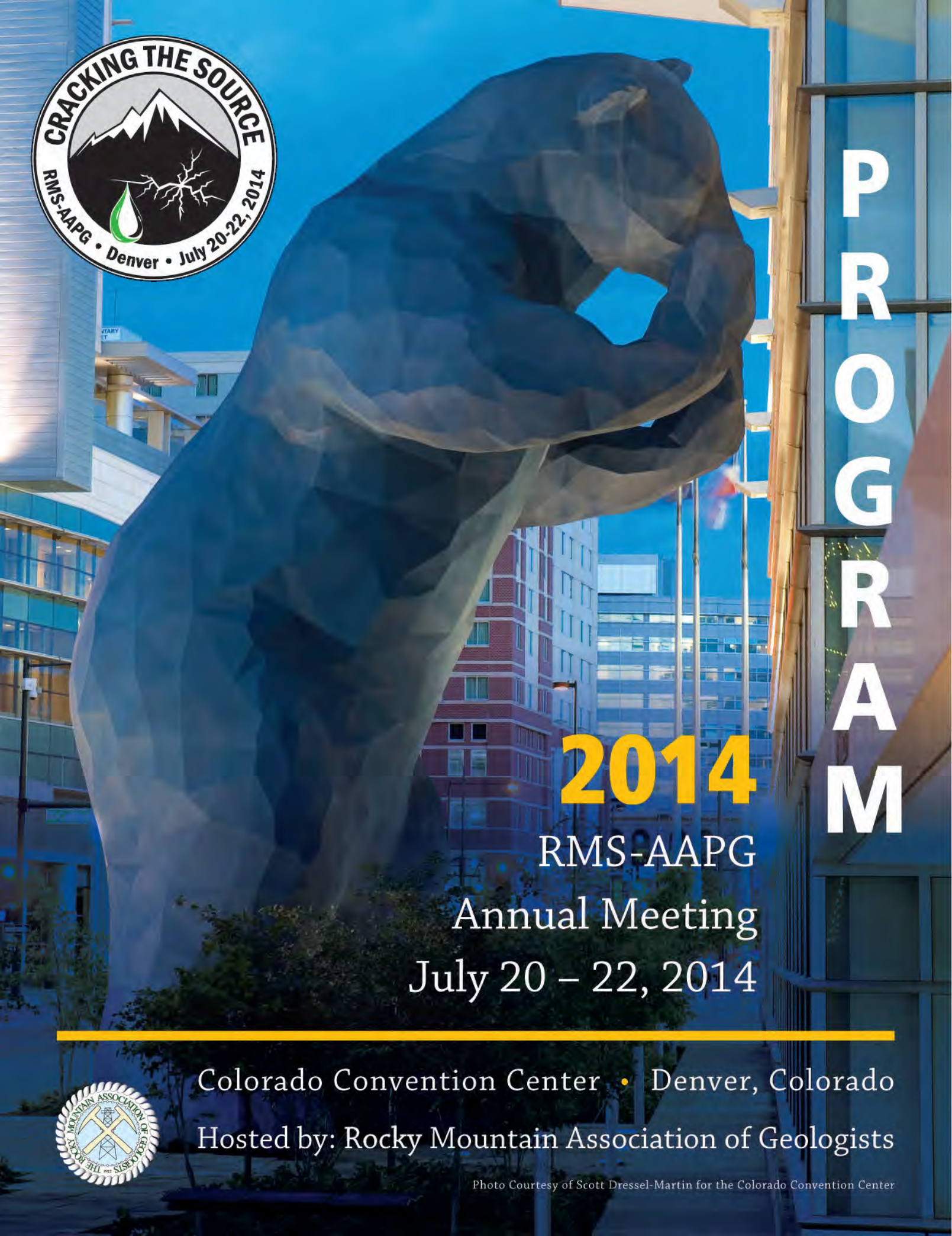

PROGRAM

2014

RMS-AAPG Annual Meeting

July 20 – 22, 2014

Colorado Convention Center • Denver, Colorado

Hosted by: Rocky Mountain Association of Geologists

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We Welcome You to Denver

On behalf of the Rocky Mountain Section of the American Association of Petroleum Geologists (RMS-AAPG) and the Rocky Mountain Association of Geologists (RMAG), we welcome you to Denver for the annual meeting of the RMS-AAPG.

Dedicated volunteers and staff of the RMAG have worked long and hard to prepare a meeting filled with excellent technical presentations, extraordinary field trips and first-class short courses. The presentations come in three enticing flavors: oral, poster and core poster. So you can see your rocks in person, on the printed page or on the big screen combined with technical discussions that will educate and entertain. In addition, we have an exhibit hall with about 50% more vendors than in recent meetings, a theater highlighting the successes of several legends of the oil and gas industry and a resume review for students.

Technical discussions are not the only item on the menu for this meeting. Our Monday night social event will be held at the Denver Museum of Nature and Science where Dr. Bob Raynolds will use Gates Planetarium to entertain and inform us about how humans have evolved over time and how our use of energy sources have and will continue to evolve. Come and join us (tickets are still available) and see some of the museum's world famous exhibits.

Speaking of menus, two luncheons are slated for the meeting. The All-Convention Luncheon and Awards Ceremony, to be held on Monday, will feature Dr. Robert D. Jarrett of Applied Weather Associates, LLC who will speak about the extreme flooding that hit northern Colorado late last summer and early fall including the 1000-year floods that wrecked parts of Boulder and Larimer Counties. On Tuesday, William J. (Bill) Barrett will keynote the Division of Professional Affairs luncheon. If you haven't heard Bill talk about his exploits before, you should attend and be amazed at his remarkable career in the oil and gas industry.

This is the premier technical conference and exhibition for the Rocky Mountain Region. The exposure to technical experts and service providers in this meeting will be tremendous and not to be missed by anyone involved in the geological sciences in the Rocky Mountains. And, don't forget Denver's prime location for outdoor adventure. While you are here or on your way home don't forget to have a grand time in Colorful Colorado.

Cat Campbell, RMS-AAPG General Co-Chair
Laura Johnson, RMS-AAPG General Co-Chair
C. Elmo Brown, RMS-AAPG President

CRACKING THE SOURCE
RMS-AAPG • Denver • July 20-22, 2014

CONTENTS

Conference Committee Chairs

Chairperson	Committee
Cat Campbell	General
Laura Johnson	General
Elmo Brown	RMS-AAPG President
Donna Anderson	Technical Program
Natasha Rigg	Technical Program
Ron Parker	Field Trips
Mary Carr	Short Courses
Laura Wray	Exhibits
John South	Exhibits
Kurt Reisser	Sponsorship
Raffaello Sacerdoti	Social Events
Mel Klinger	Publicity
Cheryl Whitney	Publications
Nick Nelson	Signage
Ryan Thompson	Signage
Jared Rountree	Lodging/Transportation
Tofer Lewis	Judging/Awards
Bryan Kaproth-Gerecht	Volunteer Chair/YPs
Mike Kozimko	Finance
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Peter Bucknam	Advisor

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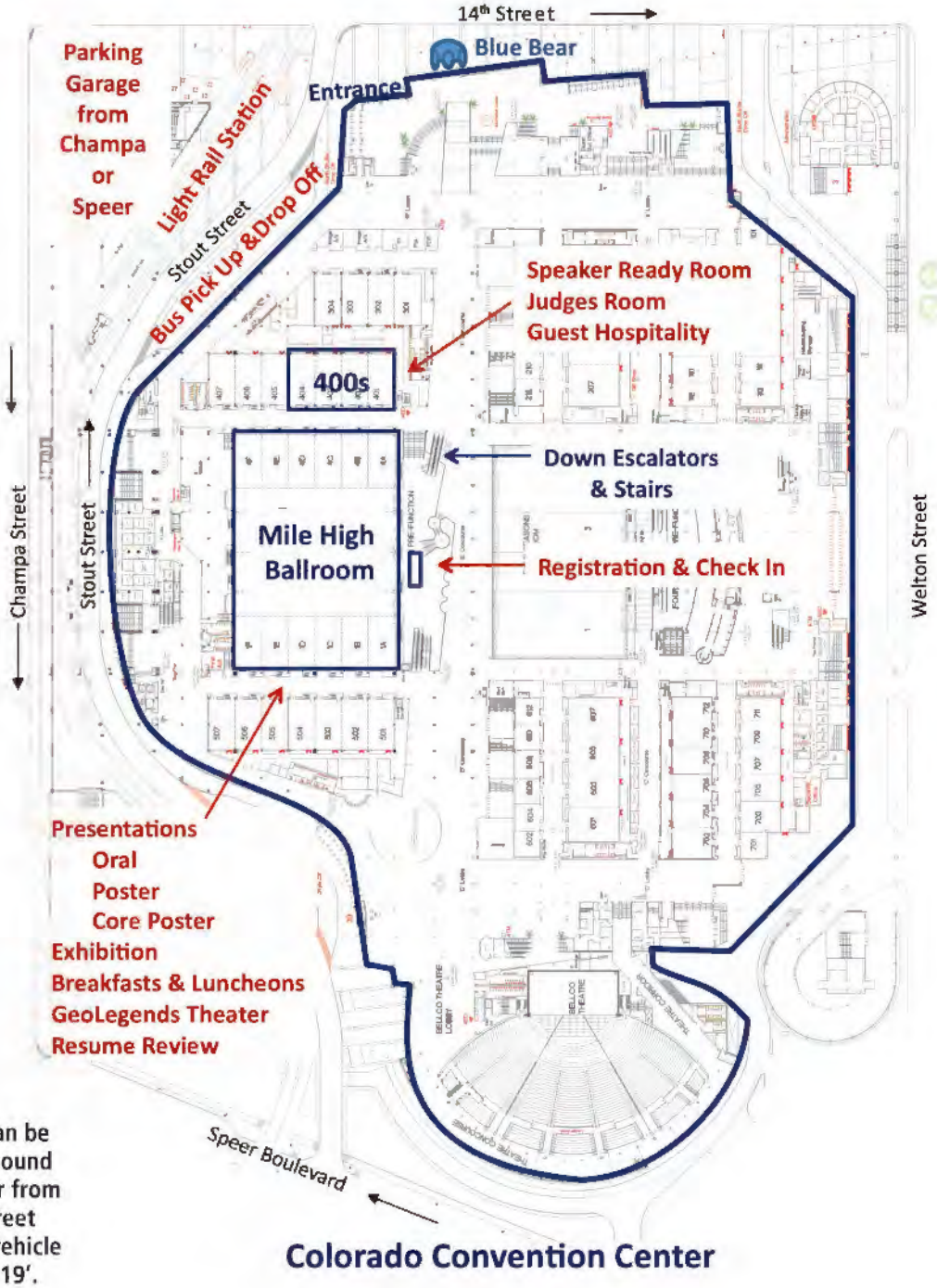
GENERAL INFO

Entrance to building will be to the right of the Big Blue Bear as you face the Convention Center (near Stout and 14th).

Theater District light rail station for D, F and H lines.



Parking

The Convention Center Parking Garage can be entered either from right lane on north-bound Speer Boulevard just after Stout Street or from left-lane of southwest-bound Champa Street just before Speer Boulevard. Maximum vehicle clearance is 8'2" and maximum length is 19'.

Hourly rates	
Up to 8 hours	$12
Up to 12 hours	$15
Up to 18 hours	$17
Up to 24 hours	$25

GENERAL INFO

Registration & Check-in — Mile High Ballroom Foyer

Sunday	12:00 p.m. – 7:00 p.m.	
Monday	7:00 a.m. – 5:00 p.m.	
Tuesday	7:00 a.m. – 1:00 p.m.	

Exhibit Hall — Mile High Ballroom

Sunday	12:00 noon – 4:00 p.m.	Exhibitor Move in (Exhibitors only)
	5:00 p.m. – 7:00 p.m.	Exhibition & Icebreaker
Monday	8:00 a.m. – 6:00 p.m.	Exhibition
	4:45 p.m. – 6:00 p.m.	Mini-Icebreaker
Tuesday	8:00 a.m. – 5:00 p.m.	Exhibition
	5:00 p.m. – 7:00 p.m.	Exhibitor Move out (Exhibitors only)

Speaker Ready and Judges Room — Room 402 and/or 403

Sunday	2:00 p.m. – 6:00 p.m.
Monday	7:00 a.m. – 5:00 p.m.
Tuesday	7:00 a.m. – 1:00 p.m.

Technical and Poster Sessions — Mile High Ballroom

Monday	8:00 a.m. – 5:00 p.m.
Tuesday	8:00 a.m. – 5:00 p.m.

Breakfasts — Mile High Ballroom

Monday	7:00 a.m. – 8:00 a.m.	Speaker/Judge
Monday	7:00 a.m. – 8:00 a.m.	AAPG House of Delegates

Luncheons — Mile High Ballroom

Monday	12:00 noon – 1:15 p.m.	All Convention Luncheon
Tuesday	12:00 noon – 1:15 p.m.	DPA Luncheon

Night at the Museum — Denver Museum of Nature & Science

Monday	6:00 p.m. – 9:00 p.m.	
	5:40 p.m. - 6:30 p.m.	Buses depart Convention Center at 10-15 minute intervals
	8:15 p.m. - 9:15 p.m	Buses depart Museum at 10-15 minute intervals

Geo-Legends Theater — Mile High Ballroom

Monday	8:00 a.m. – 4:45 p.m.	Exact times of specific showings will be posted
Tuesday	8:00 a.m. – 4:45 p.m.	

Student Resume Review — Mile High Ballroom

Monday	2:00 p.m. – 5:00 p.m.

Business Meetings — Mile High Ballroom

Monday	5:00 p.m. – 6:00 p.m.	RMS-AAPG Foundation
Tuesday	6:30 a.m. – 8:00 a.m.	RMS-AAPG Executive Meeting

Hospitality Suite — Room 401

Monday	8:00 a.m. – 11:30 a.m.
	1:30 p.m. – 4:30 p.m.
Tuesday	8:00 a.m. – 11:30 a.m.
	1:30 p.m. – 3:30 p.m.

Field Trips

#1 **Unconventional Reservoirs and Stratigraphy of Southern Denver Basin: Graneros, Greenhorn, Carlile and Niobrara Fms**

Leaders: Jeff May (Geologic Consultant) and Tofer Lewis (Enerplus)

Saturday – Sunday 8:00 a.m. – 4:00 p.m. Depart and return to Colorado Convention Center

#2 **Structure & Stratigraphy of Central Colorado Basin**

Leader: Bob Raynolds (Denver Museum of Nature & Science)

Saturday - Sunday 8:00 a.m. – 4:00 p.m. Depart and return to Colorado Convention Center

#3 **Student & YP Field Trip: Ancestral Rockies to the Western Interior Seaway: Geology & Petroleum of the Morrison Area**

Leader: Donna Anderson (EOG Resources and Colorado School of Mines, Golden, CO)

Saturday 7:30 a.m. – 4:30 p.m. Depart and return to Colorado Convention Center
or 8:00 a.m. – 4:00 p.m. Depart and return to Wooly Mammoth lot DD at I-70 & US 93, Morrison exit

#4 **Permian Depositional Systems, Cycles and Petroleum Geology along Northern Colorado Front Range (RMS-SEPM)**

Leaders: Marshall Deacon (Noble Energy Inc), Richard Geesaman (Indian Peaks Exploration) and Max Pommer (University of Texas – Austin)

Wednesday - Friday 8:00 a.m. – 3:00 p.m. Depart and return to Colorado Convention Center

Short courses

#1 **Beyond Porosity: Lithology from Logs for Geologists (PTTC)**

Leaders: Daniel A. Krygowski (The Discovery Group) and Robert M. Cluff (The Discovery Group)

Saturday 8:30 a.m. – 5:00 p.m. Denver Athletic Club, 1325 Glenarm Place, Denver

#2 **Source Rocks 101 Geologists (PTTC)**

Leader: Nick Harris (University of Alberta)

Sunday 8:30 a.m. – 5:00 p.m. Denver Athletic Club, 1325 Glenarm Place, Denver

#3 **Heath Self-sourcing Tight Oil System, Montana: Core Workshop (RMS-SEPM)**

Leaders: Richard Bottjer (Cirque Resources), Martin Cohen (Statoil), Taylor Gray (Statoil), and Peter Purrazzella (Weatherford Labs)

Wednesday 8:30 a.m. – 4:30 p.m. Weatherford Labs, 16161 Table Mt. Pkwy, Golden, CO

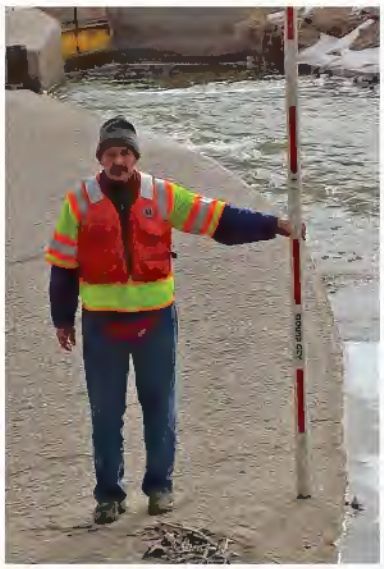
Earth Science Teacher Program

Saturday 7:30 a.m. – 4:30 p.m. **Dinosaur Ridge Facility,** 16831 W. Alameda Parkway, Morrison, CO
(C-470 and West Alameda Parkway Exit)
0.5 Continuing Education Course hours through Colorado School of Mines

Convention Bags

All excess convention bags will be donated to the Brighton and Denver Public Schools. There will be bins placed on your way out of the convention in case you want to donate your convention bag to this cause. In the case of Denver Public Schools, the bags are to be distributed to at-risk students at several of DPS's highest needs schools. More than 72% of Denver Public School students qualify for the Federal Free and Reduced Lunch program, an indicator of poverty. For these families providing school supplies is an enormous economic burden. Consequently many students start the first day of school without the necessary supplies or backpacks to carry their books. The backpack donation from you and the RMS-AAPG will help ensure that these students will be equipped for success

SPECIAL EVENTS



All Convention Luncheon and Awards Ceremony

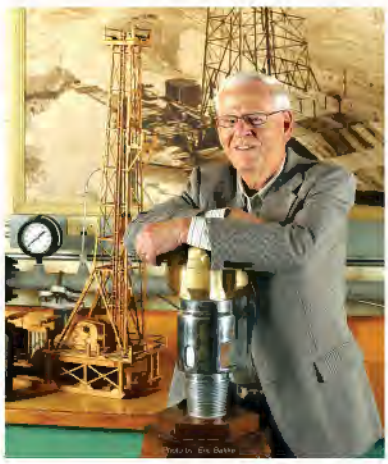
Colorado's Extraordinary Flooding in 2013

Date: Monday, July 21st
Location: Mile High Ballroom, Colorado Convention Center
Time: 12:00 noon - 1:15 p.m.
Fee: $45
Limit: 200

Keynote Speaker: Robert D. Jarrett, Ph.D., Applied Weather Associates, LLC

The All Convention Luncheon serves two purposes at the RMS-AAPG Annual Meeting. The first is to recognize several awardees who have illustrated excellence in their profession or in their presentations at the previous annual meeting. The other is a presentation by a keynote speaker on a topic usually of general interest to geologists and non-geologists alike. This year the keynote will be given by Robert D. Jarrett, Ph.D. on the extreme flooding that took place in northern Colorado last July through December including the 1000 year floods in Boulder and Larimer counties. He will contrast these floods to other historically significant floods and will discuss how to mitigate any future flooding events.

Dr. Jarrett has worked on water resources for over 40 years, first with the Army Corps of Engineers and then at the USGS where he eventually would serve as Chief of the Paleohydrology and Climate Change Project. In that capacity, his job was to conduct interdisciplinary research quantifying the magnitude and frequency of floods and developing plans to reduce loss of life and property. Since Dr. Jarrett retired as Scientist Emeritus in 2012, he has donated his time with various federal agencies and continues to mentor young scientists. He now works with Applied Weather Associates in Monument, Colorado.



Division of Professional Affairs Luncheon

Stories and Lessons from 60 Years of Rocky Mountain Wildcatting: From conventional to non-conventional oil and gas exploration to non-conventional transforming into conventional – one man's experience.

Date: Tuesday, July 22nd
Time: 12:00 noon - 1:15p.m.
Location: Colorado Convention Center
Fee: $45

Speaker: William J. Barrett

Lauded for awards ranging from IPAMS' (Independent Petroleum Association of Mountain States) Wildcatter of the year, to the AAPG Explorer of the Year Award and an Honorable PhD from Colorado School of Mines, William Jay "Bill" Barrett has enjoyed an illustrious career. Bill has participated in finding and developing 10 potential giant/near giant oil and gas fields along with many additional smaller ones in the Rocky Mountain basins including; the Madden and Cave Gulch Fields in the Wind River Basin of Wyoming, The Hilite Oil Field and the Powder River coal bed methane gas fields in the Powder River Basin of Wyoming, the Parachute, Grand Valley, Rulison and Gibson Gulch Fields in the Piceance Basin of Colorado, the Tabernacle Buttes Field in the Uinta Basin of Utah and the Red Wing Creek Oil Field in the Williston Basin of North Dakota. Bill received his BS and MS degrees in Geology from Kansas State University after spending time in the Army. He has worked for El Paso, Pan American, INEXCO, and Rainbow Resources. He is the founder of Aeon Energy, Barrett Resources, and Bill Barrett Corporation. Bill is also a philanthropist and gives generously to the AAPG Foundation, Children's Hospital and many other needy causes.

SOCIAL EVENTS

Opening Icebreaker

Date: Sunday, July 20th
Location: Exhibition Hall, Mile High Ballroom, Colorado Convention Center
Time: 5:00 p.m. - 7:00 p.m.
Fee: Free with registration

Come join your friends and colleagues for a drink, snacks and tall tales at the Opening Icebreaker. While there, visit the dozens of exhibitors showing their wares and services. The financial support of these exhibitors and our sponsors makes the annual meeting possible.

Mini-Icebreaker

Date: Monday, July 21st
Location: Exhibition Hall, Mile High Ballroom, Colorado Convention Center
Time: 4:45 p.m. - 6:00 p.m.
Fee: Free with registration

End your day … or start your evening … with our Monday Mini-Icebreaker. Continue with drinks, snacks and tall tales with your friends and colleagues. Also don't forget to visit our exhibitors and expand your horizons.

Night at the Museum

Date: Monday, July 21st
Time: 6:00 p.m. - 9:00 p.m.
Location: Denver Museum of Nature and Science, Leprino Family Atrium (West Atrium)
Buses: Leave at 10-15 minute intervals
Depart Convention Center at 5:40 p.m. – 6:30 p.m.
Depart Museum starting at 8:15 p.m. to 9:15 p.m.
Fee: $60

Join your friends, colleagues and their spouses for a night of social and educational immersion at the Denver Museum of Nature and Science. Geologist Bob Raynolds of the Denver Museum of Nature and Science will be headlining the evening with a talk in the Gates Planetarium titled: "Where have we come from and where are we going? From the Rift Valley in Africa to beyond the Internet, some global considerations."

This captivating presentation will use immersive visualizations projected in the Gates digital planetarium. Using Google Earth-based software enhanced with digital and multimedia photographs, videos and maps, Bob Raynolds will begin the presentation describing how our ancestors evolved along the lush lake margins of the African Rift and how unique geological conditions resulted in a rich fossil record from this region when basic energy needs were tied to survival. Leaping ahead to the present, tantalizing questions will be posed about the wonderful energy opportunities that lie ahead in the new, fully connected, digital world that we have created over the past 25 years. You will be challenged to consider how global energy needs will be delivered to a world-wide population with today's technologies as well as with those that have not yet been developed. Enjoy the comfortable chairs in the darkened Planetarium - this is guaranteed to be a fascinating and thought-provoking experience!

Food and beverages will be enjoyed by all during this unique opportunity to experience the museum after hours with private access to the Gates Planetarium, Australia & South Pacific Exhibit, Space Odyssey Exhibit and the Anschutz Family Sky Terrace at sunset!

OTHER EVENTS

Rocky Mountain Geo-Legends Theater

Date: Monday July 21st – Tuesday, July 22nd

Video interviews of "geo-legends" conducted by the AAPG will be shown in a theater setting. Interviews to be shown include those of Frank Royse (Wyoming thrust belt exploration); Michael Johnson (Parshall field, Bakken reservoir, ND); Jerry Albertus and Steve Kneller (rediscovery and development of Pinedale field, WY); and Sam Gary (discovery of Bell Creek Field, MT), among others. Look for a schedule and more information at the meeting!

Student & YP Resume Review

Date: Monday July 21st
Time: 2:00 p.m. – 5:00 p.m.

Just in time for the 2014 Rocky Mountain Rendezvous and other Student Expos! Several company recruiters will be on hand to offer suggestions on developing your resume and other interviewing tips. This is a great opportunity to prepare for the upcoming recruiting season. Register online ahead of time or sign-up in the Colorado Ballroom.

Hospitality Suite

Room 401

Date & Times: Monday July 21st, 8:00 a.m. – 11:30 p.m., 1:30 p.m. – 4:30 p.m.
Tuesday July 22nd, 8:00 a.m. – 11:30 p.m., 1:30 p.m. – 3:30 p.m.

RMS is excited to welcome meeting attendees' guests to Denver. A hospitality suite will be open during the meeting with snacks, information on local attractions, and a goodie bag for each registered guest. The suite will be located in the Denver Convention Center near the meeting to allow guests to mingle with meeting participants and join for social events.

AWARDS

The Awards Ceremony will occur at the All-Convention Luncheon on Monday, July 21.

Robert J. Weimer Lifetime Contribution Award

Awardee: **Dr. Lehi F. Hintze, Professor Emeritus of Geology at Brigham Young University**

The Robert J. Weimer Lifetime Contribution Award is presented annually by the Rocky Mountain Section – AAPG in recognition of an individual's contributions to the practice of the geosciences and/or petroleum geology in the region of the Rocky Mountains. The Lifetime Contributions Award is similar to the national AAPG Sidney Powers Memorial Award, the AAPG's most distinguished award.

The presentation of this award is in recognition of Dr. Hintze's lifelong efforts to map, interpret and publish on the geology of Utah. In fact, his book, "Geologic History of Utah," first published in 1980 and now in its third printing, is considered the standard reference for Utah geology. As one person noted, no geologist in Utah goes out into the field without this book containing its representative stratigraphic columns for all areas of the state. In addition, Dr. Hintze published many Utah geologic quadrangle maps in cooperation with Brigham Young University, the Utah Geological Survey and the United States Geological Survey. In recognition of his outstanding contributions to geologic mapping, Dr. Hintze received the Governor's Medal for Science and Technology from the State of Utah in 1992. In 1994, he was presented the first Dibblee Medal from the Dibblee Foundation of California. The medal is given to "a field geologist who has made outstanding contributions to the science of geology by the quantity and quality of his geological field mapping and published his work for the benefit of others." In 2003, the Utah Geological Association, in cooperation with the Utah Geological Survey, presented to Dr. Hintze the newly established Hintze Award. This award was created to "honor geologists who have made significant contributions to our understanding of Utah's magnificent geology." Dr. Hintze is a graduate of the University of Utah and holds a Ph.D. from Columbia University. During his 35 years as a professor, first at Oregon State University and then at Brigham Young University, he taught courses in Historical Geology, Stratigraphy and Field Mapping. Dr. Hintze and his wife, Ione, have been married for 72 years.

Rocky Mountain Landmark Publication Award

Awardees: **Robert A. Schalla, Independent/Consulting Geologist, and Eric H. Johnson, Independent Consultant, editors of "Oil Fields of the Great Basin," Nevada Petroleum Society Special Publication, 1994**

The Rocky Mountain Landmark Publication Award recognizes the authors or editors of a book, guidebook or other publication that over the past decade has had exceptional influence on developing new hydrocarbon plays or deeper understanding of fundamental geology within the Rocky Mountain region.

The nomination for this award noted that "We in Nevada refer to the book as the 'Green Bible,' " as Bob and Eric compiled the definitive book on oil exploration and production in the Great Basin." As Mr. Schalla stated in the publication, the idea of the book came to him while driving from Billings, Montana to Elko, Nevada in a cigar smoke-filled Ford Explorer. This kernel of an idea turned into a landmark publication still used extensively today. As he later explained, the "work compiling and editing a volume on Great Basin oil fields combined his scientific interest in the area with pure fun."

Mr. Schalla, now an independent/consulting geologist in Billings, Montana, had worked previously for OXY USA, Cities Service and Equitable Energy Resources. He has a BS from the University of California-Riverside and a MS from Oregon State University. Mr. Johnson received a BS in Geophysical Engineering from Montana Tech and a MS in Geophysics from the University of Utah. He has been exploring for oil and gas (in his words, "sometimes successfully") for 40 years; first with Union Oil Company (Unocal) and then with Meridian Oil, the BLM, Balcron Division of Equitable Resources and now as an independent consultant in Billings, Montana.

Distinguished Service to the Rocky Mountain Section Award

Awardee: **Dr. Edward D. Dolly, Consulting Geologist**

The Distinguished Service Award is presented to members who have distinguished themselves in singular and beneficial long-term service to RMS-AAPG, with emphasis on long-term and at the same time, meaningful service to the Association.
Dr. Dolly served as president of the RMS-AAPG in 2000-2001 and then Past President the following year. He served on the AAPG Advisory Council in 2003-2006 as the representative of the Section and as the representative to the Membership Enhancement and Development Ad Hoc Committee in 2002-2005. Dr. Dolly has served as a House Delegate from the Section since 1994 and served as chair of that body in 2001-2002. In recognition of his service to the House of Delegates, he received the Long Service (2012) and Honorary Member (2007) awards. In his various positions at AAPG, he has tirelessly promoted Section members for AAPG honors and awards.

One of the nominations for Dr. Dolly noted that he "has been instrumental in bringing individuals from our far flung affiliated societies together to produce great science presentations, field trips, short courses, and core reviews. He has been a mentor to all individually and corporately. Ed was instrumental in establishing the Section organizational format we have followed since Albuquerque (in 2000) which has been successful in defining leadership succession and creating opportunities for service from other than the host societies." Dr. Dolly also set up the revenue sharing plan that the Section uses today to help fund the affiliated societies of the Section from the proceeds of the annual meeting. Dr. Dolly received a BS from the University of Illinois before earning both a MS and Ph.D. from the University of Oklahoma. He began his career with Shell Oil Company before moving on to Trend Exploration Ltd and then to its successor, Filon Exploration Corporation. In addition to these companies, Dr. Dolly has worked for James Energy Management, Consolidated Oil and Gas, Anschutz Exploration Corporation, The Houston Exploration Company and as an independent geologist. Dr. Dolly is now a semi-retired, consulting geologist in the Denver area. He has served as a lifelong volunteer, not just with the RMS-AAPG, but also with the AAPG, RMS-SEPM and the RMAG.

A.I. Levorsen Award - Best Oral Presentation (AAPG)

Awardee: **Robert L. Baskin, University of Utah, for the presentation titled, "Microbialite Distribution in a Lacustrine Rift Basin, Great Salt Lake, Utah"**

This award is given by the American Association of Petroleum Geologists (AAPG) for the best oral presentation at a given AAPG section meeting (in this case, at the 2013 annual convention in Salt Lake City, Utah) with particular emphasis on creative thinking toward new ideas in exploration.

At press time, Mr. Baskin was waiting to defend his Ph.D. dissertation in Geography from the University of Utah. He also had previously earned an MS in Geography from the University of Utah and a BA in Geology from Thiel College in Greenville, Pennsylvania. He has authored or co-authored over 25 papers and given numerous presentations. Mr. Baskin is presently employed by the USGS.

Steve Champlin Memorial Award - Best Poster Presentation (WGA)

Awardee: **S. Robert Bereskin, Bereskin & Associates, Inc., Thomas C. Chidsey, Craig D. Morgan, and John McLennan for the poster titled, "Hydrocarbon Potential of the Chainman Shale, Western Utah"**

The Wyoming Geological Association sponsors this Award, which is presented to the poster author receiving the highest score at the annual Rocky Mountain Section of the American Association of Petroleum Geologists annual meeting. The award was created in 1986 to encourage poster authors to strive for excellence in their presentations and to foster the one-on-one discussions of geology for which Steve Champlin was well known. It is hoped that this award will carry on Steve's spirit of friendly cooperation for the exploration of our natural resources.

Dr. Bereskin's career includes serving as an adjunct professor at the University of Utah, Exploration Manager at a Salt Lake oil and gas company, and more than 12 years as Manager/Geoscientist at TerraTek Inc. He now serves as president of Bereskin & Associates, a consulting firm dedicated to the understanding of unconventional reservoirs.

Runge Award - Best Student Presentation (WGA)

Awardee: **John L. McFadden, Jr., University of Colorado at Boulder, Rex D. Cole and Matthew J. Pranter for the presentation titled, "Reservoir-scale Facies and Stratigraphic Architecture of the Middle and Upper Williams Fork Formation, Upper Philadelphia Creek, Douglas Creek Arch, Colorado"**

The award recognizes professional and scientific excellence in student papers presented at the annual AAPG-RMS meeting, with particular emphasis on creative thinking toward new ideas in exploration. Established in 1975, the award is provided by John S. Runge, petroleum geologist in Casper, Wyoming and is sponsored by the Wyoming Geological Association.

Mr. McFadden is currently finishing his MS. in Geology from the University of Colorado in Boulder. While at the university, he has served as the SEG student chapter secretary and the AAPG student president. He received his BA from Baylor University. Mr. McFadden is now employed at Tricon Geophysics in Denver.

Best Presentation Award (DEG)

Awardee: **Elizabeth Horne, Utah State University, for the poster presentation titled, "Field Observations and Stable Isotopic Analysis of Laterally Continuous Calcite Veins Associated with Fault Zones: Insight into Ancient Fluid Travel"**

This award is given by the AAPG Division of Environmental Geosciences (DEG) for the best oral or poster presentation at a given AAPG section meeting from among all papers in sessions sponsored by the DEG.

It should be noted that Ms. Horne performed this work as an undergraduate research project at Utah State University. She presently is working on an internship for the summer with ConocoPhillips in Houston. She will be starting at the Colorado School of Mines in fall 2014 for a MS degree in Geology.

President's Certificate for Excellence in Presentation Award (DEG)

Awardees: **Dr. Elizabeth S. Petrie, Western State Colorado University and Dr. James P. Evans, Utah State University, for the oral presentation titled, "Mechanical Stratigraphy and Stress History of Cap-rocks Analysis of Exhumed Analogs in Central and South-Eastern Utah and Implications for CCS"**

This award is given by the DEG for an oral or poster presentation at a given AAPG section meeting which runs a very close second to the paper which won the Best Presentation Award from among all sessions sponsored by the DEG.

Dr. Petrie is the Moncrief Chair of Petroleum Geology at Western State Colorado College in Gunnison, Colorado. She has BS degrees from the University of New Mexico and MS and Ph.D. degrees from Utah State University. Dr. Evans is a professor of geology with 28 years of experience at Utah State University where he has earned numerous accolades in teaching and research. His BS is from the University of Michigan and MS and Ph.D. degrees from Texas A&M University.

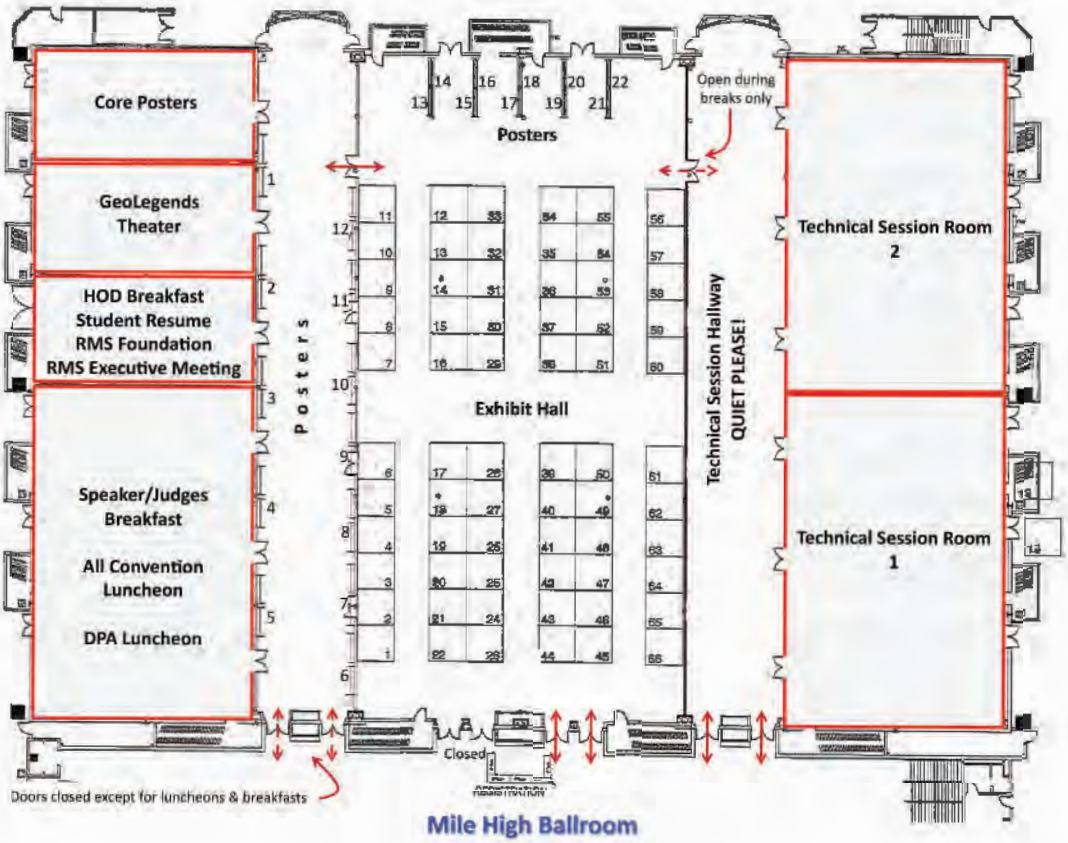
2013 Rocky Mountain Section Teacher of the Year Award

Awardee: **Debra K. Stiles, 9th Grade Earth Science Teacher, Capital High School, Helena, Montana**

Each year the RMS-AAPG chooses a K-12 teacher of earth and resource science to represent the section in a competition held by the American Association of Geologists. The teacher is chosen from a group of nominees submitted by the affiliated societies within the Section.

In Ms. Stiles' application she notes that Montana's history is rich in resource development and states, "Our lifestyle exists because of these resources, how we find them, how we extract them, how they have been managed in the past and how we manage them now. Critical decisions will be made in the future about these resources, and my students will be the ones making these decisions." As her school's principal explains in a support letter, "Debi exhibits classroom control, a great work ethic, and is dependable given a wide variety of educational circumstances. Debi never breaks ties with students once they leave her classroom; rather, she remains connected with them for the next three years. There is no doubt that Capital High School would be a much different educational environment if not blessed with Mrs. Stiles' presence."

Exhibitors, Talks and Posters, GeoLegends Theater, Student Resume Review and all of the Breakfasts and Luncheons will all be conveniently located in the Mile High Ballroom. As you pass through the Exhibit Hall, please thank our Exhibitors for helping make this convention possible with their participation



Exhibitor	Booth #
AAPG	20
ALS Corpro	22
Breckenridge Exploration Company, Inc.	31
CanAmera Coring	1
Columbine Logging	3
Core Laboratories	34 & 35
Crown Geochemistry	58 & 59
Decollement Consulting Inc.	16
DESCO Environmental Consultants	49
Digital Data Services	36
Digital Formation	9
Dolan Integration Group	29
Field GeoServices	33
Fluid Inclusion Technologies, Inc.	23
Gems and Crystals Unlimited	7 & 8
GeoEdges	54
Geokinetics	65
Geologic Data Systems	55
Geomap Company	60
GeoSteering LLC	40
Getech	38
Gustavson Associates	30
Halliburton	11
Horizon Well Logging, LLC	39
Horizontal Solutions International	45
I H S	66
iBall Instruments / BRSS	24
Richard Inden	51,52,53
Innovative Geo-Tech Resources, LLC	57

Exhibitor	Booth #
King Canyon Buffalo, Inc.	46 & 47
LMKR Resources, Inc.	42
MJ Systems	19
Neuralog	43
New Mexico Geological Society	56
NorAm Wellsite Services	62
Paladin Geological Services	63 & 64
Pason Systems	41
ProCoring	32
PTTC - Rocky Monntain Region	6
Rocky Mountain Association of Geologists	17
RMS-AAPG YP & RMAG NeoGeos	15
SCAL, Inc.	10
Schlumberger (TerraTek)	44
Seisware, Inc.	21
Selman & Associates	50
Sigma3	4
Stone Quilt Design	18
Terra Guidance	48
Terracosm Software, LLC	2
TGS	37
Thompson Solutions, LLC	28
3D Imaging Technology	25
Tracerco	13 & 14
Utah Geological Survey	12
Vista Geoscience, LLC	61
Weatherford Laboratories	26 & 27
Wyoming Geological Association	5

Monday Oral Sessions

Everything You Want to Know About Source Rocks I

Room 1

Session Chairs: Stephanie Gaswirth and Laura Wray

8:00 Introductory Remarks

8:05 Critical Relationships between Vitrinite Reflectance and Petroleum Formation: M. D. Lewan

8:45 Natural and Artificial Cracking of Oil Source Rocks and Unconventional Reservoirs: W. Dow

9:25 Break

10:10 Effects of Upper and Lower Bakken Source Rock Differences on the Charge of Middle Bakken and Three Forks Reservoirs in the Williston Basin: D. J. Thul, R. Thompson, T. L. Ganey

10:30 Bakken Formation Water and the Role of Shale Filtration, Williston Basin: Z. E. Peterman, J. Thamke, L. Neymark, T. A. Oliver, K. Futa

10:50 Utilizing Hydrocarbon Yield Determinations to Evaluate Source/Reservoir Relationships in the Bakken/Three Forks of the Williston Basin, ND: M. Millard, T. Ruble

11:10 Controls on Porosity and Pore Type within the Eagle Ford Formation, South Texas: M. E. Pommer, K. L. Milliken, A. Ozkan

11:30 Vitrinite reflectance of Cretaceous Coals and Thermal Maturity of the Niobrara Formation, DJ Basin, Colorado, USA: D. G. Hallau, R. J. Sharma, R. M. Cluff

Everything You Want to Know About Source Rocks II

Room 1

Session Chairs: Paul Lillis and Michael Dolan

1:15 Introductory Remarks

1:20 Differentiating Green River Formation Oils Sourced from Freshwater and Saline Lacustrine Facies in the Uinta Basin, Utah: J. Birdwell, R. C. Johnson, P. G. Lillis, M. Brownfield

1:40 Correlation of Oils and Tar Sands in the Green River Petroleum System, Uinta Basin, Utah: P. G. Lillis, V. M. Cumming

2:00 Sussex Sandstone Tight Oil Play, Powder River Basin, Wyoming, Extension of the Hornbuckle-Spearhead Trend with Horizontal Drilling: R. J. Bottjer, M. L. Hendricks, D. H. Stright, J. A. Bettridge

2:20 Calibration of FIS Factor 1 Response to Map API Gravity "Sweet Spots" in Unconventional Resource Assessments: D. A. Wavrek, D. L. Hall

2:40 Break

3:00 Serendipity, Sandstone, and Shale in a Revitalized San Juan Basin: S. N. Berglund, D. B. Ostby , R. W. Brooks , L. L. Wray, B. S. Kelso

3:20 Predicting Fluid Quality from Regional Thermal Maturity Studies: M. P. Dolan, P. Travers, S. Cumella

3:40 Maximize Mass Spectrometer Mud Gas Data-Experienced Analysis Matters: T. P. Wicker, B. Warren

4:00 Petroleum Occurrences in Cretaceous Age Reservoirs, Northern Bighorn Basin, Montana & Wyoming: J. R. Mitchell

4:20 A Core Calibrated Log Model Workflow for Shale Gas and Tight Oil Reservoirs: R. Cluff, E. Roberts, R. C. Hartman

Advanced Technologies for Visualization and Completion

Room 2

Session Chairs: Laura Johnson and Jared Rountree

1:15 Introductory Remarks

1:20 Advanced Seismic Imaging Tools for Unconventional Targets in Complex Geology: M. P. Brown, R. Ray, E. J. Sterne, B. Newman

1:40 3-D Seismic Proves its Value in Bakken Geosteering: A. C. Southcott, H. Harper

2:00 Multi-Reservoir Characterization with Multicomponent 3-D Seismic in North-West Denver-Julesburg Basin: A. Goswami, S. Volterrani, B. W. Horn

2:20 Play-Scale 3-D Modeling and Novel Risk-Ranking Concepts for Developing Unconventional Assets: B. Luneau, M. Belobraydic, J. Sitchler, G. Gaynor

2:40 Break

3:00 Newfield's Williston Buried Array Microseismic; Pushing the Envelope and Integrating Data: L. M. Johnson, J. Rountree, J. Shemeta

3:20 Where Did the Proppant Go?: J. P. McKenna

3:40 Completions Optimization in the Eagle Ford Shale Play: C. Telker, C. W. Neuhaus

4:00 Training Image Characterization and Multipoint Statistical Modeling of Clastic and Carbonate Formations: R. Klenner, J. R. Braunberger, N. W. Dotzenrod, N. W. Bosshart, W. D. Peck, C. D. Gorecki

4:20 Workflow Optimization Using Python Programming, a Tool Kit for Every Geoscientist: N. W. Dotzenrod, J. R. Braunberger, R. Klenner, G. Liu, C. D. Gorecki

Monday Poster Sessions

Core Poster I

- Visual and Analytical Comparisons of Upper Bakken "Shale" Cores from a West-to-East Transect, McKenzie and McLean Counties, North Dakota: L. L. Wray, M. Longman, K. Kocman, L. Johnson, G. Sha, S. Cole
- Visual and Analytical Comparisons of Upper Pronghorn "Shale" Cores from a West-to-East Transect, McKenzie and McLean Counties, North Dakota: L. M. Johnson, G. Sha, K. Kocman, S. Cole, L. L. Wray, M. Longman
- Visual and Analytical Comparisons of Lower Bakken "Shale" Cores from a West-to-East Transect, McKenzie and McLean Counties, North Dakota: K. B. Kocman, M. Longman, L. M. Johnson, G. Sha, L. L. Wray, S. Cole

Exploration/Exploitation

- Play Analysis of the Cane Creek Shale, Pennsylvanian Paradox Formation, Paradox Basin, Southeast Utah: C. D. Morgan, S. M. Carney, P. J. Nielsen, M. D. Vanden Berg, R. E. Wood
- Produced Water Modeling of Upper Cretaceous Mesaverde Group Tight-Sandstone Reservoirs in the Uinta Basin, Utah: P. J. Nielsen, R. E. Wood, T. C. Chidsey
- Basin-Scale Analysis and Options for Produced Water from Tight-Gas Sand Reservoirs, Uinta Basin, Utah: D. E. Tabet, T. C. Chidsey, Jr., C. D. Morgan, R. Ressetar, P. J. Nielsen, R. E. Wood, T. Boden, S. M. Carney, M. D. Vanden Berg, S. Kirby, H. Willis, C. Hardwick, R. Emerson
- Geothermal Assessment and Modeling of the Uinta Basin, Utah: C. Hardwick, H. Willis, M. Gwynn
- Focusing Petroleum Exploration With Regional Geochemical Surveys: D. Seneshen, J. V. Fontana
- Mechanical Stratigraphy and Well Correlation Using the Proceq Bambino in the Niobrara Shale: C. Murray, S. A. Sonnenberg

Sedimentary Geology

- Petrography of the Bakken Black "Shales" in the Eastern Williston Basin of North Dakota: M. Longman, K. Kocman, L. L. Wray
- Correlation of Niobrara-Equivalent Strata in the Eastern Uinta Basin, Utah: R. Ressetar, A. McCauley, L. Birgenheier, J. Quick
- Regional Sequence Stratigraphic Analysis of the Upper Cretaceous Telegraph Creek and Eagle formations in South-Central Montana: A. B. Brekke, J. R. Staub
- The Knoll Limestone "Bench" of the Three Forks Formation, West-Central Montana: An Exposed Unconventional Reservoir: T. Doughty, G. W. Grader, M. C. Pope
- Source to Sink Systems for Hydrocarbon Exploration in Lacustrine Basin Fill: Analog Examples from the Tertiary Duchesne River Formation, Northern Uinta Basin, Northeastern Utah: T. Sato, M. A. Chan
- Hypersaline Facies and the Termination of Eocene Lake Uinta, Upper Green River Formation, Uinta Basin, Utah: M. D. Vanden Berg, L. P. Birgenheier
- Using Surface and Point Based Statistics to Evaluate Channel-Belt Clustering in the Fluvial Lower Wasatch Formation, Uinta Basin, Utah: J. R. Pisel, D. R. Pyles, B. R. Bracken, C. D. Rosenbaum
- Geochemical Characterization of the Cow Ridge Member, a Freshwater Lacustrine Stage of the Eocene Green River Formation, Piceance Basin, Colorado: J. Birdwell, M. M. McGlue, R. C. Johnson, G. S. Ellis
- Detailed Chemostratigraphic Characterization of the Niobrara Formation, Cemex Quarry, Lyons CO: D. O'Neal
- Fourier Analysis of the Laminated Facies of the Middle Bakken Member, Sanish-Parshall Field, Mountrail County, North Dakota: V. Gent, S. A. Sonnenberg
- Complexities of Well Log Interpretation Observed Through Cored Samples, Mesaverde Group, Uinta Basin: E. Wilcox, E. Gustason
- A Geometric Approach to the Analysis of Global Eolian Hydrocarbon Reservoirs: With analogues from the Wahiba Sands of Oman: S.G. Fryberger and C.Y. Hern

Structure and Tectonics

- Comparison of Potentiometric Surfaces of the Cretaceous Dakota Group with Surfaces of Paleozoic Formations in the Midcontinent of the United States: N. J. Gianoutsos, P. H. Nelson
- Fracture Creation and Observed Pitfalls in Bakken Reservoirs, Williston Basin, North Dakota: D. Heckelsberg, Z. Yao, A. Lorwongngam, C. Cardenas, D. Guier
- Basin Evolution of the North Park – Middle Park Basin, Colorado: M. Dechesne, J. Cole, C. Martin

Tuesday Oral Sessions

New Structural Investigations: Rockies and Beyond

Room 1

Session Chairs: Ryan Thompson and John Detring

8:00 Introductory Remarks

8:05 The Nitchie Shear Zone, Wyoming: J. R. Forster

8:25 Using Microseismicity to Understand Subsurface Fracture Systems and increase the Effectiveness of Completions: Eagle Ford Shale, TX: J. Detring, S. Williams-Stroud

8:45 Tectonic Erratics - Remarkable Exotic Blocks Emplaced by the Henderson Thrust, Eureka County, Nevada: A New Petroleum Exploration Target in North-Central Nevada: S. Finney

9:05 Structural Modeling to Reduce Uncertainty, Eastern Cordillera Fold and Thrust Belt, Colombia: D. Richards, C. Ceballos

9:25 Break

9:45 Multiphase Deformation of Paleozoic and Mesozoic Units, Nebraska Panhandle, USA: C. Burberry, R. Joeckel, J. Korus

10:05 Post-Laramide Thrust Backsliding and Arch Collapse: A Mechanism for Creating Intensely Fractured Trends and High Off-Structure Production; Wind River Basin, Wyoming: R. Thompson

10:25 Paleostructural Control of Cretaceous Niobrara Productivity in a Portion of the DJ Basin of Colorado: J. T. Sperr

10:45 Permian Salt Dissolution in Silo Field, Laramie County, Wyoming: E. Finley, S. Sonnenberg

11:05 Fluid Migration and Regional Pressure Development in the Midcontinent of the United States: P. H. Nelson, N. J. Gianoutsos

Petrophysical Techniques for Core and Log Analysis

Room 1

Session Chairs: Terri Olson and Margaret Lessenger

1:15 Introductory Remarks

1:20 Enhanced Formation Evaluation of Shales Using NMR Secular Relaxation: H. Daigle, A. Johnson, J. P. Gips, M. Sharma

1:40 Solutions for Difficult Reservoirs—Direct NMR Fluid Type and Permeability: C. H. Smith, S. Ramakrishna, L. Hamilton

2:00 Characterization of Wettability using NMR and Dielectric Logging, and Pore-Scale Imaging Techniques: M. Lessenger, R. Merkel, P. Bhattad, A. Carnerup, M. Knackstedt

2:20 Applications of Pore-Scale Image Data to Exploration and Reservoir Characterization: T. Olson, L. Canter

2:40 8reak

3:00 Calibration of Petrophysical Log Response in the North and Eastern Uinta Basin to Allow Extension of Outcrop Belts into the Subsurface using Well Data: J. D. Hogan, J. Sarg, K. Tanavsuu-Milkeviciene

3:20 A Comprehensive Deterministic Petrophysical Analysis Procedure, For Reservoir Characterization: Conventional and Unconventional Reservoirs: M. Holmes, A. Holmes, D. Holmes

3:40 Application of Rapid, Integrated, Cuttings XRF, Source Rock and Trapped Fluid Analyses to Unconventional Plays: D. L. Hall, S. M. Sterner, R. Shukla, R. Moore

4:00 Using New Well Logging Technology with Ultra-Sensitive Detection of Hydrocarbons to Assess Hydrocarbon Composition, Compartmentalization, and By-Passed Pays: R. Schrynemeeckers

4:20 Distinguishing Noise from LWD Gamma Ray Data in Horizontal Wells: J. Schindler

Stratigraphy of Rocky Mountain Basins and Beyond

Room 2

Session Chairs: Aaron Adams and Ben Burke

8:00 Introductory Remarks

8:05 Facies Model and Sequence Stratigraphic Framework of the Devonian-Mississippian Sappington and Bakken Formations in Montana: M. H. Hofmann, T. Nagase, M. S. Hendrix

8:25 Sedimentary Processes and Trace Fossil Communities in the Upper Shale Member of the Upper Devonian-Lower Mississippian Bakken Formation, North Dakota, USA: S. Egenhoff, N. Fishman

8:45 Diagenesis of Organic-Rich Shale: Views from Foraminifera Penetralia, Eagle Ford Formation, Maverick Basin, Texas: W. Camp

9:05 Geological Characterization of the Uteland Butte Member of the Eocene Green River Formation: An Emerging Unconventional Carbonate Tight Oil Play in the Uinta Basin, Utah: M. D. Vanden Berg, R. E. Wood, S. M. Carney, C. D. Morgan

9:25 Break

9:45 Stratigraphic Architecture of the Frontier Formation, Powder River Basin, Wyoming: R. Rhodes, B. McElroy, E. Campbell-Stone, J. Groenhof

10:05 Abrupt 8asinward Changes in the Stratigraphic Expression of a Sequence 8oundary in the Ferron Sandstone (Turonian), Southeast Utah, USA: J. T. Korus, C. R. Fielding

10:25 Using a Fluvial Sequence Stratigraphic Framework in the Coal Bearing Formations of the Raton Basin, CO to Build a Deterministic 3-D Model: S. Osterhout, H. Soetrisno

10:45 Mass Movement Deposits in the Lacustrine Eocene Green River Formation, Piceance Basin, Western Colorado: R. C. Johnson, J. Birdwell, M. Brownfield, T. J. Mercier

11:05 Playa and Lunette Sedimentation Response to Artificial Water Levels: Case Study of the San Luis Lake Area: M. E. Brunhart-Lupo

Reservoir Characterization Blending Conventional and Emerging Technologies

Room 2

Session Chairs: Marianne Rauch-Davies and John Fontana

1:15 Introductory Remarks

1:20 Past, Present and Future Advancements in Methods for Detecting Hydrocarbon Seepage after 75 Years: J. V. Fontana, D. Seneshen

1:40 Mosser Dome Field, Yellowstone County, Montana: A Giant Stratigraphic Oil Accumulation: J. R. Mitchell

2:00 Examination of the Tyler Formation's Exploration and Development History using Current Source Rock and Reservoir Maps: T. O. Nesheim, S. H. Nordeng

2:20 Claude Shannon versus Gus Archie: Information Theory as a Guide to Log Evaluation without Petrophysics: P. E. Devine

2:40 Break

3:00 Multivariate Analysis of Geologic and Engineering Parameters on Petroleum Production in the Niobrara Formation: D. J. Thul, C. Welker, T. Anderson, M. Deo

3:20 Unconventional Exploration: Will Your Next "Sweet Spot" Have Once Been a "Hot Spot"?: E. Sprunt, J. Newman, M. Ruder, J. Edman

3:40 Seismic Diffraction Imaging on Pre-Existing Seismic Data to Predict Fracturing in Unconventional Reservoirs: M. Rauch-Davies, A. Berkovitch

4:00 Wide-Azimuthal 3-D Seismic Data Integrated with Geologic Information from Open-Hole Logs Unlocks the Secrets of a Naturally Fractured Trap in the Western Uinta Basin, Utah: J. Ehrenzeller, W. Korenkiewicz, J. Pyle

4:20 Characterization and 3-D Modeling of Devonian Pinnacle Reefs for CO2 Storage and Enhanced Oil Recovery: J. R. Braunberger, N. W. Bosshart, R. Klenner, G. Liu, W. D. Peck, C. D. Gorecki

Tuesday Poster Sessions

Core Poster II

- Sussex Sandstone, Hornbuckle Trend, Powder River Basin, Wyoming: Lithofacies and Reservoir Properties in a Tight Oil Play: R. J. Bottjer, M. L. Hendricks, D. H. Stright, J. A. Bettridge
- Reservoir Characteristics of the Codell Sandstone Tight Oil Play, Northern DJ Basin, Wyoming and Colorado: Extension of Wattenberg into the Oil Window: K. H. Smith, R. J. Bottjer, R. A. Sterling, H. C. Nowak, D. R. Wheat
- Core Facies and Geochemical Analysis of the Late Cretaceous Turner Sandstone, Powder River Basin, Wyoming: E. Gustason, T. Lewis, D. Maloney, A. Heger
- Core Facies, Log Facies and Sequence Stratigraphic Analysis of the Late Cretaceous Turner Sandstone, Porcupine Field Area, Powder River Basin, Wyoming: E. Gustason, J. Haynie, C. Hazard

Source Rocks and Petroleum Systems

- The Upper Bakken Shale Play, Elm Coulee Field, Williston Basin: S. A. Sonnenberg
- New Concept of Oil and Gas Origin: V. A. Serebryakov
- Mineralogy of the Green River Formation, Wyoming: Mining Old Data in the Light of New Models: J. Boak, G. M. Mason, K. Tanavsuu-Milkeviciene
- Gas Geochemistry of Three Tight-Gas-Sand Fields, Rocky Mountains: N. B. Harris
- Petroleum System Model of the Mississippian Bakken Formation in the Northern Williston Basin, Saskatchewan, Southwestern Manitoba, and Southeastern Alberta: D. K. Higley, S. Gaswirth, N. Gianoutsos
- Noble Gas Geochemistry at the La Barge Platform, Wyoming, USA: CO2 Source and Potential Total Petroleum System Investigation Tool: M. D. Merrill, C. D. Lohr, A. G. Hunt
- The Importance of High-Resolution Geochemistry in Downspacing Evaluations of Unconventional Plays: J. Strauss, N. Rosenau, P. Travers, M. Dolan
- Correlation of Rebound-Hammer Rock Strength with Core and Sonic-log Derived Mechanical Rock Properties in Cretaceous Niobrara and Frontier Formation Cores, Piceance Basin, Colorado: G. A. McClave
- Undiscovered Petroleum Resources for the Woodford Shale and Thirteen Finger Limestone-Atoka Shale, Anadarko Basin: D. K. Higley
- Computation and 3-D Visualization of Potentiometric Surfaces in Hydrocarbon-Bearing Formations Across the Mid-Continent: N. Gianoutsos, P. H. Nelson
- An Overpressured Deep Basin and an Underpressured Hinterland: the Greater Anadarko Basin of Oklahoma, Texas, and Kansas: P. H. Nelson, N. Gianoutsos
- In-Place Oil Shale Resources in the Saline Mineral and Saline-Leached Intervals, Piceance Basin, Colorado: J. Birdwell, T. J. Mercier, R. C. Johnson, M. Brownfield
- Assessing the Carbon Sequestration Potential within the Bear River Formation of the Wyoming-Idaho-Utah Thrust Belt: R. M. Drake, M. D. Merrill
- Microbial Mat Textures in Lithofacies of the Paradox Formation, Paradox Basin, Utah: K. J. Whidden, R. F. Dubiel, J. D. Eoff, S. J. Hawkins, K. R. Marra, O. N. Pearson, J. K. Pitman
- Sweet Spot Identification and SRV Estimation by Correlation of Microseismic Data and the Shale Capacity Concept: Application to the Haynesville: J. Reagan, E. Wojcik, M. Fackler and A. Ouenes


DINOSAUR RIDGE

ABSTRACTS

1946212 Serendipity, Sandstone, and Shale in a Revitalized San Juan Basin

Berglund, Sophie N.[1]; Ostby , Douglas B.[1]; Brooks , Robert W.[1]; Wray, Laura L.[2]; Kelso, Bruce S.[1]

1. Exploration, WPX Energy, Denver , CO, United States; 2. Williston Basin Asset, WPX Energy, Denver, CO, United States.

The San Juan Basin is experiencing an oil and gas industry revitalization as the result of completions in unconventional reservoirs in the Mancos Shale and Gallup Sandstone formations. Legacy drilling and completion operations have targeted conventional reservoirs in both the Mancos and Gallup formations for decades. Presently, the application of new technology is fueling development in previously bypassed pays in these formations. While the Mancos Shale and Gallup Sandstone reservoirs were deposited relative to the same shoreline in the Cretaceous Western Interior Seaway, they differ in depositional environment and reservoir characteristics. Serendipitously, Mancos source rock changes phase from volatile oil to dry gas coincident to changes in the nature of the reservoir. This talk will discuss the regional interplay between the changes in source rock maturity and regional stratigraphy in the San Juan Basin Mancos and Gallup Formations.

1963021 Differentiating Green River Formation Oils Sourced from Freshwater and Saline Lacustrine Facies in the Uinta Basin, Utah

Birdwell, Justin[1]; Johnson, Ronald C.[1]; Lillis, Paul G.[1]; Brownfield, Michael[1]

1. Central Energy Resources Science Center, U.S. Geological Survey, Denver, CO, United States.

Recognized petroleum source rocks in the Eocene Green River Formation, Uinta Basin include the Black shale facies and Mahogany zone shale. Recently, the informal Uteland Butte member of the Green River Formation has been targeted for development using horizontal drilling and hydraulic fracturing. Organic-rich Uteland Butte shales represent a freshwater lacustrine facies containing interbedded dolomite reflecting intermittent saline conditions. Several wells are producing oil out of dolomite-rich beds in the Uteland Butte in the western Uinta Basin. Oils from six wells in Duchesne and Uintah Counties were provided by the Bill Barrett Corporation and examined using bulk characterization methods to determine sulfur content, stable carbon isotopic signature, API gravity, and C15+ saturate, aromatic, resin, and asphaltene content. Distributions of total, saturated, and aromatic hydrocarbons were measured by gas chromatography (GC) and relative concentrations of biomarkers were determined by GC-mass spectrometry. The results indicate that oil from one well resembles Green River type A, which is derived from the Black shale facies. Oil from another well is consistent with Green River type B, which is sourced from Mahogany zone shale. The remaining four wells produce similar waxy oils that have distinctly different properties from those attributed to the established source rocks. Differences include lower carbon preference index values, higher pristane-phytane ratios, and other parameters consistent with a freshwater lacustrine origin. We will present results of geochemical analyses to ascertain if these oils originate from Uteland Butte shale or if another source is indicated.

1969218 In-Place Oil Shale Resources in the Saline Mineral and Saline-Leached Intervals, Piceance Basin, Colorado

Birdwell, Justin[1]; Mercier, Tracey J.[1]; Johnson, Ronald C.[1]; Brownfield, Michael[1]

1. USGS, Denver, CO, United States.

The Eocene Green River Formation of the Piceance Basin in western Colorado contains most of the high-quality oil shale resource in the western United States. According to a recent analysis by the U.S. Geological Survey of the potentially recoverable resource as a function of oil-shale grade, the basin contains about 920 and 352 billion barrels of potential oil resource using oil-yield cutoffs of 15- and 25-gallons per ton (GPT), respectively. Much of this rich oil shale is associated with the saline minerals nahcolite and halite or intervals in which these minerals have been leached by groundwater. This impacts the potential for oil shale resource extraction as nahcolite must be co-produced or preserved. Furthermore, the presence of vugs and breccias in the leached zones can effect groundwater movement and potentially affect the implementation of in-situ oil shale extraction technologies. To facilitate the assessment of potentially recoverable resources associated with the major mineral facies of the Piceance Basin, oil-shale zones were delineated into mineralogical-stratigraphic intervals, specifically: (1) the illitic zone, which predates the deposition of saline minerals; (2) the saline zone; (3) the leached zone; and (4) other overlying oil shale zones. The oil shale resources in each interval were further sorted according to oil-shale grade. Of the 352 billion barrels of potentially recoverable oil resources associated with high-grade (≥ 25-GPT) oil shale, the amounts present in the illitic, saline and leached intervals were 11%, 33% and 54%, respectively. Very little high-grade oil shale was associated with the overlying oil shale zones. These results highlight the importance of investigating the association between saline minerals and organic richness in the Piceance Basin oil shale, both to understand the geological setting and to facilitate resource development.

1963027 Geochemical Characterization of the Cow Ridge Member, a Freshwater Lacustrine Stage of the Eocene Green River Formation, Piceance Basin, Colorado

Birdwell, Justin[1]; McGlue, Michael M.[2]; Johnson, Ronald C.[1]; Ellis, Geoffrey S.[1]

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The Cow Ridge Member of the Eocene Green River Formation was deposited in a freshwater lake that preceded saline Lake Uinta in the Piceance Basin, Colorado. The thickest Cow Ridge deposition is in the central and northwestern portion of the Piceance Basin where it immediately underlies the Garden Gulch Member of the Green River Formation. Elsewhere in the basin, a tongue of fluvial Wasatch Formation separates the Cow Ridge Member from Lake Uinta sediments. The Cow Ridge Member is equivalent to the informal Uteland Butte member of the Green River Formation in the Uinta Basin and has been described as similar to the Luman Tongue of the Green River Formation in the Greater Green River Basin. The Cow Ridge Member is likely to be too thermally immature to have generated oil in the Piceance Basin, but it can serve as an analog for ongoing shale oil development in Uteland Butte. Outcrop samples were collected from several sections in northwestern Colorado and core samples were obtained from the U.S. Geological Survey's Core Research Facility in Denver. Samples were screened using infrared spectroscopy to assess mineral and organic content and further analyzed to determine programmed pyrolysis parameters, total organic carbon content, total carbonate, and stable isotopic composition of unaltered carbonates. Shale is the predominant lithology with interspersed marlstones, coquinas, sandstones, and some thin coal beds. Differences between the Cow Ridge Member oil shale and overlying shales of the Garden Gulch and Parachute Creek Member include the nearly ubiquitous presence of kaolinite, lower total organic carbon content, and lower hydrogen indices.

1955912 Mineralogy of the Green River Formation, Wyoming: Mining Old Data in the Light of New Models

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The Eocene Green River Formation (GRF), one of the richest source rock in the world, provides an important example for understanding formation of organic rich sedimentary rocks in lacustrine and possibly other environments. Tanavsuu-Milkeviciene and Sarg (2012) subdivided the GRF in Colorado into six stratigraphic stages in the evolution of Lake Uinta, and Boak et al. (2013) showed how mineralogic and geochemical changes related to the stratigraphic evolution. Major GRF member-level boundaries in Wyoming appear to correspond to stage boundaries in Colorado. X-ray Diffraction (XRD) data from the ERDA Blacks Fork No 1 well in the Green River Basin shows mineralogic transitions like those in the Piceance Basin. Peak height values for primary mineral peaks are not actual abundances, but can be used to identify trends in GRF mineralogy, by analogy with quantitative data from Colorado. The Tipton Member in the Blacks Fork well corresponds to the Transitional Lake Stage in Lake Uinta, with transitions from Dolomite+ Calcite+ Quartz+ Pyrite+ minor Feldspar, and Illite/ Feldspar >0.2 to Dolomite+ Siderite+ Analcime + K-feldspar+minor Pyrite with much lower Quartz, as well as Illite/ Feldspar <0.2. The Wilkins Peak Member corresponds to the Fluctuating Lake Stage in Lake Uinta, and is composed of Dolomite+Quartz+ Albite+K-feldspar±Pyrite, with Illite/ Feldspar <0.2 except in sandstone intervals. The unit is distinguished by the presence of shortite [Na2Ca2(CO3)3] and zones with Trona [(Na3(CO3)(HCO3)*2H2O], Nahcolite [NaHCO3] and Halite. Calcite appears primarily in the upper part in association with sandstones. The Laney Member is characterized by Dolomite+ Calcite+Quartz+Analcime+ Feldspar+minor Pyrite and Illite/ Feldspar <0.2, as well as local aragonite. Sodium mineral changes in the Transitional Lake reflect increasing salinity; the sequence Analcime – Albite – Shortite different from but parallel to Albite – Dawsonite – Nahcolite found in Colorado. The disappearance of shortite just below the top of the Fluctuating Lake Stage may parallel the disappearance of dawsonite in Colorado. Calcite+Quartz/ Dolomite+ Feldspar may reflect the degree of authigenic mineral formation near the sediment/ water interface. It decreases sharply in the upper Tipton, rises through the lower Wilkins Peak, fluctuates through the interval of periodic sand sheet deposition in the upper Wilkins Peak, and rises again at the Wilkins Peak/Laney boundary, where saline minerals stop being deposited. This ratio is also distinctly lower in richer oil shale. Mineral relationships suggest that redox conditions, salinity, pH, and silica activity were all important in creating the organic and sodic enrichment of the GRF. The assemblages may have relevance to less extremely enriched sedimentary rocks.

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1960751 Sussex Sandstone, Hornbuckle Trend, Powder River Basin, Wyoming: Lithofacies and Reservoir Properties in a Tight Oil Play

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The Sussex Sandstone in the Hornbuckle Trend in Converse County, Wyoming, produces oil from three main facies: bioturbated sandy mudstone, bioturbated muddy sandstone, and bedded sandstone. These facies are vertically stacked in two upward-coarsening parasequences. Detailed engineering analysis indicates that all of these facies are oil-bearing reservoirs that contribute to production. The bedded facies is cross-bedded to sub-horizontally bedded, has 5 to 14 percent porosity, and .05 to 4 millidarcies permeability. The bioturbated muddy sandstone has 4 to 14 percent porosity and .02 to .5 millidarcies permeability. The bioturbated sandy mudstone has higher clay content and has 4 to 10 percent porosity and .01 to .2 millidarcies permeability.

Two Sussex Sandstone cores provide examples of these facies. The Highland Flats Federal #13-11 core recovered 43 feet of bioturbated facies and 10 feet of bedded sandstone facies. This well was completed in 1984 for an IP of 175 BOPD after a DST recovered 240 feet of SO&GCM; this vertical completion has produced 188 MBO.

The Brazos State #14-16 core recovered 52 feet of bioturbated facies and 2 feet of bedded facies. A DST of the Sussex in this well recovered 70 feet of drilling mud indicating low permeability, so in spite of oil and gas shows in the samples, this vertical well was plugged and abandoned in 1986. Horizontal wells recently drilled adjacent to this dry hole initially produced 600 to 900 BOPD. These two wells illustrate how modern horizontal drilling and completion techniques can recover oil that older vertical completions could not.

1960766 Sussex Sandstone Tight Oil Play, Powder River Basin, Wyoming, Extension of the Hornbuckle-Spearhead Trend with Horizontal Drilling

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Oil production was first established from the Campanian Sussex Sandstone in the Powder River Basin with the discovery of House Creek Field in 1968. Oil production from a second Sussex Sandstone trend was discovered when production was established at Spearhead Ranch (1983) and Hornbuckle (1984). The first Sussex horizontal well in the Hornbuckle-Spearhead trend was drilled in 2006 by Southwestern Production Corp. The Blaylock-Federal #13-35A had excellent shows, but high formation pressures necessitated completion of the well through cemented drill pipe, resulting in a peak rate of 79 BOPD. Overpressure up to 0.65 psi/foot was underestimated due to low reservoir permeability. This geological success set the stage for additional horizontal drilling, which has now increased Sussex production in this trend from less than 500 BOPD to more than 6500 BOPD and basin wide Sussex production to more than 8000 BOPD.

The Sussex Sandstone at Hornbuckle consists of interbedded very fine to medium-grained glauconitic and calcareous sandstone, chert pebble and siderite-clast conglomerate, and silty shale. These heterolithic strata are burrow-mottled at the base and coarsen upwards. Burrow structures show a change from Cruziana to Glosssifungites ichnofauna, corresponding to the overall bathymetric shallowing and coarsening of detritus. Porosity ranges from 4 to 14 percent and is developed within the entire sandstone interval, with the best porosity developed in the higher-energy facies. Engineering analysis of production data identifies heterogeneities not observed with widely-spaced geological data, establishes the importance of the bioturbated facies to net pay, and facilitates mapping of reservoir compartments. Integration of geological models with production data analysis provides a consistent reservoir description that can be used to help maximize production from horizontal and vertical well development.

1959538 Characterization and 3-D Modeling of Devonian Pinnacle Reefs for CO_2 Storage and Enhanced Oil Recovery

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The Energy & Environmental Research Center, through the Plains CO_2 Reduction Partnership Program, has characterized various Devonian-aged pinnacle reefs in the Zama Member of the Muskeg Formation and the Keg River Formation in the Western Canada Sedimentary Basin and the Winnipegosis Formation in the Williston Basin for potential

CO_2 storage and CO_2 enhanced oil recovery. These pinnacle reefs were characterized by constructing 3-D geocellular models using a database containing geologic interpretations, well logs, and core data. The geologic models were constructed by first building structural surfaces, populating a facies model, and then performing geostatistical analysis on reservoir properties. Finally, the models were passed on to dynamic simulation for predictions.

These Devonian pinnacle reefs have been altered by diagenetic processes and cemented by anhydrite deposits, creating complex geometry and heterogeneous internal facies. In addition, these pinnacle reefs vary widely in size depending on the conditions during deposition. Thus structural models were built to capture a wide variety of sizes and internal architecture. Multiple-point statistics were used to construct facies models based on geologic interpretations that honor well data and reservoir properties were then conditioned to each facies model. The models were prepared for dynamic simulations, which calculated the total CO_2 storage of 5000–10,000 metric tons for each pinnacle, with up to 1000% additional storage when optimization techniques were utilized.

The approach utilized in this study will allow others to more efficiently construct pinnacle reef models and perform predictive simulations to determine the potential for oil recovery and/or CO_2 storage.

1967511 Regional Sequence Stratigraphic Analysis of the Upper Cretaceous Telegraph Creek and Eagle Formations in South-Central Montana

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The Santonian to Campanian Telegraph Creek and Eagle formations in south-central Montana contain a series of regressive to transgressive cycles deposited on the western margin of the Cretaceous Western Interior Seaway. This study focuses on depositional environments and stratal stacking patterns. Four cycles are identified and mapped regionally over an area of 6,000 km2 using outcrop and subsurface data to correlate 100 km up paleoslope from their maximum seaward extent.

Each cycle of progradation and subsequent transgression left behind an upward-coarsening shoreface and/or deltaic sandstone body, capped by either a transgressive sand, an erosional top or maximum flooding surface. The stratigraphically lowest cycle studied, in the upper Telegraph Creek Formation, contains a single regressive sandstone topped by a transgressive ravinement chert pebble lag. The overlying Eagle Formation is composed of three genetically related regressive to transgressive cycles: 1) a basal cycle consisting of a detached low-stand delta capped by a ravinement surface which is overlain by transgressive glauconite-rich " green" marine sands and a maximum flooding surface; 2) a middle cycle composed of a sharp-based forced regressive shoreface and deltaic deposits that are erosionally incised with the incision surface indicative of base-level fall and representing a sequence boundary, which is overlain by a subsequent transgressive tidally-influenced valley-fill; and 3) a top cycle consisting of a normal regressive shoreface deposit capped by a transgressive ravinement surface containing black-chert pebbles, representing the Claggett transgression. Each successive regressive to transgressive cycle steps consecutively basinward creating a larger progradational wedge.

1958190 Advanced Seismic Imaging Tools for Unconventional Targets in Complex Geology?

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Operators in unconventional resource plays now generally acknowledge important roles (geosteering and geohazard avoidance) for 3-D seismic data. Still, seismic is hardly "existential" to most plays, unlike traditional seismically-driven plays. If an operator acquires seismic data at all, it is only after locking up a large land position and planning the drilling program.

However, with available acreage at a premium, unconventional players will inevitably move into more geologically complex areas, where conventional time migration processing may fail to resolve faults or may mis-position steeply dipping beds.

Our case study highlights the performance of RTM (Reverse-Time depth Migration) on a 2D line from the Colorado Front Range. The basin sediments are about 12,000 feet thick, and against the mountain front, the fractured Niobrara Shale section produces oil. Laramide compression produced a low-angle thrust fault, which uplifted and tilted the basin sediments at a 40-degree angle. The resulting lateral velocity variation causes a false time structure and laterally mis-positions events on time migrations.

By closely integrating geophysics and structural geology, we constructed a geologically-feasible velocity model which produces a well-focused seismic image. We found that a TTI (tilted transverse isotropic) RTM produced the best image of the steep dips and sub-thrust features.

By combining the most advanced geophysics with structural geology, we demonstrate the potential for seismic data to play a pivotal role in de-risking unconventional plays as operators move into more complex basins.

1967161 Playa and Lunette Sedimentation Response to Artificial Water Levels: Case Study of the San Luis Lake Area

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San Luis Lake, one of the largest playa systems within the aeolian environment of the San Luis Valley, has been artificially filled and modified, to keep it at levels suitable for fishing and recreational boating, for approximately 80 years. Recently, San Luis Lake has been allowed to fully dry out, exposing the playa sediments for the first time since artificial filling began. This has had a unique effect on the sedimentation patterns within the system. Prolonged high waters levels, that have not been allowed to drop, have cut off the supply of fine sediments to the adjacent lunette system, thereby causing the dunal system to begin to erode away. This is essentially a forced climatic response in the dunes, which respond directly to their playa derived source of fines. At present, the dunes record a prolonged wet climate even though that is not the climatic regime that has been in place over the valley. This is creating a conflicting climatic record in the dunal system, with most dunes recording the semi-arid, drought affected patterns of the region, and the lunettes, in contrast, recording a significant wet period. The artificial filling has also forced a unique response in the lacustrine sediments found at the center of the playa. A thick, black, organic rich layer, not found elsewhere at the site, is found in the depocenter of the playa. This layer is up to 36 cm thick and has a pervasive, strong, sulfurous odor that can be smelled in the groundwater up to 150m away from the edge of the deposit. This effect of this layer, and the by-products it has been creating, on the groundwater, is currently unknown, but the layer does appear to be a response to the artificial fill in the playa. Other wet cycles in the region do not correlate to such layers, leading to the conclusion that forcing the system to remain filled and not allowing the cyclic dry/wet patterns has created a unique, human-related deposit in the center of the playa. This deposit is unique and while thinner versions may exist in other deposits elsewhere in the world, the thickness of this deposit is not known to be within normal ranges. While part of the thickness may be due to San Luis being located at the depocenter, the presence of such a thick layer and the fact it is impacting groundwater a fair distance from the edge of the deposit may be indicating that the deposit may be contributing to the degrading water quality in the valley.

1964714 Multiphase Deformation of Paleozoic and Mesozoic Units, Nebraska Panhandle, USA

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Renewed interest in the hydrocarbon systems of the Nebraska Panhandle stems from the increasing economic viability of unconventional plays, which must be understood in terms of regional geologic structure. We present preliminary interpretations of a seismic dataset from the north-eastern margin of the Denver-Julesburg (D-J) basin.

The study area is in the Alliance sub-basin, partially separated from the main D-J basin by the Morrill County High. Other local highs create similar, partially isolated basins. The regional stratigraphic succession includes two targets for exploration: (1) Pennsylvanian-Permian carbonate-dominated cyclothems and clastic sediments, and (2) the Cretaceous succession. Hydrocarbon plays have traditionally targeted the latter, but interest in the Paleozoic succession is increasing.

The present study analyses a series of 2D seismic lines, dominantly oriented NE-SW, with sufficient crossing lines to build a 3-D representation of the survey area. Formation tops were picked from key wells and associated velocity profiles, and then mapped across the remaining lines. The basal Cenozoic unconformity, as well as Mesozoic and late Paleozoic strata, are clearly imaged on these lines. Pre-Cenozoic units dip to the SW, consistent with the position on the margins of the D-J basin. The late Paleozoic section is subtly folded with both normal and reverse offset faults visible in the overlying Cretaceous section.

Subtle folds within the late Paleozoic section may be zones of enhanced porosity due to fold-related fracturing, making them suitable as targets for unconventional exploration. In addition, folded and fractured zones may have been further deformed in subsequent tectonic events.

1966627 Diagenesis of Organic-Rich Shale: Views from Foraminifera Penetralia, Eagle Ford Formation, Maverick Basin, Texas

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Diagenetic studies for conventional reservoirs is well-established by the petroleum industry to better understand the geologic controls of reservoir quality, designing appropriate completion fluids, and evaluating potential rock-fluid changes during primary and enhanced recovery. Until recently, shales were not considered as important petroleum reservoirs, and industry interest in shale diagenesis has been much more limited, mainly concentrated on clay diagenesis, fluid expulsion and the genesis of overpressure.

Recent advances in sample preparation and scanning electron microscope (SEM) techniques have allowed researches to adequately image clay-sized gains and to peer into nanometer scale pores that lie beyond the capabilities of optical microscopy. This study presents new methods and observations using color-enhanced backscattered electron SEM images to interpret mineral cement and organic matter paragenesis to develop a diagenetic model for Eagle Ford organic-rich shale and reservoir quality evolution.

Planktonic foraminifera tests are abundant and widespread in the Eagle Ford shale of south Texas. The initially hollow internal chambers of these minute foraminifera tests (commonly less than 100 mm long) provide sturdy and stable miniature crucibles that offer a unique opportunity to study the evolution of diagenetic products resulting from changing thermo-chemical reactions during sediment burial. Cement mineralogy and paragenesis within a single SEM specimen differs between foraminifera chambers the interparticle pores found within the surrounding calcareous and siliceous matrix. These differences may reflect fluid flow circulation and chemistry differences between the relatively isolated and restricted foraminifera chambers and the more open matrix pore network.

1965422 A Core Calibrated Log Model Workflow for Shale Gas and Tigbt Oil Reservoirs

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A simple, transparent, deterministic log analysis workflow was developed to compute critical reservoir properties in shale gas and tight oil reservoirs. The model is calibrated to core determined values including mineral volumes, porosity, fluid saturations, total organic carbon content, free and adsorbed gas storage capacities, and in-situ oil content.

The interpretive workflow starts with basic editing, environmental corrections, and quality assurance of both core and log data. Core samples must be precisely depth shifted to align correctly with the wireline or LWD log data. All available logging measurements are extracted at the matching depths of the core data. Deterministic equations are developed using a general purpose statistical regression package via univariate or multivariate, linear and non-linear regressions. Regression models are simultaneously tested and the optimal equations requiring the fewest possible logging measurements are selected. Mineralogy in weight percent is determined by regression against X-ray diffraction mineralogy; total organic carbon is determined by regression against SRA or Leco TOC contents; etc. The average inorganic and organic matrix densities are jointly determined using a general purpose solver, minimizing the error between the model predicted and the core determined porosity and TOC. Saturation model parameters are set by adjusting model parameters to minimize the error between the log model saturations and the core determined values. Adsorbed gas storage capacities are computed from a Langmuir isotherm model requiring TOC, an optimized Langmuir volume vs. TOC equation, optimized Langmuir pressure, and known or estimated reservoir pressure. Free gas and oil are computed by conventional methods from the calculated porosities and saturations corrected for the physical volume occupied by the adsorbed gas phase.

The proposed workflow has several advantages over stochastic, neural network, and other multi-mineral approaches, not the least of which is total transparency and documentation of the solution. As additional core data are acquired, the model can be quickly revised to reflect new information. It is also very simple to determine the minimum number of log curves needed to calculate reservoir properties at fit-for-purpose accuracy. This maximizes the historical log dataset that can be used and also clarifies the value of expensive or exotic logging measurements.

1967521 Comparative Geochemical and Spectral Gamma-Ray Study of the Lower Mancos Shale, Southwestern Piceance Basin, Southern Douglas Creek Arch, and Southeastern Uinta Basin, Colorado and Utah

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This study involves a comparative analysis of subsurface and surface mineralogical, geochemical, and spectral gamma-ray data for the lower third of the Upper Cretaceous Mancos Shale near Grand Junction, CO. The study interval, ~1,010 ft thick, is subdivided into three informal intervals. Interval A (base) is about 480 ft thick and spans from top of the Dakota to top of the Frontier ("Dakota silt"). Interval B, ~ 230 ft thick, is equivalent to the Blue Hill, Juana Lopez, and Montezuma Valley Members. Interval C (top), ~ 300 ft thick, includes the Fort Hays Member and lower one-third of the Smokey Hill Member. Public domain subsurface information used for this study includes total-organic-carbon (TOC; N=182), RockEval (RE; N=173), spectral-gamma-ray (SGR; N=49), and calcimeter data (N=36) from 39 wells. Most

analyses were conducted on cuttings. Two outcrop sections, totaling 714 ft., were measured (with SGR).

TOC and RE data satisfactorily differentiate the intervals. Average TOC, RE (S1, S2, and S3) values for Interval A (N=30) are 1.14wt%, 0.35mgHC/gm, 1.10mgHC/gm, and 0.25mgCO_2/gm, respectively. For Interval B (N=71), the averages are 1.69, 0.57, 2.51, and 0.34, whereas in Interval C (N=76), they are 1.31, 0.40, 1.22, and 0.32, respectively. Calcimeter data also show differences between the intervals, with interval A (N=3) averaging 14.8, B (N=15) 17.3 and C (N=18) 24.2 wt% carbonate, respectively. The SGR values from cuttings and outcrops are not sensitive enough to discriminate the three intervals. However, the vertical profiles of the K, U, and Th are useful for discriminating lithology.

1945302 Enhanced Formation Evaluation of Shales Using NMR Secular Relaxation

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Determining the porosity associated with organic and inorganic components of shales is an important but difficult part of formation evaluation in unconventional resources. Nuclear magnetic resonance (NMR) measurements offer a means of quantifying organic and inorganic porosity by separating the inorganic porosity, where proton relaxation occurs by paramagnetic interactions, from the organic porosity, where proton relaxation occurs by intermolecular dipole interactions. We performed laboratory measurements on preserved Bakken and Eagle Ford samples with a 2.2 MHz nuclear magnetic resonance (NMR) core analysis system. Additional measurements were performed on a Barnett sample in the as-received state. We constructed two-dimensional maps of T1 and T2 with different echo spacings for the T2 measurement and computed distributions of T1/T2 ratio and the secular relaxation rate, which is the difference between the transverse and longitudinal relaxation rates. Based on the distribution of T1/T2 ratios and the change in secular relaxation rate with echo spacing, we were able to differentiate organic porosity, inorganic porosity, and the relaxation signal from the organic material itself. The differentiation is based on theoretical consideration of relaxation times due to paramagnetic and dipole interactions. The T2 values we found for the organic material and associated porosity are generally shorter than 1 ms while the T1 values are generally 1-10 ms, indicating that T1 measurements may be a feasible means of quantifying organic material downhole.

1966764 Basin Evolution of the North Park – Middle Park Basin, Colorado

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The North Park- Middle Park basin, just 'behind' the Colorado Front Range, has been a target for oil and gas exploration since the early 1920s. As in the Denver Basin, recent drilling has mostly focused on the Niobrara Fm. Targets in the basin are not straightforward due to the area's structural complexity, and basin history is difficult to unravel due to absent marker beds. This study illustrates basin evolution based on field observations, paleobotany, well-logs, published seismic lines, vitrinite reflectance data and geochronology.

Detailed study of the Tertiary basin fill reveals new insights in the Laramide and mid-Tertiary evolution of this basin and the neighboring Front Range. Late Cretaceous and early Paleocene time is marked by significant (>~3000 ft) widespread erosion, and locally, as much as 7,000 ft of sediments were eroded down to the level of the Dakota Sandstone. The basin started to subside in middle Paleocene and accumulated coarse-grained, predominantly volcaniclastic deposits in the south after about 60.5 Ma. Rapid subsidence followed with sediment accumulation rates as great as ~750 m/Ma. Ponding developed and lacustrine, paludal and fluvial sediments filled the basin. Deposition shifted northward during the later Paleocene and early Eocene time. Angular unconformities within the sediments indicate active deformation during deposition, but these unconformities appear to be local. Coarse-grained sediments are generally uncommon within the basin fill, suggesting that contemporaneous uplifted source areas were distant. Rise of basement rocks in the modern Park and Front Ranges is mostly younger than these Paleogene sediments.

1965636 Using Microseismicity to Understand Subsurface Fracture Systems and Increase the Effectiveness of Completions: Eagle Ford Shale, TX

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Existing natural fractures often have a significant impact on both stimulation and production of oil and gas wells. Effective exploitation of unconventional reservoirs requires the understanding of the local tectonic history and the present day stress regime. Signal strength, high quality reflection seismic, microseismic imaging, and moderate structural complexity of the liquids-rich gas and tight oil Eagle Ford shale makes it an ideal place to study hydraulic fracturing in tight rocks. Microseismic monitoring results showed clear structural trends relating to reactivation of existing faults and fractures, and rock failure mechanisms. These results provided critical information to the operator for optimizing the hydraulic fracture design.

Microseismic data collected using a surface array allowed the full geometry of the result to be viewed with no directional bias. The geometry of the microseismicity trends related to fracturing developed during the stimulation treatment were representative of the true geometry of the structure. The large aperture and wide azimuth of the monitoring array facilitated the determination of source mechanisms from every event detected, which provided full coverage of the focal sphere of each source mechanism. The events identified two different source mechanisms, indicating a different failure mechanism for fractures than for reactivated faults.

Microseismicity with a NE-SW trend are interpreted to be related to induced or reactivated fractures. Microseismicity also formed contiguous trends across multiple wellbores in a ENE-WSW direction. These trends are interpreted to be the result of fault reactivation. Source mechanisms from faulting parallel to SHmax have failure planes striking NE-SW with normal dip-slip failure on steeply-dipping planes. Those from fault reactivation have strike-slip failure on ENE-WSW striking failure planes. The orientations of the fault-related trends parallel extensional Gulf of Mexico growth faulting. The microseismicity trends associated with fracturing are at approximately 25o to the faulting trends.

The operator combines treatment pump parameters for the wells with the structural understanding gained from the analysis of fracture trends and source mechanisms to identify zones that should be avoided in subsequent treatments. Mapped microseismicity provides critical information for modification of well spacing for subsequent wells, optimizing the completion plan and cutting costs.

1938459 Claude Shannon Versus Gus Archie: Information Theory as a Guide to Log Evaluation without Petrophysics

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Around 1950 Gus Archie, working at Shell Oil, changed petroleum exploration by developing a theoretical foundation for e-log interpretation based on certain electrical properties of rocks. From this discipline of petrophysics, Archie's Equation is universally used and needs no introduction. At about the same time Claude Shannon, working at Bell Labs, changed communication by developing a mathematical structure for messaging. Oversimplifying the explanation

here, information theory uses the received signal to assess if data have changed the probability that some predictable outcome is valid. Verification of the expected outcome is redundant and provides no new information. New data add information only if they change the weight of evidence to suggest that an unexpected event (a surprise) has occurred. For information theory, the message itself is understood only to be a choice between possible alternatives; the actual meaning of the message is not relevant.

This paper proposes that the principles of information theory provide a suitable framework for a "theory-less" evaluation of triple-combo log data by identifying unexpected or anomalous pairings in key log parameters. Further, geologic interpretations derived from these anomalies generate significant results for exploration in shale resource plays.

Examples of key cross-plot pairs (independent variable -v- dependent variable) from log data will be shown: (1) shale (clay) volume -v- average neutron-density porosity and (2) average neutron-density porosity (log scale) -v- resistivity (log scale). Where the dependent variable is predictable from the independent variable (typically a linear trend), redundancy dominates and no significant information is present. In contrast, an anomalous positive deviation of the dependent variable from the predictable baseline trend signals "surprising" information and the probability is quantifiable based on the amount of deviation. From these plots we can make geologic interpretations concerning (1) effective porosity in the shales and (2) hydrocarbon charge.

In this way the meaning of the message is separated from the probability that it is valid. Pay zones can be identified on the logs and mapped based on the coincidence of a high probability for effective porosity and hydrocarbon saturation.

1967370 Predicting Fluid Quality from Regional Thermal Maturity Studies

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The ability to predict fluid quality prior to production from tight oil and gas plays can be necessary to determine the economic viability of a play. There are many tools available to the explorationist to determine the maturity of rocks, oils and gases. The stable isotopic composition of natural gas is useful in the interpretation of gas type (i.e., bacterial versus thermal origin), hydrocarbon maturity, migration and reservoir compartmentalization. With a properly developed regional calibration, stable isotope data can be used as a reliable indicator of oil-associated gas maturity. By comparing rock and gas maturity data, we can also estimate if reservoir hydrocarbons migrated or accumulated in-situ. If a tight oil and gas play can be classified as a petroleum system with low to no migration, determination of the maturity of the fluid itself can lead to a robust fluid maturity predictor.

Gases associated with liquids production are often collected prior to completion operations in tight oil and gas plays. Mud gases can be collected while drilling, desorbing gases from collected cuttings or core rock, and production oils and gases from nearby wells can be analyzed and interpreted for fluid maturity. The framework utility of regional basin modeling is to establish a rock maturity baseline. The derived oil and gas maturity can be quickly compared to the rock maturity to delineate migration in a play. Correlation of carbon and hydrogen isotope maturity from methane, ethane, and propane to gas to oil ratio and condensate yield is established. A regional dataset such as the one presented here allows for the creation of a regional maturity map which can be an invaluable tool in identifying dry gas, wet gas, retrograde gas, volatile oil and black oil associated areas of an unconventional resource play.

1958495 Workflow Optimization Using Python Programming, a Tool Kit for Every Geoscientist

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The Energy & Environmental Research Center (EERC), in partnership with the U.S. Department of Energy National Energy Technology Laboratory and the IEA Greenhouse Gas R&D Programme, has been investigating the viability of storing large quantities of CO_2 in geologic formations. As part of this investigation, the EERC has developed an approach that integrates site characterization, modeling and simulation, risk management, and monitoring throughout a project to develop meaningful results. Each of these aspects involves manipulation of data, whether in a relational database, model, or map-based product, which may involve one or more software packages. Several time-saving and data optimization schemes have been developed using the Python programming language. This object-oriented approach has proven successful in building semiautomated workflows to optimize geographic information system (GIS), petrophysical modeling, and 3-D modeling applications.

The following three examples of Python workflows have significantly enhanced project efficiency, allowing for more time to be spent interpreting results and meeting project deadlines: 1) a GIS workflow to build maps to track CO_2 movements from output files of numerical simulation, increasing efficiency by nearly ten times; 2) a workflow to optimize petrophysical analysis by clipping, shifting, and combining geophysical well logs; and 3) a workflow to improve data transfer from a 3-D geocellular model to dynamic simulation by calculating injectivity to optimize well placement and perforations and to calculate bottomhole pressure constraints. While other programming languages can perform similar tasks, Python has an easy-to-learn syntax and module database suitable for any scientist.

1967533 The Knoll Limestone "Bench" of the Three Forks Formation, West-Central Montana: An Exposed Unconventional Reservoir

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Recent field studies in support of PRISEM's ongoing Sappington-Bakken project in west-central Montana provide a new understanding of the stratigraphy and sedimentology of unconventional carbonate reservoirs in the Three Forks Formation and their relationship to coeval strata in the subsurface of Montana, Alberta and North Dakota.

The Lower to Middle Famennian Three Forks Formation occurs between the Birdbear/Nisku and overlying Sappington/Bakken formations. The Three Forks was deposited across western North America during a global lowstand and subsequent transgression. At Logan Gulch, Montana, the Three Forks is divisible into a lower restricted Logan Gulch Member (Stettler/Torquay) and an upper restricted to open marine Trident Member (Big Valley).

The Logan Gulch Member is comprised of restricted sabkha lithologies with interbedded evaporites which are leached into collapse breccias in outcrop; this facies is 100s of feet thick in the subsurface (Potlatch Member). The overlying Trident Formation consists of restricted and subaerially exposed shales and limestones, overlain by green fossiliferous marine shales and limestones that record the incursion of open marine waters onto the craton.

The boundary between the two members of the Three Forks Formation is marked by a regionally persistent 5 to 40 ft thick limestone herein named the Knoll Limestone after a prominent knoll at Logan Gulch. The Knoll Limestone was deposited above a sharp sequence boundary incised into the underlying Logan Gulch Formation. The Knoll Limestone is a petroliferous bioturbated lime mudstone, with interbeds of cross-bedded pelloidal and intraclastic grainstone, stromatolites,

and rare brachiopods. The Knoll Limestone varies in thickness over short distances due to brecciation of the underlying Logan Gulch Member, although field relationships also reveal syndepositional salt movement. Secondary diagenetic fabrics like brecciation, dissolution, and recrystallization are associated with subaerial exposure before deposition of the overlying Trident Member. Oil and gas shows are common in the subsurface of Montana and the Knoll Limestone should be considered a tight, unconventional carbonate reservoir with low primary porosity that has been enhanced by secondary diagenesis.

The Knoll Limestone records regional flooding of the exposed Logan Gulch platform across most of Montana, Idaho and Alberta (correlating with carbonates in the Stettler or Wabamun formations). It also extends eastward into the Williston Basin where it correlates with the producing "benches" of the Three Forks Formation. Continuing studies of the Knoll Limestone in outcrop will assist in defining areas with higher primary porosity (coarser facies) and contribute to our understanding of these unconventional evaporite-associated carbonate reservoirs.

1967996 Natural and Artificial Cracking of Oil Source Rocks and Unconventional Reservoirs

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Source rocks expel oil and gas when the internal pressure generated by volume increase reactions due to the conversion of kerogen to solid bitumen and then to oil and gas exceeds the geostatic pressure. The rocks naturally rupture, oil and gas are expelled or pushed out, and the pressure drops below geostatic. This process is repeated many times as the source rock passes through the oil and gas maturity "windows". Primary oil and gas expulsion is very inefficient with less than twenty percent of the oil and gas generated ever leaving the source rock.

Unconventional reservoirs are most commonly suspended oil source rocks. They were once active but stopped generating prior to becoming spent due to cooling associated with overburden removal. Internal pressure is between hydrostatic and geostatic depending on sealing capacity and other factors. Hydrocracking artificially ruptures the source rock and some additional oil and gas are pulled out by differential pressure between the source rock and the well bore. Like primary oil migration, the process is very inefficient and less than ten percent of the oil and gas remaining in the source rock is produced.

Many factors control the efficiency of both natural oil expulsion and artificial fracking oil and gas production. Some of these include the concentration and distribution of organic matter in the source rock, the anisotropy of both the organic matter and lithological units within the source rock, the brittleness variations of source rock lithologies, natural and artificial frac barriers, oil and gas composition at various maturities, differential permeability of produced products, and a host of other factors which affect the efficiency of both source rocks and unconventional reservoirs.

1969220 Assessing the Carbon Sequestration Potential within the 8ear River Formation of the Wyoming-Idaho-Utah Thrust Belt

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The United States Geological Survey (USGS) was directed by the 2007 Energy Independence and Security Act to assess the potential geologic storage resources for carbon dioxide (CO_2) within the United States. Utilizing its probabilistic methodology for a national CO_2 geological sequestration assessment, the USGS has assessed the storage potential of the shale and sandstone dominated Cretaceous Bear River Formation within the Wyoming-Idaho-Utah (W-I-U) thrust belt.

The basic assessment unit used in the USGS methodology is the Storage Assessment Unit (SAU), which consists of a storage formation and an overlying regional seal formation. The SAUs are defined by geologic criteria that include rock properties, formation depth, and regional extents of the storage and seal formations. The methodology requires that the storage formation be porous and permeable, and at depths of 3,000-13,000 ft below ground surface to ensure that CO_2 will remain in a supercritical phase. In some instances, thrusted Bear River Formation overlies a repeated, deeper section of Bear River Formation and rock properties indicate that CO_2 could be stored at depths greater than 13,000 ft, in a separate "deep" SAU.

The storage formation and overlying seal are required to be continuous and regional in extent. Within the W-I-U thrust belt, there are thick, regionally extensive, marine shales (Aspen and Mowry Shales) which could inhibit the flow of buoyant CO_2 into overlying strata. This USGS carbon sequestration assessment has shown that there is potential for CO_2 sequestration within the structurally complex Cretaceous Bear River Formation of the W-I-U thrust belt.

1958794 Sedimentary Processes and Trace Fossil Communities in the Upper Shale Member of the Upper Devonian-Lower Mississippian Bakken Formation, North Dakota, USA

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Black, organic-rich rocks of the upper shale member of the Upper Devonian-Lower Mississippian Bakken Formation, a world-class petroleum source rock in the Williston Basin of the United States and Canada, contain a diverse suite of mudstone lithofacies. The succession consists of 3 facies associations (FAs). These are: 1) siliceous mudstones, 2) quartz and carbonate-bearing laminated mudstones, and 3) macrofossil debris-bearing massive mudstones. These FAs were deposited in three facies belts that reflect proximal to distal relationships. The macrofossil debris-bearing massive mudstones (FA 3) occur in the proximal facies belt and contain erosion surfaces, some with overlying conodont and phosphate-lithoclast lag deposits, mudstones with abundant millimeter-scale siltstone laminae showing irregular lateral thickness changes, and shell debris. In the medial facies belt, quartz and carbonate-bearing laminated mudstones dominate, exhibiting sub-millimeter siltstone layers with variable lateral thicknesses and local mudstone ripples. In the distal siliceous mudstone facies belt, radiolarites, radiolarian-bearing mudstones, quartz and carbonate-bearing laminated mudstones dominate. Total organic carbon (TOC) contents range between about 3 and 10 wt %, with a general proximal to distal decrease in TOC content. Abundant evidence of bioturbation exists in all FAs, and the lithological and TOC variations are paralleled by changes in burrowing style and abundance: two horizontal burrows and two types of fecal strings are recognized in the proximal facies belt, and only one horizontal burrow and one type of fecal strings characterize mudstones in the distal facies belt with none present in some millimeter-thick radiolarites.

Bed-load transport processes, likely caused by storm-induced turbidity currents were active across all facies belts. Suspension settling from near the ocean surface, however, most likely played a role for depositing some of the mudstones, and was probably responsible for deposition of the radiolarites. The distribution pattern of high-TOC sediments in proximal and lower TOC deposits in some distal facies is likely a function of higher accumulation rates during radiolarian depositional events leading to a decrease of suspension-derived organic carbon within radiolarite laminae. The presence of burrows in all facies associations and nearly all facies in the upper Bakken shale member indicates that dysoxic to oxic conditions prevailed during deposition throughout this mudstone sedimentary system. This study shows that in intracratonic high-TOC mudstone successions such as the upper Bakken shale member, bed-load processes most likely dominated sedimentation, and conditions promoted a thriving infaunal benthic community. As such, deposition of the upper Bakken shale member through dynamic processes in an overall dysoxic to oxic environment represents an alternative to conventional depositional models for world-class source rocks.

1958011 Wide-Azimuthal 3-D Seismic Data Integrated with Geologic Information from Open-Hole Logs Unlocks the Secrets of a Naturally Fractured Trap in the Western Uinta Basin, Utah

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Test results from an exploratory well drilled into the upper Wasatch Formation north of Brundage Canyon Field in late 2012 indicated that the bulk of the production came from naturally fractured zones. With an initial production rate of over 500 BOPD from thin-bedded, low porosity sandstones in the exploratory well, it was important for the asset team to understand the role of natural fracture enhancement before field development began. To assist with development planning, a wide- azimuthal 3-D seismic survey was shot across the prospect and surrounding area. Although geo-mechanical properties such as Young's Modulus and Poisson's Ratio may be extracted from wide-azimuthal data, the primary objectives of the 3-D survey were to gain a better understanding of the regional structural fabric adjacent to the Duchesne Fault zone and estimate natural fracture intensity and orientation.

Data from borehole image logs run in the exploratory well and several early wells showed a high frequency of open fractures with a dominant NW to SE direction in the Castle Peak Member of the lower Green River Formation. However, zones with a high frequency of open fractures in the underlying upper Wasatch Formation exhibited multiple directions. Production log runs indicated that these intervals contributed significant production to the wells. The combined data set substantiated results from the 3-D survey which showed high anisotropy associated with the Castle Peak and low anisotropy for the upper Wasatch intervals.

Integration of wide-azimuthal 3-D seismic data with borehole image and production log results was very important in understanding reservoir characteristics and mapping areal limits of naturally fractured "sweet spots". Thirteen wells have been drilled to date with an average per well EUR of approximately 100 MBOE. When full development is completed, the anticipated reserves will approach 2.0 MBOE.

1965703 Permian Salt Dissolution in Silo Field, Laramie County, Wyoming

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Within Silo Field, a Permian salt edge exists. This salt edge was believed to be the cause of faulting and fracturing within the Niobrara Formation but studies have shown that this is not the case. Using a 3-D seismic survey encompassing approximately 30 square miles, the nature of the salt edge was examined. The irregular shape of the salt edge suggests that it was caused by dissolution rather than deposition. Dissolution occurred during the Late Jurassic and Early Cretaceous. Two of the proposed mechanisms for salt dissolution include: compaction-driven water migration in the Lyons Formation and basement tectonics. Based on the seismic patterns observed, basement tectonics was the likely control on the location of the salt edge but further analysis is required to determine the role played by the Lyons Formation. The Permian salt also has an effect on the overall structure of Silo Field. The field exhibits a structural monocline in all of the strata overlying the Permian salt. Differential compaction over the salt edge creates the monocline. However, basement structure also has some control on the structural monocline. The lack of salt and timing of dissolution caused a thickened Dakota-Sundance interval in the southwestern part of the survey area. It is possible that this thickened section is the cause for high water production from the Niobrara in Silo Field. Understanding the nature of the Permian salt edge in Silo Field could have implications for understanding Permian salt dissolution and its impact in other Rocky Mountain fields.

1966410 Tectonic Erratics - Remarkable Exotic Blocks Emplaced by the Henderson Thrust, Eureka County, Nevada: A New Petroleum Exploration Target in North-Central Nevada

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Throughout north-central Nevada, Cambrian-Devonian, largely siliciclastic strata of the Roberts Mountains allochthon (RMA) overlie an autochthon of coeval largely carbonate strata. In Eureka County, masses of the carbonate strata also form topographic highs above the RMA, and on the east side of the Roberts Mountains they occur along a post-Antler thrust fault that duplicates the RMA. We propose that the Henderson thrust initially developed along the Roberts Mountains thrust and then ramped upwards and eastwards duplicating the RMA. In the process, carbonate blocks were plucked from the lower plate of the Roberts Mountains thrust and incorporated and transported in the upper plate of the Henderson thrust. Over large areas, the siliciclastic strata of the RMA in the upper plate of the Henderson thrust has been removed by erosion, but the carbonate blocks carried in the upper plate remain as topographic highs structurally overlying the siliciclastic strata of the RMA in the lower plate of the Henderson thrust. Those forming Lone Mountain and Devils Gate are several kilometers long and up to 300 m thick. They bear an analogy to glacial erratics and are termed tectonic erratics. Along a north-south trending belt in Eureka County, both upper and lower plates of the Henderson thrust dip to the east, and the tectonic erratics occur in the base of the upper plate. We propose that these erratics in the subsurface are potential reservoir rocks for oil fields such as the one at Blackburn, Eureka County.

1967387 Past, Present and Future Advancements in Methods for Detecting Hydrocarbon Seepage after 75 Years

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It has been over 75 years since German and Russian scientists first identified anomalous methane seeps above gas fields in the mid-1930's. In the United States a few years later, Rosaire and Horvitz extracted hydrocarbon gases from soil samples over oil and gas deposits. Leo Horvitz, a pioneer in the field of near-surface geochemical prospecting for oil and gas, presented his final paper titled "Hydrocarbon Geochemical Exploration after Fifty Years" at the Symposium on Unconventional Methods in Exploration for Petroleum held by the Institute for Earth and Man, Southern Methodist University in 1985. At the same symposium Leigh Price discussed the now abundant evidence and compared the many theories that attempted to explain vertical migration concluding with a now generally agreed upon gravity driven micro-bubble theory. This theory best explained the near vertical outline of most anomaly patterns found over petroleum deposits and the vertical migration "chimney" seen by both chemical and geophysical methods. Klusman modeled these migration mechanisms and calculated the rate of accent of gases which further confirmed the vertical nature of micro-seepage. Higher resolution geophysical data has confirmed the presence of the migration paths to the surface. Two AAPG Hedberg Research Conferences have been held presenting many of the theories, methods and debates on the topic. While some of the theories and techniques were controversial in the first half of the 20th century, vertical migration and micro-seepage is now widely accepted and many geochemical and remote sensing exploration methods are applied by the exploration industry to confirm the presence of hydrocarbon charged reservoirs. Instrument sensitivity has gained several orders of magnitude improving direct detection of micro-seeps in the near surface and now includes airborne methods. Complex hydrocarbon mixtures can now be differentiated, and numerous co-migrating elements can also be detected in the near-surface. Indirect methods identify many complex alteration, red-ox, electrical, magnetic and biological affects that result from the migrating hydrocarbons. The ability to detect most compounds at background levels has now introduced the requirement of sophisticated multivariate

statistical analysis to distinguish background from anomalous conditions. The current methodologies used today will along with their advantages and disadvantages will be discussed along with anticipated future developments.

1966944 The Nitchie Shear Zone, Wyoming

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The Nitchie Shear Zone is a 400 mile long surficial and topographic anomaly extending from the Fontenelle reservoir region, in western Wyoming, east and northeastward, crossing the Casper Arch. It is easily recognized in the vicinity of Nitchie Gas Field in Sweetwater County, Wyoming, where it runs east to west across the northern plunge of the Rock Springs Uplift. The localized hydrologic environment associated with the Nitchie Shear Zone (NSZ) distinguishes this surficial feature from surrounding terrains and highlights the associated geologic and geomorphic characteristics.

The linear geomorphic features that identify the NSZ transect structural features including the Rock Springs and Sweetwater Uplifts as well as the Casper Arch. At Pathfinder Reservoir, Precambrian rocks involved in the NSZ are well exposed with strong evidence of shear and related stress. Southwest of Pathfinder Reservoir the NSZ plunges into the Red Desert Basin where there is over 20,000 feet of Cambrian to Tertiary sediment above the Precambrian basement. Here, the surficial characteristics of the NSZ continue indicating near vertical faulting and fracturing propagates from basement to the surface. Similarly, the surficial expression of the NSZ along the 450 mile path from the western Green River Basin to the western side of the Powder River Basin crosses basin axes, numerous folds and complex structural terrains.

2000102 A Geometric Approach to the Analysis of Global Eolian Hydrocarbon Reservoirs: With Analogues From the Wahiba Sands of Oman

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It is recognized worldwide that eolian rocks can be very good hydrocarbon reservoirs. The "classic tank" eolian reservoir consists of a framework of well-rounded, well sorted quartz sand grains that incorporates little matrix due to removal of fines by wind. The real-world varies greatly, however, from the "classic tank" because most eolian reservoirs consist of a mélange of complex lithofacies derived from process frameworks operating at multiple scales. Practical geometric reservoir models include local and global climate conditions, sources of sand, wind direction and bedform size, accommodation space, and climatic and tectonic factors that create lacunae in sedimentation at various scales. These phenomena are best recognized through the study of dipmeter and core for any particular field; or less happily, after early water breakthrough at the crest of an oil field signals that unswept rock lies between the off-take well and the oil-water contact.

At the global scale, climate variability associated, for example, with Permian glacial cyclicity has stamped a resonant cyclicity on rock units of that age in many parts of the world. At basinal scale controls on sedimentation operate through both auto- and allocyclic processes. Regional winds bring sand to the local system where it is reworked. Fluvial avulsion and water table fluctuations among other factors also control reservoir sedimentology and stratigraphy. At the oil field scale, the reservoir characteristics are controlled mainly by facies stacking, associated bounding surfaces, and vertical trends in texture. At the outcrop scale, crossbedding typical of the various dune types is a key driver of reservoir complexity. At the microscopic scale within eolian genetic units, the poroperm properties of individual primary strata will affect recovery factors for an entire field by controlling fluid movement in pore spaces of the reservoir.

The Wahiba Sand Sea of Oman provides modern analogues for some of the reservoir styles we have seen globally. Flow models demonstrate the heterogeneity of hydrocarbon sweep that would be produced by various eolian lithofacies preserved on coastal outcrops of the Southeast Wahiba Sands.

1966267 Fourier Analysis of the Laminated Facies of the Middle Bakken Member, Sanish-Parshall Field, Mountrail County, North Dakota

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The Bakken Formation is a significant hydrocarbon source and reservoir within the Williston Basin. The Middle Bakken, which is the main horizontal target zone, is subdivided into several facies, including a laminated facies consisting predominately of 1 mm to 5 mm thick lamina pairs of very fine grained light gray sandstone and very fine grained dark gray siltstone. Additionally, each well in the eight well data set contained several laminations up to 1.2 cm thick. This study examines the origin of the laminated facies focusing on the origin of the parallel lamination. Recent hypotheses for the origin of the laminated facies include tidal, algal and hyperpycnal gravity flows. The resulting sedimentary structures are similar but are deposited in different shoreline configurations and water depths, which may result in different reservoir characteristics including lateral continuity. The primary analysis method utilizes Fast Fourier Transform (FFT) and periodograms of lamina sets to determine if an underlying tidal signature is present.

Results of the spectral analysis show the parallel laminations were deposited in a lower intertidal environment with tidal periodicity ranging from a semi-diurnal to mixed tidal system and synodically driven tidal forces. A number of thick laminations indicated non-tidal influence in laminations such as storm events. Non-sinusoidal lamination pattern resulted from a low sediment influx and probably was the result of eolian transport. Low sediment influx and low tidal range resulted in thin lamination with lack of preservation with the tidal cycles.

1964365 Comparison of Potentiometric Surfaces of the Cretaceous Dakota Group with Surfaces of Paleozoic Formations in the Midcontinent of the United States

Gianoutsos, Nicholas J.[1]; Nelson, Philip H.[1]

1. USGS, Denver, CO, United States.

Hydrocarbons are produced from oil and gas reservoirs in the Denver Basin and in the Anadarko Basin. Near the eastern flank of the respective basins, fresh water is produced from aquifers contained within the same stratigraphic units that produce hydrocarbons. Formation pressure measurements from the reservoirs and aquifers across the basins were obtained through drillstem tests in oil and gas wells and hydraulic head measurements in water wells. Combining these two sources of data, we have created a set of potentiometric surfaces for Mesozoic and Paleozoic stratigraphic units across the Midcontinent of the United States.

The potentiometric surfaces of six Paleozoic hydrologic units in the Midcontinent exhibit the following characteristics: (1) contours are generally oriented north-south, indicating that the hydraulic gradient is generally from west to east across Kansas and northern Oklahoma; (2) recharge occurs in the Ozark Plateau of western Missouri; (3) a potentiometric low occurs in eastern Kansas and Oklahoma where the Great Plains aquifers mix with recharge from the Ozark Plateau; and (4) a steeper gradient (more tightly spaced contours) is located at the Kansas-Colorado border suggesting a reduction in permeability associated with the Las Animas uplift. The Mississippian potentiometric surface is much flatter than the other surfaces, and indicates that the regional permeability of this unit is substantially greater than other Paleozoic units. All Paleozoic units are underpressured in western Kansas and eastern Colorado, as indicated by the separation between

land surface elevation and potentiometric elevations.

The Cretaceous potentiometric surface indicates a zone of recharge in southeastern Colorado and northeastern New Mexico with a broad arc of discharge extending from central Kansas into eastern Nebraska and southwestern South Dakota. From the recharge area, flow in Colorado is northward into the underpressured Denver Basin, then eastward into Nebraska. Although recharge is present in the Denver Basin, the complexity of the flow network does not allow a static head to be maintained throughout the system. Thus, the potentiometric surface of the Cretaceous (Dakota Group) differs substantially from the Paleozoic formations in flow direction and discharge locations, indicating that the Cretaceous (Dakota) hydraulic system is isolated from the Paleozoic units. Isolation is attributed to Permian evaporite sequences.

1969206 Computation and 3-D Visualization of Potentiometric Surfaces in Hydrocarbon-Bearing Formations Across the Mid-Continent

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1. USGS, Denver, CO, United States.

The determination of formation pressure is extremely valuable to the oil and gas industry as well as an emerging area of interest in carbon dioxide sequestration. To account for land surface elevation changes, regional studies require that pressure be converted to hydraulic head, a parameter commonly used in the field of hydrology. In conventional oil and gas basins, drillstem tests (DSTs) are conducted to record formation pressure for a given depth interval in a well. These DST measurements can be used to calculate hydraulic head values in deep hydrocarbon-bearing formations where water wells do not exist. The resulting calculated hydraulic head values are used to create a potentiometric surface in the same way as hydraulic head measurements from water wells. Unlike hydraulic head measurements in water wells, which have a low number of outliers, only a small subset of the DST data measure true virgin formation pressures. Our goal is to determine a potentiometric surface from DST-calculated hydraulic head values in spite of the erratic data set.

Using 3-D imaging capabilities to view and clean the data, we have developed a workflow to create potentiometric surfaces from erratic data sets in hydrocarbon-bearing formations. We have found that the potentiometric surface is more easily defined through human interpretation of the chaotic data set rather than through the application of filtering and geostatistical analysis. Instead of eliminating problematic data points (outliers), we view the data set in a series of narrow, 400-mile-long swaths and systematically select a subset of calculated hydraulic head values interpreted visually along the upper boundary surface in a two-dimensional viewer. The selected subsets for each swath are then combined into one data set for each formation from which three-dimensional potentiometric surfaces are created. We have performed this methodology for multiple formations across the midcontinent of the United States. The final product is an interactive, three-dimensional digital display containing the subsurface structure of the formation, the cluster of DST-derived hydraulic head values, the user selected subset of hydraulic head values that define the potentiometric surface, the resulting potentiometric surface, and the land surface elevation of the region.

1967396 Multi-Reservoir Characterization with Multicomponent 3-D Seismic in North-West Denver-Julesburg Basin

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Several conventional and unconventional targets have been identified and drilled in the Denver Basin, such as the Niobrara, the Codell and the Dakota J sandstones. Characterization of these reservoirs requires an integrated approach where surface seismic data is incorporated and calibrated with often sparse well data. In this study, a seismic reservoir characterization program was implemented on data from southeast Wyoming, in which a 3-D multi-component seismic survey was acquired and processed with the objective of delineating potential sweet-spots for the various reservoirs away from the limited well control.

Accurate imaging of the reservoirs was achieved by an integrated depth imaging workflow, which can be used to mitigate the risks associated with multiple lateral well landing and placement and structural hazards. With sufficient well control, the model can be refined and used for effective well design, planning and stimulation. Multi-component seismic allowed the estimation of key production drivers such as matrix porosity, total organic carbon and fracture density.

Elastic attributes and anisotropy parameters derived from seismic inversion and azimuthal velocity analysis of P and PS waves were used to estimate a number of geomechanical attributes that could be used, with sufficient well calibration, to infer mechanical rock properties in the inter-well space. Fracture characterization helped to identify dominant regional fracture directions and their association with Permo-Pennsylvanian and Laramide structural movements.

The study highlighted the value of target-oriented acquisition and processing of multi-component seismic data and seismic reservoir characterization in the early screening of multiple unconventional targets in the DJ Basin.

1970793 Core Facies and Geochemical Analysis of the Late Cretaceous Turner Sandstone, Powder River Basin, Wyoming

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This paper presents the workflow and preliminary results of a core facies and geochemical analysis of three cores of the Late Cretaceous Turner Sandstone Member of the Carlile Shale in the southern Powder River Basin. Two of these cores were drilled two miles apart in the Brooks Draw Field area of northwestern Niobrara County. The third was drilled 20 miles to the northwest. The cored interval includes the Pool Creek, Turner Sandstone and Sage Breaks members of the Carlile Shale. These three cores provide an opportunity to examine lithofacies, ichnofacies, and continuity of stratigraphic sequences and test the usefulness of elemental geochemistry as a paleoenvironment and correlation tool.

The Pool Creek consists of pervasively bioturbated mudstone and contains a high diversity, normal marine outer shelf trace fossil assemblage. The contact between the Pool Creek and the overlying Turner Sandstone is sharp and disconformable. The lower Turner Sandstone consists of streaky, lenticular, and wavy bedded heterolithic strata and contains a low diversity, stressed, restricted, or brackish water trace fossil assemblage. The upper Turner Sandstone consists of upward coarsening vertical successions of bioturbated mudstone, bioturbated shaly sandstone, and bioturbated sandstone and contains a high diversity, normal marine inner shelf trace fossil assemblage dominated by filter-feeding organisms. The Turner Sandstone is conformably overlain by the Sage Breaks.

The change from low to high diversity ichnofacies is coincident with an interpreted flooding surface between the lower and upper Turner sandstones, suggesting that salinity and/or oxygen levels improved during a relative sea-level rise. Elemental data was measured with a hand-held XRF instrument In order to determine if this possible change in seaway conditions was captured in the sediments. Results will be presented along with cores, core descriptions, and wire line logs.

1970794 Core Facies, Log Facies and Sequence Stratigraphic Analysis of the Late Cretaceous Turner Sandstone, Porcupine Field Area, Powder River Basin, Wyoming

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The USGS estimates that the Powder River Basin contains as much

as 1050 MMBO and 15,000 MCFG in unconventional, continuous reservoirs, making it one of the more prospective oil and gas basins in the Rocky Mountain region of the western United States. The Turner Sandstone has emerged as one of the "hottest" resource plays in the Powder River Basin. However, unlike its stratigraphically equivalent Wall Creek Member of the Frontier Formation, there is very little published data on the Turner Sandstone. This paper presents the workflow and preliminary results of a core facies, log facies, and sequence stratigraphic evaluation of the Turner Sandstone Member of the Carlile Shale in the Porcupine Field area of southeastern Campbell County. More than a dozen cores and hundreds of well logs were used in this evaluation.

The Turner Sandstone disconformably overlies the Pool Creek Member and is conformably overlain by the Sage Breaks Shale Member of the Carlile Shale. The lower Turner Sandstone consists of streaky, lenticular, and wavy bedded heterolithic strata and contains a low diversity, stressed, restricted, or brackish water trace fossil assemblage. The upper Turner Sandstone consists of upward coarsening vertical successions of bioturbated mudstone, bioturbated shaly sandstone, and bioturbated sandstone that are commonly "capped" by cross stratified sandstone and structureless, "cryptically bioturbated" sandstone. The upper Turner Sandstone contains a high diversity, normal marine inner shelf trace fossil assemblage dominated by filter-feeding organisms. Most conventional production was from cross-stratified and structureless sandstone facies that accumulated in elongated, isolated sand bodies or sand ridges. Much of the remaining reserves are stored in low resistivity, pervasively bioturbated, shaly sandstone that represents less active parts of the inner and outer shelf system.

1957600 Application of Rapid, Integrated, Cuttings XRF, Source Rock and Trapped Fluid Analyses to Unconventional Plays

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1. Fluid Inclusion Technologies, Inc., Broken Arrow, OK, United States.

Although unconventional resource plays are highly variable in terms of geology, geochemistry and structure, many of the key factors within these disciplines are repetitively quoted as influencing successful exploitation. These include: 1) Composition and quality of the in situ petroleum fluid(s), 2) Controls on distribution and volume of petroleum, both geographically and within a given borehole, 3) Water saturation and potential for internal or external water production, 4) Rock type and mineralogical composition for log calculations, lateral location and completion optimization, 5) Natural fracture distribution and porosity types, 6) Compartmentalization, sealing and natural interconnectivity, and 7) Relative proportions of locally generated and migrated petroleum. Often, however, available data are sparse in zones of interest, particularly in laterals typified by limited logs and no core.

A rapid, substantially automated process has been developed using archived, unpreserved cuttings from historical or recently drilled vertical or horizontal penetrations to address these questions. The sample is initially cleaned of surface contamination that can affect data quality. An enhanced depth-of-field image is collected in visible and ultraviolet light using a specialized microscopy system. Samples are then crushed under vacuum to collect quantitative data on organic and inorganic volatiles trapped in the rock via direct quadrupole mass spectrometry. Finally, the crushed rock sample is analyzed for its elemental composition by x-ray fluorescence. Trapped fluid analysis is used to help predict fluid type, composition, quality and volume in tight rock, as well as identify variability along laterals that can be exploited for more effective completions. Evaluation of major, minor and trace elements can be used to document lithology and cements, produce chemical stratigraphic profiles in otherwise monotonous sections, establish depositional environments, facies and provenance, and provide some information relevant to rock behavior during completion activities.

A subsample is used for source rock screening, but image, fluid and XRF data are collected on exactly the same rock material, thus preserving interrelationships among rock type, chemistry, texture, and trapped fluid type, quality and distribution. Generation of multiple data sets on the same small sample is also beneficial in instances where material is limited, or only a small amount can be acquired from government archives. As many unconventional plays have a significant number of historical vertical penetrations, rock-fluid databases can be established without drilling new wells, provided archived rock materials are available. One key advantage is that these historical wells can be evaluated without regard to age, drilling conditions (within reason) or mud system, and samples need no specialized preservation procedures. The entire data set can be produced in 5-7 days.

1965415 Vitrinite Reflectance of Cretaceous Coals and Thermal Maturity of the Niobrara Formation, DJ Basin, Colorado, USA

Hallau, Daniel G.[1]; Sharma, Ryan J.[1]; Cluff, Robert M.[1]

1. The Discovery Group, Inc., Denver, CO, United States.

The Niobrara Formation is a major source rock and unconventional reservoir in the DJ basin, and an understanding of its thermal maturity profile is critical for exploration and exploitation of the resource. Previous thermal maturity studies in the Denver Basin have been limited by small sample sizes, have drawn on vitrinite of questionable quality, or have relied on pseudo-measurements and/or inferior proxies to measured vitrinite reflectance. As a consequence, a reliable picture of Niobrara maturity in the DJ basin has been lacking.

To fill this substantial "data gap," we provide new vitrinite reflectance measurements for nearly 200 wells, representing the first truly exhaustive vitrinite reflectance database for the Cretaceous section of the DJ basin of Colorado, Wyoming, and Nebraska. Whole and slabbed cores from over 320 wells were examined for coaly material suitable for reflectance analysis. The present study examines coal collected from Cretaceous fluvio-deltaic sandstones (namely the J- and D-Sandstones), where it typically occurs as local, thin, isolated, and often subtle partings of coal. This is desirable because the macerals from such occurrences are large enough to identify under the microscope; in contrast, the identities of macerals that occur in marine shales and marls (e.g., Niobrara) are commonly ambiguous. A previously published depth-vs-thermal maturity profile for the DJ basin was used to project the vitrinite reflectance to the middle of the Niobrara.

More than 180 new vitrinite reflectance data points have helped to both expand and refine the maturity profile of the DJ Basin. The new data have revealed localized and previously-undocumented high and low temperature anomalies.

1965777 Geothermal Assessment and Modeling of the Uinta Basin, Utah

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1. Utah Geological Survey, Salt Lake City, UT, United States.

Produced waters from sedimentary basins may represent a significant geothermal resource. This study presents a regional assessment of geothermal potential for produced waters in the Uinta Basin of northeastern Utah. Bottom-hole temperatures (BHT) and co-produced water data for 730 oil and gas wells distributed across the entire basin are combined with existing lithological information. For 135 of the wells, a BHT correction is applied using Horner and single-BHT correction methods to account for drilling-induced temperature field disturbances. A conservative depth-dependant correction value of +2.0°C/km was calculated from 50 Uinta Basin wells with reliable Horner corrections and is applied to BHTs with insufficient data for other correction methods. Corrected temperatures and typical thermal conductivities are used in a 1-dimensional, bootstrapping method to calculate thermal gradients and surface heat-flow values for each well. Calculations reveal an average geothermal gradient of about 27.0°C/km. The average heat-flow value of wells with corrected BHTs is 67.1 mW/m2. These results are generally typical for gradient and heat-flow values in the Colorado Plateau. An average gradient of 27.0°C/km implies that wells producing fluids from depths > 2 km (6562 ft) will likely have temperatures of > 54°C (129°F). Thermal outputs are calculated using well production rates and fluid temperatures. The

average thermal output is 110 kW per well and maximum output is as high as 12 MW—energy currently lost to waste water. The highest output wells are a direct result of high volumetric production rates and are located in the Ashley Valley Field. Thermal models for the basin are created using a 3-dimensional finite-element modeling program (COMSOL Multiphysics 4.4) and are calibrated to well temperatures. Co-produced water temperatures in 673 wells are above 50°C (122°F) and may be suitable for direct-use applications such as greenhouses, space heating, and aquaculture. Binary geothermal power plants generally require a minimum temperature of 140°C (248°F) to achieve acceptable efficiency and 26 wells across the basin meet or exceed such temperatures. The high volume of co-produced water at wells with > 50°C temperatures along with the benefit of existing infrastructure make the Uinta Basin a candidate for the development of direct-use geothermal applications with the potential to support binary geothermal power production.

1962414 Gas Geochemistry of Three Tight-gas-sand Fields, Rocky Mountains

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Tight-gas-sand reservoirs in the Rocky Mountains are a major natural gas resource; yet gas compositions in these fields are largely undocumented, and controls on gas composition are poorly understood. I report a large data set of gases from: Jonah Field, Greater Green River Basin; the Mamm Creek – Rulison – Parachute – Grand Valley fields, Piceance Basin; and Greater Natural Buttes Field, Uinta Basin. The data are used to characterize gas sources, generation mechanisms, thermal maturities, and secondary alteration.

The range of production gas compositions in the three fields is similar, from pure methane to 35% C2+, with a small number of wetter gas samples. The δ13C of methane ranged from -25 to -45‰; wetter gases were isotopically heavier and less variable. The three fields are distinguishable by δ13C of CO_2, δD of the C2+ gases, ratio of i-C4 to n-C4 and noble gas parameters.

Jonah mud gases are generally wetter and isotopically lighter with increasing depth, with a wide range of compositions at any depth. Piceance gases become dryer and isotopically heavier with depth, with a shift to lighter values for the deepest samples. The stratigraphic variability in gas compositions suggests complex migration pathways, probably through fracture systems and more permeable beds.

Gas compositions are influenced by (1) mixing of gases from primary cracking with gases from secondary cracking of oil; (2) primary cracking at varying thermal maturity; (3) bacterial oxidation of hydrocarbon gases, yielding gases that are dry, with isotopically heavy hydrocarbons and light CO_2. This effect is pervasive in the upper part of the gas column at Jonah Field and locally significant in the Piceance wells.

1965388 Fracture Creation and Observed Pitfalls in Bakken Reservoirs, Williston Basin, North Dakota

Heckelsberg, Duane1; Yao, Ziheng (Michael)1; Lorwongngam, Apiwat (Ohm) [1]; Cardenas, Carlos [1]; Guier, Daniel [2]

1. Hess Corp., Houston, TX, United States; 2. Ex-Hess, Houston, TX, United States.

Hess is developing the Bakken reservoirs (Middle Bakken and Three Forks) in the Williston Basin. We are beginning to see artifacts of prior and concurrent work effecting active drilling operations. This poster will present a case-level review of such a series of well situations. We'll look at a ±10-well system that demonstrates well communication during frac, completions, and drilling operations. A review of these events leads to a discussion and likely causes of the event(s), expanding into potential mitigation effects and issues.

The review will focus in an area, where several drilling wells saw pressure communication during frac operations. An analysis of the pressures seen over 48 – 96 hours is developed, and subsequent drilling failures (bore-hole collapse) are interpreted to be geomechanically related to the frac stimulation. Evidence and support of this likelihood are reviewed.

3-D survey data in the area yields some support for the interpretation, and suggests that some seismically observed discontinuities (fault?) might contribute to communications and subsequent bore-hole instability. Production response(s) were also observed, adding support to the interpretation and evaluation.

The poster concludes with interdisciplinary lessons learned and potential cooperative opportunities to drill and produce better and more profitable wells in the future.

Proposed for the RMS of AAPG Annual Meeting, Denver, July 2014

(Subject to review and release by Hess Management, prior to presentation)

1966039 Petroleum System Model of the Mississippian Bakken Formation in the Northern Williston Basin, Saskatchewan, Southwestern Manitoba, and Southeastern Alberta

Higley, Debra K.[1]; Gaswirth, Stephanie[1]; Gianoutsos, Nicholas[1]

1. USGS, Lakewood, CO, United States.

More than 400 million barrels of oil, 380 trillion cubic feet of gas, 6,000 barrels of condensate, and 2 billion barrels of water have been produced from about 7,700 wells in the Bakken and underlying Big Valley and Torquay Formations of the Devonian-Mississippian Three Forks Group in the Canadian portion of the Williston Basin. These totals include some commingled production from the overlying Lower Mississippian Banff and Lodgepole Formations. Although the Bakken production is from conventional pools, approximately half of the well completions are horizontal.

Bakken source strata are immature for oil generation over almost their entirety within the northern Williston Basin in Saskatchewan, southwestern Manitoba, and southeastern Alberta. There is potential for self-sourced oil proximal to and north of the North Dakota border with Saskatchewan. Timing and distribution of oil generation, saturation, migration, and accumulation are based on 4D petroleum system models that were calibrated to vitrinite reflectance, temperature, and drillstem test pressure data. Petroleum generation and migration was radially northward from the Williston Basin, starting as much as 90 million years ago (Ma), with peak generation at about 65 Ma. The Alberta Basin may have contributed petroleum along the axis of the Sweetgrass Arch, which forms a hydrologic and petroleum system divide between the basins. Onset of oil generation from the Bakken equivalent in the Alberta Basin was about 65 Ma and peak generation was about 58 Ma, proximal to and under the Canadian Rocky Mountains.

1969203 Undiscovered Petroleum Resources for the Woodford Shale and Thirteen Finger Limestone-Atoka Shale, Anadarko Basin

Higley, Debra K.[1]

1. USGS, Denver, CO, United States.

In 2010 the U.S. Geological Survey assessed undiscovered oil and gas resources for the Anadarko Basin province of Colorado, Kansas, Oklahoma, and Texas. The assessment included two continuous (unconventional) assessment units (AU); the Devonian Woodford Shale Gas AU mean undiscovered resources are 16 TCFG and 192 MMBNGL, and the Pennsylvanian Thirteen Finger Limestone-Atoka Shale Gas AU of the lower Atoka Group mean undiscovered resources are 6.8 TCFG and 82 MMBNGL. Oil resources of these AUs were assessed as conventional. Both AUs are mature for gas generation within the deep basin. Gas generation from the Woodford Shale started about 335 Ma, and from the Thirteen Finger Limestone-Atoka Shale about 300 Ma. Maturation results are based on vitrinite reflectance data, and on 1D and 4D petroleum system models that calculated vitrinite reflectance (Ro), and Rock-Eval and hydrous pyrolysis transformation ratios through

time. The Woodford Shale Gas AU sweet spot and boundary were defined primarily on (1) isopach thickness from well-log analysis and published sources; (2) estimated ultimate recoverable production from existing, mainly horizontal wells; and (3) levels of thermal maturation. Measured and modeled Ro ranges from about 1.2% to 5% in the AU, which represents marginally mature to overmature for gas generation. The sweet spot included most of the Woodford Shale that was deposited within eroded channels in the unconformably underlying Hunton Group. The Thirteen Finger Limestone-Atoka Shale Gas AU has no known production in the deep basin, the boundary is based primarily on the gas generation window, and on thickness and distribution of organic-rich facies from these mainly thin shale and limestone beds.

1967552 Facies Model and Sequence Stratigraphic Framework of the Devonian-Mississippian Sappington and Bakken Formations in Montana

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1. Department of Geosciences, University of Montana, Missoula, MT, United States.

The Devonian-Mississippian Bakken/Three Forks Formations in the Williston Basin, in Montana and North Dakota, are one of the most prolific petroleum systems in the United States, but production results are highly variable, indicating that these rocks, like conventional reservoirs, display considerable geological heterogeneity.

In western Montana, rocks of the Bakken equivalent Sappington Formation - the middle and lower Bakken members and the Sappington Formation contain conodonts indicative of the Upper Devonian Expansa Zone and Lower Mississippian Praesulcata Zone - preserve a wide variety of sedimentologic characteristics and facies reflecting complicated and interrelated processes of sediment production and dispersal.

The Sappington Formation contains facies ranging from organic-rich, fine-grained mudrocks (max. 14.8% TOC) to silty, very fine-grained sandstones in the middle Sappington member. Abundance of hummocky cross stratification in siltstone and very fine-grained sandstone from several localities suggest that storms were an important mechanism for dispersing sediment across the shelf, whereas a diverse suite of trace fossils suggests subsequent reworking by a robust infauna in a largely open marine environment.

Taking into account the diachroneity of those facies belts, we identified four genetically related sequences in the Sappington Formation. Each sequence is bound by sequence stratigraphic significant surfaces that were also identified in well log data throughout Montana. The results from our outcrop work provide a framework for the facies heterogeneity and reservoir architecture of the Sappington Formation and as such allowed for the development of a sequence stratigraphic framework also applicable in other parts of Montana and the Williston Basin.

1963629 Calibration of Petrophysical Log Response in the North and Eastern Uinta Basin to Allow Extension of Outcrop Belts into the Subsurface Using Well Data

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1. Geology and Geological Engineering, Colorado School of Mines, Golden, CO, United States.

The Green River Formation of the Uinta Basin, Utah is a proven petroleum system with many existing, highly productive fields in sandstone and carbonate facies. Other, finer-grained facies (siliceous and carbonate mudrocks) have been identified as potential basin wide unconventional plays. The economics of individual wells, however, are highly dependent on local facies, which are currently difficult to predict. This complication arises from the discontinuous nature of depositional units, compounded by the unusual log responses observed within the Green River Formation.

This study focuses on the eastern portion of the Uinta basin, which is constrained by the Uinta Uplift in the north, the Douglas Creek Arch to the east and the Uncompahgre Uplift to the south. Through detailed study of outcrop, incorporating spectral gamma ray, combined with correlation of cores, a better technique for calibrating logs is defined. By combining a number of petrophysical properties, using porosity, gamma ray, and resistivity logs, misinterpretations of facies due to unusual log responses can be avoided.

The calibration technique was used to interpret well logs across the east of the basin and then generate a number of regional cross-sections to provide a framework for higher resolution correlations at a localized scale and thus better prediction of reservoir quality. These regional lines expand upon existing work done on Ravens Ridge in the north east of the basin and in the adjacent Piceance basin.

1936636 A Comprehensive Deterministic Petrophysical Analysis Procedure, For Reservoir Characterization: Conventional and Unconventional ReservoirsCopyright 2014, held by the submitting authors.This paper was prepared for presentation at the AAPG RMS Annual Meeting in Denver, CO, July 20-22, 2014.

Holmes, Michael[1]; Holmes, Antony [1]; Holmes, Dominic[1]

1. Digital Formation, Denver, CO, United States.

The past ten years, we have developed a number of petrophysical models for specific requirements:

Rock Physics Modeling

Create pseudo acoustic (both compressional and shear) curves, based on Gassmann and Krief geophysical models. The model allows for the estimate of acoustic data where no (or limited) acoustic data exists. From this modeling, mechanical properties can be made. Reference Holmes, SPWLA 2004, SEG 2005.

Relative Permeability Modeling

Profiles of irreducible water saturation, are compared with the actual water saturation. Reference Holmes AAPG 2009. Using the technique of Corey (1954) continuous profiles of relative and effective permabilities to both fluid phases can be created. Knowing viscosities of reservoir fluids water/hydrocarbon can be determined as continuous curves.

Petrophysical Analysis of Unconventional Reservoirs

Involves examination of the shale intervals independently of the clean formation. Additionally consideration of the total organic carbon (TOC) content of the reservoir is required. Quantitative calculations of free and adsorbed hydrocarbons need to be assessed for a complete analysis. Reference AAPG 2010, 2011, 2013.

A Technique (unpublished) to Identify Fractures

Developed to estimate the presence of fractures, both open and healed-from standard open hole logs. Anonymously rapid rates of change with depth are attributed to fractures. If the trend is to higher porosity, open fractures are suggested.

SUMMARY

This paper presents how these various models can be combined:

-Porosity, fluid saturation, shale volume, permeability

-In-place and recoverable hydrocarbons

-Free hydrocarbons in the shale fraction

-TOC and adsorbed hydrocarbons

-Profiles of relative and effective permeabilities to the fluid phases

-Profile of water/hydrocarbon ratios

-Brittle vs. ductile distinction

Examples from unconventional oil and gas reservoirs of North America are presented and include Niobrara, Bakken (oil), Western Canada, Barnett and Utica (gas).

1958720 Newfield's Williston Buried Array Microseismic; Pushing the Envelope and Integrating Data

Johnson, Laura M.[1]; Rountree, Jared[1]; Shemeta, Julie[2]

1. Newfield Exploration Company, Denver, CO, United States; 2. MEQ GEO, INC, Denver, CO, United States.

Newfield installed a buried array in the Williston basin to monitor microseismic events during hydraulic fracturing of the Bakken and Three Forks formations in 10,000-foot laterals. The seismic array covers 58 square miles with 229 stations spaced at approximately 3000 feet, with 3 geophones buried at 300, 250, and 200-foot depths. The array has proved to be useful in mapping microseismicity during hydraulic fracturing with 300 to 400 microseismic events per well. Approximately 10% of the events are clearly visible in the NMO traces, with high signal to noise ratios. The array microseismic has also been useful in determining fracture geometry and variability in induced fracture half length from well to well. We are confident in the XY resolution but working to better understand the Z (vertical) resolution on the array.

We extended the microseimsic analysis in three key pilot areas by integrating microseismic data with other diagnostic completion, pressure, and temperature data. In one area we combined microseismic monitoring with chemical and radioactive proppant tracers. In another area we monitored downhole pressure in a offset well to determine induced fracture pressure interference. The data integration from these pilots demonstrates that the microseismic events are imaging the hydraulically disturbed volume. We see good correlation of event density populations with chemical and radioactive tracer data in offset wells, along with excellent correlation of microseimsic events intersecting offset wells with timing of pressure and temperature anomalies observed from downhole gauges. We also designed the pilots to test frac order vertically and laterally and were able to use the microseismic data to see frac shadowing and depletion sinks from existing wells.

1958802 Visual and Analytical Comparisons of Upper Pronghorn "Shale" Cores from a West-to-east Transect, McKenzie and McLean Counties, North Dakota

Johnson, Laura M.[1]; Sha, Grant[1]; Kocman, Katie[2]; Cole, Simon[3]; Wray, Laura L.[3]; Longman, Mark[2]

1. Newfield Exploration Company, Denver, CO, United States; 2. QEP Resources, Inc, Denver, CO, United States; 3. WPX Energy, Denver, CO, United States;

Core acquisition in the Williston Basin has not only provided detailed analytical data on reservoir and source rocks, but has also helped to quantify and correlate complex lithologies that make up the Upper Devonian lower Bakken and Pronghorn members of the Bakken Formation. Given the variety of nomenclature applied to the Pronghorn, the authors have subdivided the formation into an upper and lower interval where the upper interval consists of black "shale" similar to the lower Bakken and the lower consists of mixed limestone, siltstone, and sandstone. A variety of analytical data and stratigraphic relationships of the upper Pronghorn from six cores along a 52-mile-long west-to-east transect provide a rich suite of information for regional comparisons. The upper Pronghorn is classified as a silty organic mudstone with rare thin bioturbated limestone beds near the base. The upper Pronghorn varies in thickness from 0 to 31 feet along the transect.

Visually, the differences between the lower Bakken "shale" and upper Pronghorn are subtle. Upon close inspection of the core you can discern visual differences and the contact between the two that is not readily apparent from core photos. Analytical and visual data from this transect clearly show the boundary between the base of the lower Bakken and the upper Pronghorn interval is defined by: 1) lower TOC, 2) lower silicon, 3) more bioturbation 4) coarser quartz grains (vf sand) and 5) more common silt laminae in the upper Pronghorn. The boundary is also easily recognized on wireline logs. The upper Pronghorn is thickest in the westernmost cores and is absent in the two easternmost cores of the transect. Compositionally, the upper Pronghorn mudstone facies in this transect is composed of quartz (18-25% eolian and biogenic quartz), dolomite (12-31%, detrital and authigenic), illite/mica (17-27% increasing westward), K-spar (9-16%), albite (1–5%), calcite (3%, mostly biogenic), pyrite (1-3%, authigenic), minor mixed-layer illite/smectite, and chlorite (2-7%).

The upper Pronghorn is part of a transgressive sequence that reaches a maximum in the lower Bakken "shale." The upper Pronghorn is not as laterally continuous as the lower Bakken "shale" and varies significantly in thickness across the basin. Although the upper Pronghorn is not as organic-rich as the lower Bakken "shale," it is a source rock and its presence is an important part of the Bakken petroleum system.

1957198 Mass Movement Deposits in the Lacustrine Eocene Green River Formation, Piceance Basin, Western Colorado

Johnson, Ronald C.[1]; Birdwell, Justin[1]; Brownfield, Michael[1]; Mercier, Tracey J.[1]

1. Energy, U.S. Geological Survey, Denver, CO, United States.

Mass-movement deposits interbedded with laminated sediments are common in lacustrine strata of the Eocene Green River Formation, Piceance Basin, western Colorado, comprising the majority of some stratigraphic intervals. Lake Uinta, a saline lake, formed when much smaller freshwater lakes expanded across surrounding alluvial plains. Mass-movement deposits were rare early in the history of Lake Uinta, but increased in abundance as marginal shelves prograded into the newly expanded lake. Mass-movement deposits accumulated near the base of these expanding shelves. Total organic matter increases in areas where mass-movement deposits accumulated, suggesting that organic matter from marginal areas was entrained along with mineral matter. In addition, intervals that include abundant mass-movement deposits generally contain a higher concentration of organic matter that laminated intervals. Saline Lake Uinta frequently transgressed and regressed across the marginal shelves as water supply varied providing opportunities to erode and transport mineral matter and organic matter toward the center of the lake. In the central part of the lake, mass-movement deposits consisted of massive organic-rich beds that typically contained clasts or "blebs" of mineral matter. Lake Uinta expanded later in its history, and deepwater conditions prevailed over much of the marginal shelves. Mass-movement deposits become rare during this period, and laminated oil shale was deposited over most of the lake. Mass-movement deposits again became common during the infilling stage of Lake Uinta as volcaniclastic sediments progressively filled in the lake from the north.

1961086 Training Image Characterization and Multipoint Statistical Modeling of Clastic and Carbonate Formations

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1. Energy & Environmental Research Center, University of North Dakota, Grand Forks, ND, United States.

In partnership with the U.S. Department of Energy, the Energy & Environmental Research Center and the Plains CO_2 Reduction Partnership Program have built several 3-D geocellular models for the purposes of studying CO_2 storage and CO_2 enhanced oil recovery (EOR). A training image (TI) library was established to represent a broad range of both clastic and carbonate formations in various structural settings. 3-D facies models were built using the TIs in a multipoint statistics (MPS) workflow to represent depositional patterns that correlate to geologic interpretation and features seen in modern analog environments.

With project budget and time constraints, using the MPS workflow allowed multiple geocellular models to be built with realistic results and proved to be useful in creating facies models for field- to basin-sized projects with little or no data regarding facies distribution. Classic geological interpretation in the form of analogs, maps, well logs, and cross sections was used to create the TIs. The TIs were created from

the geologic interpretations by "painting the image" in comparison to simulated techniques. The MPS workflow then uses the TI (in addition to soft data and hard data if applicable) to populate the facies property. Applying a similar workflow will improve characterization and reduce uncertainty in areas where limited data are available to assess CO_2 storage and EOR potential. In addition, the workflow will increase project efficiency when multiple formations are being investigated.

1961106 Visual and Analytical Comparisons of Lower Bakken "Shale" Cores from a West-to-east Transect, McKenzie and McLean Counties, North Dakota

Kocman, Katie B.[1]; Longman, Mark[1]; Johnson, Laura M.[2]; Sha, Grant[2]; Wray, Laura L.[3]; Cole, Simon[3]

1. QEP Resources, Inc., Denver, CO, United States; 2. Newfield Exploration, Denver, CO, United States; 3. WPX Energy, Denver, CO, United States.

The upper Devonian lower Bakken member of the Bakken Formation is classified as a silty, organic-rich mudrock, and is a major hydrocarbon source rock in the Williston Basin of North Dakota and Montana. Data collected from six cores along a 52-mile east-west transect provide a rich suite of stratigraphic and analytical information for regional comparisons. Six slabbed cores of the lower Bakken, as defined by the authors, reveal visual similarities and differences of this world-class source rock. Additionally, chemostratigraphic interpretation of key elements from handheld XRF data clearly demonstrates trends within the mudrock that help better characterize the depositional and diagenetic variations of the lower Bakken.

The lower Bakken in this transect varies in thickness from 10 to 38 feet. Detrital silt is disseminated throughout the interval and occurs as scattered grains and thin, locally discontinuous laminae that are visible in the slabbed core. These eolian silt grains, along with a variety of pelagic fossil fragments and fecal pellets, settled through a stratified water column and accumulated on a mostly anoxic seafloor. At the top and base of the lower Bakken, thin, in-situ bioturbated intervals have been recognized by whole core CT scans documenting minor periods of dysoxic conditions.

X-ray diffraction results show that components varying along the transect include quartz (30-45%, detritral, biogenic and authigenic), kerogen (11-18 wt. %, mostly type II), illite/mica (13-29%), K-feldspar (5-11%), dolomite (2-11%, both detrital and authigenic), albite (1-8%), mixed layer illite/smectite (3-15%, increasing eastward), pyrite (3-9%, all authigenic) and calcite (0-7%, mostly as skeletal fragments).

The boundary between the base of the Lower Bakken "shale" and upper Pronghorn interval is defined by: 1) lower TOC, 2) lower silicon, 3) more bioturbation and 4) coarser quartz grains (vf sand) in the upper Pronghorn mudrock. Although this boundary is subtle in the core, it is easily recognized on wireline logs and in analytical analyses. Integration of analytical data from cores and wireline logs aids in characterizing and understanding the lower Bakken "shale."

1967436 Diagenesis of the upper Three Forks Formation - the North Dakota Perspective

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The upper part of the Three Forks Formation in the Williston basin of North Dakota and Montana is one of the prime targets for oil exploration in the onshore part of the US today. The unit is mainly composed of dolomite, yet the details of dolomite formation and its relative timing are yet unknown. This study is the first that combines cement generations and porosity into a diagenetic scheme based on detailed microscopical observations. The upper Three Forks Formation shows a total of seven dolomite generations along with some anhydrite and pyrite. Most of the rock consists of an inclusion-rich dolomite, likely dolomite II, that forms mm- to sub-mm-size rhombic crystals showing overgrowth of five more alternating clear and inclusion-rich dolomite generations, and in places a core of iron-rich dolomite I. Porosity types in the Three Forks Formation are intercrystalline, intracrystaline, and "moldic" which here stands for the dissolution of entire dolomite crystals. Detrital components are quartz, feldspars, mica, and clay particles.

The Three Forks Formation was most likely deposited on a mixed carbonate-siliciclastic ramp as a limestone unit with varying amounts of detrital input. Initial replacement of limestone into dolomite probably occurred early entirely changing the texture of this unit. Several dolomite phases occurred during burial post-dating early dolomitization. The effective porosity, characterized by intercrystalline and "moldic" pores, is linked to the dolomitization, most likely originally to an early event as no late dolomite is seen filing these pores. Up to centimeter-size voids, though, representing mostly non-effective porosity is generally partly filled with several generations of dolomite and leaving some part of the vugs open. This indicates that most likely the voids were found before the last few generations of dolomite cement, and also that not all open space was easily occluded by these dolomitizations but left some of the porosity untouched.

Based on a limited data set, porosity distribution in the upper Three Forks Formation does not show a clear link to the distribution of dolomite. However, it does show a trend to overall increased values from the east (less than 1%) to the west (around 5%) with a north-south extending zone of maximum porosities (about 10-12%) around 103.5°. It is therefore likely that potential hot spots in this basin are rather located in western ND while towards the east porosities are less promising.

1966037 Abrupt Basinward Changes in the Stratigraphic Expression of a Sequence Boundary in the Ferron Sandstone (Turonian), Southeast Utah, USA

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The deltaic Ferron Sandstone is one of the few rock bodies in which a single sequence boundary (SB) can be traced in continuous exposure over long distances. The SB has been traced for ~70 km along strike, but the present study is the first to document the character of the SB and its enclosing strata basinward along depositional dip on the southern flank of the Henry Mountains syncline. Sixteen sections were measured from ~20 m of strata bounding the SB from the main outcrop belt eastward for a distance of 8 km. Up-dip, the SB is underlain by low-angle cross bedded to ripple and flat laminated sandstone (mouth bar). The SB lies atop a heavily rooted siltstone and ~.5 m thick coal or underlies a surface of incision at least 5 m deep. Overlying strata are tabular to trough cross bedded, locally pebbly, medium sandstone (channel deposits). Down-dip, the lower part consists of 2-3 coarsening-upward sandstone/siltstone (delta front) cycles capped by 1-2 m thick, sharp-based cross bedded and hummocky cross stratified sandstones (mouth bar). The SB becomes a cryptic surface atop a thin (<1m), massive to faintly laminated, carbonaceous siltstone, which is overlain by a thoroughly bioturbated transgressive sandstone. The upper part contains heavily bioturbated and carbonaceous mouth bar sandstones transitional into coarsening-upward delta front cycles. The exceptional exposure provides novel insight: Although the SB is clearly defined up-dip, within just 8 km down-dip it is identifiable as a major unconformity only upon very close inspection and detailed correlation.

1964537 Characterization of Wettability using NMR and Dielectric Logging, and Pore-scale Imaging Techniques

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Characterization of the wettability within a sandstone reservoir is critical for understanding the type and volumes of fluids that will

be produced during both primary completion (Anderson, 1986) and secondary waterflood recovery (Morrow, 1990). The oil reservoirs within the Green River Formation of the Uinta Basin (Utah) in the Greater Monument Butte Unit (GMBU) have variable wettability validated through traditional core methods such as USBM wettability and relative permeability measurements. There are over twenty defined producing sandstone reservoir intervals within the Green River Formation with variable depositional environments, mineralogy and rock quality. Due to the reservoir variability, characterization of wettability through traditional core analysis techniques is cost prohibitive and time-consuming. A log based technique was developed because GMBU is currently under conversion to a waterflood unit, and a cost-effective method for characterizing reservoir wettability would be beneficial for sweep efficiency and increasing ultimate recovery.

The wettability of a reservoir depends on the mineralogy of the open pore space and the type of oil in the reservoir. Oils with a higher asphalteine and resin content tend induce more oil-wetness due to the polar nature of these hydrocarbon compounds. Similarly, carbonates tend to be more oil-wet due to the polar electrical charge on the mineral surfaces. The types and volumes of either oil or water that are produced from a reservoir depend on the scale and wettability of the pores where the fluids reside. Consequently, mapping of the pore-scale distribution of fluids and wettability is important for predicting produced fluids.

Chen et. al. (2013) proposed the use of NMR logging to map the presence of oil-wet pores. In this paper micro-CT imaging in preserved state samples is used to identify occupancy of oil at the pore scale in 3-D and BSEM pore-scale imaging techniques to detect the presence of deposited asphalteines within pores allowing for an effective mapping of wettability within a rock at micro- and macro-pore scales (Knackstedt et. al., 2011). This information provides the foundation for integrating pore-scale wettability with the petrophysical response. Results are presented that validate and extend the work of Chen et. al. (2013) using pore-scale imaging of wettability and open-hole dielectric data integrated with NMR open-hole logging data. We use this integrated technique to characterize the variable wettability of GMBU reservoirs.

1969208 Critical Relationships between Vitrinite Reflectance and Petroleum Formation

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Vitrinite reflectance (%Ro) is a critical parameter in determining the amount of thermal stress (temperature and time) a source rock experienced during its burial history. Increasing reflectance of vitrinite is attributed to the growth of aromatic-ring clusters that results in their gradual alignment with increasing thermal stress. This process represents bond formation, as opposed to bond breaking in the process of petroleum formation. As a result, reaction kinetics for vitrinite reflectance are not the same as those for petroleum formation. For example, oil generation from high organic sulfur-bearing kerogen starts oil generation at a low thermal stress (<0.5 %Ro), and low organic sulfur-bearing kerogen starts oil generation at a high thermal stress (>0.8 %Ro). Therefore, it is critical to have good oil-generation kinetic parameters that can be applied in a thermal history that is based on vitrinite reflectance. This variable relationship between vitrinite reflectance and petroleum formation has been shown to be critical in the onshore Gulf Coast, Western Canada Sedimentary Basin, Mesopotamian Basin, Rocky Mountain basins, California Coastal basins, and Polish Carpathians.

The variability between vitrinite reflectance and petroleum formation may also be accentuated by the occurrence of so-called suppressed vitrinite. The reflectance of this vitrinite increases significantly slower than that of vitrinite from humic coals subjected to the same thermal stress. For example, a thermal stress capable of increasing the reflectance of typical vitrinite from 0.5 to 1.0 %Ro may only increase from 0.5 to 0.6 %Ro for suppressed vitrinite. Therefore, it becomes critical to know whether a reflectance value is suppressed in determining the thermal history of a source rock and the boundaries for its primary (source-rock sourced) and secondary (oil-cracking sourced) gas generation. Source rocks with suppressed vitrinite have been observed in the Phosphoria Formation, Woodford Shale, Bakken Shale, and Alum Shale.

1967045 Correlation of Oils and Tar Sands in the Green River Petroleum System, Uinta Basin, Utah

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The Eocene Green River Formation in the Uinta Basin, Utah, is comprised of thick packages of organic-rich calcareous shales and marlstones interbedded with coarse clastic rocks deposited in a freshwater to hypersaline lake. Petroleum source rocks in the formation have generated several different forms of petroleum (oil, gas, tar sands, and native bitumen), some of which are significantly biodegraded. Numerous studies have recognized two oil subtypes in the basin. The most common oil type, Green River A, is derived from the lower black shale facies of the Douglas Creek Member. Less common is Green River B derived from the Mahogany zone of the Parachute Creek Member. Oils produced from the Eocene Wasatch Formation are herein considered a third oil subtype. Bulk properties (high pour point) and geochemical composition (elevated pristane/phytane and land-plant biomarker ratios) suggest that Wasatch oils are sourced from the freshwater fluvial-lacustrine interval in the lower Green River Formation.

Biomarker geochemistry provides insight into the biodegradation process as well as the pitfalls of genetic characterization of biodegraded oils and tar sands. Although it is widely regarded that the Uinta Basin tar sand oils are derived from the Green River Formation, correlation to a specific organic facies is difficult due to significant biodegradation. Preliminary correlations based on degradation-resistant biomarkers suggest that the Sunnyside tar sand deposit contains Green River A oil type, whereas the Raven Ridge tar sand deposit contains Green River B oil, consistent with a geologic model of oil migration updip from their respective source facies.

1956989 Petrography of the Bakken Black "Shales" in the Eastern Williston Basin of North Dakota

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The Upper Devonian (Fammenian) and Lower Mississippian (Kinderhookian) Bakken Formation in the eastern Williston Basin of North Dakota is ~25 to 30 m thick and consists of a lower black "shale," a middle dolomitic siltstone, and an upper black "shale". The black "shales," which comprise about half the Bakken thickness, are better described as silty organic-rich black mudrocks, and are excellent hydrocarbon source rocks where thermally mature. The bulk of the 23 m.y. represented by Bakken deposition is reflected by accumulation of mud comprising the "shales" at a calculated average depositional rate of ~0.7 mm/1000 yrs vs. ~5 mm/1000 yrs for the middle-member.

Petrographic study of the "shales" shows that they are silty, dolomitic non-fissile mudrocks which average 15 to 20 wt% TOC where thermally immature and about 10 wt% TOC where thermally mature with a vitrinite reflectance approaching 1.0%. These organic-rich mudrocks are pyritic and generally lack evidence of bioturbation and bottom currents except in the transitional meter or two at their base and top. Randomly distributed detrital silt grains composed of quartz, dolomite, and feldspar comprise 5 to 20% of both "shales." Very early pyrite partly filled some algal cysts prior to compaction. Delicate fossil fragments derived from brachiopods, echinoderms, fish, algal cysts including Tasmanites, radiolarians, and conodonts occur sporadically in

the "shales." They represent pelagic organisms or rafted skeletal debris derived from well-oxygenated shallow surface waters in the Bakken Sea rather than transported lags or benthic organisms living on the anoxic, H2S-rich sea floor.

Where silt laminae are present, they occur as somewhat discontinuous layers only a few silt grains thick with no evidence of traction bottom currents. These silty laminae are interpreted as fallout from dust storms that blew out over the Bakken Sea. Flattened fecal pellets sinking from shallow oxygenated waters have previously been misinterpreted as burrows. Previous claims that agglutinated foraminifers occur in the shales are also false in that these silicified organic remains are dominantly authigenic chert rather than detrital silt. In summary, most of the Bakken black "shales" represent deposition on an anoxic sea floor probably similar to that found in present-day Jellyfish Lake in Palau, but on a tremendously larger scale.

1959984 Play-Scale 3-D Modeling and Novel Risk-Ranking Concepts for Developing Unconventional Assets

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Spatial heterogeneity substantially affects mud-rock reservoir behavior. Success is determined by reservoir quality as well as drilling and completion quality. Geoscientists are challenged to characterize unconventional petroleum systems with existing 2D solutions. Zonal maps are limited by averaging, and detailed facies models are constrained by project scale, effort, and calibration data density. These challenges are amplified in plays with multiple horizontal wellbore landing horizons, where target selection may not be consistent area to area. This paper presents a new scalable tool suite that efficiently predicts spatial heterogeneity and ranks well placement and landing zones using 3-D geomodeling technologies.

The 3-D assessment workflow characterizes reservoir quality, charge access, and completion quality with quantitative property models. A calibrated 3-D geomodel maximizes data investment by quantifying spatial variability. Asset and well-scale ranking are implemented by incorporating risk-mapping elements on a grid-cell and proximity basis. Reservoir- and completion-quality risks are defined for a given play by a desired set of conditions. The superposition of desired conditions at the geocellular level integrates the concepts of reservoir and completion quality into spatial rank, providing a technical basis for decisions.

The 3-D modeling and ranking workflow increases evaluation and operations team efficiencies. Production-driver property models represent the statistical variation of measurements, and uncertainty is quantifiable. The software ensures that the process repeatedly incorporates new calibration data within the drilling cycle. Decisions regarding well placement, target selection, and resource deployment are founded on an integrated, multidisciplinary, technical basis, enabling consistent implementation of optimization evaluation and design results.

1964399 Correlation of Rebound-hammer Rock Strength with Core and Sonic-log Derived Mechanical Rock Properties in Cretaceous Niobrara and Frontier Formation Cores, Piceance Basin, Colorado

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A key component to success with low-permeability, organic-rich rock resource plays is targeting rocks that contain natural fractures or that can be effectively hydraulically stimulated. Hardness and brittleness are key mechanical properties for rock types that are susceptible to fracturing . Typically, these rock properties are measured by sonic wireline logs or through triaxial tests on rock core. Core-based rock measurements are costly and therefore usually provide limited data sets. Sonic-log derived properties have limited bed resolution, which is a significant issue in many shale reservoirs where rock properties can vary significantly over small stratigraphic intervals. An alternate method using hand-held devices such as rebound hammers has recently been shown to produce reliable, reproducible rock strength results that correlate to laboratory and logging techniques. The advantage of hand-held equipment is significant cost savings and the ability to take measurements at a single-bed scale (less than 4 cm2 [0.62 in2]), thus more data can be gathered within a particular rock unit.

A low-energy rebound hammer was used in this study to characterize rock strength (confined compressive strength [CCS]) in Niobrara and Frontier Formation cores from the Piceance Basin in Colorado. Leeb strength values that were obtained from the rebound hammer were converted to unconfined compressive strength (UCS) values using the method described by Zahn and Enderlin, 2010. UCS values were then converted to CCS using an empirically derived correlation of UCS and CCS from Core Lab's North America Shale Consortia data set. The results show a strong correlation between the laboratory-measured triaxial CCS and the micro-rebound hammer CCS measurements when plotted against depth. Furthermore, there is a good correlation between the log-derived Young's modulus, bulk modulus and Poisson's ratio with the micro-rebound hammer data. This study shows that hand-held rock strength tools such as the micro-rebound hammer serve as an economical and reliable option for assessing rock brittleness and hardness, thereby providing critical mechanical properties for resource play targets.

1967188 Where Did the Proppant Go?

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Effective propped fracture half-lengths following a hydraulic fracture stimulation of a wellbore can be difficult to quantify. Therefore, different techniques for modeling proppant distributions must be applied to the same dataset for validation purposes. A proppant-filled Discrete Fracture Network (DFN) model is applied to two wells targeting the Muskwa and Evie Members of the Horn River Formation. Another technique for identifying microseismic signatures associated with the initial slickwater pad and the proppant-laden fluid was applied to both wells to obtain observed proppant distributions. The similarity of the distributions from each technique gives validation to each procedure and results can be used to optimize future completion techniques.

The study objective is to compare proppant distributions using a proppant-filled DFN method to the observed proppant distributions using a technique to separate fluid-induced microseismicity from proppant-laden fluid-induced microseismicity. Proppant distributions are broken up by their perpendicular, parallel, and vertical components with respect to microseismic distances from their respective stage centers. The distributions of each component are compared in terms of their mean values +/- one standard deviation and results are within ~15% of one another. These propped fracture distributions can be used to evaluate wellbore and stage spacing intervals. This suggests that when these techniques are combined, the proppant distribution in a formation following a hydraulic fracture stimulation can be well constrained to yield good estimates. The model results are used as a completions-diagnostics tool for evaluating the effectiveness of the stimulation and make future completion techniques more efficient and economically more valuable.

1967205 Noble Gas Geochemistry at the La Barge Platform, Wyoming, USA: CO_2 Source and Potential Total Petroleum System Investigation Tool

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Initial analyses of noble gas isotopes, major element isotopes, and gas composition data from high carbon dioxide (CO_2) natural gas samples at the La Barge Platform, Wyoming, USA, indicate that the CO_2 has a strong crustal signature. This finding is in line with geochemical, mineralogical, and fluid inclusion analyses that suggest that inorganic

thermochemical sulfate reduction (TSR) is the source of La Barge's CO_2 . Isotopes of noble gases released from hydrocarbons during TSR carry the isotopic signature of the air-saturated sea water and crustal environment of the hydrocarbon source rock. Helium isotope ratios reported relative to their concentrations in air ranged from 0.077 to 0.085 (R/Ra); these values as well as those of neon and argon indicate crustal origin.

La Barge Platform is the largest source of CO_2 used in enhanced oil recovery (EOR) at oil and gas fields across the northern Rocky Mountains. The field is located in southwestern Wyoming, west of the towns of Big Piney and La Barge. The field produces natural gas (21% average) and CO_2 (65% average) from the Mississippian-age Madison Limestone. In this initial round of sampling, three gas samples were collected from 14,500 to 16,500 feet of depth at three different well heads.

These results are an initial effort towards describing the total CO_2 system at La Barge; this includes source, reservoir extent, connectivity, and differentiability or fingerprinting. CO_2 generated from TSR is chemically related to the source hydrocarbon and its total petroleum system. Noble gas isotope analyses may be another tool in defining extents and tracing migration in total petroleum systems and associated CO_2 systems.

1967143 Utilizing Hydrocarbon Yield Determinations to Evaluate Source/Reservoir Relationships in the Bakken/Three Forks of the Williston Basin, ND

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The Bakken/Three Forks Petroleum System hosts variable source/reservoir relationships throughout different portions of the Williston Basin. While some of these relationships are easily discernible from production and wireline log data, others most readily become evident by comparing production results to geochemical data of the Upper and Lower Bakken Shales. In order to better identify and characterize these relationships a series of "Hydrocarbon Yield" maps were created for the Upper and Lower Bakken Shales using a method recently described in a paper by Ruble and Lewan (2013). The method computes a volume of hydrocarbon yield (MBOE/640 acres) by multiplying the thickness of the shales by the amount of S2 that has been converted into hydrocarbons. The generated maps are then compared to production data for both the Middle Bakken and Three Forks formations. Four distinct trends have been identified in this study:

-The bulk of the data fits in a highly correlative trend of lower water cuts in areas with increasing hydrocarbon yield, typical of "basin centered oil accumulations."

-A smaller subset shows a group of high water cut in areas of significant hydrocarbon yield." Wells in this subset consist primarily of good reservoir quality in the Middle Bakken, which suggests that these areas have poor trap integrity.

-Another subset shows a trend of wells with low water cut in areas of low hydrocarbon yield. Wells in these areas exhibit extremely good reservoir quality in the Middle Bakken and show evidence of a possible charge contribution from migrated oil.

-The bulk of the Three Forks wells tend to show a typical "basin centered oil" trend, with a small subset of wells with low water cut and minor hydrocarbon yield from the presumed source (Lower Shale). The small subset occurs in areas where the Lower Shale and Middle Bakken have pinched out, placing the Three Forks in direct contact with the oil generating Upper Shale.

While this approach does provide a new understanding of the Bakken/Three Forks source/reservoir relationships, it can also prove beneficial when used in the evaluation of other basins and formations.

1967555 Mosser Dome Field, Yellowstone County, Montana: A Giant Stratigraphic Oil Accumulation

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Surface and subsurface mapping of a valley fill depositional system in the Fall River Fm. (L. Cretaceous) in southern Montana reveals the presence of a giant oil accumulation that may have originally contained more than two billion barrels of oil. This major stratigraphic trap on the northeast flank of the Bighorn Basin is one of the largest in the Rocky Mountain region of the U.S. Except for a small area at Mosser Dome oil field, the oil contained in this trap is viscous heavy oil (<15° API). Extending a distance of twenty-two miles with a maximum width of four miles, the forty-eight square mile accumulation is found in porous sandstone that reaches a thickness of over ninety feet. The sandstone reservoir, known as the Greybull sandstone, was deposited in a westward flowing valley fill system. In the area of the Mosser Dome accumulation, two separate fault zones deflected the fluvial system to the northeast for a distance of sixteen miles before it resumed its westward flow direction. The large deflections of the valley fill system combined with southward regional dip to form a giant stratigraphic oil trap. Geochemical analysis of the oil indicates a source in the Permian age Phosphoria Fm. Subsequent introduction of bacteria-bearing fresh water caused the oil to be degraded, leaving relatively immobile asphaltic oil in the reservoir. The Mosser Dome stratigraphic trap is an excellent analog for non-degraded oil and gas accumulations in similar settings in the Fall River Fm. in the deeper portions of the Bighorn Basin.

1967556 Petroleum Occurrences in Cretaceous Age Reservoirs, Northern Bighorn Basin, Montana & Wyoming

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Oil and natural gas have been produced from Cretaceous age sandstone and conglomerate reservoirs in more than a dozen fields in the northern Bighorn Basin. Depths of production range from 1,000 feet to 14,500 feet. Lower Cretaceous reservoirs have cumulative oil and gas production of 6 MMBO and 56 BCFG. Upper Cretaceous reservoirs have produced 20 MMBO and 110 BCFG. All of the fields are on structural closures. Production is primarily from three stratigraphic intervals. They are in (A) the Pryor Conglomerate interval of the Cloverly Fm., (B) the Greybull Sandstone interval of the Fall River Fm., and (C) the Frontier Sandstone. The Pryor and Greybull reservoirs are Lower Cretaceous age while the Frontier is Upper Cretaceous. The Pryor is comprised primarily of fluvial deposits. Reservoir sandstones in the lower portion of the Greybull are of fluvial origin while those in the upper portion are thought to be estuarine to shallow marine. The Frontier sandstones are marine deposits. Oils produced from the Lower Cretaceous intervals are in two distinct geochemical groups. On shallow structures along the flanks of the Pryor and Beartooth Mountains the oils are 10 to 22° API gravity and are biodegraded. Geochemical analysis of the low gravity oils indicates they came from a marine carbonate source likely contained in the Permian age Phosphoria Fm. The oil traps containing this biodegraded low gravity oil may have had more than three billion barrels of original oil in place. The Mosser Dome field area in Yellowstone County, Montana houses a giant stratigraphic trap in the Greybull Sandstone once containing as much as 2 billion barrels of Phosphoria sourced original oil in place. Deeper in the basin the oils from Cretaceous rocks are 44-60° API gravity condensates. Gas chromatograph analyses of these oils suggest two separate oil families. The higher gravity condensates from the Lower Cretaceous age Pryor and Greybull are similar to each other and likely had the same source. They are quite different from the distinctive 44° API gravity oil produced from the Upper Cretaceous Frontier Fm. Source rock analyses of eighty-three Lower Cretaceous age core samples from fifteen wells in southern Montana show TOC values as high as 4.56% with all samples being in the early to middle oil generation window. The samples from the basal portion of the

Thermopolis Fm. had the highest TOC values. The Thermopolis is more than 350 feet thick. Significant hydrocarbon shows were seen on mud logs and drill stem tests from this black shale interval in Carbon County, Montana. It is the most likely source for the condensates produced from the Pryor and Greybull reservoirs. The oil produced from the Frontier Sandstone is assumed to have been sourced in the underlying Mowry Fm.

1956638 Play Analysis of the Cane Creek Shale, Pennsylvanian Paradox Formation, Paradox Basin, Southeast Utah

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The Cane Creek shale is a transgressive-regressive sequence in the lower portion of the Pennsylvanian Paradox Formation, Paradox Basin, southeast Utah. The Cane Creek is tens of feet to nearly 200 feet thick, over- and underlain by beds of salt, and divided into A, B, and C intervals (in descending order). The B interval is the primary hydrocarbon source rock and productive zone consisting of black organic-rich shale, dolomite, dolomitic siltstone, and some anhydrite. Significant porosity (up to 15%) is found in the dolomite and dolomitic siltstone, but permeability is generally low (~0.1 mD); naturally occurring fractures are necessary for economic production. The A and C intervals, mostly dolomite and anhydrite, are the seals for the B interval, helping prevent fracture communication with the adjacent salt beds.

Oil production was first established from the Cane Creek shale in the 1960s. Horizontal drilling renewed the play in the 1990s, but development is slow due to difficult terrain, as well as complex stratigraphy and structure. Six fields have produced over 3.8 million barrels of oil, only a small fraction of the U.S. Geological Survey's estimated undiscovered recoverable oil reserves in the Cane Creek and other Paradox Formation shale beds.

The Utah Geological Survey is conducting a multi-year, U.S. Department of Energy-funded study of the shale oil potential of the Cane Creek. In support of our study, operators have provided core and extensive core analyses which we will display, along with regional play mapping and evaluation.

1967000 Mechanical Stratigraphy and Well Correlation Using the Proceq Bambino in the Niobrara Shale

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The Proceq Bambino is a hand-held rebound hammer that can measure brittleness through non-destructive testing and increase the resolution, accuracy, and confidence in lateral geomechanical estimations. Ernst Schmidt invented the Schmidt Rebound Hammer in 1948. The Schmidt Hammer consisted of a spring-loaded hammer. When the hammer was released and impacted a surface, the height of the hammer rebound would be recorded. The Schmidt Hammer was produced by Proceq and originally used in concrete quality assurance testing. It was preferable to other testing methods because it could be conducted in-situ and was non-destructive. Schmidt Hammer rebound values could be correlated to unconfined compressive strength (UCS). The Schmidt Hammer was not ideal for core testing due to high impact velocity and destruction of core samples.

In 2006, Proceq developed a hand-held, low impact velocity rebound hammer, the Bambino. The Bambino had an LCD display and an internal memory storage device mounted onto the shaft. While the Schmidt Hammer only recorded rebound height, the Bambino gave readings in Leeb Hardness (HLD). An HLD unit was calculated as the ratio of rebound velocity to impact velocity (VREB/VIMP). Preliminary data was taken from a Niobrara core to demonstrate the repeatability, precision, and non-destructiveness of the Bambino. A relationship between HLD values and geomechanical properties such as UCS, Young's Modulus, and Poisson's ratio was found after conducting Bambino testing on cores from the Niobrara Shale. These relationships, coupled with the non-destructive, high-resolution data collection methods of the Bambino, made the Bambino a useful tool in geomechanical characterization of the Niobrara.

The Niobrara is a late Cretaceous formation located in the Denver Basin. The Niobrara is composed of two members, The Fort Hays Limestone and the overlying Smoky Hill Chalk. A series of chalk-marl sequences make up the Smoky Hill member. Each chalk-marl sequence showed a characteristic HLD value range. The differences in HLD values from differing lithologies and sequences was attributed to the Bambino's sensitivity to lithologic and microstructure changes. The HLD values were used to determine brittleness. Brittleness characterization greatly impacts the ability to predict hydraulic fracturability and fracture propagation.

Currently, these geomechanical properties can only be determined for cored intervals. The high cost and scarcity of cored intervals, therefore, limits the amount of geomechanical data available in a given basin. A correlation between geomechanical logs and sonic logs was made. As this correlation is better understood and refined, geomechanical properties can be predicted for wells where no core is available. Accurate predictions can greatly improve the efficiency of fracture stimulation designs, forecasts, and simulations.

1961875 Fluid Migration and Regional Pressure Development in the Midcontinent of the United States

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Our construction of potentiometric surfaces for Paleozoic and Cretaceous (Dakota Group) strata, based on drillstem tests and water well levels, reveals the pressure control exerted by outcropping strata. The Dakota Group is isolated from land surface by the overlying Pierre Shale, and Permian evaporites isolate the deeper Paleozoic aquifers. Gradually, halite beds in Permian evaporites dissolved, creating a highly saline plume of formation water that expanded downward because of its high density. As the plume expanded, mixing with fresher waters created a wide range of salinity values across the Midcontinent, especially in Kansas and Oklahoma. With erosion and outcrop exposure, each aquifer equilibrated with atmospheric pressure, causing an adjustment of hydraulic head from east to west, with each potentiometric surface responding over time to regional flow properties. Laramide thrusting, in combination with narrow outcroppings along the Front Range of Colorado, restricted recharge to the now-static confined aquifers, which are presently underpressured. As a state of underpressure developed, gas migrated in response to the changing pressure regime, most notably filling the Hugoton gas field in southwestern Kansas. The timing of underpressure development was determined by the timing of outcrop exposure and tilting of the Great Plains.

Thus, the disposition of water and hydrocarbons in the Midcontinent has been driven by a combination of tectonics and erosion. An improved understanding of regional hydrology has significance for underpressured oil and gas reservoirs in the western part of the Midcontinent, for the potential sequestration of carbon dioxide, and for injection of waste water.

1969213 An Overpressured Deep Basin and an Underpressured Hinterland: the Greater Anadarko Basin of Oklahoma, Texas, and Kansas

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The greater Anadarko basin exhibits two disparate hydrologic regimes in close proximity, as defined by pressure measurements from drillstem tests in numerous oil and gas wells. An overpressured (pressures greater than hydrostatic) deep basin in rocks of Mississippian and Pennsylvanian age is bounded on the north and west by strata with

pressures that are less than hydrostatic. The pressures from drillstem tests are used to construct potentiometric surfaces providing map views of the two regimes. From east to west, hydraulic head increases by several hundred feet in each rock formation, but elevation increases by thousands of feet. The low hydraulic gradient is attributed to good connectivity to the discharge point and restricted recharge. The apparent underpressuring phenomenon, which also increases from east to west, is a consequence of the vertical separation between surface elevation and hydraulic head.

Overpressuring in the deep basin has persisted since Permian time, but underpressuring in the hinterland developed relatively recently as a response to downcutting and exposure of Pennsylvanian strata in central Oklahoma. The discharge locus lies along and east of the north-south trending Nemaha fault zone, which lies at a lower elevation than the underpressured hinterland to the west. West of the Nemaha fault zone, the entire system is isolated from surface by a 1,000-ft thick cap of Permian evaporites and shales. Hydrologic modeling is required to better understand the system and explore the possibilities for carbon sequestration.

1945024 Examination of the Tyler Formation's Exploration and Development History using Current Source Rock and Reservoir Maps

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The Tyler Formation contains two separate petroleum systems: a northern, basin-centered petroleum system that contains organic-rich marine shale within the lower Tyler section, and a southern petroleum system containing organic-rich limestone beds in the upper Tyler. The southern petroleum system has yielded >99% of Tyler production to date with a 60 year history of exploration and development along the southern margins of the Williston Basin (southwestern North Dakota). Exploratory drilling has recently been initiated to test the southern Tyler petroleum system's potential as a resource play. Reexamining the previous 60 years of Tyler activity with current geologic maps and information regarding source rocks and conventional reservoirs will provide insight into current and future exploration efforts.

Production began from the Tyler in 1954 with Amerada-Northern Pacific Railway's Dan Cheadle Unit #1 located in southern Billings County, southwestern North Dakota. Since the Dan Cheadle discovery, over 85 million barrels (BBLS) of oil have been produced from the Tyler Formation from 298 productive wells to date. Most of the productive Tyler wells have been vertical with a handful of horizontal completions.

Based on productive wells drilled, the peak years of Tyler activity occurred during 1964-1975 when 117 successful Tyler wells were drilled (approximately one new productive well per month). Peak production occurred during the middle 1960's through the late 1970's when Tyler production totaled between 200 and 300 MBO per month. Water injection began in the early 1970's for enhance oil recovery and to date has injected ~228 million BBLS water into Tyler reservoirs versus 143 million BBLS of recovered water. Since the end of 1997, Tyler production has steadily decreased with only 20 additional productive wells being drilled and completed.

Most of the Tyler production to date has come from a series of bar-type sandstone bodies that trend approximately east-west and are collectively referred to as the Dickinson-Fryburg trend. Most of these sandstone bodies form isolated, oil-saturated porosity pods. Interpreted as either barrier and/or back-barrier sandstones deposited along shore, productive pay sandstone usually displays 10-20% porosity with permeability values of several hundred millidarcies. Organic-rich, argillaceous limestone beds overlay, as well as sometimes underlay, these productive sandstone reservoir bodies and have locally sourced Tyler hydrocarbons. Changes in the quantity and quality of Tyler source rocks across the Dickinson-Fryburg trend controls the amount of hydrocarbon charge within these isolated sandstone reservoirs. In areas where there is high source rock to reservoir ratio, fluid overpressure (pre-production) is often present and production yields oil with low water cuts (prior to water injection).

1960221 Produced Water Modeling of Upper Cretaceous Mesaverde Group Tight-Sandstone Reservoirs in the Uinta Basin, Utah

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The Maastrichtian Upper Cretaceous Mesaverde Group has been and continues to be a major, tight-sand gas reservoir in Utah. It consists of over 9,000 feet of fluvial, coastal plain, braided stream, wave-dominated deltaic, and beach sandstone and siltstone with interbedded transgressive Mancos Shale tongues and marine sandstones. Gas production from Mesaverde fields increased from 80 BCFG in 2002 to 287 BCFG in 2012. Produced water increased from 2 million bbls in 2002 to 26 million bbls in 2012. The amount of produced water could increase by at least 1 million barrels per year.

Handling produced water requires a significant investment in treatment and disposal. The cost for treatment and disposal will continue to climb as the water/gas ratio increases during prolonged production of the wells. Produced water has been historically evaporated or injected in disposal wells or could be reused in enhanced oil recovery, hydraulic fracturing, drilling mud preparation, and oil shale production.

Our study focuses on detailed stratigraphic, petrophysical, and produced-water-production data from wells penetrating the Mesaverde Group. Results will include formation and unit tops, lithology, thickness, temperature, pressure, and other petrophysical data. Using these data, petrophysical modeling of type logs from the Mesaverde will be used to extrapolate potentially available produced water quantity and quality into geologically less well-known areas targeted by future exploration. Water quality and quantity associated with existing gas production will be evaluated and used to help understand produced water management and amounts.

1965620 Detailed Chemostratigraphic Characterization of the Niobrara Formation, Cemex Quarry, Lyons CO

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The Cemex Lyons Quarry located 4 km northeast of Lyons, CO targets the Fort Hays Limestone of the Late Cretaceous Niobrara Formation on the western flank of the Denver-Julesburg Basin. In 2011, 24 exploration cores were drilled in a 60-acre field area north of the quarry to determine the extent of the Fort Hays Limestone. Cores from the 24 wells contain a nearly complete section of the Smoky Hill Member of the Niobrara Formation, the Fort Hays Limestone, and the uppermost section of the Codell Sandstone. With the recent advent of the portable XRF machine, chemostratigraphic characterizations have gained popularity in the Niobrara Formation of the Denver Basin. However, no study has been performed on such a small area with a high density of cores. This study will thus use XRF analyses, thin section petrography, and SRA to characterize the chemostratigraphy of the Niobrara Formation north of the Cemex quarry, relating trace element data to TOC values. Initial research suggests that small-scale heterogeneities in depositional styles, trace element distribution, and lateral bentonite continuity can be observed between cores only 150 m apart. Further research will attempt to geochemically fingerprint bentonite beds to discover further details about the paleoenvironment and provide a basin-wide correlation technique.

1966972 Applications of Pore-Scale Image Data to Exploration and Reservoir Characterization

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Improved scanning electron microscope technologies have made it possible to capture and quantify information about unconventional mudrock reservoir characteristics at very high resolution. Types of data that can be captured by SEM images of very fine grained samples include pore types, pore shapes, pore size (average diameter and pore size distribution), micro-fabrics, brittleness index, and elemental/mineralogy mapping.

Significant progress has been made with respect to upscaling SEM data to one-inch plug scale samples. Tiled images of AR-polished samples are now possible to collect at high resolution, providing the link to routine core analysis sample end-trims. Nano- and micro-pore data, as well as meso-pores and microfractures, can be mapped and distributed within these larger scale samples. This new workflow allows for more informed sample selection for high resolution SEM data collection and reservoir characterization.

While the upscaling problem has not been fully solved, information from pore scale images can be applied to log interpretation and combined with other analyses to enhance our understanding of source rock reservoirs and controls on production from these reservoirs. Examples from the Niobrara Formation reveal that pore type and shape characteristics as defined from SEM images affect NMR log interpretation and evaluation of potential target intervals for horizontal wells. Pore sizes and types change with increasing thermal maturity in the Niobrara in the DJ Basin. The relationship of clay morphology to permeability in chalks and marls is also important.

1967283 Using a Fluvial Sequence Stratigraphic Framework in the Coal Bearing Formations of the Raton Basin, CO to Build a Deterministic 3-D Model.

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The Raton Basin of southern Colorado and northern New Mexico contains Cretaceous coal bearing sediments (Vermejo and Raton Formations) deposited in a foreland basin setting during the final retreat of the Western Interior Seaway. Facies trends show an overall progradational system with short retrogradational periods within the Raton Formation. A fluvial sequence stratigraphic framework developed in these coastal sediments has been used to build a 3-D deterministic model using Petrel. This fluvial framework divides the section into two part cycles which include a period characterized by lower rates of accommodation creation, multistoried incised channel-fill type architecture and the development of paleosols and a period characterized by higher rates of accommodation creation, higher percentages of fine-grained sediment accumulation, single-storied aggradational channels and the formation of coal. Coal seams, averaging two feet thick in the Raton Basin, are continuous because of their ability to drape topography during deposition and are well preserved because of their resistance to erosion during the early stages of development. The coal seams are used as the main correlation unit. Correlated coal seams provide boundaries enabling the identification of time equivalent low accommodation channels and the low and high accommodation surfaces. The framework of tops is built in Petrel and used during the model building process in the creation of surfaces, horizons and zones which make up the deterministic model. This work has resulted in an enhanced understanding of this complicated system and the ability to history match individual well production in eclipse simulations, thus improving reserves management.

1965361 Bakken Formation Water and the Role of Shale Filtration, Williston Basin

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Post-depositional shale filtration may have been an important process in producing highly saline pore water in the Bakken Formation. Upper and lower members of the Bakken are organic-rich black shales that were deposited in deep, anoxic environments. The middle unit is mostly a fine-grained, commonly dolomitic, siltstone deposited in a shallower environment. Water from wells producing oil out of the Bakken Formation is about an order of magnitude more saline (27 to 34 percent) than modern sea water (3.5 percent). Concentrations of sodium, potassium, chloride, and bromide, respectively, are 8, 17, 10, and 14 times larger than sea water values. Calcium and strontium are enriched by a factor of 40 and 200, but magnesium was depleted probably by diagenetic precipitation of dolomite in the middle siltstone. Reduction of sulfate by a factor of 10 led to the precipitation of pyrite in shales. Evaporation of sea water in tidal flats and dissolution of evaporates are commonly proposed mechanisms to explain saline water in deep formations. The latter is the prevailing explanation of saline waters in carbonate and some clastic reservoirs in the Williston Basin, but neither process adequately explains the salinity and element ratios of Bakken Formation water. More likely, pore water was trapped in the middle Bakken by the low permeability upper and lower shales. Overpressures developed during compaction forced some the pore water through the tight shales which functioned as ion filters. Solutes were concentrated in the residual pore fluid remaining in the middle unit of the Bakken Formation.

1957885 Using Surface and Point Based Statistics to Evaluate Channel-Belt Clustering in the Fluvial Lower Wasatch Formation, Uinta Basin, Utah.

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The Eocene lower Wasatch Formation of the Uinta Basin contains exceptional outcrops of low net-sand content (37% sand) fluvial strata. This study quantitatively documents the stratigraphy of a 7 km wide by 300 meter thick strike-oriented outcrop in order to develop a quantitative database that can be used to improve our knowledge of how some fluvial systems evolve over geologic time scales. Data used to document the outcrop are: (1) 550 meters of decimeter scale stratigraphic columns that document grain size and sedimentary structures; (2) detailed photopanels used to document architectural style and lithofacies types; (3) thickness, width, and spatial position for all channel belts in the outcrop, and (4) directional measurements of paleocurrent indicators.

Five different methods are used to document channel-belt clustering within the outcrop using both surface and point based statistics. These methods include: (1) ocular inspection, (2) Ripley's K function, (3) R3 Method, (4) channel density maps, and (5) the compensation index. Key upward and lateral characteristics of the outcrop are the following. First, the shapes of 243 channel belts are documented. The average width, thickness and aspect are 110 m, 7 m, and 16:1, respectively. Importantly, the size and shape of channel belts does not change upward. Second, channel belts are documented to spatially cluster. Key upward patterns in channel-belt clustering are a marked change from non-amalgamated isolated channel-belt clusters to amalgamated channel-belt clusters. Critically, stratal surfaces can be correlated from mudstone units within the clusters to time-equivalent floodplain strata adjacent to the cluster demonstrating that clusters are not confined within fluvial valleys. Finally, proportions of floodplain and channel belt elements underlying clusters and channel belts vary with the style of clusters and channel belts laterally and vertically within the outcrop.

1960713 Controls on Porosity and Pore Type within the Eagle Ford Formation, South Texas

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Scanning electron microscopy of Ar-ion milled samples from the Eagle Ford Formation, South Texas shows that compaction, cementation, bitumen generation, and generation of secondary porosity within organic matter (OM) are important factors in porosity evolution. Samples of varying compositions and maturities provide insight into these processes.

Porosity in low-maturity samples is dominated volumetrically (values range from 0.1% to 11.4%) by relatively large, primary inter-particle pores (average sizes within samples ranging from 62.6nm to 143.1nm). Larger pores are typically associated with coccolith debris that is aggregated into pellets. Porosity and pore size correlate positively with calcite abundance and inversely with OM and clay volumes. Porosity loss is interpreted to occur through compaction of ductile kerogen and clays, and to a minor degree by cementation and infill of early bitumen.

In high-maturity samples the observed OM includes a greater fraction of bitumen than in the low-maturity samples. Porosity in high-maturity samples is dominated volumetrically (values range from 0.2% to 3.6%) by smaller OM-hosted secondary pores (average size ranging from 11.1nm to 14.9nm). Mineral-associated pores are present, but are typically smaller (average size within samples ranging from 20.3nm to 40.7nm) and less abundant (values range from 0.0% to 1.9%) than at low maturity. Porosity correlates positively with volume measurements of OM and calcite, and correlates inversely with clay volume. Compared to low-maturity samples, porosity has been lost through cementation, bitumen filling, and, possibly, greater compaction in these high-maturity rocks, but additional porosity has been generated through organic maturation.

At both low and high maturity, the evolution of the pore system can be explained by responses of the primary detrital assemblage to evolving physical and chemical conditions in the subsurface.

1964952 Seismic Diffraction Imaging on Pre-existing Seismic Data to Predict Fracturing in Unconventional Reservoirs

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The pre-drill knowledge of natural fracture swarms and small offset faults is very important as these geological elements can either help increasing the flow rate or can interfere with the drilling and fracking process and negatively influence the production rate. Seismic resolution from conventional reflection imaging is generally not sufficient to resolve these small scale rock properties. Diffracted waves are events that are produced by the scattering of a wave after it meets a discontinuity such as fracture swarms, small amplitude faults and karsts that cause local sharp changes in the geometrical or lithological characteristics.

The MultiFocusing diffraction imaging technology uses the MultiFocusing concept to separate the diffraction component from the overall wave field. The amplitudes of diffracted waves are usually much weaker than those of specular reflections. Diffractions are essentially lost during the conventional processing/migration sequence, or they are masked in conventional seismic stacked sections. Local structural and lithological elements in the subsurface of a size comparable to the wavelength are commonly ignored during processing and identified indirectly during interpretation but not from direct measurements. We are able to show results of diffraction studies over 3 distinctly different study areas, the Levant Basin, Siberian Basin and North America.

1966063 Correlation of Niobrara-Equivalent Strata in the Eastern Uinta Basin, Utah

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Examination of geophysical logs from about 150 oil and gas wells allowed us to correlate the Late Cretaceous Niobrara Formation in Colorado to time-equivalent strata within the Mancos Shale of the eastern Uinta Basin, Utah. A preliminary structure map shows the top of the Niobrara equivalent (NE) deepens from near sea level at the Utah-Colorado line to more than 9000 feet below sea level about 40 miles to the northwest. Along the same path, the NE thickens from 1150 to more than 1450 feet. Most of the thickening occurs in the upper part of the NE, which we interpret as a highstand sequence set. The lower and middle parts of the NE, represented by lowstand and transgressive sequence sets, respectively, maintain relatively constant thicknesses.

Based on log character and limited core data from the NE, we suggest that the unit contains and is immediately adjacent to some of the more hydrocarbon-prospective parts of the Mancos Shale. Much of the upper NE consists of a sediment-starved shelf facies association (a primary target) and the base of the NE overlies a heterolithic organic-rich facies association (a secondary target). Given the thickness of the NE and variations in burial depth, organic maturation levels of the unit should also vary significantly. Applying our maturation model of the Uinta Basin, we predict vitrinite reflectance values for the top of the NE to range from 0.55 in westernmost Colorado to 1.45 northwest of the Natural Buttes oil field; predicted values at the base of the NE are 0.63 and 1.65 at the same locations. Further exploration should determine whether the NE in the Uinta Basin has petrophysical characteristics similar to those that make the typical Niobrara Formation so productive to the east.

1967401 Stratigraphic Architecture of the Frontier Formation, Powder River Basin, Wyoming

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The Cretaceous Frontier Formation in the Powder River Basin of Wyoming, USA contains actively produced unconventional hydrocarbon reservoirs. One facies of interest within the Wall Creek Member of the Frontier Formation consists of thinly interbedded sandstones and shales with varying degrees of bioturbation. Determining potential for new plays is partly dependent on understanding this facies' sedimentology and architecture. Ten cores have been documented in addition to four full stratigraphic sections and two partial stratigraphic sections measured along a north-south traverse at the western margin of the basin.

Comparisons of measured stratigraphic sections reveal that all sections exhibit sequences that grade up from shales, to non-bioturbated thinly interbedded facies, to bioturbated thinly interbedded facies, to a unidirectional cross stratified sandstone facies. Sandstone bodies range in thickness from 20 cm to 26 meters and almost ubiquitously contain cross stratification indicative of unidirectional or channelized flow, implying a southerly paleo-transport direction. Bioturbation via vertical and horizontal burrows of the thinly interbedded facies is common.

These preliminary data support the hypothesis that the sequences shown are deltaic in nature. The primary evidence includes the great abundance of unidirectional cross stratification, the amount and nature of the bioturbation, and the ordering of the facies.

1967490 Structural Modeling to Reduce Uncertainty, Eastern Cordillera Fold and Thrust Belt, Colombia

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Uncertainty in modeling the extent of productive and prospective thrust sheets in the Piedemonte area of the Eastern Cordillera is high, owing to the difficult environment for seismic imaging. In spite of ample 2D and 3-D seismic data and several iterations of reprocessing, imaging the productive and potential thrust sheets proves elusive, thus a rigorous structural modeling process is necessary to reduce uncertainty on trap sizes and extents. Reprocessed 3-D seismic, along with new information from several recently drilled wells, provide the base for a refined 3-D model of the area.

The thrust-bounded packages each typically contain Paleogene Mirador, and sometimes Barco and Upper Cretaceous Guadalupe Formations. These units are low porosity sandstone reservoirs, but are strongly fractured. The productive and prospective thrust sheets underlie shallow to surface structures, notably the Nunchia syncline and the El Morro anticline. The shallow features are well imaged and combined with surface mapping constraints, provide important aids to interpretation of the deeper thrust sheets.

The antiformal stack of thrust sheets extends for tens of kilometers along-strike, from the Recetor area, through Piedemonte and into the Niscota area. Individual thrust sheets also extend for tens of kilometers along strike, as supported by production history, pressure interactions and occasional tracer data. Wells aligned in the dip direction provide the best base for interpreting sections and understanding dip extent of the thrust sheets. Iterative balancing of sections using all wells yields sections where the cutoffs are best constrained. The shortening and stacking of the prospective thrust sheets must explain the translation and uplift of the Nunchia syncline and other shallow structural features. Changes in style and number of thrust sheets along strike are reflected in changes in the Nunchia syncline and other shallower features. Interpretation and balancing of sections that are constrained by the wells yield a fault network that accounts for all the structures. Carrying the interpretation through a network of sections provides an interpretation template for the 3-D seismic volume. Further testing for balance in 3-D yields a model with significantly reduced uncertainty.

The refined model aids in evaluating potential reserves, extent and connections between the various thrust sheets and in defining targets for drilling, including untested thrust sheets with production potential.

1948872 Source to Sink Systems for Hydrocarbon Exploration in Lacustrine Basin Fill: Analog Examples from the Tertiary Duchesne River Formation, Northern Uinta Basin, Northeastern Utah

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Facies architecture and sequence stratigraphy have become increasingly important topics for oil and gas exploration in lacustrine basins worldwide. Extensive, well-exposed outcrops of the Tertiary Duchesne River Formation can be traced from source to sink, and thus comprise a classic study example for hydrocarbon modeling. In the Uinta Basin, the juxtaposition of a lower organic rich lacustrine source rock and an overlying, coarse-grained fluvial sandstone yield ideal conditions for upward hydrocarbon migration into a suitable reservoir. Here, the Duchesne River Formation represents the last stage of the lacustrine basin sequence. The fluvial - lacustrine facies record tectonic control stemming from uplift of the E - W elongate basin-bounding Uinta Mountains. The basal member is characterized by a high net-to-gross braided river system in the west and a low net-to-gross sinuous or isolated small stream system in the east. Extensive paleocurrent data show dominant southerly transport, perpendicular to the basin axis. However, texturally mature sediments in the western part of the basin suggest long transport distance from a different source terrain, specifically the Sevier fold thrust belt. The multiple transport patterns indicate that the drainage system along the basin axis was important for development of a large-volume and high-quality reservoir system. This late-stage basin fill example demonstrates the importance of deciphering the complex input of multiple source terrains combined with distinctive fluvial sand-body architectures.

1959573 Distinguishing Noise from LWD Gamma Ray Data in Horizontal Wells

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Other than drill rate and directional information; Gamma Ray is often the only MWD/LWD data gathered during the drilling of a horizontal well that can be used as an indicator of geology. While the tool and the telemetry system are simple; there are many parts that must work together in order for the geologist to have usable data to properly land and steer a well. While the Gamma Ray tool is simple in design; it's value is often misunderstood or overestimated by those that use it.

Elementary techniques of log/data evaluation are often overlooked because of trust in technology. Understanding the technology, breaking down the parts of the system and a review of available data can often help identify problem data or noise gathered during the drilling of a horizontal well.

Simply remembering that the data must fit within the bounds of the offset data character and range is paramount to successful interpretation of the GR data. This step is often overlooked because of the expense of gathering the data; and thereby the high intrinsic value placed upon it. Spurious GR values have convinced even the most experienced geologist and mudloggers to misinterpreted drill samples.

Proper interpretation of GR data can reduce costly and unnecessary adjustments to the directional path of a well. Understanding the operation of the telemetry system and the limits of the data can reduce the overall well cost by reducing trips to replace working tools or sidetracks to stay in zone.

1958022 Using New Well Logging Technology with Ultra-Sensitive Detection of Hydrocarbons to Assess Hydrocarbon Composition, Compartmentalization, and By-passed Pays

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A variety of logging technologies provide information during drilling as to the presence of hydrocarbons. However, these logging technologies do not measure hydrocarbons directly, but rather measure hydrocarbon proxies and infer hydrocarbon presence and phase based on this data. These technologies, while sophisticated can lack specificity and sensitivity when trying to accurately identify hydrocarbons.

Additionally, some new technologies can monitor hydrocarbons from n-C1 (methane) to n-C8 (octane) and expand the scope of hydrocarbon detection. These new technologies can clearly detect gas range organics and can infer light oils and condensates. However, all of these technologies lack the ability to measure the heart of the oil or liquid hydrocarbon fingerprint of n-C7 (heptane) to n-C15 (pentadecane). Thus accurately characterizing and differentiating between multiple oil fingerprints becomes difficult, if not impossible, for current technologies. As such, these limitations negatively impact the ability of companies to properly assess and evaluate plays like the Eagleford that have numerous stacked liquid pays.

However, advances in well logging technology now provide the ability to analyze downhole cutting samples to directly characterize the composition of hydrocarbons vertically through the prospect section. This provides the unique ability to look at a broad compound

range from C2 to C20, which is significantly more expansive than the limited traditional ranges of C1-C5 or C1-C8 of most well gas logging techniques. The result is the ability to not only characterize gas and condensate range hydrocarbons, but also characterization multiple liquid or oil phase hydrocarbons contained in the stratigraphic intervals. The increased sensitivity and carbon range provides the ability to:

- Clearly distinguish between various hydrocarbon phases
- Distinguish multiple oil signatures
- Identify by-passed pay
- Infer compartmentalization
- Avoid false positives from mud log data (C1-C5) for fracture or fault gases
- Avoid false negatives from mud gas line monitoring for:
- Under-pressured formations
- Thick mud systems
- Be used for 3-D evaluation field wide
- Infer sulfur content of oils
- Assess depositional environment, thermal maturity age, biodegradation with geochemical plots, which you cannot do with other technologies

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1966399 Focusing Petroleum Exploration With Regional Geochemical Surveys

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A regional onshore geochemical exploration survey was carried out over the Yukon Flats and Nenana basins in east-central Alaska. The objectives of the survey were to focus exploration within a 2,100 square mile area and demonstrate the existence of liquid hydrocarbons in these supposed "gas-prone" basins. Lake bottom sediments were chosen as the preferred sample medium for the survey because the lakes are thought to be thermal windows through permafrost, they can be collected rapidly with helicopter support, and their effectiveness for detecting oil and gas fields was demonstrated in a previous study over the Tuk oil and gas fields in the Mackenzie Delta of northern Canada. The lake sediment samples were analyzed for headspace, saturated and unsaturated C1 to C7 hydrocarbons and also for traces of crude oil using Synchronous Scanned Fluorescence.

The regional lake sediment geochemical survey over parts of the Yukon Flats and Nenana basins was effective in that liquid hydrocarbons were detected and the initial 2,100 square mile survey area was reduced to about 500 square miles of prospective ground based on the location of oil and wet gas microseeps. The location of a subsequent 40 square mile 3-D seismic survey was guided by the results of the geochemical survey. Regional lake sediment geochemical exploration surveys are a cost-effective tool for demonstrating the existence of liquid-based petroleum systems in remote untested basins. The surveys also help focus more cost-prohibitive geophysical surveys and drilling.

1950059 New Concept of Oil and Gas Origin

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Oil and gas genesis (or origin) is an important scientific problem. The question of oil and gas origin, disputed between supporters of organic and inorganic theories, has not been resolved during the last one hundred years. The organic hypothesis identify oil and gas origin from remains of buried dead organisms, while the inorganic hypothesis argues hydrocarbons are formed from hydrogen and carbon coming from depth of the Earth. However, now there is a further concept.

Integration of numerous empirical data has led to the conclusion that oil and gas formation is not only a lengthy geological process as with the organic or inorganic theories but rather a natural phenomenon dependent on geochemical circulation of movable carbon and water through the earth's surface (biospheric concept). As a result, the biospheric concept scientifically substantiates that oil and gas are 'renewable' mineral resource.

A key provision of biospheric concept is polycondensation (abiogenic) synthesis of gas and oil hydrocarbons in the earth's crust with involvement of meteoric waters. Our study in the late 80's presented the possible mechanism of water circulation under temperature change (positive or negative thermodynamic gradient of pore pressure) during the climatic circulation process in the interior of the earth's crust and the impact of this phenomenon on many geological and geochemical processes, including migration and accumulation of hydrocarbons.

To investigate and prove these concepts authors completed specialized experiments, whose findings and more importantly the consequences, as they apply to the scientific and applied fields, are very interesting. Experiments have shown that the formation of hydrogen and hydrocarbons from H_2O andCO_2 is active in the sedimentary rocks, even at atmospheric pressure and room temperature.

This identified process explains, in particular, the replenishment phenomenon of oil and gas reserves at a number of developed fields, changes in chemical composition of oil and the scale of modern degasation of hydrogen, methane and carbon dioxide into the atmosphere. Among other applications, it also enables the authors to offer patented technologies for production of hydrogen and hydrocarbons from water and CO_2 in either aboveground or subsurface conditions. These make it possible to reduce the expected problems of energy and environmental crises, specifically by utilizing carbon dioxide (CO_2) as a working agent.

1956666 Solutions for Difficult Reservoirs—Direct NMR Fluid Type and Permeability

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Conventional reservoir calculations using resistivity and density/neutron porosity have been the industry standard for defining reservoir characteristics. The calculation of water saturation from these measurements is used in every reservoir situation. Many reservoirs are not easily analyzed; therefore, various and complicated analysis techniques have been developed.

The great hope with the introduction of NMR tools to the industry was that reservoir parameters could be established and applied in an uncomplicated manner. Recent advances in technology of NMR responses have produced the ability to capture polarization time and relaxation time in a single pass through the reservoir. Nuclear magnetic polarization time has been demonstrated to have a relationship to the fluid type in the reservoir. The relaxation time (T2) gas has been used to characterize permeability with an excellent relationship to production. The Bray-Smith permeability equation was developed from this observation. This equation incorporates relaxation time and calculates permeability. No alteration to the equation for rock type or texture changes was needed.

This paper presents examples of logs in three different and difficult-to-evaluate reservoirs. A reservoir with lenticular sand, another with a thinly-bedded sand and shale sequence, and a conglomerate/mudstone reservoir are each evaluated for fluid type and permeability. Effective porosity, fluid type, and permeability are all resolved accurately by the NMR. Comparisons to production results are presented.

1961943 Reservoir Characteristics of the Codell Sandstone Tight Oil Play, Northern DJ Basin, Wyoming and Colorado: Extension of Wattenberg into the Oil Window

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The Cretaceous Codell Sandstone has been producing gas and oil in the Wattenberg Field in Colorado since 1979. Recent advances in

horizontal drilling and multi-stage fracture stimulations have facilitated the extension of the Wattenberg Field into the northern DJ Basin in southeastern Wyoming and northern Colorado, where stabilized production rates up to 1300 BOPD are associated with recently completed horizontal Codell wells. This new play area in Laramie County, Wyoming and northern Weld County, Colorado is thermally in the oil window. Codell Sandstone oil producers have gas-oil ratios less than 2000 scf/bbl.

The Codell Sandstone thins from north to south due to erosional truncation beneath an angular unconformity at the base of the Fort Hayes Limestone Member of the Niobrara Formation and ranges from 18 to 33 feet in gross thickness. The Codell Sandstone is a very-fine to fine-grained sandstone and produces oil from two main facies: bioturbated sandstone and laminated sandstone. The laminated facies is parallel to sub-horizontally bedded, has 8 to 15 percent porosity, and .01 to 0.10 millidarcies permeability. The bioturbated sandstone has 8 to 13 percent porosity and .008 to .05 millidarcies permeability. The Codell Sandstone is a low-resistivity pay zone that produces oil with low water cuts from zones with less than 10 ohm-m resistivity. Clay content is 15-25% with abundant microporosity as imaged with epifluorescent microscopy, accounting for high bound water content and explaining the low formation resistivity.

Two Codell Sandstone cores provide examples of these facies. The Noble V.O. Child #30-09 core in Laramie County, Wyoming, recovered 25 feet of Codell Sandstone, including 22 feet of bioturbated facies and 3 feet of laminated facies. The Noble Lazy D #03-09 core in Weld County, Colorado, recovered 18.5 feet of Codell Sandstone, including 11 feet of bioturbated facies and 7.5 feet of laminated facies. Core oil saturations and fluorescence under ultraviolet light indicate that the Codell Sandstone is oil saturated in both cores. Nearby horizontal wells drilled and completed in the Codell Sandstone indicate that oil can be recovered economically extending Codell production more than 50 miles north of Wattenberg.

1949353 The Upper Bakken Shale Play, Elm Coulee Field, Williston Basin

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The Upper and Lower Bakken shales are the source beds for the Bakken Petroleum System of the Williston Basin. Reservoirs for this system include the shales, the lower Lodgepole, Middle Bakken silty dolostones, and Three Forks silty dolostones. The Upper shale was a drilling target in the late 1970s through the early 1990s in southwest part of the basin in North Dakota (termed the depositional limit play or Billings Nose play). The discovery of the giant Elm Coulee Field changed drilling strategies to focus on the Middle Bakken dolostone member. As this play extended into North Dakota, drilling success was also encountered in the upper Three Forks dolostones.

The Upper Bakken shale has recently been targeted with horizontal drilling and multistage fracture stimulations along the southwest edge of Elm Coulee Field where the Middle Member pinches out. In this area wells are drilling into the Upper shale and then completed with multistage fracture stimulations. The fracture stimulations extend into the adjacent Lodgepole and Three Forks formations. So in essence, these new wells target multiple pays. Factors thought to be important in this Upper shale play include: orientation of horizontal laterals, bed thickness, natural fractures, shale mineralogy, abnormal pressure, and TOC content. This play is a similar to the previous depositional limit play in North Dakota except the wells are completed with multistage fracture stimulations.

Exploration success in the Upper Bakken shales suggests that future drilling should also target the Lower Bakken shales.

1967160 3-D Seismic Proves its Value in Bakken Geosteering

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Improved geosteering performance has been hailed publicly by WPX Energy management as a key driver in achieving lower well costs in the Williston Basin. Geosteering errors in the basin were reduced by 90% from mid 2012 to early 2013. This impressive improvement is in part attributable to the use of advanced processing of 3-D seismic data. Using 3-D seismic for geosteering applications requires (1) resolving the Bakken interval, a well documented challenge in the Williston Basin, and (2) accurately converting seismic surfaces to depth, an easy task filled with hidden problems.

Resolving the Bakken interval is the most critical and arguably the most difficult objective for 3-D seismic data in the Williston Basin today. 130 square miles of 3-D data were reprocessed rigorously at the front end so that high frequency "extender" (HFE) approaches had a chance to produce stable and geologically plausible results. Upper Bakken, Lower Bakken and Three Forks horizons were mapped using the HFE volume, providing higher confidence geosteering surfaces.

Converting to depth with HFE 3-D seismic shed light on another important challenge with creating accurate geosteering surfaces: well tops and their accuracy. Careful examination of both logging procedures and depth calibration of wire line versus MWD/LWD tools must be performed. Examples can be shown that this issue is more the culprit for depth conversion inaccuracies than uncertainty in seismic velocities. Additionally PSDM comparisons are available to take advantage of carefully vetted well tops and meticulous seismic velocity determinations.

WPX Energy has demonstrated bottom-line value in applying 3-D seismic data as a geosteering tool when proper attention has been paid to seismic processing and depth conversion.

1968024 Paleostructural Control of Cretaceous Niobrara Productivity in a Portion of the DJ Basin of Colorado

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Subtle thickness changes within the Cretaceous Niobrara are associated with changes in hydrocarbon productivity from the Niobrara in a portion of the DJ Basin of Colorado. Isopachous maps of the Niobrara show thick and thin trends parallel to the Colorado Mineral Belt in Weld and Morgan Counties, in northern Colorado. Locally thinner Niobrara areas are more likely to be economically productive from the Niobrara. Thins also occur where relatively higher resistivity values are measured by electric logs in the Niobrara 'B' chalk. Niobrara 'B' chalk resistivity is related to productivity in this area. Differences in the basement structure and composition can control local heat flow. Areas of thinner Niobrara may have experienced higher temperatures in the past than thicker areas of Niobrara, maturing source material within the Niobrara to a higher level than nearby thicker and cooler areas. Higher maturity levels increase the gas content within the reservoir and elevate pressure, improving the productivity of Niobrara wells. Microfractures, created by oil expulsion from source material within the Niobrara, enhance porosity and permeability improving productivity. Enhanced porosity in the Niobrara B Chalk due to depositional and diagenetic changes in these thinner areas of Niobrara may also have increased productivity. Careful mapping of the abundant well control within the DJ Basin can aid in a successful exploration program for the Niobrara.

1966837 Unconventional Exploration: Will Your Next "Sweet Spot" Have Once Been a "Hot Spot"?

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One of the persistent problems encountered during exploration for unconventional plays is the inability to identify the "sweet spots" prior to leasing and drilling. Typically, seismic is used for high grading, but it is expensive, ground access can be limited resulting in partial coverage and, as with many technologies, the interpretations can be ambiguous. However, there are less expensive alternatives such as remote sensing, integrated organic/inorganic petrography, gravity, magnetic, and various types of thermal maturity data that can be used to initially identify areas with higher production potential. After this initial screening evaluation, the high graded areas can subsequently be appraised using more expensive techniques. Using less expensive screening alternatives up front can improve results and project economics.

In separate studies, experts have recently independently converged on the concept of using a combination of less expensive screening technologies to identify areas of localized high heat flow where recurrent movement of basement faults in areas already known to contain rich source rocks results in the maturation and trapping of hydrocarbons by hydrothermal fluids. Their publications indicate that at both a mega-scale as well as a micro-scale, an internally consistent genetic model can be developed that shows, in multiple diverse locations, "sweet spots" for oil accumulations in unconventional plays are often related to local "hot spots". In turn, igneous intrusions into sedimentary successions, which are far more common than is generally realized, often drive the hydrothermal activity that is responsible for these "hot spots". Recurrent movement on faults and lineaments that extend to the basement can provide conduits for hydrothermal fluids into the sedimentary section. At such "hot spots", the hydrothermal fluids and associated volatiles can have a significant impact on hydrocarbon generation and migration as well as on host rock permeability, porosity, fracturability, and overpressuring.

In this presentation, examples given from the Eagle Ford at First Shot Field in Texas and the Parshall and Stanley fields in the Williston Basin illustrate that better production is related to areas of localized convective heat flow. Convective heat flow via hydrothermal fluids is much more efficient than the transfer of heat by conductive heat flow. Evidence for hydrothermal activity in both areas is provided by relatively inexpensive screening techniques. Such examples demonstrate the commercial benefit of exploiting low cost alternative methods to effectively and efficiently identify "sweet spots" for unconventional plays. A different tool box adapted to unconventional resource exploration can improve project economics.

1967379 The Importance of High-resolution Geochemistry in Downspacing Evaluations of Unconventional Plays

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Downspacing studies are emerging as the most important geological evaluations to fully understand the economic potential of North American tight oil and gas plays. Understanding fluid communication or compartmentalization in high-density well fields can optimize well spacing and orientation of laterals. This can be achieved through baseline fluid and gas characterization during well-drilling, followed by routine monitoring of production fluids and gases.

Baseline geochemical evaluations can be made using a variety of samples: mudstream gases, gases desorbed from cuttings or cores, source rock extracts, and early production fluids or gases. While standard geochemical analyses, such as traditional gas chromatography, provide useful characterization data, they may lack the precision for tracking communication between wells. Emerging technologies, specifically two-dimensional gas chromatography (GCxGC), are now more economically viable for upstream applications.

The analytical capabilities of GCxGC flame ionization detection (FID) and time of flight mass spectrometry (TOF-MS) have been proven in tracing degraded, oil-associated compounds in environmental quality assessments. In upstream applications, they have the potential to offer unprecedented resolution for distinguishing between production fluids. Furthermore, using subtraction algorithms, well-coordinated GCxGC analyses can diminish the influence of oil based drilling fluids in baseline well field studies.

This presentation will discuss unconventional hydrocarbon characterization using GCxGC, as well as single and triple quadrupole mass spectrometry (GCMS & GCMS/MS). Highlighted will be the values and limitations of these technologies for determining optimal well spacing and achieving maximum production.

1960262 Basin-Scale Analysis and Options for Produced Water from Tight-Gas Sand Reservoirs, Uinta Basin, Utah

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The production and disposal of water from tight-sand gas reservoirs in the eastern Uinta Basin, Utah, and elsewhere affects the economics of gas resource development and has recently become a topic of much public debate because produced water is the largest-volume waste stream associated with these unconventional gas plays. Environmentally sound management of produced water can be a significant cost associated with gas extraction, so there is an economic incentive to minimize this waste stream and/or reuse produced water in hydrocarbon development, and companies are actively pursuing these technologies. Balancing the water-use needs and produced-water disposal requirements associated with shale/tight-sand gas development creates significant material handling challenges to both industry and regulators. These challenges are complicated by an operating environment where many individual producers of varying sizes exist within a field, each with varying water needs and production, and a production timescale of decades for the basin as wells play out and new ones are completed.

Over 328 BCFG and nearly 50 million bbls of water were produced from the Uinta Basin in 2013. The major tight-gas sand reservoirs in the basin are the Tertiary (Eocene) Wasatch Formation and several formations in the Cretaceous Mesaverde Group. Three major components of our study are: (1) compilation and analysis of past and new information on the thickness, structure, depth, lithology, water quality, and temperature of all aquifer/reservoir units in the basin from the surface (alluvium) down through the Jurassic Glen Canyon Group; (2) mapping of reservoirs/aquifers (structure, thickness, porosity, permeability, lithology) and produced water (quantity, geochemistry, temperature); and (3) statistical analysis of water production quantity and quality to identify and forecast volume trends for each discrete tight-sand gas-producing interval. These components will be incorporated into an evaluation of the existing infrastructure for produced water management/reuse and the recommendations for best management practices of the produced waters in the eastern part of the Uinta Basin.

1967254 Completions Optimization in the Eagle Ford Shale Play

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Hydraulic fracture stimulation treatments of a two well pad in the Eagle Ford shale of Texas were monitored for induced seismicity. Data acquired during the treatments was analyzed and used to optimize

the treatment design, including wellbore spacing, stage length, stage spacing, and treatment schedule. A discrete fracture network (DFN) was modeled, with a fracture for every microseismic event. Each fracture's orientation and dimensions was modeled using the event's source mechanism, energy of the event, rock properties, and injected fluid volume. A distance-based proppant filling methodology was used to model the portion of the total stimulated rock volume (SRV) that will be productive. The horizontal perpendicular, horizontal parallel, and vertical components of each event's location was calculated with respect to its stage center, and a statistical analysis of those components was used to evaluate the treatment design.

1923459 Post-Laramide Thrust Backsliding and Arch Collapse: a Mechanism for Creating Intensely Fractured Trends and High Off-Structure Production; Wind River Basin, Wyoming

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The mechanisms and timing of fracturing are important parameters to predicting intensely fractured trends with enhanced formation permeability and production potential. Fracture analyses were used to test hypotheses for the structural development of the Wind River Basin in Wyoming. These hypotheses include: pre-Laramide regional compression or forebulge migration; syn-Laramide ENE-WSW horizontal compression and left-slip faulting; and multiple post-Laramide hypotheses: 1) elastic strain release following Laramide shortening; 2) near-surface mechanisms; 3) regional extension due to transtensional plate interactions or epierogeny; and/or 4) localized extension due to backsliding on thrust faults during collapse of basin-bounding arches.

Fracture data from Cambrian to Eocene strata throughout the basin included 1,900 joints and minor faults measured at 45 outcrop stations and 14,775 previously interpreted fractures from 39 micro-resistivity image logs. Inferred stress axes, calculated using eigenvector analysis, show two distinct clusters indicating two stages of deformation: syn-Laramide ENE-WSW horizontal shortening followed by post-Laramide extension consistent with variation in the modern stress. Post-Laramide fractures in the basin parallel NW-SE striking joints observed across the Rocky Mountain foreland, except in the vicinity of E-W trending basin-bounding arch margins where these fractures closely parallel arch-bounding thrust faults.

Fracture analyses and seismic data indicate localized extension in proximity to basin-bounding thrust faults and backsliding on these thrusts that is probably due to arch collapse. Recently completed wells at Frenchie Draw gas field probably intersected off-structure, intensely fractured trends that parallel the margins of what appears to be a collapsed anticline. These wells have uncommonly high production rates.

1967311 Effects of Upper and Lower Bakken Source Rock Differences on the Charge of Middle Bakken and Three Forks Reservoirs in the Williston Basin

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Observation of the Bakken-Three Forks petroleum system in the Williston Basin reveals that, in areas of relatively low source rock maturity, Three Forks reservoirs can yield economic volumes of petroleum, while Middle Bakken reservoirs primarily produce water. This study uses an integrated approach to link the observed charge trends to geologic and geochemical properties at the locations where the Three Forks is the more productive reservoir.

Prior studies of Bakken source rock properties have sought to explain production sweet spots in the Williston Basin by treating the Upper and Lower Bakken units as layers of identical source rock. This study, of more than 2600 pyrolysis analyses, reveals that subtle differences between the two source beds, along with reservoir quality differences cause preferential charge into Three Forks reservoirs at early maturation stages in the basin.

Specifically, the geochemical data show that the Lower Bakken source beds are of higher quality and generate petroleum sooner than the Upper Bakken source beds. The lower Bakken source beds, while lower in original total organic carbon, have higher original hydrogen indices. Curve fitting of the hydrogen index vs. Tmax plot shows that lower Bakken source beds reach petroleum generation and expulsion at lower total thermal stress.

1967325 Multivariate Analysis of Geologic and Engineering Parameters on Petroleum Production in the Niobrara Formation

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Studies that model the relationship between petroleum production, geology and engineering parameters indicate that six of top eight factors that contribute to ultimate recovery are inherited from nature. At the same time, bivariate comparisons of petroleum production, geologic information and engineering data have shown moderate to poor correlation (r values <0.6) in two-dimensional space (Welker et al., 2013)

This study utilizes principal component analysis and hierarchical cluster analysis to expose the complex relationships between production, geology and engineering across a range of source rock maturities and well types in the Niobrara play.

Analysis of the data (from Silo Field, the Hereford area and the Greater Wattenberg Area) demonstrates that some properties can substitute for others in the prediction of ultimate recovery. The analysis also reveals that current data density in these areas may not adequately represent the homogeneity (both vertically and geographically) to clearly define the relationships this work hoped to expose.

1952831 Geological Characterization of the Uteland Butte Member of the Eocene Green River Formation: An Emerging Unconventional Carbonate Tight Oil Play in the Uinta Basin, Utah

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The Uteland Butte Member of the Green River Formation records the first major transgression of Eocene Lake Uinta after the deposition of the alluvial Colton Formation. The Uteland Butte ranges in thickness from less than 60 ft to more than 200 ft and consists of limestone, dolomite, organic-rich calcareous mudstone, siltstone, and rare sandstone. This unit has historically been a secondary oil target of vertical wells tapping shallower overlying reservoirs and/or deeper fluvial-lacustrine sandstone units. Recently, companies have targeted the relatively thin, porous, dolomite beds of the Uteland Butte via horizontal drilling. Several companies have targeted the Uteland Butte in the southwestern part of the basin with only limited success due to the normal, or only slightly overpresured, nature of the reservoir. However, in the central, overpressured portion of the basin, just south of the Altamont field, companies have had more success. The main horizontal drilling objective, as analyzed in several cores, is a 4- to 12-foot-thick interval of fractured dolomite, with porosities between 14 and 26%, interbedded with organic-rich limestone. TOC values in the adjacent rocks range between 2 and 5%, while Ro values range between 0.7 and 1.1, indicating the reservoir is most likely self-sourcing. Exploration has also commenced on the eastern side of the basin in which the shallower Uteland Butte records a more proximal,

fresher water facies. A refined geological and reservoir characterization study of the Uteland Butte Member using newly acquired core, cuttings, and geophysical logs is currently underway to help delineate play boundaries, guide resource estimations, and inform recovery methods.

1952854 Hypersaline Facies and the Termination of Eocene Lake Uinta, Upper Green River Formation, Uinta Basin, Utah

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The early evolution of ancient Lake Uinta has been the focus of significant study due to the enormous hydrocarbon reserve in the Uinta Basin's lower to middle Green River Formation (GRF). In contrast, the upper GRF, which includes strata of the lake's highest level (Mahogany zone), as well as three previously poorly delineated hypersaline phases, is less understood but still important for developing a complete lacustrine system evolutionary model. We used detailed descriptions and mineralogy from ten cores transecting the basin were used to help delineate these three hypersaline lake phases and better define the events related to the closing of Lake Uinta. Lake Uinta's first hypersaline phase, recorded in the Uinta Basin, occurred during maximum lake level at Mahogany zone time. Saline minerals, mostly nahcolite nodules and small shortite crystals, were deposited in the lake's paleo-depocenter in central Uintah County, but also in a sub-basin in west-central Duchesne County. The second hypersaline phase is represented by a basin-wide small-saline-crystal facies (both nahcolite and shortite), as well as a large-saline-nodule facies (nahcolite), also centered on the lake's eastern paleo-depocenter. This second phase includes the Birds Nest aquifer and is believed to mark a transition to a more restricted lake basin. Near the end of the second hypersaline phase, sediments originating from the east and north began to infill the lake, pushing the paleo-depocenter to the west. The third hypersaline phase is represented by a thick deposit of lacustrine sediments with disseminated saline minerals (nahcolite and shortite) and bedded salts (halite and trona) centered in north-central Duchesne County.

1965585 Calibration of FIS Factor 1 Response to Map API Gravity "Sweet Spots" in Unconventional Resource Assessments

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Fluid Inclusion Stratigraphy (FIS) has been used for decades to successfully evaluate critical aspects of petroleum systems such as reservoir content, phase state, seal effectiveness, and migration pathways. This presentation extends those fundamental concepts to the unconventional realm and demonstrates the manner in which the calibrated FIS response is capable of directly measuring the API gravity as part of "sweet spot" assessment (e.g., prior to leasing). This is a distinct advantage over optical-based methods that fail to account for the gas phase contribution (e.g., gas-oil ratio) to the reservoir content, and is particularly advantageous when the hydrocarbon inclusions are hosted in a carbonate lithology. The advantages are demonstrated by the fact that the relative proportion of dissolved gas in the oil phase can account for up to 20°API gravity variation in the produced hydrocarbon resource, that fluid inclusions are difficult to image in carbonate lithologies (i.e., matrix and cements) due to the frequent small size and problematic optical properties, and that the fluorescence response of hydrocarbon is biased to the liquid phase since the fluorescence originates from the distribution of aromatic hydrocarbon components (i.e., benzene and higher aromatics).

The Factor 1 response variable is the output from HCA and PCA statistical processing of the raw FIS signal (i.e., 1-180 amu) that provides a continuum between dry gas (i.e., <-2), wet gas/condensate (i.e., -2 to +1), and oil (i.e., >+1). For each of these intervals, the gas content is reflected in a continuous scale that is subsequently calibrated with known reservoir contents that allow the gas-oil ratio and API gravity to be determined. While the generic calibration is robust, additional precision is provided with the flexibility to include local calibrations. This method is superior to the optical-based fluorescence determination (i.e., including fluorescence spectroscopy) since a larger sampling of the resource is analyzed, the subjective color determinations are avoided, costs are lower, turn-around time is faster, and the output includes the gas phase dissolved in the liquid fraction. Best practice protocol includes analysis of a vertical profile through the target resource, and integrating the output with other parameters in the unconventional resource evaluation toolkit (e.g., basin modeling, rock mechanics, and mineralogy). The method is demonstrated to be particularly useful in complex reservoir facies, including complications introduced by fault offsets, to provide input for determining optimal lateral placement and length.

1969209 Microbial Mat Textures in Lithofacies of the Paradox Formation, Paradox Basin, Utah

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The Paradox Basin is an asymmetric basin that subsided in the Pennsylvanian and Permian, and contained an inland saline lake during the Pennsylvanian. Marine waters likely entered the basin by seepage through porous clastic and/or carbonate units that formed a southeastern barrier to the ocean, and by periodic storm and seasonal high-tide washovers. This study identified lithofacies within the Pennsylvanian Paradox Formation based on description of two subsurface cores. A typical vertical succession of lithofacies consists of irregular laminated anhydrite, halite-sylvite, evenly laminated anhydrite, silty dolomite, and gray to black mudstone. Microbial textures were recognized in each lithofacies, including the organic-rich black mudstone. This idealized lithofacies sequence represents a complex interplay of regional climate, and local and global sea level changes.

The irregular laminated anhydrite is interpreted to have been deposited in a gypsiferous, arid, tidal-flat environment with little clastic or freshwater input. Anhydritic lithofacies transition upward into the halite-sylvite facies, which represents a shallow salina environment and hyper-saline conditions. Microbial and thin-shale laminae occur within the halite-sylvite facies. The evenly laminated anhydrite lithofacies formed above the halite-sylvite facies as additional water input decreased lake salinity. Alternating dark- and light- colored laminations in the two anhydrite facies are interpreted as microbial mat laminations and anhydrite, respectively. The silty dolomite facies represents increased rainfall and clastic input to the basin, and it includes ripped-up microbial mat fragments. The gray to black shale facies was deposited in a perennial meromictic lake during periods of salinity stratification. In thin section, peloidal, clotted fabrics are locally recognized. Linear pyrite stringers are also present, and in some cases the linear stringers are folded back on themselves, suggesting rolled-up microbial mat fragments. The recognition of microbial mat textures in each of the lithofacies in the Paradox Formation encourages further research into the controls on mat development because of their potential importance in understanding climate fluctuations and the deposition of source rocks.

1966255 Maximize Mass Spectrometer Mud Gas Data-Experienced Analysis Matters

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Modern surface logging of mud gases at the well site while drilling often makes use of a mass spectrometer. Today's portable mass spectrometers have detection capabilities which far exceed traditional gas chromatography. While the mass spectrometer's mud gas data provides a tremendous amount of information, it is not fully

understood and greatly underutilized. The mass spectrometer gas curves can provide useful information given by more than visual inspection of individual curves, but a much greater understanding of their meaning and use comes with statistical analysis, ratios, cross-plots, and experienced interpretation.

Statistical analysis of mud gas data can reveal reservoir qualities not otherwise readily observed. For example, normalizing mud gas values and direct comparison with various molecular weight species can begin to characterize hydrocarbon compositions and isolate zones of interests. Standardizing mud gas values and comparison with rate of penetration can establish a mean value across a well's data set and allow gas curves to be evaluated as they deviate from average which can be indicative of particular "sweet spots" or even depleted sections. Applying gas component ratios and cross-plotting the mass spectrometer data set provides convincing evidence for zones of "likeness" or "unlikeness" which may signal compartmentalization, compositional variations, water saturation, secondary porosity/permeability and other notable geologic conditions.

1967509 Complexities of Well Log Interpretation Observed through Cored Samples, Mesaverde Group, Uinta Basin

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Most natural gas production in the Greater Natural Buttes field in the Uinta Basin, Utah comes from channel deposits within the Mesaverde Group. Within this study area, the 2000 – 2500 ft thick interval is informally subdivided into the Lower Neslen, Upper Neslen, Farrer and Tuscher. The intervals are defined from outcrop descriptions fifty miles to the south and contacts do not correlate well into the subsurface. Subsurface correlations, if done at all, are subjective and cannot be considered reproducible. To accurately create a geocellular model, correlations and intervals must be clearly defined. Understanding the depositional environment through an analysis of facies and facies association provides the foundation for subsurface correlations and geocellular modeling.

The purpose of the study is to test the hypothesis that facies associations and associated well log response would provide a foundation for more accurate subsurface correlations, geo-cellular modeling, and ultimately, hydrocarbon recovery. To test this hypothesis, a detailed sedimentological and stratigraphic assessment was conducted using available core data sampled from the Mesaverde Group. Core descriptions allowed for interpretation of facies and facies associations, which were compared to a well log suite. Core samples from the Tuscher, Farrer and Neslen will be shown to display the complexities of identifying channels in logs. Facies, facies associations, mineralogy, and extent of bioturbation are all compared to log motifs and discussed as a possible explanation for the well log complexity. This study addresses the importance of core analysis as it provides sedimentological and stratigraphic information more valuable than outcrop, which may not accurately represent the reservoir.

1958453 Visual and Analytical Comparisons of Upper Bakken "Shale" Cores from a West-to-east Transect, McKenzie and McLean Counties, North Dakota

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1. WPX Energy, Denver, CO, United States; 2. QEP Resources, Inc., Denver, CO, United States; 3. Newfield Exploration, Denver, CO, United States.

Data from six lowermost Mississippian (Kinderhookian) upper Bakken "shale" cores along a 52-mile-long transect in the Williston Basin in North Dakota provide a rich suite of stratigraphic and analytical information for detailed comparisons. Thickness of this silty, organic-rich mudrock varies from 14 to 21 feet with no consistent regional trend evident along the transect. A visual display alone of three slabbed cores reveals some color variations but fails to show the subtle compositional and textural components of this interval. Analytical results from all six cores, however, serve to characterize and contrast these world class source rocks as they change from peak oil generation to thermally immature.

Detrital silt, disseminated throughout the interval, occurs as scattered grains and thin, locally discontinuous laminae that are visible in the slabbed core. These eolian silt grains, along with a variety of pelagic fossil fragments and fecal pellets, settled through the stratified water column and accumulated on a mostly anoxic seafloor, although there were some minor periods of dysoxia indicated by burrowing. Mineral assemblages identified in thin sections and by SEM EDS are surprisingly diverse. X-ray diffraction results show that the major components that are relatively constant along the transect include quartz (30-50%, detrital, biogenic, and authigenic), kerogen (10-20 wt. %, mostly Type II), illite/mica (15-25%), and K-feldspar (4-8%). The constituents that vary the most include dolomite (2-13%, both detrital and authigenic), albite (2-9%), mixed-layer illite/smectite (1-17%, increasing eastward), pyrite (3-14%, all authigenic), and calcite (1-7%, mostly as skeletal fragments).

Present-day as well as estimated original TOC values highlight the well-known westward increase in thermal maturity of the Upper Bakken from east to west with a few interesting exceptions close to the Nesson anticline. Corresponding organic pore development is also related to increasing thermal maturity.

Elemental data from hand-held X-ray fluorescence show considerable vertical and lateral variability. The resulting chemostratigraphic interpretation of key elements has defined recognizable, fairly geographically continuous sequences that offer new insights into depositional processes and environments.

NOTES

DENVER AREA ATTRACTIONS

Downtown Area Attractions

Denver Art Museum 13th Avenue between Bannock and Broadway www.denverartmuseum.org

Kirkland Museum of Fine & Decorative Art 1311 Pearl Street www.kirklandmuseum.org

Clifford Still Art Museum 1250 Bannock Street www.cliffordstillmuseum.org

Byers-Evans House Museum 1310 Bannock Street www.ByersEvansHouseMuseum.org

Molly Brown House Museum 1340 Pennsylvania Street www.mollybrown.org

Denver Firefighters Museum 1326 Tremont Place www.denverfirefightersmuseum.org

The Money Museum at the Federal Reserve Bank 1020 16th Street www.KansasCityFed.org/moneymuseum

The Denver Mint 320 West Colfax Avenue www.usmint.gov/mint_tours/

Colorado State Capitol Broadway between 14th Street and Colfax Avenue www.colorado.gov/capitoltour

Colorado Governor's Mansion 400 E. 8th Avenue
www.colorado.gov/cs/satellite/governorsresidence/GRES/1212052629611

Children's Museum 2121 Children's Museum Drive just off of Water Street www.mychildsmuseum.org

Downtown Aquarium 700 Water Street www.downtownaquarium.com

Elitch Gardens Amusement Park 2000 Elitch Circle near Speer Boulevard & Auraria Parkway www.elitchgardens.com

Greater Denver Area Attractions

Denver Museum of Nature and Science 2001 Colorado Boulevard www.dmns.org

Denver Zoo 2300 Steele Street www.denverzoo.org

Denver Botanic Gardens 1007 York Street www.botanicgardens.org

Wings over the Rockies Hanger 1 at 7711 East Academy Boulevard www.wingsmuseum.org

Dinosaur Ridge National Natural Landmark 16831 W. Alameda Parkway, Morrison, CO www.dinoridge.org
7/21-7/25 Junior Paleontologist summer day camp for 8-12 year olds

Morrison Natural History Museum 501 Colorado Highway 8, Morrison, CO www.mnhm.org

Colorado Railroad Museum 17155 W. 44th Avenue, Golden, CO www.ColoradoRailroadMuseum.org

Coors Brewery Tours near 10th and Ford Streets, Golden, CO www.millerscoors.com/brewery-tours/Golden-Brewery.aspx

Butterfly Pavilion 6252 W. 104th Avenue, Westminster, CO www.butterflies.org
7/21-7/25 Nature Explorers summer day camp for 5-10 year olds

Activities

Denver BCycle Bicycle Share Stations scattered across town, two on 14th Street near Convention Center
https://denver.bcycle.com/default.aspx

Denver has miles of bike paths including the one that borders Cherry Creek just south of the convention center.
Download a bike map at www.denvergov.org/portals/708/documents/Bike_Map_Final_2012.pdf

Colorado Rockies Baseball Coors Field at 20th and Blake Streets www.colorado.rockies.mlb.com
Monday-Wednesday (7/21 – 7/23) vs Washington Nationals

Denver Outlaws Outdoor Lacrosse Sports Authority Field at 1701 Bryant Street www.denveroutlaws.com
Sunday (7/20) @ 1 pm vs Florida Launch

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