Eastern Section American Association of Petroleum Geologists
46th Annual Meeting
Morgantown, West Virginia
September 24-27, 2017

Program with Abstracts

Hosted by:
Appalachian Geological Society
West Virginia University Department of Geology and Geography

With support from the West Virginia Geological and Economic Survey

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Welcome

The Appalachian Geological Society and West Virginia University welcome you to Morgantown for the annual meeting of the Eastern Section AAPG. We are so pleased to be able to host this event at the recently renovated, beautiful Marriott Waterfront Hotel. All the meeting events are either located within the Hotel proper or within a short walking distance along the Monongahela River rail trail. This meeting is set up differently than many of the other Eastern Section Meetings. Your meals during the meeting are included with your registration (spouses also). Meals include the Icebreaker/Dinner, 2 breakfast buffets, 2 lunch buffets, and the dinner/Core Workshop.

Our meeting theme, "Beasts of the East: Unconventional Shales" was chosen because Morgantown is located in the heart of the Marcellus and Upper Devonian Shale trend, on the eastern edge of the expanding Utica Shale exploration and lying over the deepest portion of the Appalachian basin with Rogersville and other Cambro-Ordovician shale potential. Our technical program and field trips have been designed to complement Morgantown's geographic location in the Appalachian Basin.

We look forward to seeing you at the Icebreaker/Dinner at Oliverio's on the River. We have a live bluegrass Band "The Hillbilly Gypsies" performing for us. They will be followed by our own "Jammin' Geologists".

The Organizing Committee including K. Lee Avary (Consulting Geologist), Joe Cook (ECA), Phil Dinterman (West Virginia Geological Survey), Paula Hunt (West Virginia Geological Survey), Emily Jordan (Northeast Natural Energy), Frank Lafone (WV GIS Technical Center), Joe Lebold (West Virginia University), Jessica Moore (West Virginia Geological Survey), Ed Rothman, (Consulting Geoscientist), and Andrew Waggener (Triana Energy), have worked to make the 46th annual meeting of the Eastern Section of AAPG a great one.

General Co-Chairs,

Pete Sullivan, ECA and Tim Carr, West Virginia University

2017 Organizing Committee

General Co-Chairs	Pete Sullivan and Tim Carr
Technical Program	Lee Avary and Tim Carr
Finance and Registration	Ed Rothman
Meeting Logistics	Joe Cook
Exhibits	Tim Carr
Sponsorship	Emily Jordon
Publicity and Social Media	Drew Waggener
Website	Frank Lafone

Core Workshop	Phil Dinterman and Jessica Moore
Field Trips	Paula Hunt
Judging	Lee Avary
Printing	Lee Avary

Eastern Section AAPG Officers

Website: www.esaapg.org

President	John Hickman, Kentucky Geological Survey, University of Kentucky
Vice -President	Patrick Gooding, Kentucky Geological Survey, University of Kentucky
Secretary	Drew Waggener, Triana Energy
Treasurer	Scott Gorham, Seneca Resources
Advisory Council	Craig Eckert, EQT

Appalachian Geological Society Officers

Website: www.appgeosociety.org

President	Drew Waggener, Triana Energy
Vice -President	Joe Cook, Energy Corporation of America
Secretary	Emily Jordon, Northeast Natural Energy
Treasurer	Rachel Vass, Navigator Environmental & Technical Services

General Information

Registration Hours:
Morgantown Marriott at Waterfront Place

Monday, September 25	3:00 p.m.-7:00 p.m.
Tuesday, September 26	7:30 a.m.-3:30 p.m.
Wednesday, September 27	7:30 a.m.-11:00 a.m.

Parking

Parking is available at the Waterfront Place Garage, $2 hourly, and $10 daily. Valet parking, fee: $14 daily

Maps

Floor plans for the Morgantown Marriott at Waterfront Place are located on the last two pages of this program.

Exhibits

Please visit our exhibitors in the Platinum Foyer. We appreciate their support. Exhibit hours are:

Tuesday, September 26 from 8:00 a.m. to 5:00 p.m.
Wednesday, September 27, from 8:00 a.m. to 12 noon

Presenters and Judges Room

Oral presenters should bring their presentation file to Wharf A-B as soon as possible to allow time to organize the presentations for each session. Note that computers in Wharf A-B are **NOT** networked with those in the session rooms, so your presentation **MUST** be turned in before the beginning of your session.

Oral and poster presenters: Please attend the **breakfas**t on the day of your presentation (see below).

Judges may pick up judging packets in the Wharf AB room if they did not receive them at the breakfast.

The Presenters and Judges Room (Wharf AB) will be open Monday, September 25 from 3:00 p.m. to 8 p.m.; Tuesday, September 26, 7:00 a.m. to 6:00 p.m.; and Wednesday, September 27, 7:00 -8:00 a.m.

Presenters, Judges and Session Chairs Breakfast and Information

All speakers, poster presenters, judges and session chairs should gather for breakfast in Salon GH, 7:00-8:00 a.m., after serving themselves from the breakfast buffet, set up in Foyer FH. Information will be provided on session timing, audio-visual equipment, and judging.

Speakers should bring their presentation file to Wharf A-B as soon as possible to allow time to organize the presentations for each session. Note that computers in Wharf A-B are **NOT** networked with those in the session rooms, so your presentation **MUST** be turned in before the beginning of your session.

Poster presenters should attend the breakfast to receive information on poster board assignments and times for judging. Poster presenters should set up their posters between 7:30 and 8:00 a.m. for morning posters or between 12:30 p.m. and 1:00 p.m. for afternoon posters. Poster presenters are asked to be at their posters from 10:00 to 11:00 AM or from 3:00 to 4:00 PM. Longer time spans are encouraged.

Judges will receive forms and instruction from Lee Avary, Judging Chair. If you are unable to attend the breakfast, please pick up your judging forms in Wharf A-B. All forms should be returned to Lee Avary, or left at the registration desk.

Business Meetings

AAPG House of Delegates Breakfast

Tuesday, September 26, 7:00 a.m.-8:00 a.m.
Salon F (by invitation)
Hosted by David Entzminger, Chair, AAPG House of Delegates

Eastern Section AAPG Executive Council Luncheon

Tuesday, September 26, Salon G-H, noon-1:00 p.m., (by invitation)

Eastern Section AAPG Committee on Section Meetings Breakfast

Wednesday, September 27, 7:00 a.m.-8:00 a.m.
Salon F (by invitation)

Special Events

Opening Session

Monday, September 25, 4:00 p.m.-5:00 p.m.
Salon FGH

Honors and Awards Ceremony

Monday, September 25, 5:00 p.m.-6:00 p.m.
Salon FGH

Ice breaker Reception

Monday, September 25th, 2017, 6 p.m. to ?,
Oliverio’s Ristorante on the Wharf, 52 Clay Street, Morgantown, WV

ES AAPG 2017 meeting attendees are invited to start the first evening off in style at our “one of a kind” ice breaker. A short walk from the hotel, Oliverio’s Tuscan-inspired eatery, with its big city feel and small town charm will host a full sit-down Italian dinner. Live music will serve as a back drop allowing each attendee the opportunity to network with colleagues and reconnect with old friends. Oliverio’s offers inside dinning or you can escape to their year round deck for one of the most beautiful views of the Monongahela River. Later, stick around and listen to the Jammin’ Geologists as you enjoy complementary beverages and desserts as well as a full cash bar. The night is sure to be warm, inviting and fun!

The path to Oliverio’s

Exit the Waterfront Hotel doors adjacent the check-in desk and take the steps to your left down to the scenic Caperton Trail. The entire walk is less than a third of a mile and the scenery makes the distance seem even shorter.

Jammin’ Geologists

Monday, September 25, 8:00 p.m.-11:30 p.m.
Oliverio's Ristorante on the Wharf, 52 Clay Street, Morgantown, WV

A tradition at Eastern Section annual meetings, Jammin' Geologists is the premier venue for your musically gifted colleagues to show off their talents. We promise a lively event, with a cash bar. All are welcome to participate, so please bring your instrument and join the fun. Or just sit and watch, and sing along. This event has become a highlight of Eastern Section meeting, so don't miss it. For more information, please contact Kevin Strunk, kstrunk@indy.net.

Pioneering Women in Petroleum Geology Display
Morgantown Event Center B

Pioneering Women in Petroleum Geology
100 Years - Celebration Wall

Don't miss the opportunity to experience this beautiful and historical display celebrating incredible discoveries and achievements of the first 100 female members of AAPG. This display will be located in the Morgantown Event Center (MEC) B – the same place where we will gather for lunch each day. This display was created for AAPG's 100th anniversary and made its debut in April at the AAPG Annual Convention and Exhibition in Houston as the culmination of a multi-year research effort by the PROWESS (Professional Women in Earth Sciences) Committee, spearheaded by Robbie Gries. A book, *Anomalies*, and video documentary provide more details about these pioneering women. A limited number of copies of *Anomalies* are available to purchase at the AAPG Bookstore in the Exhibits area. The Bookstore will also have information on how to order your copy.

Core Workshop

Tuesday, September 26, Morgantown Event Center A, 7:00 p.m.-9:00 p.m.

Representative sections of cores ranging in age from the Berea to the Rogersville will be on display, along with accompanying posters and data.

YP Happy Hour
Tuesday, September 26, Morgantown Marriott Bourbon Prime Bar, 8:30 p.m. - 10:00 p.m.

All YP's are invited to Happy Hour in the Bourbon Prime Bar. Snacks and raffle items will be available.

Calendar of Events

Sunday, September 24

7:15 a.m.	What the H? Field Trip departs, Lobby

Monday, September 25

10:00 a.m. - 3:00 p.m.	Student Expo, MEC B
10:00 a.m. -4:00 p.m.	Exhibitor setup, Foyer
1:00 p.m.-4:00 p.m.	Deckers Creek Field Trip
3:00 p.m.-7:00 p.m.	Registration open, Foyer
3:00 p.m.-8:00 p.m.	Presenters and Judges Room open, Wharf AB
4:00 p.m.-5:00 p.m.	Opening session, Salon FGH
5:00 p.m.	What the H? Field Trip returns
5:00 p.m.-6:00 p.m.	Honors and Awards Ceremony, Salon FGH
6:00 p.m.-??	Icebreaker Reception, Oliverio’s
8:00 p.m.-11:30 p.m.	Jammin’ Geologists, Oliverio’s

Tuesday, September 26

7:00 a.m.-8:00 a.m.	Breakfast Buffet, all registrants, Foyer FH
7:00 a.m.-8:00 a.m.	Presenters, Session Chairs and Judges Breakfast, Salon GH
7:00 a.m.-6:00 p.m.	Presenters and Judges Room open, Wharf AB
7:00 a.m.-8:00 a.m.	House of Delegates Breakfast, Salon F
7:30 a.m.-3:30 p.m.	Registration open, Foyer
7:00 a.m.-5:00 p.m.	Exhibits open, Foyer
8:00 a.m.- 12 noon	Oral Session, Approaches to Improve Reservoir Performance, Salon D
8:00 a.m.- 12 noon	Oral Session, Overview and Impact of Shale Production, Salon E
8:00 a.m.-12 noon	Poster Session, Foyer
12 noon-1:00 p.m.	Lunch Buffet, all registrants, MEC B
12 noon-1:00 p.m.	Eastern Section AAPG Executive Council Luncheon, Salon G-H
1:00 p.m.-5:00 p.m.	Oral Session, Energy and Environment, Salon D

1:00 p.m.-5:00 p.m.	Oral Session, Unconventional Plays, Salon E
1:00 p.m.-5:00 p.m.	Poster Session, Foyer
5:5o p.m.-6:00 p.m.	Presidential address, AAPG President Charles Sternbach, MEC A
6:00 p.m.-7:00 p.m.	Dinner buffet, all registrants, MEC A
7:00 p.m.-9:00 p.m.	Core workshop, MEC A
8:30 p.m.-10:00 p.m.	YP Happy Hour, Bourbon Prime Bar, with snacks and raffle items

Wednesday, September 27

7:00 a.m.-8:00 a.m.	Breakfast Buffet, all registrants, Foyer FH
7:00 a.m.-8:00 a.m.	Presenters, Session Chairs and Judges Breakfast, Salon GH
7:00 a.m.-8:00 a.m.	Presenters and Judges Room open, Wharf AB
7:00 a.m.-8:00 a.m.	ES Committee on Section Meetings Breakfast, Salon F
7:30 a.m.-11:00 a.m.	Registration open, Foyer
7:00 a.m.-12 noon	Exhibits open, Foyer
8:00 a.m.-12 noon	Oral Session, Devonian-Mississippian, Salon D
8:00 a.m.-12 noon	Oral Session, Geologic & Engineering Approaches to Reservoirs, Salon E
8:00 a.m.-12 noon	Poster Session, Foyer
11:30 a.m.-1:00 p.m.	Lunch Buffet, all registrants, MEC B
1:00 p.m.	Meeting concludes. Safe travels, thanks for attending and see you next year.

Exhibitor List and Contacts

We thank the 2017 exhibitors who have helped make this a successful meeting. Please take time to visit their tables during the meeting.

Company	Contact	Email	Website
AAPG Bookstore	Karin Alyea & Audrey Corte	kalyea@aapg,.org acorte@aapg.org	www.aapg.org
LMK Resources	Seema Sophie	ssophie@lmkr.com	http://www.lmkr.com/
National Energy Technology Laboratory	Dustin Crandall	dustin.crandall@netl.doe.gov	https://www.netl.doe.gov/
Neuralog	Bryan Mills	bmills@neuralog.com	http://www.neuralog.com/
ROGII	Vlad Karén Payrazyan	karen@rogii.com	www.rogii.com
West Virginia University Department of Geology & Geography	Tim Carr	tim.carr@mail.wvu.edu	http://www.geo.wvu.edu/

Student Activities

Eastern Section AAPG Student Expo

Monday September 25, 10:00 a.m. to 3:00 p.m. with potential for interviews to follow

Lunch Provided

Marriott Waterfront Hotel, MEC

Sponsored by:

Antero Resources

Southwestern Energy Company

EQT Production

Raptor Consulting, Inc.

Seneca Resources

This year, the Student Expo will start at 10:00 a.m. with a brief talk by an industry representative, followed by round robin networking discussions where students rotate and talk to industry professionals. The Expo will be capped by a networking luncheon. Students will be able to interact with the professionals hosting the tables and network with professionals and fellow students over an informal pizza lunch. We appreciate the support of our sponsors for this event.

Opening Session Agenda

Monday, September 25, 2017

4:00 p.m. Morgantown Marriott at Waterfront Place
Salon FGH

Welcoming Remarks

- Pete Sullivan, General Meeting Co-Chair (with Tim Carr)
- Andrew Waggener, President, Appalachian Geological Society
- Tim Carr, Chair, Department of Geology & Geography, West Virginia University
- Michael Hohn, Director and State Geologist, West Virginia Geological & Economic Survey
- John Hickman, President, Eastern Section, AAPG

Introduction of National AAPG Officers

- Charles Sternbach, President, AAPG
- Dan Schwartz, Vice-President, Sections
- David Entzminger, Chair, AAPG House of Delegates
- Jim Hill, President, AAPG Division of Professional Affairs

Honors and Awards Ceremony

Joan Crockett, Chair, Honors and Awards Committee, Presiding
Ed Rothman and Murray Matson, Committee Members

Eastern Section AAPG 2017 Presentation Awards from 2016 Annual Meeting

A.I. Levorsen Memorial Award Best Paper Award: David R. Blood, "*Redox Conditions during deposition and early diagenesis of the U. Ord. Point Pleasant Ls of southwestern PA and northern WV: Insights from pyrite framboids and trace elements*"

Division of Environmental Geosciences Best Poster Award (Eastern Section): Ethan S. Davis and Thomas M. Parris, "*Revising the Fresh-Saline Water Interface in Eastern Kentucky*"

Division of Environmental Geosciences Best Paper Award (Eastern Section): Amy Townsend-Small *"Stable isotopic constraints on methane migration into groundwater and emissions to the atmosphere from unconventional natural gas extraction: Examples from OH, CO, TX*"

Energy Minerals Division Best Poster Award (Eastern Section): Tyler S. Bodine and Michael T. May, "*An Analysis of a Near-Surface Big Clifty (Jackson) Sandstone Reservoir in Logan County, Kentucky*"

Ralph L. Miller Memorial Best Energy Minerals Division Paper Award (Eastern Section): Julie Floyd and Stephen F. Greb, "*Subsurface Analyses of the Bedford-Berea Petroleum System in Eastern Kentucky*"

Vincent E. Nelson Memorial Best Poster Award: Joel R. Sminchak, James E. Hicks and Glen R. Larsen, "*Subsurface Geomechanics, Fracture Breakdown Pressures, and Fracture-tunnels in the Midwest U.S.*"

Margaret Hawn Mirabile Memorial Best Student Paper Award: Allison L. Young, Carlton E. Brett, Peter Holterhoff, Thomas Algeo, and Patrick I. McLaughlin, "*Late Ordovician (Katian) Upper Lexington-Kope Equivalents in the Point Pleasant Basin of Eastern Ohio: Correlation and Paleoenvironments of the Utica Point Pleasant System*"

Best Student Poster Award: Andrew M. Parent, Ernest C. Hauser, and Doyle R. Watts, "*New Insights into Precambrian Seismic Stratigraphy, South-Central Indiana*"

Pittsburgh Geological Society Award for Best Presentation on Appalachian Geology: David R. Blood, "*Redox Conditions during deposition and early diagenesis of the U. Ord. Point Pleasant Ls of southwestern PA and northern WV: Insights from pyrite framboids and trace elements*"

2017 Eastern Section AAPG Service Awards

Certificates of Merit (2017 Annual Meeting Committee): Pete Sullivan, Tim Carr, Emily Jordon, Joe Cook, K. Lee Avary, Ed Rothman, Drew Waggener, Paula Hunt, Joe Lebold, Ron McDowell, Mitch Blake, Phil Dinterman, Jessica Moore, Jaime Toro and Frank Lafone

Division of Environmental Geosciences Meritorious Contributions Award: E. Scott Bair

Gordon H. Wood, Jr. Memorial Award: Robert C. Milici

Outstanding Educator Award: Ann Harris

George V. Cohee Public Service Award: Albert D. Kollar

Distinguished Service Award: John B. Hickman

Honorary Membership: Charles A. Sternbach

John T. Galey Memorial Award: Robert D. Jacobi

End of Opening Session and Awards Ceremony

All meeting attendees are invited to the icebreaker (including dinner) which will begin at 6:00 pm at ***Oliverio's Ristorante On The Wharf***, 52 Clay Street, Morgantown. The restaurant is a short scenic walk away; just exit the Waterfront Hotel doors adjacent to the check-in desk and take the steps to your left down to the scenic Caperton Trail. Turn right onto the Caperton Trail and walk along the Monongahela River for just over 0.3 mile to Oliverio's. We'll see you there!

Technical Program Schedule

Speaker is first author unless indicated by an asterisk (*).

Tuesday Morning, September 26

Approaches to Improve Reservoir Performance
Sponsored by Cabot Oil & Gas
Salon D
Session Co-Chairs: Peter Voice and Craig Eckert

8:00 a.m. Delineating Compressional Structures Through Refined Geosteering Methods—Chad Koury

8:30 a.m. Geophysical Characterization of Mississippian Carbonates of South Central Kentucky and Northern Tennessee—Matthew Bentley, Michael T. May and Thomas B. Brackman

9:00 a.m. Structural and Crustal Evolution of the Pre-Mt. Simon Below West-Central Indiana: Evidence from Seismic Reflection—Andrew M. Parent, Ernest C. Hauser and Doyle R. Watts

9:30 a.m. Reservoir characterization and 3D Modeling of Silurian Reef Slopes: Pipe Creek Jr. Quarry, Grant County, Indiana —G. Michael Grammer, Jim Karsten, Dennis Prezbindowski*, Benjamin Dattilo, and Jonathan Havens

10:00 a.m. Break

10:30 a.m. Depositional Controls on Reservoir Quality in the Dundee-Rogers City Interval: Lithofacies and Production Characteristics—Peter J. Voice and William B. Harrison, III

11:00 a.m. Assessing Unconventional Resource Potential of Lower Cretaceous Carbonates in the South Florida Basin, USA—Tim E. Ruble and Stephanie Brightwell-Coats

11:30 a.m. Geoscience evolution: extensive data integration for real time geosteering and modeling in unconventional reservoirs—Vlad Karen Payrazyan, Igor Kuvaev, Igor Uvarov, and Julian Stahl

Overview and Impact of Shale Production
Salon E
Sponsored by Antero Resources
Session Co-Chairs: Sean Kayser and Kris Carter

8:00 a.m. Marcellus, Utica/Point Pleasant provide 91% of U.S. shale gas production growth since start of 2012—Olga Popova, Gary Long, Jeffrey Little, Christopher Peterson, Neal Davis, Emily Geary, Andrei Butterfield, Steven Grape, Elizabeth Panarelli, April Volke and Barbara Mariner-Volpe

8:30 a.m. Mapping and Reservoir Characterization of Geologic Intervals for NGL Storage Applications—Kristin Carter, Douglas Patchen, Jessica Moore, Mohammad Fakhari, Gary Daft, Phillip Dinterman, Michael Solis, Robin Anthony, Katherine Schmid, Brian Dunst, Antonette Markowski and Stephen Shank

9:00 a.m. Challenges with Marcellus Shale Horizontal Exploration Within or Near the Allegheny Highland—Cole Bowers, Energy Corporation of America

9:30 a.m. The map that changed the NEW World: the Erie Canal (200th Anniversary) and Amos Eaton—Charles A. Sternbach

10:00 a.m. Break

10:30 a.m. Mapping reservoir stress conditions using hydraulic fracturing microseismicity—Orlando J. Teran

11:00 a.m. Defining the Geologic and Economic Limits of the Marcellus Wet Gas Play—Matthew C. Weinreich

11:30 a.m. Permian Basin Activity - Reagan County Texas—Joseph Cook

Tuesday Morning, September 26, Poster Session
Foyer
8:00 a.m-12 noon

Porosity and CO_2 Storage Capacity of the Maryville-Basal Sandstone Section in the Kentucky Geological Survey 1 Hanson Aggregates Stratigraphic Research Well, Carter County, Kentucky— J. Richard Bowersox, Stephen F. Greb and David C. Harris

Analysis of the Conasauga Group and Basal Sandstone (U. Cambrian) in the KGS No. 1 Hanson Aggregates Well, Carter County, Kentucky—Stephen F. Greb, J. Rick Bowersox, and David C. Harris

A Parametric Analysis of Carbon Dioxide Sequestration Potential in Depleted Marcellus Shale Gas Reservoirs—Burak Kulga and Turgay Ertekin

Volumetric and 3-D property modeling of the Grand Tower Formation in the Salem Field, Southern Illinois—Mansour Khosravi Rokrok

Lithostratigraphy of Middle and Upper Devonian Organic-Rich Shales in West Virginia—Susan E. Pool and Ray M. Boswell

The Prediction of Orthorhombic Differential Horizontal Stress Ratio for Shale Reservoir—Ni Ma, Xingyao Yin, Zhaoyun Zong, and Chengyu Sun

Modeling and interpretation of a high-relief Precambrian unconformity on 2D seismic reflection lines near Wabash, Indiana—Michael R. Green, Ernest C. Hauser and Doyle R. Watts

Tuesday Afternoon, September 26

Energy and Environment
Sponsored by Antero Resources
Salon D
Session Co-Chairs: Dan Soeder and Cole Bowers

1:00 p.m.	Comparative Analysis of Transport and Storage Options from a CO_2- Source Perspective—Tim Grant, David Morgan, Donald Remson, Allison Guinan, Chung Yan Shih, ShangMin Lin, and Derek Vikara
1:30 p.m.	Using well log analysis to identify residual oil zones at Noble and Kenner West Oil Fields, Illinois—Nathan P. Grigsby, Nathan D. Webb and Scott M. Frailey
2:00 p.m.	Importance of Basin Tectonics in Alleviating Uncertainty in Carbon Storage Projects—Hannes E. Leetaru, Jared T. Freiburg, Robert A. Bauer, John H. McBride
2:30 p.m.	Earthquakes and History: Arguments over hydraulic fracturing and arguments over history—Conevery Bolton Valencius
3:00 p.m.	Break
3:30 p.m.	Origin of Non-Hydrocarbon Gases in Petroleum Reservoirs – A Review—Christopher D. Laughery
4:00 p.m.	The Evolving Role of Geoscientists in Climate Change Science—Gregory R. Wrightstone
4:30 p.m.	2017 Air Regulation Requirements—Thomas Seguljic

Unconventional Plays
Sponsored by Antero Resources
Salon E
Session Co-Chairs: Randy Blood and Merril Stypula

1:00 p.m.	Structural Control of the Point Pleasant Formation Deposition and Production—Devin M. Fitzgerald, M. Wes Casto, and Robert B. Thomas, Sr.

1:30 p.m. The origin and evolution of shell beds in Ordovician shales of southwestern Pennsylvania (Point Pleasant and associated units) and their implications for the preservation of organic carbon—Benjamin Dattilo, David R. Blood, and William P. Gilhooly, III

2:00 p.m. Quantitative characterization of fracture frequency variations using a linear piecewise regression analysis and the Akaike Information Criterion—Alex P. O'Hara and Robert D. Jacobi

2:30 p.m. Identifying Lithosomes of the Marcellus Shale: A Provenance Approach—Amy L. Weislogel

3:00 p.m. Break

3:30 p.m. Aromatic compounds as maturity indicators and correlation markers - Example from New Albany Shale extracts and oils, Illinois Basin—Donna C. Willette

4:00 p.m. Deposition, Diagenesis and Hydrocarbon Generation in the Ordovician Point Pleasant Limestone and the Devonian Marcellus Shale: Comparing and Contrasting Two Appalachian Basin Unconventional Reservoirs—David R. Blood

4:30 p.m. An Interpretation of Core Derived Water Saturations Using Water Isotope Analysis—Ashley S. B. Douds, Merril J. Stypula and David R. Blood

Tuesday Afternoon, September 26, Poster Session
Foyer
1:00 p.m.-5:00 p.m.

Meso- and Macro-Scale Facies and Chemostratigraphic Analysis of Middle Devonian Marcellus Shale in Northern West Virginia, USA—Thomas Paronish, Timothy R. Carr, Dustin Crandall and Johnathan Moore

Causation of carbonate cements in sandstones near the overpressured top seal in Niuzhuang Sag of Bohai Bay Basin, China—Zhang Tianjiao and Shanwen Zhang

Geological model and Natural fracture characteristics in carbonate rocks gas reservoir constrained by multi-factors as an example of HT area fractures—Qiqiang Ren, Jin Qiang and Feng Jianwei

Pine Hall Formation: Type section designated – Dan River basin, Stokes Co., North Carolina—Jeffrey C. Reid, Katherine J. Marciniak, Walter T. Haven, and Kenneth B. Taylor

Use of Iodine for Petroleum Exploration—Daniel H. Vice

Direct Kerogen characterization of Marcellus Shale collected from Marcellus Shale Energy and Environment Laboratory—Vikas Agrawal and Shika Sharma

Data-driven Approach to Refine Carbon Storage Efficiency Factors for Regional-scale Offshore Saline Reservoirs—Andrew Bean, Kelly K. Rose, Randal B. Thomas, and Emily M. Cameron

Wednesday Morning, September 27

Devonian-Mississippian

Salon D
Session Co-Chairs: Scott McCleery and Marty Parris

8:00 a.m. Organic Matter Content and Thermomaturation Trends in the Ohio and Sunbury Shales, Eastern Kentucky, Central Appalachian Basin—Cortland F. Eble, Paul C. Hackley, Stephen F. Greb*, and Thomas M. Parris

8:30 a.m. Porosity and Permeability of Berea Reservoirs (Upper Devonian) in Eastern Kentucky—Stephen F. Greb, Ethan S.L. Davis, and David C. Harris

9:00 a.m. Probabilistic Assessment of Tight-Gas Sands Using a Data-Driven Modeling Approach—Emre Artun, Burak Kulga, and Turgay Ertekin

9:30 a.m. Pore types, capillary pressure, and diagenetic controls on reservoir quality in the Upper Devonian Berea Sandstone, Eastern Kentucky—David C. Harris, T. Marty Parris and J. Richard Bowersox

10:00 a.m. Break

10:30 a.m. Molecular and Isotopic Composition of Associated and Nonassociated Gases and Evolution of Gas in the Berea Sandstone, Eastern Kentucky—T. Marty Parris, Paul C. Hackley, Steven F. Greb and Cortland F. Eble

11:00 a.m. Oil-source rock correlation studies in the shallow Berea Sandstone, northeastern Kentucky—Paul C. Hackley, T. Marty Parris*, Stephen F. Greb, Cortland F. Eble, and David C. Harris

Geologic & Engineering Approaches to Reservoirs
Salon E
Session Co-Chairs: Brandon Nuttall and Bill Harrison

8:00 a.m. Time-Dependent Performance Evaluation of Cyclic Injection of Gas Mixtures into Hydraulically-Fractured Wells in Appalachian Sandstones—Emre Artun

8:30 a.m. Kentucky oil history: the approaching 200th anniversary of the Beatty well—Brandon Nuttall

9:00 a.m. Optimizing Perforations—David J. Hatton and Payam Kavousi Ghahfarokhi

9:30 a.m. Hilbert Transform of Distributed Acoustic Sensing (DAS) Fiber Optic Data: A New Attribute to Assess Hydraulic Fracturing in Marcellus Shale—Payam Kavousi Ghahfarokhi and Timothy R. Carr

10:00 a.m. Break

10:30 a.m. Performance Forecasting and Characterization of Carbonate Reservoirs Using Data-Driven Models—Emre Artun

Wednesday Morning, September 27, Poster Session
Foyer
8:00 a.m-12 noon

Atmospheric gas concentrations in the pre- and post- production phases of an unconventional oil and gas recovery operation at the MSEEL test site, West Virginia—James P. Williams, Matthew Reeder, Natalie Pekney, John Osborne, Michael A. McCawley, and David Risk

TOC estimation of the New Albany Shale Group and Maquoketa Shale-Using ∆logR Evaluation Technique, Southern Illinois—Mansour Khosravi Rokrok and Donna C. Willette

Numerical Validation of Stimulated Reservoir Volume Approach in Shale Reservoirs by using a Compositional, Dual-porosity, Dual-permeability, Multiphase Reservoir Simulator—Burak Kulga and Turgay Ertekin

Modelling of an Ancient Fluvial Depositional Environment Using 3D-Photogrammetry and Paleohydrology, the Middle Pennsylvanian Allegheny Formation, South-Central West Virginia, USA—Olu-Segun Abatan, Amy Weislogel, and B. Mitch Blake

Geologic characterization in preparation for the assessment of oil and gas resources in Upper and Middle Devonian black shales of the northern and central Appalachian Basin—Michael H. Trippi, Catherine B. Enomoto, Debra K. Higley, William A. Rouse and Frank T. Dulong

Counter-regional detachment structures, southwestern Pennsylvania, central Appalachian basin: Implications for Marcellus Shale gas exploration and production—Dengliang Gao, Thomas Donahoe, Taizhong Duan, and Peter Sullivan

Field Trips

What the H!? Paleozoic Stratigraphy Exposed

Sunday, September 24 and Monday, September 25, 2017

Cost: $250 (includes meals and lodging)

Leaders: Ron McDowell and Mitch Blake from the West Virginia Geological and Economic Survey (WVGES) along with Jaime Toro from West Virginia University

Description: This two day field trip will allow participants to examine rock outcrops ranging in age from Ordovician through Pennsylvanian along a relatively new stretch of highway with fantastic exposures (US 48, or "Corridor H") and farther south along US 33. The trip will be a west-to-east traverse from the Allegheny Plateau across the Allegheny Front and into the Valley and Ridge province in eastern West Virginia. Units include the Reedsville/Martinsburg, Tuscarora, Tonoloway, Helderberg Group, Oriskany, Marcellus, Mahantango, Foreknobs (Greenland Gap Group, formerly Chemung), Hampshire (Catskill), Spechty Kopf, Price, Mauch Chunk Group, and Conemaugh Group. We leave very early on Sunday morning, spend the night in Moorefield, WV, and return on Monday in time for the Ice Breaker Dinner. Lunches both days, dinner Sunday evening, and lodging Sunday night are included in the cost of the trip. Continental breakfast is at the hotel Monday morning.

Deckers Creek Rail Trail

Monday, September 25, 1:00 p.m.-4:00 p.m.

Cost: $15 (includes bicycle rental, snacks and shuttle service to starting point)

Leader: Joe Lebold, West Virginia University

Description: Come join us for a leisurely bicycle ride down the Deckers Creek Rail Trail. The AAPG Young Professionals are sponsoring the trip. Departure will be by vans from the lobby of the Waterfront Hotel Monday at 1:00 pm and will return to the hotel prior to the icebreaker. There will be stops for a snack and possible side excursion to a local pub.

The route parallels the creek through a deep water gap in Chestnut Ridge, formed by the Chestnut Ridge Anticline. Rocks exposed along the way, dating from the Upper Pennsylvanian to the Middle Mississippian periods, preserve the transition from a passive continental margin to the alluvial plains developed in the shadow of the rising ancestral Appalachian Mountains. The course of Deckers Creek roughly follows the trend of perpendicular joint sets in the bedrock, while the rocks' varying resistance to weathering creates changes in the slope along the way. In all, the trail drops nearly 1000 feet over a distance of 16 miles and crosses the western boundary separating the High and Low Appalachian Plateau physiographic provinces.

The trail occupies the former Morgantown and Kingwood (M&K) Railroad right-of-way which once connected the Baltimore and Ohio Railroad to the east with the railroads of the Monongahela River Valley. The M&K transported coal, limestone, and sand, the latter used by the glass industry in the Morgantown area. Although most mining operations have been abandoned, Greer Industries still operates a limestone quarry next to the trail.

Participants are encouraged to bring their own helmets if possible, although extras will be provided. It would also be helpful to know your inseam for bicycle sizing purposes. Snacks and beverages will be provided along the way.

Core Workshop

Tuesday, September 26, 7:00 p.m.-9:00 p.m., MEC A

Berea (Upper Devonian) core, eastern Kentucky

Stephen F. Greb and David C. Harris
Kentucky Geological Survey, University of Kentucky

The Berea Sandstone in eastern Kentucky has long been a producing oil and gas horizon, but production has increased in recent years because of horizontal drilling. Oil is produced from the Berea at shallow depths in northeastern Kentucky, and gas is produced downdip in southeastern Kentucky. KGS holds nine cores from the Bedford-Berea interval, four of which have significant Berea preserved, plus 18 shallow, near-surface cores along the outcrop belt. A core book containing pictures and information on many of these cores will be available soon.

Although the Berea is called a sandstone in eastern Kentucky, grain-size analyses shows it is mostly a coarse siltstone. Bedding in the Berea is characteristic of marine shelf deposits grading into slope (or ramp) deposits of the Bedford Shale. The most common bedding in Berea cores is massive, parallel-laminated, and soft-sediment deformed (convoluted, flow rolls, ball-and-pillow structures) beds. Low-angle laminated beds in some core may represent hummocky bedding, swaley bedding, and parts of soft-sediment deformed beds. Representative core boxes from two wells are laid out for the workshop today in order to examine typical Berea sedimentary structures and reservoir properties. For more information on the Berea petroleum system see Parris and others, 2017, Berea Sandstone petroleum system at the KGS website, www.uky.edu/KGS/.

Ashland Exploration 1 Hattie Neal (API 16127000740000)

Location: Lawrence County, Ky.   KGS Core Call No./ O&G Record No.: C-5691/ 11647

Geophysical logs: INDUCTION (SP, RES, COND), TEMP, RADIOACTIVITY (GR, NEUT), CFD (CAL, GR, Comp. Den. Porosity, Bulk Density)

Well completion date: 8/7/1981   Core Depth: Top of Berea at 1484.5[?] feet

Bedford-Berea Core Interval Thickness: 33.5 feet (with gaps)

Bedford-Berea Total Thickness: 113 feet

Field: None (no name); 4.1 miles west of Fallsburg oil field

Completion: Oil and gas from Berea (1499-1510; 1514-1520; 1552-1564). Initial production after treatment was 3 BOPD-2BWPD, 11 MCF/D

Summary: The Hattie Neal core is 27 feet thick, representing the upper 33 ft. of the Berea. The density log shows two porosity zones (1500 to 1510 feet and 1514 to 1520 feet) with greater than 10% porosity, in the upper part of the Berea. Both were perforated for completion. Original core-measured oil saturations from these intervals were 4.6 to 12.7 and 1.1 to 19.1 respectively.

Equitable Production Company 504353 EQT (API 16195060410000)

Location: Pike County, Ky.   KGS Core Call No./O&G Record No.: C-6591/ 137835

Geophysical logs: GR, TEMP, CAL, Neutron Porosity, Gas Detector, Comp. DEN, PE, Density Porosity, Matrix DEN, IND

Well completion date: 3/24/2009 Core Depth: 3824-3949 feet (Berea)

Bedford-Berea Core Interval Thickness: 93 feet (with gaps) representing 114 feet

Bedford-Berea Total Thickness: 114 feet

Field: Elkhorn City DBS

Completion: Horizontal gas well in Lower Huron Member, Ohio Shale.

Summary: The EQT 504353 core is well south of the current Berea oil play, but the core contains in situ bitumen in the Berea, representing cracked oil. The bitumen impregnation provides insight into the initial oil migration into Berea reservoirs, and a variety of scales of flow barriers within this tight "sandstone" [coarse siltstone] reservoir. In parts of the core, bedding is difficult to infer because the beds are completely uniform in staining; in other parts of the core, staining highlights bedding that would otherwise appear massive without the staining. Thin sections show multiple generations of cement.

Northeast Natural Energy (NNE) MIP 3H (API 4706101707)

Marcellus Shale Energy and Environmental Laboratory (MSEEL) consists of four producing horizontal wells and two vertical pilot wells. In the second half of 2015, the NNE MIP3H was drilled, and a total of 111 feet of continuous whole core and 50 sidewall cores (1.5 inch diameter) were recovered across the **Marcellus** and adjacent formations. The whole core was microCT scanned and split prior to sampling. Integrated geological and petrophysical characterization uses core and well log data. Macro-scale lithofacies were defined through a combination of core and CT-scan descriptions. Meso-scale shale lithofacies based on mineralogy and total organic content were developed using a combination of triple combo and advanced logging tools that were calibrated to core data (XRD and source-rock pyrolysis). Chemostratigraphic analysis utilizing x-ray fluorescence was used to determine the major and trace-element trends associated within the Devonian Marcellus-Mahantango interval. Petrophysical analysis shows three well-developed organic mudstone facies are present in the Marcellus interval.

EQT J. Leeson 1 (API 4701705644)

The **Marcellus** Shale and, to a lesser extent, the **Geneseo** Shale constitute a sizable portion of the natural gas produced in the United States. Indeed, in 2015 Pennsylvania and West Virginia accounted for 21% of dry natural gas produced in the United States (EIA, 2016) driven largely by production from these formations. The significant role the Marcellus and Geneseo shales play in the U.S. Energy makeup necessitates the need for a thorough understanding of the geological aspects of these formations that shape and influence their reservoir architecture and ability to produce hydrocarbons. To this end, we provide an update to the analysis conducted by Blood and Lash (2013) and Douds and Zhou (2013) and assess the geologic setting, stratigraphy, sequence stratigraphy, chemostratigraphy and pyrite morphology of the Marcellus Formation and Geneseo Member represented in EQT Production's J. Leeson core of Doddridge County, West Virginia. More detailed information about this core is available in a report on the Appalachian Geological Society's website **www.appgeosociety.org**

PPG Industries Brine Well 36 (API 4705100674)

This core offers a rare glimpse of the **Salina F-4 salt** unit, a target of solution-mining activities in Marshall County, WV, since World War II. The core, drilled in 1980, was recently analyzed as part of a study of potential candidates for subsurface storage of natural gas liquids. Results of the Appalachian Storage Hub study, conducted by researchers from the state geological surveys of Ohio, Pennsylvania, and West Virginia, were released to the public on September 1, 2017.

The large-diameter core has not been slabbed and features many examples of fracturing and structural deformation. Data sets that will be presented for this core include a graphic log and descriptions, full elemental geochemistry, and a complete set of photographs.

The Sandhill Well (API 4710700351)

Drilled in 1955 near the crest of the Burning Springs anticline in Wood County, WV, by the Hope Natural Gas Company in conjunction with the South Penn, Manufacturers Light and Heat, and Columbian Carbon Gas companies, this core represents the first well in West Virginia to penetrate the entire Paleozoic section from the “Coal Measures to the Precambrian”. Nearly 2,870 feet of the well was cored, mostly from the basal Cambrian and Ordovician sections. The core samples were split amongst researchers from ten different institutions and initial results were presented in West Virginia Geological Survey Report of Investigations 18 (*A Symposium on the Sandhill Deep Well, Wood County, West Virginia*).

In 2013, the Ordovician section of this core experienced renewed interest due to its location near the active **Utica/Point Pleasant** shale gas drilling fairway. Over the following four years, several researchers described and analyzed this portion of the core, including representatives from CoreLab and Chesapeake Energy. Results of these investigations include whole-rock pyrograms, source rock analyses, x-ray diffraction results, and vitrinite reflection reports. These data will be presented along with a section of the core taken immediately above and below the Trenton/Point Pleasant contact.

Exxon Jay P Smith 1 (API 4709901572)

Data from the **Rogersville Shale** in this core from Wayne County, West Virginia, generated interest in the deep Cambrian interval that is currently being explored. The core, drilled in 1974, shows TOC values up to 4.5% in parts of the Rogersville Shale. This well along with several others was drilled by Exxon as a series of basement tests in the Appalachian basin. This core was studied by the state surveys and results were detailed in the Rome Trough Consortium study released in 2001. Since that time, other studies have proposed the Rogersville Shale as a source rock with significant potential. Also, this core has been of interest for operators wanting to explore the Rogersville Shale in Kentucky and West Virginia. Several wells have been permitted and/or completed, with most of the activity centered in eastern Kentucky. Though production numbers from these wells are sparse, the interest in the Rogersville is ongoing.

The core available for viewing shows interesting sedimentary features in the shale and data acquired from multiple entities will be presented that will include source rock analyses and x-ray diffraction results.

Abstracts

Speaker is first author unless indicated by an asterisk (*).

Modelling of an Ancient Fluvial Depositional Environment Using 3D-Photogrammetry and Paleohydrology, the Middle Pennsylvanian Allegheny Formation, South-Central West Virginia, USA

Olu-Segun Abatan[1], Amy Weislogel[1], and B. Mitch Blake[2],

[1] Department of Geology and Geography, West Virginia University
[2]West Virginia Geological and Economic Survey

This project uses state of the art 3D photogrammetry combined with paleohydrologic analysis of an ancient fluvial system to better define the facies architecture and facies association of the ancient fluvial channel. Fluvial systems are composed of sedimentary deposits in channelized environments dominated by flowing water. The morphology of fluvial systems is influenced by sediment supply, accommodation space and intensity of flow within the channel. Fluvial geomorphic response to these factors are characterized by a change in channel geometry and the formation of distinct sedimentary features which are distinguished based on geometry, scale and facies. Paleohydrologic analysis employs empirical equations for estimating paleochannel dimensions. The paleochannel dimensions estimated for static modelling, include paleochannel depth and width. 3D photogrammetry is used to construct a 3D photomosaic which captures sedimentary features from an outcrop of an ancient fluvial deposit. This data is then combined with channel dimension information acquired through Paleohydrologic analysis, and data from measured outcrop section, to develop a 3D model of the ancient fluvial depositional environment. The 3D photogrammetry and paleohydrologic analysis were used to investigate and model the Middle Pennsylvanian Allegheny Formation (MPAF). The MPAF is a north-west prograding clastic wedge which originated from tectonically uplifted highlands along the east-central Appalachian basin. Preliminary sedimentary data showed that sandstone deposits below the Lower Kittanning Coal (LKC) member of the MPAF were more arenitic than the sandstone deposits above the LKC. Preliminary estimates of channel dimensions revealed channel flow depth ranging from 7m to 11m for the MPAF deposits immediately above the LKC and, 7m to 12m for the MPAF deposits immediately below the LKC. The use of 3D Photogrammetry to construct a photomosaic, combined with paleohydrologic analysis of ancient fluvial deposits improves the ability to define accurately, the facies architecture and facies association of the ancient fluvial channel from an outcrop data. The ability to determine the thickness and width of a channel is essential in estimating reservoir extent in exploration and development of petroleum resources of a fluvial depositional system.

Direct Kerogen characterization of Marcellus Shale collected from Marcellus Shale Energy and Environment Laboratory

Vikas Agrawal and Shika Sharma, Department of Geology and Geography, West Virginia University

Kerogen is an insoluble macromolecule, formed by degradation and condensation of different biomolecules. It is the source of all hydrocarbon generated from the organic rich shales. Despite its importance, it still remains to be one of the least studied component of shales. Previous work has indicated that shale with similar kerogen type and reservoir parameters such as thermal maturity, produces different amounts and type of hydrocarbons (HCs). This indicates that chemical structure and composition of kerogen play a major role in HC generation and production. To determine the sweet spots of HC extraction and increase the efficiency of HC production there is a need to better characterize chemical properties of kerogen at the molecular level.

We extracted kerogen from core samples collected from Mahantango and different zones of Marcellus Shale at the Marcellus Shale Energy and Environment Laboratory (MSEEL) site in Morgantown, West Virginia. Direct kerogen analytical techniques such as XPS (X-ray photoelectron spectroscopy), ATR-FTIR (Attenuated total reflection-Fourier transform infrared spectroscopy), ^{13}C solid state NMR (Nuclear magnetic resonance) and Raman spectroscopy were used to determine the molecular structure of kerogen. Our results indicate that kerogen from all samples are mainly composed of highly aromatized carbon with minor amount of aliphatic carbon chains. The aromatic carbon fraction was dominated by aromatic bridgeheads carbon atoms and protonated aromatic carbon atoms indicating these carbon chains are refractory in nature and does not contribute significantly in hydrocarbon generation potential. Additionally, only minor amount of carbon chains such as such as mobile and immobile alkyl, methoxyl and alkyl-substituted aromatic carbons were observed, indicating that these functional groups are more prone to thermal degradation and have higher hydrocarbons generating potential.

Performance Forecasting and Characterization of Carbonate Reservoirs Using Data-Driven Models

Emre Artun, Middle East Technical University Northern Cyprus Campus

The pace of operations in the oil industry keeps increasing with higher volumes of data becoming available in shorter periods with newer technologies and processes. This requires industry professionals to analyze the data at the same pace, and make quick and reliable decisions to manage assets better and create value. Unconventional modeling approaches are necessary to extract more information from limited data for optimum utilization of hydrocarbon resources so that development projects would not be affected from volatile oil prices. In this study, a data-driven modeling approach utilizing neural networks is followed to better understand reservoir characteristics and flow dynamics from limited data in carbonate reservoirs. Two case studies are considered to test the proposed methodology: 1) Estimation of infill well performance in an oil reservoir with water flooding patterns, 2) Estimation of resistivity logs from surface-seismic attributes. Models are developed using seismic attributes, historical production/injection data, well logs and derived reservoir properties. For the infill-well-performance model, two key types of information presented for model-training are: 1) oil/water rate data from offset wells, 2) estimated ultimate drainage area that is calculated using Voronoi grids for each well to account for interference effects. Developed model was able to accurately predict oil production rates and water cuts for the existing wells with correlation coefficients greater than 0.80, capturing the fluid-flow dynamics within the reservoir and demonstrating the potential to estimate the performance of new development wells. For the reservoir characterization model, 39 surface seismic attributes, well locations and depth are used as inputs to predict induction conductivity, induction resistivity and short-normal resistivity logs. Using 14 wells for training, logs of 3 wells in the testing set were predicted with a correlation coefficient of 0.83. The study shows that neural-network based data-driven models can be used to estimate well performance and well logs accurately using field data. The workflow presented is very efficient in terms of manpower and computational-time requirements when either high-fidelity models or computational resources are not available. Using only real data reduces the risks related to potential uncertainties in reservoir modeling and interpretations for unexplored locations.

Time-Dependent Performance Evaluation of Cyclic Injection of Gas Mixtures into Hydraulically-Fractured Wells in Appalachian Sandstones

Emre Artun, Middle East Technical University Northern Cyprus Campus

Single-well cyclic gas injection is a promising method to increase recovery from depleted and fractured reservoirs. The process is primarily driven by a diffusion process through the fracture surface, allowing the oil in the matrix to be displaced towards fractures, resulting in improved oil production. The method is attractive because of lower investment requirements as compared with larger field-scale flooding projects. It was previously shown both in the field and through experimental/modeling studies that nitrogen and carbon-dioxide can be used effectively in

Appalachian Basin sandstones for cyclic injection in the presence of hydraulic/natural fractures. In this study, injection of mixtures of nitrogen, carbon-dioxide and methane gases is evaluated using a compositional reservoir model that represents a hydraulically-fractured, stripper-production well with characteristics of Appalachian sandstones and a 36-API gravity crude oil sample taken from the Appalachian Basin. By varying process design parameters such as injection rate, injection period, soaking period, economic rate limit and injected gas composition, 5000 simulation runs were completed to assess the applicability of the process. Results were analyzed by defining an economic indicator that takes into account discounted values of incremental oil produced, volume of injected gas, oil price and costs of injected gas for varying project periods between 1 year and 20 years. Among the ranges studied, it was observed that the process would result in a positive net present value for all the cases, up to 6 years of project time. Feasibility beyond 6 years depends on the operational parameters. Keeping the injection rate below 400 MCF/d, injection duration less than 20 days, economic rate limit below 4 STB/d and soaking period greater than 30 days would contribute to the successful application of this process. It was observed that the injected gas composition does not significantly affect the efficiency since each type of gas contributes to the recovery mechanism differently. However, economic analysis favors nitrogen since the cost of generation is lower than other gases. Results were also used to develop a screening model that is based on neural networks that forecasts the efficiency. This model was validated with 500 blind cases, with a correlation coefficient of 0.95. Analysis of this model confirmed previous findings regarding the importance of all operational parameters except gas composition.

Probabilistic Assessment of Tight-Gas Sands Using a Data-Driven Modeling Approach

Emre Artun[1], Burak Kulga[2], and Turgay Ertekin[2]
[1] Middle East Technical University Northern Cyprus Campus
[2] Pennsylvania State University

Tight-gas sand reservoirs are considered to be one of the major unconventional resources. Due to the strong heterogeneity, very low permeability and advanced well designs with multiple hydraulic fractures; performance forecasting, characterization and optimum exploitation of these resources become challenging with conventional modeling approaches. In this study, it is aimed to develop data-driven predictive models for tight-gas sands and use them for probabilistic assessment of these resources. Data-driven models are based on artificial neural networks that can complement the physics-driven modeling approach, namely numerical flow-simulation models. Two different classes of data-driven models are trained and validated by using data from a numerical reservoir model for tight-gas sand reservoirs: 1) a forward model to predict the horizontal-well performance, once the initial conditions, operational parameters, reservoir/hydraulic-fracture characteristics are provided, 2) an inverse model to estimate reservoir/hydraulic-fracture characteristics once the initial conditions, operational parameters, observed horizontal-well performance characteristics are provided. The forward model is validated with blind cases by estimating the 10-year horizontal-well performance (i.e., cumulative gas recovery) with an average error of 3.7%. While the development of the inverse model was more challenging due to the inverse nature of the problem, reservoir and hydraulic-fracture characteristics are estimated with an average error below 20%, reducing the uncertainty associated with these parameters significantly. A graphical-user-interface application is developed that offers an opportunity to use the developed tools in a practical manner by visualizing estimated performance for a given reservoir or obtaining estimates of certain reservoir and hydraulic-fracture parameters, within a fraction of a second. Practicality of these models is also demonstrated with a case study for the Williams Fork Formation by assessing the performance of various well designs and by incorporating known uncertainties through Monte Carlo simulation. P10, P50 and P90 estimates of the horizontal-well performance and reservoir/hydraulic-fracture characteristics are quickly obtained within acceptable accuracy levels.

Data-driven Approach to Refine Carbon Storage Efficiency Factors for Regional-scale Offshore Saline Reservoirs

Andrew Bean[1], Kelly K. Rose[2], Randal B. Thomas[3] and Emily M. Cameron[3]

[1] Oak Ridge Institute for Science & Education
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[3] AECOM Corporation

Carbon capture and storage (CCS) is an effective method of curbing anthropogenic CO_2 emissions. The National Energy Technology Laboratory's (NETL, Dept. of Energy) CCS assessment efforts have been focused on applying efficiency factors that describe the percentage of geologic pore space that will be occupied by injected carbon dioxide. Efficiency factors have been primarily utilized in onshore scenarios. However, considering the vast resource potential in deep saline formations, offshore carbon storage is gaining more attention. Therefore, it is necessary to refine NETL's onshore efficiency factors for the offshore environment.

We present our approach to refine the specific efficiency factor for net-to-gross thickness of sand suitable for offshore CO_2 storage. Unlike previous efforts that are simulation-based or limited in scope, we constructed a data-driven, regional-scale methodology for offshore storage. Our method leverages in-house well logs from the Gulf of Mexico (GOM) and the Bureau of Ocean Energy Management's (BOEM) Oil and Gas Sands Atlas. Following statistical analyses (Spotfire and ArcGIS), we chose a representative subdomain of the GOM as a case study. We interpreted well logs (Petra) that contained sand formations within the GOM subdomain that met specific criteria to compare with attributes from BOEM's database. Maps were generated (ArcGIS) that visualize this comparison. Our analysis found that the BOEM database lacked critical sand thickness information. We recommend a methodology that utilizes empirical relationships specific to each subdomain built from public data and our well log interpretations that maximize spatial coverage and minimize storage estimate error.

Geophysical Characterization of Mississippian Carbonates of South Central Kentucky and Northern Tennessee

Matthew Bentley, Michael T. May and Thomas B. Brackman, Western Kentucky University

Use of geophysical tools is one of the best options for collection of subsurface data over broad areas between boreholes or drill wells. Such tools are minimally invasive and applicable in several geologic sub disciplines. Combination of geophysical data with petrofacies and petrophysical data permits the most accurate interpretative view of reservoirs. Instrumentation used in this study includes: Electrical Resistivity Tomography (ERT), Refraction Microtremor (ReMi), and Ground Penetrating Radar (GPR). Testing of the GPR has proven it to be efficient at defining several geological features such as folds and faults, stratigraphic framework (bedding planes), anthropogenic (mining voids), and karst features. Minimally, GPR can be used to define fault zones and possibly fracture zones from the surface down 100 to 200 meters below ground surface. Testing is being conducted at several sites however, the Salem-Warsaw limestone units are the primary focus in this study. These limestones, despite being nearly exposed or exposed at the surface, are nonetheless charged with hydrocarbons. The Salem-Warsaw stratigraphic interval has been an important hydrocarbon producer in the southeastern Illinois Basin and remains prospective today. The oil in place creates a unique opportunity to study these saturated lithofacies in the context of 1) resistivity profiles from nearby wireline logs as well as 2) in the context of ERT profiles generated near the surface. The Salem-Warsaw in the study area is also moderately dissolved, creating karst plain geohazards (flooding, collapse) that are challenging for engineers and city planners. Integration of geophysical and geological data is providing an expanded view of important Mississippian reservoirs and simultaneously is aiding in locating voids or conduits responsible for karst geohazards at the surface.

Deposition, Diagenesis and Hydrocarbon Generation in the Ordovician Point Pleasant Limestone and the Devonian Marcellus Shale: Comparing and Contrasting Two Appalachian Basin Unconventional Reservoirs

David R. Blood, EQT Production

Appalachian Basin shale gas has now become a well-known component of U.S. natural gas production. Indeed, as of 2015, Pennsylvania accounted for 18% of domestic dry natural gas production, driven largely by the Devonian Marcellus Shale, and to a lesser extent, the Ordovician Point Pleasant Limestone. While these two shale plays display similar production mechanisms, the conditions under which these deposits accumulated were markedly different. Vertical chemostratigraphic profiles and pyrite morphology trends were developed on core taken from both formations. The Marcellus exhibits enrichments in redox sensitive trace elements, a framboid population detailing abundant small, <5 µm framboids, with subordinate large framboids, and occasional bioturbation. These observations suggest that sediments accumulated under dominantly anoxic to euxinic bottom waters that were occasionally subjected to periods of (dys)oxia. The high total organic carbon content of the Marcellus is the result of increased preservation due in part to favorable oxygen-depleted conditions, while concentration was controlled by dilution from clastic influx. Conversely, the Point Pleasant comprises mudstones and marls largely devoid of redox-sensitive trace elements, with minimal pyrite, a paucity of iron, and a number of in situ shell bed horizons. These observations suggest the Point Pleasant accumulated under oxic to dysoxic bottom water conditions. Further, the lack of biolimiting iron, and lower preservation potential due to oxidation of organic matter, yielded a formation of lower organic carbon concentration, where preservation occurred via rapid burial. It is noteworthy that, despite the lower organic carbon content, the Point Pleasant hosts a pore pressure gradient far in excess of that observed in the Marcellus. While expulsion fractures, including Mode I vertical catagenic fractures, are common to the Marcellus, they are infrequent to absent in the Point Pleasant study area. One explanation is that the pressure needed to overcome the compressive stress carried by higher modulus, carbonate-rich sediments was never achieved, thus limiting fracturing and hydrocarbon expulsion and preserving its high pressure. Conversely, stress build-up from pore pressure resulting from hydrocarbon generation in lower modulus, more clay-rich Marcellus sediments achieved the tensile strength of the rock causing it to fracture and release hydrocarbons, subsequently lowering its pressure.

Challenges with Marcellus Shale Horizontal Exploration Within or Near the Allegheny Highland

Cole Bowers, Energy Corporation of America

Why does the Marcellus not produce as much gas in the Allegheny Highland as it does in other areas due west? Areas like Doddridge and Harrison County, WV have proven to produce 1.8 - 2.2 BCFE per 1,000 feet of lateral consistently whereas wells in the Allegheny Highland consistently range between 0.8 - 1.2 BCFE per 1,000 feet of lateral or worse.

County scale 2D seismic, a microseismic survey, rock properties from well logs and well production are used to characterize the structural and stratigraphic frame work for Marcellus Shale within the Allegheny Highland.

Three Marcellus Shale horizontal wells in Webster County WV (within the Allegheny Highland) have produced 0 Mcf after stimulation. A microseismic survey on one of non-producers indicated that fracture stimulation was primarily focused below the Marcellus. It is assumed that basal frac barrier effectiveness potentially affected well performance in Webster County, WV. Therefore, rock properties from well logs of the Marcellus Shale and the underlying Onondaga Limestone were compared over a larger area to highlight the importance of basal frac barrier effectiveness in relation to production performance. Also, county scale 2D seismic will be shown and interpreted to help determine possible completion hazards.

It is proposed that the thickness and volume of shale in the underlying Onondaga Limestone, difference in minimum horizontal stress between the Marcellus and Onondaga, proximity to the structural front, and fault presence at Silurian to Ordovician level all play a role in frac barrier effectiveness.

Porosity and CO_2 Storage Capacity of the Maryville-Basal Sandstone Section in the Kentucky Geological Survey 1 Hanson Aggregates Stratigraphic Research Well, Carter County, Kentucky

J. Richard Bowersox, Stephen F. Greb and David C. Harris, Kentucky Geological Survey, University of Kentucky

The Kentucky Geological Survey drilled the 1 Hanson Aggregates stratigraphic research well, Carter County, northeast Kentucky, to test in situ rock properties in the subsurface for their potential as CO_2 storage reservoirs and confining intervals (cap rock). The Middle Cambrian Maryville-Basal sands interval (4600-4720 feet) were evaluated to determine effective porosity, clay volume, and standalone potential CO_2 storage reservoir capacity. The interval is composed of two muddy dolomitic sandstones, each about 30 feet thick, separated by about a 40-ft interval of sandy dolomitic mudstones. The upper unit is the Maryville sandstone, an informal subsurface member of the Maryville Limestone, whereas the lower is the informal Basal sandstone which overlies a thin Granite Wash on Precambrian Grenville basement. Effective porosity and clay volume in the strata were calculated from the density log using a three matrix shaly-sand model. Four formation lithologies were identified from primary lithology and clay volume: muddy sandstone, sandy mudstone, dolomitic mudstone, and dolomitic claystone. Average effective porosity calculated in the Maryville sandstone is 8.9% with clay volume of 35.3%. Average effective porosity in the Basal sandstone is 8.7% with 41.2% clay volume. Effective porosities calculated in this evaluation are a good match with porosity measured in core plugs from the intervals. Porosity and net reservoir thickness for calculating potential CO_2 storage volume were determined using an industry-standard 7% porosity cutoff. In the 664,500-acre study region around the 1 Hanson Aggregates estimated effective porosity greater than the 7% cutoff is 13.7% and average net reservoir thickness is 34 ft. Storage volume was determined using the methodology of the U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory. Estimated P50 supercritical CO_2 storage volume for the Maryville- Basal sandstone interval is 654 metric tons/acre and 434.6 million metric tons in the study region. Thus, about 1530 acres would be required to store 1 million metric tons of supercritical CO_2 in the Maryville-Basal sands interval. Thin reservoir sandstones, low permeability (~50 mD), low reservoir volume, and low fracture gradient of 0.581 psi/foot measured in a step-rate test, however, probably makes the Maryville-Basal sandstone interval unsuitable for standalone CO_2 storage in the southern Appalachian Basin. More likely is that the interval would be part of a stacked-reservoir CO_2 storage project, although there are no current or future plans to store CO_2 in the region.

Step-Rate Test Results from the Kentucky Geological Survey 1 Hanson Aggregates Stratigraphic Test Well, Carter County, Kentucky

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The Kentucky Geological Survey (KGS) drilled the 1 Hanson Aggregates test well in northern Carter County to evaluate reservoir characteristics and CO_2 storage capacity of the Knox Group and basal sands in the Southern Appalachian Basin in eastern Kentucky. The well was completed with 9and 5/8 -inch groundwater-protection casing cemented at 355 feet and 7-inch casing cemented at 2944 feet to anchor BOPE during drilling and testing. The wellbore was open below 2944 feet to the TD of 4835 ft. The well program included extensive electric log suites, coring, and core analysis to better understand the in situ reservoir and rock properties of potential CO_2 storage reservoirs. Step-rate tests were conducted to determine injection rates, pressures, and fracture gradients in the Maryville-Basal sands, Copper Ridge Dolomite, and Rose Run Sandstone. During the late 1990s EPA Regions 8 and 9 injection-well reviews found fracture gradients in the Midwest of 0.48 to 0.91 psi/foot in Mt. Simon Sandstone and strata correlative to the Knox, hence step-rate testing was prudent for evaluating CO_2 storage potential in the 1 Hanson Aggregates. Test intervals were isolated by setting a cement plug at the base and an inflatable packer on 2-inch tubing in the open wellbore at the top. Surface-readout pressure gauges were set below the packer to monitor wellbore pressure during testing, and above the packer to monitor annulus pressure for communication with test intervals. Formation water samples were swabbed prior to each step-rate test. Swabbing water from the Maryville-Basal sands interval was unsuccessful because of little fluid entry; however samples were collected from the Copper Ridge and Rose Run. Step-rate tests were conducted using fresh drinking water purchased from the Grayson municipal water system. The Maryville-Basal sands were tested in the interval of 4585-4709 ft. Pumping rates were maintained for 15-minute steps from 0.25 to 2.0 BPM. The interval fractured at a pressure of 2689 psi (0.58 psi/foot gradient) after injecting 135 BW. The Copper Ridge was tested in a vuggy interval of 369-3945 ft. Pumping rates were maintained for 5-minute steps from 0.25 to 5.5 BPM. The interval did not fracture, although pumping pressure increased from 2173 psi to 2370 psi (0.62 psi/foot) during the test. The test was terminated after pumping 866 BW. The Rose Run was tested in an interval of 3257-3318 ft. Pumping rates were maintained for 7-minute steps from 0.5 to 8.0 BPM, and the test was terminated after pumping 1020 BW at about 1945 psi (0.59 psi/foot) without pressure increase during the test. Low formation permeability (~50 mD) and fracture gradient probably precludes the Maryville-Basal sands for CO_2 storage in the region, however both the Copper Ridge and Rose Run would be candidates for CO_2 storage reservoirs and waste fluid injection.

Mapping and Reservoir Characterization of Geologic Intervals for NGL Storage Applications

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The Appalachian Oil & Natural Gas Research Consortium recently completed the Appalachian Storage Hub for Liquid Ethane Study to identify potential storage reservoirs for natural gas liquids (NGLs) derived from the liquid-rich Marcellus and Utica shale plays. The project objective was to identify the best options for storage proximal to a proposed pipeline from areas of shale production in southwestern Pennsylvania to end users in southern West Virginia and northeastern Kentucky. The study's Area of Interest (AOI) included 50 counties centered along the Ohio River Valley corridor in the tri-state region of Ohio, Pennsylvania and West Virginia. Survey geologists from each of these states collaborated to complete the study within a year's time, assessing three types of storage opportunities (mined-rock caverns, salt caverns and depleted siliciclastic gas reservoirs) through their desktop evaluation of 10 discreet geologic intervals: the Mississippian Greenbrier Limestone for subsurface mining; the Upper Silurian Salina F4 salt for the creation of cavities through brine extraction; and depleted gas fields in sandstone reservoirs in the Lower Mississippian (Keener to Berea interval); Upper Devonian (Venango, Bradford and/or Elk intervals), Lower Devonian (Oriskany Sandstone); Upper Silurian (Newburg Sandstone); Lower Silurian (Clinton/Medina and Tuscarora sandstones); Lower Ordovician (Rose Run sandstone); and Upper Cambrian (Gatesburg Formation and Upper Sandy member). The research team prepared maps of depth, thickness and extent for each interval; compiled existing siliciclastic reservoir data at the field level using multiple regional data sources; and conducted new qualitative petrographic analyses to support reservoir characterization activities. This information was used to identify a short list of the most promising NGL storage reservoirs, to which geology-based ranking criteria developed specifically for this study by the research team were applied. As a result of these efforts, we identified multiple prospects in the AOI where stacked NGL storage opportunities (i.e., a combination of mined-rock caverns, salt caverns and/or depleted gas reservoirs at different depths within a given geographic area) are recommended for further investigation at the site level.

Permian Basin Activity - Reagan County Texas

Joseph Cook, Energy Corporation of America

As oil starts to make a comeback after possibly one of the biggest downturns in history, the Permian Basin finds itself at the forefront of energy news. Almost half the rigs that are currently drilling are doing so in Texas and two thirds of those rigs are drilling the Permian Basin. With this in mind, what do you know about the Permian Basin? I have chosen Reagan County, Texas, residing in the Midland Basin, a sub basin of the Permian for our discussion. We will look at some of Reagan County's history, geology and activity. You may find that rooted in this west Texas County there is a legacy that we can all be proud of.

The origin and evolution of shell beds in Ordovician shales of southwestern Pennsylvania (Point Pleasant and associated units) and their implications for the preservation of organic carbon

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Shell beds in black shales have been interpreted as sediments transported from shallower carbonate shelf environments rather than as autochthonous deposits. If the shells were deposited in place, these intervals would indicate water column oxygenation. Defining bottom water redox better constrains models of total organic carbon (TOC) accumulation, which may provide essential nanoporosity. We investigated this possibility by examining the textures and compositions of shell beds in a core from southwestern Pennsylvania, where the Point Pleasant comprises a lower shell bed interval (~2% TOC), a middle shell bed free interval (~4% TOC) and an upper shell bed interval (~3% TOC). The upper shell bed interval consists of numerous thin shell beds one or two shells thick, dominated by dalmanelid brachiopods and thin shelled-trilobites, similar to other Ordovician black shales. The delicate shells are typically flat lying pavements with mud matrix and show little or no breakage. The thicker shell beds of the lower interval are more species diverse. They show varying degrees of breakage, less flat, more random orientations of platy fragments, a range of limestone textures, and phosphorus enrichment. Our observations support the hypothesis that shell beds formed in place. The morphology of pavements in the upper unit suggests brief periods of oxygenation with minimal penetration of oxygen to underlying mud. Thicker shell beds of the lower unit are also compatible with growth in place where higher diversities are consistent with more oxygen. Phosphorus enrichment suggests longer periods of accumulation under fluctuating interstitial redox conditions caused by reworking events that also generated chaotic textures and breakage. Preliminary correlations (isotopes pending) suggest thin shell beds in this interval are laterally extensive, covering an area from southwest Pennsylvania to western Ohio and central Kentucky that is difficult to reconcile with a model of downslope transport. While highest TOC values occur in the shell-free interval, some black shale organics were preserved through periods of water-column oxygenation. During the longer periods it took to accumulate thicker shell beds, oxygenation of accumulating shell gravels would have consumed organics as they formed but did not strongly affect previously buried carbon. The preservation of organics in this relatively quiet basin may have depended on rapid pulses of burial rather than a low oxygen water column.

An Interpretation of Core Derived Water Saturations Using Water Isotope Analysis

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Gas-in-place (GIP) models play a critical role in the assessment and valuation of unconventional reservoirs, the quantification of recovered hydrocarbon, completion simulation, and production modeling. Integral to these models is an accurate quantification of hydrocarbon and water saturations within pores. Standard Gas Research Institute (GRI)-based shale core analysis involves determination of the in situ fluid saturations by measuring the amount of water and oil extracted from the sample, often via the Dean Stark method. Reported core water saturations for the Marcellus Shale in southwestern Pennsylvania and northern West Virginia average approximately 30% of the pore volume. However, calculations of cation exchange capacity (CEC) demonstrate that the clays in the reservoir are under-saturated (often >75% desiccated) with respect to water, indicating the clays would absorb water, a phenomenon commonly observed when spraying water on the core surface. Furthermore, the full load of water pumped during completions is rarely captured during the flow back, suggesting its possible uptake by the formation. In order to understand the nature of water/rock interactions in the Marcellus Shale, several field and lab experiments were carried out on core and cuttings. Wax preserved full diameter core were extracted using a Dean Stark apparatus and the fluids were analyzed for oxygen and deuterium isotopes. When these data points are plotted on δ18O and δ2H plot, they follow an evaporation trend that originates at the isotopic signature of the surface waters used in the drilling mud. The same trends can be seen by plotting flow back water isotopes with time. These observations would suggest that some portion of the water extracted during GRI shale core analysis is an artifact of the drilling process and not in situ, yielding an underestimation of gas-filled porosity and resultant calculated GIP. Finally, the fractionation of oxygen and deuterium isotopes may be impacted by present day reservoir temperature, permeability, porosity, clay content, and thermal maturity history, or a combination of these factors. On-going studies are focused on understanding how these factors alter the isotopic signature of the waters extracted from core and during flow back.

Organic Matter Content and Thermomaturation Trends in the Ohio and Sunbury Shales, Eastern Kentucky, Central Appalachian Basin

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One hundred fifty-eight samples of Ohio and Sunbury shale core and well cuttings, from 14 bore holes, were sampled along a north/northwest (NNW) to south/southeast (SSE) transect in eastern Kentucky. The transect essentially parallels regional dip, with the NNW end representing an area where the shale is relatively thin (<200 m) with minimal burial depth (0 to 600 m), and the SSE end representing an area where the shale is thicker (>200 m) and more deeply buried (600 to 1,400 m). Sample points from individual cores were selected to best represent the black shale interval at each core location. An additional 21 samples were collected from locations along the Ohio/Sunbury shale outcrop belt in northeastern Kentucky. All of the samples were analyzed for total organic carbon content (TOC) and vitrinite reflectance (VR_o). Selected samples were analyzed for solid bitumen reflectance (Br_o), Rock Eval pyrolysis, and major, minor and trace element composition as determined from x-ray fluorescence (XRF). TOC values ranged from 0.23 % to 21.64 %, with core average TOC values being higher towards the NNW. Vitrinite reflectance values range from 0.5 - 0.6 % VR_o random on the NNW end of the transect to 1.2 to 1.3 % on the SSE end. Solid bitumen reflectance measurements were collected on 21 samples and show a similar pattern, being lowest (0.3 to 0.4 %, BR_o random) on the NNW end of the transect, and highest (1.4 to 1.5 %, BR_o random) on the SSE end. Rock Eval analyses performed on 64 samples, show a pattern of increasing T_{max} from NNW (420 to 4300 °C) to SSE (440 to 4600 °C), and decreasing Hydrogen Indices (HI) from >500 at locations to the NNW, to <100 at the SSE end. Collectively, the petrographic and Rock Eval thermomaturation data all show an increase from the NNW end of the transect to the SSE end, which is the direction of increasing shale thickness and present depth of burial. Major, minor and trace element concentrations, determined for 21 samples from the outcrop belt on the NNW end of the transect, indicate the Ohio/Sunbury shale to be dominated by SiO_2 (avg. 57.9 %) and Al_2O_3 (15.8 %). The shale samples are also enriched in several trace elements including Cr (avg. 179 ppm), Mo (avg. 241 ppm), Ni (avg. 197 ppm), V (avg. 1194 ppm), Zn (avg. 259 ppm) and Zr (avg. 263 ppm). Element ratios (e.g., Ni/Co, V/Cr and V/V+Ni), used to assess paleoredox conditions, indicate mainly dysoxic to anoxic conditions during sediment and organic matter accumulation.

Structural Control of the Point Pleasant Formation Deposition and Production

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Early drilling and production observations in the Point Pleasant Formation in Ohio suggest that structural setting influences production. To test structural setting versus production, Point Pleasant horizontal completions (~800 wells) were categorized into five structural settings based on Trenton and shallow residual mapping. The settings are (1) Structural High, (2) Transitional High, (3) Platform, (4) Basinal, and (5) Deep Basin. Cumulative production in terms of thousand cubic feet gas equivalent (Mcfe) were calculated and normalized to Mcfe/1,000 feet of lateral. The structural setting with the highest cumulative production after 24 months is the Basinal setting which produced 12% more reserves than the average, and 30% more than the Structural High, the worst performing structural setting. The Structural High, Transitional High, and Deep Basin settings all fell below the average 24 month production. The advantage of the Basinal setting is that it is structurally low, low relief, and normally near a carbonate source. These geologic elements limit the energy and oxygen within the basin while providing the proper carbonate-shale ratio. The Basinal setting offers the best environment for the deposition and preservation of organic material. Existence of the organic beds can be observed in cores, geophysical logs, and formation imaging logs. The Platform setting is a structurally elevated area inside the Basinal setting and has the advantages of the Basinal setting. Comparison of Point Pleasant core total organic carbon values between Structural High, Transitional High, and Basinal wells within similar thermal maturity bands show that more organic material is preserved in the Basinal setting than in the Structural High and Transitional High settings. The Deep Basin setting has total organic carbon values similar to the Basinal setting, but has lower carbonate-shale ratios and higher clay content that constrain production. The quantity, thickness, continuity, and subsequent preservation of the organic beds appear to be critical components in the enhancement of Point Pleasant production. The preservation of organic material in the Point Pleasant shale is controlled by underlying basement structures and Knox paleotopography. The organic beds may also be the starting point for an interconnected horizontal porosity system that develops as thermal maturity progresses.

Counter-regional detachment structures, southwestern Pennsylvania, central Appalachian basin: Implications for Marcellus Shale gas exploration and production

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3D seismic data in southwestern Pennsylvania, central Appalachian basin, demonstrate that the structures in the Devonian section are dominated by the east-vergent folds and reverse faults, which contrasts with the west-vergent ones that have been well known in the basin. Vertical (cross-stratal) variation in fold curvature and fault throw indicates an increase in contraction from Upper Silurian to Middle Devonian followed by a decrease from Middle Devonian to Upper Devonian. Lateral (along-stratal) variation in fold curvature and fault throw indicates a decrease in contraction from the east to the west. These observations, along with previously reported observations from wells and 2D seismic lines in adjoining areas, suggest a major post-salt, counter-regional detachment structure in the western central Appalachian that was most likely driven by gravitational pull from the east during the Acadian orogeny.

Marcellus Shale gas exploration and production data hint at a strong correlation of gas potential and productivity to natural faults from both local and regional perspectives. Locally, the gas productivity drops significantly towards major northeast-trending reverse faults. Regionally, the overall exploration activity decreases towards major northwest-trending cross-strike lineaments. This correlation is opposite to what was previously reported in conventional reservoirs in the basin. We interpret that in shale gas reservoirs, large-scale (> shale thickness) faults, particularly the cross-regional wrench faults, caused sustained leakage of released gas from the reservoirs, while small-scale ones (< shale thickness) could potentially retain the released gas in the reservoirs. We conclude that investigating the characteristics of natural faults is fundamental to the successful exploration for and effective development of shale gas in the central Appalachian basin.

Hilbert Transform of Distributed Acoustic Sensing (DAS) Fiber Optic Data: A New Attribute to Assess Hydraulic Fracturing in Marcellus Shale

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Distributed acoustic sensing (DAS) technology also known as distributed vibration sensing (DVS) utilizes optical fibers to measure the dynamic strain at all points along the fiber. Fiber optic distributed acoustic sensing (DAS) data were recorded for 28 stages in the MIP-3H well at the Marcellus Shale Energy and Environment Laboratory (MSEEL) outside of Morgantown, West Virginia. We calculated two attributes to evaluate vibration frequencies around the fiber during the stimulation; they are calculated on each of the 493 traces for every 30 seconds during the hydraulic fracture stimulation (one SEGY file for every 30 seconds). The first attribute is the energy attribute: a summation of the squared amplitude of the DAS traces. Secondly, the DAS data are transformed into the Hilbert domain to calculate the instantaneous frequency attribute. Traditionally, the instantaneous frequency attribute of 3D seismic data is calculated for reservoir characterization in order to identify abnormal attenuation and thin bed tuning. It can also be used as a hydrocarbon indicator, since high frequency contents get attenuated more when they encounter fluid. In this study, we show that the instantaneous frequency attribute can be calculated for the DAS data to acquire details about vibration around the fiber. We use the average of the instantaneous frequency attribute calculated for every 30 seconds during the stimulation to detect abnormal vibration decay. Our result shows that instantaneous frequency reveals low frequencies in the stages below and above the stimulated stage while the energy attribute is only limited to the stimulated stages and does not show vibration in adjacent stages. The higher the energy attribute, the lower the instantaneous frequencies. Instantaneous frequency attribute is sensitive to the fluid existence; higher frequencies are attenuated faster than lower frequencies. Thus, a higher energy attribute in the DAS data would be associated with a high amount of injection fluid around the fiber and within the casing. Local low frequency zones in adjacent stages of the stimulation target might suggest temporary hydraulic connection via faults and fractures during the stimulation. We noticed low frequency zones in Stage 4 during stimulation of Stage 5. These local low frequency zones were also detected in the earlier stages of stimulated Stages 6, 10, 21, and 24. These findings could explain the observed abnormal temperature increase in the distributed temperature sensing.

Reservoir characterization and 3D Modeling of Silurian Reef Slopes: Pipe Creek Jr. Quarry, Grant County, Indiana

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Silurian reefs are significant hydrocarbon reservoirs in the Michigan Basin, having produced over 490 MMBO and 2.9 TCF of gas. Primary production from the reefs is typically low, averaging 20-25% due to the complex internal heterogeneity of the reservoir. To date, a majority of the exploration and development of these reservoirs has been directed towards the cores of the reefs, rather than the associated reef slope deposits. Slope deposits of the Pipe Creek Jr. reef exhibit many similarities to productive slope reservoirs in the rock record (e.g. Poza Rica trend in Mexico; Malampaya in the Philippines; Tengiz and Karachaganak in the Caspian region). As such, the depositional processes and resulting geometries of potential reservoir and seals in these Silurian reef slopes, as well as early diagenetic modification and effect on reservoir quality, likely have many similarities to those found in other forereef reservoirs. The current study is focused on the forereef slope deposits of the Pipe Creek reef complex and includes an in-depth analysis of the facies distribution, bed geometries, and reservoir characterization of the reef slope deposits, coupled with the development of a drone-based, georeferenced, 3-D outcrop model developed in Petrel. The Pipe Creek Jr. Reef has been previously studied with a focus on faunal assemblages, dolomitization of the reef, and the general depositional facies of the reef core. The reef complex has an inferred circular structure, with a minimum thickness of 48m, and the original height of the reef has been speculated as being anywhere from 35 to 200 meters. The exposed reef flank (forereef) facies consist of a mixture of coarse skeletal grainstone-packstones, stromatactis mudstone-wackestones, and argillaceous silty dolomite mudstones. Similar to what is seen in other forereef deposits, lenticular bedding consisting of skeletal packstones and grainstones deposited by grain flow processes make up the majority of the 40-45 degree depositional slopes. In addition, slump scars and channels are common, as are resedimented blocks from the inferred reef crest. Synsedimentary (Neptunian) dikes filled with marine cements are also common. Insights related to reservoir architecture in the forereef facies of these Silurian reefs can potentially open up additional exploration and development opportunities and increase hydrocarbon recovery efficiencies in existing similar complex reef reservoirs.

Comparative Analysis of Transport and Storage Options from a CO_2- Source Perspective

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Transport and storage costs are critical for any source in their effort to keep overall carbon capture and storage (CCS) costs at a minimum. For the source, cost effective storage is a combination of suitable storage and transportation sufficient to accommodate the total mass of CO_2 to be sequestered. The Department of Energy's National Energy Technology Laboratory (NETL) recently completed a comparative analysis on the selection of a suitable saline storage reservoir in conjunction with transportation by a dedicated pipeline or a trunk line system from the perspective of the CO_2 source. This study combines costs for capture, transportation, and storage for a collective evaluation on the cost of CCS and tests the methodology for analyzing combined CCS costs and selecting proximal storage for sources capturing different masses of CO_2. Component cost within the CCS value chain has been calculated at different annual rates of CO_2 captured for different sources modeled over a 30-year period. Capture costs modeled are for three super critical pulverized coal power plants (550 MW, 482 MW, and 400 MW net power output) and three industrial plants: steel, cement and natural gas processing. Annual capture ranged from 3.90 to 0.65 million tonnes per year. Seven reservoirs were selected for modeling. The Rose Run 3 and 4 reservoirs are in western Pennsylvania within the Appalachian Basin. The modeled sources are within 100 and 200 kilometers (km) of either Rose Run reservoir. Further away, the Mt. Simon 10 reservoir is located on the western edge of the Appalachian Basin in western Ohio, the Mt. Simon 6 reservoir is on the platform between the Appalachian and Illinois basins in central Indiana, and the Mt. Simon 3 is within the Illinois Basin in central Illinois. The other two reservoirs are in the Gulf Coast Basin: the Lower Tuscaloosa 8 reservoir in west-central Mississippi and the Frio 3a reservoir in the upper Texas Gulf Coast. Each reservoir was modeled for both a dome and regional dip structural setting. The dedicated pipeline system modeled connects a single source to its storage site. With a trunk line, each source needs its own gathering pipeline to connect to the trunk line and a distribution pipeline to connect between the trunk line and storage site. Cost effective CCS depends on the total mass of CO_2 captured and stored which in turn depends on the annual rate of capture, transport distance, and project life.

Analysis of the Conasauga Group and Basal Sandstone (U. Cambrian) in the KGS No. 1 Hanson Aggregates Well, Carter County, Kentucky

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The Kentucky Geological Survey No. 1 Hanson Aggregates well was drilled as part of a series of carbon-storage research projects under Kentucky House Bill 1 (2007). The goal of the project was to collect subsurface data on potential deep reservoir rocks and confining strata in eastern Kentucky to better enable future evaluations for carbon storage.

Three samples from the Nolichucky Shale and one sample of shale from the Maryville Limestone of the Conasauga Group were analyzed with advanced shale analysis and have matrix permeabilities of 2.27 10^{-8} to 9.33 x 10^{-10} md, for a mean permeability of 1.67 x 10^{-8} md. The Nolichucky samples alone have a mean permeability of 9.2 x 10^{-9} md. Mercury capillary injection pressures were analyzed from three shale samples adjacent to samples collected for shale permeability analysis. The three samples averaged 3.4 x 10^{-5} Swanson permeability and have a median pore-throat diameter of 0.008 nm. These results indicate that the Nolichucky Shale should be an adequate confining interval for deeper reservoirs.

Two deeper sandstones were analyzed as potential reservoirs. The lower part of the Maryville Limestone contains dolomitic sandstones informally termed the "Maryville sandstone" (4,610 to 4,683 feet). Twelve samples have porosities from 2.49 to 17.93 percent, with a mean porosity of 8.71 percent. Although porosities are moderate, permeabilities are mostly low: 0.0003 to 16.4 md, with a mean of 1.81 md. One sample (4,637.9 feet) has a permeability of 16.4 md. If that sample is not included, the other nine samples have a mean permeability of 0.35 md.

The Basal Sandstone (4,684.3 to 4,720.9 feet) coarsens upward from Grenville basement. Analysis of 15 samples from the upper sandy part of the interval showed porosities from 2.17 to 17.84 percent, with a mean porosity of 11.27 percent. Permeabilities ranged from 0.007 to 97.8 md, with a mean of 18.52 md. Six samples had permeabilities of less than 1 md. Nine samples had permeabilities of more than 1 md. Five samples from the lower shaly part had porosities ranging from 6.02 to 12.84 percent, with a mean porosity of 8.49 percent. Permeabilities ranged from 0.001 to 7.19 md, but if the 7.19 md sample is excluded, the other four samples have permeabilities of 0.001 to 0.091, with a mean of 0.033 md.

Porosity and Permeability of Berea Reservoirs (Upper Devonian) in Eastern Kentucky

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Historic porosity and permeability data in the Kentucky Geological Survey oil and gas database (n=583 from 18 wells) and a recent collection of new data contributed by industry (n=91 from four wells) were compared to improve our understanding of Berea reservoir characteristics in Kentucky. Although called a "sandstone," the Berea is actually a siltstone in Kentucky, and is defined as a tight reservoir.

Historic Berea porosity and permeability data show a weak relationship (R^2=0.57), with mean porosity of 12.8 $\pm$2.7 percent, ranging from 2.8 to 19.5 percent, and mean permeability of 2.0 $\pm$3.4 md, ranging from 0.02 to 25.0 md. A significant number of data points are below measuring limits (impermeable, 0, < 0.1, < 0.2 md) and had to be excluded from analysis. New data collected by industry from four Berea cores stored at the Kentucky Geological Survey core library were derived from pulsed neutron permeability, which is capable of measuring much lower permeabilities than older techniques. The lowest permeability in the new Berea data set (excluding shale) is 0.00005 md. Mean permeability is 0.2 $\pm$0.4 md, ranging from 0.00005 to 2.5 md. Most of the new permeability values are between 1.0 and 0.01 md. Mean porosity is 8.9 $\pm$2.9 percent, ranging from 2.0 to 16.1 percent. Combining the new data set with the historic data (minus data below detection limits) yields a much better relationship between porosity and permeability (R^2=0.81). Essentially, in tight siltstone reservoirs like the Berea, exclusion of low-permeability data (or data below old detection limits) can mask any porosity versus permeability relationship. For the combined data, mean porosity is 11.6 $\pm$3.3 percent, ranging from 2.0 to 19.5 percent. Mean permeability is 1.4 $\pm$2.9 md, ranging from 0.00005 to 25 md. For permeabilities greater than 0.1 md, porosities are generally greater than 10 percent. All porosity values above 12 percent have permeabilities greater than 0.1 md.

Porosity and permeability data from four cores were also compared to bedding and XRD analysis for dolomite, pyrite, and clays. The best permeabilities and porosities from the four sample cores are in low-angle (likely hummocky) beds with some dolomite cement, but less than 5 percent dolomite, less than 8 percent illite and mica, and less than 15 percent total clays. Considerable variability and ranges were found for all of the comparisons, which highlights the complexity of reservoir permeability in tight Berea reservoirs.

Modeling and interpretation of a high-relief Precambrian unconformity on 2D seismic reflection lines near Wabash, Indiana

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A study of ten 2D seismic reflection lines recently made available for study by CountryMark in Wabash and Miami Counties of north-central Indiana provides insight into the nature and evolution of the Precambrian unconformity upon the Eastern Granite-Rhyolite Province (EGRP) of the U.S. Midcontinent. The Precambrian unconformity on the ten unmigrated seismic sections occurs at approximately 0.5 second two-way travel time and is characterized by significant undulations, diffractions and classic bow-tie artifacts. Ray-trace modeling using real examples of the relief upon the Precambrian unconformity as exposed in EGRP outcrops of the St. Francois Mountains of southeast Missouri produce strikingly similar undulations, bow-tie structures and diffractions. These comparable seismic patterns and the presence of undeformed granite recovered from drill holes ~8 miles to the NE and ~24 miles to the NW of these seismic lines support an interpretation of undulating paleo-topography carved atop Precambrian crystalline bedrock like that observed in the St. Francois Mountains. This geological comparison is further supported by the potential field map patterns in this part of north-central Indiana which exhibit ring patterns suggestive of caldera complexes like that mapped in the St. Francois Mountains exposures. Elsewhere in Indiana, Ohio, and Illinois seismic reflection data reveal an unconformity of relatively low relief, however, those examples generally occur in areas where layered rocks (likely sedimentary or volcanogenic) lie below the Paleozoic platform cover. A conclusion and prediction of the present study is that the unconformity beneath the Mt. Simon Sandstone in the US Midcontinent may exhibit significant relief in areas underlain by crystalline bedrock and low relief in areas with more easily eroded sedimentary or volcanoclastic strata.

Using well log analysis to identify residual oil zones at Noble and Kenner West Oil Fields, Illinois

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Carbon dioxide enhanced oil recovery (CO_2-EOR) has been used to produce oil from thick, naturally occurring intervals of low oil saturation, or residual oil zones (ROZs), in the Permian Basin. Residual oil zones are widespread within the Permian, Big Horn, and Williston Basins that, in addition to CO_2-EOR, have potential for significant storage of CO_2. Traditionally, open-hole well log analyses focus on higher oil saturations with specific analyses focused on irreducible saturation and movable hydrocarbons. Identifying ROZs in other basins requires methods to find lower oil saturations resulting from the natural water flooding processes that form ROZs. This study presents a procedure that uses a combination of established well log analyses to identify ROZs. This study uses conventional and shaly-sand well log analyses to identify and characterize the thickness and residual oil saturation of suspected ROZs beneath the main pay zones in the Cypress Sandstone at Noble and Kenner West Oil Fields, Illinois. Archie, ratio, and dual-water methods were used to calculate oil saturation, and a combination of the moveable hydrocarbon index, bulk volume water, and apparent water resistivity were used to aid in picking the top and base of the main pay and ROZs. The oil saturations estimated for four wells at Noble Field were validated with pulsed-neutron logs, and the depths of the ROZ for 20 wells at Kenner West were validated with oil saturations from core analysis reports. The ROZ well log analyses procedure has been effective for both fields. Preliminary results indicate a ROZ approximately 25-30 feet (~8-9 m) thick at Noble and 30-50 feet (~9-15 m) thick at Kenner West. Residual oil saturation at both fields is around 20-30%. Core flood studies are planned to estimate actual residual oil saturation to water; additionally, new core will be cut to measure residual oil saturation directly. Planned work includes analyzing wells on the basin scale to identify areas that have a high potential to contain a ROZ and mapping the lateral distribution of ROZs within the Illinois Basin.

Oil-source rock correlation studies in the shallow Berea Sandstone, northeastern Kentucky

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Light sweet oil is produced from the Upper Devonian Berea Sandstone in northeastern Kentucky at shallow depths (~2,200 feet and less) where the postulated source rocks (underlying Upper Devonian Ohio Shale and overlying Mississippian Sunbury Shale) appear to be immature for oil generation. To determine if local source rocks were indeed the source of produced oils, geochemical data from source rock bitumen extracts (n=20) and Berea oils (n=6) were compared. Results show Berea oils are of one family and from a similar source rock based on API gravity (35-42), sulfur (0.17-0.21%), SARA fractions (1.2-1.4 sat/arom), *n*-alkane envelopes, C isotopic compositions ($\delta^{13}C$, -30.2 to -30.5‰ whole oil), normal sterane distributions (e.g., 45.3-47.1% C_{29} αααR), correlations between individual sterane and hopane concentrations and similarity in extended hopane concentrations. Berea oils are identical in $\delta^{13}C$ composition to Berea-reservoired crude oils in eastern Ohio, likely originating from the same source rocks, and are dissimilar to oils reservoired in lower Paleozoic eastern Ohio strata. Berea oils and organic matter in the postulated source rocks are from a marine source based on multiple proxies including Pr/Ph (>1) and terrestrial-aquatic (0.06-0.20) ratios, CPI values (~1), *n*-alkane maxima (centered at C_{15-17}), $\delta^{13}C$ compositions, and presence of tricyclic terpanes (from *Tasmanites* and/or bacterial biomass). The data cannot resolve whether the Ohio Shale or Sunbury Shale is the primary source of oils because of similar bitumen extract Pr/*n*-C_{17} and Ph/*n*-C_{18} ratios, sterane distributions, $\delta^{13}C$ values, and sterane/hopane and tricyclic terpane ratios. Sterane isomer ratios and C_{27} (Ts/Ts+Tm) hopanes are poor predictors of thermal maturity in the Berea system when compared to measured R_o values, possibly due to open-system behavior or analytical issues, e.g., co-elution. Sulfurization of organic matter may explain high S (up to 7.5 wt.%) concentrations in some bitumen extracts and suggests generation of low S Berea oils occurred in the mid- to late oil window. R_o equivalent values from the methylphenanthrene index suggest generation of Berea oils occurred at 0.7-0.9% R_o and require updip migration of 5-20 mi at a minimum and 40-50 mi at a maximum, explaining production of shallow light sweet oil in an area of immature source rocks.

Pore types, capillary pressure, and diagenetic controls on reservoir quality in the Upper Devonian Berea Sandstone, Eastern Kentucky

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The Upper Devonian Berea Sandstone is a low-permeability natural gas and oil reservoir in eastern Kentucky. Thin sections of Berea siltstones from five cored wells were examined as part of a larger study of the Berea petroleum system at the Kentucky Geological Survey. Cores span a range of depths, from +4 feet in Johnson County to -2,448 feet in Pike County (sea level datum). This petrographic work documents the pore types and diagenetic controls on reservoir quality in this very fine-grained unit. Though porosity is commonly greater than 10 percent, Berea reservoirs in Lawrence and Johnson counties typically have low-permeability (less than 1 md). Pore types observed include primary intergranular and secondary moldic pores, and microporosity. Intergranular porosity is the most abundant pore type, but secondary porosity is important in the updip areas. These pores are formed by dissolution of framework grains, such as plagioclase, rock fragments, glauconite and carbonate grains. Higher porosity samples have a significant contribution from secondary porosity. Microporosity occurs in partially dissolved framework grains and with clays. Capillary pressure analysis on six core plugs indicates median pore throat diameters of 0.07 to 2 microns. For the highest permeability samples, oil column heights of 100 feet are necessary to achieve oil saturations of 50 percent or greater. Since Berea pay zones are much less than 100 feet thick, down-dip

continuity of the reservoir is needed to generate displacement pressures required for commercial oil saturations. Intergranular and fracture-fill cements that reduce porosity and permeability include quartz overgrowths, ferroan (Fe) dolomite, siderite, pyrite, and kaolinite. Quartz cements predate secondary porosity development and formation of Fe-dolomite, siderite, and pyrite cements. Fe-dolomite replaces grains and fills secondary pores and fractures, indicating its late timing. Siderite occurs in secondary pores, and replaces Fe-dolomite, making it one of the latest events. Berea reservoir samples from the single downdip well in Pike County lack secondary porosity and contain solid bitumen in intergranular pores. Though the well currently produces gas, the presence of bitumen indicates prior oil saturation. Since framework grain composition between the updip and downdip areas appears to be similar, differences in diagenesis likely reflect different burial and fluid flow histories.

Optimizing Perforations

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The principal of perforation gun technology has not undergone vast modifications since its introduction to the petroleum industry. Perforation geometrical parameters such as shot size, shape, approach angle, and drilled angle influence the fluid pressure regime around the perforations. Three aspects of unconventional reservoirs can be optimized for robust well performance: production, hydraulic fracturing, and proppant migration. To optimize production, the near-bore pressure losses must be minimized. Most of the pressure losses are because of perforations and tortuosity. We model the reservoir pressure with losses vs. flow rate using nodal analysis (IHS Harmony Software) and decline curve analysis for a single well model (EXCEL); flowrate and ultimate recovery factor are significantly improved with minimizing pressure losses. Changing the shape of perforations also affects the hydraulic fracturing process. Our computer simulation using ANSYS software for a homogenous media with eight perforations, using laminar and turbulent models shows that if the circle was changed to an oval, during injection, high stress regimes would occur at the ends, in effect causing fractures to propagate from the ends. The use of fracturing ballistics gel experiment also shows a correlation between perforation shape and fracture width, length, and height. For a vertically drilled well, if the long axis of the oval is vertical, fractures show improved height gain. If the oval long axis is horizontal, fractures show width gain. We also evaluated the flow streamline for two models: the first model has an oblique shot penetration angle, while the other model has straightly penetrated shots. As the penetration angle becomes more oblique, pressure losses are seen to decrease. In conclusion, if parameters of a perforations are changed it is possible to optimize a specific well to the developer’s desires.

Volumetric and 3-D property modeling of the Grand Tower Formation in the Salem Field, Southern Illinois

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Since its discovery in 1938, Salem Field, in south-central Illinois, has produced over 400 million barrels of oil from Mississippian and Devonian reservoirs. The main producing intervals of the Devonian Grand Tower Formation are dolomitized carbonates with vuggy and intercrystalline porosities. To date, over 1,100 wells have been drilled and completed in the formation covering an area of 19,000 acres. From 1938 to 1940, initial productions from these wells reached a producing rate of approximately 2,030 barrels of oil per day. However, the rates declined to less than 31 barrels of oil per day for those wells completed between 2010 through 2014. This study generated detailed 3-D geocellular models to characterize porosity and water saturation trends, estimate original hydrocarbon in place and to identify potential areas for future enhanced oil recovery (EOR) projects. Wireline logs, including gamma ray, porosity, photoelectric, density and resistivity logs, were used to delineate 2-D and 3-D structural and stratigraphic framework of the reservoir. The 3-D structural framework was divided into 4 distinct zones, 28 vertical layers, and

450,000 cells. The porosity and water saturation data were calculated from wireline logs and populated stochastically within the 3-D grids, using Sequential Indicator Simulation (SIS) and Sequential Gaussian Simulation (SGS) algorithms. Examination of property models revealed that the main hydrocarbon bearing intervals consist of dolomite and dolomitic limestone in the middle parts of the formation with a range of 10 to 25% porosity. The average net pay thickness of reservoir is about 60ft (18m) in northern parts of the field, decreasing southward to around 30ft (9m) due to the presence of thin and dense limestone intervals, interbedded with porous dolomite intervals. The volumetric and uncertainty analysis indicates that the stock tank original oil in place (STOOIP) of the Grand Tower Formation in the field is approximately 218 million barrels of oil. This research suggests that there are significant oil reserves still to be recovered. The 3-D models in this study can be used for locating potential sites for water flooding and EOR.

TOC estimation of the New Albany Shale Group and Maquoketa Shale-Using ∆logR Evaluation Technique, Southern Illinois

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Accurate quantification of the total organic carbon (TOC) content of source rocks is a crucial parameter in the evaluation of organic-rich unconventional reservoirs. Organofacies in source intervals can vary dramatically in a lateral and vertical sense. Petrophysical data provide an avenue to map these changes without relying on expensive lab analyses. In mature basins, the vast majority of petrophysical data is determined from older logging suites. The ∆logR technique developed by Passey, et al., 1990, allows the use of these data in mapping reliable TOC estimates. For this study, eight wells were selected to compare core-derived TOC data with those computed from the ∆logR technique in southern Illinois. Shale intervals within the New Albany Shale Group (Devonian to lower Mississippian) and Maquoketa (Ordovician) were analyzed. The ∆logR technique relies on the density difference of organic carbon (0.9-1.05g/cc) and mineral matrix (2.65-2.71 g/cc) that porosity logs (sonic, density, or neutron) measure. This requires the overlaying of a sonic, density, or neutron curve in arithmetic scale on a deep resistivity curve on logarithmic scale. Baseline is determined in a shale interval with low organic content. Once baseline is established, the separation between the porosity and resistivity curves can be calibrated over intervals with higher organic content. This calibration requires an estimation of the level of organic metamorphism (LOM) or how far density or transit time deviates from that of barren rock at the same state of compaction. Level of organic metamorphism (LOM) was calculated by using cross plots of measured TOCs from analyses vs ∆logR, and by vitrinite reflectance (R_o) data determined from nearby wells. Results computed from the ∆logR method indicate a range of values between 2 to 9% TOC for the New Albany Shale Group and 0.5 to 3.2% TOC for the Maquoketa Shale. More importantly, the TOC values computed from the ∆logR method compare reasonably well with values determined from sample analyses. The ∆logR technique for these intervals gives satisfactory results with a range of 0.8 to 1.36% TOC standard deviation. Problems arise in correlating laboratory and log data when there are depth matching errors between logs and core and digitized petrophysical curves are of poor quality. In summary, ∆logR technique can provide reasonable TOC estimate for shale intervals within the Illinois Basin.

Delineating Compressional Structures Through Refined Geosteering Methods

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Horizontal gas development wells drilled in the Marcellus Formation in Susquehanna County, Pennsylvania encountered tight fold structures, as detected through geosteering. However, compared to fold analogues in outcrop and in laboratory settings, the geosteering interpretations generated from existing methods depicted these sub-surface structures with varying accuracy. To more acutely determine the cross-sectional profile of these geologic structures, I developed a method whereby an algorithm is used to project and extrapolate the existing geosteering data into a valid 2-dimensional cross-section.

Using this new method, I have determined that Devonian strata in the Appalachian Basin have an overlying detachment in the Upper Marcellus Member and an underlying detachment in the Esopus Formation. These detachments are bedding-parallel faults that periodically cut up-section to form fault propagation folds. 3rd and 4th order folds (wavelengths and amplitudes of tens of feet) are disharmonically contained within 1st and 2nd order folds (wavelengths of ½-mile or greater). In each case, conjugate chevron folds dominate the structures observed, indicating that shortening did not exceed 30%, in any case.

3-dimensional formation surface maps were constructed from the projected and extrapolated 2-dimensional cross-sections. These surface maps reveal, in more detail, the structural complexity that is not resolvable through basic seismic imaging. This enhanced view of the subsurface will greatly increase the effectiveness of horizontal drilling programs by being able to construct more accurate directional drilling plans, as well as anticipate changes in geologic structure in order to keep each horizontal wellbore within the optimal zone of production.

A Parametric Analysis of Carbon Dioxide Sequestration Potential in Depleted Marcellus Shale Gas Reservoirs

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An investigation involving four different project design parameters that are horizontal wellbore length, stimulated reservoir volume (SRV) fracture permeability, SRV fracture porosity, and SRV fracture spacing was carried out using the in-house PSU-SHALECOMP model, which is a compositional dual porosity, dual-permeability, multiphase reservoir simulator. The simulator treats the shale gas formation as a dual-porosity, dual-permeability system with micropore and macropore structures representing the shale matrix and natural fracture network, respectively. Furthermore, the model is capable of investigating the effects of water present in the micropore structure as well as the effects of matrix shrinkage and swelling as a consequence of the carbon dioxide injection and production operations. In the numerical experiments considered, primarily rock and fluid properties and reservoir conditions representative of a Marcellus shale scenario were utilized as the basis to examine potential production rates of methane and cumulative methane production capacities. Horizontal well configurations together with the implementation of a computationally inexpensive SRV model with the ability to generate similar behavior to that of an equivalent discrete fracture network model have been instrumental in the analysis. Carefully designed numerical experiments show that as the wellbore length gets shorter, bottom hole pressure constraint is reached in a much shorter period of time. The carbon dioxide injection rates are increased in longer wellbores enabling the injection of carbon dioxide more effectively as the reservoir contact area increases. It is also observed that it is essential to obtain higher fracture permeabilities within the SRV zone to be able to effectively produce methane during the depletion period and to inject carbon dioxide. In the investigation of the SRV fracture porosity, it is shown that SRV fracture porosity values have a pronounced effect on bottom hole pressure, which may lead to longer injection periods. In the last part of the parametric study, it is presented that as the SRV fracture spacing value becomes smaller more carbon dioxide can be adsorbed by the shale matrix, since the surface area and hence the adsorption sites in the stimulated reservoir volume zone are increased because of hydraulic fracturing operations.

Numerical Validation of Stimulated Reservoir Volume Approach in Shale Reservoirs by using a Compositional, Dual-porosity, Dual-permeability, Multiphase Reservoir Simulator

Burak Kulga and Turgay Ertekin, The Pennsylvania State University

Most existing unconventional gas reservoir simulators often treat shale gas reservoirs as dual-porosity, single-permeability flow systems with no water saturation and with no permeability in the micropore (matrix) structure. The PSU-SHALECOMP, is a compositional dual-porosity, dual-permeability, multi-phase reservoir simulator, which also incorporates the effects of water presence in the micropore structure and those of matrix shrinkage and swelling. In PSU-SHALECOMP, shale gas reservoir is treated as a dual-porosity, dual-permeability

system consisting of shale matrix and fracture network allowing realistic natural fracture spacing characteristics. In the simulator, computations on the partial adsorption capacity of gas components are based on the thermodynamic equilibrium between gas components in the free and adsorbed phases following the ideal adsorbed solution model using an analogy to vapor-liquid-equilibria calculations. Apart from the aforementioned capabilities of PSU-SHALECOMP, the concept of stimulated reservoir volume (SRV) approach is introduced to the numerical models. The SRV is approximated by modifying the values of fracture spacing, fracture permeability and fracture porosity where the hydraulic fractures exist. In the validation phase of the simulator, rock and fluid properties and reservoir conditions of Marcellus Shale gas reservoir were used with the implementation of a computationally inexpensive SRV model, which has the ability to generate similar behavior in terms of production performances to that of an equivalent discrete fracture network model. The results were also compared with a series of normalized field production data that is obtained from existing Marcellus Shale wells, and it is shown that the PSU-SHALECOMP simulator with the implementation of SRV model is capable of matching the historical data very efficiently and rapidly.

Origin of Non-Hydrocarbon Gases in Petroleum Reservoirs – A Review

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Natural gas in the Earth's crust typically contains 70 to 100% methane, 1 to 10% ethane, lesser amounts of propane through hexane, and traces of higher hydrocarbons. Nitrogen (N_2), carbon dioxide (CO_2), and hydrogen sulfide (H_2S) vary from traces to 100%. Non-hydrocarbons impact the economic value of produced gas by diluting the BTU value of the hydrocarbons. CO_2 and H_2S pose operational problems for field infrastructure. H_2S is a serious threat to human health. Noble gases occur in trace to minute amounts in reservoirs. More than 0.3% helium increases the economic value of a gas accumulation. Noble gases provide precise information on the origin and movement of sedimentary fluids because the isotopic composition of noble gases uniquely indicates the origin of fluids in which they are dissolved, or the physical processes of migration and mixing of these fluids.

Sources of N_2 in petroleum reservoirs include the atmosphere (air contamination and evaporites), magma (mantle outgassing), oxidation of kerogen-derived ammonia in pore waters, and high-temperature release from inorganic fixed ammonium in potassium-rich silicates. N_2 stable isotope ($\delta^{15}N$) data cannot be used to quantify the contributions of different N_2 sources in subsurface fluids because of uncertainty in the isotopic range of various end members and the overlapping range of $\delta^{15}N$ for respective nitrogen end members. The combined use of $\delta^{15}N$ and noble gas systematics, however, effectively facilitates the interpretation of N_2 sources in petroleum reservoirs.

Sources of CO_2 in petroleum reservoirs include sedimentary organic matter and organic acids, microbial degradation or oxidation of hydrocarbons, thermochemical sulfate reduction (TSR), inorganic dissolution of carbonates, and magma. Variations in the stable carbon isotope composition ($\delta^{13}C$) of CO_2 and hydrocarbons might be diagnostic of gas origins, but the $\delta^{13}CO_2$ of high-CO_2 reservoirs often falls within the overlapping range of carbonate breakdown and magmatic degassing making it difficult to distinguish between these sources. The high solubility of CO_2 in water, and its high reactivity, complicates the interpretation of CO_2 sources because the extent of gas phase interaction with formation water is a critical parameter in determining CO_2 sinks. The integration of noble gas systematics can be used to constrain CO_2 sources and interaction with formation waters.

H_2S can be generated in the subsurface by bacterial sulfate reduction, thermal cracking of sulfur-rich organic matter or sulfur-rich oil, TSR, and hydrolysis of metal sulfides in highly acidic reservoirs. In addition, there are several operational H_2S generation mechanisms related to well completion methods. Combined use of sulfur and carbon isotope systematics, produced water chemistry, reservoir petrology, and seismic data are necessary to correctly determine the source of H_2S in petroleum reservoirs.

Importance of Basin Tectonics in Alleviating Uncertainty in Carbon Storage Projects

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Carbon Capture and Storage (CCS) is on a cusp of moving from small volume CO_2 injection test sites to large-scale commercial projects. The increased rate of injection will raise both the reservoir pressure and the volumetric (lateral and vertical) extent of the plume. A combined regional and site-specific approach to geologic characterization will be necessary to understand the uncertainty and potential risks, including microseismicity, involved with any injection program. The Cambrian Mt. Simon Sandstone is one of the most important formations for CO_2 storage in the Continental United States. The sediments of the lower Mt. Simon were deposited in a Precambrian failed rift basin that formed during the breakup of the supercontinent of Rodinia in what is now the Illinois Basin. This rifting event accommodated deposition of over 2,600 feet (792 m) thick Mt. Simon siliciclastic sediments. Examination of 2D and 3D seismic data integrated with well and log data are leading to better understanding of the geologic risks for CCS. In the Illinois Basin, these data suggest that accommodation of Mt Simon sediments was accompanied by contemporaneous faulting in the lowermost Mt. Simon and Precambrian rocks. The preservation and architecture of Mt. Simon reservoir rocks may, in some areas, be controlled by Precambrian topography that was formed by faulting and by erosion into the underlying rhyolite basement. One million tonnes of CO_2 have been injected into the Mt. Simon Sandstone at the Illinois Basin - Decatur Project (IBDP). Continuous seismic monitoring before, during, and after injection, shows that microseismicity increased during injection, tends to occur in spatial clusters, and occurs not only in the Mt. Simon, but also in underlying (Argenta) clastics and Precambrian igneous rocks. The 3D seismic data at this area suggest that much of the microseismicity is proximal to interpreted faults that extend from the basement up into the lowermost Mt. Simon strata. The faults near clusters of microseismic activity are critically oriented with respect to the maximum stress direction. Addressing uncertainty around the potential for microseismic activity associated with commercial-scale CCS requires not only identification of a suitable reservoir and its petrophysical characteristics, but also the extent and orientation of existing local faults and their relation to regional stress orientation.

The Prediction of Orthorhombic Differential Horizontal Stress Ratio for Shale Reservoir

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The effective prediction of in-situ stress plays an important role in the exploration and development of shale reservoirs. The differential ratio of the maximum and minimum horizontal stresses (DHSR) is one of the important parameters for prediction of hydraulic fracture. Here we present a new equation which is derived for expressing the differential ratio of the maximum and minimum horizontal stresses in orthorhombic anisotropic media. Apart from that, the new approach based on azimuthal anisotropic elastic impedance inversion is proposed to evaluate Orthorhombic Differential Horizontal Stress Ratio (named as ODHSR) robustly. In this paper, we considered the effects of vertical anisotropy and horizontal anisotropy on shale reservoirs. According to the linear slip theory of Schoenberg and Sayers, the compliance matrix of orthorhombic anisotropic media can be simplified to the sum of the background compliance matrix and the excess compliance matrix. The background media is vertical transverse isotropy (VTI) or some lower symmetry. Incorporating the generalized form of Hooke's law, we derived the equation of principal stresses and Orthorhombic Differential Horizontal Stress Ratio. This equation establishes the relationship between seismic data and anisotropy parameters together with elastic parameters like S-wave velocity and density. With this equation, we estimate the stress indicator (ODHSR) with S-wave velocity, density, and normal fracture compliance and anisotropy parameters. These parameters are derived from azimuthal-angle stack seismic gathers by azimuthal anisotropic elastic impedance (EI) inversion. One field case study from a shale reservoir in the east of China is used to validate the application of azimuthal anisotropic elastic impedance inversion for

ODHSR. Amplitude-preserved processing procedure has been implemented before inversion of the full azimuth real data. Subsequently, the six azimuthal-angle stack seismic gathers are used to obtain the inverted results of azimuthal anisotropic elastic impedance. The elastic parameters and anisotropy parameters for ODHSR are estimated from the inverted results of azimuthal anisotropic elastic impedance. It is seen that the ODHSR shows anomalously low value at well location obviously. Compared with the conventional inversion results, we can conclude that the proposed method can improve the accuracy in the prediction of optimal zones for hydraulic fracturing.

Kentucky oil history: the approaching 200th anniversary of the Beatty well

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Kentucky's petroleum industry began with exploration and development of brines and salt. The importance of these resources is reflected both in the abundance of Kentucky place names such as Oil Springs and Salt River and in the resources' continued protection. This usually forgotten history tells the tale of emerging resources and technology development before 1859 when Col. Drake drilled his well in Pennsylvania' often recognized as the birth of the modern oil industry. In 1806, the Ruffner brothers invented surface casing, tubing, and packers in their quest for salt water near Charleston, W.Va., and demonstrated that brines could be produced by drilling. In 1807, John Francis discovered salt water on Richard Slavey's homestead at the confluence of Bear Creek with the South Fork of the Cumberland River, McCreary County, Ky. In 1811, Francis and Slavey petitioned the Commonwealth and received a grant of 1,000 acres on the condition that they produce 1,000 bushels of salt, which they accomplished before 1818. Around this time, Martin Beatty was operating an iron furnace at Cumberland Gap and very likely heard of the successes of Slavey and Francis. He crossed the gap into Kentucky and acquired 1,000 acres from Francis to establish his own salt works. He contracted with Marcus Huling and Andrew Zimmerman to sink a well near the mouth of what is now Oil Well Branch along the South Fork. Sometime before Dec. 4, 1818, at a depth of about 170 feet, the well began flowing up to 100 barrels of oil per day, becoming the "Father of American Flowing Wells." The oil having ruined the salt water, Beatty abandoned the well, established a salt works downstream, and pursued a career in politics. Huling and Zimmerman, however, contracted with Beatty to construct wooden barrels and with local fishermen to take petroleum downriver by boat. After two disastrous attempts, a longer overland route was found and the oil was sold to local merchants, who in turn sold it to the manufacturers of medicinal preparations. In an 1820 letter, Huling indicated he had sent about 2,000 gallons of the oil to Europe, but had not yet made any money. Many tales are told of this well: rivers on fire, a fugitive murderer, and ruined goose feathers. The well was finally plugged Oct. 18, 2011, by the U.S. Forest Service. By virtue of sales and international speculation, the Beatty well is thus not only one of the earliest oil producers, but one of the first commercial oil wells in North America.

Quantitative characterization of fracture frequency variations using a linear piecewise regression analysis and the Akaike Information Criterion

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We present a new quantitative approach for characterizing fracture frequency variations using a linear piecewise regression (LPR) analysis and the Akaike Information Criterion (AIC). Break points calculated for the LPRs produce linear segments with varying slopes for a cumulative fracture frequency (CFF) curve. An AIC value is calculated for each LPR model in order to determine the optimal number of linear segments that fit the CFF data. The optimal number of segments is obtained by minimizing the AIC value for a single dataset. Results from the statistical analysis produced three CFF slope intervals that define the distribution of possible fracture frequencies unique to the geologic setting from which they were derived. A total of 3678 fracture and vein measurements were collected using scanline, scangrid, and abbreviated methods at 38 sites in the Utica black shale and overlying coarser clastics of the Mohawk Valley in eastern New York State. To produce a CFF curve, fracture frequency is summed along a transect perpendicular to the strike of the fracture set. The piecewise function in the R package, "Segmented" calculates break points where the slope of the CFF changes. The AIC model selection method produces LPRs with the optimal number of breakpoints and segments by penalizing additional parameters introduced with each new segment. A comparison with the Bayesian Information Criterion (BIC) found that AIC models outperformed the BIC method because the BIC equation over-penalized additional parameters. Segmenting the CFFs produced three unique slope intervals, each with a set of defining characteristics. Background frequencies are defined by an average CFF slope of 8 with no significant changes in slope (including prominent frequency peaks). The average background fracture frequency is 2.4 fractures/m. Transition frequencies exhibit higher CFF slopes, averaging 111, and higher average fracture frequency of 12.3 fractures/m. Fracture intensification domains (including fractures in fault damage zones) are defined by the highest average CFF slope of 1649, produce prominent frequency peaks (>50 fractures/m) and have the highest average fracture frequency of 44.6 fractures/m. Results of the piecewise analysis provide quantified boundaries that can be used to create a fracture frequency framework for a defined geologic setting, aiding in predictions of fracture frequency variations due to local structural features.

Structural and Crustal Evolution of the Pre-Mt. Simon below West-Central Indiana: Evidence from Seismic Reflection

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Two distinct seismic reflection sequences below west-central Indiana provide insight to the poorly understood evolution of the eastern U.S. midcontinent basement. The uppermost sequence, termed here the Wilbur, is composed of weak, discontinuous reflections and thins westward. Internal reflections of the Wilbur parallel those of the underlying sequence termed here the Quincy sequence which continues to at least the base of the seismic record at 2 s TWT. This deeper Quincy sequence is composed of high-amplitude, stratified reflections and shallows westward. Stratigraphic (lapouts) and structural (undulating reflections, doming) complexities typify this deeper unit. These sequences may be regional patterns and yield new interpretations of pre-Mt. Simon geology. Weak reflectivity is also characteristic of the Middle Run Formation, a pre-Mt. Simon lithic arenite, below southwest Ohio (Shrake et al., 1991), which overlies and is apparently concordant with a high-amplitude layered sequence of unknown lithology. In southwestern Indiana and southern Illinois, COCORP data revealed the Centralia sequence (Pratt et al., 1992), thought to represent layered volcanics/clastics/sills of the Eastern Granite-Rhyolite Province (EGRP). The paucity of deep wells across the region, however, still leaves major questions regarding the overall composition and regional distribution of pre-Mt. Simon rocks. These data suggest two plausible geologic scenarios: (1) Similar weak reflectivity of both the Middle Run and the Wilbur sequence, which both overlie very reflective layered sequences, may indicate regional correlation of these pairs of sequences. This model suggests that pre-Mt. Simon structure was initiated by Grenvillian compression, as new detrital zircon (Moecher et al., 2017) and seismic (Peterman, 2016) research suggest that the Middle Run (~1.03 Ga) pre-dates the Grenville Front compressional event (~0.99 Ga). Regional extent of the Middle Run is favorable of a foreland basin tectonic and depositional environment. (2) The Wilbur and Quincy sequences of west-central Indiana may pre-date the Middle Run entirely and instead be older, sedimentary and/or volcanic units associated with the EGRP. Doming of the Wilber and Quincy sequences may then be attributed to late magmatism associated with the EGRP, the Southern Granite-Rhyolite Province magmatism (1.40-1.34 Ga) and/or the emplacement of 1.27 Ga intrusive suites into the midcontinent basement (Bickford et al., 2015).

Meso- and Macro-Scale Facies and Chemostratigraphic Analysis of Middle Devonian Marcellus Shale in Northern West Virginia, USA

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Marcellus Shale Energy and Environmental Laboratory (MSEEL) consists of four produced horizontal wells and two vertical pilot wells. In order to gain a detailed understanding of the Middle Devonian Marcellus Shale and surrounding Upper Devonian shale intervals, we focused on the two vertical pilot wells (MIP-3H and MIP-4H). Understanding the vertical and lateral distribution of the shale lithofacies and changes in chemostratigraphy are critical to understanding the impact of depositional and diagenetic environments on hydrocarbon generation and production. Integrated geological and petrophysical characterization of the Marcellus and adjacent Onondaga through Mahantango units was performed using core and well log data. Macro-scale lithofacies were determined through a combination of core and CT-scan descriptions. Meso-scale shale lithofacies based on mineralogy and total organic content were developed using a combination of triple combo and advanced logging tools and calibrated to core data (XRD and source-rock pyrolysis). Chemostratigraphic analysis utilizes x-ray fluorescence to determine the major and trace-element trends associated within the Devonian Marcellus-Mahantango interval. Devonian Marcellus-Mahantango interval is composed of six shale lithofacies both at the meso- and macro-scale. Petrophysical analysis shows three well developed organic mudstone facies are present in the Marcellus interval. Chemostratigraphic (trace element concentrations) and petrophysical data (spectral gamma derived uranium content) indicate the highly organic mudstone (TOC > 6.5 weight percent) facies in the lowest part of the Marcellus Shale were deposited in a highly anoxic environment compared to overlying units, and the decreased detrital influence indicated by silicon, aluminum, and titanium trends, allowed for better preservation of organic matter.

Molecular and Isotopic Composition of Associated and Nonassociated Gases and Evolution of Gas in the Berea Sandstone, Eastern Kentucky

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The molecular and isotopic composition of natural gas samples from the Upper Devonian Berea Sandstone and Ohio Shale were analyzed to understand the origin of gas produced from the Berea Sandstone in eastern Kentucky. The gas analysis was part of a broader geochemical investigation into the Berea petroleum system by a public-private consortium in 2015 and 2016. Gas samples were collected along a north-to-south transect extending 85 miles from southern Ohio to southeastern Kentucky, and included six associated gas samples (OAG) from Berea oil wells in the northern updip (-260 to -1,191 feet) part of the play and two nonassociated gas samples (NAG) from the Ohio Shale in southern downdip (-1,831 to -4,964 feet) locations.

In the context of a Schoell plot, all samples are thermogenic oil-associated gas, and are wet gases with methane/(ethane + propane) ratios ranging from 1.9 to 7.9. Compared to the shallower OAG samples, the isotopic composition of CH_4 for the deeper NAG samples is more enriched in ^{13}C and ^{2}H, reflecting increased thermal maturity. When plotted versus depth, the isotopic composition for CH_4 becomes more positive and gas dryness increases for most samples.

The $\delta^{13}C$ values for methane (C1), ethane (C2), propane (C3), and n-butane (C4), measured on three OAG and two NAG samples, show progressive enrichment in ^{13}C with progressively higher molecular weight. When plotted versus the inverse carbon number, the $\delta^{13}C$ values define two populations in which all the OAG and shallowest NAG samples define a trend depleted in ^{13}C for C1-C4 compared to the deepest NAG sample. For the isotopically depleted population, the $\delta^{13}C$ composition of n-butane (-33.7 to -34.4‰) is 2 to 3‰ more negative compared to bitumen extracts (-29.1 to -30.9‰) measured in this study, which are interpreted to be possible sources for Berea oil and gas. Though separated by about 50 miles, similarity among the four isotopically depleted samples suggests that gas in these wells was generated from a similar source and under similar thermal-maturity conditions. Located 25 miles south of the shallower NAG sample, the deepest NAG sample is enriched in ^{13}C by 4 to 7‰ among the gas components and the $\delta^{13}C$ composition for n-butane is more enriched in ^{13}C (-26.7‰) than extract values in this study and other published values for kerogen in the area. The enrichment suggests that this deeper gas was generated from cracking of kerogen, bitumen, or oil under higher thermal-maturity conditions.

Geoscience evolution: extensive data integration for real time geosteering and modeling in unconventional reservoirs

Vlad Karen Payrazyan, Igor Kuvaev, Igor Uvarov, and Julian Stahl, ROGII, Inc

Over the past 5-7 years, effective and low-cost geosteering technologies became a game changer for unconventional development in North America, allowing thousands of oil and gas companies to stay profitable during the ongoing economic downturn.

Modern geoscience and geosteering technologies indicate an increasing focus on IT and software, rather than downhole hardware tools. IT technologies have advanced enormously over the past 8-10 years, but these capabilities are not yet fully endorsed by oil and gas industry. Modern computing power, low cost storage facilities, super-efficient algorithms, big data analysis, artificial intelligence and cloud collaborative technologies will eventually completely transform the current practices. This will lead to a new way of how we model reservoirs, geosteer wells, integrate data and communicate with each other. But this process is an evolution, rather than a revolution, due to a fact that the oil and gas industry is conservative and adapts slowly to new technical and economical trends and realities.

Knowing the true stratigraphic position of a well trajectory, constantly and proactively monitoring this position and adjusting as needed in real time while drilling - represent a significant breakthrough in keeping the well in the best target zones no matter how thin those are. However, this is just the beginning. The next step in **geoscience technology** is to be able to integrate massive amounts of available data, such as previously drilled wells, production history, various types of logs, cores, seismic, maps, correlations, regional geological trends, etc. Connect this with the modern **IT capabilities** and you get geoscience to be real time, high resolution, fully collaborative, intelligent and automatic.

Lithostratigraphy of Middle and Upper Devonian Organic-Rich Shales in West Virginia

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[2] National Energy Technology Laboratory

Middle and Upper Devonian organic-rich shale formations in West Virginia include significant oil and gas source rocks and reservoirs. Formal lithostratigraphy for these units is well established in the southern and eastern portions of the state, but is typically less well-defined in the northern and central areas where the units occur deep in the subsurface and where resource development is currently concentrated. Historically, subsurface lithostratigraphic terminology has been assigned by reference to units defined in outcrops along the basin margins and extended into the state through correlation of well log information. However, terminology emanating from the more distal northern (western New York) and western (Ohio and Kentucky) basin margins is not always readily reconciled with terminology established in more proximal outcrops along the Allegheny Front and extended westward. As a result, the geographic distribution and lithostratigraphic nomenclature for many of these units remains unsettled in the basin center. In this study, correlation of log data from approximately 400 wells throughout West Virginia enables detailed mapping of Middle and Upper Devonian organic-rich facies, allowing the determination of vertical and lateral lithostratigraphic unit boundaries throughout the West Virginia subsurface. Recommendations for nomenclature are based on precedence and utility. Units described and mapped include: 1) the Middle Devonian Hamilton Group and its constituent Mahantango and Marcellus formations; 2) the Tully Limestone; 3) the Burket Shale Member of the Harrell Shale and its lateral equivalent Geneseo Member of the Genesee Formation; and 4) the extent of the Upper Devonian Genesee, Sonyea, West Falls, and Java formations (as well as the lower part of the Huron Member of the Ohio Shale) and the position of their lateral eastward boundary with the age-equivalent Brallier Formation.

Marcellus, Utica/Point Pleasant provide 91% of U.S. shale gas production growth since start of 2012

Olga Popova, Gary Long, Jeffrey Little, Christopher Peterson, Neal Davis, Emily Geary, Andrei Butterfield, Steven Grape, Elizabeth Panarelli, April Volke and Barbara Mariner-Volpe, U.S. DOE EIA

The productivity of natural gas wells in the Marcellus and Utica/ Point Pleasant is steadily increasing because of ongoing improvements in precision and efficiency of horizontal drilling and hydraulic fracturing occurring in the Appalachian region. Since January 2012, natural gas production from the Marcellus and Utica/ Point Pleasant has accounted for 91% of the increase in natural gas production from low permeability formations reported in EIA's Drilling Productivity Report (DPR). The DPR provides a month-ahead projection of both oil and natural gas production for the seven most significant shale formations in the United States. The DPR identifies trends in total production and rig productivity, expressed as new-well gas production per rig. The May 2017 edition of the DPR noted that average new-well gas production per rig in the Marcellus play was 3.2 million cubic feet of natural gas per day (MMcf/d) in January 2012. In June 2017, new-well gas production per rig increased to 13.4 MMcf/d. This trend corresponded with an overall increase in the amount of natural gas produced in the Marcellus play during the same period. The DPR also indicates that the Marcellus play produced an estimated 6.3 billion cubic feet of natural gas per day (Bcf/d) in January 2012, increasing to 19.2 Bcf/d in June 2017. The Utica play also experienced significant gains in rig productivity and production. In January 2012, new-well gas production per rig in the Utica play averaged 0.31 MMcf/d. June 2017 new-well gas production per rig is 10.6 MMcf/d. The DPR also indicates that the play's total natural gas production increased rapidly over the same period: production in June 2017 was almost 30 times higher than in January 2013 (4.4 Bcf/d and 0.15 Bcf/d, respectively). Increases in natural gas production from the Appalachian region occurred because of many factors, including: greater use of advanced drilling techniques; increased number of stages used in hydraulic fracturing operations; increased use of techniques such as zipper fracturing; and use of specific components during well completion. EIA's latest data show that natural gas produced from U.S. shale formations now accounts for 62% of total U.S. dry natural gas production. Collectively, shale gas production from the Marcellus and Utica plays increased by 17.1 Bcf/d from January 2012 to June 2017, making the Appalachian region the driving force behind overall U.S. natural gas production growth.

Pine Hall Formation: Type section designated – Dan River basin, Stokes Co., North Carolina

Jeffrey C. Reid, Katherine J. Marciniak, Walter T. Haven, and Kenneth B. Taylor, North Carolina Geological Survey (NCGS)

The Late Triassic (Norian) Dan River basin, is a continuous gas assessment unit (AU). The rift-lacustrine basin, formed from the opening of the Atlantic Ocean, basin is filled with Triassic strata divided into five formations that in ascending stratigraphic order are: 1) the Pine Hall, 2) Walnut Cove, 3) Dry Fork, 4) Cow Branch and 5) Stoneville formations.

The NCGS' 2015 "Town of Walnut Cove" (SO-C-01-15) was continuously cored to a depth of 1,477 feet ending in metamorphic basement rocks (Reid and others, 2015). The core hole investigated the basin's unconventional hydrocarbon resource potential, apparently cored all the Pine Hall Fm., and afforded the opportunity to designate its type section.

We designated the Pine Hall Fm. type section from a depth of 423.7 feet to 1,451.2 feet, including a basal pebble conglomerate from a depth of 1,414.5 feet to 1,451.2 feet immediately above the unconformable Paleozoic metamorphic basement contact. Most of the Pine Hall Fm. consists of recurring fining upward "packages" of gray, medium- to coarse-grained sandstone (frequently calcareous) deposited as 4-6-inch high foreset cross bed packages (~1-10 feet-thick) capped by either red siltstone, or gray- to black, organic-rich siltstone or mudstone with diverse pedogenic features. Moderate porosity and permeability suggests the Pine Hall Fm. as a potential reservoir for continuous hydrocarbon accumulations. The shale and siltstone beds that are interbedded with coarser-grained strata may act as effective seals.

Previous workers did not designate a type section due to lack of stratigraphically informative, continuous sections. Olsen and others (2015) designated a lectostratotype from 573.0-806.2 feet core depth in nearby core hole SO-C-02-81, where it consists primarily of red clastic rocks with abundant carbonate nodules and mottled strata of pedogenic origin.

Olsen, Paul E.; Reid, Jeffrey C.; Taylor, Kenneth B.; Kent, Dennis V.; and Whiteside, Jessica H., 2015, Revised stratigraphy of Triassic age strata of the Dan River basin (Virginia and North Carolina, USA) based on drill core and outcrop data: *Southeastern Geology*, v. 51, No. 1, March 2015, p. 1-31.

Reid, Jeffrey C.; Taylor, Kenneth, B.; Marciniak, Katherine J.; Haven, Walter T.; Channell, Ryan A.; and Warner, Chandler I., 2015, North Carolina Geological Survey Open-File Report 2015-06: Dan River basin stratigraphic core hole 'Town of Walnut Cove' (SO-C-1-15), Stokes County, North Carolina: Prelim. results, 24 p.

Geological model and Natural fracture characteristics in carbonate rocks gas reservoir constrained by multi-factors as an example of HT area fractures

Qiqiang Ren, Jin Qiang and Feng Jianwei, China University of Petroleum

Geological model and natural fracture characteristics in carbonate rocks gas reservoir constrained by multi-factors play a significant role in gas exploration and exploitation. Based on seismic, geological, logging and thin sections data, we discussed the fracture formation mechanism and re-characterized the core fractures in HT area. The formation periods of fracture were inferred by means of balanced cross-section technique and fluid inclusions tests, so that we can establish geological model for fractures. Then the relationships between the fracture parameters and tectonics, lithology, physical properties, interlayer frequencies, filling degree were analyzed in detail, and the main controlling factors for distribution of fracture parameters were concluded and optimized. Combined with the principle of ancient tectonic restoration and structural physical simulation test, the distribution of carbonate reservoir fractures was predicted through fold principal curvature method, fractal theory and fracture mechanics simulation method. The result indicated that the structural fractures are dominated in HT area and make up a great proportion in the west. High angle fractures (60°-90°) are well-developed in the west, while low angle (0-30°) fractures in the east. Filling degree decreased from west to east with full-filling in the west and half-filling in the east. The development of fractures was divided into three stages: late Caledonian (calcite, mud full-fulling, mainly invalid fractures), late Hercynian (high angle fractures, half-fulling and full-filling) and Himalayan (high angle fractures, open, half-filling and un-filling). Based on finite element numerical simulation and superposition of fractures, present fractures were mainly influenced by Himalayan movement and corresponding with Himalayan fractures. Structural fractures were mainly developed in well X8 and X2, and the degree of fracture development reduced from west to east. The connectivity between well X5 and X401 was poorer in the lateral, and better between well X401 and X4. The development characteristics of single well vertical fractures were researched through finite element and discrete element numerical simulation. Fractures were not developed in thick mudstone, while it was well developed in cross layer of sand-mudstone and marlite-limestone. Reticular fractures were well developed in thick limestone, and performed a well connectivity. Only faults can penetrate the interlayers, while fractures cannot.

Assessing Unconventional Resource Potential of Lower Cretaceous Carbonates in the South Florida Basin, USA

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The South Florida Basin incorporates southernmost Florida, including the Keys and eastern Gulf of Mexico. It is a relatively simple SW dipping structural basin with predominantly Cretaceous sediments. In this study, the two main unconventional exploration targets are the L. Sunniland Fm. and Pumpkin Bay Fm. The Sunniland is composed of mixed organic-rich/lean limestone and dolomites; shales are scarce to absent. Most conventional oil is found in carbonate reservoirs in the U. Sunniland and from fractured limestone in the LSRZ. The Pumpkin Bay is reported to contain organic-rich, argillaceous carbonates that are the likely source for oil in the mid/upper Pumpkin Bay and the brown dolomite zone of the overlying Lehigh Acres Fm. An integrated investigation was conducted to assess hydrocarbon prospectivity of these L. Cretaceous source rocks, with a focus on the Collier Hogan 20-3 well. The L. Sunniland represents a moderate geochemical risk for shale oil development. It is a good source with zones of elevated organic richness (1.29 wt.% TOC) and dominantly oil-prone Type II-S kerogen. However, thermal maturity parameters indicate it is in the early oil window for Type II-S kerogen (0.56% R_o) and key risk ratios are below minimum thresholds for shale oil. Hydrocarbon yield calculations suggest the interval generated moderate amounts of oil and a majority of this has been retained within the source rocks. Core extracts and production oils are sulfur-rich (3.8 wt.%) and heavy (API 19.1°); characteristics associated with low maturity oil. Biomarker analyses clearly correlate produced oil with in-situ generation from the L. Sunniland. Although whole oil fingerprints showed abundant light hydrocarbons, bulk fractional analysis show elevated polar+asph content (35%), suggesting the in-situ oils may be relatively immobile. The Pumpkin Bay was not extensively sampled, however, geochemical data suggest poor source potential (0.23 wt.% TOC) and a high risk for shale oil. Organic matter is composed of inert Type IV and gas-prone Type III kerogen. Thermal maturity parameters place the Pumpkin Bay in peak oil window (0.68% R_o) for Type II-S kerogen, but only incipient generation for a Type III kerogen. This amount of conversion would be sufficient to generate only trace amounts of hydrocarbons. Core extract biomarkers contain features associated with lean source rocks deposited under oxidizing conditions and clearly distinguish Pumpkin Bay from L. Sunniland samples.

2017 Air Regulation Requirements

Thomas Seguljic, HRP Associates, Inc.

As the calendar turns, the march of new air regulations continues for the oil and gas industry within the Marcellus and Utica basins. During 2017, a number of new air requirements from new permits to GHG reporting methods and fugitive emission testing will impact natural gas production and transmission operations within Ohio, Pennsylvania and West Virginia. It is imperative that operators understand the potential impact of these requirements on their operations, position themselves to reduce the impacts and develop a system to identify and implement/track requirements. This presentation will focus on both federal and state (PA, WV, and OH) proposed and new requirements for 2017, as well as expected trends including: As the calendar turns, the march of new air regulations continues for the oil and gas industry within the Marcellus and Utica basins. During 2017, a number of new air requirements from new permits to GHG reporting methods and fugitive emission testing will impact oil and natural gas production and transmission operations within Ohio, Pennsylvania and West Virginia. It is imperative that operators understand the potential impact of these requirements on their operations, position themselves to reduce the impacts and develop a system to identify and implement/track requirements. This presentation will focus on both federal and state (PA, WV, and OH) proposed and new requirements for 2017, as well as expected trends including:

- Fugitive leaks testing requirements
- New GHG reporting requirements
- New general permit for well pads and compressor stations
- Pigging emissions
- CTGs
- Electronic reporting
- What to expect from the Trump administration

The map that changed the NEW World: the Erie Canal (200th Anniversary) and Amos Eaton

Charles A. Sternbach, President AAPG 2017-2018 and Star Creek Energy Company, Inc.

We draw historical analogy between Simon Winchester’s story of William Smith (the first geologic map of England, 1815) with Amos Eaton (the first geologic map of NY and the New World (1818 cross section and 1822 map). Both pioneering efforts share similarities: canal digging creates fresh outcrops, need for geoscientists to evaluate local resources, canal pathways provide vital access to move fuel for the Industrial revolution and manpower to open isolated regions.

Amos Eaton was a traveling lecturer who founded the Rensselaer School for Engineering (RPI, 1824). Like William Smith in England, Eaton suffered many hardships in his personal life. Field work and applied science differentiated the American model of education from pure science education of European traditions. Early graduates founded many state geological surveys in the US which provided energy, critical resources, paving the way to an improved way of life. Many AAPG Eastern Section members will remember Gerald M. Friedman, a modern day Amos Eaton, and a keeper of the flame for practical geoscience education.

Mapping reservoir stress conditions using hydraulic fracturing microseismicity

Orlando J. Teran, MicroSeismic Inc.

The state of stress of the reservoir is one of the dominant factors controlling the reservoirs response to stimulation as well as the effectiveness of the treatment design. For instance, the orientation and magnitude of the maximum horizontal stress strongly affects the stimulated range of fracture orientations and in turn the geometry of the stimulated zone (i.e. localized vs distributed fracturing). The hydraulic horsepower, which takes into account the reservoir stress states and pressures, may be sufficient to stimulate certain parts of the reservoir, but any variations in the stress state can result in adverse effects such as damaging nearby wells ("frac hits"), out-of-zone growth, and damaging earthquakes. Furthermore, the reservoir stress state can also impact the hydraulic conductivity of stimulated fractures.

In this study a catalogue of microseismic focal mechanisms is used to map the stresses onto the microseismic fracture planes and evaluate the states of stress throughout the stimulated rock volume. Focal mechanisms are derived using full waveform fitting techniques, and for each solution the true fracture plane was identified and this was then used to invert for the orientation and relative magnitude of the maximum horizontal stress. Friction laws are then used to constrain for each event a suite of geomechanical parameters (failure potential, dilation tendency, and excess pore pressure) in order to identify fracture populations likely to control fluid flow, those that required different stimulation pressures in order to contribute to flow, and the mechanical conditions that favored out-of-zone growth and reactivation of geohazards. Additional observations, such as net wellbore pressure measurements and geophysical logs, are used to calibrate the model as well as to further understand the geological, geomechanical and treatment-related variables affecting the overall stimulated rock volume. The method is applied and discussed in the case of a microseismic event catalogue obtained during the stimulation of two horizontal wells landed in the Eagle Ford, where large variations in fracture patterns as well as geohazards were observed. We will also show examples from other plays to demonstrate that this workflow is applicable to all plays.

Causation of carbonate cements in sandstones near the overpressured top seal in Niuzhuang Sag of Bohai Bay Basin, China

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The well-developed carbonate cementation in sandstones near the overpressured top seal (present-day depth: 2400~2900m) in Niuzhuang Sag are closely related to the overpressured fluid activities, commonly with carbonate content between 12%~32.5%. Through the data analysis of 90 carbonate cements samples selected from sandstones near the overpressured top seal by electron-microprobe showed that carbonate cements could be mainly divided into three kinds, including calcite, ferrocalcite and ankerite. Their diagenetic sequence can be determined as calcite→ferrocalcite→ankerite combined with X-ray diffraction and cathodoluminescence data. According to the observed results of the carbonate fluid inclusions, the depositing temperature of the calcite, ferrocalcite and ankerite cements in sandstones near the overpressured top seal are significantly much higher than the original formation temperature that indicated an obvious effect by overpressured thermal fluid invasion. Furthermore, the above researches were tested by using oxygen isotope geological thermometer and the results were consistent with the actual observation values that the precipitation temperature of calcite, ferrocalcite and

ankerite cements range respectively from 85 to 105□、110 to 130□ and 125 to 140□, for the homochromous overpressure fluid of δ^{18}OOSM is respectively around 0.00‰、0.20‰ and 0.25‰; the δ^{18}OPDB values fluctuate from -15.2‰ to -14.2‰ for calcite 、-14.2‰ to -10.3‰ for ferrocalcite and -13.2‰ to -10.6‰ for ankerite; However, the δ^{13}CPDB values of carbonate cement formed in the late diagenetic stage have an obvious positive drift, ranging from -1.6‰ to 3.4‰, which proves that the dissolution-reprecipitation process of Es4 lacustrine carbonate seems to play an important role in the source of δ^{13}CPDB. The carbon isotopic fractional distillation within carboxylic acid molecules also has some influence.

Geologic characterization in preparation for the assessment of oil and gas resources in Upper and Middle Devonian black shales of the northern and central Appalachian Basin

Michael H. Trippi, Catherine B. Enomoto, Debra K. Higley, William A. Rouse and Frank T. Dulong, U.S. Geological Survey

The U.S. Geological Survey (USGS) will assess continuous oil and gas resources in multiple Upper and Middle Devonian black shales of the northern and central Appalachian basin. The black shales that were studied are the Cleveland Shale Member of the Ohio Shale, the Huron Shale Member of the Ohio Shale, the Pipe Creek Shale Member of the Java Formation, the Rhinestreet Shale Member of the West Falls Formation, the Middlesex Shale Member of the Sonyea Formation, and the Geneseo Shale Member of the Genesee Formation (equivalent to the Burket Shale Member of the Harrell Shale). These shales range in age from Givetian to Famennian. They are present in New York, Pennsylvania, Ohio, West Virginia, Kentucky, Virginia, and Tennessee between the Appalachian fold belt to the east and the Cincinnati Arch to the west. The assessment units (AU) for Huron Shale, Middlesex Shale, Pipe Creek Shale and Rhinestreet Shale extend into Lake Erie. These shale members were deposited in marine environments in a foreland basin. Anoxic to dysoxic conditions varied through time. Total organic carbon content of all of the shale members varies from 1 to 13 percent within the assessment area, and contains predominantly Type II marine and Type II/III mixed kerogens. The younger strata contain slightly more Type III terrestrial kerogen and less calcite. The Geneseo Shale carbonate content averages 19 percent with a maximum of 66 percent preserved carbonate content, while the Cleveland Shale has a maximum of 2 percent carbonate content. The Cleveland Shale and Huron Shale maximum thicknesses are 100 feet and 400 feet, respectively. The Rhinestreet and Geneseo Shales exceed 3400 feet and 125 feet, respectively. Within the assessment areas, the shale members are in oil, wet gas and dry gas thermal maturity windows. Natural fractures in all of these shale members facilitate production of oil, natural gas and natural gas liquids (NGL). The Huron, Cleveland, Geneseo-Burket, and Rhinestreet shales are self-sourced and have significant historical gas production, with minor oil and/or NGL production in the Huron Shale. After decades of extracting hydrocarbons with vertical wells, operators recently utilized horizontal drilling and multi-stage fracturing to increase production rates.

Earthquakes and History: Arguments over hydraulic fracturing and arguments over history

Conevery Bolton Valencius, Department of History, Boston College

I'm a historian. I usually deal with old events and dead people. But when the earth started to shake in the mid-continent a few years back, I found myself trying to understand present events and people very much alive. I wrote a book about the New Madrid earthquakes of 1811-12. When social media posts from Arkansas and Missouri began to warn "Fracking is going to set off another Big One on the New Madrid fault!" I wanted to figure out what in the world they meant. In the scientific literature, I found a thoughtful set of investigations into how oil and gas production in shale plays can in certain circumstances trigger quakes, but I also found sensationalist arguments by non-scientists about past earthquakes and present dangers. Claims about earthquake history and claims about the history of hydraulic fracturing play two main roles in current debates over the environmental and social impacts of "fracking". Debate over fracking-related earthquakes takes place on top of debates over the history of hydraulic fracturing itself. Advocates for hydraulic fracturing argue that the industry draws upon old and established techniques, while critics howl that “fracking” is new, untested, and unknown. Debates over the history of the technology are debates over the appropriateness and safety of shale oil and gas production. At the same time, both advocates and critics of hydraulic fracturing were surprised by induced seismicity in the shale plays, and many regarded energy-related earthquakes as a new phenomenon. The history of induced seismicity, though, shows that seismic events triggered by oil and gas development broadly and specifically by underground injection have long been recognized. In discussion of whether hydraulic fracturing is new or old, there are two sides, with two clearly opposed views of the history and present advisability of shale development. Yet surprise about fracking-related earthquakes has been widely shared by both critics and supporters of hydraulic fracturing. People on many sides of this issue ignored clearly-available historical background. Perhaps historical context may offer ways to bring together conversation within polarized debates. Internet alarm about the New Madrid Big One may seem far from serious history of oil and gas extraction. Yet current quakes and current debates show that the history of induced earthquakes and the history of hydraulic fracturing shape debates over the future of shale.

Use of Iodine for Petroleum Exploration

Daniel H. Vice, Pennsylvania State University, Hazelton

Iodine is highly mobile so it is transient and highly variable in concentrations in the soil environment. These increased concentrations of iodine and bromine are often associated with oil and gas fields; however, there is a debate as to whether the halogens migrate with the hydrocarbons or are already present in the soil and what process causes the halogen association with the hydrocarbons. Nevertheless, surface geochemical surveys of iodine concentrations have been used as a pathfinder™ for locating oil and/or gas accumulations for more than 40 years. Background values of iodine appear to range from 0.1 to 15 ppm while anomalous concentrations appear to range from approximately 3.5 to 10.5 ppm, which would be one to two standard deviations from the mean. Iodine surveys have been conducted in many regions of the US including: 1) California, 2) Rocky Mountain, 3) Texas, 4) Mid-West, and the 5) Appalachian Basin. One survey has been reported from the Thrace Basin in the European portion of Turkey. The wide range of geologic and climatic regions that iodine surveys have been used in suggests that they can be an effective exploration method, but the data do not provide any type of correlation between positive results and exploration success. One advantage of this exploration method is that one person can collect samples using a standard soil probe, so the method is quick and cost-effective. Tedesco (1995) suggests that the use of the iodine surveys along with other exploration methods can increase the exploration success rate by about 25 percent. Leaver and Thomasson (2002) used crosstab plots and Chi-square statistics to suggest that the association between iodine anomalies and oil and gas fields is not random.

Depositional Controls on Reservoir Quality in the Dundee-Rogers City Interval: Lithofacies and Production Characteristics

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The Dundee-Rogers City interval has been a prolific producer of hydrocarbons since the 1920’s in the Michigan Basin with cumulative production of more than 360 million barrels of oil. Three general categories of reservoirs are found in the Dundee-Rogers City: 1.) primary and intercrystalline porosity in dolomites sealed by anhydrites (western central Lower Peninsula), 2.) vuggy and intercrystalline porosity in hydrothermal dolomite reservoirs (central Lower Peninsula), and 3.) primary porosity in limestone reservoirs (eastern Lower Peninsula). In the central and eastern basin, the Dundee-Rogers City reservoirs are sealed by a combination of tight limestone (Dundee-Rogers City) or shale (Bell Shale). The Dundee Formation consists of a paralic to open shelf carbonate deposits. The Dundee exhibits a trend of deeper water deposits to the east, with dominantly tidal flat, sabkha and shallow lagoon deposits in the west, followed by sand shoals, patch reefs, and open shelf deposits in the central and eastern Lower Peninsula. The overlying Rogers City Formation represents a flooding event with deeper water outer shelf deposits laid on top of the Dundee. Grain-rich beach deposits bear both intergranular and open fenestral porosity. In the eastern basin, primary porosity includes intraskeletal (patch reefs), intergranular (shoals) and vugs.

Dolomitization in the western Dundee was early and preserved primary depositional fabrics. In the central basin, primary porosity provided pathways for dolomitizing fluids to invade fractured Dundee-Rogers City limestones. Dolomitization enhanced the porosity generating both intercrystalline and vuggy porosity. This phase of dolomitization is not fabric preserving. Fracturing and fluid migration are linked to reactivation of basement structures during the Acadian and Alleghanian orogenies. Limestone and Dolomite Reservoirs in the Dundee-Rogers City interval behave differently during production. Dolomite reservoirs maintain near virgin reservoir pressure throughout their production history. Strong bottom water drive pushes the oil-water contact up during production and produced water increases throughout the lifetime of wells in the dolomite reservoirs. Conversely, the limestone Dundee reservoirs tend to exhibit overall decrease in reservoir pressure during production. Water production is much lower in the limestone reservoirs. The limestone reservoirs are more productive during secondary production operations.

Defining the Geologic and Economic Limits of the Marcellus Wet Gas Play

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Over the past decade various reservoir models have been used to predict the production potential of the Marcellus shale. Current models benefit from over 8,000 producing well data points and allow operators to focus on offsetting production. However, defining the limits of the wet gas Marcellus shale play has proven difficult despite existing production data sets. The economics of the wet gas play are largely dependent on natural gas liquid yields which are typically not publicly available. The geologic factors that allow for economic production of wet gas are constrained to a specific area with distinct boundaries. The geologic factors are often interrelated and require a systematic approach to properly evaluate. Laurel Mountain Energy recently developed and executed a workflow that extends and further defines the limits of the wet gas Marcellus Shale play. The Marcellus play can be segmented into two economic areas based hydrocarbon production. Economics in the dry gas portion of the play are based on production of pipeline quality, methane-rich gas. The wet gas play relies on dry sales as well as revenue received from processed natural gas liquids and condensate. Uneconomic conditions can occur where natural gas liquid yields increase BTU beyond pipeline specification but are insufficient to offset the cost to process-out liquids. Additionally, areas with increasing NGL yields are shown to be limited by overall production quantity. Ultimately, these economic conditions are controlled by specific geologic factors. The wet gas Marcellus play is defined by geologic factors that affect the liquid content of the reservoir and the ability to flow economic quantities of hydrocarbons. The relationship between present day reservoir depth and other critical geologic factors shows the delicate nature of the wet gas play. Depth has an inverse correlation to liquid yield and hydrocarbon molecule size but a positive correlation to reservoir pressure and porosity development. The balance of these geologic factors can be quantified and used to define the economic limits of the play when the proper data sets are obtained. Laurel Mountain Energy recently developed and executed a workflow to delineate a wet gas Marcellus Shale prospect near the perceived limits of the play. A systematic approach was developed in order to analyze individual geologic factors and avoid nonessential testing. The results graphically indicate the limits of each critical factor and can be mapped to indicate the margins of economic production. Offsetting well information was used to extrapolate the critical factors across the Marcellus Shale wet gas play.

Identifying Lithosomes of the Marcellus Shale: A Provenance Approach

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Controls on mudrock deposition can produce localized and time-transgressive lithosomes that vary in terms of rheologic properties and organic richness. Currently, there are few reliable techniques for delineating or predicting the extent of mudrock lithosomes across a play. One approach to this problem is mudstone provenance, which can be used to predict the direction and timing of detrital dilution in an organic mudstone depocenter.

Integrated mineralogic, geochemical, and petrographic analysis of Marcellus Shale and Mahantango Formation mudrock samples recovered from 2 well-bore cores in Monongalia Co., West Virginia (MSEEL MIP-3H and WV-6), reveal contributions of northern- and eastern-derived clastic detrital influx. Major and trace element geochemistry indicates a felsic, upper continental crust sediment source, with mineralogy reflecting an increased influx of extrabasinal phases with time. In particular, the upper part of the Marcellus Shale reflects influx of chlorite that is not observed in the lower part, which is attributed to increasing contribution from exhumed metasedimentary rocks in the Acadian fold-belt. However, Sm-Nd isotopic analysis reveals δNd values that increase upsection from -9.85 to -11.65 and depleted mantle model ages (TDM) that decrease from ~1.85 Ga to ~1.65 Ga. Overall, TDM ages decrease upsection as δNd values decrease. These results require contribution of extrabasinal detrital sediments from erosion of both the Superior Craton to the north and the adjacent Acadian fold-thrust belt to the east, with increasing contribution from Acadian sources with time. In contrast, previous work by other researchers in western and central New York documents younger TDM of the Marcellus Shale (1504-1689 Ma) and lower ÎµNd values (approx. -5) that reflects greater contribution of Acadian-derived sediment compared to Superior craton-derived sediment in this part of the basin. These different provenance results support distinctive lithosomes for the Marcellus Shale in NY compared to WV. In order to explain the greater input from the Superior Craton in WV compared to NY, either the Catskill delta system mainly transported detrital clays from the Superior craton and influx of Acadian-derived material only locally overprinted this signature in NY, or the Marcellus Shale developed in a time-transgressive manner longitudinally across the Acadian basin and variation in provenance reflects a secular change in the source-to-sink system.

Aromatic compounds as maturity indicators and correlation markers - Example from New Albany Shale extracts and oils, Illinois Basin

Donna C. Willette, Illinois State Geological Survey

Aromatic compounds such as alkylbenzenes, naphthalenes, phenanthrenes, and dibenzothiophenes are useful as maturity indicators in basin analysis. They are resistant to biodegradation, can span a wide range of thermal maturities, and under elevated temperatures, can still be identified and analyzed. These indicators respond to an increase in thermal stress with a predictable alkylation progression of a given parent compound or a shift in the isomer distribution of alkyl-aromatic homologues towards thermally more stable isomers. Numerous studies on the maturity trends of the New Albany Shale within the Illinois Basin have utilized vitrinite reflectance ($_{Ro}$) measurements, T_{max} (temperature at which the maximum rate of hydrocarbon generation occurs during pyrolysis of a kerogen sample) data, and conodont analysis. Interpretation of maturity trends determined from this data can be problematic due to vitrinite suppression, measurements derived from bitumen reflectance (vs R_o), paleogeotherm control on vitrinite reflectance, and differing laboratory protocols in geochemical analyses. Sweeny and Burnham (1990) developed a model for vitrinite maturation that integrates chemical kinetic equations over time and temperature to account for the elimination of water, carbon dioxide, methane, and bitumen from vitrinite. Using the EASY %R_o method, calculated R_o can be determined for specific time/temperature conditions and constrained using aromatic compounds such as methylphenanthrenes and triaromatic steroids. These correlations provide an alternative method for mapping thermal maturity across basins with complex burial histories. Source rock extracts from the New Albany shale were analyzed from various depths across the Illinois basin using gas chromatography-mass spectrometry (GCMS) to calculate specific aromatic compound concentrations. These data were plotted against calculated and measured R_o values. Problematic zones of suppressed vitrinite were identified along with indications of higher maturity (than previously interpreted) trends within the New Albany shale. Maturity indices calculated within the New Albany shale in central and eastern Illinois are elevated relative to R_o determination from reflectance measurements. Utilization of aromatic maturity markers (when calibrated appropriately) provide an invaluable measure of thermal maturity in basins with complex burial histories that may cause other methods to be problematic.

Atmospheric gas concentrations in the pre- and post- production phases of an unconventional oil and gas recovery operation at the MSEEL test site, West Virginia

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[4] **Department of Occupational and Environmental Health Sciences, West Virginia University**

The Marcellus Shale Energy and Environment Laboratory (MSEEL) in West Virginia provides a unique opportunity in the field of unconventional energy research. By studying near-surface atmospheric chemistry over several phases of a hydraulic fracturing event, the project will help evaluate the impact of current practices, as well as new techniques and mitigation technologies. A total of 10 mobile surveys were conducted around the MSEEL site that contains 3 test wells (1 science well and 2 natural gas producing wells) and over several miles of nearby regional routes. Our surveying technique involved using a vehicle-mounted Los Gatos Research Ultraportable Methane/Acetylene Analyzer that provided geo-located measurements of methane (CH_4) and carbon dioxide (CO_2). The ratios of super-ambient concentrations of CO_2 and CH_4 were used to separate drilling- and fracturing-related observations from the natural background concentrations over the various well pad developmental stages. We found that regional background methane concentrations were elevated in all surveys, with a mean concentration of 2.699ppm (n = 98369), which simply reflected the mix of anthropogenic and natural CH_4 sources in this riverine urban location. Over time and through successive stages of well development, we noted a progressive rise in the occurrence of enriched methane in the vicinity of the developed wells. While there was a moderate degree of variability over time, we did observe a higher occurrence of CH_4-enriched observations during and after production began at the test site (~25% of measurements within 500 meters of the test wells) compared to the baseline surveys (>10% of measurements). This change was expected, as we anticipated some level of increased emissions from the well pads as production began. However, we did not expect the rise to be so noticeable. The results of this study show that there is a statistically significant increase in the occurrence of enriched methane values in the vicinity of the well locations when we compare pre-production to post-production surveys, and that pre-existing methane sources in the immediate vicinity must be accounted for when assessing environmental impacts.

The Evolving Role of Geoscientists in Climate Change Science

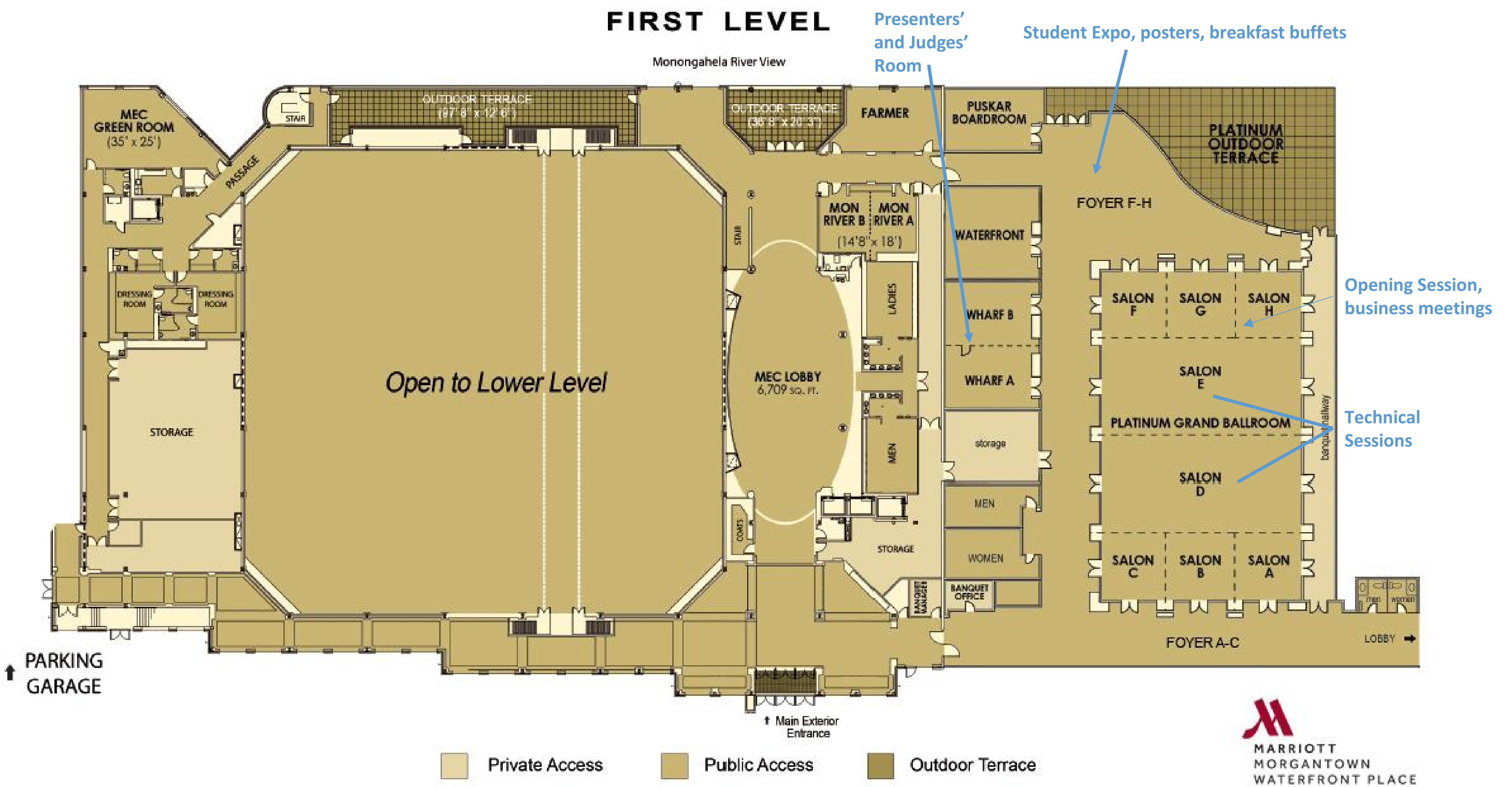
Gregory R. Wrightstone, Wrightstone Energy Consulting

In the on-going debate concerning natural versus anthropogenic drivers of modern climate change, a long-term geologic perspective is greatly needed. As geologists, we study and learn from the deep past, often in hundreds of thousands to hundreds of millions of years. We study the current geologic processes and use the principle of uniformity to recognize that the same processes and laws in operation today were also valid and operating in the past. One of the first principles we learned as undergraduates was “The present is the key to the past”. In climate science, the geologists’ role should be to use the corollary of this scientific principle to reverse the typical usage and apply the knowledge of the Earth’s climate history to better predict what may happen in the future: “The past is the key to the future”.

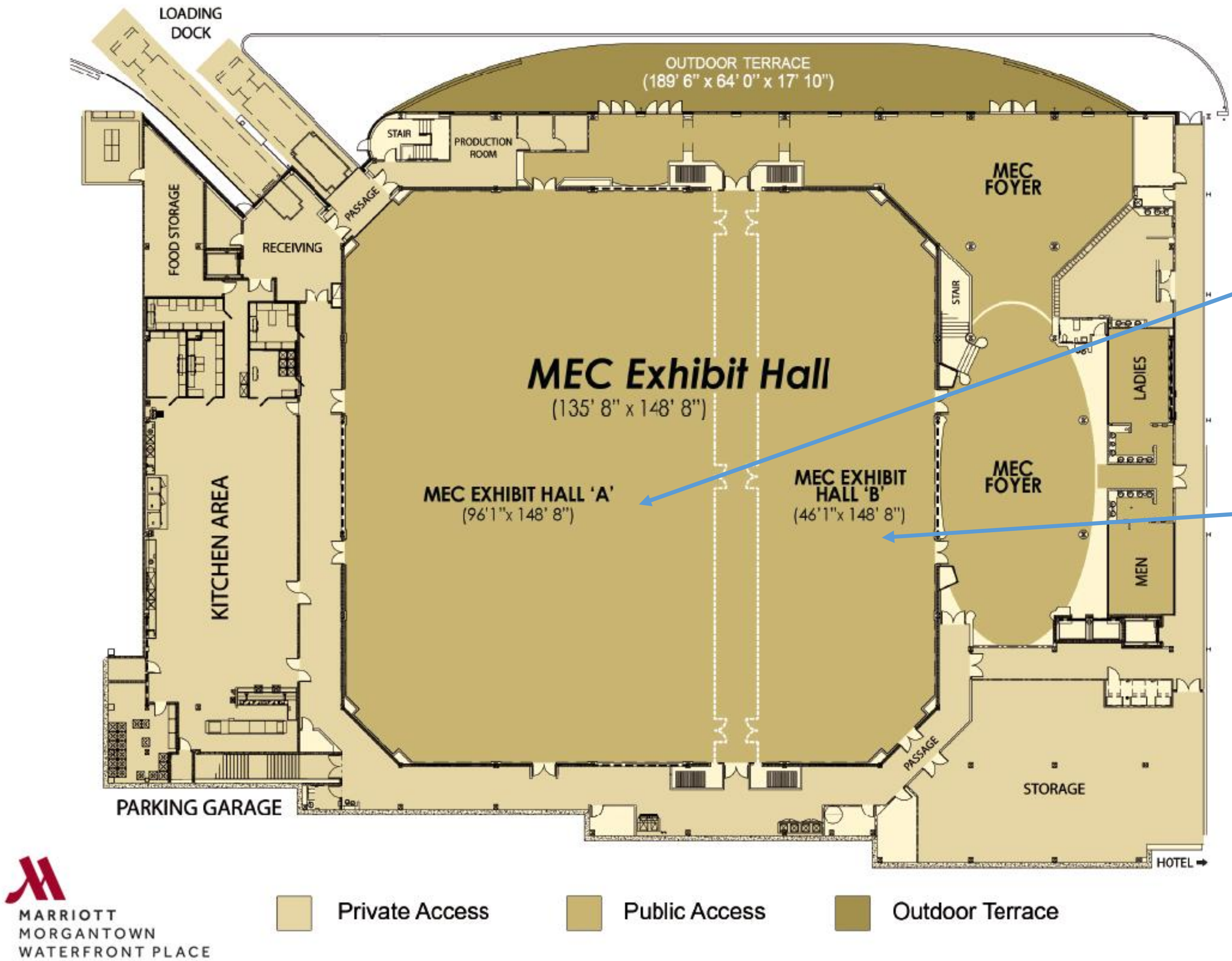
Much of the climate science used to bolster the notion that anthropogenic greenhouse gases are the primary driver of the current warming trend use only the relatively short period of instrumentation-based data. Direct measurements of carbon dioxide only began in 1958 at the Mauna Loa Observatory and thermometer-based temperature data extend back to the mid-19th century. The historical length of this data is just a blink of the eye to a geologist and provides a much skewed perspective on the relationship between CO_2 and temperature. A long-term geologic view is required to properly analyze the planet’s climate history in order to better predict what may occur in the future.

A review of long-term climate history clearly shows that both temperature and CO_2 have risen and fallen dramatically and regularly for the last 600 million years and that changes over the last 100 or so years are neither unusual nor unprecedented. All of those past climate changes were 100% naturally driven and the processes driving the past changes did not suddenly end at the beginning of the Industrial Revolution.

In today's politically charged atmosphere surrounding the climate-change debate, a geologic fact-based perspective is sorely needed.

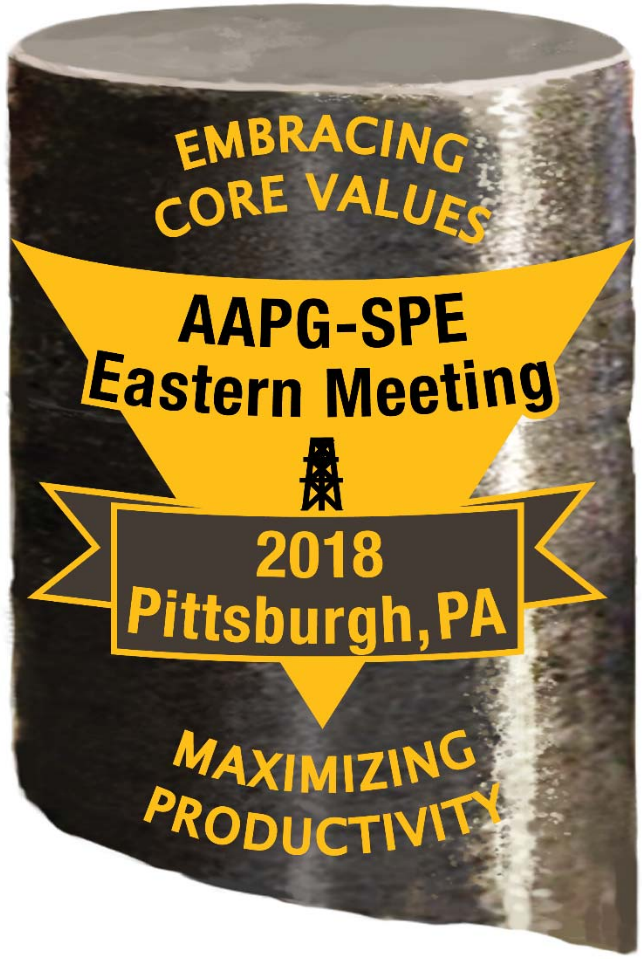

FIRST LEVEL
Monongahela River View
Presenters' and Judges' Room
Student Expo, posters, breakfast buffets
Opening Session, business meetings
Technical Sessions
MEC GREEN ROOM (35' x 25')
STAIR
PASSAGE
OUTDOOR TERRACE (97'8" x 12'6")
OUTDOOR TERRACE (36'8" x 20'3")
FARMER
PUSKAR BOARDROOM
PLATINUM OUTDOOR TERRACE
FOYER F-H
MON RIVER B
MON RIVER A
(14'8" x 18')
WATERFRONT
WHARF B
WHARF A
storage
MEN
WOMEN
BANQUET OFFICE
BANQUET MANAGER
LADIES
STORAGE
COATS
DRESSING ROOM
DRESSING ROOM
Open to Lower Level
MEC LOBBY 6,709 SQ. FT.
SALON F
SALON G
SALON H
SALON E
PLATINUM GRAND BALLROOM
SALON D
SALON C
SALON B
SALON A
banquet hallway
men
women
LOBBY
FOYER A-C
PARKING GARAGE
Main Exterior Entrance
Private Access
Public Access
Outdoor Terrace
MARRIOTT MORGANTOWN WATERFRONT PLACE

GROUND LEVEL



Keynote Address, Core Workshop and Tuesday dinner

Lunch Tuesday and Wednesday and Pioneer Women Display



Save the Date

2018 Eastern Section Meeting,
American Association of Petroleum Geologists

2018 Eastern Regional Meeting
Society of Petroleum Engineers

Co-hosted by Eastern Section AAPG,
Pittsburgh Section SPE,
Pittsburgh Association of Petroleum Geologists
and Pittsburgh Geological Society

Wyndham Grand Pittsburgh Downtown
October 7-11, 2018
Pittsburgh, PA