and economics are dependent upon projected recoverable gas versus development costs. The New Albany Shale, Illinois Basin and the Barnett Shale, Ft. Worth Basin, respectively, are examples of these shale gas system types. However, thermogenic gas derived from shales may also be produced from intraformational tight sands (e.g., the Bossier gas system of Central-East Texas), another unconventional gas system type.

Comparison of these unconventional play, system, and gas types is made among known and prospective hydrocarbon systems.

Examining the Relationship Between Time Stratigraphic Surfaces and Reservoir Development for the Bradford Group Sandstones

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The Bradford Group sandstones belong to the Upper Devonian Lock Haven Formation of west-central Pennsylvania. The Bradford Group sands represent an active gas play in the Punxsutawney, Pennsylvania study area. The Punxsutawney study area consists of 400 square miles at the junction of Clearfield, Jefferson, and Indiana counties, Pennsylvania.

The Bradford Group consists of the Warren through Kane sands for purposes of this study. Bounding time stratigraphic surfaces such as flooding surfaces and sequence boundaries are used to identify parasequences within the Bradford Group sandstones. Parasequence stacking patterns and reservoir occurrence are characterized relative to a published Devonian sea level curve to examine the role of eustacy, sedimentation rate and subsidence in the development of the Bradford Group reservoirs.

Pitfalls in Seismic Exploration for Trenton/Black River Reservoirs in the Michigan Basin

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Seismic exploration for Trenton/Black River hydrocarbon reservoirs in the Michigan Basin may be complicated by shallow ray path anomalies that may affect the reflection character of the Trenton/Black River interval. Lateral changes in glacial drift thickness and/or composition may cause both false structures and false apparent stratigraphic variations on seismic sections. Using short source and geophone arrays in seismic data acquisition may improve shallow resolution and therefore aid in identifying anomalous drift features that may be affecting the deeper data. In addition, comparing seismic sections at various stages of processing may help identify potential problem areas in terms of drift statics corrections. Specifically, comparing an elevation-only statics version of a seismic section with its

corresponding refraction statics version can identify potential false structures.
The Silurian Salina Group is another potential source of problems in exploring for Trenton/Black River reservoirs. The interbedded salt/carbonate facies of the Salina Group produce strong interbed multiples which can significantly contaminate the seismic data below this interval. These interbed multiples arise due to the very high velocity and density contrasts between the salts and carbonates which produce very high acoustic impedance contrasts. These multiples may be recognized by careful modeling with synthetic seismograms using both velocity and density information. These multiples remain a significant problem in the salt portion of the Michigan basin.

Utica-Trenton Relationships in the Subsurface of Eastern New York

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Stratigraphic interrelationships between the classic Trenton and Utica rock sequences have been studied in outcrop in New York over many years. Recent studies have described a complex relationship, which in the past has been treated in a rather generalized manner. Studies of these same sequences in the subsurface have focused on general relationships as well. New tools for analysis and depiction of strata in boreholes allow a detailed visualization of these sequences in the subsurface and an opportunity for a more realistic comparison with outcrop studies.

Until recently, detailed, bed-by-bed study of stratigraphic sequences in the subsurface required full-diameter cores. In the Trenton interval in New York, full-diameter cores are virtually non-existent in the areas where gas is produced. Conventional petrophysical logs have severe inadequacies in comparison with outcrop, as even the standard gamma-ray tool averages vertical information over a span of at least a meter, and no conventional tool provides any information that can be related to rock textures and depositional fabrics.
The advent of formation imaging logs acquired over large intervals allows analysis in detail similar to full-diameter cores. This tool reveals bedding patterns which may be compared to outcrops with confidence. With such data, and the extrapolation it allows to conventional well logs, demonstration of shelf – slope – basin transitions between carbonate and shale facies is possible. In this case, the length of slope involved in the transition approaches 100 miles (160 kilometers). The scale of these relations has significance to gas production and to exploration.

Subsurface Stratigraphy of the Devonian Dundee Formation, Michigan Basin, USA – A Log Based Approach

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A distinct hard ground surface separates two disparate facies tracts in numerous Middle Devonian, Dundee Formation cores in the Michigan basin subsurface. This sharp stratigraphic contact is distinguished by scour and/or dissolution of a partially lithified surface, which is commonly bored and/or eroded, and overlain by rip up clasts. This contact probably represents both subaerial and subaqueous exposure surfaces and a subsequent period of slow sediment accumulation. Diverse supratidal to shallow marine, shoal-water carbonate facies occur below this contact, basin wide. More lithologically homogeneous, fossiliferous, mudstone-wackestone facies overlie the hard ground surface in core and are indicative of transgression to more distal, open marine conditions.

Analysis of hundreds of wireline logs throughout the basin reveals a widespread gamma ray marker (grm) coincident with the hard ground/marine flooding surface observed in core. Although present across much of the basin, the grm does not always occur apparently due to local variability of carbonate lithofacies, especially in more open marine Dundee successions in the eastern basin. A corresponding sharp decrease in porosity, inferred from lithodensity logs, commonly coincides with the grm and is typically present even when the grm is not.

Formal basin lithostratigraphy does not subdivide the Dundee Formation. This investigation supports the idea that the Rogers City Limestone, recognized in outcrop, is actually a laterally extensive unit that can be differentiated from the underlying Dundee (aka "Reed City equivalent") Formation throughout the Michigan basin subsurface. Log-based, stratigraphic subdivision of the Rogers City - Dundee succession is important in understanding the primary depositional history, genesis, and distribution of highly productive, secondary dolomite reservoirs in the Rogers City.

Testing the Efficacy of CO_2 for Enhanced Oil Recovery in the Illinois Basin

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To date 4.3 billion of an estimated 14.1 billion barrels OOIP in the Illinois Basin have been produced. The Midwest Geologic Sequestration Consortium estimates the CO_2 EOR to be 0.86-1.3 billion barrels. This projected increase is based on reservoir characterization and simulation carried out for nine representative producing sites, three each for the Basin's most prolific producing formations. A portion of injected CO_2 also remains in the subsurface, effectively sequestering it from the atmosphere.

To analyze CO_2's EOR potential in the Basin, the Consortium will perform field tests at four sites using various methods. The first test is a huff and puff of a single producing well. In this scenario, CO_2 is injected into the subsurface and allowed to "soak" for a period to re-energize the oil surrounding the wellbore; this well is then produced, and oil and gas production can be measured.

The geology of candidate sites was studied in detail using logs, geological records, and core analyses of the producing formations. Records supplied by the operators were used to study the production characteristics. Reservoir simulation of final candidates was performed using the VIP compositional simulation package (Landmark Graphics Corporation) based on geological models and reservoir characteristics obtained from core and well log analyses.

Before beginning injection, each site will be monitored to establish a baseline for CO_2 in the atmosphere and groundwater. This allows assessment of the efficacy of the method for in-zone CO_2 storage, as pre-and post-injection statistics allow assessment of the method's efficacy for EOR.

Recent Appalachian Basin Mergers and Acquisitions

Knobloch, Timothy, James Engineering, Inc.

A presentation has been prepared of recent Appalachian Basin acquisitions to provide operators better insight into the historic basis for asset sales. The materials presented are drawn from public data sources, press releases, and Securities and Exchange Commission Reports.

The presentation includes a discussion on "Price Drivers" - factors that influence a purchase or sale price and "Pricing Yardsticks" – common methods for determining an asset's worth including quick look "Rule of Thumb" methods and reserve based methods. The presentation compares the historic impact of the prime interest rate and natural gas prices on oil and gas asset acquisition values. Historic average Appalachian Basin asset values are presented for the years 2000 – 2005 in $ per mcfe of proved reserves and in $ per mmcfdeq.

Details of acquisitions are presented including the asset size($), annual cash flow, daily production, net proved reserves, geographic location, well count, miles of pipeline, and acreage.

Acquisition details are presented for Great Lakes Energy Partners acquiring Pine Mountain, NCL Appalachian Partners acquiring Equitable's Pennsylvania and Ohio Assets, Enervest acquiring Belden and Blake, and Chesapeake's acquiring of Columbia Natural Resources. Comparisons are also made to the previous sale of Belden to Capital C and the CNR to Triana sale. Finally, a comparison is made of the "Price Drivers and Pricing Yardsticks" for each of the acquisitions presented.

Types and Origin of Dolomites in the Beekmantown Group (Cambro-Ordovician) of New York

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Petrographic and geochemical studies of selected samples from the Beekmantown Group (Cambro-Ordovician) of central and western New York revealed six dolomite textures. These dolomite textures have been classified based on crystal sizes, shapes, uniformity, and trace element distribution. These textures are as follows: 1) unimodal, very finely crystalline, planar-e (euhedral) dolomite, 2) unimodal, very finely crystalline, plannar-s (subhedral) dolomite, 3) medium to coarsely crystalline, planar-e (euhedral) dolomite, 4) coarsely crystalline, non-planar dolomite (non saddle dolomite), 5) very coarsely crystalline, non-planar dolomite (saddle dolomite), and 6) polymodal dolomite.
These dolomite types may be originated as replacement dolomite, primary dolomite (penecontemporaneous), and void filling dolomite.

In places, the process of dolomitization was interrupted by silicification, chemical compaction (stylolitization), and dedolomitization (calcitization).

Chemical analysis using electron microprobe indicates the presence of varies trace-chemical elements including iron, manganese, strontium, and silicon in the dolomite textures. These elemental variations and their concentration values strongly indicate that dolomites of the Beekmantown Group form under various conditions within different environmental settings.

Origin of Peloidal Textures in Black River and Trenton Carbonate Petroleum Reservoirs in the Appalachian Basin

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Limestones and dolostones in the Ordovician Black River and Trenton Formations of the Appalachian basin contain normal marine skeletal assemblages and a variety of non-skeletal grains including ooids, peloids, and aggregates. Peloids are the most abundant non-skeletal carbonate grains observed in the rocks and their origin is both complex and diverse. Some peloids occur as original framework grains formed by physical processes, and some are diagenetically altered grains. Most peloids in the Black River and Trenton rocks, however, are not grains, but are marine cements that precipitated *in situ* on or slightly below the sea floor.

Peloids that we interpret as cement are decimicron-sized and consist of a dark nucleus composed of micron-sized calcite surrounded by a rim of euhedral microspar. The nuclei consist of clots of submicron-sized opaque material, which may be organic or mineral. These characteristics in conjunction with uniform crystal size, restricted size range, consistent texture, monomineralogy, and association with hardgrounds and other marine cements support our interpretation of these peloids as cement. In limestones, the peloidal cements occur as groundmass, as internal cement within skeletal grains, as cement filling fabric-selective pores, and as a mimic replacement of allochems. In dolostones the peloidal cement occurs as ghosts within planar and nonplanar dolomite.

Precursor peloidal cement fabrics are ubiquitous in Black River and Trenton hydrothermal dolomite reservoirs. The original textures of peloidal limestones might have influenced subsequent dolomite fabrics and the development of porosity in the rocks. If so, determining diagenetic facies may be an important component in understanding and developing Black River and Trenton carbonate reservoirs in the Appalachian basin.

Upper Devonian Sandstone Sequence Stratigraphy Using Well Logs

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The Upper Devonian sandstone play in the northern Appalachian Basin subsurface is comprised of numerous, usually tight, sandstones encased in marine shales. Regional correlation and mapping of individual reservoirs has been hampered by lack of a consistent and meaningful stratigraphic framework.

Sequence stratigraphy using well logs provides a process and a model to delineate genetically-related sandstone bodies, correlate them over wide areas, and construct geologically meaningful maps of key reservoir parameters and trends.

Use of well log-based sequence stratigraphy requires the construction of a grid of detailed, regional cross-sections, each extending scores of miles in stratigraphic dip and strike directions. Sequence stratigraphic correlations also require noting the surfaces of discontinuity against which sands and shales onlap or are truncated beneath. Once these surfaces of discontinuity (sequence boundaries) with regional extent are recognized and correlated it can be seen that they are common in the Upper Devonian section of the northern Appalachian Basin and are likely the result of repeated small, relative sea level changes across a very low angle foreland shelf ramp. In this setting lowstand and transgressive tract deposits had a relatively high preservation potential, but highstand deposits were rarely preserved.

Isopach mapping of the sands deposited between subsequent sea level drops will produce maps of sand bodies that were laterally coeval. This increases the accuracy of reservoir mapping and meaningfulness of reservoir trends for exploration or development drilling.

A Switch in Joint Driving Mechanism as Evidence for Passage of a Morrowan Peripheral Bulge at the Onset of the Alleghanian Orogeny

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NW- and ENE-trending joints are pervasive throughout the Upper Devonian shale succession of western New York. The fact that joints of both sets terminate against higher modulus carbonate concretions indicates that they formed as natural hydraulic fractures produced when organic-rich rocks, including the Rhinestreet and Dunkirk shales, were buried to the oil window. Both NW and the subsequent ENE joints formed within a regional stress field related to the Alleghanian clockwise rotational transpressive collision of Gondwana against Laurentia. This tectonic scenario is complicated by north-trending joints that predate the NW joints and are most densely formed at the contacts of gray shale and overlying black shale units. These joints appear to have originated in the higher modulus carbonate by elastic contraction. Specifically, a tensile Earth stress causing a uniform level of extensional strain over the entire Upper Devonian shale succession was enhanced in the stiffer carbonate. Propagation of these early joints required an axis of tensile stress oriented ~EW, consistent with passage of an inferred westward-migrating peripheral bulge in advance of oblique plate convergence in New England. The studied Upper Devonian shale crops out in that area of the Appalachian Basin where the modeled tensile stress caused by uplift and lithospheric flexure related to passage of the peripheral bulge, relative to burial-induced compressive stress, is optimum. Eventually, subsidence of the peripheral bulge carried the shale succession into the oil window during the Alleghanian orogeny resulting in the propagation of fluid driven joints in black shale.

Vitrinite Suppression in Devonian Black Shale, Western New York State: Preliminary Results

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Vitrinite reflectance ($\%R_o$) is perhaps the most widely cited index of thermal maturity in a source rock. However, there is increasing evidence that the $\%R_o$ of some hydrogen-rich source rocks is suppressed. Suppression of vitrinite is most readily recognized by anomalously low $\%R_o$ values on maturity profiles. It has been described from some Devonian-Mississippian black shales of the Appalachian Basin by comparison of measured $\%R_o$ with that of overlying Pennsylvanian coals as well as by burial/thermal models constrained by maturity indices other than $\%R_o$. Preliminary analysis of Devonian black shales of western New York state and northwest Pennsylvania suggests that these rocks, too, have been affected by vitrinite suppression. Measured %Ro of relatively close-spaced samples collected from the base of the Upper Devonian Rhinestreet and Dunkirk shales in western New York varies irregularly from 0.51 to 0.77. Moreover, comparison of the Rock-Eval hydrogen index (HI) and measured $\%R_o$ for > 50 Devonian black shale (principally Marcellus shale) samples reveals a trend similar to that of the New Albany shale, which has been affected by vitrinite suppression. Specifically, a reduction of HI from > 400 mg/g to ~ 125 mg/g is accompanied by little change in $\%R_o$. At HI ~ 125 mg/g, however, %Ro increases sharply from ~ 0.75 to >2.5 as HI drops to near zero. These results suggest that vitrinite was suppressed in the lower or mid oil window maturities in the Marcellus and younger black shale units in this region of the Appalachian Basin, a factor that should be taken into account in exploration strategies.

Dolomite Textures and Porosity Development in Trenton and Black River Formation (Middle Ordovician) HTD Carbonate Reservoirs, Appalachian Basin, USA

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Two distinct dolomite textures – planar and transitional to nonplanar – occur in fractured carbonate petroleum reservoirs of the Trenton and Black River Formations in the Appalachian basin. Planar dolomites consist of micron- to centimicron-sized, euhedral to subhedral crystals that selectively replace limestone matrix in all depositional facies. Less common planar-p and planar-e dolomite locally replace allochems, and rare planar-c dolomite fills pore space. Planar textures in peritidal facies might have formed during reflux and/or mixing zone diagenesis. Planar textures in subtidal facies likely formed in association with compaction-driven fluid flow in burial environments. Planar textures also occur where hydrothermal dolomite replaces limestone adjacent to fractures and faults.

Transitional to nonplanar dolomites are entirely hydrothermal. They consist of decimicron- to millimeter-sized crystals in fractured rocks adjacent to faults. Transitional and nonplanar-a dolomites occur as an obliterative replacement of allochems, matrix, and cement in limestones, and as neomorphic recrystallization of planar dolomite. Nonplanar (saddle) dolomite occurs as pore-lining and pore-filling cement.

Distinctive pore textures in Trenton and Black River reservoirs vary with carbonate rock type. Porosity is partially related to depositional texture in productive dolograinstones and dolopackstones. These rocks consist of planar-s to nonplanar-a and saddle dolomite. Mesoporosity is fabric selective, consisting of moldic and intercrystalline voids. Macroporosity is not fabric selective, and consists of small to medium vugs and fractures. Microporosity is both intercrystalline and intracrystalline. Porosity formed through a combination of fracturing, selective dissolution of allochems, and dissolution of calcite and dolomite cements.

Porosity in productive dolowackestones and dolomudstones is not fabric selective. Macroporosity consists of vugs, channels, fractures, and breccia. Vugs formed through selective dissolution of allochems followed by corrosive enlargement of the initial void. Vugs also formed through dissolution of calcite, dolomite and other cements. Channel, fracture, and breccia porosity developed in conjunction with hydraulic fracturing and brecciation by hydrothermal fluids. Some channel porosity formed through reopening stylolites.

Hydrothermal dolomitization accompanied porosity development in Trenton and Black River reservoirs. It did not provide or increase it. Porosity in all dolostones was modified by late-stage precipitation of nonplanar dolomite, calcite, quartz, feldspar, sulfides, sulfates, and oxides. Pyrobitumen lines and fills most pores.

Geochemistry of Natural Gases from Trenton and Black River Carbonate Reservoirs, Eastern USA – Implications for Deep Basin Hydrocarbon Resources in the Appalachians

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Fractured carbonate reservoirs in the Middle Ordovician Trenton and Black River Formations of the Appalachian basin contain significant natural gas reserves. Thermogenic gas is produced from platform and ramp limestones in eastern Kentucky and central West Virginia, and from hydrothermal dolomite (HTD) reservoirs in platform carbonates in northeast Ohio, south central New York, and north central Pennsylvania.

The distributions of stable carbon ($\delta^{13}C_1$ - $\delta^{13}C_4$) and hydrogen (δ^2H_{CH4}) isotopes in Trenton and Black River gases from Kentucky, West Virginia, and Ohio show that the hydrocarbons were generated from early to post mature marine source rocks in Ordovician and possibly Cambrian strata. The $\delta^{13}C_1$ - $\delta^{13}C_4$ distributions in gases produced at Homer field in Elliott County, Kentucky and at York field in Ashtabula County, Ohio reveal compartmentalization in the reservoirs. Ethane is depleted in ^{13}C relative to methane in the West Virginia gases suggesting heterogeneities in the source organic matter, thermogenic gas mixing, methane oxidation, or diffusive gas leakage from the reservoirs.

Hydrocarbons produced from HTD in the Black River Formation of New York and Pennsylvania are unusual. Methane is depleted in ^{12}C ($\delta^{13}C_1$ = -32.7 to -26.02 permil). The C_1 to C_3 alkanes are significantly more enriched in ^{12}C with increasing molecular mass. These gases exhibit a strong negative correlation between $\delta^{13}C$ and δ^2H of methane, and some display an inverse correlation between $\delta^{13}C$ and δ^2H of methane and ethane. These isotope distributions apparently resemble those of postulated abiogenic gases. δ^2H values and C_1/C_{2+} ratios in our samples, however, indicate a thermogenic origin, and noble gas systematics implies a Middle Ordovician shale source. We attribute the unusual geochemistry of the Black River gases to a combination of fluid alteration during reservoir diagenesis, and mixing of thermogenic and deep basin hydrothermal/geothermal gas.

Non-hydrocarbons in the New York and Pennsylvania gases have multiple sources. $^3He/^4He$ and $^{40}Ar/^{36}Ar$ vary between 0.01 – 0.196 Ra and 295 – 1521, respectively, and are due to measurable contributions from the mantle and crust. Nitrogen comprises between 0.10 and 14.14 mole percent of the gases. $\delta^{15}N$ of the gases ranges from -10.2 to +0.4 permil. Combined nitrogen and noble gas systematics indicate the presence of magmatic, crustal, and atmospheric nitrogen in the gases. $\delta^{13}CO_2$ in the gases is -6.7 to -3.0 permil, indicating a carbonate source for this minor constituent. As much as 0.51 mole percent H_2S occurs in the Wolpert #1 well in Bradford County, Pennsylvania. The $\delta^{34}S$ of this gas is +14.7 permil. Geochemical and petrographic data indicate that the H_2S formed through thermochemical sulfate reduction.

Lower and Middle Ordovician hydrothermal dolomites on Anticosti platform: Contrasting patterns and fluid history.

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World-class conventional hydrocarbon reservoirs are hosted by Paleozoic hydrothermal dolomites (HTD). By definition, a hydrothermal fluid has temperature at least 15ºC over that of the ambient burial fluid. If late burial allows the rock unit to be exposed to temperatures higher than those recorded by an early hydrothermal event, it is the difference of temperature at that event which is critical.

In Quebec, the carbonate units in the St. Lawrence Platform occur at multiple stratigraphic intervals from the Lower (Beekmantown Group and the Romaine Formation), the Middle (Chazy Group and Mingan Formation) and the Upper (Black River and Trenton groups) Ordovician.

Ordovician HTD occurs in the Anticosti platform, although data from passive margin (Romaine) to foreland basin (Mingan) carbonates suggests significant distinctions. Saddle and matrix-replacement dolomites of the Romaine Formation are characterized by high FI homogenization temperatures (up to 151°C), high $^{87}Sr/^{86}Sr$ ratios (0.709142 to 0.712862) and low Sr content (average 180 ppm). Conversely, the replacement dolomite of the Mingan Formation is characterized by lower FI homogenization temperatures (below 128°C), lower $^{87}Sr/^{86}Sr$ ratios (0.708815 to 0.709034) and higher Sr content (average 513 ppm). T_h of saddle and replacement dolomites are above maximum burial temperature recorded by both units, in particular in the northern part of the island (135°C and 110°C for the Romaine and Mingan, respectively), therefore, both dolomites are interpreted as hydrothermal in origin. Limited geoscience data indicate that two different fluids were responsible for the alteration of both formations, timing of the fluid pulses are currently unknown.

Evaluation of Deep Saline Reservoirs and Entrapment for Carbon Sequestration using Seismic Reflection Data.

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The Ordovician St. Peter Sandstone and Cambrian Mt. Simon Sandstone are saline reservoirs that underlie much of the Illinois Basin. Both are used for natural gas storage in the northern part of the basin and are currently being evaluated as reservoirs in which to successfully sequester carbon dioxide. However, no St. Peter or Mt. Simon gas storage projects have been undertaken in areas where these reservoirs are deeper than 4,500 ft. In the deeper part of the basin, relatively few wells (approximately 25 wells) have penetrated these saline reservoirs and thus seismic reflection data are necessary for characterizing the nature of the reservoirs and the geometry of the traps that contain them.

Although the Mt. Simon is over 2,000 feet thick in the northern part of the Illinois Basin, seismic reflection data and well logs suggest that it is thin or absent over local Precambrian paleo-highs south of this depocenter. In some cases, the Mount Simon may truncate onto the flanks of these paleo-highs. The geometry of these traps can be identified by the thinning and termination of seismic reflector packages. The character of the internal stratigraphy within these reservoirs and the overlying confining strata can also be assessed using seismic data. Commonly, structure maps on shallower horizons defined by oil and gas wells are used to project the deeper structure. In the Illinois Basin, the shallow and deeper strata are not necessarily structurally aligned; the crests can be laterally offset by thousands of feet. In some cases deep-seated faults penetrate only these lower Paleozoic strata and can only be accurately mapped with 3-D seismic reflection data.

The Middle Devonian Hamilton Group Shales in the Northern Appalachian Basin: Production and Potential

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The rocks of the Hamilton Group are the oldest strata of the Devonian gas shale sequence. The black and gray shale found in the Hamilton Group mark the first terrigenous sediment deposited by the erosion of the Acadian Mountains. The group overlies the Onondaga Limestone, and consists of black and dark gray shales in the lower part, and limestone, light gray shale and mudstone in the upper part. The Hamilton Group outcrops in New York State along the northern and eastern margins of the Allegheny Plateau. The group thickens from 250 feet near Lake Erie to over 2,500 feet in Ulster and Green counties. Formation depths range from outcrop to 8,000 feet in Sullivan County (southeastern New York). The Hamilton has been subdivided into four units: the Marcellus, Skaneateles, Ludlowville, and Moscow. The basal unit of the Hamilton is the Marcellus Shale, the primary exploration target. As the lowest most unit, the Marcellus formation is regionally extensive, covering most of the northern Appalachian Basin.

Measured total organic content of the Marcellus Formation ranges from less than 1% to over 11%. Thermal maturity is geographically-controlled. In the eastern reaches of New York and Pennsylvania, these shales are in the dry gas window. To the west, the shale is more likely in the oil window. Kerogen has been measured as either Type II or Type III.

Since 1900, fewer than 100 Hamilton shale wells have been drilled in New York State. Recently, a flurry of test wells has been permitted in the area surrounding Watkins Glen. These new wells show promise and the application of new methods may make the Hamilton Group the next big shale play.

The Utica Shale: Evolution and the Potential for Natural Gas Production

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One of the oldest and most widespread black shales is the Utica Shale. It was deposited very broadly across the Appalachian Basin and covers thousands of square miles. In New York, depth varies from outcrop to depths over 9,000 feet in the southern portion of the state. Thickness varies from tens of feet in the west to over 1,000 feet in the east.

The Utica is a massive, fossiliferous, organic-rich, thermally-mature black to gray-black shale, and is considered to be the source rock for Lower Devonian through Cambrian hydrocarbon production and shows. The shale was deposited in a deep marine basin with a subsiding trough that generally trended north-south. It interfingers with the basal Dolgeville Formation, which is composed of alternating beds of limestone and shale. Source rock for the organic-rich black shale was supplied from the eroding Taconic highlands to the east. As the deep marine trough was filled in, the deposition of the upper formations of the group spread westward. The westward migration was periodic which is reflected in the presence of a number of facies intervals, which are bounded by unconformities or condensed intervals. Each unit represents a pulse of subsidence and subsequent sedimentation in the basin. Each interval onlaps argillaceous limestone, and has shifted westward with respect to the underlying unit. Each depositional interval records a deepening event. Stratigraphic work to date indicates that each overlying black shale unit is thinner than the previous one.

Units of the Utica have significant fracturing and abundant pyrite indicating deposition in anoxic conditions. The shale is sub-bituminous and “fresh samples can be ignited.” If a fresh sample is submerged in water, “an oily sheen rises to the water's surface.” Though data is sparse, TOC’s has been measured at over 3% by weight in New York, Ontario and Quebec. Analysis of cores show that the Utica thermally-mature with some mobile oil. Gas shows have been encountered in wells in eastern and central New York.

Current shale plays such as the Barnett and Antrim show that every shale play is somewhat unique, each with its own characteristics and problems. It is clear that the fractured Utica Group Shale offers the potential to be an economic natural gas play. More research is needed that addresses the geologic and reservoir properties of the shale.

Integration of Fracture Patterns and Lineaments for Fault Mapping in Southwestern Chenango County, New York

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This study integrates surface structure data with lineaments to map possible fault patterns in southwestern Chenango County, New York. Bedrock in the region is the Middle to Upper Devonian Catskill Delta Complex. Previous work in the region was by Pyron et al. (2003) who correlated lineaments from an aerial photo mosaics with soil gas and paleomorphic data to determine possible structure trends in fractured shale wells in the Genegentslet field.

Characteristics of approximately 2500 surface bedrock fractures were collected within the study area, following standard UB Rock Fracture Group protocols. Fracture characteristics are displayed using modified rose diagrams which show fracture orientation, frequency, and fracture abutting relationships. Three fracture sets are common to this region: NNE-, E- and a N60° E-striking set. Fracture intensification domains (FIDs), which are characterized by closely spaced fractures, are also common in the region. In other study areas FIDs have been found to indicate faulting.

Bedrock fracture data are combined with EarthSat (1997) lineaments, DEM lineaments and aeromagnetic gradients. A N-trending zone of widely-spaced EarthSat (1997) lineaments is coincident with an aeromagnetic anomaly and sites that display N-striking fracture cleavage. Lineament zones that trend NNE, NNW, ENE and WNW are coincident with sites where we observed FIDs that parallel the lineament trends. Based on a proprietary seismic reflection profile, an ENE structure can be found on the seismic line which coincides with surface fractures, FIDs, and Landsat lineaments (EarthSat, 1997).

Carbonate margin depositional dynamics of the Lower Silurian Taconic and Salinic foreland basins: a high frequency eustatic signal superimposed on long-term basin evolution

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New sequence stratigraphic analysis along the Cincinnati Arch reveals striking similarity between classic Lower Silurian sections of the Niagara region and outcrop and subsurface data from southwestern Ohio. The strata of these two regions contain a Llandovery succession made up of couplets of hardground-bearing glauconitic grainstone-ironstone and (largely barren) shale-dominated intervals, forming 4[th]-order depositional sequences. Three complete lower Llandovery depositional sequences and the lower part of a fourth, deposited during the Taconic Orogeny, show little change from southern Ohio southwestward into central Kentucky (~150 km), indicating depositional strike. However, these strata show a high degree of facies change in sections to the northwest of this strike line, indicating the direction of depositional dip. These strata are removed under a late Llandovery age erosional unconformity that is regionally angular. The erosion is so extensive that across western Ohio, northwestern Kentucky, and eastern Indiana only a portion of the lowermost depositional sequence is preserved, similar to the pattern of stratal overstepping developed in the Niagara region. The erosion is to extensive on the Cincinnati Arch that the uppermost Llandovery age strata rest upon the Upper Ordovician in parts of eastern Indiana, suggesting the axis of the Cincinnati Arch resided several tens of kilometers west of its present location during the Llandovery (nearly coincident with the Upper Ordovician Sebree Trough). The uplift of the arch during the late Llandovery is coincident with renewed basin subsidence further to the east and is interpreted as far-field tectonic response to the onset of the Salinic Orogeny.

The influence of geologic structures on the distribution and production of oil and gas from continuous (unconventional) hydrocarbon accumulations in the Appalachian Basin

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During its 2002 assessment of technically recoverable, undiscovered hydrocarbon resources in the Appalachian Basin, the U.S. Geological Survey classified assessment units as containing either conventional or continuous resources. Conventional resources are in fields defined by structural and stratigraphic traps, where reservoir fluids and gases are stratified within the trap. Continuous resources extend widely in tight sandstone, black shale, and coal bed reservoirs that show little or no stratification of reservoir fluids and gases. Although continuous reservoirs yield hydrocarbons almost wherever they are drilled, the amount of hydrocarbons produced ranges widely and depends upon local variations within the reservoir, including small-scale geologic structure. Examples of structural influence on hydrocarbon distribution in continuous reservoirs occur in Silurian sandstones, Devonian shales and sandstones, and Pennsylvanian coal beds. Basin-center continuous and transitional accumulations in Silurian sandstone reservoirs in New York, Pennsylvania, and Ohio have hydrocarbon production that is enhanced by geologic structure. For example in Ohio, increased production from Silurian sandstones and Devonian shales may be related to local fracture porosity associated with the Cambridge arch. In Devonian shales in eastern Kentucky, fracture porosity related to the Rome trough and to subhorizontal decollement within the shales has facilitated gas production. In continuous Devonian and conventional Mississippian sandstone accumulations in Pennsylvania, hydrocarbons are segregated locally within anticlines and synclines, even though they are distributed regionally with little or no water in the reservoirs. Finally, in Pennsylvanian coal beds in southwestern Virginia, enhanced gas production is associated with fracture porosity related to subhorizontal decollement with coal beds.

Natural Irradiation – The New Approach to Hydrocarbon Source Rock Evaluation

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Hydrocarbon source rock evaluation is a very important tool for hydrocarbon exploration and production development. Despite methodical differences of present methods, estimation of the kerogen maturity is based on thermodynamic principles. Practically, only geothermal heat is taken into accounts.
At least three major types of evaluation methods are applied:
a) a) Methods based on the Arrhenius equation (Tisso' et al. method);
b) Methods based on determination of paleoheat flux (Lopatin' method);
c) Methods based on lab paralysis of rock formation samples.
Historical application of these methods for the same objects quite often provided significantly different results. Methodological problems are also aggravated by reconstruction uncertainness of many applied geological parameters such paleodepth, paleotemperature, and others.
It is known that many hydrocarbon source rocks have high levels of natural radioactivity due to their enrichment by radioactive elements such as Uranium. Thus, radioactive decay is also an important cause of kerogen chemical alterations. For example, highly radioactive Upper Jurassic Bazhenov shales are the recognized as major hydrocarbon source rock in Western Siberia (Russia), particularly for such giant oil fields as Samotlor, Mamontovsk, Salym, Krasnoleninsk and others.
Bazhenov shale presently contains 23.5 g/ton of Uranium (98% of the initial content). Our quantitative evaluation showed that energy produced by decayed Uranium disseminated within the formation is more than sufficient for a high degree maturation of the formation kerogen.
Taking into account organic rich rock radioactivity is also a base of paleo organic geochemistry reconstruction that may be quite different from interpretations based on thermodynamic principles. The formation mechanism of active hydrocarbon particles (ions and radicals) from kerogen under irradiation is very different from the formation mechanism due to heating. Results of irradiation, in contrast to geothermal heating, are not dependant directly on formation temperature but on irradiation dose rate and timing. Therefore, one can expect a different quantitative and qualitative hydrocarbon output from a source rock. However, because natural clay catalysts such as montmorillonite and smectite play an important role in ion and radical accumulation, a source rock geothermal and irradiation heating has to also be taken into account to evaluate chain reactions of accumulated active particles resulting hydrocarbons.

Regional age and facies relations in the Black River, Trenton, and Utica Groups of the central and northern Appalachian Basin: Potential for testing models of tectonic control on fractured reservoir genesis.

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The deposition of the Black River, Trenton, and Utica groups (BrTU) reflects the overall drowning of southern Laurentia during formation of the Taconic Foreland basin. One phase of faulting and fracturing that led to mineralization and development of petroleum reservoirs may also to have been related, in part, to this same set of tectonic events. The BrTU history of deposition offers an opportunity to test this model.

Recent graptolite and conodont biostratigraphic results and geochemical fingerprinting of K-bentonites reveal that interactions between subsidence, sea level change, and sediment supply resulted in differences in BrT thickness of over an order of magnitude and differences in age of the base of the overlying shale cap of more than 5 MY. In the western Great Valley and eastern Valley and Ridge from northern VA-WV into PA and NJ and in the Hudson Valley, NY, Trenton facies are within the *Phragmodus undatus* Zone at their top and the overlying black shales are within the *Climacograptus bicornis* Zone – this despite passage across the PA reentrant and onto the NY Promontory. The Deicke and Millbrig (D-M) K-bentonites lie at or just above this contact. Across strike, in the central Valley and Ridge and lower Mohawk Valley, the Trenton facies are up-dip equivalents of the *C. bicornis* Zone shales, contain the D-M set, and are within the *Plectodina tenuis* Zone at their top. They are disconformably overlain by Utica Group rocks of the *Corynoides americanus* Zone. This pattern continues westward--the Trenton-Utica contact steps upward repeatedly.

Trenton Limestone Reservoirs in Northern New York: Where does the gas come from?

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The Trenton Limestone has produced gas in New York for almost 120 years in numerous shallow (<2500 ft) fields near Lake Ontario, NY. Wells encountered intense pressure kicks that typically blew down to very low rates in a few hours or days. Most of the production occurred in the late 1800s and early 1900s and there is little modern data. A study was undertaken to answer the questions: Does hydrothermal dolomite have anything to do with this production? Is there any porosity in the limestones that might work as a reservoir for natural gas? Does the gas come from fractured limestone or fractured shale or both? To answer these questions we acquired 160 sidewall cores along with a full suite of logs in a recently drilled well that had strong gas shows from several intervals in the Trenton Limestone.

The cores from the productive intervals have no matrix porosity in the limestone and no significant dolomite. SEM photos showed what may be minor microporosity in the shales and shaley limestones. The FMI from the well showed no significant vertical fractures in the intervals with shows. Based on this data and other observations, it is our conclusion that most of the gas in this well came from horizontal bedding plane partings between interbedded limestone and shale. The bedding-plane partings are interpreted to have been propped open by the high pressure of the gas. When they were penetrated, the overpressured gas flowed back at high rates but quickly blew down to almost nothing as the partings closed due to the lithostatic pressure. Wells with longer lasting production may penetrate open vertical fractures that connect larger pore volumes. Targeting areas with vertical fractures around faults and/or developing new drilling and completion techniques may help make this an economic play.

Shale Fabric and Sedimentary Processes – A Review

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Presented here is a review of common fabric signatures in gray and black shales and the sedimentary processes responsible for their formation. Macro– and microfabric features are revealed in x-radiographs and thin-section and scanning electron microscope photomicrographs. Macrofabric analysis shown by x-radiography reveals: (1) well developed lamination indicating absence of bioturbation; (2) indistinct lamination resulting from slight disruption of sediment features by bottom-flowing currents and/or minor bioturbation; or (3) absence of lamination indicative of extensive bioturbation. Petrographic analysis of organic-rich gray to black shales reveals four specific lamination types: (1) fine, (2) thick, (3) wavy, (4) lenticular – each useful indicators of sedimentary processes. These techniques when combined with scanning electron microscope analysis show fabric signatures of shale forming processes such as: (1) the influence of suspension settling and/or bottom flowing currents; (2) the role played by clay flocculation or dispersion upon fabric, (3) the impact of benthic microbial mats and bioturbation upon final particle orientation. Fabric evidence combined with other geological features is thus useful in determining not only the original sedimentary processes but also in predicting properties of shale which influence primary hydrocarbon migration.

Optimizing Hydraulic Fracturing Performance in Northeastern Fractured Shale Formations.

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The primary purpose of stimulating fractured shale formations in Northeastern America is to extend the drainage radius by creating a long fracture sand pack that connects natural fractures and increases flow channels to the wellbore. However, most of the fracturing pad fluid leaks off into natural fractures resulting in shorter effective frac lengths and a significant damage zone surrounding the fracture. This is due in part to inadequate fluid loss control properties of the injected fluid and high capillary forces that retain fluid in the formation. Surfactants are used to lower high capillary forces and help well cleanup of the injected fluids. However, many of these additives adsorb rapidly within the first few inches of the shale formations, reducing their effectiveness resulting in phase trapping of the injected fluid.

This study describes the laboratory experiments and field data comparing various surfactants and multi-phase fluid system to determine their leakoff and adsorption properties when injected into a 6 foot laboratory shale packed column. A laboratory comparison study of these systems was used to select additive combinations to apply within the fracturing fluid to restore pad leakoff efficiencies and improve flowback of injected fluid from fractured shale gas wells.
Data collected from various fractured shale formations of Northeastern region confirms experimental shale packed column and core flow investigations.

Reservoirs treated with proposed multi-phase fluid demonstrate exceptional leakoff efficiencies, 50% less skin damage, and higher flow rates when compared with conventional treatments. These investigations and presented data can be used to optimize hydraulic fracturing performance of fractured shale formations.

Trenton-Black River Play Overview, Research Summary and Resource Assessment

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The current Trenton-Black River gas play began when Columbia Natural Resources (CNR) drilled the discovery well for the Glodes Corners Road field in Steuben County, New York in 1985. However, it was not until a full decade later, in 1995, that CNR drilled a confirmation well, and 1996 before the first wells went on line. The play then developed rapidly in New York, attracting national interest as more discoveries were made and large open flows and annual production were reported. By 1999, four fields had been discovered in New York, and the play had moved into Ohio and West Virginia with the discovery of York and Cottontree fields, respectively. This same year, the Appalachian Region of PTTC began to host a series of workshops on the play, which led to the creation of an industry-government-funded Trenton-Black River Research Consortium. The main goal of the Consortium was to compile all available information into one basinwide playbook, complete with analyses and interpretations made from a multidisciplinary, integrated study of the data. Three additional objectives were defined: to develop a resource assessment model for this complex, unconventional play; to develop a model to explain the origin of dolomite reservoirs; and to define possible fairways within which to concentrate further exploration.

The gas resource contained in these reservoirs is significant. To assess this resource, the Trenton-Black River assessment area was divided into two separate plays, a hydrothermal dolomite play in the shallower, western side of the basin, and a fractured limestone play immediately adjacent to the east. The boundary between these plays approximates the western edge of the Rome trough and the eastern, fault-controlled edge of the former Black River ramp.

The method used to estimate gas resources in each play area required that team members estimate the number and size of undiscovered fields in the assessment area, fields that can be expected to be discovered within the next 30 years. The number and sizes of undiscovered fields were estimated at three levels of probability - 90%, 50% and 10% - and resource numbers were calculated for each probability level for both plays. The final assessment numbers for the entire assessment area are as follows: there is a 90% probability that at least 2.7 Tcf of gas will be discovered; a 50% chance that at least 6.0 Tcf will be discovered; and a 10% chance that as much as 11.0 Tcf will be discovered. These numbers are quite comparable to estimates made during an independent assessment by the Potential Gas Committee in 2004. The corresponding PGC estimates were 2.5, 5.4 and 8.5 Tcf at the same levels of probability.

A Review of the Petroleum Systems of the Northern Appalachian Basin

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Oil and sediment geochemical analysis have been undertaken to establish the various petroleum systems in the northern Appalachian Basin. Restored richness data for sediments from over 50 wells indicates clearly that Middle-Upper Devonian sediments are the primary source facies in the northern Appalachian Basin. This is clearly substantiated by oils that are associated with these Devonian sources. Black shale source facies of the Upper Ordovician (Utica and equivalents)are also represented in oil and sediment data. Middle Ordovician carbonates (Trenton-Black River) as a source are not pervasively apparent in the sediment richness data however, oils with the characteristic Ordovician, *G. prisca* associated chemistry indicate the importance of a Middle-Ordovician source. Organic rich Middle Cambrian shales have been measured in a well in Kentucky; however, oil data does not substantiate a Cambrian source.

Oil geochemical data show that both the Ordovician sources have contributed to accumulations in the Cambrian, Ordovician and Silurian. Several mixed oils show that the Devonian sources have also contributed to Silurian and Mississippian as well as Devonian accumulations.

Maturity data indicate that the source horizons over much of the study area are well beyond oil generation and are generating or have generated gas. Future studies are concentrating on sampling and correlating gases with their source horizons.

Thickness and texture of cross strata formed by river dunes and unit bars: implications for paleo-channel reconstruction and permeability heterogeneity of fluvial deposits.

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Cross strata formed by dunes and unit bars are the most common sedimentary structures of fluvial sandstones and conglomerates, and can be readily recognized in cores. Experimental and field studies indicate great variability in the thickness, texture, and permeability of individual cross strata within a cross-set, related to the three main mechanisms of formation: (1) pre-sorting of sediment arriving at the lee-side of the bedform, related to superimposed bedforms and longer-term variations in water flow and sediment transport; (2) sorting due to differential deposition on the lee-side and associated grain flows; (3) movement of sediment on the lee-side by water currents in the flow separation zone. Bedform superimposition (e.g., ripples or bedload sheets on dunes; ripples or dunes on unit bars) is of primary importance in generating cross stratification, but its role has been seriously underestimated. The exact nature of superimposition depends on the nature of flow and sediment transport. The size of a superimposed bedform relative to the host bedform controls not only the thickness of the cross stratum, but also its angle of inclination, and the spatial distribution of texture and permeability. The 3-D character of high permeability (thief) zones and permeability barriers is intimately related to the nature of bedform superposition. Careful study of cross stratification in cores and outcrops can lead to quantitative interpretation of types of host and superimposed bedforms, which is a pre-requisite for quantitative interpretation of channel geometry (e.g., width and depth) and prediction of the 3D distribution of the permeability.

Regional Cross Sections Illustrating the Middle and Upper Ordovician Stratigraphic Framework in the Appalachian Basin

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The Ohio Division of Geological Survey (ODGS), in conjunction with the State geological surveys in Kentucky, Pennsylvania and West Virginia, and the New York State Museum Institute recently completed a regional study of the Ordovician Trenton-Black River interval in the Appalachian Basin. This industry-government partnership was partially co-funded by the U.S. Department of Energy and a consortium of oil and gas companies.

A network of regional cross sections across the Appalachian Basin was generated by the ODGS to unravel the regional Trenton-Black River stratigraphy and facies relationships, which are necessary for understanding the exploration potential of these productive reservoirs. Cross sections were tied to open-file and published reports, continuously cored Trenton-Black River wells, geophysical well logs, and Geolog sample descriptions. Six geophysical log cross-section lines oriented parallel to strike, and 12 cross-section lines oriented perpendicular to strike were constructed.

The stratigraphic framework developed by these cross sections established regionally consistent formation/interval boundaries that were used for development of structure, isopach, and facies maps. These cross sections also were critical in understanding the Trenton-Black River depositional environment, basin architecture and facies distribution, which has important implications for Trenton-Black River exploration. The relationship of the deeper-water Utica/Point Pleasant Sub-basin to the thick Trenton/Lexington carbonate platforms that rim much of this sub-basin is illustrated and defines a potential exploration trend. Regional correlations also indicate a clean carbonate in the upper portion of the Trenton in portions of western New York, which may have exploration potential for hydrothermal dolomite reservoirs and is yet untested.

Regional Stratigraphic and Facies Relationships of the Ordovician Trenton-Black River Interval in the Appalachian Basin

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The Ohio Division of Geological Survey (ODGS) conducted a regional stratigraphic investigation of the Trenton-Black River interval in the Appalachian Basin, as part of an integrated, comprehensive study with the State geological surveys of Pennsylvania, Kentucky, New York, and West Virginia. The primary objectives of the ODGS were to define Trenton, Black River, Utica and equivalent lithostratigraphic units within a regional framework, model the depositional environment and basin architecture, and integrate these findings with the results of other tasks of the consortium to delineate potential areas of exploration interest. ODGS geologists generated a network of regional stratigraphic cross sections, interpreted geophysical logs and integrated with cores for regional mapping of selected Cambrian-Ordovician intervals, created generalized maps showing the major tectonic features and basin architecture during Middle Cambrian through Late Ordovician time, and constructed generalized facies maps for the Black River and Trenton/Point Pleasant equivalent strata.

The stratigraphic framework established in this investigation allowed lateral facies changes in the Trenton-Black River interval to be separated and mapped regionally for the first time. As deposition of these facies was tectonically influenced, detailed mapping of them is critical to understanding basin evolution and reservoir development. Trenton isopach and facies maps indicate that exploration potential exists along much of the depositional platform margin, especially where there are well-developed, clean carbonates. Stratigraphic work also indicates that in northwest Ohio some of the best hydrothermal dolomite (HTD) reservoirs are from the skeletal shoal grainstones that developed along the platform margin, while in New York, HTD reservoirs have been restricted to the Black River mudstones.

The south-central New York–northeastern Pennsylvania thermal maturity high: Distribution, origin, and control on natural gas composition

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Conodont color alteration index (CAI) isograds of 4, 4.5, and 5 in Ordovician rocks define a region of high thermal maturation (200-mi-long by 140-mi-wide) that extends from north-central/northeastern Pennsylvania into south-central/southeastern New York. The broad central part of the thermal maturity high is marked by CAI 4.5 and 5 values, whereas the northern and western margins of the high are defined by closely spaced CAI 3.5, 4, and 4.5 isograds. CAI 2.5 and 3 isograds in Lower-Middle Devonian rocks of south-central New York closely mimic the thermal maturation pattern defined by the CAI 3.5-4.5 isograds in the underlying Ordovician rocks. Previously recognized variations in illite/smectite and apatite fission-track ages in a Middle Devonian bentonite bed corroborate the western margin of the thermal maturity high.

We interpret the thermal maturity high to represent the original outline of the northeastern part of the Appalachian foreland basin where a thick overburden of Upper Devonian Catskill delta and Carboniferous deposits had accumulated. Although this overburden is now absent, it may have been as thick as 20,000 ft according to one estimate. A secondary factor that may have contributed to the thermal maturity high is higher-than-normal heat flow caused by crustal extension, intrusion of late Mesozoic kimberlite bodies, or warm circulating fluids.

Natural gas accumulations in Ordovician and Silurian reservoirs within the thermal maturity high are dry (C_1/C_1-$C_5 \geq 0.98$) and isotopically heavy ($\delta^{13}C_{methane} \approx -31$ per mil). These gases probably were derived from the Ordovician Utica Shale source rock and commonly involved vertical migration of about 1,000 ft.

Reservoir Characterization of Northern Michigan Niagaran Pinnacle Reefs

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Porosity and permeability distribution in Northern Michigan Niagaran pinnacle reefs is controlled by the geometry of depositional facies, which were later affected by exposure to meteoric water and hypersaline brines, followed by an episode of salt plugging. An understanding of depositional and diagenetic processes affecting porosity results in a model capable of predicting reservoir quality rock within individual reefs.

Three depositional facies have been recognized within the productive section of the reefs. These include mud mounds deposited below wave base, coral-stromatoporoid reefs and a restricted marine section reflecting increasing salinity in the basin. The mud mound facies always has very low porosity except when affected by isolated fractures. The coral-stromatoporoid and restricted marine facies contain porosity sufficient to be economically viable hydrocarbon reservoirs unless filled with halite salt crystals.

The stratigraphy of the reefs results in a tight mud mound core in the more basinward reefs, which does not exist in the shorter, more shelfward reefs. The tight mud mound facies, where present, is overlain by the porous coral stromatoporoid and restricted marine facies. Salt plugging is more prevalent in the basinward reefs, coincident with the presence of the mud mound cores. Where it occurs, it is more pervasive in the upper sections of the reefs. The basinward reefs commonly exhibit a "do-nut" of porosity encircling the mud mound below the base of salt plugging. The more shelfward reefs have no mud mound facies and salt plugging is minimal, resulting in reefs that consist of porous reservoir quality rock throughout.

Hydrothermal alteration of Proterozoic 'Grenville' marble and Cambrian Potsdam Sandstone by seismically-pumped fluids, Adirondack Lowlands of northwestern New York State

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Well-exposed NE-trending strike-slip shear zones in the Adirondack Lowlands of northeastern New York State were active during burial diagenesis of the Cambrian Potsdam Sandstone. Hydrothermal fluids interacted with basement marble to produce widespread dolomitization, hydrothermal leaching and alteration of silicate minerals. Cambrian sandstone overlying the basement was injected as fluid slurry into corrosion pipes and tunnels and cemented by quartz, illite, chlorite, apatite and minor authigenic phases. Fluid inclusion data suggest the mineralizing system was generally 120-180ºC with fluid salinities 12-18 wt. % NaCl equivalent. Stable isotope data on hydrothermal carbonate minerals are consistent with evolved basinal brines ($\delta^{18}O_{SMOW}$ in the range +8 to +11 ‰) as the mineralizing fluid. Patterns of dissolution and void development in marble and paragenesis of minerals within the marble and sandstone suggest fluctuating fluid composition in terms of carbonate saturation and oxidation state. Multiple zonation of void fill and alternating ferric-ferrous mineral precipitates argue for rhythmic fluid pumping within the shear zone/hydrothermal system framework.

The tectonic, structural and stratigraphic setting of this mineralizing system forms an excellent model for the basement-cover root zone of HTD reservoir systems. Seismic pumping of locally-derived connate waters best explains the scale and distribution of hydrothermal dolomite. Hydraulic connection between sheared, altered basement rock and overlying carbonates undergoing hydrothermal dolomitization is critical to allow sufficient flux of Mg to promote dolomitization. Active seismic pumping of fluids during wrench faulting was likely a key element in the development of HTD reservoirs.

Surface Geochemical Expression of Hydrocarbon Seepage Over a Utica-Trenton Play Area, New York

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An area north of the Finger Lakes and west of the Adirondacks in New York has produced natural gas from Ordovician Utica-Trenton Group strata since 1889. Of the 365 wells drilled in the area, 223 produced natural gas. Since the late 1960s, this area has seen renewed exploration interest because of the historical production and higher gas prices. Of the 11 wells drilled over the past 5 years, only 4 have had apparent commercial success. Based on these poor drilling results, which were largely seismic-driven, less costly exploration methods were sought to complement seismic surveys. In a recent NYSERDA project, several surface geochemical methods were assessed to determine their value to gas exploration in the area.
Direct Geochemical collected 170 shallow (1-foot) and deep (8-foot) soil samples along public roads over both productive and non-productive areas. The samples were dried, sieved and analyzed for low and high temperature thermally desorbed C_1-C_8 hydrocarbons and an acid-extract was analyzed for 26 major and trace elements.
Conclusions from the geochemical survey are as follows:
(1) Low temperature desorption of deep soils reveals strong methane (up to 1%) and C_1/C_2 anomalies over and adjacent to productive areas.
(2) High temperature desorbed hydrocarbons in shallow soils better discriminate between productive and non-productive areas than those in deep soils. Variables that contribute most to the discrimination are propane, nButane, methane and nHeptane.
(3) Both shallow and deep soils over productive areas are anomalous in barium, potassium, calcium, magnesium and strontium. In the shallow soils, silver, antimony, thallium and selenium are anomalous near the productive area.

Under-Explored Lower Paleozoic Strata in Illinois

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Lower Paleozoic units represent 50 percent of the volume of rock in the Illinois Basin yet only two percent of all exploratory wells penetrate these strata. Devonian, Silurian and Ordovician reservoirs account for 7.5 percent of the petroleum produced in Illinois. These reservoirs provide a guide to the potential for Lower Paleozoic production and the opportunity for new exploration targets in the Basin. Prolific Devonian reservoirs, both siliciclastic and several types of carbonate, have been established though lightly explored. Silurian reservoirs, commonly associated with various reef settings, exhibit compartmental characteristics that have both field development and new play potential. Non-reef Silurian production has also been established. Ordovician reservoirs are limited to the Trenton carbonate, closed structure fields leaving the prolific hydrothermal play as pure potential. Diagenetic alteration has played a key role in the formation of reservoirs in existing Lower Paleozoic reservoirs. These units have not been extensively explored, in part because of the greater drilling depths and the practice of penetrating deeper horizons mostly in fields where shallower production has been established. This strategy has brought sporadic results because many of the traps in Lower Paleozoic units are stratigraphic and structural closure may shift with depth. Updated contoured structure maps on key horizons illustrate shifting of some features with depth.

An Illinois Basin Consortium project funded in part by the U.S. DOE is focusing on existing petroleum reservoirs and the potential for new discoveries in Lower Paleozoic units. Major tasks for this project include creating a digital catalogue of existing reservoirs and developing models of the stratigraphic and structural framework of Lower Paleozoic units using available subsurface data. These products will be available in digital format on an ArcIMS website. Preliminary results suggest that applying new exploration strategies to the Illinois Basin can result in significant new discoveries in Lower Paleozoic units.

Outcrop Analog for Lower Paleozoic Hydrothermal Dolomite Reservoirs, Mohawk Valley, New York

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Geochemical analysis and field relations of the Palatine Bridge dolomite outcrop in the Mohawk Valley of New York suggest that it has undergone significant fault-related hydrothermal diagenesis. This study focuses on fluid inclusion, stable isotope, 3D-Ground penetrating radar, core analysis, and surficial observation which all show a link between faulting, dolomitization, and other hydrothermal alteration. It is a scaled analog for Trenton / Black River hydrothermal dolomite reservoirs of the eastern United States. The outcrop is in the Lower Ordovician Tribes Hill Formation, which is an early Ordovician shaley limestone.

The outcrop has an en-echelon fault, fracture and fold pattern. Geochemical analysis, though helpful in characterizing the conditions of formation, do not define its origin absolutely. A 3-D ground penetrating radar survey of the quarry floor has helped to map out faults, fractures, anticlines, synclines and the extent of dolomitization. Most of the dolomitization occurs in fault-bounded synclines or “sags”. The dolomite structures are highly localized, occurring around the faults and are absent away from faults and fractures. Trenches cut across the outcrop help relate offset along faults to the overall geometry of the dolomitized bodies. Comparison of the Palatine Bridge outcrop to producing hydrothermal dolomite reservoirs reveals significant similarities. Although the outcrop is much too small and shallow to act as a producing gas field, it may be studied as a scaled analog to help petroleum geologists characterize existing gas plays and prospect future areas of exploration.

FRACGEN™ Stochastically Generates Fracture Networks Consistent with Data

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FRACGEN™ generates fracture networks for highly fractured reservoirs (< 60,000 fractures) consistent with field data (e.g., outcrop data, fmi and other logs) and a geologist’s intuition. It uses four Boolean models of increasing complexity through a Monte Carlo process that samples statistical distributions for various network attributes of each fracture set as found from the data. Three models account for hierarchical relations among fracture sets, and two generate fracture swarming. Termination/intersection frequencies may be controlled implicitly or explicitly. The code also is being upgraded to allow specification of fractal properties for the fracture network. FRACGEN provides an output file that specifies length, orientation, and effective aperture for each fracture. This output file can be used by a unique reservoir engineering code, NFFLOW, to perform reservoir engineering studies for geologic sequestration of carbon dioxide. This presentation describes use of FRACGEN to describe a reservoir in the Oriskany Sandstone in West Virginia.

Interpretation of Coal-Seam Sequestration Data Using a New Swelling and Shrinkage Model

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This paper deals with the influence of swelling and shrinkage of coal on the production of methane from, and sequestration of carbon dioxide in, a coalbed reservoir. A three-dimensional swelling and shrinkage model was developed. It is based on constitutive equations that account for coupled fluid pressure-deformation behavior of a porous medium that undergoes swelling and shrinkage. The swelling and shrinkage strains are computed on the basis of the amounts of different gases (e.g., CO_2, CH_4) sorbed or desorbed. The amounts of sorption and desorption are computed from measured isotherms with the aid of the Ideal Adsorbed Solution model for mixed gases. The permeability of the reservoir is modified according to the swelling-shrinkage model.

The paper presents numerical results for the influence of swelling and shrinkage on reservoir performance during injection of carbon dioxide. The paper includes results from a number of examples, and analysis of a field injection into a coal seam at a site in the San Juan basin. Results show that with the incorporation of swelling and shrinkage into the analysis, it is possible to get a better history-match of production data. Results also show that coal swelling can reduce the injection volumes of carbon dioxide significantly. The interpretation of field data with the new swelling-shrinkage model shows that the coal swelling during carbon dioxide sequestration in coal-seams is an important factor that can influence field performance.

Fault-driven depositional controls on the Upper Devonian stratigraphic section in New York State

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The Upper Devonian stratigraphic section in western New York contains one of the few outcrop examples of sandstones that comprise the oil and gas reservoirs in the northern Appalachian Basin. We created a stratigraphic framework by integrating data from over 3000 outcrops and 350 well-logs with our sequence stratigraphic analysis, which enables both the correlation of units over relatively long distances and predicts lateral variations and boundary conditions within the context of the depositional environment.

An important discovery observed both in outcrop and cross-section was the proliferation of syn-depositional fault activity. The reactivation of basement faults by the Acadian orogeny controlled the deposition and preservation potential for many of the stratigraphic units. Our prime example is the Rushford Formation, outcrop correlative of the Bradford Third oil sands in northwest Pennsylvania. The shoreface sequences that comprise the Rushford Formation are orientated north-south along faults of the Clarendon-Linden Fault System. Growth fault geometries and intensive soft-sediment deformation indicate syn-depositional faulting. We have observed similar relationships for reactivation of northeast trending Rome

Trough-Iapetan Opening faults in the southern portion of our field area. Reactivation of northwest-trending faults appear to have also influenced depositional patterns.

Other implications of the fault-influenced deposition involve linking paleoflow data with thickness data, in order to determine sand body architecture (orientation/shape) for the "lensing" sandstones in the upper part of the stratigraphic section.

Widespread Hydrothermal Dolomitization of Trenton and Black River Groups, Eastern North America

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Geochemical and fluid inclusion analysis confirm that most or all dolomite found in the Trenton and upper parts of the Black River Group in the northern Appalachian Basin is of a structurally controlled hydrothermal origin. A hydrothermal origin for the dolomites can be demonstrated where primary dolomite fluid inclusion homogenization temperatures exceed maximum burial temperatures by at least 20°C. Using these criteria, virtually all of the dolomite found in the Trenton and upper parts of the Black River in Kentucky, Ohio, Michigan and Ontario is of a hydrothermal origin. This is a very large volume of dolomite (hundreds or possibly thousands of cubic kilometers).

Using published data on the amount of fluid required to dolomitize limestone, more than one hundred trillion barrels of saline brine would likely be required to make that amount of dolomite. That is probably more fluid than is contained in the Appalachian and Michigan Basins combined.

Mass balance models for this dolomitization must be able to explain the source of the magnesium and the volume of fluid required to make this amount of dolomite. One possible solution is recycling of fluid where fluids flow up active faults and then back down where they are reheated and recharged with magnesium or "forced episodic convection." Another possibility is that seawater slowly recharges the aquifers that source the hydrothermal fluids over a broad area and that the salinity increases due to heating. It may also be that some dolomitization occurs at very shallow depths, due to mixing of hydrothermal fluids and seawater. In any case, hydrothermal dolomitization must now be considered to be an option for widespread pervasive dolomitization.

Fracture Intensification Domains, Lineaments and Faults in the Skaneateles Lake Region of the Alleghanian plateau of New York State

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This study integrates surface structural data with topographic, aeromagnetic and EarthSat (1997) lineaments in order to locate faults and to determine if local changes in the stress field related to these faults caused the local fracture patterns to deviate from the regional fracturing pattern. The field area is located in central New York State and stretches from the western side of Skaneateles Lake to the eastern side of Otisco Lake. This study demonstrates that several faults do occur in the field area and that their trends relate to older fault systems rather than assumed thin-skinned Alleghanian patterns. Fracture and lineament data, collected using standard UB Rock Fracture Group protocols, suggest the location of possible faults. A N-S trending fault was recognized with down-dip slicken lines in the Tully Limestone near Borodino. This fault is part of a larger N-trending fault system based on fracture and lineament data. Other probable fault trends include ENE-striking reactivated Iapetan-opening fault systems indicated by master fractures coincident with lineaments and NW-striking faults. Seismic data from Skaneateles Lake (Lyons et al., 2005) support the latter two fault trends. Much of this faulting deviates from Alleghanian fracture trends observed by Engelder and Geiser (1980) and was apparently influenced by preexisting fault systems. The weights of evidence statistical techniques shows good correlation between coinciding topographic lineaments and fracture data for the ENE, N-S and NW trends while NNW and NNE trends are not well correlated.

Soil Gas Hydrocarbons: A Dual Purpose Tool Towards Perfecting the Search in Petroleum Exploration

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Soil Gas Hydrocarbons (SGH) is an extractive procedure which releases organic compounds adsorbed on B-horizon soil samples. Soil acts as a long-term collector of organic compounds that migrate to the surface from hydrocarbon based plays. Soil Gas Hydrocarbon surveys are focused on the hydrocarbons in the C5-C18 range, which are very stable. Through analysis of the extracts with Gas Chromatography-Mass Spectrometry, the SGH procedure provides a highly selective and sensitive method which can detect down to the parts-per-trillion (ppt) range. Over 160 specific hydrocarbons are reported for each sample. Survey datasets are typically very clean and easily interpretable.

Geochemical anomalies of hydrocarbons over petroleum bodies have been noted in the literature for several decades. These anomalies may arise through current flows from oxidation-reduction cells involving both hydrocarbon and mineral bodies. Researchers also suggest that hydrocarbons may be able to migrate as microgas bubbles through thousands of metres of cover. SGH has the ability to vector to the vertical projection of a target as well as identify the type of buried target studied through forensically determined signatures. These capabilities have been researched and developed for over 10 years

SGH surveys have been conducted over several fields in Southwestern Ontario and Southeastern Saskatchewan, Canada, having depth to the play at up to 3,000 metres. Some case studies will be shown in this presentation.

Time-Structure Maps of the St. Lawrence Lowlands Platform, Southern Québec – Tool for the Identification of Structural Sags and Potential Hydrothermal Dolomite (HTD) Hydrocarbon Reservoirs.

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Regional time-structure maps of the Precambrian basement and top of Trenton Group have been produced using over 400 seismic profiles and 120 wells from the St. Lawrence Lowlands. These new maps show the presence of N-S to NE-SW basement faults that parallel the St. Lawrence River, and which are interpreted to have formed during the Cambrian rifting event of Laurentia. A second system of orthogonal E-W oriented faults are interpreted to be related to the Ottawa-Bonnechère graben and to transform faults associated with the drift phase of Iapetus. This structural pattern is also observed on the top of Trenton time-structure map, which implies that these two fault systems were active from the Cambrian to at least the Late Ordovician. Hence fault reactivation may have taken place during the Taconian Orogeny, with a possible strike-slip component in the form of wrench faults. Such structures represent elsewhere prime targets for the formation of HTD reservoirs.

The time-structure maps reveal the presence of several structural sags originating at the top of the Trenton Group. These occur in the Lac St. Pierre and Lotbinière areas, forming linear depressions measuring approximately one km in width by up to 50 km in length. A number of hydrocarbon discoveries have been made along very similar structures in the United States (Albion-Scipio, Lima-Indiana, Finger Lakes) and Ontario (Dover, Lakeshore), within HTD reservoirs associated with the Trenton-Black River interval. However, although these rock formations occur throughout the St. Lawrence Platform in Québec, the HTD play remains to be tested.

Correlations and Computer Generated Structure and Isopachous Maps of the Late Devonian Oil Sand Section in Western New York and Northern Pennsylvania

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Detailed subsurface correlations of Gamma Ray logs from over 850 wells in western New York and northern Pennsylvania have been made. Six major sand sedimentation zones were identified. More than

25 additional names have been applied to these six zones. Three structure maps, drawn on the base Cube, base Bradford Second and base Dunkirk black shale were constructed. Some of the Alleghenian fold axes are clearly shown by these maps. Seven Isopachous maps of various sandstone sections, based on 50% or greater sand content, were also prepared. There show the areas of greatest sandstone thickness for each zone studied. Four Cross-Sections showing East-West and North-South correlations will also be shown.

What WAS going on in the Late Devonian?

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Late Devonian/Early Mississippian rock units in central Pennsylvania and western Maryland include distinctive rock types and sequences some of which are found nowhere else in the Appalachians. Diamictite-bearing sequences exist in the Spechty Kopf (PA) and Rockwell Formation (MD) while in the Huntley Mountain Formation (PA) there are conglomerates with exotic pebbles and quartz-rich sandstones marked by large-scale, water-release structures capped by what appear to be sand volcanoes.

These distinctive sequences occupy a small part of the *Retiospora lepidophyta – Indotriradiates explanatus (LE)* palynozone in the upper part of the Famennian Stage. Sparse, preliminary palynological data suggest that the same palynozone includes all or part of the Murrysville Sandstone of southwest PA.

The variety, wide distribution and apparent contemporaneity of these rocks strongly constrain any origin scenario proposed for them. Falling sea-level and cooling climate provide less obvious constraints. The diamictites require sudden delivery of massive amounts of poorly sorted sediment (including exotic pebbles) to the deposites. The quartz-rich sandstones with water-release structures also require sudden deposition. Deposition of the gravels with exotic pebbles found in the Huntley Mountain Formation, strongly cross-bedded gravels in the Knapp and the Murrysville sands likewise may have been deposited rapidly.

Sedimentary processes effective over a large area for a short period of time are required to explain the origin of these rocks. Processes related to orogeny, climate, major storms, sea-level change, and impact events must be considered.

Greenbrier Limestone Reservoir Controls and Exploration Strategies – Central WV

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Oolitic zones in the Greenbrier Limestone provide a prolific producing reservoir throughout much of central and southern West Virginia, eastern Kentucky and southwestern Virginia. In the central West Virginia counties of Kanawha and Jackson, structure plays a dominant role in the geographic distribution of the productive oolite resrvoirs. Also recognized in this area is the structural segregation of the reservoirs, with a small gas cap up-dip, large oil productive area and finally water downdip.

The Hicumbottom Oil Fields, located in northern Kanawha County, were discovered in the 1940s during drilling targeting the deeper Oriskany Sandstone. Cumulative production from the two fields exceeded 2.5 MMBO. Both oil fields were located on the crests of northward plunging anticlines and anticlinal noses. The present day structures were proposed to have been active during the deposition of the Greenbrier Limestone and provided topographically high areas above wave base, along which the oolitic shoals were accumulated.

A prospective oil productive area on trend with the existing fields was identified based on structural mapping. A soil gas survey was completed in this exploratory area in 1992 and led to the drilling of an exploratory well in 1994. This well flowed oil and water measured at 190 bbls/day and is interpreted to be on the downdip edge of a new oil field. It is likely that a significant oil field similar in size to the Hicumbottom Fields will be discovered by offsetting the exploratory well in a structurally higher location.

Ordovician K-bentonite Illitization and Tectonic Compression in Eastern New York: Applying K/Ar Dating to Examine a Potential Link between Development of Within-Ash Slickensides and Alleghanian Far-Field Tectonics.

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Preliminary outcrop examination of numerous K-bentonite beds (altered volcanic ashes) at several different stratigraphic horizons within the Late Ordovician basinal Utica Shale and coeval basin margin deposits in the Mohawk Valley region of eastern New York, shows that approximately one third of these beds display bounding and/or internal planes of horizontal to oblique structural displacement (slickensides) characterized by thrust-related grooves. Slickensides appear to be solely associated with illitized (clay) ash beds and have not, so far, been found to cross-cut carbonate cemented ash layers. Some slickensides yield only bidirectional data, but many present good unidirectional information. Moreover, discovery of one slickenside yielding two groove azimuths indicates that relict displacements may reveal a complex history of changing structural dynamics.

Directional data suggest the influence of Alleghanian events, indicating that this study may allow for a constraining mechanism for the timing of ash illitization processes relative to far-field tectonic compression as suggested by southern Appalachian Basin studies. Slickenside formation may possibly have occurred synchronously with the illitization of volcanic ash beds; which can be tested using K/Ar dating to determine the timing of illitization of ash beds displaying similar, different, and multiple slickenside groove orientations. Results from this testing may show that slickenside genesis concurrent with, or subsequent to, hydrothermal tuff-to-illite transformation at depth within an Alleghanian far-field stress regime, closely parallel widespread early joint and cleat development observed elsewhere in the Appalachian Basin by others.

Recent Additions and Ongoing Features of the Indiana Geological Survey's Online Petroleum Database Management System

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The Indiana Geological Survey's (IGS) Petroleum Database Management System (PDMS) was made available online in 2003 (< www.igs.indiana.edu/pdms >). At that time the PDMS contained one module which provided (and continues to provide) extensive data on more than 71,000 petroleum test wells drilled in Indiana. This module is at present termed the "Table Viewer" of the PDMS. Well records can be searched and sorted by various criteria. Complete data for individual wells is printable in a convenient well history report. For those who wish to incorporate PDMS data into their own databases or mapping programs, all the PDMS well data tables can be downloaded, in whole or in part, as ASCII spreadsheet files.

In 2005, a second module, the Map Viewer, went online. It offers an interactive map interface that presents considerable well data in map view, as well as other supporting spatial data such as topographic maps, aerial photographs, and cultural and natural features. The map view may be configured to show productive formations (pay zones), wells with samples or cores, and wells which have been designated as "Type Wells" (so designated for their particular geologic significance).

The Field Viewer module, added in 2006, summarizes information on more than 800 oil, gas, and gas storage fields in the state. A table and accompanying graph portray current and cumulative primary and secondary oil production for each oil field. Links to available field studies are also presented.

Additional resources in the PDMS include IGS Petroleum Topic Reports (short single-topic reports related to petroleum geology in Indiana) and an extensive interactive Help.