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THE SPWLA TODAY NEWSLETTER

INSIDE THIS EDITION

SPWLA 2018—London England

59th Annual Symposium
June 2-6, 2018

SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS

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CALENDAR OF EVENTS

March 6, 2018

Using Mudlogging as a Formation Evaluation Tool - Course
Instructor: Bill Donovan
Frank S. Millard Training Center
Houston, TX, USA
www.spwla.org

March 7, 2018

Formation Testing SIG Meeting
Theme : "Thrive in the Lower for Longer Environment"
Repsol Services Co
The Woodlands, TX USA
www.spwla.org

April 15-17, 2018

SPWLA 2018 Spring Topical Conference
Theme "Petrophysical Data-Driven Analytics: Theory and Applications"
SPWLA Frank S. Millard Training Center
Houston, TX
www.spwla.org

April 15-18, 2018

2018 SPWLA Abu Dhabi Topical Conference
Theme "Representative Carbonate Reservoir Models "The Role of Petrophysics"
Abu Dhabi, UAE
www.spwla.org

June 2-6, 2018

SPWLA 59TH Annual Logging Symposium
London, United Kingdom
www.spwla2018.com
June 26-28, 2018
Formation Testing, New Advances and Applications
Course Instructor: Hani Elshahawi, Shell International E&P
SPWLA Frank S. Millard Training Center
Houston, TX
www.spwla.org

July 30-31, 2018

The Role of Well Logs in Geomechanics
Course Instructor: Amy Fox, Enlighten GeoScience
SPWLA Frank S. Millard Training Center
Houston, TX
www.spwla.org

From the President

Brett Wendt
SPWLA President 2017–2018

Dear SPWLA Members (and since this publication is open to the public potential members too!),

There has been a whirlwind of activity to report!

The most obvious activity is this inaugural edition of *The SPWLA Today* newsletter. A completely new offering that is dedicated to the community aspects of our organization, which will allow *Petrophysics* to thrive as a pure technical journal without the need to also act as a communication platform. While this may not seem like a very big change, the possibilities this creates are virtually unlimited. There was a constant (and valid) friction when attempts were made to use *Petrophysics* as anything other than a technical publishing platform. As a result, SPWLA has never had the ability to serve its members as an organization at the core of a community.

The SPWLA Today changes this. As you will immediately see, we are using this opportunity to increase the communication from your Board. One of the consistent messages I receive from members is that the Board fails to communicate sufficiently. I have thus required the following columns for inclusion in this publication:

- "From the President" – President (continues as usual)
- "From the Editor" – Vice President Publications (continues with a new focus)
- "Up Next" – President-Elect (provide insights into what they will pursue; challenges they see today)
- "Tech Today" – Vice President Technology (Symposium updates/planning, paper submissions, etc.)
- "The Invoice" – Vice President Finance (financial updates, budgeting, spending initiatives, advertising)
- "Informative Technology" – Vice President Information Technology (web functions, online offerings, database management, etc.)
- "Learning Opportunities" – Vice President Education (distinguished speakers, Topical conferences, students, webinars, etc.)
- "Regional Understandings" – This will rotate through the Regional Directors with one domestic and two international regions being highlighted in each issue.

But this is only the half of it. *The SPWLA Today* is also an opportunity for you to participate. Submissions for regular columns or content will be considered and are encouraged. Are you retired and want to pass on some advice? Are you new to the industry and want to know why things are the way they are? Well now you can make your voice heard. Consider becoming a regular columnist.

All "In the Society" material, including Chapter News, "In Memoriam, as well as From the President, and nontechnical From the Editor content has been removed from *Petrophysics* and will appear in *The SPWLA Today*. "The Bridge," which was a social platform dedicated solely for young professionals will be integrated into *The SPWLA Today.* We encourage those who remember other columns or content (such as op-eds columns, cartoons, commentaries, and discussions) that were removed from *Petrophysics* through the years to consider submitting such work again. SPWLA once again has a place for you to express yourself!

Another big undertaking was the effort to modify the SPWLA Bylaws and Articles of Incorporation to allow changes via electronic communications. The difficulty of paper ballots and postal mail has acted as a deterrent in keeping our society up to date with technology and practices for far too long. As I anticipate that the motions will have passed by the time this is read, let me say thank you for your participation. With passage, I intend to hold additional ballots to implement other updates and improvements to these documents before my term is over.

Our symposium in London is fast approaching and all signs point to it being a fantastic year. We had a record number of abstracts submitted, so the technical content should be compelling and vibrant. The organizing committee has been working hard to set up the venue and secure sponsorship so that the event runs smoothly and to everyone's expectations. We have been very fortunate to have such a dedicated group of volunteers.

This will be my last opportunity to ask you for submissions for awards. I know that we have members deserving of recognition (particularly for service). Once again, please submit any nominations to Luis Quintero for consideration.

As always, I am open to any comments or ideas. Please let me hear what you think!

From the Editor: Introduction to the March 2018 SPWLA Newsletter

Carlos Torres-Verdín
Vice President Publications

Your *SPWLA Newsletter* is here!

There has been much discussion behind the scenes and among SPWLA Board members about the pros and cons of diverting social content from *Petrophysics* into a more appropriate and self-evolving publication. The intention has always been both good and constructive: we have witnessed how modern times and modern technology have changed the ways in which we communicate and interact with our peers. It is also clear that the SPWLA has evolved and continues to evolve in multiple ways and we need to be flexible and attentive to our youngest generation of professionals. They will soon be the heart and soul of our society. This is where we are now: an interesting crossroads that demands new, more creative, and more flexible ways to communicate with our members on dimensions other than technical, scientific, or engineering.

The *SPWLA Newsletter*, temporarily named *The SPWLA Today*, will be in transition and evolution during the rest of 2018. We don't have a final format but we do we have the beginning of a constructive endeavor to improve and expand the way in which we communicate with our members and with other professional societies. And other than diplomacy, respect to others, and themes that are related to our professional society, there are no strings attached and no inflexible rules as to what can be part of *The SPWLA Today*. Even informal technical notes/commentaries are welcome!

Let me take this opportunity to invite our readers to not only submit comments or suggestions for change and improvement, but also to become authors of special columns. Anything that resonates among SPWLA members, young or mature, will find a niche in *The SPWLA Today*. Diversity of thought and interest are good and encouraged. You can also volunteer to be part of the ad-hoc editorial committee!

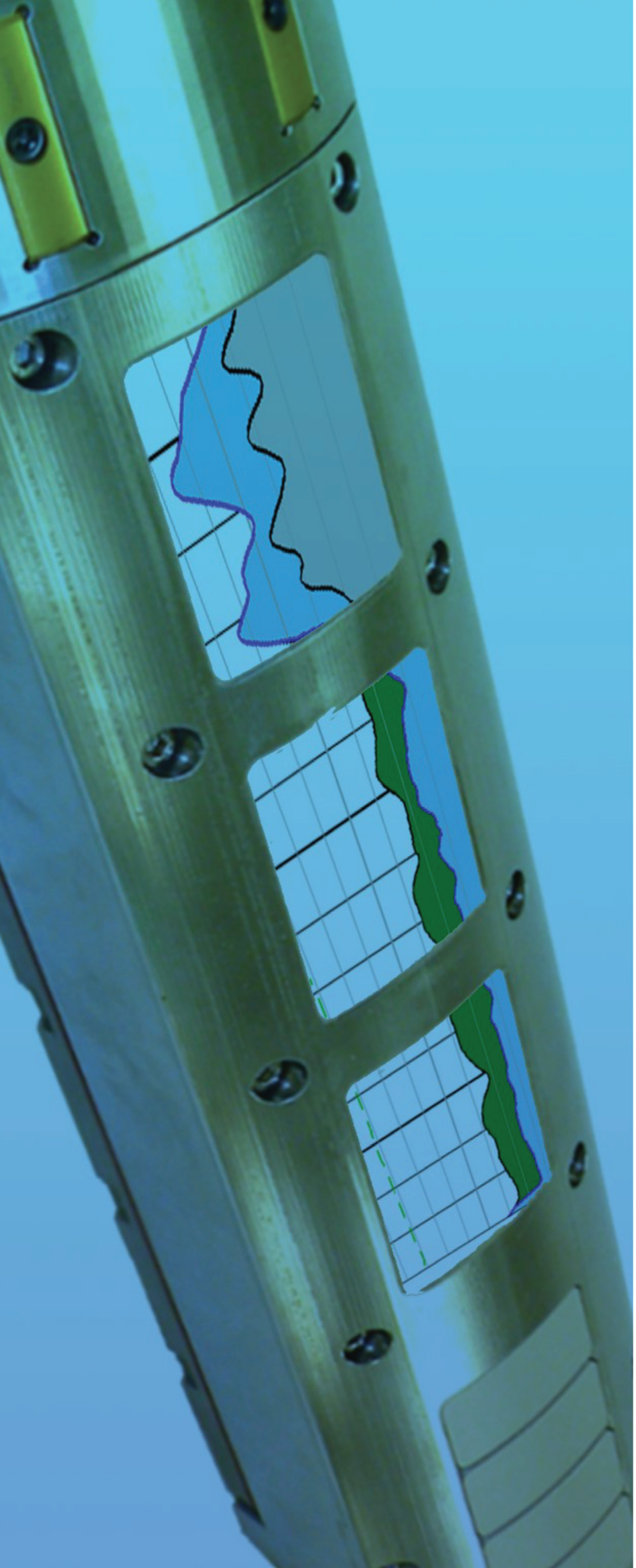
Here are some examples of ideas that we have thus far received for potential topics of interest and discussion to be included in *The SPWLA Today*:

- "What we need and what we have in formation evaluation now, where is the overlap?"
- "Why do we continue to express Archie's equation in so many different ways?"
- "Formation evaluation from the trenches of a small operating company"
- "Interesting adventures in the day-to-day life of a petrophysicist"
- "Where do I really learn petrophysics?"
- "Why are petrophysicists usually not consulted by reservoir engineers?"

The sky is indeed the limit…

Please be informed that the publication of *The SPWLA Today* will alternate with that of *Petrophysics*, i.e., every other month, and this will constrain the speed with which we will be able to "spread the news." However, if we opt for a web-based platform for *The SPWLA Today* we might be able to populate every issue with articles and columns as soon as they clear the ad-hoc editorial committee.

In closing, I would like to thank the SPWLA Board and SPWLA Members for their help, cooperation, foresight, and overwhelming support of our new publication. Rest assured that we will do everything possible to make *The SPWLA Newsletter* and enduring success—a publication by SPWLA members and for SPWLA members!



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For more information on how the Array Dielectric eXplorer service can help improve the quality of your reserve estimates, contact a BHGE representative or visit bhge.com.

Up Next

Zhipeng "Z" Liu
2017–18 SPWLA President–Elect

Dear SPWLA members and friends of SPWLA,

It is my honor to serve as your 2017–2018 President-Elect. As an organization with a nearly 60-year history, SPWLA has experienced its fair share of Boom-to-Bust cycles. Throughout this current market situation, SPWLA has managed to stay strong, positive and proactive on a smaller budget. With a tremendous amount of effort and donation of valuable time and resources, most of our Chapters and SIGs have remained active to serve you. We even managed to add a few Student and professional Chapters last year, and have a few more additions in the pipeline thanks to enthusiastic members' initiative. Our monthly webinar and educational video service offered to our members are also growing. This isn't the first O&G industry downturn and certainly won't be the last. We must remember that this downturn is only temporary. Thanks to you and your involvement—SPWLA is open for business! It is more important now than ever to stay engaged with your SPWLA Chapter and SIG activities to further your knowledge-base, strengthen your skills, and to nurture and grow your professional network. What better way to extend your professional network than to attend the 59th Annual SPWLA Symposium hosted by the London Chapter (a thriving chapter of 400 strong). When the next boom comes, you will be prepared to not just survive, but also ride the wave and thrive.

Jesús. M. Salazar
2017–18 SPWLA VP Technology

In my first column I will explain part of my duties as Vice President of Technology (VPT) and how the abstract selection process for the symposium works. My first task as VPT was to form a new technology committee (TC) to help with the abstracts selection. I'm proud to have selected a diverse group of professionals from the industry and academia scattered all over the world. The TC includes 35 members located in 10 countries representing all the regions with SPWLA's membership. The committee compiles 25% of female representation, a breath of experience with accomplished young professionals and several veterans with 30+ years in the industry, and a good mix of operating and service companies and universities.

In August 2017 we issued the first call for abstracts and included the notice in several issues of *Petrophysics*, on the society's website, and via emails until the process closed on November 6. A total of 450 abstracts were submitted from all types of institutions and companies. This is both an indication that our oil and gas industry is showing signs of recovery and that London is a place that attracts people from all over the world, which makes it an excellent venue. These abstracts were assigned to the TC honoring everyone's subject matter expertise, whenever possible. Each TC member had to read at least 172 abstracts. Every abstract was reviewed by at least 11 referees and given a score. The chief criteria for grading were originality (new approach to existing methods and contribution to the advancement of formation evaluation), writing (no grammatical errors and easy to understand, i.e., a well-communicated message), and zero commercialism. We also had ground rules, such as no reviewing papers from same company where the referee is a co-author, or with possible conflict of interest. As you can see, it's a very transparent process that guarantees a fair chance to everyone who submitted an abstract.

On December 6, the TC met in Houston and via teleconference to finalize the program. We selected the top 125 abstracts and sent notices of acceptance and rejection later that month. Based on previous experience, we expect a few withdrawals closer to the date of the symposium. The program will showcase 51 oral presentation and approximately 50 to 60 eposters.

Below, are two figures illustrating the diversity in topics and authors' professional affiliations. The first is a pie chart with the percentage of accepted papers by topic of solicited abstracts. The second figure illustrates the percentage of accepted abstracts by affiliation. For the first time, we will have a category on the hot topic of Data Analytics and its application to formation evaluation.

The job of the TC is far from done, we still need to work with authors on the final paper submission, which includes minor reviews, ranking of best papers, and chairing sessions during the symposium. As you can see, it's a lot of work for these volunteers. So, when you bump into a TC member, say thank you. I hope you find this column informative and at the same time will encourage you to register and book your ticket to London to attend the 59th Annual Symposium.

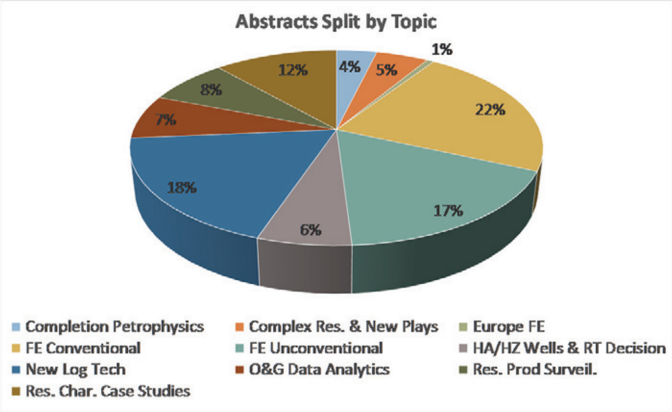

Fig. 1—Percentage of accepted abstracts by topic.

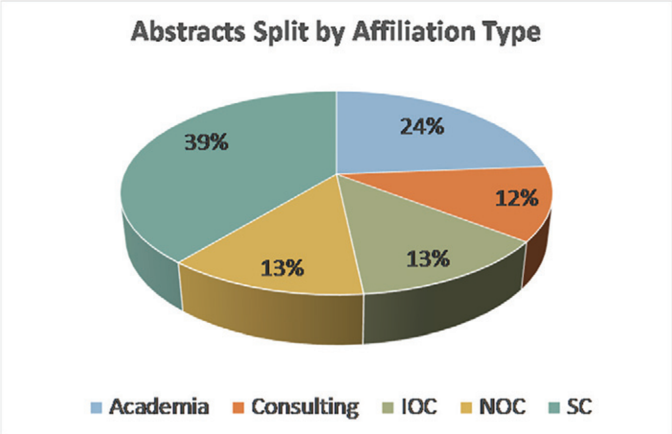

Fig. 2—Percent of accepted abstracts by employer affiliation. Academia, universities and government research institutions; Consulting, individuals and consulting companies; IOC, international oil company (major or independent); NOC, national oil company; and SC, service company (includes all logging vendors and large software companies).

Informative Technology

Mehrnoosh Saneifar
2017–2018 Vice President
Information Technology

I received the position of VP-IT from Zhipeng Liu in June 2017. It is my great pleasure and honor to serve SPWLA and to make our organization ever more visible in the oil and gas industry with the help of Information Technology. The following is a summary of my activities during the past months.

Upon taking the position, I worked on finding vendor alternatives that would provide free access to SPWLA videos at a low cost for the organization. At that time, our members had to pay an annual fee for a subscription to access the SPWLA videos on the Knowledgette website. After a few months of evaluating different options, as well as discussing a more convenient plan with Knowledgette, we signed off an agreement that would grant SPWLA members free access to both SPWLA and AAPG videos on the Knowledgette website. To obtain free video access on Knowledgette, please contact SPWLA staff.

I also recruited web-design services for upgrading our website. I am working together with the SPWLA staff to simplify our website as well as making it look more professional and easier to navigate. This work is ongoing. We expect to launch the upgraded website in a few months.

Another area I am currently working on is the 2018 SPWLA Symposium mobile application. We are working with the same vendor that URTeC used last year. Our members who attended URTeC expressed positive feedback on the mobile application. We are hoping that the mobile app would create undisrupted and inclusive access to the symposium information this year.

Please feel free to email me your feedback and ideas for improvement via VP-InfoTech@spwla.org.

Zoya Heidari
Vice President Education

The activities of the Education Committee from July 2017 to February 2018 include (1) offering training programs, such as webinars and short courses, (2) organizing topical conferences, (3) developing the annual distinguished speakers program, and (4) planning for the SPWLA annual student paper contest and promoting students engagement in SPWLA activities. I would like to share briefly the main accomplishments of the SPWLA Education Committee during this time interval.

Training Programs: The main SPWLA training programs include webinar series and short courses at the SPWLA training center. We continue holding monthly webinar series in collaboration with the VP-IT, Mehrnoosh Saneifar, and her team. This program is running successfully. I would like to highlight one of the unique outcomes of this successful program, the educational online library of training courses, which are uploaded on the Knowledgette website. Most of the videos in this library are from our webinar recordings. I encourage you to visit the online SPWLA library of training courses on the Knowledgette website, which is an amazing educational resource for the SPWLA members and specially our Young Professionals.

Katerina Yared, a member of the SPWLA Education Committee, is leading the short-course program at the SPWLA Frank S. Millard Training Center. I would like to highlight four of our recently scheduled training courses, "Formation Testing, New Advances and Applications," offered by Hani Elshahawi, "The Role of Well Logs in Geomechanics," offered by Amy Fox, "Basic Well Log Analysis" offered by George Asquith, Dan Krygowski, and Rick Lewis, and "Using Mudlogging as a Formation Evaluation Tool," offered by Bill Donovan.

Please contact us, if you are interested in offering a short course at the SPWLA training center. Based on the positive feedback from our webinar attendees, we have decided to expand the SPWLA training activities by offering distance-learning short courses. Our first distance-learning course will be on "Introduction to Basic Well Log Analysis," taught by Dan Krygowski. SPWLA members will soon receive more information about this exciting new program.

Topical Conferences: We had a successful Fall 2017 topical conference on "Quest for Quality Data in High-Angle/Horizontal (HAHZ) Wells." Many thanks to Mayank Malik and his team for organizing this great event, which led to reviving SPWLA "High-Angle/Horizontal Well" Special Interest Group (SIG). The SPWLA Spring 2018 topical conference will be on "Petrophysical Data-Driven Analytics: Theory and Applications" and will be cochaired Chicheng Xu and Irina Borovskaya. I encourage you to register and attend this topical conference.

Distinguished Speaker Program: The SPWLA Education Committee announced 19 distinguished speakers for 2017–2018. Among these 19 distinguished speakers, 15 were selected based on the ranking of their presentations at the 2017 SPWLA annual symposium. For the first time, we called for nominations for distinguished speakers from regional SPWLA chapters. Four of the 2017–2018 distinguished speakers were selected by the Education Committee from the nominations originating with our regional chapters. The distinguished speakers continue traveling locally and internationally to visit SPWLA chapters. In March 2018, the SPWLA Education Committee plans to announce a call for nominees for the 2018–2019 distinguished speakers program to the regional chapters of SPWLA. I invite the SPWLA members and regional chapters to nominate stellar members of our society to participate in the Distinguished Speakers Program.

Student Paper Contest: We plan to hold the 2018 SPWLA international student paper contest during the annual symposium in London. Tim Pritchard is the Chair of the 2018 Student Paper Contest Committee. Based on the successful experience of student involvement across the international SPWLA community in 2017, the SPWLA board of directors and the 2018 SPWLA annual symposium student paper committee have decided to conduct Internal Student Chapter Paper Contests (ISCPC) as a preselection step for participants of the 2018 SPWLA International Student Paper Contest (2018 SPWLA ISPC). Both the ISCPC and the SPWLA ISPC will have separate categories for undergraduate, MSc, and PhD level students. In order to compete in the 2018 SPWLA ISPC, students must either win the nomination of their SPWLA student chapter, or submit an abstract. Students who do not have an ISCPC scheduled at their university are welcome to participate in the international paper contest by completing the abstract submittal form and submitting an abstract to papercompetition@SPWLA.org on or before March 31, 2018. We look forward to hosting our wonderful student members during the 2018 SPWLA Annual Symposium in London.

Please contact me, or the SPWLA Education Committee at VP-Education@SPWLA.org, if you have any questions, comments, or suggestions regarding the educational activities of SPWLA.

Education Committee
Zoya Heidari (SPWLA VP Education)
Katerina Yared (Director of the SPWLA short-course program)
Tim Pritchard (Chair of the 2018 student paper contest)
Carlos Torres-Verdin (SPWLA VP Publications)
Mike Webster (Regional Director, Europe)
Freddy Garcia (Regional Director, Latin America)
Josephina Schembre (Chapter at Large representative)

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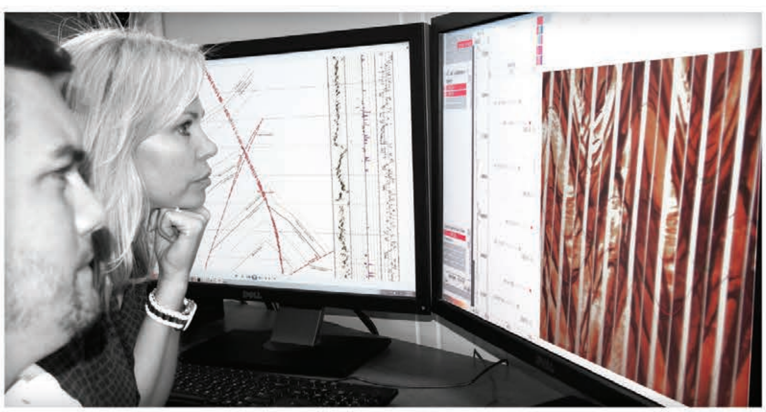

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Regional Learnings: Asia Pacific Region

A comment I often hear from people in this part of the world is that our society is focused on Houston and the USA, and that people in this region are forgotten. However, we actually have a lot of very active chapters across our region and there are many ways for people to get involved and make the most of their membership of the SPWLA.

We have active chapters in Australia, China, India, Indonesia, Japan, Malaysia and Thailand, and the number of chapters in the region is growing. I have had the honor and the pleasure of presenting at many of these chapters in recent years and I can say that the committees running them are very enthusiastic and there is a lot of keen interest from our colleagues across the industry.

If you live in the region and there isn't a chapter where you are based, then why not set one up? The benefits and rewards of doing so are great and you can contact me if you need help.

One issue often raised is that most conferences and symposia are held in The States or in Europe and there are not enough opportunities for petrophysicists in our region to attend such events. People want to present and publish their work, network, share knowledge and learn new ideas from people involved in the same region. While there are conferences on petrophysics and integrated disciplines in the region, many of them concentrate on specific countries. A lot of people want to see more regional events.

In 2008, a Regional SPWLA conference was held in Bangkok, Thailand, attracting petrophysicists from around the region, all of whom thought it was very a worthwhile event. Unfortunately, there wasn't another regional conference in Asia Pacific until August 2016, which was also in Bangkok.

That was a four-day conference, with a 'field trip' to a core store and some local cultural attractions, followed by a day of commercial presentations from service companies and two days of technical presentations. Considering how hard the downturn was hitting us all at that time, the conference went very well, with over 100 people participating from nine different countries. There were many suggestions then that such events should be held regularly, either every year or every second year, and rotated around the chapters in the region.

This year, the Indonesian chapter, based in Jakarta, is going to hold the next SPWLA Regional Conference. Their theme is "Empowering Applied Petrophysical Concepts and Technology: Unlocking Hidden Potential in Mature Fields" which is a very important topic in many countries in this region. It is an activity that really showcases the true value of the petrophysicist, where new reserves can be identified by taking a fresh look at old data and applying new ideas and interpretation techniques. We could call it "cheap exploration" because the wells have already been drilled, the cuttings, logs and core are already acquired and the facilities are often in place. We just need to spend time reconsidering what has been done and how we can now do it better!

The Asia Pacific SPWLA Regional Conference, Bangkok, Thailand, August 2016.

The conference will be held in Bogor, which is about 50 km south of Jakarta, October 25–26, 2018. The committee is still working out the final details and a call for abstracts will be sent out and will also appear on the SPWLA website very soon.

This is the first column from the region in this new SPWLA newsletter. In future columns I hope to include details of other upcoming events in the region so that those who travel regularly can make plans to attend and also to enable chapters to coordinate trips for speakers travelling around the region.

Hopefully, we can make it easier for our chapters to work together, to organize great events and to continue to keep the society active in our region. Also, hopefully, we can add a new focus for the SPWLA in our dynamic and exciting region!

Rick Aldred,
Regional Director

ABERDEEN CHAPTER
(Aberdeen Formation Evaluation Society, AFES)

Recent Events

30 November 2017 – The December meeting of AFES was actually held on 30 November, with the Annual Charity Quiz night. This year saw victory go to the "Quizzards of Oz" team from TAQA, who came along dressed as characters from the classic movie "Wizard of Oz". As usual, there was a great turn out with a good time had by all and as a bonus, AFES was able to raise over £1,000 towards the Royal Aberdeen Children's Hospital A.R.C.H.I.E. Fund.

AFES December 2017 meeting. President Ed Downer with the 2017 AFES Quiz Champions.

20 January 2018 – AFES welcomed Davide Di Tommaso (Operations Manager Petrophysics, Weatherford) who presented a talk entitled, "The Use of New LWD High-Resolution Ultrasonic Imaging Tool to Unlock the Reservoir Potential." This new imaging tool is designed to enable operators to obtain high-resolution structural, stratigraphic, and borehole geometry information in both water and oil-based muds by means of acoustic impedance contrast and ultrasonic amplitude measurements. Results from the very first deployment of this new imager in Europe were presented. As usual there were plenty of questions to the speaker followed by networking session.

14 February 2018 – AFES members showed their love of petrophysics, by turning out on a snowy evening to hear Marta Prymak (ConocoPhillips) deliver a talk entitled "Evaluating Thin-Bed Pay in Deepwater Sandstones of the Forties Reservoir of Callanish and Enochdhu Fields." Marta's interesting talk, which was based on work she carried out during her MSc studies led to many questions and discussion points.

AFES February 2018 meeting. Marta Prymak receiving a speaker's gift from AFES President Ed Downer.

Future Events

The program of technical meetings for 2018 is published on the AFES website www.afes.org.uk or our Facebook page for up to date information.

The call for abstracts for the 15th DEVEX conference has closed and details of the 2018 event, which is being held at the Aberdeen Exhibition and Conference Centre, 8–9 May are being updated regularly on the conference website www.devex-conference.org. This year's conference theme is "Working Together from Pore Space to Pipeline." DEVEX is organized jointly by AFES and the Aberdeen Chapters of PESGB and SPE.

AUSTRALIA CHAPTER
(Formation Evaluation Society of Australia, FESAus)

General News

FESAus, the Australian chapter of SPWLA combines the formation evaluation societies from around Australia predominantly FESQ. Technical meetings are held in Perth on the second Tuesday of each month, with webcasts of the presentations available soon after for members from other states to view. Please visit www.fesaus.org for meeting information.

2018 Committee members

Past President — Nariman Nouri
President — Adrian Manescu
Vice President/Assistant Treasurer/Newsletter Coordinator — Wesley Emery
Treasurer/Company Secretary — Callum Rideout
Website Coordinator/Data Standards Focal Point — Martin Storey
Secretary/Inter-Society Liaison/Social Coordinator/Special

Events and Awards — Leanne Brennan
Sponsorship Coordinator — Andrea Paxton
Monthly Meeting Coordinator — Meretta Qleibo
Membership Coordinator — Siobhan Lemmey
New Technology Forum Coordinator — Ben Van Deijl
New Technology Forum Coordinator — AbdelRahman Elkhateeb
Education Group Leader — Matthew Josh
Audio Visual Coordinator — Nigel Deeks
Audio Visual Coordinator — Yang Xingwang
Education Group Team — Paul Pillai
Committee Member — Gerry McGann
Committee Member — Scott Cole
Victoria Representative — Matthew Durrant
NSW Representative — Harris Khan
SA Representative — Barbara Stummer
Fahad Khan

Recent Events

13 February 2018 – The monthly technical presentation was conducted by Dr. Mark Deakin and titled "Some Really Useful Things You Can Do As a Petrophysicist." The talk addressed the barrage of data we are confronted with as petrophysicists, which holds information that too often lies on the shelf unused. He provided a few reminders of ways we can use our information more fully.

- No core? B*Qv lies forgotten in S_w100 zones
- Circumvent your resistivity questions. Plot wellsite NMR T_2 bins as bulk volume water vs HAFWL logs for a resistivity free S_w
- Is your reservoir nonstrongly water-wet? Examine what you already know
- Managers: How to inflate your GIIP numbers with core!
- Generic routine core data provides copious answers through simple inversion
- What makes us choose certain data and methods over others? Familiarity or reason? Data Hierarchy - the essential prerequisite to the integrating the barrage of modern data
- Is the geomodel abusing your perfect petrophysical results?

Mark's talk was well received with a great deal of discussion and sharing of ideas.

FESAus February 2018 meeting. Mark Deakin (left) and FESAus President Andrian Manescu (right).

Upcoming Events

13 March 2018 – Ruslan Badamshin/Ryan Crawford, "Best in Class Core Analysis on Thin-Bed Reservoir Rock."

26 April 2018 – Ben Van Deijl, "Psychology of Decision-Making" short course, Woodside auditorium

10 July 2018 – Tim Conroy, "Accelerating and enhancing Petrophysical Analysis:—A Case Study of an Automated System for Well Log Outlier Detection and Construction."

11 September 2018 – New Technology Forum – Hardware

09 October 2018 – Matt Shaw, "Uncertainty in Petrophysical Properties for Reservoir Modeling"

Please visit the Technical Meetings section of the chapter website www.fesaus.org for details on upcoming technical talks.

BANGKOK CHAPTER

General News

The organizing committee has unfortunately lost Khun Ronarong Paramatikul (Secretary), who has had to leave the group due to work commitments. The role of secretary has been taken up by Ronald Ford (Gaia Earth Sciences Limited).

Recent Events

The Bangkok Chapter held well-attended meetings in both January and February. Special thanks to Scientific Drilling who sponsored wine for these meetings.

25 January 2018 – Mr. David Bowling (Baker Hughes) presented an extremely well-received talk entitled, "Integrating Geomechanical Workflows With Real-

Time Log Analysis to Make Better Decisions." Mr. Bowling outlined the benefits geomechanical analysis can have in challenging drilling environments, with examples of both successful outcomes and some disasters where no analysis was performed.

Bangkok chapter January 2018 meeting. Andrew Cox (keft), Chapter President presenting David Bowling (Baker Hughes with a speaker's gift.

28 February 2018 – Khun Pratt Boonyasatphan (PTT Exploration and Production) presented a case study on "Unconventional Shale Reservoir Characterization" using the Chumsaeng Formation of the Phitsanulok Basin in Thailand. The talk detailed the integrated analysis performed, to determine the relationship between the geophysical, geochemical, and geomechanical properties of the rocks, including a simultaneous seismic inversion further define the geomechanical properties. This study is an excellent practical example of the analysis of shale reservoirs.

Upcoming Events

22 March 2018 – The meeting will be held at the ENCO Complex (Tower C) in Bangkok. Room and topic is not yet finalized—several potential subjects are being reviewed.

BOSTON CHAPTER

General News

The renovation of the Boston Chapter website, http://boston.spwla.org, is now complete. SPWLA general members and Boston affiliate members are invited to browse the site to know more about our mission and events.

Recent Events

Over the past quarter, the Boston Chapter hosted four stimulating and well-attended talks and networking luncheons at Schlumberger-Doll Research Center, Cambridge, MA:

01 December 2017 –Abbie Morgan (Aera Energy) presented her SPWLA Distinguished Lecture titled "Petrophysics and Geology Intertwined: A Case Study of an Integrated Modeling Workflow"

12 January 2018 – Hannah Kaplan (Brown University) presented a lecture titled "Reflectance Spectroscopy for Organic Detection on Early Earth, Mars, and Asteroids"

Boston Chapter January 12, 2018 meeting. Ravinath Kausik (center, Chapter president) presents Hannah Kaplan (Brown University) with her speaker plaque as a token of appreciation, together with Chapter officers (left to right) Sushil Shetty, Julie Kowan, and Tancredi Botto.

19 January 2018 – Fikri Kuchuk (Schlumberger) presented a lecture titled "Advances in Pressure Transient Testing"

28 February 2018 – Holger Thern (Baker Hughes GE) presented his SPWLA Distinguished Lecture titled "Integrating Gas and Oil Zone Evaluation Using NMR, Conventional, and Mud Gas Logging Data—A Norwegian Logging-While-Drilling Case History. "

Upcoming Events

SPWLA talks take place at Schlumberger-Doll Research Center, Cambridge, Massachusetts. Check our chapter website for details of scheduled future events.

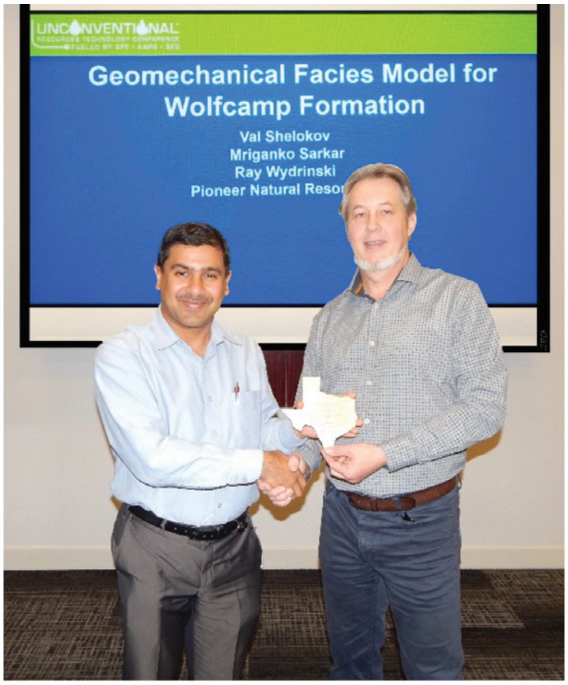
DALLAS CHAPTER

General News

First, we want to say thanks to those who are supporting the Dallas Chapter, for 2017–2018. Second, we want to welcome Mriganko Sarkar as Chapter President for 2017–2018 session, he has been a devoted officer in the past six years.

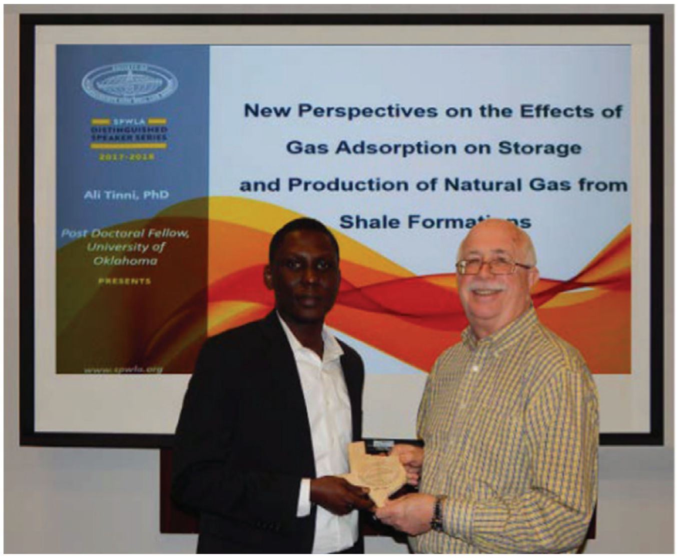
Recent Events

November 2017 –Valeri Shelokov to gave a presentation on "Geomechanical Facies Model for Wolfcamp Formation." This talk had full attendance and it generated a great discussion between the attendees.



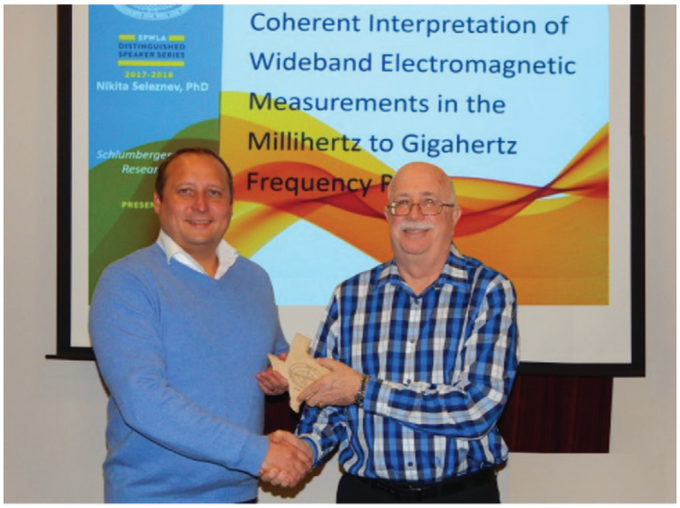
Dallas Chapter November 2017 meeting. Chapter President Mriganko Sarkar (left) presents the speaker's award to Valeri Shelokov (right).

December 2017 – Ali Tinni (Post-Doctoral Fellow, University of Oklahoma) gave a talk titled "New Perspectives on the Effects of Gas Adsorption on Storage and Production of natural Gas from Shale Formations." The presentation was informative and well received by the chapter membership. Ali identified the issue of assuming an adsorbed phase density, which impacts the estimated maximum adsorption capacity and the shape of the isotherm further leading to inaccuracies in the quantification of an absolute adsorption isotherm. He showed that by measuring the NMR T_2 spectra of the shale core plugs of Barnett and Eagle Ford shale formations at pore pressures between 500 and 4,000 psi, while maintaining a constant confining pressure of 5,000 psi, the methane storage capacity could be independently obtained.



Dallas Chapter December 2017 meeting. Ali Tinni (left) receiving the Dallas chapter speaker's award from Ray Wydrinski, Chapter Treasurer.

January 2018 – Nikita Seleznev (Schlumberger-Doll Research) gave a talk titled, "Coherent Interpretation of Wideband Electromagnetic Measurements in the Milliherts to Gigahertz Frequency Range." The speaker introduced the concept of spectral induced polarization. He also showed that wideband data inversion enabled the estimation of five formation parameters: water-filled porosity, water salinity, cation exchange capacity, dominant grain size, and cementation exponent.



Dallas Chapter January 2018 meeting. Nikita Seleznev (left) receiving the Dallas Chapter speaker's award from Ray Wydrinski, Chapter Treasurer.

08 February 2018 – Michael Sullivan (Chevron) gave a presentation on "Color Cubing of Spectral Gamma Ray—a Novel Technique for Easier Stratigraphic Correlation and Rock Typing."

Upcoming Events

Please visit the Dallas chapter webpage on the national SPWLA website for the upcoming planned meeting dates & topics.

DENVER CHAPTER
(Denver Well Logging Society, DWLS)

General News

Join us for the monthly DWLS meetings, which are held the third Tuesday each month, beginning in September and running through May. Meetings take place in the Mercantile Room at the Wynkoop Brewing Company in downtown Denver. The networking social begins around 11:20 AM, lunch is served at 11:45 AM, and the technical presentation starts at 12:00 PM. The cost for the DWLS luncheon is $20 and guests are welcome to attend. Visit the DWLS website at www.dwls.spwla.org to make your luncheon reservations, renew your membership, or join the society.

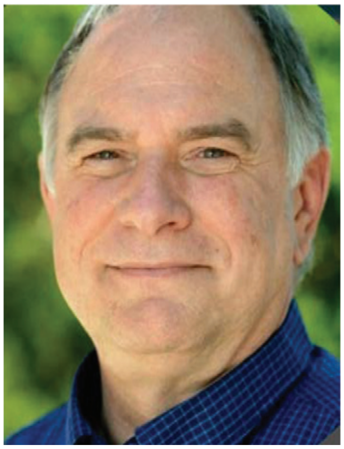
The DWLS currently has 380 Active Members, 266 of which are Lifetime Members. Recently, 11 new members were welcomed into the society. Visit the DWLS website to learn more about the membership metrics and the luncheon attendance statistics.

The DWLS is sponsoring scholarship and grant opportunities for graduate students attending a college in the United States Rocky Mountain region, which includes the states of North Dakota, South Dakota, Colorado, Wyoming, Utah, Idaho, Montana, New Mexico, Arizona, and Nevada. Graduate students who are pursuing a degree in a field related to upstream oilfield well log interpretation, specifically petrophysics, geomechanics, geophysics, petroleum, or geology, are encouraged to apply. Application materials and further details are available on the SPWLA website.

Recent Events

16 January 2018 – Alan Byrnes (Whiting Petroleum Corporation) gave a well-attended talk titled "Application of Integrated Core and 3D Image-Based Rock Physics to Characterize Niobrara Chalk properties."

20 February 2018 – Dick Merkel (Denver Petrophysics LLC) gave a presentation on methods for calculated determination of variable wettability for the Middle Bakken and Three Forks in the Williston Basin.



DWLS January 2018 meeting. Alan Byrnes (Whiting Petroleum Corporation) was the technical presentation.

DWLS February 2018 meeting. Dick Merkel (Denver Petrophysics LLC) gave the technical presentation.

Upcoming Events

20 March 2018 - Join us for the March meeting of the DWLS, which will be taking place at the Wynkoop Brewery in downtown Denver. Bill Donovan (Donovan Brothers Inc.) will be presenting during the technical lunch.

Be sure to visit our calendar page to see what is scheduled for the upcoming speaker line up.

FRANCE CHAPTER
(Société pour l'Avancement de l'Interprétation des Diagraphies, SAID)

General News

The SAID board received the very sad news that Hugues Monrose died in the night of October 20, 2017 (see *Petrophysics*, December 2017, page 682). Hugues was a former SAID president and continued to regularly attend all

SAID meetings. The board decided to dedicate the November SAID workshop to his memory—He would have been delighted to attend such a refreshing topic: "Application of Big Data and Machine Learning to Petrophysics."

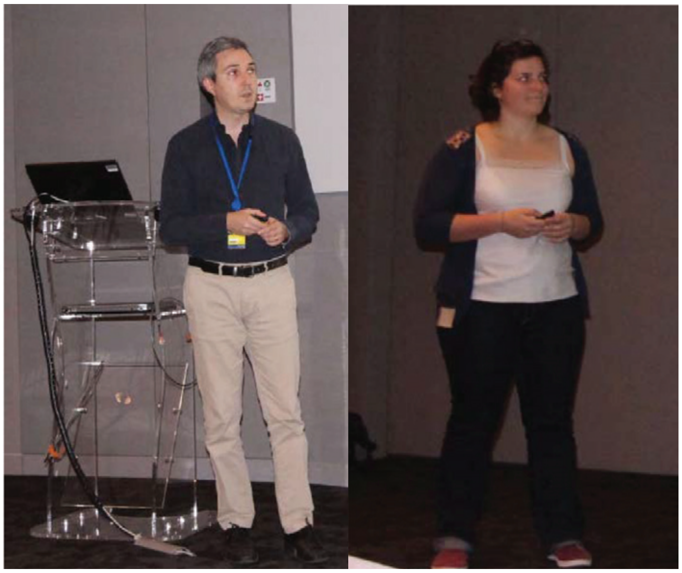
Recent Events

15 November 2017 – SAID tried a new workshop format organized around two to three presentations only and scheduled at the end of the day (4:00–7:30 PM). The topic, quite appealing, "Application of Big Data and Machine Learning to Petrophysics", attracted a large audience at the Schlumberger auditorium in Paris—La Défense, as well as in live streaming via the web. The session led to fruitful discussions during and after the meeting between presenters and the audience. The three talks were selected for their complementarity to cover a wide range of applications: from data standardization, normalization and quality control, to log reconstruction and interpretation.

Emmanuel Caroli (TOTAL) – "Use and Applicability Of Machine Learning For Formation Evaluation"

Valérian Guillot and Héloïse Beurdouche (Schlumberger) – "Partial Log Reconstruction Using Machine Learning"

Héloïse Beurdouche (Schlumberger) – "Marker Recognition And Validation Using Data Analytics and Machine Learning"



SAID Chapter November 2017 meeting. (Left) Emmanuel Caroli (SAID president) presenting the way TOTAL uses machine learning to generate interpretation scenarios and interpret giant log datasets. (Right) Héloïse Beurdouche (Schlumberger) during her two talks about log reconstruction and quality control with machine learning.

Upcoming Events

March 2018 – Once again SAID seeks to broaden the horizon of formation evaluation with its first session on "Borehole Seismic—Latest Technologies and Case Studies." The meeting will take place in room Van Straelen at Société Géologique de France, 77 rue Claude Bernard in Paris. A warm welcome to our colleagues from geophysics to attend SAID meetings!

HOUSTON CHAPTER

Recent Events

11 December 2017 – At the well-attended Software Show held at Weatherford International, various representatives from leading software companies gave excellent presentations on the advantages of their software packages. It was very informative and instructional. Agenda and Abstracts can be found on the Chapter website: https://www.spwla-houston.org/. Photos from the varous vendor presentations are below.

31 January 2018 – At the Downtown event, which was hosted by BHP, Philip M. Singer (Rice University) presented a talk on NMR in organic shale, "Current Research Activities at Rice University." Aidan Blount (Shell) gave the talk at the Northside luncheon on "The Application of the Combination of NMR logging and NMR Measurements on RSWC Samples at the Wellsite to Identify Producible Oil in Tight Rocks."

Upcoming Events

Refer to the Chapter Website for links to each event https://www.spwla-houston.org/

21 February 2018 Downtown (Uptown) – Michael J. Sullivan (Chevron), Color Cubing of Spectral Gamma Ray – A Novel Technique for Easier Stratigraphic Correlation and Rock Typing."

22 February 2018 – (Northside) Nikita Seleznev (Schlumberger-Doll Research), **"**Coherent Interpretation of Wideband Electromagnetic Measurements in the MHz to GHz Frequency Range**."**

27 March 2018 – Houston Chapter cosponsors the SPE GCS Hiring Event

09 May 2018 – Houston Chapter Spring Topical Seminar, Chevron Auditorium

30–31 May 2018 – Data-Driven Drilling and Production meeting, Hilton Houston Post Oak-Galleria (Chapter members receive a 20% discount— sign up for our mailing list to receive the code.


Mark MacKenzie (Green Imaging Technologies) – "Measuring Gas Isotherms in Shales Using NMR"


Bernd Ruehlicke (Eriksfiord, Inc.) Eriksfiord, Inc – "Borehole Image Logs to Bracket the Stress Tensor—Take Out the Guess Work"


Nicholas Harvey (Harvey Rock Physics) – "LogScope—A Mobile and Agile Solution"


Constantine Vavourakis (Paradigm) – "Geolog 8: Building the industry Standard Field Development Platform"


Oswaldo Viloria) Antaeus Technologies) – "Secure Cloud-Based Software Platform for the Energy Industry: A new Collaboration Proposition"


Dr. Michael Frenkel (iTomography) – "Disruptive MicroCT 3D Image Reconstruction Workflow and Software for Digital Rock Applications"


Houston Chapter President Irina Borovskaya and Event Coordinator Jeff Crawford calling out raffle winners among the show participants


Paul Schatz (INT, Inc.) – "E&P Visualization in the Cloud: A Critical Component of Your Digital Transformation"


Chris Hanton (Perigon) – "Data Management Doesn't Have to be Daunting"


Constantine Vavourakis (Paradigm) giving a demonstration of Geolog 8.


Fred Jenson (CGG GeoSoftware) – "Machine Learning Using Python via PowerLog Extensions"

Samira Ahmad (Schlumberger) – “Petrophysical Evaluation in a Cased Well with Complex Completions: A case Study Using the Next Generation High Temperature Pulsed Neutron Logging Tool”

Igor Uvarov (Rogii, Inc.) – “StarSteer Geosteering Software: Extensive Data Integration for Real-Time Geosteering and Geological Interpretation”

Derek Garland (WellDrive) – “It’s 3 AM. Where Are Your Data?

Jacob Proctor (Ingrain, Inc.) – “Using RhoB and PE Values Obtained From Digital Rock Analysis for Validation of Wireline Data”

Ted Kernan (WellLogData) – “Well Log Data Made Easy”

MALAYSIA CHAPTER
(Formation Evaluation Society of Malaysia, FESM)

General News

The Formation Evaluation Society of Malaysia (FESM) is based in Kuala Lumpur. Technical meetings are held on the fourth week of each month. For meeting information, please visit our chapter website at www.fesmkl.com.

Recent Events

16 November 2017 – Rick Aldred (Consultant) presented a talk entitled, “Improved Interpretation of Laminated Formations in Mature Fields Using Calculated R_h and R_v Logs From Conventional Resistivity Measurement In Multiple Wells”. He introduced a new technique by detecting electrical anisotropy from conventional resistivity logs in multiple wells with different angle of relative dip, allowing user to identify laminated pay intervals and create R_h and R_v curves. He presented a case study result to differentiate low-resistivity laminated shaly sand pay interval from bioturbated shaly sand.

FESM November 2017 meeting. Rick Aldred presenting in the technical session.

NORWAY CHAPTER
(Norwegian Formation Evaluation Society, NFES)

Recent Events

10 January 2018 – Just after the festive season David Maggs (Global Domain Head Petrophysics, Schlumberger), was invited to present his talk on "Laminated Reservoirs—What Can You Do With Pesky LWD Data?" David Selvaag Larsen, NFES VP Program, kicked off the new technical year at the Solastranden Gård, welcoming many members of the local SPWLA chapter. The crowd enjoyed a very well presented and informative session, explaining approaches to correct and use LWD data acquired in vertical, high-angle and horizontal wells. David demonstrated through a series of case studies and examples how workflows and data integration can be modified and applied to fully use LWD data for a complete CPI.

NFES January 2018 meeting. David Selvaag Larsen, NFES VP Program (left), presents David Maggs (Schlumberger) with the NFES ice bear in gratitude for his well attended and delivered presentation.

07 February 2018 –Gianbattista Tosi (Well Planning Lead ENI Norge) attracted many participants joining the NFES monthly meeting. Gianbattista illustrated a workflow that has been developed to recalibrate reservoir structures via integration of surface seismic with synthetic seismic, derived from ultradeep-reading EM logging-while-drilling (LWD) measurements. His very interesting talk was followed by a fruitful expert discussion. A big thank you to Gianbattista

NFES February 2018 meeting. Gianbattista Tosi (ENI Norway) (left) receives a keepsake from David Selvaag Larsen, NFES VP Program (right) for his great talk.

The Norwegian Formation Evaluation Society would also like to thank its 2018 sponsors Baker Hughes, Logtek, Schlumberger and Wintershall. Their contributions allow us to continue the technical monthly meetings in the current format—our main forum for technical presentations and professional discussions. Tusen takk!

Upcoming Events

NFES's monthly seminar will continue running on the first Monday in the month at Solastranden Gård at 11am.

March 2018 –NFES welcomes Brice Fortier and Oliver Lopez (Statoil) who will present their innovative petrophysics method "Combining Borehole Image Logs and 3D X-Ray Computed Tomography of Cores for New Insights in Reservoir Evaluation and Characterization."

SAUDI ARABIA CHAPTER

Recent Events

13 November 2017 – The SPWLA Saudi Arabia Chapter (SAC) in coordination with SPWLA KFUPM Student Chapter conducted its first student research contest and announced that Mr. Amjad Hassan, a PhD Student from KFUPM, is the winner. Amjad's research work on "Determination of Water Saturation Distribution in Complex Reservoirs using Conventional Well Logs," was considered by a team of judges as innovative in resolving a fundamental challenge in petrophysics. Coordinated by Mr. Nacer Guergueb, SPWLA SAC VP

Academic and Student Affairs, and Dr. Mohamed Ahmed, President of SPWLA KFUPM Chapter, the event of SPWLA SAC student research contest was opened by Dr. Abdulaziz Al-Kaabi, Dean of Petroleum Engineering and Geoscience Colleage and Dr. Tareq Al-Ghamdi, SPWLA SAC President. Acknowledgement and appreciation letters were presented to other participated students. The objective of SPWLA SAC Student Research Contest is to encourage students in petrophysical research to resolve today and tomorrow's industry challenges.

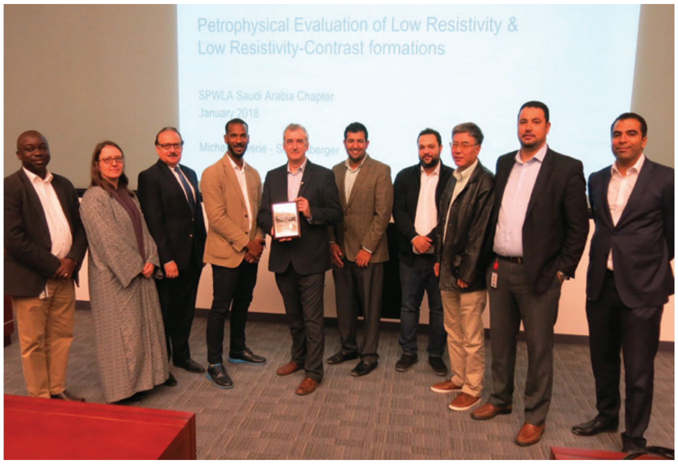
Saudi Arabia Chapter November 2017 first student research contest. Group photo of Committee members of the SPWLA-SAC, and KFUPM-SPWLA Chapter at KFUPM, college of PE&G, Dhahran. From left to right: Dr. Shirish Patil KFUPM-CPG Graduate Committee Chairman, Dr. S. Mark Ma VP Technical Programs SPWLA-SAC, Nacer Guergueb VP Academic and Students Affairs, SPWLA SAC, Dr. Abdulaziz O. Al-Kaabi Dean, College of Petroleum Engineering and Geosciences KFUPM, Dr. Tareq Al-Ghamdi President SPWLA-SAC, Dr. Mohamed Ahmed President SPWLA-KFUPM Chapter. PhD program students: Zeechan Tariq, Ahmed Sadeed. Khaled Zidan and Amjad Hassan.

Saudi Arabia Chapter November 2017 first student research contest. Standing (left to right): Dr. S. Mark Ma VP Technical Programs, SPWLA SAC, Dr. Tareq Al-Ghamdi President, SPWLA-SAC, Dr. Mohamed Ahmed President SPWLA-KFUPM Chapter, and Nacer Guergueb VP Academic and Students Affairs, SPWLA SAC. Seated, PhD program students who participated in the final contest presentations: (left to right) Khaled Zidan, Amjad Hassan, Zeechan Tariq, and Ahmed Sadeed.

28–29 November 2017 – SPWLA SAC in collaboration with Dhahran Geoscience Society (DGS) conducted a two-day workshop on "Linking Geological Facies and Petrophysical Rock Types." The main objectives of the workshop were to review the current methodologies used for geological facies characterization and petrophysical rock type determination, and explore possible links between the two. This joint event was opened by Chapter President Dr. Tareq AlGhamdi and DGS President Dr. Abdulaziz Muhaidib, who highlighted the importance of collaboration among different disciplines for improved understanding fundamental issues, such as potential links between geological facies and petrophysical rock types. A keynote speech was delivered by Dr. Mr. Aus Al Tawil, Manager of Reservoir Characterization Department in Saudi Aramco, who provided an excellent overview of where we came from and where we are going in the era of digital transformation of industrial revolution 4.0. With 12 presentations in six sessions and a panel discussion, the event was a great success finished up with an interactive quiz-game and a recap summary. More than 200 professionals actively participated in this event.

Saudi Arabia Chapter and Dhahran Geoscience Society joint workshop November 2017.

31 January 2018 – SPWLA SAC started 2018 with a technical luncheon delivered by Michel Claverie (Schlumberger Wireline Petrophysics Technical Director, London) on "A Review of Low-Resistivity and Low-Resistivity-Contrast Pay With Focus on Africa." This topic was so attractive that more than 80 professionals participated in this event. A token of appreciation was presented to Michel by Saudi Aramco management.



SAC January 2018 meeting. Speaker Michel Claverie (Schlumberger) received a token of appreciation from the Chapter officers.

TEXAS TECH UNIVERSITY (TTU) SPWLA STUDENT CHAPTER

Recent Events

2–3 February 2018 – The TTU SPWLA chapter hosted its first short course, which was titled "Petroleum Systems Fundamentals for Petroleum Engineers and Geoscientists." The course was taught by John Dribus (Schlumberger Reservoir Characterization Global Geology Advisor) and was held at the Bob L. Herd Department of Petroleum Engineering. There 55 students who attended comprised 40 petroleum engineering and 15 geoscience majors.

TTU Student Chapter February 2018 Short course. From left: Ibe Ezisi (President), John Dribus (Schlumberger), Gheith Mehdawi (Vice President), Marshal Wigwe (Student), Elizabeth Reeder (Student), George Asquith (Faculty/Professor), Daniel Owusu-Ansah (Student), and Amir Ghwel (Student).

TTU Student Chapter February 2018 Short course.

Upcoming Events

March 2018 – Student paper contest. Date TBD.

THE UNIVERSITY OF TEXAS AT AUSTIN STUDENT CHAPTER

General News

The spring semester is underway and the Student Chapter of SPWLA at UT-Austin has been busy preparing for and participating in two campus-wide volunteering events: Introduce a Girl to Engineering Day and Explore UT. These annual events provide an excellent opportunity for our chapter to give back to the community while sharing our passion for engineering and geosciences with K-12 students from across Texas. Participants and their parents say that our hands-on activity, called "Fracking with Jell-O," gives them a better understanding of the petroleum industry and helps dismiss some common misconceptions associated with hydraulic fracturing.

Recent Events

12 January 2018 – The chapter hosted SPWLA Distinguished Speaker Dr. Nikita Seleznev (Schlumberger-Doll Research Center) for a technical seminar entitled "Coherent Interpretation of Wideband Electromagnetic Measurements in the Millihertz to Gigahertz Frequency Range." The talk was very well attended and we sincerely thank Nikita for visiting Austin and sharing his interesting work.

24 February 2018 – Chapter members partnered with the Petroleum Graduate Student Association and Women in Petroleum and Geosystems Engineering for "Introduce a Girl to Engineering Day" at The University of Texas at Austin. Over 8,000 elementary and middle school students participated in the event, which gave them a chance to explore careers in science, technology, engineering, and mathematics.

03 March 2018 – Chapter members volunteered at "Explore UT" at The University of Texas at Austin. The campus-

wide event, which is described as the "biggest open house in Texas," featured engaging activities and inspiring demonstrations designed for visitors of all ages.

Upcoming Events

09 March 2018 – The chapter will host SPWLA Distinguished Speaker Abbie Morgan (Aera Energy) for a technical seminar entitled "Petrophysics and Geology Intertwined: A Case Study of an Integrated Modeling Workflow."

0 March 2018 – The chapter will hold a local student paper contest to nominate members for the 2018 SPWLA Student Paper Contest in London. We hope that this year's local winners can continue the outstanding success achieved at last year's annual symposium in Oklahoma City, where our members won first place in the Bachelor's, PhD, and E-Poster divisions!

UT-Austin Student Chapter January 2018 meeting. Chapter officers are showed with SPWLA Distinguished Speaker, Dr. Nikita Seleznev. From left to right: Mohamed Bennis (Treasurer), Colin Schroeder (President), Tianqi Deng (Webmaster), Nikita Seleznev (Speaker), Matt Ramos (Vice President), Artur Posenato (Secretary), and Mohammed Al-Obaidi (Public Relations).

SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS

SPWLA Young Professionals Newsletter

the bridge

My Road to Volunteering—Have You Found Yours?

March 2018

Jesús. M. Salazar
2017–2018 SPWLA VP Technology

Back in the late 1990s, ca 1997, in my home country, Venezuela, I was in my last year of college. My major was physics, and I was working as a research assistant in a lab where the main research was electron paramagnetic resonance (EPR). It was interesting to run experiments based on theories I had learned in my classical electrodynamic and solid-state physics classes. However, I didn't see myself working in a lab where equipment broke often. Around the same time, there was a rumor in the physics department about how well physicists were fitting in the oil industry, specifically doing geophysics or petrophysics. I'm not going to lie that I also got tempted by the salaries I heard graduates were getting in service and operating companies and the opportunities of training and travel. So, I started knocking on doors to find an oil-and-gas-related internship. I managed to find a one-year internship with Maraven, a former subsidiary of PDVSA, the Venezuelan national oil company. This internship allowed me to have enough material to write my senior thesis to get my physics degree—not my most illustrious piece of writing but enough to graduate. I was immediately offered a job in the same company and told that I was going to be a petrophysicist. Back then I had wear a tie and a suit, and I was loving it. When I started to work, my mentor, Miguel Expósito, gave me a form and told me "now you must become an SPWLA member, I'll be your sponsor," and boom, I became a member, and I started reading the symposium transactions, *The Log Analyst*, and the website. By that time, we had a timid SPWLA chapter in Venezuela, and occasionally we were lucky enough to have a distinguished speaker come by and give a talk. The last one I remember was Dick Merkel, in Maracaibo, when he was SPWLA president. That was perhaps my first-time volunteering for SPWLA, helping the local chapter officers organize the talk logistics.

A few years later, I was applying to attend graduate school in the US and needed funding. I learned that the SPWLA Foundation offered scholarships and grants to students around the world. Upon applying to the foundation, I was bestowed $1,000 US in the form of a grant. For a student coming from a third-world country, that goes a long way. I decided to attend the University of Texas (UT) at Austin where I received masters and doctoral degrees in petroleum engineering. I wasn't an outsider anymore. During my studies, I was awarded three more SPWLA Foundation scholarships and had the opportunity to work with people involved with the SPWLA, such as my academic advisor Carlos Torres-Verdín, and my industry mentor Jim Klein. Carlos was involved as editor and author in the *Petrophysics* journal and Jim was SPWLA President when he mentored me during an internship at ConocoPhillips. Jim encouraged me to volunteer for the local SPWLA chapter, which I did by helping the local officers organize meetings at the UT campus, and as the student activities liaison for the 2007 Symposium in Austin. I also started presenting at the symposiums and publishing papers in *Petrophysics*—we even won the "*Petrophysics* Best Paper" award in 2006.

Once I was out of graduate school and moved to a new job in Houston, I asked myself, "how do I stay involved?" I reached out to the local Houston Chapter with a perfect timing—it was time for an election. This first time, I got elected secretary, then VP Westside the year after, and finally Chapter President. During that time, we updated the by-laws, organized several talks by different experts, topical conferences, software shows, golf tournaments, and hosted the Annual Symposium in 2009, all for the benefit and enjoyment of the membership. I also ran unsuccessfully (twice) for positions in the Board of Directors (BOD) of the International Society, I was on the *Petrophysics* editorial board for four years and on the Annual Symposium Technology committee also for four years. I finally made it to the BOD last year as VP Technology where I'm having a great time managing a group of outstanding professionals to bring you a strong technical program for the London Symposium. And if you read at the beginning of the YP section, I'm part of the editorial board of The Bridge, which is a nice initiative of various volunteers to engage young blood in our society, and I'm not even a YP anymore. So, there are many different avenues for you to volunteer. When I first signed up as a member, I would have never thought that by getting involved I was going to reach this point.

I'm very grateful for all the benefits I've received from the SPWLA, and that's the main reason I volunteer. It feels good to give back. Most of the benefits we receive as members happen because of the help provided by volunteers to organize talks and conferences, edit papers, rank abstracts, evaluate applications for scholarships, website management, you name it. If you're interested in volunteering, the first step is to talk to your local chapter officers or one of your BOD members. You don't need to run for an elected position if it's not your thing. But if you do run for positions and don't get elected, just try again next year. Bare in mind that being a volunteer also looks good on your resume and provides you with soft skills that are critical to succeed in the industry. I hope these comments have shown the various paths that built my road to volunteering, and I truly hope that sooner or later you find yours.

My SPWLA activity through the years. Top left as a newbie grad student at the University of Texas at Austin in Fall 2002 with the department of petroleum engineering in the background. Top right presenting a poster during the 2007 Symposium in Austin Texas. Bottom left as Houston Chapter Westside VP presenting the speaker award to Dr. Quinn Passey in Fall 2010. Bottom right during the award ceremony in the 2014 Symposium in Abu Dhabi with award recipient Dr. Carlos Torres-Verdín and a few of his former students.

Haiku of the Month:

Buoyancy battles
With capillary forces.
Charging can occur.

What is your favorite math or science joke?
Send your favorite photo from your trip, along with a caption telling us about your experience to spwlayp@spwla.org or use SPWLA social media. We'll pick one or two to share in our next issue.

Where did you go on your most recent vacation?
Adam Haecker: I went to Japan after the Symposium. This is a picture from Miyajima Island. The tori gate here is built in a tidal flat. It is a world heritage site.

SPWLA Networking Happy Hour

Join us to kick-off the spring season with our first 2018 **SPWLA Networking Happy Hour** at Canyon Creek Café on March 22, 6:00–9:00 PM. The entire SPWLA community is invited. Come and mingle with fellow petrophysics enthusiasts!

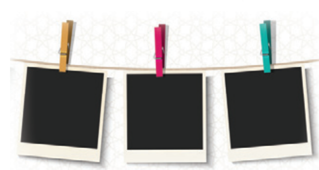
SPWLA's Happy Hour at Houston Heights, December 2017

Everybody is welcome!

When: *6-9 PM Thursday, March 22, 2018*
Where: *Canyon Creek Café,*
6603 Westcott Street
Houston, Texas 77007

Contact us: SPWLAYP@SPWLA.ORG
We encourage you to contact us with any suggestions for improving our group and/or if interested in participating in our activities.

Send us your articles, stories, fun moments, photos, etc. to be published in The Bridge.



SPWLA 59th Annual Logging Symposium
London, UK June 2–6, 2018
Abstracts

NOTE: Tentative Program. Selected papers listed below may not be in the order in which they will be presented. The final technical program may differ from that shown due to paper withdrawals. All technical sessions will be held at Old Billingsgate, London, UK. Photography and video/audio recording of any kind is strictly prohibited in all areas including technical sessions, workshops and exhibition hall.

COMPLETION PETROPHYSICS

Enhancing Reservoir Rock Mechanical Characterization—New Approacht Quantitatively Determine the Imminent Failure State During Multistage Triaxial Testing

Syed Shujath Ali, Ali Al Dhamen, Guodong Jin and Saad Bilal, Baker Hughes, a GE Company

This paper presents a new and robust approach for enhancing the multistage triaxial (MST) testing, which is extremely viable for mechanical characterization in the case of limited core samples available (e.g., unconventional shale). The method continuously monitors the radial-strain gradient (RSG) and uses it to determine quantitatively the stress state immediately prior to rock failure, thus enabling more consistent and accurate determination of failure parameters including cohesion, friction angle, and unconfined compressive strength (UCS). Examples are given to illustrate the method and comparison of results from the new method versus other approaches. One fundamental challenge is always associated with MST testing—how to define the unloading point for each stage. Existing methods either monitor the volumetric strain or control the radial strain during testing. One commonly used criterion is to unload the stress when the volumetric strain approaches zero or a maximum value (inflection point). For some types of rock, they could fail before the zero volumetric strain, while for many other rocks the inflection point criterion may be too conservative. The radial-strain control method usually gives one enough time to unload the stress when approaching the failure. However, the subjective judgment must be made regarding the unloading point. It is not uncommon that a wrong estimation could occur when interpreting these stress-strain curves. We developed and used a quantitative approach to define the unloading points through continuously monitoring the RSG during MST testing. RSG was calculated in real time as the ratio of the change of radial strain and the change of time, and its critical value is determined from the single-stage triaxial (SST) test or UCS test. The proposed method is tested and validated on reservoir rocks including sandstone, carbonate, and shale. For each rock type, at least four samples are drilled from the same piece of whole cores, among which three are used to perform SST tests for constructing the failure envelope and one for MST test with various unloading criteria applied.

For UCS and SST tests, irrespective of the applied confining pressures, samples were observed to fail at almost the same RSG values. MST tests were performed using the RSG criterion derived from either the UCS or SST test. Failure parameters from MST tests with the new RSG criterion generally match very well with those from SST tests. However, they might be a little conservative because of the accumulated damage from each stage. Compared with the volumetric inflection point controlled method, our new method produced less error, in which the result from SST tests is used as a benchmark.

We believe that our RSG method is unique. It can be implemented practically to decide the unloading point for each stage consistently so as to avoid an early stop or breaking the plug before the last stage.

With few samples available, RSG method enables a more accurate determination of failure parameters from MST testing that are important for many applications such as reservoir stress-state determination, log dynamic-static correlation, wellbore stability, and hydraulic fracturing design.

Thick-Wall Cylinder Strength and Critical Strain Limit From Core Tests and Well Logs, Implications for Sand Control Decisions

Abbas Khaksar, Feng Gui and Yan Zheng, Baker Hughes, a GE company

Thick-wall-cylinder (TWC) or hollow-cylinder (HC) core tests are routinely used in analytical and numerical sanding evaluation required for sand control and well completion decisions through the identification of sand-production risks, quantification of sanding rate and also as a scale model of wellbore or peroration stabilities. In these tests, a hollow cylinder is loaded under increasing hydrostatic stress until collapse occurs in the walls of the cylinder. The hydrostatic stress at which failure initiates in the internal wall is reported as the TWC-internal and the stress that causes external wall failure is called TWC-external or TWC collapse. Numerical modeling of rock failure and in particular some sand-production prediction methodologies require the stress condition corresponding to the initiation of internal wall failure to define the critical strain limit (CSL) beyond which rock failure and sanding is expected under the wellbore flowing condition. Identification of failure initiation during TWC tests however is not straightforward and requires special laboratory setup and techniques or plug seizes which are not routinely available. The standard TWC (external wall failure) tests are not conducted routinely and the quantity of tested plugs is often not adequate to establish local correlations. Also, preparation of high-quality plugs for TWC tests is not straightforward and sometimes is difficult due to the shortage or poor quality of core material. Unlike the uniaxial compressive strength (UCS), there are very few publically available empirical equations to estimate TWC from well logs and to our knowledge there is no published relationship between CSL and other petrophysical and rock mechanical properties. In this paper, we show a series of novel empirical equations between core measured TWC strength and other rock properties, including porosity, UCS, and well logs such as acoustic transit times and dynamic elastic moduli for a range of reservoir sandstones (and carbonates) from different geological age and lithofabrics. The applicability of these empirical equations is discussed and examples of the misuse of equations with erroneous sand control and well completion decisions are shown when typical TWC equations are used beyond their range of applicability. We then show several strong correlations between the numerically modeled CSL from advanced TWC tests and measured UCS or dynamic elastic moduli for sandstones. This will follow with a discussion on the rock physics basis of observed CSL trends and their implications for accurate sanding evaluation, sand control and well completion decisions.

COMPLEX RESERVOIRS AND NEW PLAY TYPES

Calculated Determination of Variable Wettability in the Middle Bakken and Three Forks, Williston Basin, USA

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The determination of oil in place can be problematic in formations with varying wettability using resistivity based saturation models. This is because the Archie *n* saturation exponent increases as wettability goes from water-wet to mixed-wet to oil-wet. The Middle Bakken and Three Forks in the Williston Basin are both in this category and are formations with highly varying wettability.

In this study, we examined a combination of triple combo, NMR, dielectric, and core data to determine wettability and the Archie *n*. By examining fluid composition as a function of T_2 or T_1 distribution, we could examine wettability as a function of mineralogy (including clay), porosity, pore size, and depth. The advantages of this technique over using special core analysis are (1) reduced cost, (2) a continuous measurement with depth, and (3) the ability to determine these values in-situ. The inherent changes in fluid properties resulting from core extraction, the changes in wettability because of core cleaning, and the uncertainty in measuring core at reservoir conditions is effectively eliminated with this technique.

Our results show that the Middle Bakken is mixed-wet with intervals that are more oil-wet. It was determined that as a result the increased carbonate and chlorite content in the Three Forks, this formation is more oil-wet than the Middle Bakken. In both formations, the cleanest intervals are the most oil-wet. Using the calculated variable *n*, a favorable comparison with core SCAL and saturations was obtained, and will be shown in the paper. CRIM inversion of dielectric data, which gives a totally independent determination of bulk volume water, confirms the water volumes calculated with the variable n resistivity model.

Determining the Formation Properties and Hoop Stresses With Innovative Formation Integrity Test Designed Using a Wireline Straddle Packer, a Field Example

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Unconventional reservoirs have very low permeability, vertical and lateral heterogeneity, and complex geological settings. To make decisions about completing these wells, the formation and seal integrity, as well as the minimum principal stress in the formation, must be known. This paper presents a field example wherein a formation-integrity test was conducted using a wireline straddle packer with injection capabilities to determine the formation properties and hoop stress. The analysis of a formation-integrity test includes two parts: preclosure analysis and post-closure analysis. The preclosure analysis uses the analysis of early pressure falloff data to determine the minimum principal in-situ stress of a particular formation at a specific depth. The tests are usually performed by injecting a small volume of fluid into an isolated zone at low rates to create a small fissure. The minimum principal in-situ stress is usually determined from analysis of the pressure decline after shut-in, but is sometimes determined from analysis of the pressure increase at the beginning of an injection (fissure reopening). The pressure decline after shut-in of the tool pump is analyzed by using the G-function and square-root-time methods. The point at which the G-function derivative begins to deviate downward from the linear trend is identified as the point at which the fissure closes. The cycles of injection and falloff were repeated four times. In each cycle, the pressure was reduced by approximately 20 psi. From these four cycles, a customized model was developed based on petrophysical data, and poromechanical simulations were performed to quantify the hoop stresses around the wellbore.

The simulation results were validated based on pressure, volume, and flow-rate data. Quantification of the stresses around the wellbore for each of the four fluid-injection and pressure-falloff cycles provides additional information that is not captured by a traditional G-function analysis. Understanding the pressure and stresses around the wellbore is critical for successful reservoir completion and development. Although challenges exist in measuring these reservoir properties with conventional methods traditionally used in the industry, this new and innovative method of using a wireline formation-tester tool with a straddle packer represents a step forward in terms of overcoming such challenges.

Fundamental Controls of “Perched” Water Contacts: From Recognition to Modeling

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Building realistic and reliable subsurface models requires detailed knowledge of both the rock and fluids. While the hydrocarbon volume estimation has a profound impact on the viability of a development, next to the saturation-height models and free-fluid-levels the hydraulic communication or permeability have a significant role as well.

While in different parts of the same field different free-fluid-levels (leading to different fluid contacts for the same rock quality) could be identified, the hydraulic communication at the field level could be challenged. At the same time, building and initializing a model based on different free-water-levels (zero capillary pressure) is challenging.

In this work, we propose a new strategy in modeling such an effect, also known as “perched” water contacts. Perched water contacts are the result of water entrapment during the hydrocarbon migration. Field observations and dynamic simulations are used to highlight the best modeling route for the Integrated Reservoir Model (IRM) as well as diagnostics for perched contact identification. In addition, we study the fundamental controls that lead to the perched contacts formation—a valuable tool that has a significant impact in the IRM. The importance of this knowledge is significant as confusion persists between perched contacts and hydroactive aquifers.

Grain-Size Distribution, Grain Arrangement, and Fluid Transport Properties: An Integrated Rock Classification

Method for Tight-Gas Sandstones

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Clastic rocks with variable grain sizes exhibit different flow properties depending on how the various grain sizes are geometrically arranged within the grain pack. Grain arrangement must be assessed to quantify dynamic petrophysical properties when rocks exhibit nonunimodal grain-size distributions. A nonunimodal throat-size distribution will be observed, for instance, in cases where different grain sizes are arranged in laminated form (e.g., aeolian sandstones). Clastic rocks that have been subject to extreme diagenesis and recrystallization, such as tight-gas sandstones, often exhibit bimodal grain and pore-throat size distributions.

This paper investigates the impact of grain arrangement on permeability and capillary pressure in clastic rocks that exhibit multiple grain sizes. Two extreme cases are studied for grain packs that include variable grain sizes: when grains are (1) randomly dispersed, and (2) laminated in the grain pack. Equations are derived to calculate permeability in each case. Additionally, shale concentration is accounted for in the calculation of permeability for both laminated and polydispersed grain arrangements. A three-dimensional chart is constructed to illustrate the behavior of permeability with respect to rock type fraction and shale concentration. The assessment includes the calculation of permeability anisotropy resulting from grain-size laminations. Synthetic samples of grain packs are also constructed and subject to pore-scale fluid flow simulations to calculate permeability and throat-size distribution and to examine how these properties change with different grain-size arrangements.

Finally, a new rock classification method that considers grain arrangement, capillary pressure, shale concentration, and permeability is introduced and verified with measurements acquired in a Carboniferous tight-gas sandstone from northern Germany. Our method of rock classification yields improved permeability calculations compared to widely used classification methods, such as Winland R35, which implicitly assume a unimodal throat-size distribution. The new rock classification method can be readily adapted to calculate more specialized fluid-transport properties, such as relative permeability. It can also be modified to account for capillary pressure during both imbibition and drainage and their consequence of saturation-height behavior.

Integrating Advanced Wireline Logging, Traditional Core Analysis, and Digital Rock Analysis to Identify and Characterize a Reservoir Target Within the Osage Formation in Blaine County, Oklahoma

Mark Sutcliffe, Council Oak Resources; Erek Hutto, Halliburton; Bryan Guzman and Gustavo Carpio, Ingrain

This case study describes an integrated evaluation of reservoir properties from the Osage formation in the NW STACK play area of Blaine County, Oklahoma. The Meramec and Osage lithostratigraphic horizons represent Mississippian-age rock units that vary between carbonate, siltstone, and chert lithologies. These are tight, low-permeability rocks in which pore-size distribution, pore interconnectedness, and permeability represent significant differentiators for reservoir quality. Potential reservoir targets were initially identified and mapped using legacy well logs consisting of gamma ray, resistivity, neutron, and density logs, but the reservoir storage potential was still quite uncertain because of log vintage, borehole conditions, and geologic uncertainty.

Traditionally, interest in the NW STACK area was primarily focused on the Meramec Shale and fractured areas of the Mississippi Lime, which overlie the Osage chert. The Lau pilot was taken by Council Oak to better understand and assess what lateral targets may exist within their Blaine County acreage. Advanced logging suites, core acquisition, and core analytical techniques were used to improve the understanding of reservoir horizons encountered within the wellbore. Nuclear magnetic resonance (NMR) data collected using an NMR tool and elemental information collected using the elemental spectroscopy tool provided important evidence of significant hydrocarbon storage and unconventional reservoir potential within a siliceous zone.

This potential reservoir zone was horizontally drilled and hydrofractured within the siliceous zone because of its storage, indicated on well logs, and its perceived brittleness. Whole core, collected before logging, subsequently showed that this siliceous zone was a bioturbated spicular chert. However, discrepancies existed between core measurements of porosity relative to NMR estimates. NMR estimates were 1 to 2% greater than estimates based on the cleaned and dried crushed rock analyses. To better understand the distribution of porosity within these spicular cherts, and to investigate the discrepancy between NMR analyses and conventional core techniques, digital rock physics was used to quantify the porosity distribution within the spicular chert facies. These scanning electron microscopy (SEM)-based techniques from digital rock analyses demonstrated the presence of porosity and the interconnectivity of the pore networks within the spicular chert.

The NMR data combined, with the SEM-based techniques, provided evidence to support the existence of storage and deliverability within the spicular chert, which was consistent with the productivity of the horizontal well. T_1/T_2 maps provided additional support that a continuum of pores existed down to very small pore sizes and that those pore sizes were charged with hydrocarbon. When combined, the pore imaging and NMR T_1/T_2 maps provided great insight into why traditional core analysis techniques may underestimate storage and a level of understanding not attainable from either technique alone. T_1/T_2maps provide information relevant to pore size and fluid charge, whereas the SEM data provided visual displays and information about the distribution of pores relevant to the interpretation of T_1/T_2plots.

Optimized Reservoir Management With a Campaign of Production Logging in the Deepwater Gulf of Mexico Mars Field

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Managing multiple reservoirs through commingled production requires careful planning and continued surveillance. Depending on the reservoir pressure and productivity of the layers, production wells are frequently supported by a waterflood injection program. The future field development program depends on accurate downhole flow profile and reservoir depletion characteristics. Production logging is typically used for determination of flow profile and to identify any water shutoff opportunities to improve hydrocarbon production. The technique can be extended to provide selective inflow performance for all the reservoir zones, to identify depleted zones, and to assess the performance of a fieldwide waterflood program.

This paper discusses a recent campaign of five production logs, conducted in three Mars basin wells, located in deepwater Gulf of Mexico. Performing reservoir surveillance and obtaining a downhole production flow profile in a deepwater environment often becomes challenging because of well intervention risks. Almost all the production logs were in commingled zones without smart completions and had either malfunctioning or miscalibrated downhole pressure gauges. Because the logging operations were combined with downhole pressure-gauge swaps and pulls, this removed standalone intervention costs associated with data acquisition in a costly deepwater environment.

Real-time monitoring of production logging data helped ensure the well was under stable conditions and enabled optimization of the logging program. The pressure tool in the logging string recorded measurements at the downhole pressure gauges to ascertain proper functioning. Production log (PL) results are presented from three wells. In the first well, three production logs were run over a period of 10 years, while the rest have one set of PL surveys. In one of the wells prior to logging the lower zone was believed to be higher pressure, which was also suggested by geochemical analysis. The PL not only invalidated the previous understanding of the commingled reservoir zones, but also highlighted misallocation of production. In another well, the selective inflow performance revealed that the waterflood injection had increased the reservoir zone's pressure to near parity. This suggested that the higher producing zone could be ramped up to an even higher rate without risking significant pressure depletion and becoming a future drilling concern. Lastly a PL/gravel-pack log were run in a subsea well with known voids which hasn't been performed by Shell in nearly a decade due to the risks around pressure control involved with a subsea PL. The log revealed that the gravel pack had settled in and that nearly the entire perforated interval was contributing to production. This enabled the operator to relax the production constraints.

Production logging was used in a wide range of applications showcasing the importance of the technique in prudent reservoir management. Data obtained from multiple production logging runs helped understand zonal contributions, layer pressures, productivity index, permeability profiling, calibrating downhole pressure gauges, water injection support, and the impact of gravel-pack voids. It also helped improve reservoir models and commingled well allocation, and influenced future field development plans in the basin. These measurements, interpretations, and actionable insights helped further development of a mature deepwater field.

Water-Wet or Oil-Wet: Is it Really That Simple in Shales?

Ishank Gupta, Jeremy Jernigen, Mark Curtis, Chandra Rai and Carl Sondergeld, University of Oklahoma

Knowledge of rock wettability is needed as it plays an important role in hydrocarbon recovery. Wettability has a direct impact on well productivity, recovery factors and enhanced oil recovery (EOR) performance. With the advent of unconventional reservoirs, the problem of wettability determination has become more complex due to their ultralow permeabilities and multiple-wettability systems. Several nuclear magnetic resonance (NMR)-based methods have been proposed in the literature to determine wettability of shales. Scanning electron microscope (SEM) images can also be used to distinguish between different types of pores. Consequently, resulting models, interpretations and predictions have benefitted by partitioning the shale rocks into oil and water wet networks. Previous work showed that oil- and water-wet pores do not form separate networks and are connected with each other through mixed-wet pores.

In this study, NMR experiments were done on 47 samples from Marcellus, Woodford, and Eagle Ford shales. The experiments showed that samples from these formations were grossly water-wet, mixed-wet and oil-wet, respectively. The correlation of average wettability index with total organic carbon (TOC) showed that 5 wt% is the critical TOC content required to achieve connectivity and generate oil-wet pathways. Similarly, correlation of average wettability index with clay content showed that above 65 wt% clay content, samples had well-established water-wet pathways, making the samples predominantly water-wet. The lower critical threshold for clay content was 10 wt%.

The threshold values of 5 wt% TOC and 10 wt% clays represent same volumetric fraction (~10%) of the rock. This is considering the typical values for average densities: 1.4 g/cm^3 for kerogen, 2.65 g/cm^3 for clays, and 2.6 g/cm^3 for the rock. Thus, it is evident from the results that as soon as a rock component reaches 10% volumetric fraction, it starts getting connected and thus starts affecting the connectivity of the rocks. The figure of 10% can be thought of as percolation threshold for connectivity in shale rocks. A method is also demonstrated to quantitatively assess the fraction of different pore types from SEM images. A mixed-wet pore has both oil-wet and water-wet pore surfaces in the same pore and thus can be accessed by both water and hydrocarbons, alike. The fractions of different pore types were in sync with the observations from the macroscopic imbibition experiments. For instance, oil-wet Eagle Ford samples had a higher fraction of organic pores (22.5%) while water-wet Marcellus samples had a higher fraction of inorganic pores (40%). The samples from all the three shales had a high fraction of mixed-wet pores (57% in Marcellus, 69% in Eagle Ford and 68% in Woodford). This knowledge of fractions of different pore types can be instrumental in modeling connectivity pathways.

EUROPE FORMATION EVALUATION

A Full-Field Petrophysical Evaluation of a Clastic Giant Oil Field: Best Practices for Delivering Consistent Petrophysical Properties to Improve Reservoir Models and Production Forecasting

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This paper presents a case study of a full-field petrophysical evaluation over a giant oil field using a global interpretation model that optimizes key data controls from all available cored wells. The philosophy of the study is to deliver a consistent and reproducible petrophysical product that can model hydraulic units in the reservoir model more effectively to improve STOIIP estimates and production forecasting.

The oil field has now been in production for 10 years and to date 650 MMBO have been produced via 55 development wells. The field has currently entered a significant time in its field management as it comes off plateau and water cut is 50%. Recently, 4D seismic has been acquired to support production surveillance efforts and two drilling campaigns are being planned on the field for 2018–2020.

The objective of the new evaluation is to improve upon previous quick-look evaluations that may have been performed on an individual well basis by multiple interpreters using various parameters and workflows that may be inconsistent and not easily replicated.

In this study, some novel interpretation techniques have been followed that integrate all available petrophysical data and which are calibrated to a comprehensive core database: (1) Detrending of petrophysical data using crossplot techniques to characterize geological formations without the requirement to finely subzone intervals and to avoid excessive parameterization; (2) providing quality-assured and conditioned well-log data, such as gamma-ray data in and around casing points and improvement of shale volume estimates; (3) optimizing the formation evaluation workflow against core porosity and relating petrophysical properties to geological facies and flow zone indicators (FZI); and (4) determining petrophysical cutoffs by calibration of net-reservoir to oil stain on cores.

The workflows result in an improved database containing conditioned well logs that provide more confidence to multidisciplinary subsurface teams and the methods used are more repeatable and auditable. Since the interpretation included the overburden section a well-constrained shale volume-sonic slowness relationship may be used to model velocity data over intervals where sonic data are absent or have not been acquired. This global seismic model can improve well-to-seismic integration by giving greater confidence in depth conversion and well ties.

Over the reservoir section, the improved calibration of petrophysical properties against core has been made by studying depth-shifted white-light and UV core photographs. This has highlighted potential upside in net-reservoir estimates over all zones including thin beds that previously may not have been apparent.

The revised interpretation can be directly related to FZI and hydraulic units to support subsurface models by integration of petrophysical properties with an effective core description. Some of these techniques and practices may be directly applicable to other multiple well interpretations and regional studies elsewhere

Use of Advanced Wireline Logs to Reduce Uncertainties in a Complex Reservoir—A Case Study From the Ivar Aasen Oilfield in the Norwegian North Sea

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The Ivar Aasen oilfield is located on the Gudrun Terrace on the Eastern flank of the Viking Graben in the Norwegian North Sea. The field was discovered in 2008. The reservoir is located within a sedimentary sequence of Middle Jurassic to Late Triassic age, which consists of shallow marine to fluvial, alluvial, floodplain and lacustrine deposits overlying a regionally extensive, fractured calcrete interval. The sequence exhibits a complex mineral composition (quartz, feldspars, clays, carbonates, organic matter) and is both vertically and laterally heterogeneous at a sublogging sensor scale. Shale layers and redeposited shale and calcrete fragments are present in various forms throughout the sequences.

The formation evaluation in early field evaluation was based on traditional logs, such as gamma ray, neutron, density, and resistivity. The evaluation based on these logs was associated with large uncertainty, particularly in the more complex sediments. This is because it can be difficult to estimate basic properties, such as shale volume, net fraction, porosity and permeability, when dealing with heterogeneities at a scale lower than the resolution of the sensors. Estimated in place volumes and reserves can be significantly off in such cases. It is much harder to optimize well placement and drainage strategy when there are large uncertainties in formation properties and in place volumes. Due to this, it was decided in 2014 to attempt to reduce the mentioned uncertainty when an opportunity emerged. The rig to be used on the Ivar Aasen drilling campaign, arrived early. Instead of planning for several months of idle rig time, a more aggressive strategy was chosen. The Ivar Aasen team and partners decided to address the mentioned uncertainty by drilling three data wells in the available time window.

In 2015, three 'geopilots' were drilled with OBM, cored and subsequently logged with advanced wireline tools to tackle the challenges described above. The cores were used to improve the understanding of the depositional environment, the depositional facies and their impact on the reservoir performance (porosity-permeability correlations and petrophysical model parameters). Specialized wireline logs were used to characterize mineralogy (high-definition neutron-induced spectroscopy), saturation in laminated shale/sand sections (triaxial induction), fluid identification and pore volumes (well formation testing, nuclear magnetic resonance), and finally near-wellbore saturation using nonresistivity-based methods (nuclear magnetic resonance, dielectric dispersion). A Thomas-Stieber-based thin-bed formation evaluation method was applied to interpret the abovementioned data. Older existing wells were reinterpreted by the same method, also benefiting from the parameters measured in the 'geopilots'. The improved understanding of the reservoir properties based on the mentioned data and interpretation results contributed to a drastic increase of the in-place volumes in the Triassic Skagerrak 2 reservoir zone in the Ivar Aasen Field. Before the 'geopilots' were drilled, Skagerrak 2 volumes were estimated to be 20% of the total Ivar Aasen volumes. After all the data from the 'geopilots' were implemented, Skagerrak 2 in place volumes had increased to 45%. These results called for a change in drainage strategy. Skagerrak 2 water injection was implemented as well as the trajectory of several producers were changed. Ivar Aasen production started 24 December 2016. Production data support the abovementioned finds and paint the picture of a successful drainage strategy made possible by the decision to reduce uncertainty.

FORMATION EVALUATION OF CONVENTIONAL RESERVOIRS

A Model-Independent Definition of the Gamma-Ray API Unit

Christian Stoller, Libai Xu and Cornelis Huiszoon, Schlumberger

The American Petroleum Institute (API) gamma-ray unit (gAPI) was established in the late 1950s, and is defined by the gamma-ray (GR) tool response in the API natural gamma-ray calibration pit at the University of Houston. The 4-ft diameter concrete formation with a 5.5-in. cased borehole consists of a high-radioactivity zone and two low-radioactivity (barren) zones to establish a net radioactivity. A value of 200 gAPI is defined as the difference in the count rates between the high- and low-activity regions for the GR tool eccentered in the borehole. The high-activity zone was designed to have 4% potassium, 12 ppm uranium, and 24 ppm thorium by weight.

The 4.89-in. casing inner diameter is too small to calibrate the majority of logging-while-drilling (LWD) gamma-ray tools in this standard formation. In addition, the formation may no longer exist in a few years and the casing is deteriorating. It is therefore necessary to define the gAPI unit in a new way that is consistent with the present definition but is independent of the formation and borehole configuration. This can be achieved by defining the gAPI as the response to given concentrations of three radioactive elements in the formation. These are not the assigned or measured concentrations of the various elements in the API formation, but rather correspond to net concentrations after subtraction of the background from the barren formations and correcting for attenuation by the casing and borehole fluid. The proposed definition is consistent with the present standard and resolves apparent discrepancies when trying to compute a gAPI value from Th, U, and K concentrations. Accordingly, the proposed definition enables the computation of gamma-ray values in gAPI units based on Th, U, and K concentrations measured on core samples that is consistent with the logging data.

After careful analysis of the formation data acquired using different spectral natural gamma-ray tools and after computing the net elemental concentrations, we propose that 200 gAPI should be measured in any borehole traversing a formation that contains a certain amount of potassium, uranium, and thorium. The tool must measure this amount independently of borehole size and borehole fluid and in both open and cased holes. The essence of our proposed definition is that it defines the gAPI as a property of the formation; environmental corrections will assure that the borehole effects, including the tool position in the borehole, are properly accounted for.

The presentation will provide details on the proposed model-independent definition of the gAPI unit as a formation property, provide proposed elemental concentrations that correspond to 200 gAPI, and explain the applicability of the new definition across wireline and LWD measurements.

A New Algorithm for High Depth Resolution Slowness Estimate on Sonic-Array Waveforms

Bassem Khadhraoui, Saad Kisra and H.M.T Nguyen, Schlumberger

A key objective of wellbore sonic data processing is to estimate the slownesses of the propagating sonic waves through the surrounding formation rock. Without loss of generality, our focus is to estimate the slowness of the compressional waves generated by a monopole source. The original processing techniques designed to estimate compressional slowness consisted, generally, in estimating the arrival-times on the recorded waveforms. With the known transmitter/receivers spacings, slowness was then derived. These arrival-time based techniques are data-driven techniques because they mostly depend on the data and therefore require little modeling. Because the slowness is computed for a pair of neighboring receivers, the data-driven techniques can provide a high depth resolution slowness log (e.g. six inches). They are however, very sensitive to the data quality yielding reliability issues when picking arrival-times. The array-based technique introduced by Kimball and Marzetta, slowness time coherence (STC) is a model-driven approach that was designed to address the weak aspect of the data-driven techniques. In order to improve the robustness of detecting the onset arrivals, STC assumes a constant slowness across the receiver array for the considered receiver-array aperture. The depth resolution of STC is hence, provided by the length of the receiver array used in the processing. A minimum of four receivers is usually needed to define a reliable receiver array for STC. A larger number of receivers used in the processing provides a more reliable onset-arrival detector, but has a poorer resolution because of the larger receiver aperture.

Here, we introduce a new technique called the fast arrival-time and slowness estimate (FTSE) that combines the strong aspects of both data and model-driven approaches. This technique is based on a fast and robust model-driven multiwaveform algorithm which is applied to the data in order to guarantee a reliable detection of the onset arrivals. For this purpose, the short time average/long time average operator is applied to every waveform. The output of this operator is used to generate a set of candidate arrival-times. Finally, a Hough transform is applied to the set of arrival-time candidates available in a shot gather. Thanks to the robustness of the multichannel model driven approach, a detection of the onset of compressional arrivals is obtained, yielding a good estimate of both compressional arrival times and slowness values. The results of the model-driven approach are then, used to guide the picking of the true arrival times of the compressional waves. Finally, the obtained arrival times are used to derive a high depth resolution slowness log.

We will review the above techniques and demonstrate the efficiency of FTSE on real data acquired with both wireline and logging-while-drilling sonic array tools. The superiority of FTSE is clearly highlighted in a thin-bed layers environment where 6-in. sonic data have been recorded.

A Novel Visualization for Elemental and Mineralogical Data as an Aid to Correlation and Interpretation

Joanne Tudge, Weatherford; Jennifer L. Kharrazi, Weatherford Labs; and Obren Djordjevic, Newfield Exploration

Mineralogical and elemental data, obtained from XRD, XRF, or ICP, is of significant value not only in terms of clay characterization and constraining petrophysical interpretations, but in applications related to chemostratigraphy and chemosedimentology. Such applications include using trace metal proxies for organic richness, developing zonations for geosteering and completions, assessing drill paths in horizontal wells, recognizing cavings and assisting in well stability concerns, and determining chemical signatures of sediments for use in well correlation.

It is increasingly common for mineralogical and elemental data to be related to downhole logs, including spectroscopy, density, neutron and gamma in order to enhance rock physics models and geomechanical analyses, for example. The large size of elemental (XRF, ICP) and mineralogical (XRD) datasets can make them difficult to interpret visually. Binary and ternary diagrams show correlations and trends but are difficult to interpret at a glance and lack the depth component for comparison to downhole logs.

A visualization is proposed which represents relative proportions of elemental or mineralogical data as a function of depth. It uses the principle of color cubing where values of three parameters are related to values in the red, green and blue color spectrum [RGB]. Its application to spectral gamma-ray data (Th, K, U) is already known, but in this paper, we extend the approach to typical combinations of lab-based elemental and mineralogical data. For example, color cubing of XRD results for total clay, carbonates and 'other minerals' shaded beneath the total gamma log (from lab or downhole data) helps to demonstrate whether a high gamma reading linked to high potassium (K) is caused by clay minerals or K-feldspar. Additionally, SiO_2, CaO and Al_2O_3 can be combined to create a simple but useful color-coded lithology log. Other elements can be combined for specific uses depending on the formation and what is being investigated (i.e., diagenetic processes, provenance changes, clay changes).

This new application of a visual display technique enhances chemostratigraphic correlations, improves understanding of elemental and mineral relationships with downhole logs, and provides a way to incorporate large datasets into a visual interpretation. The advantages of using this technique with various mineralogical and elemental combinations are discussed, and some useful correlations are considered and illustrated with case studies.

Advances in NMR Fluid Typing Assist in the Petrophysical Evaluation of a Carbonate Well Drilled With Oil-Based Mud

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Nuclear magnetic resonance (NMR) is the key petrophysical evaluation technology in Brazil's deepwater Apatian stromatolytic carbonate reservoirs. As such, it is extremely important to obtain accurate fluid typing, which provides volumetric fractions of water, oil and oil-based-mud filtrate (OBMF). A common means of fluid typing is based on using diffussivity-T_2 (D-T_2) maps. However, when the fluid properties are very similar the D-T_2 maps fail to resolve them, which reduces the quality of the evaluation. Other attempts using 1D spectra-either T_1 or T_2 distributions-are normally not considered and typically evaluated via cutoff.

In this work, we present a solution for fluid typing based on blind-source separation (BSS), a statistical machine-learning technique. Specifically, we separate sources (fluid components) blindly based on their statistical independence, which is the only requirement imposed on the NMR input data. Considering the three fluids mentioned above, this requirement is reasonably fulfilled.

Results show that determining BSS based on independent component analysis (ICA) is a powerful technique to retrieve the fluid components of the NMR signal. For T_1 or T_2 spectra, we are able to retrieve the fluid components. Results were also validated by simulations and comparing against lab data.

With respect to the OBMF component, its presence indicates good permeability. Thus, we elaborate on an OBMF-based permeability equation that implicitly honors the presence of unconnected vuggy porosity and is independent on cutoff values. Finally, the OBMF-based permeability can be used as a rock-quality indicator to support depth-selection decisions for pressure tests and fluid sampling.

An Experimental Multiphysics Method for Quantifying Cation Exchange Capacity of Clay-Rich Rocks

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Quantification of electrical rock-fluid interfacial interactions is crucial for reliable formation evaluation, since they impact borehole geophysical measurements, such as electromagnetic measurements, as well as fluid flow in porous media. These interactions become even more important in clay-rich formations. cation exchange capacity (CEC) is commonly used to quantify electrical rock-fluid interfacial interactions and the influence of clay minerals on electrical conductivity of clay-rich rocks and clay-bound water. Quantification of CEC is, however, challenging. Conventional methods, such as wet chemistry, multiple salinity, and membrane potential, have limitations associated with their application in in-situ condition, certain type of formations, and use of empirical correlations. To overcome the aforementioned challenges, we recently developed a new method for CEC assessment in pure clay minerals by integrating N_2 adsorption-desorption, nuclear magnetic resonance (NMR), and X-ray diffraction (XRD) measurements. In this paper, we (a) introduce a new workflow for CEC evaluation in rocks with complex mineralogy and presence of multiple types of clay minerals, and (b) cross-validate the effective CEC from the new method against directly-measured CEC from multiple salinity and wet chemistry method in powdered and intact rock samples.

The introduced workflow/formulation for CEC estimation in rocks incorporates quantitative characterization of mineral composition as well as N_2 adsorption-desorption and NMR measurements. To test the workflow, we started with synthetic powdered rock samples, which were manually mixed with different minerals with known composition. We performed NMR and XRD measurements to obtain volume of hydration water and interlayer spacing variations, respectively. To assess surface area of each mineral, we performed successive controlled N_2 adsorption-desorption measurements and proposed an inversion algorithm to estimate surface area of each mineral in multiple samples. Then, we used those results as inputs for CEC estimation. Meanwhile, for actual rock samples, we started with quantitative XRD measurements to obtain the composition of different minerals and then quantified volume of hydration water, interlayer spacing variations, and surface area for CEC estimation. Finally, we cross-validated CEC estimation, both for synthetic rock samples and actual rock samples, with CEC estimates from the wet chemistry and multiple salinity methods.

The proposed workflow was successfully tested on both synthetic and actual rock samples. In the case of synthetic rock samples, we estimated CEC of four samples with 10 wt% montmorillonite and 90 wt% quartz, 20 wt% montmorillonite and 80 wt% quartz, 10 wt% illite and 90 wt% quartz, and 25 wt% illite and 75 wt% quartz to be 15-, 28-, 8-, and 18-meq/100g, respectively. The actual rock samples contained 20 to 40% volumetric concentration of clay with CEC ranging from 30 to 50 meq/100 g. The CEC estimates from the new method in both cases of synthetic and actual rock samples were in agreement with those from the direct measurements, with errors of less than 7 meq/100 g. The experimental results demonstrated reliability of the introduced method for CEC assessment, which is promising for in-situ and real-time CEC quantification. The outcomes of this paper can be applied to variety of formations with complex lithology and can be an onsite supplement application for mud logging.

An Integrated Formation Evaluation Approach to Characterize

a Turbidite Fan Complex—A Case Study From the Falkland Islands

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The oil and gas potential of the basins surrounding the Falkland Islands has attracted exploration drilling that resulted in the discovery of the Sea Lion Field in the North Falkland basin in May 2010. More recent exploration drilling has resulted in new oil discoveries to the south of the Sea Lion Field, which has not only confirmed the area as a significant hydrocarbon province but has also boosted the chance of commercializing the resources of the North Falkland Basin. The primary oil targets are stacked and amalgamated deepwater lacustrine turbidite fans with each fan comprising multiple lobes. In exploration and appraisal wells, porosity characterization, permeability assessment, pressure measurements and hydrocarbon fluid identification, are essential input data for robust reservoir characterization and resource estimations.

A comprehensive suite of advanced logging measurements, in addition to conventional log measurements, has been used to facilitate data analysis and calibration to laboratory core measurements. The pressure gradients and fluid samples obtained from formation testing, when combined with the wireline log measurements, are critical in determining the thickness, quality, and connectivity of hydrocarbon zones, which in turn impacts the commercial evaluation of the well. In these remote offshore basins, where rig costs are high, the ability to focus data acquisition in specific zones of interest, minimize the logging time while identifying and reacting early in real time to data points that lie off the expected trends can add significant value to the operating company.

Formation evaluation challenges include hydrocarbon identification, estimating oil viscosities, and resolving fluid contact uncertainties. In addition establishing whether there are any baffles or barriers in the system or significantly varying reservoir properties as a consequence of facies changes has the potential to complicate the evaluation in respect of permeability characterization and volume estimation.

A method of facies classification using a combination of resistivity-based borehole imaging data and nuclear magnetic resonance (NMR) data is outlined in this paper. This method, when combined with conventional log data, has shown encouraging results in terms of identifying lithofacies and determining a rock-quality index. The mud logs and gamma-ray logs were interpreted with the borehole image logs in these turbidite reservoirs, which resulted in the identification of four distinct depositional lithofacies. These lithofacies were integrated with the free fluid index (FFI)/bulk volume irreducible (BVI) ratio determined from the NMR data. The FFI/BVI ratio was used as an index for rock quality index (RQI) classification. The RQI was subsequently used to optimize formation pressure testing and sampling points.

The contribution and importance of lithofacies identification is typically ignored when optimizing formation pressure depths and interpreting the results. The methodology presented in this paper uses an integrated workflow jointly developed by the operator and service company that allowed detailed reservoir evaluation in the zones of interest and real-time adjustments to the data-acquisition program.

An Integrated Workflow to Estimate Permeability Through Quantification of Rock Fabric Using Joint Interpretation of Nuclear Magnetic Resonance and Dielectric Measurements

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Variable depositional cycles and severe diagenesis are among the main contributing factors to the complex pore network encountered in complex formations such as carbonates. This complexity is often not taken into account reliably in conventional models for permeability assessment. Conventional methods for permeability assessment, including electrical-based models (e.g., Katz and Thompson) and nuclear magnetic resonance (NMR)-based models (e.g., Coates and Schlumberger-Doll-Research), either require pore-scale characterization of pore network or extensive calibration efforts, such as detection of cutoff values and assessment of constant model parameters. Fluid saturation also often affects reliability of conventional electrical- and NMR-based methods. Joint evaluation of dielectric permittivity and NMR measurements enables capturing conducting/effective porosity, pore-network connectivity, tortuosity, and pore-size distribution for real-time and reliable permeability evaluation, which significantly improves permeability assessment. Such joint interpretation enables taking into account pore structure in assessment of permeability as well as required corrections for fluid saturation.

The objectives of this paper include (a) introducing a parameter that quantifies rock fabric features (e.g., pore structure and directional connectivity of pore network) by combined evaluation of dielectric permittivity and NMR measurements, (b) developing a new physics-based permeability model that incorporates the quantified rock fabric, and (c) verifying the reliability of the new permeability model in core-scale domain using dielectric permittivity, NMR, mercury injection capillary pressure (MICP), and permeability measurements.

We first establish the relationship between rock fabric and hydraulic permeability through pore-scale numerical simulations of fluid flow, dielectric permittivity, and NMR magnetization decay. We apply the lattice Boltzmann method, the frequency-domain finite volume method, and a random walk algorithm for modeling fluid flow, dielectric permittivity, and NMR magnetization decay, respectively. Then, we introduce a new permeability model and validate it through laboratory experiments. NMR and multifrequency dielectric permittivity measurements performed on core samples are used as inputs to the new model. Finally, we estimate permeability using the new model in core-scale domain and compare the results against permeability measurements performed on the same core samples.

We successfully validated the new permeability model on core-scale samples from different lithofacies taken from two carbonate formations. Estimates of tortuosity, effective conducting porosity, and pore-size distribution were used for quantification of rock fabric. We applied the quantified rock fabric in the introduced multiphysics permeability model, which significantly reduced the relative error in permeability estimates, compared to conventional permeability models. Although the rock fabric features required by the introduced method should be obtained from pore-scale images, it should be noted that these quantitative properties can be obtained from rock cuttings, and are shown to be consistent in each rock type. The new method minimizes the need for cutoffs and excessive calibration efforts in permeability assessment by honoring and quantifying rock fabric.

Applications of Time-Lapse LWD to Improve Petrophysical Interpretations and Drive Operational Efficiencies

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The Shah Deniz field is a giant, high-pressure, gas-condensate field located about 100 km offshore in the South Caspian Sea, Azerbaijan. The field consists of multiple stacked reservoirs with large contrasts in pore pressure. There is a very narrow drilling window and reservoirs are drilled with high overbalance. Sensitive shales also make borehole conditions challenging for logging. In addition, clay-rich sands, variable invasion and thin beds affect log responses and make petrophysical interpretation difficult. High-quality, targeted data acquisition is therefore essential. Because of the drilling conditions, Logging while drilling (LWD) has become the most common method of acquiring petrophysical data. A major advantage of LWD is that the tools continuously acquire data. It is thus possible to acquire time-lapse data, either as part of a plan, or opportunistically during normal drilling activities. These data are typically cost-effective and low risk to acquire, but have high value, both for short-term operations and for long-term reservoir description. This paper describes six ways that time-lapse data have added significant value on Shah Deniz. First, time-lapse resistivity data are used to identify (and avoid perforating) water-producing sands through invasion-profile modeling. Resistivity modeling gives information about log quality, depth of invasion and invasion rate. It provides insight into likely fluids in the reservoir to inform the perforation strategy. Additionally, analysis of time-lapse nuclear logs has been important for making corrections to log-derived porosity in gas sands where the gas response has been suppressed due to invasion and clay content. Time-lapse resistivity is also used operationally in losses investigations. When a well is drilled with no losses and resistivity is acquired, a baseline as- drilled log is established. If losses subsequently occur due to drilling-induced fractures, a relog can reveal the location of the losses. This is important information when trying to eliminate the losses. Relogging with a reduced mud weight can show the fracture closing and a return to as-drilled resistivity values. Time-lapse image logs reveal how the wellbore enlarges and changes shape with time. This can reveal stress orientations and has helped to troubleshoot drilling events, such as stuck pipe or failing to get casing strings to bottom. A time-lapse gamma ray is used to create a pseudo-caliper to refine cement job volumes when a physical caliper is not available. When the borehole enlarges over time, the source of radioactive material moves further from the detector and causes a predictable reduction in the observed gamma ray values between time-lapse datasets. Finally, when dedicated logging passes are not acquired, valuable data can be extracted when pulling out of hole at even normal tripping speeds. Examples will be presented of occasions when very sparse data points have been used to solve drilling issues. In summary, the paper will demonstrate that the total value that can be delivered from time-lapse LWD far exceeds that derived from as-drilled data alone.

Clays in the Fulmar Reservoir of Central Graben North Sea—A Boon or Bane?

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Reservoir petrophysics is the most important study that defines qualitatively and quantitatively a reservoir's performance. The reservoir itself is characterized as clean, heterogeneous or poor in quality based on its mineralogical composition. Clay minerals are crucial minerals that decide reservoir quality. Not only do the clays affect the reservoir quality but they also play a key role in understanding source rock and hydrocarbon-generation, as a tool for depositional environment characterization, stratigraphic correlation and identification of exploration targets. Hence, understanding the clays is essential. The Fulmar Formation is the principal reservoir within the North Sea Central Graben. The Upper Jurassic Kimmeridge Clay Formation is the source rock, although coals of the Middle Jurassic Pentland Formation are also locally mature for oil. Besides gas and oil, many of the high-pressure, high-temperature (HPHT) Fulmar reservoirs comprise condensate. The association of overpressure and clay diagenesis appear to be the main factors in controlling reservoir quality and the migration of pore fluids and hydrocarbons. The reservoir consists of thick, highly bioturbated sandstones deposited on a subsiding shallow-marine shelf under the influence of tectonic movements. The formation has been cored extensively, and is mostly homogeneous in appearance. Although kaolinite, illite, mixed-layer illite/smectite, chlorite, smectite, and mixed-layer chlorite/smectite have all been identified in the Fulmar reservoirs, it is observed that illite is dominant. The clay mineralogy of the Fulmar sandstones differs between wells, and may vary with depth within a well. Since clay mineralogy leads to significant variation of porosity, permeability, and wireline log response there is need for a systematic study of clays during the exploration and appraisal phases of a field. Clays seem to have beneficial as well as deteriorating effects on the reservoir quality of the deep Fulmar sandstones. On the positive side, the deep HPHT Fulmar reservoirs have high porosities, which have been attributed to conversion of smectite to illite, inhibiting macroquartz cementation, thereby preserving porosity. Thus, overpressuring, coupled with early clay coatings, has prevented compaction at depths >10,000 ft. The impact of overpressure on reservoir quality will be active only when the reservoir is sealed suitably for long duration by very fine-grained and ductile shales. On the other hand, the distinct relationships between lithofacies and reservoir quality appear to be closely related to the bulk-rock total clay content. Porosity and permeability are functions of depth, clay content and grain size. Increasing clay content means increasing the ratio of microporosity to macroporosity, thus, reducing reservoir quality. Hence, either way clays are crucial. For reserve calculations, the ability to determine from wireline logs the total clay content in hydrocarbon-bearing reservoirs is very important. Distribution of these clays in the sandstones may be dispersed, laminated, or structural and these variations result in different facies, which, if not understood, could lead to misinterpretations. This study demonstrates how integrated analysis through petrophysical and geological methods could help interpret clay type, volume, distribution and morphology for reservoir characterization from well data in the Fulmar reservoirs.

Cost- and Time-Effective Prediction of Local Rock Properties by X-Ray Interaction Statistics

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Technology Center

RCAL/SCAL characterization, as many of other geoscientific description protocols, exhibits the inherent lack of ubiquity and sampling bias due to the finite nature of experimental resources, samples and time. On the other hand, digital rock physics is a novel technique for rock properties quantification using imaging, image analysis and numerical simulations on digital models. This technology can be applied in any rock sample from plugs to cuttings and radiographic inspection can be performed in seconds per sample. One of the important technology boosts this technique experienced, which allowed a wider implementation, was the development of lab-based X-ray systems (as an alternative for synchrotron based protocols). This recent advance can provide tabletop X-ray solutions at any lab, offering the possibility to perform radiographic/tomographic protocols in a cost-efficient scheme.

X-rays interact with matter based on target density and atomic number, depending on the material under inspection and the accelerating voltage used. Reservoir properties like porosity, permeability and acoustic response are also causally related to these scalars (density and atomic number). The main goal of this work is to study the predictive potential of radiographic results quantified by X-ray attenuation statistical cumulates for some RCAL/SCAL properties. Radiographic screening can be performed in a matter of seconds per sample, as previously stated, providing an initial very cost- and time-efficient protocol to obtain rock properties information.

Fifteen samples were chosen from a particular well with several siliciclastic intervals exhibiting different rock qualities (even shale intervals). A comprehensive RCAL/SCAL project was developed around these samples where porosity, permeability and acoustic response were measured among other reservoir properties. A fast, cost-effective radiographic screening was applied to the complete universe of samples. Each sample radiograph was around 25 seconds of exposure time, which gave a total time of less than one hour for the complete X-ray protocol. A linear multivariate scheme was applied to the X-ray attenuation response. The mentioned RCAL/SCAL properties (porosity, permeability and acoustic velocities) were considered as independent variables while several statistical cumulates from the registered X-ray attenuation were used as a the linear vector base.

The results showed a significant predictive power of those X-ray attenuation statistical cumulates regarding porosity, permeability and acoustic velocities. Porosity and permeability exhibited the higher possibility to be predicted using the derived linear coefficients ($R2 > 0.9$ and $R2 > 0.8$, respectively) while acoustic velocities showed a lower level of prediction ($R2 > 0.7$). The latest property prediction could be improved by multi-energy acquisitions protocols which will be studied somewhere else. Cross-validation was applied to the complete set with errors within a reasonable geological uncertainty in the interval. The constructed linear model could allow faster and cheaper data population along the complete interval in this well for a more precise earth model built by adding estimated data points from X-ray information where no RCAL/SCAL was obtained. Other well models are needed to verify the robustness of the procedure, also multi-energy acquisitions are suggested for a more accurate acoustic response estimation.

Defining Net-Pay Cutoffs in Carbonates Using Advanced Petrophysical Methods

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Assessment of netpay cutoffs in carbonates is more challenging than in clastics due to inherent heterogeneity of pore architecture and permeability. Historically, the success rate of flowing perforations is low, and operators tend to “over-perforate” to capture all potential flowing zones. Asset teams must assign net thicknesses for the purpose of modeling and resources assessment. Simple porosity cutoffs, which might be adequate for sandstones often fail in complex carbonates. This study was overtaken to assess definition of cutoffs in carbonates and leverages applications of NMR logging, capillary pressure and in-situ flow measurements.

First, we looked at the cutoffs defining hydrocarbon charge into the pore system. Proper determination of this cutoff can help better estimate HCIP. To address this question, we have developed NMR T_2 shape and 2D shape analyses to define the minimum porosity and/or permeability with detectable hydrocarbon signal. The T_2 shape analysis were performed for several carbonate fields around the world, yielding porosity cutoff for hydrocarbon charge varying between 1.5 to 5%, depending on reservoir type. Second, extensive MICP data from these carbonate fields were used to predict an entry pore-throat radius corresponding to potential hydrocarbon charge. The predicted entry pore-throat log combined with the pore-throat size corresponding to capillary pressure at specific HAFWL allowed to define zones which were never penetrated by hydrocarbon charge due insufficient capillary pressure. Definition of those zones collaborated very well with results from the NMR T_2 Shape analysis, extending our ability to define “gross hydrocarbon” for fields without NMR data.

The same MICP data were also used to define a pore-throat size best correlated with permeability. Pore-throat radius predictions were performed for limestones, dolomites and general carbonates, which are more robust than conventional Winland/Pittman equations.

The next cutoff investigated was the minimum value of permeability that correlated with observed flow of in-situ fluids, i.e., production logs, derivative of temperature, and wireline pressure tests. This cutoff would correspond to the conventional “net reservoir” definition. The use of permeability mitigates the need for porosity cutoffs, which usually varies by rock types. We have predicted permeability from logs using the K-nearest-neighbor method, which reconstructs well the core-permeability distribution. The study performed in the different carbonate reservoirs yielded permeability cutoffs varying between 0.01 and 1 mD.

This approach allowed us to define a set of recommendations for definitions of net reservoir and net pay, and to provide a practical methodology to assess hydrocarbon potential. The methods presented here can be applied to any conventional reservoirs.

Downhole Fluid Analysis Combined With Gas Chromatography: A Powerful Combination for Reservoir Evaluation

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Downhole fluid analysis (DFA) provides vertical and lateral fluid gradients in reservoirs especially for solution gas, liquids, and dissolved solids (the asphaltenes). These data can then be used for thermodynamic analysis using the cubic equation-of-state for gas-liquid analysis and the Flory-Huggins Zuo equation-of-state (FHZ EoS) for solution-asphaltene analysis. Thermodynamically equilibrated reservoir fluids, in which the gradients measured by DFA match those calculated by the equations of state, imply reservoir connectivity. Disequilibrium can imply recent reservoir fluid geodynamics (RFG), which are known to impact major production concerns. Detailed compositional analysis of the reservoir fluids using conventional gas chromatography (GC) and two-dimensional gas chromatography (GCxGC) can be used to check the validity of the thermodynamic analyses. In addition, GC methods can be used for classic geochemical analyses, which themselves can address validity of thermodynamics applied to the reservoir. Seven reservoirs are examined here with DFA, GC, and GCxGC, exploring many different reservoir concerns. Connectivity and its inverse, compartmentalization, are recurring concerns and are effectively addressed. Viscosity profiles throughout reservoirs are accounted for using simple models with input from petroleum system modeling providing identification of key geologic processes controlling viscosity. GCxGC is shown to support simple thermodynamic modeling enabling connectivity analysis, which is then validated in production. Biodegradation is shown to yield two endmember viscosity profiles, no in-reservoir gradients versus large in-reservoir gradients, and the governing RFG processes are clearly identified. Water washing has a secondary effect on oil quality and factors that control the extent of water washing are shown. A universal protocol is presented for reservoir evaluation of all seven reservoirs that elucidates key reservoir concerns in a very efficient manner. This protocol is generally applicable for reservoirs in all stages of exploration, appraisal, and development.

Dynamic Petrophysical Properties of Laminated Rocks: An Experimental Investigation

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Laminae included in rock samples are considered small-scale heterogeneities that introduce anisotropy to the larger-scale rock system. They can be described in terms of grain-size variation as in a clastic sediment that is interbedded with shale layers. Such variations in grain size translate into variations in pore and pore-throat size distributions and control the effective permeability of the rock. Ultimately, they impact hydrocarbon recovery. In this paper, we implement an experimental workflow to study and quantify the impact of laminations on dynamic petrophysical properties in the presence of two distinct types of layering: cross and parallel layering. Accordingly, properties are measured under two flow conditions: across (perpendicular flow) and along layers (parallel flow).

We fabricated two cylindrical composite rock samples in which the first sample was interbedded with a lower permeability rock (Berea sandstone interbedded with Kentucky sandstone), while the second was interbedded with a higher permeability rock (Kentucky sandstone interbedded with Berea sandstone) to represent the layering cases defined above. Multiple laboratory experiments were carried out to measure mercury intrusion capillary pressure (MICP) and saturation-dependent relative permeability. These measurements were complemented with microcomputed tomography images and nuclear magnetic resonance (NMR) measurements. In the case of perpendicular-flow experiments, we sealed the subsamples into a cylindrical sample in order to allow mercury to flow across them. The seal surrounds the samples and forces mercury to intrude only through the two ends (faces) of the composite samples. In the case of parallel-flow experiments, we sealed each piece individually first and then sealed the entire stack. This is done to ensure that flow pathways in between the pieces are sealed. We observed a bimodal pore-size distribution for Berea interbedded with Kentucky sample, but a unimodal pore-size distribution for Kentucky interbedded with Berea sample from MICP data in the case of cross layering. On the other hand, in the case of parallel layering, we observed a bimodal pore-size distribution for the two rock arrangements. Capillary pressure was higher by approximately 80% in the cases of perpendicular flow compared to parallel flow. Conversely, relative permeability was higher by approximately 40% in the cases of parallel flow compared to perpendicular flow. Furthermore, capillary pressure and relative permeability hysteresis became more pronounced in the cases of perpendicular flow.

Grain laminations are naturally pervasive in sandstone reservoirs and play a critical role in capillarity and fluid flow of two immiscible fluid phases. In core data analysis, samples are taken from intervals considered representative of one single rock type. When data are quality checked, petrophysical measurements from samples that exhibit grain laminations are often excluded. This bias propagates to simulation work and leads to results that do not match field data. Our work provides valuable data for reservoir modeling of laminated rock systems and helps to understand the effects of laminations on hydrocarbon production in sandstone reservoirs.

Estimating In-Situ Relative Permeability and Capillary Pressure From Multiphysics Wireline Measurements

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Relative permeability and capillary pressure parameters play a vital role in reservoir modeling where multiphase fluid flows are commonly encountered. However, efficiently obtaining representative relative permeability and capillary pressure parameters remains a longstanding challenge for the oil industry. To date, special core analysis in the laboratory (SCAL) is still the most applied method for determining this information. The limitations of this technique are obvious. The length scale of the cores is usually much smaller than the scale required for reservoir modeling, which, consequently, leads to challenges with upscaling. In addition, the process is costly and time-consuming, with experiments often requiring months or years to complete. Another critical issue is that the cores are often contaminated and altered, not representing the reservoir conditions. All these factors make the relative permeability and capillary pressure measurements unreliable for reservoir performance prediction. Therefore, fine-tuning those parameters to history match the production data is necessary before using them for forecasting.

We propose and develop a comprehensive workflow, in presence of water-based-mud drilling fluids, to estimate in-situ relative permeability and capillary pressure curves by integrating multiphysics wireline measurements, including array resistivity, dielectric, nuclear magnetic resonance (NMR), and formation testing and sampling. Array resistivity logs are widely used for estimating the radial invasion profile and formation connate water saturation. However, they are not sensitive to the residual oil saturation because these measurements are relatively deep, whereas the movable oil is not completely displaced by mud-filtrate invasion. Dielectric logs have shallow depths of investigation and hence are ideal for estimating residual oil saturation. In addition, they can be used to determine Archie's parameters *m* and *n*. NMR data can be used to estimate irreducible water saturation and from the T_2 distribution, we can estimate a pore-size distribution index, which can help constrain the solution when inverting for relative permeability and capillary pressure curves. NMR data can also be input to computation of a continuous permeability log that can be calibrated to permeability from cores or formation tests. Based on the derived pore-size distribution index, we can further narrow the physical bounds for Corey's exponents in the relative permeability model, i.e., the curvatures of relative permeability curves for the water phase and oil phase. By integrating multiphysics wireline measurements, a reliable workflow is developed for determination of relative permeability and capillary pressure parameters with less uncertainty. The representative scale of these estimated parameters can be inches to feet, depending on the filtrate invasion depth. The time needed for data processing is negligible compared with laboratory core analysis experiments. Importantly, the relative permeability and capillary pressure parameters are estimated from downhole measurements, hence at in-situ reservoir conditions. This means further calibration or corrections for reservoir-modeling applications are not required.

This workflow demonstrates an efficient method to obtain in-situ relative permeability and capillary pressure data, which can help fill the gap in reservoir modeling and simulation. The method has been successfully applied to different reservoir formations including shaly sands, carbonates, and unconsolidated siliciclastic reservoirs with heavy oil.

Estimation of S_W From NMR T_2 Logging

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We used conventional logging while drilling (LWD) nuclear magnetic resonance (NMR) transverse relaxation time (T_2) data to estimate virgin zone water saturation (S_w) in environments challenging to conventional resistivity based evaluation, such as fresh water, high shale content, varying or unknown water salinity, and uncertain Archie parameters (*a*, *m*, *n*). It is important to stress the use of while drilling data to minimize the effect of invasion, although the latter can be corrected.

The technique relies on the T_2 log-mean equation written for a binary fluid system of water and hydrocarbon: $T_{2lm} = (T_{2lmw}\text{^}S_w) \times (T_{2lmhc}\text{^}(1-S_w))$. It is trivial to expand the equation to accommodate more fluids, such as filtrate or bound water. The water endpoint, T_{2lmw}, is obtained from the fluids-substituted 100% water endpoint corrected for partial saturation. The hydrocarbon endpoint, T_{2lmhc}, if unknown, can be estimated from the difference between the original T_2 distribution and the 100% water T_2 distribution after fluids substitution.

The salient point is that computing S_w from the T_{2lm} equation is always possible unless the fluids endpoints are identical, in contrast to computing saturations from the fluids volumes obtained by partitioning the T_2 distribution. For example, we have found that S_w can be estimated reliably even when T_{2lmw} and T_{2lmhc} are in the same decade of T_2 relaxation time, while their respective T_2 distributions are inseparable due to severe overlapping. Moreover, the technique is visual and straightforward to QC, i.e., S_w is the weighted distance of the log data point with respect to the water endpoint and the hydrocarbon endpoint in the logarithmic space.

The first example is laboratory data of a sandstone, first saturated with water, then desaturated with kerosene at fixed saturation steps. The controlled measurements allow the explanation of the algorithms used in the S_w from NMR T_2 workflow.

Several field examples demonstrate the cases of (a) water relaxing faster than hydrocarbon ($T_{2lmw} < T_{2lmhc}$) such as conventional reservoirs with light oil, (b) water relaxing slower than hydrocarbon ($T_{2lmw} > T_{2lmhc}$) such as unconventional reservoirs or heavy oil reservoirs, (c) varying hydrocarbons such as reservoirs with a gas cap above different oils with various API gravity, and (d) varying water salinity, such as waterflooded reservoirs in mature fields. In the examples, we compare S_w determined from NMR T_2 with S_w determined from deep resistivity, pulsed neutron capture sigma (that is independent of *a*, *m*, *n*) and joint-inversion of resistivity-sigma (that is used in the case of unknown water salinity) to show the viability of the new technique when conventional approaches fail to deliver reliable answers.

Exporting Petrophysical Properties of Sandstones From Thin-Section Image Analysis

Dutt Tripathi, Lori Hathon and Michael Myers, University of Houston

Estimation of the petrophysical properties of subsurface samples using imaging techniques and image analysis has received a lot of attention in recent years. Most of this has been focused on 3D imaging and subsequent modeling of formation properties, termed Digital Rock Physics, or DRP. This work typically requires that an intact sample of material is available. For cases in which sample type or quality are not sufficient for 3D imaging, or where cost is prohibitive, modeling of petrophysical properties using standard thin section images and image analysis is a viable alternative. We apply a Carmen-Kozeny type model to thin-section images of samples for which laboratory measurements of porosity and brine permeability were made. The input parameters measured in thin section include the total porosity, a measure of the tortuosity, and an estimate of the specific surface area. This has allowed us to model absolute permeability to within a factor of two for samples with laboratory-measured permeability ranging from 3 mD to 3 D. A key input parameter to this model is the estimate of specific surface area. The 2D estimate of specific surface area is the ratio of the intergranular-porosity perimeter to the total area analyzed. In practice, as image magnification changes, and as downsampling or filtering of the image are applied during analysis, the measure of specific surface area also changes. We illustrate the application of a fractal analysis for sandstones in thin section, which allows the impact of magnification and processing to be accounted for when modeling permeability from 2D image data. In addition to the 2D image analysis, we apply the lattice Boltzman model to high-resolution micro-CT scans of the same samples. The 3D images of the samples are analyzed with various commercially available software packages and the results of image filtering, segmentation, and permeability modeling using each of those products are compared. In general, the 2D model performs as well as, or better than, the 3D model for estimating absolute permeability. In addition, we compare pore-size distributions measured in 2D to the 3D pore size from micro-CT, and to inverted NMR T_2 data. Finally, total porosity from 2D image segmentation agrees to within ±2% of laboratory-measured porosity, over a range of porosities from 15 to 35%. The advantages of thin-section imaging for estimating petrophysical properties, include the ability to (1) identify framework grain types for provenance and reservoir quality modeling studies, and (2) differentiate between detrital and authigenic phases (e.g., detrital quartz framework grains versus quartz overgrowths), and to establish paragenesis.

Extracting Rock Cation Exchange Capacity From Electromagnetic Measurements

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Shaly formation cation exchange capacity (CEC) is an important parameter in formation evaluation, and in reservoir and production engineering since it is directly related to the type of clays. Currently, CEC is measured in the laboratory, which requires clay preserved core samples. Thus, CEC data may not be readily available when needed. On the other hand, it would be desirable if CEC could be obtained downhole immediately after drilling, especially from the most commonly run formation evaluation logs, which the main objective of this paper.

Induced polarization phenomena are widely observed from electromagnetic (EM) surveys conducted on porous media containing clays, such as shaly sands. Complex conductivity, with in-phase and quadrature components, was introduced to properly describe the induced polarization conductive phenomena of shaly porous media under external EM fields. The in-phase and quadrature conductivity components can be computed from the R- and X-signals of array induction measurements (AIM); one of the most commonly run logs for every vertical well drilled. It is observed that the in-phase and quadrature components of complex conductivity have a well-defined relationship with petrophysical properties of CEC and water saturation. Consequently, CEC may be extracted from downhole measurements of AIM R- and X-signals.

In this paper, a detailed workflow of using R- and X-components of AIM logs to extract formation CEC downhole has been established. Field logs were used to test the workflow. The calculated CEC values were checked, first, against published data from two sources. Then they were compared with calculated CEC from formation elemental spectral mineralogy logs. Good agreements were observed for both comparisons. Considering that EM logs are widely available for all existing oil fields; the established workflow provides a practical application of using EM logs to extract CEC downhole. Comparing to laboratory CEC data, downhole CEC are abundant and more representative to the target formation, enhanced formation evaluation is achievable.

High-Resolution Hyperspectral Imaging Technology: Subsurface Characterization Through Multidiscipline Integration

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Hyperspectral core imaging (HCI) technology was used to enhance characterization of a thin-bedded reservoir in the Permian Basin. Originally developed for the mining industry, HCI uses a combination of short-wave infrared light (SWIR) and long-wave infrared light (LWIR) to create a visual ‘map’ of the minerals in a core that respond to reflectance principles. HCI, which requires no special preparation other than that the core be clean and dry, can be applied rapidly and provides mineralogical results related to various energy emitted in wavelength spectrum by either halogen-bulb reflectance (short-wave quantification) or heat reflectance spectra (long- wavelength quantification).

HCI provided detailed, high-resolution mineralogical and textural information of a conventional whole-cored interval and was used to produce interpreted mineral maps to refine stratigraphic models, explain petrophysical responses, and guide selection of plug locations for conventional and special core analysis. Digital HCI-derived single mineral curves calibrated to X-ray diffraction data (XRD) were imported as curves to display mineralogical variations with depth alongside openhole wireline logs.

HCI was successfully applied and used as an integrative tool across additional data streams, associating openhole wireline properties, overlays of textural relationships of mineralogical assemblages, and rock typing models with colocation of petrophysical properties to obtain better understandings of mineralogical-to-petrophysical links. We illustrate how hyperspectral imaging can be a powerful aid in geological and petrophysical quantification and property ‘upscaling’ from SEM- and thin-section scales to depositional-system-level understandings.

Improved Interpretation of Electrical Resistivity Measurements in Mixed-Wet Rocks: An Experimental Core-Scale Application and Model Verification

Chelsea Newgord, Artur Posenato Garcia, Ameneh Rostami and Zoya Heidari, The University of Texas at Austin

Interpretation of electrical resistivity measurements for assessing hydrocarbon saturation in mixed-wet and hydrocarbon-wet rocks often requires extensive recalibrations of resistivity models, since wettability impact is not reliably incorporated in conventional resistivity models. Recently, we analytically derived a new resistivity model through pore-scale analysis that incorporates parameters to account for wettability and pore complexity. This new model requires experimental verification to enhance its applicability in core- and log-scale domains. The objectives of this paper are (1) to experimentally quantify the influence of wettability on electrical resistivity measurements, (2) to validate the new resistivity model that incorporates the wettability index for mixed-wet rocks as input, and (3) to demonstrate that the actual wettability and geometry of the pore structure, obtained from core samples and pore-scale images, can quantitatively define the input parameters to the new resistivity model. By incorporating both the wettability and pore-structure parameters into the new resistivity-saturation model, we ensure that the coefficients connecting resistivity to water saturation are physically meaningful to minimize excessive calibration efforts.

We first selected core samples covering a wide range of complexity in pore structure. We altered the wettability by injecting a solution with different concentrations of surfactant into the cores using a coreflood setup. We controlled the surfactant concentration to prepare the samples as water-wet, mixed-wet, and oil-wet. To measure the actual wettability of the samples, we used a combination of the USBM and Amott-Harvey methods. Then, we used a coreflood setup to vary the water saturation. After injecting water, we verified the pore volume occupied by water through nuclear magnetic resonance measurements. We then measured the electrical conductivity of each sample. The geometry of the pore structure was quantified by analyzing three-dimensional pore-scale images obtained from microcomputed tomography as well as MICP measurements. Finally, we used the introduced resistivity-based method for assessment of water saturation and compare the estimates of water saturation from the new model with the actual water saturation of core samples.

We successfully verified the reliability of the new resistivity model for mixed-wet sandstone and carbonate core samples. The surfactant injection altered the wettability in the range of -0.39 to 1.0 on the Amott Index scale. We showed that the Amott Index is directly related to the wettability parameter, used as an input to the new resistivity model. The results also demonstrated that wettability is quantifiable by resistivity measurements, if combined with other measurements. Moreover, we verified that the input geometry-related parameters to the new resistivity model can be estimated, within 25% of relative error, directly from the actual geometry of the pore structure, quantified at the pore-scale domain. Consequently, all the coefficients required by the new resistivity model were proven to be physically meaningful, and the water saturation estimates were improved by more than 10% in comparison to estimates obtained from Archie's model. The outcomes of this paper are promising for reliable interpretation of resistivity logs in mixed-wet formations with complex pore structure for improved assessment of hydrocarbon saturation with minimal calibration efforts.

Integrated Interpretation of Multifrequency Dielectric-Dispersion Measurements in Mixed-Wet Rocks

Artur Posenato Garcia and Zoya Heidari, The University of Texas at Austin

The interaction between the solid and fluid phases, characterized by the wettability of the formation, strongly affects the fluid distribution in the pore-space and consequently the conductivity and the polarization mechanisms of the rock. Resistivity models that incorporate rock wettability for improved assessment of hydrocarbon reserves have been recently developed. However, wettability and pore structure in such models still have to be determined from core measurements and imaging methods. Dielectric-dispersion measurements can simultaneously provide information about different polarization mechanisms at different frequencies, which are affected by porosity, grain-size distribution, and wettability. Thus, a multifrequency interpretation of dielectric measurements can provide information about volume of fluids as well as solid-fluid interfacial properties such as wettability and cation exchange capacity. In this paper, we introduce a new mechanistic model to enhance petrophysical interpretation of mixed-wet formations by integrating multifrequency dielectric measurements.

The objectives of this paper include (a) to quantify the influence of wettability on broadband dielectric dispersion mechanisms, (b) to incorporate wettability and interfacial polarization at fluid-fluid and solid-fluid interfaces in an integrated broadband workflow for dielectric measurements, and (c) to simultaneously estimate porosity, grain-size distribution, water saturation, and wettability of the formation by applying the introduced workflow. All the parameters required by the introduced workflow are associated to physical mechanisms at microscopic- and pore-scale or geometrical features of the rock.

The induced polarization at the electrolyte-solid interface is characterized by a mechanistic model of Stern and Gouy-Chapman layers honoring the electrochemical interactions occurring at the surface of grains and clays. We also introduce a model to characterize the electrolyte-hydrocarbon interface, which originates from the adsorption of hydroxyl ions. We integrate the aforementioned solid-fluid interfacial mechanisms with the bulk properties of fluids and grains through the sequential application of a differential self-consistent effective medium model, making explicit the dependence on wettability. The petrophysical properties of the rock are estimated by minimizing an objective function using a downhill simplex method. The objective function is defined by the Euclidean norm of the difference between the complex dielectric permittivity measured and the one estimated with the proposed model for the frequency interval encompassing the response of the dominant polarization mechanisms.

We successfully applied the introduced inversion algorithm to sandstone core samples and sintered glass filters with different mesh sizes at different wettability conditions obtained by a silanization process. The complex dielectric permittivity measured from 100 Hz to 3 GHz in the laboratory was in agreement with the complex dielectric permittivity obtained from the proposed analytical workflow. The measurements confirmed that the wettability has a detectable influence on relaxation time and loss tangent. Moreover, the detected alteration of dielectric dispersion was correlated to wettability of the samples obtained from conventional methods of quantifying wettability, including Amott and USBM. Finally, wettability, saturation, and porosity of the samples were simultaneously estimated with relative errors inferior to 25% by applying the introduced inversion algorithm. The outcomes of this paper can significantly enhance petrophysical interpretation of mixed-wet rocks by integrated interpretation of multifrequency dielectric dispersion measurements.

Interpreting the Whole Well

Christopher Skelt, Chevron Energy Technology Company

Petrophysical analysis of conventional clastic reservoirs typically focuses on reservoir intervals with scant attention being paid to most of the footage that is written off as so-called shale. While prioritizing potential reservoir intervals is understandable, thoughtful consideration of nonreservoir is worthwhile. This paper discusses the value of detailed analysis of shale intervals and introduces a practical scheme for delivering a frame-by-frame petrophysical analysis from top-to-bottom of the wells that recognizes that formation properties of interest to the subsurface community are different in sands and shales and that each lithology consequently has its own evaluation priorities.

The underlying principle, that the petrophysical model should address what we need to know about the subsurface, is illustrated by reference to a six-well deepwater turbidite dataset from offshore West Africa. Three main lithology types are present, sand, shale and carbonate, each of which merited its suite of petrophysical models, spliced together using lithology-driven model selection logic.

Most of the footage was shale with significant bulk, mineral and textural property variation about the regional depth-based property compaction trends. Analysis showed that shale at the hard end of the property range was associated with the sands. The range in bulk properties correlated with systematic variations in clay mineralogy, elemental chemistry and resistivity anisotropy. Results supported stratigraphic interpretation, and illustrated the potential for vertical property variations to cause seismic reflections that could be misinterpreted as sand-shale boundaries. About 20% of the footage was massive feldspathic sand and intervals of alternating sand and shale beds unresolved by the logs. We quantified net reservoir footage and the petrophysical properties of the sand fraction, porosity, permeability and fluid saturation, using a generalized variant of the Thomas-Stieber laminated petrophysical model that additionally estimated the significant K-feldspar fraction. Laminated shale in the sands was considered synonymous with the hard end of the property range in the shale intervals, providing continuity between the sand and shale-focused models after model selection.

The carbonate beds were thin, and their chemistry ill-defined, so our goal was simply to identify them from their density departure from the regional hard shale compaction trend.

Logging suites varied in comprehensiveness from LWD quad-combo to wireline quad-combo with NMR, spectral gamma and triaxial induction logs, and data quality varied from poor to good, so relations observed in data-rich intervals were transformed to external inputs guiding the analysis of data-poor intervals. In washed-out sandy intervals where only the gamma ray and resistivity logs were dependable, replacing inadequate quality logs with locally derived data-driven relations enabled us to deliver continuous volume fractions of sand, K-feldspar, the three shale textures and a fluid analysis.

The single spliced result simplified data management while addressing the needs of a diverse stakeholder community. The work presented here was executed using commercial software tools on the desktop of most petrophysicists. While space restricts us to one case study, the principles are transferable and have been demonstrated in other clastic depositional environments.

Lifting the Fog of Confusion Surrounding Total and Effective Porosity in Petrophysics

Paul Spooner, Lloyds Register

The Aberdeen Formation Evaluation Society 2016 AGM was followed by a lively ‘Porosity Debate’, which was started by recognizing that there are many definitions of effective porosity in the industry, e.g., there are six definitions on Wikipedia. An appreciation of these different definitions is fundamental to petrophysics because volumetric results might have been generated using one specific definition while the enduser of those results, maybe a geomodeler or reservoir engineer, might assume it was something else. Obviously, this can lead to considerable confusion and significant uncertainty in the STOIIP.

The ‘Porosity Debate’ was planned to be a discussion of the merits of the various definitions, but it very quickly moved on from definitions to methodology in a deterministic workflow. Should you first compute total porosity and from that effective porosity, or vice-versa? Various arguments were put forward to support both positions and a lively debate ensued. However, it is not really a case of which to solve first, but rather ensuring ‘consistency’. A ‘consistent’ methodology is one that honors a valid rock model, the rock model sums to one, yields both total and effective porosity, the results are the same whichever is solved first, and where possible agrees with core data. This paper reviews several rock models and deterministic porosity methodologies common in the industry, and demonstrates the inconsistencies inherent in many of them.

It would be reasonable to expect consistent definitions of total porosity and effective porosity across all petrophysical workflows, for example that the definition of effective porosity in both deterministic and nondeterministic workflows is the same. However, this is often not the case for several reasons: deterministic methods are often V_{shale} workflows while nondeterministic methods are often V_{clay} workflows; the user may not be clear which definition was used in their interpretation; some software products use different definitions of effective porosity between methodologies.

One methodology is detailed that is volumetrically consistent regarding total and effective porosity, and that can be implemented in terms of V_{clay} or V_{shale}. This methodology is not new or novel in any way, it has been in use within the industry in one form or another for several decades, but it is often misunderstood and the significance of its consistent approach often under- appreciated.

Porosity and water saturation can be solved iteratively to yield a consistent result. After all, that is what Gus Archie originally proposed: that the calculation of water saturation depends on the porosity, and that the calculation of porosity depends on the water saturation. Without iteration you must assume the flushed zone water saturation to calculate porosity, and if that assumption is in error then the porosity, and hence hydrocarbon pore volume, are wrong. With a ‘consistent’ methodology porosity and water saturation can be provided in both total and effective systems, there is no need for it to be either-or, both are valid.

This paper seeks to lift the fog of confusion.

Monte Carlo Processing of Petrophysical Uncertainty

Rick Aldred, Consultant

Monte Carlo processing is used to assess the impact of uncertainties in many different fields of measurement and analysis. In complex petrophysical interpretations, both in chains of deterministic analyses and in optimized modeling solutions, there are a number of different ways that this technique can be applied. Furthermore, the different methods give starkly different results from the same input values and uncertainties.

The concepts behind Monte Carlo processing in petrophysical interpretations are reviewed and the impacts of the results on hydrocarbon-in-place estimates are discussed. The different ways in which Monte Carlo processing is applied in petrophysics is then examined in detail, especially regarding the treatment of parameter dependencies.

Results are presented where the different techniques have been used on a single case study. Input parameters and uncertainties were kept constant across these processes, but the results were found to vary simply due to the way in which the process was applied.

Petrophysical evaluations involve random and systematic uncertainties on measurements and parameters, along with uncertainties based on the selection of which interpretation model should be used. With most uncertainty applications it is difficult to quantify model-based uncertainty. However, a process is described whereby Monte Carlo uncertainty results from different models can be combined to give a full petrophysical uncertainty assessment along with valid statistical results and probabilities.

Sensitivity analysis in Monte Carlo processing allows the interpreter to assess the relative impact of each input uncertainty. This can lead to an assessment of the value of the information that is required to eliminate the larger uncertainties.

Recommendations are made regarding the most appropriate methods to use and why. It will be noted that the best techniques generally deliver the smallest final uncertainty range with a corresponding increase in evaluated hydrocarbon-in-place for the reported pessimistic case.

Non-Darcy and Multiphase Flow in Tight Carbonate Rocks

Peyman Mohammadmoradi and Apostolos Kantzas, University of Calgary

Diagenetic phenomena notably complicate the solid matrix and pore space structures making it a challenging petrophysical task to generalize flow and transport properties of tight carbonates. On the basis of the evidence currently available, the conventional relationships cannot adequately reflect the multiscale heterogeneity of carbonate reservoirs. Digital rock physics modeling techniques, together with microtomography imaging tools, provide a promising opportunity to extract the role of small-scale features in fluid flow behavior of complex geological formations. Here, a comprehensive pore-level study is conducted to explore the effect of ultralow porosity and heterogeneous pore space on the multiphase fluid flow properties of a tight carbonate reservoir. The discussion not only centers on the impact of microheterogeneities on the multiphase flow and transport, it also elucidates the influence of non-Darcy flow on the hydrocarbon production performance. The overall size of the digital rock under consideration is 21 mm and the imaging resolution is 35 μm/pixel. The fluid flow is simulated applying a combined approach of pore morphological method and computational fluid dynamics (CFD), and then the relative permeability and capillary pressure curves, resistivity index, apparent permeability, and residuals are predicted. The insights drawn from the experimental measurements are supplemented with those from pore-level simulations, and the results suggest that the non-Darcy flow and fracture lining minerals can remarkably diminish the formation production potential by altering the rock petrophysical properties.

Novel Estimation of Reservoir Fluid Composition Using Nuclear Measurements

Vitor Villar de Andrade e Silva and John C. Rasmus, Schlumberger

Determining in-situ hydrocarbon composition from log measurements is accomplished today by first assuming that a hydrocarbon type is present (gas, oil), assigning log parameters to them and, finally, using a minimization technique to solve for their volumes. The problem with this technique is that the various log properties assigned are not rigorously constrained to be consistent with respect to the composition of the hydrocarbon or the downhole pressure and temperature. A database of log parameters for various hydrocarbon fluid types at downhole pressures and temperatures is needed.

This problem is solved by studying a database of 500 reservoir samples from around the world having compositional data and flash analysis available. A flash calculation package was used to compute the density at downhole conditions for these fluid mixtures and the results were compared and analyzed statistically against the measured mixture compositions provided by the laboratory. The gas chromatography analysis of these samples was mined, the samples clustered according to their compositional distribution and averaged around their centroids. These clusters were then classified into distinct hydrocarbon fluid types (methane, gas, wet gas, condensate, light oil, black oil, heavy oil, asphaltenes-rich oil). The performance of six different equations of state (EOS) was compared and the three-parameter Peng- Robinson EOS with Peneloux's correction yielded the best results.

For each fluid type, the EOS-predicted downhole mixture density at the formation pressure and temperature is then used in a nuclear forward modeling program that converts the mixture composition and mixture density to nuclear parameters such as electron density (ρe), hydrogen index (HI), and thermal-neutron capture cross section (∑).

The result is a program that can be used to determine the nuclear log properties, while assuring the properties' consistency to each other for any given fluid type, reservoir pressure and temperature.

A novel technique was then devised to take the reservoir hydrocarbon fluid nuclear properties and use them together in an n-dimensional space to predict the hydrocarbon composition.

This first requires a multiphysics inversion technique to invert for the downhole reservoir fluid density, HI, and sigma using wireline or LWD measurements.

The model then estimates the mass fractions of each hydrocarbon component of the reservoir fluid mixture by calculating the spatial distance between the reservoir fluid nuclear properties and the fluid types EOS-derived properties. The proposed algorithm produces a continuous "composition log" for the entire interval of interest.

The use of EOSs to predict fluid densities and properties is the enabler that allows computing the type of hydrocarbons and their volumes with this multiphysics inversion.

Petrophysical Rock Typing Based on Pore Geometry Improves Permeability and S_{wirr} Estimation in Heterogeneous Sandstone Formations

Ting Li and Chanh Cao Minh, Schlumberger

In complex reservoirs, variations in pore geometrical attributes define distinct hydraulic units, which must be accounted for in a permeability prediction model. In this paper, we study an offshore siliciclastic brownfield where the reservoirs are highly heterogeneous with matrix permeability ranging from 0.1 mD to 1 D. LWD Triple-combo and NMR T_2 relaxation data were acquired while drilling. Core samples were taken in the target sands and conventional core analysis was performed. We characterize the pore-geometry variations by classifying core samples into a number of petrophysical rock types (flow units) using a novel scheme.

The novel classification is done by applying carefully designed cutoffs to the pore-throat radii (PTR) of the core samples and is propagated to the entire well with a machine learning algorithm. For each rock type, the variables in the Timur-Coates permeability equation are calibrated with core measurements and a continuous permeability is computed using the calibrated parameters. The workflow consists of the following detailed steps. (1) Compute pore-throat radius from core porosity and permeability using established equations. Classify the samples by defining a set of pore throat radius cutoffs based on statistical analysis, modified Lorenz plot and poroperm crossplot. (2) For each rock type, calibrate the T_2 cutoff value (and/or the multiplier) in the Timur-Coates equation by minimizing the difference between measured and predicted permeabilities. (3) With supervised machine learning, learn rock type classification from cored intervals and propagate the classification to uncored intervals using selected log curves. (4) Compute a continuous Timur-Coates permeability for the entire well using the calibrated parameters pertinent to each petrophysical rock type.

The PTR workflow significantly improves the match between core and predicted permeability, as demonstrated in a number of development wells. By comparison, a conventional permeability model is unable to capture the permeability variations seen in the core data. An additional deliverable is a calibrated T_2 cutoff curve that varies with the flow units. The variable T_2 cutoffs can then be applied to the study well or an offset well containing the same rock types to improve the accuracy of irreducible water saturation (S_{wirr}) estimates from NMR bound fluid volume.

Petrophysical Uncertainty Analysis Using Spatial Bootstrapping

Robert K. Mallan, Julian Thorne, Philip Rice, Emmanuel Toumelin and Jean-Baptiste Clavaud, Chevron; Bruce Bilodeau, Chevron (retired)

An unbiased assessment of volumetric uncertainty is critical for resource and reserve estimates and developing an effective uncertainty management plan in green fields. Key components of the volumetric uncertainty are the uncertainties of petrophysical properties like porosity and water saturation. Uncertainties in petrophysical interpretation are usually not accounted for, or at best derived using Monte-Carlo simulation. However, Monte-Carlo methods rely on model parameter distributions (e.g., matrix and fluid endpoint properties) that are subjective estimates typically poorly constrained, and therefore produce predisposed uncertainties of predicted logs. Furthermore, uncertainties in these parameters are often derived independently of each other, meaning that dependencies are usually missed, which results in the overall overestimation of petrophysical uncertainty. The scheme presented here addresses uncertainty estimation through an approach tied to core data. This data-driven approach produces distributions of model parameters consistent with core data and that intrinsically respect parameter dependencies; it therefore generates more meaningful ranges of interpreted logs to feed geocellular models and asset development decisions.

Bootstrapping is a statistical subsampling scheme that allows uncertainty in the model to be assessed from the data themselves. For the method presented, the "data themselves" are the pertinent petrophysical properties from core samples, i.e., porosity, grain density and saturation. This method draws from available core data to produce a range of viable models honoring the core data. Each model is optimized to match its respective subset of core data, where the subsets are drawn from the total population of core data through a spatial bootstrap sampling scheme. These models are then propagated to all well data, wherefrom P10, P50, and P90 logs of these properties are derived.

This paper shows how we combine this bootstrap uncertainty scheme with a deterministic petrophysical analysis, and apply the resulting workflow to several fields. We show how this method produces more reliable and realistic uncertainty estimates of log-predicted petrophysical properties versus conventional methods. We also discuss different approaches to defining the uncertainty metric from the generated distribution of models, their physical meanings in terms of property uncertainty, and the subsequent impact on modeling reservoir uncertainty.

Petrophysics-Driven CO_2 EOR Scoping Study: A Field Case Demonstration

Anand Selveindran, Peila Chen, Ganesh Thakur, Sriram Balasubramaniam and Sushanta Bose, University Of Houston

CO_2 EOR scoping studies typically overlook the importance of a comprehensive geological and petrophysical description of the reservoir, focusing more on reservoir and fluid parameters, well pattern and surface facility design. This often leads to a suboptimal EOR project design or project failure.

The purpose of this study is to propose and validate a workflow that fully incorporates a geological and petrophysical understanding into a CO_2 EOR scoping framework. Key parameters investigated are the depositional setting, reservoir heterogeneity and structural features. The significance of the improved workflow was demonstrated in a CO_2 EOR scoping study for an onshore India oilfield. The improved CO_2 EOR scoping workflow integrates the disciplines of geology, petrophysics, reservoir engineering, economics and surface facility design. The work began with reservoir geological interpretation to evaluate properties of the hydrocarbon-bearing formations. The petrophysical analysis made use of openhole logs (GR-resistivity-neutron-density log suites) with routine core analysis data. Key reservoir parameters, such as porosity-permeability distributions and Dykstra-Parsons coefficient were incorporated into a static geological model. Concurrently, a comprehensive field production and pressure analysis was performed using reservoir engineering techniques, such as static and flowing material balance and voidage balance. Waterflood performance was assessed using analytical tools, such as ABC plots and capacitance- resistance-model (CRM). This multidisciplinary workflow provided the understanding of lateral and vertical sand continuity, flow barriers, compartmentalization (structural and sedimentary), flow property variation and remaining fluids in place. The impact of these properties on the CO_2-injection process was captured using both dimensionless analysis techniques and dynamic reservoir simulation.

Reservoir geological description, coupled with the dynamic production performance, indicated significant heterogeneities associated with a fluvial deltaic depositional environment. The key heterogeneity parameters, including Dykstra-Parsons coefficient and the geological connectivity factor, demonstrably affected waterflood performance. Areas with a high sand continuity factor showed excellent waterflood performance, with over 70% areal sweep efficiency based on the CRM model analysis. The areas with poorer geological connectivity factor resulted in a lower sweep

efficiency (<50%). The relationship between the Dykstra-Parsons coefficient and vertical sweep efficiency was clearly established by investigating fluid-saturation profiles from the history-matched simulation model. With an understanding of vertical and lateral sand continuity, porosity-permeability and reservoir thickness, an optimized well spacing and CO_2-injection parameters were designed. In an area with better sand continuity, a wider injector-producer spacing (60 to 80 acre) was designed. The area with a poorer sand continuity and higher reservoir heterogeneity required a much tighter spacing (~25-acre spacing). Integrating this information with a map of remaining oil saturation, allowed for the estimation of oil recovery and CO_2 volume required. CO_2-injection volumes were reduced by as much as 15% for areas with an excellent geological connectivity factor, without compromising oil recovery. An economic optimization study was then conducted.

This workflow has demonstrated the importance of a robust petrophysical evaluation to the success of an EOR scoping study. It improved the field economics by more than 10%, by reducing well count and screening off areas with poor potential for CO_2 EOR.

Pore Space and Organic Content Analysis From a Delaware Basin Well

Joel D. Walls and Tiffany Rider, Ingrain, a Halliburton Service; Brian Driskill and Melanie Durand, Shell Exploration and Production

A core analysis program was conducted on a Delaware Basin well in west Texas. The second Bone Spring and Wolfcamp formations were selected for a core-testing program. The main objective was to understand reservoir quality, including porosity, fluid saturation, mineralogy, pore size, and pore type. An additional objective was to compare scanning electron microscope- (SEM) based digital rock analysis (DRA) results to physical laboratory tests, such as GRI crushed rock porosity and total organic carbon (TOC).

Plug samples were obtained for X-ray diffraction (XRD) mineralogy, pyrolysis, TOC, DRA, and retort analysis. DRA included Fourier transform infrared (FTIR) mineralogy, argon-ion milling, SEM imaging, image processing, and segmentation. The pore size and volume fraction of organic porosity, inter- and intra-granular porosity, and solid organic matter were computed. Rock material from near each plug was used for Dean-Stark extraction (S_w, S_o) and helium porosity. Thus, the relationships between key rock properties, such as clay content vs. TOC, bulk volume water vs. clay content, and bulk volume oil vs. porosity associated with organic matter (PAOM), were determined.

In these samples, TOC was observed to be related to clay content, but not linearly. Rather, TOC increases with clay content up to approximately 30% by weight clay, then begins to decrease. Total clay, silica, and carbonate from XRD and FTIR were in good agreement, although XRD indicated slightly higher clay content than FTIR. As reported elsewhere, SEM-derived porosity is generally lower than helium porosity. In addition, the difference between the two is strongly related to total clay, suggesting that clay-bound water may be a key factor. This is supported by GRI and XRD data that show bulk volume water is directly correlated to total clay with a near-zero intercept. (1) Understanding that a sweet spot for TOC exists at approximately 30% clay content in these formations may help to target the best reservoir. (2) Although image resolution and damage to organic porosity from ion-milling are commonly provided explanations for why SEM porosity on ion-milled samples is routinely lower than helium porosity, this work suggests a different reason: capillary-bound water on clay mineral surfaces. This water is driven off in Dean-Stark and retort methods, thus counted as part of total porosity. However, the SEM images do not resolve this adsorbed layer of water on clay surfaces. (3) When clay-bound water volume is added to SEM porosity and plotted vs. GRI porosity, a linear fit with a slope of near 1 and a correlation coefficient r2 of approximately 0.8 is obtained.

Pore-Type Partitioning for Complex Carbonates: Effective Versus Total Porosity and Applications to Electrical Conductivity and Diffusivity

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The pore-scale characterization of complex carbonate rock is of considerable importance in the context of optimizing hydrocarbon recovery due to structural heterogeneity, resulting in complex spatial fluid distributions. Recent advances in micro-CT techniques allow imaging such pore systems at various scales. Here we present a workflow to determine effective and total porosity for different pore types and apply this knowledge to improve our understanding of electrical properties by integrating experiment and simulation in a consistent manner via integrated core analysis. The workflow is general and applicable to other petrophysical measures.

Defining as microporosity voxels in tomograms containing porosity below voxel resolution, a pore-typing technique is introduced separating microporous rims of oolithes from other types of microporosity using Indiana Limestone; about 50% of the pore space falls into the microporosity category for the chosen sample size of diameter (resolution) 1 in. (11 µm). High-resolution imaging is used to characterize these two different types of microporosity regions. Effective and total porosity fields are derived via differential imaging techniques.

Image registration of the high resolution (1 µm) tomogram with the low-resolution acquisitions shows the oolithes rims' different topology and geometry. While the rims exhibit well-connected porosity in the high-resolution image, they appear as a particular microporosity type at low resolution. Various corners are lost due to partial volume effects and imaging noise in the low-resolution data. The low-resolution pore typing allows us to derive microporosity specific total-to-effective porosity transforms. We used the latter regional transforms to establish regional Archie parameters. Experimentally measured formation factor and resistivity index as well as NMR diffusivity at partial saturation are compared with direct image-based calculations considering both the case of globally and regionally defined Archie parameters. In particular, we find reasonable agreement with the experiments for higher water saturations using global parameters. For low wetting-phase saturation pore typing should be included in image-based resistivity index calculations.

Reducing the Uncertainty of Porosity, Saturation and Completions Optimization With NMR Logging-While-Drilling

Sunday Adole, Boqin Sun and Keith Boyle, Chevron

In the current "capital constrained" operating environment, understanding the value of information, data-acquisition scope and time are critical contributory factors towards well cost reduction. Using nuclear magnetic resonance logging-while-drilling (NMR LWD) provides an opportunity to reduce rig time and logging cost but also acquires valuable information for field development optimization. In the subject reservoir, there is a requirement to accurately identify fluid type, irreducible water saturation (particularly in intervals of moderate to low reservoir quality), pressure testing and completion alternatives for optimal recovery in the target reservoir.

A workflow was developed to derive an optimal data-acquisition sequence and determine the best rate of penetration (ROP) for acquiring high-quality data. A processing module was developed within the interpretation software, to help determine optimum processing parameters, and interpretation scheme. With this workflow, clay-bound water and irreducible water saturation values were used to calibrate the shaly-sand interpretation and thus obtained a good match between NMR LWD porosity and density-neutron porosity in water zones. This calibration, however, did not reconcile the significant porosity difference (2 to 3 p.u.) between the density-neutron and NMR porosities in the hydrocarbon intervals. To resolve this mismatch, we identified the oil peak transverse relaxation time (T_2), which was very different from movable water peak. This was then used to perform hydrocarbon typing which in turn was used to improve the density-NMR interpretation to match the porosity difference observed in the hydrocarbon zones. This difference was due to the low hydrogen index of the oil as a result of the high gas/oil ratio (GOR). This allowed us to derive the oil saturation and equivalent gas saturation to match the GOR. These results clearly show the value of NMR LWD for reducing the uncertainty of petrophysical evaluations for this field.

Performing in-house post processing maximized the value of the NMR LWD. Integration of all available data acquired e.g. well logs, NMR LWD, LWD pressure profiling, production information, and reservoir simulation forecasts, gave reliable OOIP/reserves estimates and helped to refine the completion strategy for optimal oil recovery.

Resistivity Log Modeling and Inversion, Now a Reality for Improving Petrophysical Analysis, Assisting Real-Time Operation Decisions and Much More

Hanming Wang, Bo Gong and Emmanuel Toumelin, Chevron

Resistivity logs are present in most well logging suites to quantify hydrocarbon saturation, and to map near-wellbore formation geometry. The complexity of the tool response resulting from geological structure, reservoir thickness, well deviation, rock anisotropy, and the location and shape of fluid contacts, requires forward modeling and inversion of the electromagnetic-wave propagating through the formation in order to produce a correct interpretation. Resistivity modeling and inversion have been limited within research and computing centers for the past decades within operating companies. Thanks to advances in computer hardware and simulation algorithms and the dedicated effort of internal development and deployment, it's only recently that resistivity modeling and inversion capabilities have expanded from traditional petrophysics to real-time G&G operations decisions. The successful deployment of this capability brought significant upside to Chevron business, demonstrated by numerous worldwide examples.

In this paper, we highlight a selection of these case studies aiming to: (1) Interpret resistivity log response in a highly-dipping/folded formation; (2) improve petrophysical analysis in a thin reservoir; (3) improve petrophysical analysis in a high-resistivity-contrast reservoir; (4) improve petrophysical analysis in a high-angle, horizontal well; (5) assist geosteering decisions through prejob study, while-drilling modeling and post-job analysis; (6) improve LWD-to-wireline resistivity log quality to save rig time and costs; and (7) assist G&G for real-time operations decisions for completion, pore pressure prediction and sidetrack planning. Based on these examples, we will also discuss remaining challenges in resistivity logging measurements and interpretation.

Robust Vuggy Dolomite Pore Typing and Quantification With LWD T_1 and Wireline T_2 Intrinsic Logs

Songhua Chen, Wei Shao and Mahmoud Eid, Halliburton

The identification of vuggy dolomite pore size is very important for determining perforation depths for certain Middle East carbonate reservoirs; the dolomitization and vug sizes in these reservoirs vary from well-to-well and even from depth-to-depth in a well. Although dolomite can be easily identified by comparing NMR porosity and apparent density porosity computed with limestone matrix density, in-situ pore size is only detectable with nuclear magnetic resonance (NMR) logging. Although sensor configuration and design varies, substantial magnetic field gradient are common in the sensitive volume of all wireline NMR tools. Thus, the basic T_2 log yields apparent T_2 (denoted as $T_{2apparent}$) distribution, in which the longer T_2 components are reduced more significantly than the shorter T_2 components. The amount of shift of T_2 depends on the gradient and the intrinsic T_2 (denoted as $T_{2intrinsic}$) of the underlying pore fluid. As the result, vug porosity, which is associated with larger pores, is affected more by the tool gradient. This gradient-caused T_2 shift significantly complicates pore typing because the large pores in calcite limestone and vugs in dolomite have very similar apparent T_2 values.

Many logging-while-drilling (LWD) NMR tools are low-gradient tools which, in theory, reduce the difference between $T_{2intrinsic}$ and $T_{2apparent}$. In practice, drilling-induced lateral vibration partially spoils echo refocusing, causing the acceleration of the observed echo decay. The slower the relaxation-decay component, the greater the effect of the vibration-caused echo-refocusing spoilage because the failure of refocusing all spins accumulates as the number of echoes increase. Because long CPMG echo trains are required to obtain adequate T_2 spectral resolution for vuggy pores, the problem is significant. Consequently, the while-drilling T_2 log becomes an "apparent T_2" log, even though the tool gradient is very low.

This paper describes two solutions for distinguishing and quantifying vuggy dolomites with wireline and LWD NMR logging, respectively. For wireline NMR, an inversion-forward-modeling-inversion technique enables the computation of both $T_{2intrinsic}$ and $T_{2apparent}$ distributions for any tool gradient and any interecho time. For LWD NMR, the best solution is to acquire a T_1 log with a broadband saturation pulse followed by narrow-band excitation and refocusing pulses.

The paper presents several wireline and LWD NMR logging examples to demonstrate the robustness and effectiveness of these proposed solutions. The detailed data acquisition and processing methods are presented for obtaining both $T_{2intrinsic}$ and $T_{2apparent}$ in a single wireline logging run. The wireline-logged wells have varying fractions of dolomites from depth-to-depth and from well-to-well. With both $T_{2intrinsic}$ and $T_{2apparent}$, the dolomite vug pores can be nonambiguously quantified. One of these wells was logged with both LWD and wireline NMR tools, where LWD T_1 log and wireline $T_{2intrinsic}$ log show a consistent capability to distinguish vuggy dolomite and quantify the vug pore size and volume in zones where $T_{2apparent}$ shows same signature as the nearby calcite limestone depths.

The Impact of Pore Type on NMR T_2 and MICP in Bioclastic Carbonate Reservoirs

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Bioclastic deposits constitute important carbonate Presalt reservoirs, sustaining for decades a significant oil production from offshore Brazilian fields. Nuclear magnetic resonance (NMR) logs show highly homogeneous reservoirs, contrasting with formation tests and production logging data, which indicate heterogeneous productivity from these reservoirs. In order to understand the effects of pore types on the mercury intrusion capillary pressure (MICP), NMR and conventional petrophysical data, we conduct a comparative study based on petrography, conventional petrophysics (porosity and permeability), MICP, laboratory NMR assays for the determination of the transverse relaxation time distribution (samples saturated with water and water irreducible/isoparaffin), and determination of S_{wirr} by centrifugation. The selected samples were characterized according to conventional petrography, including the identification of predominant pore type, clasts and pore sizes. As revealed by the petrographic characterization, samples were divided in two distinct sets: one with moldic porosity and another with interparticle porosity. The former presenting higher irreducible water saturation values than the latter. Analyses of MICP in rocks with a predominance of moldic porosity indicate narrower pores throats than rocks with predominantly interparticle pores, which might reflect on low permeability. When NMR calculation was performed (e.g., Coates equation), rocks with moldic porosity showed slightly lower permeability values than those with interparticle porosity. However, according to petrophysical laboratory data, rocks with moldic porosity have significantly lower permeability values. As for centrifuge assay, S_{wirr} values were about 9% higher than those obtained with the standard 100-ms cutoff on T_2 relaxing time, which weakly correlated with each other. The distribution of T_2 in water saturated samples show consistency with MICP in some samples; although, distribution of T_2 and MICP mode does not correlate. Similarly, the analysis of T_2 distribution with samples saturated with S_{wirr} and isoparaffin show no relation with the pore size or distribution of pore throats. The NMR technique is not able to identify the pore size when the reservoir is saturated with a wetting phase (water) and a nonwetting phase (oil/oil based drilling mud). MICP cannot be related to pore size in bioclastic rocks, considering that moldic pores are often connected by narrow pore throats. Moldic porosity rocks are less permeable and have slightly higher S_{wirr} content, which is detected by NMR. This work shows that the evaluation of bioclastic carbonate reservoirs by NMR without supporting rock data can fail on predicting permeability as the duality of porous system of these rocks generates opposite permeability patterns which cannot be easily identified in NMR logging.

Trimodal Characterization of Multicomponent Induction Interpretation Error Resulting From Model Selection and Tool Response Uncertainty

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The multicomponent induction log provides both the resistivity measured transverse (vertical) to the bedding (R_v) and the resistivity measured longitudinally (horizontal) to the bedding (R_h). Typical multicomponent induction interpretation models these resistivities in terms of an anisotropic shale fraction, an isotropic sand fraction, shale anisotropic resistivity, and sand isotropic resistivity. There are more parameters than unknowns, but given the appropriate parameters from another source, it is possible to solve for the sand resistivity with at least three models: (1) Given the shale fraction and shale horizontal resistivity, solve for the sand resistivity and the shale vertical resistivity; (2) given the shale horizontal and vertical resistivity, solve for the sand resistivity and the laminated shale fraction; and (3) given the shale fraction and the ratio of the shale vertical over horizontal resistivity, solve for the sand resistivity and the shale horizontal resistivity. However, there are cases in which the sand can be macroscopically anisotropic; in these cases, the three classical models fail.

This paper extends the multicomponent induction interpretation model to account for the macroscopically anisotropic sands. The proposed three-component model, dependent upon an anisotropic shale fraction, an isotropic macroporous sand fraction, and an isotropic microporous sand fraction, is applied to generate some synthetic multicomponent induction resistivity data.

The research described in this paper indicates that it is possible to generate the trimodal synthetic multicomponent induction data (synthetic parallel and transverse resistivity) using the following parameters: laminated shale fraction, shale vertical, and horizontal resistivity; macroporous sand fraction and its associated porosity, water saturation, and water resistivity; and microporous sand fraction and its associated porosity, water saturation, and water resistivity. The two sand water saturations are modeled from capillary pressure curves. In the process, some uncertainty is applied to the generated synthetic vertical and horizontal resistivity data that is consistent with the existing tool uncertainty characterization database. The paper presents results for the four models summarizing the interpretation accuracy (water saturation and net pay) as a function of parameter error and tool uncertainty. Finally, the paper includes a discussion of the results obtained when the four models were applied to some actual deepwater Gulf of Mexico (GOM) well data.

Upscaling of Digital Rock Porosities by Correlation With Whole-Core CT-Scan Histograms

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The porosity of the reservoir rock is one of the most critical variables for the quantification of reserves in an oil field. Conventional techniques for porosity determination include well logging and laboratory core plug measurements. More recently, digital rock technologies were developed to augment traditional core analysis and to achieve faster decision-making. However, vastly different length scales need to be consolidated to produce a proper description of the reservoir. For example, digital rock techniques generally measure features of the rock matrix at the micrometer to millimeter scale (which is often below a representative elementary volume and does not capture rock heterogeneity), while traditional core plugs are several centimeters in diameter and some well-logging tools operate at a vertical resolution around one meter. In conventional oil reservoirs, the core-plug porosities and digital rock porosities compare well with results from nuclear magnetic resonance (NMR) logs. NMR logging tools measure the porosity by means of the nuclear spins of hydrogen contained in hydrocarbons and formation brines. These tools average the signal vertically over roughly one meter due to the time it takes to polarize the nuclear spins and its limited sensitivity.

Apart from the representative elementary volume challenge, there is also the question of heterogeneity. In thin-bedded reservoirs, the measured core-plug porosities may not agree with the NMR log porosity, since the core plugs may sample only select beddings while the NMR tool averages over several bedding zones. Here we show that a whole-core CT scan can be used to statistically average porosity values to scale from digital rocks to the NMR log resolution. We investigated a thin-bed reservoir with layers of halite-filled sandstone alternating with layers free of halite at variable layer thicknesses. We found that there is a good correlation between the Hounsfield units of the whole-core CT scan and the measured core-plug porosity. This relationship was established by averaging the Hounsfield units at the location from where the core plugs were drilled. A similar correlation was found for digital rock porosities and the areas in the core plugs. The upscaling was performed by converting the histogram of Hounsfield units of each slice in the CT scan to a histogram of porosities. After that, the length scale was increased by moving averages in the vertical direction. The resulting synthetic porosity log compared well with the NMR porosity within the uncertainty band over a total depth interval of 53.6 meters, except for two intervals of roughly 6 meters where the synthetic porosity was undercalled.

We anticipate that this method may be extended to other challenging reservoirs, such as thinly bedded unconventionals. Since CT scans are taken routinely of the whole cores before core analysis, it would be highly rewarding if there are correlation coefficients that are applicable for specific geological settings. If such correlations can be found, they could be used to estimate synthetic porosity logs before the core plugs are measured, which may lead to faster decisions in the field.

Upscaling of Saturation-Height Functions

Alan Johnson, Integrated Petrophysical Solutions Ltd

The input of representative values of fluid saturation to static and dynamic reservoir models is normally achieved by means of saturation-height functions. Usually these relationships are designed to represent formation water saturation as a function of both height above the capillary free-water-level and one or more parameters representing reservoir quality, typically porosity and/or permeability. These functions are derived from core-based capillary measurements, directly from log-determined water saturations or, ideally, some combination or reconciliation of the two.

The step from core-to-log saturation, in itself, involves a considerable degree of upscaling as the volume of rock represented by a single value of log-derived saturation is many times the volume represented by a single core measurement. While this aspect will be addressed, the paper focuses primarily on the step of upscaling typical saturation-height functions from the log to the geomodel scale.

When applying these functions to a cell in the geomodel, the typical industry approach is to use the height of that cell above the free-water-level together with the upscaled values of log-derived porosity and/or permeability for that cell. For volumetric calculations and dynamic simulation applications it is quite common to upscale these parameters using an arithmetic averaging procedure. The question arises as to whether the average values derived in this way are the optimum values to use in saturation-height models. The paper aims to quantify the potential volumetric errors resulting from applying standard upscaled reservoir-quality parameters and go on to suggest procedures which may be applied to avoid or at least minimize these errors for several commonly used saturation-height models.

The study uses a number of simulated wells, with varying reservoir properties designed to cover a range of reservoir properties. Saturations are calculated, at the log scale, using different saturation-height models, derived from a real capillary dataset. The log rock-property data are then upscaled to a range of model-layer thicknesses and the comparisons between the log-scale and upscaled hydrocarbon pore volumes are used to investigate the potential volumetric errors resulting from different upscaling methodologies. Strategies to define the most appropriate upscaling techniques for various function types are discussed.

The key conclusion is that, depending on the saturation-height function being applied, the use of customized upscaling methods for permeability, porosity or other rock-quality parameters, usually provide more accurate representation of layer saturations for volumetric applications than the standard, default approaches commonly used. It is emphasized that these upscaled properties are designed for saturation-height input only and must be carried through the workflow as separate entities to the standard upscaled parameters intended for other model applications.

Wireline Formation-Fluid Sampling—From Making the Value Case, to Applying the Lessons Learned—A Guide to Improve Rate of Success While Taking Fluid Samples in the Lower-For-Longer Oil-Price Environment

Wilson Pineda, Eric Soza, John Bergeron, and John Williams and Doris Gonzalez, BP

Downhole fluid samples are one of the most critical pieces of information for reservoir characterization. They are used to inform fluid properties and are a key input into the understanding and prediction of reservoir performance and recovery. Understanding fluid properties is also critical to efficiently operate the well and reduce flow-assurance problems. As lower commodity prices are the new norm in the industry, every effort should be made to ensure fluid-sample acquisition is successful, this in turn will help to keep the sample collection cost as expected and fluid information will be available for the life of field development.

The case to collect fluid samples requires balancing the value of the information versus risk and cost. The planning should consider many factors from vendors' experience, well complexity, deployment options, formation fluids, borehole fluids, real-time contamination monitoring, probe positioning etc. Job planning should also cover the selection of the proper technology, such as probe type, mud filters, pumps, samples bottles etc. During the operation, decisions are typically needed to update the program based on newly available information or unexpected operational challenges. Once the operation is completed, lessons learned should be properly captured and shared with vendor as part of continuous improvement. Efforts to increase efficiency should include the reduction of tool plugging and tool fishing, among others. This paper is intended to share lessons learned from several years of collecting fluid samples in several fields using multiple wireline vendors. The work includes building the business case for fluid sampling, planning, execution and capturing lessons learned. Sampling environments include unconsolidated sands, highly depleted reservoirs and deep, deviated wells where conveyance and depth control are challenging. Many of the operations were performed in wellbores with high concentration of lost circulation material (LCM) including stress cage as part of the drilling-mud formulation.

FORMATION EVALUATION OF UNCONVENTIONAL RESERVOIRS

Advanced Dipole-Shear Measurements With a New Logging-While-Drilling Sonic Tool

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It has been well known for some time that obtaining reliable dipole-shear information from LWD tools is a formidable challenge due to the strong coupling between the formation and collar flexural modes. However, the benefits that a logging-while-drilling (LWD) dipole acquisition can bring, both in terms of the applications of the measurement and the time savings associated with the conveyance method, mean that it has remained an area of close focus. Obtaining the dipole fast- and slow-shear anisotropy information (azimuth and shear slowness) would allow LWD sonic data to be used for a wide range of applications where understanding acoustic anisotropy is critical. These range from accurate time-to-depth migration of surface seismic to wellbore stability to completions and production optimization.

It has been recently demonstrated that the formation and collar flexural modes are separated in the frequency-slowness domain in certain fast formations, which is the case for many unconventional shale hydrocarbon formations. In addition, it has also been shown that the higher order dipole mode in fast formations can be of use for extracting formation shear slowness through a model-independent approach. The effectiveness of using high-frequency components from higher order azimuthal modes is also corroborated by modeling studies and field data analysis. These previous papers have focused on data acquired with existing LWD sonic tools. Thus, the dipole data acquisition was not necessarily optimal to make a standard slowness log due to the lack of sufficient data density.

This paper presents while-drilling dipole field data, acquired in fast formations, with a newly developed LWD multipole sonic tool, which can acquire four-component dipole waveforms at the same data density as the standard acquisition. It discusses the challenges of acquiring reliable, dipole waveforms with a fully rotating tool and how they were addressed. Shear-slowness processing results using the low-frequency first-order and high-frequency second-order dipole modes are shown, along with dispersion curves to quality control the data. The quality of the acquired dipole dispersions is compared with the modeling results obtained with a detailed tool structure built for the new tool. Finally, the obtained shear slowness from the LWD dipole tool is compared with the shear slowness from a wireline dipole tool. These results show that the acquisition of reliable dipole data is possible in a while-drilling environment, under the conditions shown, and that the data can be adequately quality-controlled to provide consistent shear slownesses when compared to a benchmark reference. The limits of the measurement are also adequately communicated. The results of the field data pave the way for an expansion of the measurement capability across a range of borehole sizes and open the door to a variety of new applications for LWD measurements.

An Unsupervised Learning Algorithm to Compute Fluid Volumes From NMR T_1-T_2 Logs in Unconventional Reservoirs

Lalitha Venkataramanan, Noyan Evirgen, David Allen and Albina Mutina, Schlumberger

A key objective for formation evaluation in unconventional reservoirs is to estimate reservoir quality by quantifying the volumes of different fluid components from nuclear magnetic resonance (NMR) T_1-T_2 maps. Spectroscopy-based tools can estimate the total organic carbon in a reservoir. Resistivity and dielectric tools are sensitive to the water-filled porosity. Only NMR tools have the capability and sensitivity to further partition the hydrocarbon and water into fluid components based on their properties and geometry in the pore space.

T_1-T_2 maps from wireline NMR logging tools show unique signatures for hydrocarbons, such as bitumen and producible and bound oil and gas. Similarly, capillary and clay-bound water and water in larger pores have different signatures. However, these signatures depend not only on the fluid and the pore geometry but also the geometrical configuration of oil and water phases within the pore space. Where the formation is homogenous, variation in T_1-T_2 maps at the different depths is due to variation in fluid volumes. These volumes are usually calculated by using predetermined cutoff values obtained from analysis of laboratory data in the T_1-T_2 domain. However, these cutoff values are lithology dependent and also a function of the unknown fluid properties. Thus, is desirable to have an automated algorithm that can compute fluid volumes from T_1-T_2 maps.

In this paper, we describe an unsupervised learning algorithm to estimate the footprint of the different fluids in T_1-T_2 maps and subsequently compute their fluid volumes. Leveraging our knowledge of the physics of the relaxation processes and measurements of laboratory datasets, we propose a hierarchical clustering method consisting of the following steps. First, we use the signal-to-noise ratio in the data to obtain a rough estimate of the overall footprint of all the fluids. Second, assuming each point in T_1-T_2 space corresponds at most to one fluid, a non-negative matrix factorization technique is used to compute a footprint corresponding to the different fluids. A hierarchical clustering method is used to ensure that the footprint of each fluid is compact and connected in the T_1-T_2 domain. Subsampling of the maps is used to study the stability and compute the most likely number of fluids present. The final step consists of applying the mask corresponding to the different fluids to the measured T_1-T_2 maps to determine the fluid volumes. There are a few key advantages of this method over other methods proposed in the literature. First, it does not require predetermined information about cutoffs to distinguish fluids. The cutoffs are automatically estimated from the data. Second, simulations show that the method does not require a wide variation in fluid volumes at different depths. This allows the petrophysicist to pick a relatively short depth interval consisting of one rock type to study measurement variation due to variations in fluid properties. Last, it provides a framework to automatically compute the number of fluids in the underlying dataset. We demonstrate the application of this method on simulated datasets.

Assumptions and Uncertainties in Petrophysical Models for Shale-Gas Formations and Their Effect on Resource Calculations

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A key uncertainty in evaluating a shale-gas resource is the estimation of gas-in-place (GIP). In areas, such as the UK, where the shale-gas industry is in its infancy and public opinion gives no leeway for error, being able to minimize the number/length of wells drilled has advantages for both economic success and environmental impact minimization.

Shale gas refers to fine-grained formations (mudstones) where organic matter has matured sufficiently to produce predominantly gas, but that gas has not migrated any significant distance. Petrophysical analysis is complicated by both petrophysical and geological heterogeneity within the formation, and by the existence typically of both free- and adsorbed-gas components. The latter is fixed onto organic surfaces and held in place by pressure but these gas phases may occupy adjacent volumes and separating out the two to avoid double counting is an important step. The location of the gas is sometimes considered to be isolated in organic pores or to exist in both organic and mineral pore spaces.

The objective of this study is to evaluate a number of contrasting published shale-gas methodologies to assess the effect on resource estimates of uncertainties inherent within the models, the sensitivity of different parameters and the underlying assumptions about the physical system made within each model.

We present a detailed evaluation of six contrasting petrophysical models with variations in model outputs for GIP assessed for both absolute values and for downhole trends. A subset of these models is carefully compared, firstly, using petrophysical measurements on core samples as model constraints, and secondly, ensuring equivalency of parameter values across models. This enables conclusions to be drawn on relative model robustness in relation to the influence of different inputs, different assumptions about the location of the gas, and different statistical techniques employed for analysis.

The establishment of a framework of models through which any shale dataset can be run generates a number of key findings; small changes in parameter choices can have a large effect on the absolute value for GIP; measurements on core (despite the associated uncertainties) are critical to provide model constraints; different assumptions about the location of the GIP can result in contrasting downhole trends between models. These results have consequences for the selection of downhole intervals for shale-gas extraction and highlight the importance of continuing to progress our understanding of shale-gas petrophysics and the variations between different geological formations. We conclude that by considering a selection of models with differing underlying assumptions, intervals of greater uncertainty can be identified, and this is an approach that can effectively be applied to any shale formation.

Automatic Well-Log-Based Fabric-Oriented Rock Classification for Optimizing Landing Spots and Completion Intervals in the Midland Basin

Mohammed Al-Obaidi, Artur Posenato Garcia and Zoya Heidari, The University of Texas at Austin; Brian Casey, Richard Williams and Jeff Spath, Texas Oil and Gas Institute

Organic-rich mudrocks are characterized by complex fabric structure that arises from a variety of depositional and diagenetic processes, which are often difficult to quantify. Such complex fabric significantly governs petrophysics and geomechanics and causes large variations in performance of the wells. Quantifying the complex rock fabric of organic-rich mudrocks using conventional well logs is challenging due to the high vertical heterogeneity of such reservoirs and poor vertical resolution of conventional logs. Image logs provide a continuous and high-resolution record of the rock sequence and can capture fabric-related features, such as the presence of laminations in different scales, clasts, and burrows. Automatic integration of image logs, conventional logs, and core measurements can, however, be challenging and is not commonly used for rock classification and formation evaluation. In this paper, we propose a method for automatic characterization of rock fabric by joint interpretation of image logs, conventional well logs, and core measurements in unconventional rocks of the Midland basin.

The objectives of this work include (a) developing an intelligent rock-fabric recognition workflow that uses image logs as inputs, (b) integrating the identified rock fabric with conventional logs and core measurements for rock classification and for selection of optimum rock classes for completion, and (c) using the rock classification outcome to improve formation evaluation.

First, we combined multiple object-oriented image processing algorithms to detect fabric-related features (e.g., laminations and clasts) from image logs. Then we integrated the detected rock fabric with conventional logs and core measurements and feed them into support vector machine then neural networks to generate a depth-by-depth rock classification. Once the classification scheme was optimized, petrophysical models were improved on a class-by-class basis. Next, we trained a new classification scheme based on conventional logs with the results from the integrated classification and extended it to wells without image logs. Finally, we recommended the best rock classes as candidates for future developments.

We successfully applied the proposed method to a dataset from the Wolfcamp shale in the Southern Midland Basin and Ozona Arch. The dataset consisted of eight wells with image logs, two of which were used as blind test wells, as well as 10 additional wells with no image logs. We compared the results of petrophysical analysis and observed 20% improvement in estimates of petrophysical and compositional properties of the rocks compared to the cases where automatic rock-fabric detection and image analysis was not implemented as part of the formation evaluation workflow. Comparison of the recommended completion intervals in the blind test against production data revealed that wells completed within recommended zones outperform the next tier of wells by approximately 25%. The results showed that quantifying fabric-related features from image logs can be used to improve completion decisions not only in the wells with image logs, but also in the neighboring wells without such measurements.

Beyond the Wellbore Hydraulic Fracture Diagnostic Using Deep Shear-Wave Imaging

Sergey Stolyarov, Sergey Kotov, Eduardo Cazeneuve and David Gadzhimirzaev, BHGE

Understanding the stimulated reservoir volume and mapping hydraulic fractures away from the wellbore remain as the largest challenges in unconventional plays development. Tracer technologies and production logging that are currently available provide information only a few inches beyond the wellbore. Far-field microseismic mapping offers an image of micro-earthquakes that are caused by shear slippage during a hydraulic fracture treatment. Although the location of the associated microseismic events enables spatial mapping of the stimulated rock volume, particularly its orientation and growth characteristics, the microseismic deformation does not provide direct information about hydraulic fracture effectiveness.

The deep shear-wave imaging processing (DSWI) provides a visual representation of geological features and hydraulic fractures up to 100 feet from the wellbore. DSWI nicely fills the resolution space between conventional near-wellbore diagnostic technology and far-field microseismic mapping. Shear-wave azimuthal sensitivity enables estimation of the hydraulic fracture geometry away from the wellbore and direct visualization of the actual reservoir volume have stimulated.

This paper presents the case study of the post-hydraulic fracture diagnostic in a shale reservoir using deep shear-wave imaging technology. The information derived from the pre- and post-hydraulic fracture imaging enables a better understanding of stimulation treatment effectiveness and fracture propagation away from the wellbore. This imaging can also be used for newly drilled wells completion optimization and identifying previously unstimulated zones for refracturing.

The accuracy and credibility of the DSWI hydraulic fracture diagnostic was confirmed by running a crossed-dipole acoustic log in a well with 100% water cut. Radioactive material presented in produced water caused up to 150 API increase in gamma-ray activity because of precipitation associated with pressure drop in a hydraulic fracture. The study showed that the lateral intervals with a substantial increase in gamma-ray activity matched with the hydraulic fracture locations identified by the DSWI process.

The case histories highlight the value of the information obtained from the DSWI to enhance fracture optimization, to improve ultimate recovery, and to reduce overall operational cost.

Experimental Quantification of Kerogen Wettability as a Function of Thermal Maturity

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Kerogen is often considered to be fully hydrocarbon-wet in reservoir characterization. Wettability of kerogen is, however, not well quantified and understood. Our recent experimental measurements of electrical resistivity, dielectric constant, and elastic properties of kerogen at different thermal maturities suggest that kerogen wettability could significantly vary with thermal maturity. These results also indirectly suggest that kerogen can be water-wet in low thermal maturities. Thermal maturation induces changes in the chemical structure of kerogen and alters its oxygen and hydrogen content. This process affects surface properties of kerogen and can influence its wettability. Assumptions made about wettability of kerogen affects interpretation of borehole geophysical measurements such as electromagnetic measurements. Quantification of kerogen wettability is also crucial in designing successful reservoir development strategies. To the best of authors' knowledge, there has been no previous experimental study to reliably determine wettability of pure kerogen, because of the challenges associated with kerogen isolation and with determining wettability of powders. In this paper, we introduce a workflow to experimentally determine kerogen wettability and document kerogen wettability as a function of its thermal maturity. The objectives of this paper are (a) to experimentally quantify wettability of kerogen at different thermal maturity levels, and (b) to quantify the influence of chemical composition of kerogen on its wettability.

We first isolated kerogen from organic-rich mudrock samples at different thermal maturity levels. The extracted kerogen samples were then synthetically matured by increasing temperatures at the rate of 4°C/min up to 650°C under a controlled environment. We used X-ray photoelectron spectroscopy (XPS) to quantify the changes in chemical composition of kerogen. For wettability measurements, we used the Wilhelmy-plate and sessile-drop methods. A glass slide is coated with kerogen powder using an adhesive and inserted into a glass beaker filled with water. Once the slide is in equilibrium with water, the contact angle made by the water-kerogen interface was measured using a goniometer. We then determine the wettability of kerogen and investigate the correlation to its thermal maturity. We also simultaneously measured electrical conductivity and dielectric permittivity of the kerogen samples.

We successfully determined wettability of kerogen samples isolated from two different organic-rich mudrock formations and synthetically matured to different levels of thermal maturity. Results indicate that kerogen becomes more hydrocarbon-wet at high thermal maturity levels and remains water-wet at low thermal maturity levels. The results obtained were in agreement and were used to explain the current and previous measurements of electromagnetic properties and Young's modulus of kerogen and mudrock samples at different thermal maturities. The XPS measurements showed a decrease in O/C ratio with increase in thermal maturity of kerogen. This observation explains the decrease in water-wettability with increase in thermal maturity of the samples. The outcome of this paper improves formation evaluation of organic-rich mudrock by providing quantitative information on wettability of kerogen. It can also contribute to enhancing the assumptions made in reservoir simulators developed for organic-rich mudrocks and significantly improves our understanding of fluid flow mechanisms in these unconventional reservoirs.

Fast Pressure-Decay Permeability Measurement for Intact Tight Rocks

Zheng Gan, Ted Griffin, John Dacy, Harry Xie and Robert Lee, Core Laboratories LP

Matrix permeability is one of the most important factors used to evaluate the long-term production of hydrocarbon reservoirs. However, for shale reservoirs that have ultralow matrix permeability in the range of tens to hundreds of nanodarcies (nD), the laboratory measurement of the matrix permeability of intact (nonparticalized) samples has remained a challenge. The widely used measurement methods, such as pulse-decay and steady-state, have two primary limitations (1) measurements take hours or even days, and (2) commonly present sample fractures affect the measured permeability value.

In this study, a new pressure-decay permeability method is proposed for ultratight rocks to overcome these limitations. The principle of the pressure-decay experiment is that system gas pressure is higher than pore pressure of the core sample so that gas penetrates the core sample and permeability is derived from the decrease of system gas pressure. In order to validate the proposed pressure-decay technique, experiments were conducted on the following intact rock samples (1) a set of different types of rocks including a Marcellus shale plug, (2) a set of Eagle Ford shale plugs, and (3) a Marcellus shale plug with open, connected fractures. A series of comparative studies of the permeability results from pressure-decay, pulse-decay, and steady-state experiments on these core samples confirmed that the proposed pressure-decay experiment can provide accurate matrix permeabilities of ultratight rocks. Tests can be completed within one hour and the measurement range is from 1.0×10^{-1} to 1.0×10^{-6} md. Further, the proposed method has the following advantages: (1) measured matrix permeability by the new pressure-decay method isn't affected by the open, connected fractures, whereas these fractures make the pulse-decay and steady-state permeability results increase by three orders of magnitude; (2) the new pressure-decay experiment is 10 times faster than the pulse-decay experiment and 20 times faster than the steady-state experiment; and (3) the proposed pressure-decay experiment can provide the gas-filled pore volume and the fracture volume during the permeability measurement, whereas the pulse-decay and steady-state experiments cannot.

Giant Oil Discovery West Of Shetland—Challenges for Fractured Basement Formation Evaluation

Chiara Cavalleri, Heike Delius and Kamaljeet Singh, Schlumberger; Daniel Bonter and Robert Trice, Hurricane Energy

In Spring 2017, Hurricane Energy concluded its latest appraisal campaign by drilling three exploration/appraisal wells and one development well in the Greater Lancaster area, West of Shetlands, UKCS. The area is located on the Rona Ridge, which is a prominent NE-SW trending basement high with tremendous upside potential. The main target is a fractured tonalite/granitic basement that has undergone a complex tectonic history. Seismic-scale fault zones that are between approximately 30- and 70-m wide represent regions of enhanced porosity and permeability, and so are targeted by horizontal production wells designed to transect as many as possible. The background fractured basement between these fault zones is also heavily fractured, and contributes to flow. This work shows how the initial fault recognition based on seismic data was gradually refined over the progress of the appraisal and has been corroborated by drilling and logging results. Consequent to extensive evaluation programs, the number of fault zones across the field has dramatically increased and a comprehensive picture of the complex network emerged. This is fundamental for field modeling and simulation, particularly when distributing properties away from well control. Fractured basement reservoirs require specialized thinking when it comes to acquiring data and interpreting the dynamic behavior of the often intricate, flow pathways through the hydrodynamic fracture network. An expert integration of well data, from different disciplines and scales of measurement have been applied and proved essential for this formation evaluation.

Hurricane incorporates drilling parameters, mudlogging data, high-resolution gas chromatography, logging-while-drilling and wireline logs, drillstem test data and production logging to analyze and model the reservoir. It is the combination of these disparate datasets that is key to Hurricane's analysis, as a focus on only one set of data can lead to erroneous conclusions. A comprehensive and detailed static and dynamic model brings these various analyses together to describe the behavior of the reservoir at a field scale. During the recent drilling campaign, a set of high-quality petrophysical and geological data were obtained through wireline logging. These data compare well to the data collected on previous wells, demonstrating consistency in the reservoir properties across the structure. A thorough wireline program on Lancaster, incorporating extensive production logging runs with petrophysics and borehole images, has been used to infer an oil water contact that appears comparable to that identified in the first well drilled on the structure. Borehole microresistivity images with advanced nuclear magnetic resonance and high-definition elemental spectroscopy were immediately combined in novel workflows to characterize the rock texture, lithofacies and fracture distribution. Many extra-large sidewall cores were acquired, positioned based on initial results to avoid areas of particularly intense fracturing, affording a good recovery success rate. The sidewall cores are being used for further detailed evaluation, calibration of the borehole measurements and ground truth of oil presence. Drillstem testing and advanced production logging finally provided the last piece of information required to understand and complete the puzzle, and relating the static interpretations to the dynamic behavior of the reservoir.

Integrating Measured Kerogen Properties With Log Analysis for Petrophysics and Geomechanics in Unconventional Resources

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Workflows developed for log analysis in conventional reservoir rocks are difficult to apply in organic-rich shales due to the presence of abundant kerogen (solid and insoluble organic matter) in shale. There are two primary reasons for this difficulty. First, kerogen is considered as part of the solid matrix but responds to traditional porosity logs (density and neutron) as a fluid. Estimating the porosity from logs therefore requires a method to separate the kerogen and fluid signals. Common methods to estimate kerogen content via basic logs include regressions to inverse bulk density (Schmoker) and the ΔLogR method (Passey). Both methods attempt to separate kerogen from pore fluids by establishing a baseline response in a nearby kerogen-free section and by assuming that the kerogen-rich section and the kerogen-free section have identical petrophysical properties (other than kerogen content). The ΔLogR method requires calibration to total organic carbon (TOC) from core or cuttings, and an error arises for samples that are not solvent-washed such that an unknown fraction of TOC is from oil and not kerogen. When the kerogen content can be determined accurately using these methods, a second difficulty is that the petrophysical properties of kerogen, such as density and hydrogen index, vary over a wide range, impacted by geologic forces, such as maturation. No logging tools are available to measure these kerogen properties directly.

This paper describes a novel wellsite method combining log measurements with cuttings analysis that overcomes these challenges, providing a measured separation of kerogen and pore fluid along with measured petrophysical properties of kerogen. The method involves diffuse reflectance infrared Fourier transform spectroscopy (DRIFTS) measurements of cuttings. Prior to measurement, the cuttings are cleaned of formation fluid and drilling mud, isolating the organic signal from kerogen. DRIFTS measures the vibrational frequencies of chemical bonds in each formation component, including structural groups in kerogen, and newly developed transforms quantify petrophysical properties of kerogen directly from its DRIFTS signal. The method has been optimized for the analysis of drill cuttings and can be performed at the wellsite, for vertical and deviated wells with any mud type. DRIFTS is therefore particularly suited for the petrophysical interpretation of shale.

Two examples illustrating an integration of DRIFTS cutting analysis with downhole logs are presented. In the first, DRIFTS is used to matrix-adjust a density-porosity log to provide a direct measurement of shale porosity, without relying of the common assumption that the porosity of a shale is identical to the porosity in a nearby kerogen-free interval. This workflow can be used in either vertical or horizontal wells with minimal logging suite. In the second example, DRIFTS is used to estimate anisotropic elastic and stress profiles along a lateral after calibration in a vertical pilot. This method of integrating cuttings analysis with downhole logs provides a practical method to solve many challenges inherent to log interpretation in organic-rich shales.

Maintaining and Reconstructing In-Situ Saturations: A Comparison Between Whole Core, Sidewall Core, and Pressurized Sidewall Core in the Permian Basin

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Core analysis has historically been held as the ground truth for petrophysical model calibration. With the advent of unconventional resources, vendors and operators alike have scrambled to improve and develop core analytical technique to accurately measure the quality of these tight reservoir rocks. Fluid saturations are a critical component of this evaluation, and much effort has been made to quantify the as-received gas, water, and oil components of the pore space using Dean-Stark extraction, retort, and other complementary analyses.

While much of the focus has been on assessing the core in the condition it arrives in the lab, a key question remains: how have the fluid saturations changed as the core sample has traveled from the reservoir to the testing facility? Prior observations in the Permian Basin indicate an average of 35% initial gas saturation, suggesting that a third or more of the pore saturating fluids, are never directly measured in the lab. This uncertainty creates a significant error bar around estimations of in-place volumes and how to calibrate a predictive water saturation model.

Getting this analysis right is critical to one of the core tenets of a practicing petrophysicist: performing highly predictive evaluations that enable profitable and sustainable business decisions.

A Permian Basin comparison will be presented using a variety of core-acquisition techniques acquired over the same reservoir intervals. In this example, whole core, rotary sidewall cores, and pressurized rotary sidewall cores were each acquired. An experiment was designed to help mitigate fluid loss in the various acquisition methods, helping guide the petrophysicist on the reconstruction of accurate in-situ saturations. Additionally, this data-acquisition program was designed to allow the methods to be compared and contrasted in both their operational practicality and quality of core acquired.

A common assumption is that the void space at surface is hydrocarbon that has escaped the rock due to gas expansion; this statement will be tested. Is there any water loss from in-situ to lab conditions? Can whole core or pressurized sidewall coring—with a controlled drawdown to atmospheric pressure—help maintain in-situ fluid saturations and retain oil within the rocks? Finally, does understanding this increase the predictive power of a practicing petrophysicist tasked with evaluating the productivity of unconventional reservoirs? Through detailed testing and analysis of the acquired rocks and other data, these questions are addressed.

Multifrequency NMR Relaxometry-Based Fluid Typing of Shale Rocks

Ravinath Kausik, Yanchun Liang, Denise Freed and Kamilla Fellah, Schlumberger-Doll Research; Gary Simpson, Consultant

Fluid typing in unconventional tight-oil shale pilot wells is vital for determining the sweet spots for landing horizontal drainholes. This is primarily because the total organic carbon (TOC) in these plays comprises kerogen and bitumen, which are the solid and the highly viscous hydrocarbon that do not flow, in addition to the lighter oil, which is the hydrocarbon fluid that is produced. Identifying the confining environment of the lighter hydrocarbon, namely organic or inorganic pores, and the fraction of it that is recoverable is important for determining the reservoir quality of the play. Additionally, determination of the water saturation and its separation into free and clay-associated (bound) fractions is vital for determining the produced fluid composition and the water cut.

In this study, we investigated the fluid-typing capability of 2D nuclear magnetic resonance (NMR) T_1-T_2 relaxometry at multiple frequencies at a fundamental level and determined the answer products available from different measurements, such as wireline logging, logging while drilling (LWD), wellsite drill-cuttings analysis, and laboratory core analysis studies. We employed the fast field-cycling relaxometry technique to determine the NMR spin-lattice relaxation (T_1) dispersion in the frequency range from 10 kHz to 20 MHz, thereby helping us understand the fluid-typing capabilities for the different tool architectures. The experiments were conducted on the two fractions of TOC visible to downhole NMR tools, namely the viscous bitumen and the lighter hydrocarbon. The NMR T_1-dispersion measurements of these bulk components were compared with those under confinement in the shale rock matrix, demonstrating the changes in mobility due to wettability and its impact on fluid typing. We studied samples from the upper Bakken and middle Bakken intervals of the hybrid Bakken petroleum system, which enabled us to delineate the effect of organic versus inorganic confinement on the mobility of these organic fluids. We contrast these dispersion results with those of the free and clay-associated (bound) water fractions, demonstrating how these differences provide the basis for the fluid-typing ability of 2D NMR T_1-T_2 relaxometry measurements.

In conclusion, we provide a fundamental understanding of the fluid-typing ability of NMR relaxation measurements on multiple platforms, based on the frequency dependence of the T_1 relaxation times. The relaxation dispersion of the bitumen and the lighter oil in bulk versus in-situ in organic or inorganic pores, and that of the water in free or clay-associated (bound) states reveal the differences in molecular mobility which enables NMR relaxometry measurements to identify them. We discuss how such fluid-typing helps us obtain the reservoir producibility index (RPI), the key reservoir quality metric in tight-oil shale plays.

Natih B Carbonate Source Rock: Resource Assessment to Production Test

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Production results from the Natih B oil-bearing clean Cretaceous carbonate source rock are correlated to an integrated interpretation of measurements and postproduction geochemical data. The full picture from pilot-well location selection, based on an unconventional resource assessment, to sidetrack horizontal-well design and optimization to the findings from the post-multistage fracturing production test is presented and discussed.

A full logging suite including while-drilling measurements was acquired in the pilot vertical well. Reservoir quality (RQ) and completion quality (CQ) assessments were made by integrating all available measurements, and the while-drilling cuttings data provided information on thermal maturity (recent measurements on source rocks while drilling) and served as calibration for TOC, minerology and fluid type.

The RQ assessment indicated the reservoir to be a low-porosity (3 to 7 p.u.) laminated carbonate with a high resistivity (>10,000 Ω·m), kerogen-hosted-porosity layer alternated with a kerogen-lean layer with conventional pores. The mud-gas logs provided a qualitative signal of liquid hydrocarbon presence. While-drilling two independent proxies were applied to assess the thermal maturity. Kerogen maturity from diffuse reflectance infrared Fourier transform spectroscopy (DRIFTS) analysis indicated a 0.6 to 0.7% vitrinite reflectance equivalence (VRE), implying early-to-peak oil maturity level. A maturity computation using symptomatic gas ratios using quantitative mud gas logs indicated ~0.65% VRE (in agreement with the DRIFTS proxy). The pilot well could not be tested due to operational issues. The best landing-point selection for the lateral was based on integrated RQ-CQ analysis with the potential mobile oil expected to be in the kerogen-lean layers with conventional porosity (based on nuclear magnetic resonance measurements). The lateral was geosteered using logging-while-drilling measurements, DRIFTS TOC, and mud-gas data. After drilling, a wireline quad-combo log (triple-combo with dipole sonic) was acquired. RQ-CQ evaluation was performed for completions and hydraulic fracture design optimization. The hydraulic fracturing operation was successful with three stages propped as per engineered design. The production (low API gravity oil) from the lateral could be directly correlated to the maturity from both the DRIFTS analysis on cuttings and the geochemical analysis of the produced oil sample. The geochemical results generally suggest a source with possible appreciable quantities of sulfur, which may have favored early oil generation resulting in a high polar content, low maturity, low API gravity, viscous oil.

The most significant new finding is the correlation between advanced recent reservoir characterization methods for maturity and the production performance of the Natih B carbonate source rock. The fluid maturity level from the geochemical biomarkers analysis was in good agreement with the maturity evaluation from other while-drilling diffuse reflectance infrared Fourier transform spectroscopy analysis and mud gas ratios which were available in near real time. The workflows and lessons learned during the full cycle of Natih B source rock evaluation in Oman can be applied in parallel scenarios: exploration of source rock in general; and exploration of the Natih B source rock or equivalents elsewhere in the region.

New Nuclear Magnetic Resonance Log T_2 Cutoff Interpretation Parameters for the Unconventional Tight Oil of the Bakken Petroleum System Using 2D NMR Core Laboratory Measurements on Native State and Post-Cleaned Core Samples

Gary A. Simpson, Consultant; Neil S. Fishman, Consultant; Stephanie Hari-Roy, Hess Corporation

Operators have embraced the use of nuclear magnetic resonance (NMR) well-logging measurements to evaluate the hydrocarbon-producing potential of unconventional reservoirs such as the tight-oil Bakken Petroleum System (BPS) in North Dakota. With the use of NMR logging in these reservoirs, the widespread use of conventional NMR T_2 interpretation parameters has been incorporated into the analysis. Typical T_2 cutoff interpretation parameters in use are ≤ 3 ms clay bound water, 3 to 33 ms for capillarity-bound fluids, and >33 ms for free fluids, which is the traditional value used for carbonate reservoirs. While it appeared that these conventional parameters gave a satisfactory interpretation on NMR logging data, a set of laboratory NMR core measurements has led to a reevaluation of the T_2 cutoff parameters of NMR data traditionally used for the BPS. The set of NMR laboratory data came from a comparative study among three commercial core laboratories on core saturation measurement techniques made on samples from the BPS. One part of the study was to confirm that core plugs from the BPS cleaned using the Dean-Stark core-cleaning protocols established in the API RP-40 core-cleaning standards, did not completely clean all fluids from these core samples. To confirm this assumption, the laboratories made native state 2D NMR measurements on core plugs before the plugs were subjected to a Dean-Stark cleaning process. The measurements were repeated at the end of the completed cleaning process to evaluate the presence of any remaining fluids left in the core plug. Examination of the NMR data sets confirmed the incomplete cleaning assumptions. NMR measured post-cleaned core samples revealed water, oil, and bitumen remained in the cleaned core plugs. After extensive study of the dataset it became apparent that the traditional T_2 interpretation parameter cutoffs were incorrect, and thus yielded incorrect saturation values on

the core and log data. The data revealed that NMR T_2 cutoff for free fluids ranged between 0.7 and 1.0 ms, and not the traditional 33-ms value. Secondly, the dataset suggested that the clays in the core sample were likely oil-wet and that clay-bound water T_2 cutoff component was ≤0.4 ms. The capillary-bound water portion was observed between the clay-bound T_2 cutoff and the free-water T_2 cutoff value. The data also seemed to indicate the possibility of dual wettability for reservoir samples. Lastly, this work identified the need to make hydrogen index corrections on both NMR core and log porosity measurements. These corrections allow the appropriate computation of formation waters volume due to the hypersalinity that exists in the BPS (300,000 to 400,000 ppm NaCl). These corrections are not typically applied to NMR logging or core data in the BPS. This work has identified new NMR T_2 cutoffs parameters that give more accurate formation saturation analysis and indicate methods for correcting the measurement for salinity that needs to be applied to NMR logs and core data to achieve more accurate results.

Temperature Dependence of 2D NMR T_1-T_2 Maps of Shale Rocks

Ravinath Kausik, Kamilla Fellah, Ling Feng and Denise Freed, Schlumberger-Doll Research; Gary Simpson, Consultant

Two-dimensional (2D) nuclear magnetic resonance (NMR) T_1-T_2 maps are fast becoming the industry standard for fluid typing in unconventional shale rocks due to their sensitivity to molecular mobility. The increasing mobility of the different fluid components of unconventional plays—ranging from solid kerogen, viscous bitumen, clay-associated water, oil in oil-wet organic pores to fluids (oil and water) in the mixed-wet inorganic pores and natural fractures—is measured by this methodology to determine the fluid types and their confining environments for the construction of universal 2D maps of different wells. However, one of the biggest challenges for the universal application of this methodology is that the impact of variation in the temperature between different basins, wells, or even multiple depths within a well, on the 2D NMR T_1-T_2 maps needs to be well understood.

The main objective of this paper is to understand the changes in molecular mobility of the different fluids in shale rocks as a function of temperature and their influence on 2D NMR T_1-T_2 maps. For this purpose, we performed NMR relaxation experiments on both the extracted bulk components of shale rocks, such as kerogen, bitumen, light oil, and water, as well as investigated them under confinement, such as bitumen and oil in organic kerogen pores, oil and water in inorganic pores, other than clay-associated water. This enabled us to obtain a universal picture of the different fluids in both bulk state versus under oil-wet or water-wet confinement, with different pore sizes and surface relaxivity.

The multitemperature NMR relaxometry experiments were conducted on both low- and high-frequency NMR systems to enable comparison with the logs and to obtain the highest-resolution data quality, respectively. It has been demonstrated that the relaxation-time dependence of light oil is proportional to viscosity over temperature. The temperature dependence of bitumen or heavy viscous oil relaxation times is proportional to viscosity over temperature with a power law of -0.45. Both the heavy oil and light oil in the oil-wet organic pores of the kerogen show a much weaker dependence on temperature. This can be explained by the fact that fluids in the wetting environments are constrained in their motions by the surface interactions (and residence times), and if these are not significantly changed by increases in temperature. We also compare this relaxation behavior with that of the oil or water in mixed-wet inorganic matrix, where a much stronger temperature dependence due to the lower reduction in the bulk phase mobility can be observed.

In conclusion, we investigated the 2D NMR T_1-T_2 response of different shale rock components such as bitumen, oil, and water in a bulk state as well as in oil-wet (organic kerogen) or mixed-wet (mineral matrix) confinements. The hybrid Bakken petroleum system was used as the template for these experiments, with the behavior of the upper Bakken organic mudstone interval contrasted with that of the middle Bakken inorganic matrix. Based on these studies we propose a more universal understanding of the 2D NMR T_1-T_2 logging-based fluid typing.

The Use of Pre- and Post-Fracture Stimulation Logs to Better Integrate Static Petrophysical Analysis With Dynamic Data From Production Logs

Jose Murta de Oliveira Neto and Alexey Yakovlev, Royal Dutch Shell Plc.

Unconventional reservoirs have numerous challenges, from the common low permeability and complex pore-geometry rocks to challenges in better understanding dynamic properties after fracture stimulation. Often questions are asked: Is this really a poor quality rock (nonreservoir)? Has the rock been properly fracture stimulated? Can we use any log in such a predictive way that will have a good correlation with where is the flowing coming from? In this paper the authors focus on how data integration has played a key role in linking the outcome from production logs (PLT) of target zones that were perforated and how the use of pre- and post-fracture stimulation logs helped ascertain fracture height on a log-based perspective.

Petrophysical analysis identified the zones of interest, with the NMR log providing first insights of movable and bound fluid volumes. Two different types of cased-hole logs were used to address fracture height (1) crossed-dipole sonic (anisotropy), and (2) pulsed-neutron logs (sigma mode and inelastic capture mode). Both logs were run before and after the fracture stimulation operations, so an "apples-to-apples" comparison could be made minimizing uncertainties of comparing logs from different service companies. A third quality-control check was performed using temperature logs, but due the long-time between operations (pre- and post-frac logs) the temperature difference was quite subtle.

Fracture stimulation operations were performed in six different intervals and the use of non-radioactive traceable proppant in all stages helped to better understand fracture height, with both cased-hole logs showing very good match. It also confirmed that all stages were successfully fractured stimulated. Overall, the log-based interpretation of fracture height did not correlate very well with the net-pressure match derived from the post-frac analysis, with both cased-hole logs showing lower than expected fracture height. The temperature log showed a better correlation, but it was used in a more qualitative way.

Integration of static petrophysical properties with dynamic data showed a good match and together with the pre- and post-frac logs were critical to give the asset confidence that an optimum selection of potential reservoirs was carefully chosen and more important, that all stages were successfully fractured stimulated with the post-fracture logs clearly identifying the traceable proppant. Some discussions remain in the true height of the fracture and limitations of each method. This needs to be captured and taken into account, as will be shown in the paper.

Values of 20-MHz NMR Core Analysis for Unconventional Mudstones

Z. Harry Xie and Zheng (Jon) Gan, Core Laboratories LP

Because of its great sensitivity to solid organics and other advantages, high-frequency (20 MHz) NMR core analysis has been applied extensively to unconventional mudstones and gained market acceptance in the oil and gas industry. The high-frequency NMR correlation time plots, e.g., the T_1-T_2 mapping techniques, have the sensitivity and resolution in the relaxation-time space to detect and quantify all liquids and solids that contain hydrogen in mudstones. The state-of-art high-frequency NMR core analysis techniques are used in two ways in order to study petrophysical and petrochemical properties of unconventional core samples: (1) Static measurements to quantify liquid porosities, liquid saturations, and solid/immobile organics; (2) dynamic measurements under reservoir conditions to study changes of each constituent due to temperature, pressure and fluid flow in the sample. This paper presents the technical advantages of high-frequency NMR compared to conventional low-frequency (2 MHz or lower) NMR. Typical NMR 2D maps from various shale formations will be shown with emphasis on quantifying water and organics together with comparisons with traditional Dean-Stark analysis and Rock-Eval pyrolysis. The dynamic NMR measurements reveal that solid organics in the unconventional formations play a key role in oil and gas generation and production. Optimized mathematical algorithms in NMR data inversion to obtain 1D relaxation distributions and 2D maps are also discussed.

HIGH-ANGLE/HORIZONTAL WELL EVALUATION AND REAL-TIME DECISION-MAKING

Geosteering in Complex Mature Fields Through Integration of 3D Multiscale LWD Data, Geomodels, Surface and Time-Lapse Seismic

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Success of horizontal infill wells targeting bypassed zones are challenged by uncertainties in the reservoir description but also by fluid content variation generated by differences in sweep efficiency over time. Optimizing well placement of such producer wells has a direct impact on cost and recovery. This could, also, potentially unlock targets not accessible today with currently used methods and technologies. Innovative interpretation methods based on efficient measurements to map structure and fluids around high-angle and horizontal wells while drilling are critical for future success in a marginal, but increasingly strategical, business on the Norwegian Continental Shelf.

Novel integration and advanced 2D inversions allow identification of structural and fluid events laterally to the well path, tens of meters way from the borehole. Therefore, in an unprecedent manner, this paper presents a new possibility to remotely map azimuthally not only the geological structure but also the fluid distribution that was only possible previously by drilling into the zones of interest.

The presented methodology has been developed to build a realistic, high-resolution geomodel reconciling all the subsurface measurements made at different scales, including real-time LWD measurements, 1D and 2D resistivity inversions, interpreted dips and time-lapse seismic data. It is described how ultradeep directional resistivity measurements and inversion-derived reservoir maps bridge the gap in scale and resolution between the standard LWD acquisition and the surface seismic data. Moreover, a novel full 2D deep azimuthal inversion of the ultradeep directional resistivity measurements generates 2D images in a plane perpendicular to the wellbore providing substantial new information to delineate the 3D reservoir structure.

This workflow determines the fluids distribution with greater certainty by combining the deep azimuthal resistivity profiles with the time-lapse surface seismic.

The methodology was applied in a horizontal infill well in an offshore Norwegian field. Integration of all subsurface measurements unveils both the 3D complexity of the geological environment, including subtle faults, and the fingering path of the waterfront coming sideways at the toe of the well.

The case study illustrates how reconciling logging-while-drilling measurements, ultradeep directional resistivity inversions with surface seismic, time-lapse seismic and sedimentological and structural models is essential to enable reservoir mapping in complex geological structures with fluid migration. The integrated interpretation from measurements made at different scales can significantly improve the understanding of the 3D reservoir structure and fluid distribution around a horizontal well. The integrated workflow has been beneficial for the planning and drilling of horizontal wells, especially to optimize geosteering for productivity of infill wells in the complex settings of mature fields.

A Novel High-Definition Inversion of Deep Directional Electromagnetic Measurements-While-Drilling Enhances the Mapping of Layered Reservoir

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The most recent ultradeep directional electromagnetic technology is capable of investigating the reservoir resistivity profile more than 150 feet away from the wellbore. Experience acquired worldwide has highlighted the opportunity to improve the quantitative delineation of limited thickness layers further away, compared to currently used inversion techniques. In this paper, we propose the high-definition inversion for mapping layered reservoirs, taking into account prior reservoir knowledge.

The novel model-driven inversion methodology provides a high-definition reservoir map suited for narrow strata delineation and early reservoir detection to be used in well-placement operations. By integrating the prior field geological knowledge, the algorithm is able to consistently and accurately map finer features of the layered formations further away from the wellbore, resulting in an enhanced and expedited real-time steering decision-making process.

Information from offset wells and/or the seismic interpretation is defined as a reference pattern used in the inversion cost-function minimization process, in addition to traditional data misfit and regularization. Moreover, this method has a unique fault-tolerant ability in case the reference model is not representative, or when there is a depth shift in the entire reference model.

The inversion method has been validated on several datasets including geosteering in an ENI field within an oil reservoir consisting of fluvial and deltaic deposits of Triassic age. The enhanced interpretation of reservoir structure through new inversion helps to better understand the well production behavior. Compared to the conventional inversion method, the new results show significant improvements in terms of limited thickness layer delineation and early reservoir detection. The reservoir resistivity map obtained using the new method depicts geological feature earlier with superior lateral continuity and fewer artifacts. The interpretation is enhanced by defining the reference model with a-priori reservoir knowledge, naturally preserving these details if they are supported by deep directional measurements, resulting in finer structural interpretation consistent with all the data. The novel workflow eliminates the tradeoff between high resolution and increased depth of investigation in the reservoir mapping applications, providing high definition geologically consistent structural information.

Application of Numerical Simulation and High-Fidelity Proxy Modeling to Interpretation of Downhole Fluid Sampling

Morten Kristensen and Nikita Chugunov, Schlumberger

Acquisition of fluid samples using wireline formation testers (WFTs) is an integral part of reservoir evaluation and fluid characterization. Recent developments in formation tester hardware have enabled wireline-based fluid sampling in a wide range of downhole conditions. The increasing complexity of fluid sampling operations and the need for optimizing the sampling process call for a model-based approach for use in planning and during sampling operations. Efficient planning, including the selection of optimal hardware along with identification of favorable zones for sample acquisition, requires quantitative evaluation of hardware performance over a wide range of deployment conditions. For real-time contamination monitoring, recent work demonstrates that a model-based approach may improve contamination estimates, especially in difficult sampling environments and for complex tool inlet geometries (e.g., focused probes). Finally, both real-time and post-job interpretation of formation properties often require a model-based approach, in which parameters of a reservoir model are inverted using downhole fluid analysis (DFA) sensor measurements.

The objective of this study is to develop a comprehensive set of forward models of filtrate contamination cleanup, including methods for speeding up model evaluation to enable applications in real-time inversion and uncertainty quantification.

We present numerical forward models for both miscible (e.g., oil sampling in oil-based mud) and immiscible (e.g., oil sampling in water-based mud) filtrate cleanup. The models cover conventional and focused sampling tools, apply to wells of any deviation, and account for complex tool operating modes. The numerical simulation models use high-resolution, fully unstructured grids; which are rigorously verified through convergence studies and by comparison with analytical solutions. We present a sensitivity study of sampling in deviated wells and discuss the impact of invasion and formation anisotropy on sampling efficiency. Using a Corey parameterization of relative permeability, we show how previous work on fast proxy modeling for miscible cleanup can be extended to immiscible cleanup conditions. The resulting proxy models enable rapid interpretation workflows. An example of such a workflow is presented for relative permeability inversion from WFT measurements of water-cut and pressure. This recently developed methodology complements laboratory measurements of relative permeability on core samples.

Building on previous work in this area, this paper extends the state-of-the-art in two key directions: (1) High-resolution forward models of filtrate cleanup are presented honoring well deviation, tool inlet geometry, and complex tool operating modes; and (2) fast proxy models are developed for immiscible cleanup conditions to enable probabilistic planning and real-time inversion workflows. Synthetic and field examples for both planning and interpretation workflows are presented in the paper.

Azimuthal Imaging Using Deep Directional Resistivity Measurements Reveals 3D Reservoir Structure

Michael Thiel and Dzevat Omeragic, Schlumberger

The reservoir-scale deep directional electromagnetic (EM) logging-while-drilling technology is now routinely being used to map boundaries and fluid contacts for strategic well placement, reservoir navigation, and more recently, for reservoir characterization. Real-time data interpretation is based on continuous inversion of a local 1D layered resistivity profile. All standard inversion approaches ignore the lateral changes of the reservoir, which are contained in the measurements, and only a longitudinal 2D representation of the 3D reservoir structure around the well is provided. This inversion approach limits the ability to make real-time well-placement steering decisions with respect to lateral reservoir heterogeneities, such as faults to the side of a horizontal well.

In this paper, we present a new inversion that can provide deep 2D azimuthal resistivity images in a plane transverse to the wellbore; thus, the new inversion is able to map lateral reservoir heterogeneities. The minimally biased algorithm uses a nonuniform 2D pixel discretization of the imaging plane, initially perpendicular to the near-horizontal well. This algorithm takes advantage of the full 3D sensitivities of deep directional resistivity measurements to map the 2D resistivity distribution. A fast EM simulator is used to reconstruct the tool response in complex 2D anisotropic formations for arbitrary tool orientation. Adaptive regularization enforces consistency and avoids data overfitting. Continuous azimuthal 2D imaging along the well path generates a 3D map of the reservoir in the proximity of the wellbore.

The inversion was initially validated using several synthetic scenarios with various complexities. Subsequently, the algorithm was applied to multiple field datasets from the North Sea and offshore Brazil, all of which resulted in the first 3D reservoir maps derived from deep directional resistivity measurements. Examples include consistent imaging of faults on the side of the wellbore, when approaching, crossing, and moving away from the faults. The imaged fault orientation was found to be consistent with the seismic interpretation. We will also present imaging of complex fault structures and erosional surfaces, consistently azimuthally imaged over long well sections, which can be used to construct a 3D model of the surface.

The new workflow is the first application of a 2D inversion for full reservoir-scale azimuthal imaging using deep directional resistivity measurements, with no assumption about the scenarios. This workflow can be used to populate 3D models of a subsurface formation. If applied in real time while drilling, the workflow has the potential to significantly reduce drilling hazards because it enables true 3D steering toward or away from lateral targets.

Quantifying the Value of Information (VOI) In Geosteering: A North Sea Case Study

Michael Rabinovich, Boris D'arcy and Rory Leslie, BP

The value of information (VOI) has become a predominant theme in modern-day well execution. It has been realized as an effective tool for exploration and production (E&P) companies to use in order to stay competitive in a low-cost environment. At the same time, there is a challenge to discover and produce oil and gas from increasingly complex reservoirs in a cost-effective manner while achieving maximum recovery. Technological advances in proactive geosteering have enabled operators to do this in the most challenging subsurface environments, with the aid of deep and extradeep azimuthal resistivity services. E&P companies have the task of deciding when it is appropriate to incur the additional cost of acquiring such services. To aid in these circumstances VOI is fast becoming a prevalent component to the well planning process when acquiring data and as such, is one that requires as much focus as the data.

The Arundel field in the Central North Sea, UK, presents a complex subsurface environment, comprised of stacked pay zones of varying thickness and uncertain lateral continuity. A narrow true vertical depth (TVD) window to drill in—between an oil-water-contact (OWC) standoff and the roof shale—gave very little room for error. The regional operations team had the task of evaluating the option of deploying advanced geosteering services, which, given the subsurface attributes listed above, presented additional challenges and uncertainties.

A specialized artificial intelligence (AI) algorithm was developed in-house that enabled the team to evaluate the incremental value added from running extradeep azimuthal resistivity services. This was achieved using 3D geocellular subsurface models generated by the regional subsurface team. The algorithm is capable of modeling the responses of the azimuthal resistivity tools, among others, and intelligently simulating subsequent drilling decisions that would maximize total net pay. This technique was applied on seven predrill subsurface models representing the range of expected pay distribution. The result showed an average of 42% increase in net pay when compared with conventional geometric drilling predictions. These results enabled the local operations team to make an informed decision to run the extradeep azimuthal resistivity services in Arundel. The well was subsequently drilled and geosteered with the extradeep azimuthal resistivity tool resulting in a 44% increase in net pay relative to base-case predictions.

In this paper, we discuss the VOI algorithm and its application on seven predrill net-to-gross models for three different geosteering tools (gamma ray, azimuthal resistivity and extradeep azimuthal resistivity). We also show the results of geosteering with the extradeep azimuthal resistivity tool in the Arundel well.

Skewering a Pancake: Geosteering Challenges in a Thinly Bedded Sandstone Reservoir

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Arundel is a small oil field discovered in 2000 by well 16/23-6, which penetrated a thin oil column of Lista-age sandstones. The field has been developed through a single subsea horizontal well drilled along the crest of the structure.

Offset well data highlighted the potential for a wide variation in stratigraphy between wells. Sand thinning, pinch-outs and subseismic faulting were risks identified during well planning. In addition, the oil column was only 25-m thick with a 15-m offset required for water-cut management, leaving only a 10-m vertical window for well placement. Because the structure was too thin to be resolved with seismic imaging, geosteering with extradeep azimuthal resistivity was essential for successful well delivery.

Prior to well execution, resistivity modeling was key in understanding the capabilities of extradeep azimuthal resistivity. Resistivity logs from offset wells highlighted a number of measurement hurdles: resistive mud invasion, dielectric effects, and thin sands with low-resistivity contrast. Through collaboration, the operator and service provider teams assessed the risks to well delivery and prepared appropriate contingencies for each measurement issue. In addition, by using an in-house developed AI algorithm on prewell geocellular models, the operator was able to assess the value of geosteering with extradeep azimuthal resistivity by predicting the incremental net sand added.

In Q2 2017, the Arundel development well successfully reached TD, having used an extra-deep resistivity tool to steer the 1,400-m wellbore, sometimes within sand only 2-m thick. The successful geosteering in this well resulted in a 44% increase in net pay relative to base-case predictions. Technical excellence and flawless communication and collaboration between the provider's and operator's operations and central teams were critical in overcoming real-time challenges, such as identifying a problem with a calibration signal and minimizing its effect on geosteering operations. In this paper, we describe the planning process, resistivity modeling results, real-time collaboration, and critical geosteering decisions made and lessons learned from well execution.

Towards 3D Reservoir Mapping: Information Content in Deep Directional Resistivity Measurements

Dzevat Omeragic, Michael Thiel and Niloofar Farnoosh, Schlumberger-Doll Research; Jean Seydoux and Jean-Michel Denichou, Schlumberger D&M; and Hanming Wang, Chevron

When introduced more than a decade ago, the first generation of directional resistivity technology for proactive geosteering had a big impact on well-placement efficiency, maximization of reservoir contact, and mapping of nearby boundaries. New, deep directional resistivity measurements and automated real-time inversion-based interpretation are now routinely used to map reservoir boundaries and contacts more than 100 ft from the wellbore, thus helping to refine reservoir-scale models.

The latest generation of deep directional resistivity tool contains a full set of triaxial couplings of electromagnetic propagation measurements. The measurements currently used for real-time interpretation are designed for 1D multilayer formations. This paper presents the extended measurement set, which provides the information required for 3D steering and reservoir characterization. Spatial sensitivity plots are presented for all measurement classes. Examples from 1D to 3D are used to demonstrate how each measurement set contributes to distinguishing and interpreting various scenarios. The analysis is extended to drilling along the formation strike, in addition to 3D steering to lateral targets in the presence of arbitrary anisotropy, boundaries and contacts. Insight is provided on directional angles and generalized 3D propagation EM responses. Several field examples illustrate their value.

The information content of a set of real-time measurements is assessed using a data-resolution matrix approach, adapted for nonlinear problems. The analysis is performed using the latest generation of inversions, starting from the 1D Oklahoma formation with a range of resistivity, anisotropy and bed thickness. In addition to finding the most important subset of measurements, this approach also helps to identify redundancy and correlations in the data and can be used to optimize the measurement set for real-time interpretation. Also discussed, are practical aspects of closely related evaluation of uncertainties through the inversion-derived model covariance matrix.

Knowledge of the measurement sensitivities enables enhanced interpretation strategies to be devised. One example is the use of crossplots for steering with respect to lateral features, such as faults. A crossplot of generalized directional measurements in combination with a 1D inversion can be used to place the well with respect to caprock and oil-water contacts while detecting a lateral fault at a distance. This allows for trajectory corrections to avoid the fault, without compromising well placement with respect to the features above and below the well. Examples of artifacts seen in standard 1D real-time interpretation caused by 3D features are presented. These can be used to help identify lateral targets. A 2D inversion prototype is used to evaluate uncertainties on several synthetic models. The methodology is validated on field data where a lateral fault is crossed at high relative azimuth.

Using Directional LWD Resistivity Measurements to Accurately Place Wells and Reduce Costs in Complex Turbidite Formations

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The benefits of extradeep azimuthal reading logging-while-drilling (LWD) resistivity tools have been well documented in several papers, which outlined the advantages of using these types of data to avoid the need for pilot holes and unplanned sidetracks. Typically, the focus of these tools is to land the well in a particular target sand and to then maximize net-sand length in the wellbore.

This paper will demonstrate additional benefits that these types of measurements can offer which include; reducing seismic depth uncertainty while increasing the confidence of the reservoir boundaries; and providing more information on the depositional architecture of the reservoir to aid integrated subsurface description. Cost savings can also be realized using these measurements, not only by mitigating pilot holes and unplanned sidetracks, but by increasing the confidence of a geological model during drilling, thereby allowing an increased drilling ROP and eliminating costly delays, e.g., waiting on interpretation of biostratigraphic data to enable well planning updates to occur.

Finally, this paper looks at the importance of ensuring prejob modeling is accurate and representative of the types of formations to be drilled, provides alternative scenarios to the reference case model and how case sensitivities can be used to provide models that match the realized outcome, increasing confidence in the results and speeding up the geosteering decision-making process.

This work was performed in an offshore Tertiary deepwater turbidite formation, comprising a system of stacked, confined and unconfined sands with complex fill patterns and multiple incision surfaces. The well consisted of four individual target sands that dipped to the north and displayed an offset stacking pattern with two sands targeted at the crest and two additional sands downdip. As the downdip target sands were previously unpenetrated, seismic depth uncertainty was large resulting in an opportunity to run extradeep azimuthal resistivity measurements to ensure that the sands could be located and drilled to maximize net-sand length in the reservoir section.

High-angle wells drilled in turbidite formations can be challenging to geosteer because of the unpredictability of the structure of the formations themselves and because the boundaries between net and non-net intervals are often not distinct due to anisotropic effects. The ability of extradeep directional LWD resistivity tools to remotely detect hydrocarbon-bearing reservoir and image the formation boundary when approaching helps to reduce the geological risk. The data from these tools can be quickly and accurately applied to a model which leads to better and more timely decisions that can decrease rig time, reduce costs and increase the probability of drilling a successful well.

NEW BOREHOLE LOGGING TECHNOLOGY

A Comprehensive Neutron Porosity from a Pulsed-Neutron Logging Tool

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The neutron-porosity measurement is one of the most widely used well-logging technologies. In cased hole, tools equipped with a pulsed-neutron generator (PNG) and multiple gamma-ray detectors have several advantages over conventional neutron tools with an AmBe source and neutron detectors. These include a deeper depth of investigation and more petrophysical measurements, such as capture cross-section (sigma), fast-neutron cross section (FNXS), and spectroscopy. However, two major challenges exist for the PNG neutron porosity to gain a wider industry acceptance. One is the PNG neutron-porosity formation response, which is different from the AmBe neutron porosity, mainly due to the different source energy. Another one is that complex borehole conditions, often present in cased holes, can have a big impact on pulsed-neutron measurements relative to their porosity sensitivity and this can degrade their accuracy.

In 2015, a slim pulsed-neutron tool equipped with three gamma-ray detectors and a self-compensated neutron-porosity

measurement was introduced. The algorithm was optimized to minimize and eliminate various borehole effects. Since then, several major improvements have been developed to deliver a comprehensive neutron-porosity measurement and address the remaining challenges. The basic principle of the self-compensation is to use a count-rate ratio during the neutron burst (named burst ratio) to correct a count-rate ratio during a time interval after the burst (named capture ratio). Because the burst ratio contains inelastic gamma-ray events induced by fast neutrons, its formation response is more affected by fast-neutron transport and is different from that of the capture ratio. An extensive modeling study has found that the formation response can be balanced by combining the burst ratio and the capture ratio to reproduce the conventional neutron-porosity response. The paper illustrates the optimization of balancing the weights and timing gates for the burst and capture ratios to achieve a neutron-porosity measurement that is not only self-compensated for various borehole effects, but also has an AmBe-like response. Because three detectors can provide two sets of ratios, two independent neutron porosities can be measured with two different depths of investigation. The agreement between the two brings confidence for the measurement accuracy. Separation between the two can be caused by residual borehole effects or invasion, and can be used for further corrections and quality checking.

This neutron porosity with reliable quality checks has many applications in cased hole. It can be used for a standalone formation evaluation without openhole logs. It can also be used together with openhole logs to monitor changes in the reservoir gas, water, or oil saturations. If deployed in open hole, this technique provides an option to replace the AmBe neutron porosity. A wide range of modeling results and laboratory measurements are used to illustrate the optimization process and the measurement response. Openhole, simple cased-hole, and complex cased-hole log examples demonstrate the measurement performance in various environments.

A New Permeability Model Combining NMR and Electrical Resistivity Measurements for Complex Formations

Lu Chi and Sven Roth, iRock Technologies

Conventional permeability models based on mercury injection capillary pressure (MICP) curves, including Katz-Thompson and Swanson models, require estimation of microscopic length parameters from core MICP experiments. Therefore in wells lacking core data, these models cannot be applied to estimate permeability. On the other hand, conventional nuclear magnetic resonance (NMR) permeability models (e.g., Coates and SDR models) can provide consecutive permeability assessment along the wellbore, but they are often unreliable in complex formations. They also require parameter adjustment for different rock types. We herein propose a new model for depth-by-depth permeability assessment in complex formations, by combining borehole NMR and electrical resistivity measurements. Our new model can estimate permeability more accurately than conventional permeability models.

The objectives of this paper are (a) to introduce a new directional permeability model combining borehole NMR and electrical resistivity measurements, (b) to test the reliability of the new model for directional permeability assessment in formations with complex pore structures (e.g., complex carbonate and tight-sand formations), and (c) to reevaluate previous models for directional permeability assessment.

We numerically simulate the directional permeability, directional electrical resistivity factor, directional mean hydraulic radius (MHR), and NMR relaxometry, in 180 digital rock samples using our proprietary pore-scale simulation software. The digital rock samples are obtained by micro-computed-tomography (micro-CT), nano-CT, and focused-ion-beam scanning electron microscope (FIB-SEM) on real rock samples, including dolostone, limestone, carbonate, sandstone, and sandpack samples. Then we reevaluate a conventional permeability model (Katz-Thompson) for estimating directional permeability, by calibrating it on part of the rock samples and testing it on the others. Next, we develop a new model to estimate directional permeability using NMR relaxometry and electrical resistivity factor. Specifically, we calculate a porosity-weighted T_2 value from NMR relaxometry to approximate the microscopic length parameter in the MICP curve, and incorporate this T_2 value in the new permeability model. The new permeability model is calibrated on part of the rock samples and tested on the others. We then theoretically and numerically demonstrate the correlation between the calculated NMR T_2 value and the microscopic length parameter in MICP curve. Furthermore, we calculate several NMR characteristic parameters mentioned in literature, incorporate them in the new permeability model individually or jointly, and compare their effectiveness in estimating rock permeability.

The introduced permeability model is successfully applied to 180 rock samples from different formations with distinct pore geometry. The rock permeability ranges from 2.74^{-6} mD to 48 D, spanning eleven orders of magnitude. Results show that the estimated permeability from the proposed model is in good agreement with the target permeability in almost all cases. We also compare our new model with previous NMR permeability models in the literature, showing that our new model can predict permeability more accurately. Our proposed model can be applied to wells with NMR and directional resistivity logs, overcoming the requirement for core measurements. It also shows a potential in estimating relative permeability in hydrocarbon-bearing formations. The outcomes of this research can significantly improve permeability assessment in complex reservoirs, including carbonate and tight sandstone.

A Revolutionary X-Ray Tool for True Sourceless Density Logging With Superior Performance

Matthieu Simon, Avto Tkabladze, Sicco Beekman, Jani Reijonen, Justin Mlcak and Rahul Grover, Schlumberger

Formation bulk density is classically measured by irradiating the formation with gamma rays emitted by a ^{137}Cs source, and counting the Compton scattered photons returning to the well-logging instrument with gamma-ray detectors. For at least three decades, logging companies and operators have attempted to replace this method of bulk density measurement, to reduce the risk of losing a radioactive source in the well or during transportation and storage, and to improve radiation safety in all locations where the sources are handled. The continued success of ^{137}Cs sources for density logging shows that attempts at their replacement have been somewhat unsuccessful, due to the measurement quality or the practicality of alternative logging instruments.

An X-ray-density pad sonde was engineered to measure bulk density without a radioisotopic source. The pad contains a rugged, compact X-ray generator with an endpoint energy larger than 300 keV. The generator is the core of the tool and emits a controlled, stable X-ray flux into the formation. The scattered X-rays are detected by strategically placed scintillation detectors. The pad-tool architecture reduces the effects of standoff significantly compared to a mandrel geometry.

Modeling and experimental data prove that the physics of the formation density measurement using a sonde with an X-ray generator and scintillation detectors can be described in the same way as the traditional density measurement, which is based on a monoenergetic gamma-ray source. We find that the ^{137}Cs gamma-ray source density measurement and the X-ray density measurement differ in the relative magnitude of the responses to formation density and lithology (photoelectrical factor, Pef), and not in the fundamental physics. The endpoint energy larger than 300 keV ensures that the attenuation of the source X-rays in the formation is dominated by the Compton effect, like the attenuation of the gamma rays from a ^{137}Cs source. The contribution of the photoelectric effect to the attenuation of the X-rays is increased, although it remains much smaller than that of the Compton effect, and makes the corrections for lithology and borehole fluid straightforward.

A characterization database was acquired to confirm the physics of the measurement and to derive robust density and Pef algorithms. Plots of near- and far-detector count rates for different mudcake thicknesses and mud types show spine-and-ribs behavior similar to ^{137}Cs density tools. Field logs acquired in wellbores give a tantalizing perspective of the benefits of X-ray density measurements. Improved precision and vertical resolution logs in several client wells show the maturity of this breakthrough technology and its ability to operate successfully in real-world oilfield conditions.

Borehole Acoustic Imaging Using 3D STC and Ray Tracing to Determine Far-Field Reflector Dip and Azimuth

Nicholas Bennett, Adam Donald, Sherif Ghadiry, Mohamed Nasser and Rajeev Kumar, Schlumberger; and Reetam Biswas, Schlumberger, University of Texas

A new sonic imaging technique uses azimuthal receivers to determine individual reflector locations and attributes, such as the dip and azimuth of formation layer boundaries, fractures, and faults. From the filtered waveform measurements, an automatic time-pick and event-localization procedure is used to collect possible reflected arrival events. An automatic ray-tracing and 3D slowness time coherence (STC) procedure is used to determine the ray-path type of the arrival event and the reflector azimuth. The angle of incidence of the reflected arrival is related to the relative dip, and the variation in the arrival times at the individual sensors is related to the azimuthal orientation of the reflector. This information is then used to produce a 3D structural map of the reflector, which can be readily used for further geomodeling.

This new technique addresses several shortcomings in the current state-of-the-art sonic imaging services within the industry. Similar to seismic processing, the current sonic imaging workflow consists of iteratively testing migration parameters to obtain a 2D image representing a plane in line with the desired receiver array. The image is then interpreted for features, which is often subjective in nature and does not provide quantitative results for use in further downstream boundary or discontinuity characterization.

A field example is presented from the Middle East in which a carbonate reservoir was examined using this technique and subsequently integrated with wellbore images to provide insight to the structural geological setting, which was lacking seismic data due to surface constraints. Structural dips were picked in the lower zone of the main hole and used to update the orientation of stratigraphic well tops along the well trajectory. 3D surfaces were then created and projected from the main hole to the sidetrack to check for structural conformity. One of the projected surfaces from the main hole matched the expected depth of the well top in the sidetrack but two were offset due to the possible presence of a fault. This was confirmed by parallel evaluation of the azimuthal sonic imaging data acquired in the main hole that showed an abrupt change in the relative dip of reflectors above and below the possible fault plane using the 3D STC and ray tracing. Dip patterns from both wells showed a drag effect around the offset well tops, further confirming the presence of a fault. A comparison of the acquired images pinpointed the depth and orientation of the fault cutting both wells to explain the depth offset of the projected 3D well top surfaces.

Dielectric Permeability Logging

Jan Henrik Norbisrath, Statoil ASA

Permeability prediction from log data in formations with complex pore structures remains one of the “holy grails” in petrophysics. Traditional wireline and LWD data are limited in their application to modeling permeability in complex lithologies, and often produce inaccurate estimates. Given the complexity of pore structures in these reservoirs, porosity-permeability relationships also tend to fail at producing reasonably accurate permeability estimates. This paper presents a novel method to accurately predict matrix permeability in carbonates and other complex lithologies using dielectric-dispersion logs.

A core study has established the feasibility of permeability predictions from dielectric core-plug measurements, using an empirical model based on phase-shift and amplitude dispersion in the kHz range. The technique has now been adapted to dielectric wireline logs using dispersion phenomena in the MHz range that are sensitive to the pore geometry. We show the application of the technique in a North Sea carbonate reservoir where we acquired dielectric logs and ~300 core-plug permeability measurements.

An empirical model trained on a subset of the core-plug data using unconstrained nonlinear optimization achieves a correlation coefficient of $R^2 = 0.75$ between the dielectric wireline-predicted permeability and core-plug-measured permeability. Testing of a second method using an artificial neural network with dielectric logs as input predicts permeability with an $R^2 = 0.89$, although the accuracy and dependability is under evaluation as new core and dielectric wireline data from additional wells become available. Both methods were also tested with other log data as input (e.g., NMR and sonic) yet dielectric logs are able to achieve a better correlation to core-plug-measured permeability. This method allows forward modeling of a relatively accurate continuous matrix permeability log curve for the entire length of the dielectric logging run. The modeled permeability shows an excellent match with subsequently available core-plug measurements and mobility data from dynamic well tests. The results suggest that this method is applicable to carbonate reservoirs, and further evaluation of the method in additional wells and lithologies is ongoing.

Dynamic Logs Endorsing Nuclear Magnetic Resonance Accuracy Results With Respect to Conventional Logs in High Vertical Heterogeneity Reservoirs for Mature Fields: Case Study, Ecuador

Xavier Ramirez, Jeimmy Fuerte and Jose Gregorio Mata, Halliburton; Rommel Castillo and Dario Cuenca, Petroamazonas

This paper (1) compares production results and the evaluation of conventional logs versus advanced logs, such as nuclear magnetic resonance (NMR), in a mature field, (2) discusses vertical reservoir heterogeneity and different flow units in apparent homogeneous reservoirs, and (3) identifies bypassed oil reserves resulting from poor sweep efficiency.

A petrophysical evaluation was performed using conventional and advanced logs. Comparing the results with dynamic production logs and demonstrating the NMR evaluation was more accurate than conventional log evaluation to identify different flow units.

Traditional interpretations with conventional tools did not identify the water entry problems caused by different flow unit systems, which resulted in production sweep effects from nearby wells. NMR identified this problem, the reservoir quality, and the vertical heterogeneity and its effect on water entry. It was determined that a uniform sweep did not exist from the bottom to the top of the reservoir, so the aquifer water entry depended exclusively on reservoir quality related to flow unit characterization and capacity, as permeability and seal distributions are locally developed.

Adding to this complex scenario of identifying bypassed zones and the noncorrelation with conventional logs is carbon dioxide (CO_2) hiding the presence of the true porous zones, potentially leaving remaining reserves that could be overestimated or underestimated.

Comparing dynamic logs versus static logs resulted in a credible endorsement of NMR, demonstrating its advantages and accuracy over conventional logs and a better technical application for recovering the remaining reserves and optimization of a mature field.

Fast Multidimensional NMR Logging Provides Advanced Fluid Characterization at a Step Change in Logging Speed

Albina Mutina and Nate Bachman, Schlumberger; and Lerrys Rendon, PDVSA

Operational efficiency in formation evaluation has become critical, considering the current trends in the oilfield industry. The impact has been especially felt by advanced measurement logging services, including fluid typing by nuclear magnetic resonance (NMR), where logging speeds are limited by physics and large suites of multidimensional data. However, improving efficiency cannot come at the cost of the accuracy of the answers. Recent work shows that optimization of a single frequency of operation (that is, a single depth of investigation) allows for only modest efficiency gains based on careful acquisition-mode design with tailored sensitivity to the known formation properties and expected fluids of the reservoir. Significant improvements in speed require a multifrequency approach in which data across multiple depths of investigation are used simultaneously to increase efficiency by up to a factor of three.

One focus of this work is to address the challenge of maintaining the necessary accuracy of NMR fluid-typing answers while still benefiting from a full suite of NMR diffusion and relaxation data. We expand on previously described optimization techniques of diffusion-relaxation acquisition modes wherein subsets of the NMR sequence are distributed across multiple frequencies, or shells. We call this method split shell acquisition (SSA). The subsequent method of processing all the data together into a single three-dimensional (3D) inversion is called combined shell processing (CSP). The petrophysical applicability is for cases in which an invasion profile from independent multiple frequencies is not required.

There are numerous ways to approach NMR sequence optimization, including analytical sensitivity calculations, quick-look inversion computation for porosity accuracy, signal-to-noise ratio (SNR) expressions, and Monte Carlo methods. For this study we used all four methods in combination with the SSA strategy of assigning different parts of the NMR sequence to different frequencies of operation. We defined our optimization criteria as obtaining the fastest possible logging speed without compromising the answer quality for the given expected fluids. Two key differentiators are (1) that the method exploits the different NMR properties of each frequency of operation toward optimal sensitivity to fluids, and (2) that the inversion fitting function simultaneously fits data from all frequencies.

Downhole logging data were successfully acquired and processed using the SSA acquisition and CSP processing. The results are consistent with modeling and laboratory data used to build the operating mode, thus proving the method for obtaining fast fluid-typing answers. We have achieved an increase in logging speed of almost a factor of three compared with the single-frequency logging speed. We also show how the efficiency gains can be used alternatively to provide enhanced polarization and sensitivity to long relaxation time constants, which is applicable to both carbonate and sandstone reservoirs.

Field-Test Results of a New High-Resolution, Dual-Physics, Logging-While-Drilling Imaging Tool in Oil-Based Mud

Carlos Maeso, Emmanuel Legendre, Hiroshi Hori, Rajan Dua, Raja Shahnawaz Khan, Mathias Horstmann and Jean-Christophe Auchere, Schlumberger

Borehole imaging at the time of drilling has been available since the first azimuthal tools were designed and put into use in the 1990s. In water-based muds, numerous improvements in both the resolution and quality of images have been made, particularly in microresistivity logging tools. The challenge to extend these capabilities to oil-based mud (OBM) has been addressed in a new tool designed to acquire high-resolution images in the logging-while-drilling (LWD) environment. The data are maximized by a dual-physics technique using separate resistivity and ultrasonic imaging sensors.

The new tool is introduced along with the key design features that overcome the challenges associated with LWD imaging in oil-based mud. Sensors are positioned on the rotating drill collar with resulting standoff between the sensors and the formation. For the resistivity image, the tool's electromagnetic signal must pass through this gap, which acts as an insulating layer. High-resolution electromagnetic pulses are sent through the mud from the sensor to the formation at multiple frequencies (similar in principle to recently introduced wireline imaging tools for OBM). A novel processing algorithm combines the multiple individual frequencies to produce a robust image across a wide range of resistivities. A set of ultrasonic sensors is positioned close to the resistivity sensors on the tool collar. The high-sampling rates and focusing of the sensors deliver a resolution comparable to wireline ultrasonic imaging tools for the ultrasonic images. Multiple sensors are used for both types of physics measurement, and rapid firing and recording by the sensors maximize full-borehole coverage in the majority of rotary drilling conditions.

An experimental version of the tool has been field tested in a broad variety of drilling and geological environments. To date, over 35,000 ft of data have been acquired in wells ranging from vertical to horizontal. Data acquisition has been in clastics, carbonates, and evaporites having various formation properties. The field-test data have confirmed the metrology of both physics types; i.e., resistivity and ultrasonic imaging. Examples are presented demonstrating the range of measurements under different borehole and geological conditions. Results to date have exceeded expectations in terms of imaging capabilities. Moreover, the acquisition of resistivity and ultrasonic images has frequently proved to be complimentary, with the resistivity images rich in bedding features and the ultrasonic images more sensitive to fractures and borehole conditions.

Focused Nuclear Magnetic Resonance

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Borehole NMR has become an important source of petrophysical information, helped by the development of increasingly sophisticated hardware. However, in order to address the most fundamental challenge to the utility of NMR—namely the inherent nonuniqueness of the inversion—It is necessary to take a holistic approach in which hardware, job planning, inversion and analysis are considered as a whole. It is especially important to understand the role of signal-to-noise, and develop strategies to deal with it, recognizing that physics dictates that some of the most ambitious interpretation objectives may not be compatible with fast logging speeds.

Starting with hardware, a new logging tool has been developed to maximize signal from the formation and minimize noise from the borehole. Negligible borehole signal and high tolerance to tool-orientation error result from focusing the static magnetic field within a 90° sector. Extremely low coupling between the RF antenna and the borehole allows power consumption to be kept small, eliminating the need for fluid excluders, even in very saline muds, and is important for reliability and operational flexibility. Control of the static magnetic field uniformity along the sensor, together with optimally shaped symmetrical prepolarization zones, allow for motion-artifact-free logs and accelerated polarization of fluids with long T_1 components. Tight control of phase and amplitude characteristics of transmit and receive paths ensure acquisitions have negligible levels of systematic echo-train distortions. Higher gradients allow improved characterization of heavy oil and other small diffusion-coefficient fluid components, and are a factor in addressing the commercial pressures for higher logging speeds in unconventional reservoirs.

The operation of the tool is tightly integrated with the design of the data processing and analysis, and manifests itself in highly flexible activation sequences, which are capable of being optimized for particular interpretational needs. This is particularly useful for fluid typing from T_2-D and T_1-T_2 in unconventional reservoirs, noting that the existence of a theoretically optimum sequence is no guarantee that it can be physically realized. A sophisticated job-planning tool and laboratory testing of the activation sequences are critical to this aspect, and operationally the sequences may be optimized on a zone-by-zone basis. Subsequent processing uses the field acquired data to identify the best trains to pass to the inversion, which facilitates the use of new evolving simultaneous joint inversion techniques for better analysis.

Field trials were conducted in over 50 wells encompassing diverse borehole and formation environments. Relative to the tool used as a basis for comparison, results demonstrate step-change improvements in data quality. Processed results and interpretations are reviewed relative to core and data from supporting logs, which also highlight and the benefits of integrating multiple data sources. The new service not only significantly improves confidence in the commonly delivered NMR petrophysical properties; it contributes to a better understanding of what can be achieved and how to achieve it.

High-Resolution Slowness Measurements Using Advanced Ultrasonic Pitch-Catch Technology

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Probing formation elastic properties, both in azimuth and radius, is important when evaluating near-wellbore damage as well as intrinsic and stress-induced anisotropy. These measurements have various potential applications ranging from accurate seismic migration to drilling safety, geosteering, and production and completions optimization. A conventional approach for evaluating these complex formations is to employ a dipole or unipole sonic tool. These tools operate from approximately 0.1 to 20 kHz and are able to deliver azimuthal slowness information with an approximately ≥1-ft depth of investigation. On the other hand, evaluating formation slownesses by focusing on near-wellbore features within a few inches of the depth-of-investigation is very challenging with these standard sonic tools. Data from the shallow depth-of-investigation is important because due to the presence of the borehole, the formation tectonic stress is redistributed and induces a large slowness variation around the near-wellbore, which can be a used as a guide to wellbore stability. In addition, resolving slownesses of thin beds or other features that are <1 ft in thickness, is nearly impossible with the standard sonic logging tool due to the relatively large receiver apertures.

To address these challenges, the authors have developed an advanced ultrasonic pitch-catch (microsonic) technology for a logging-while-drilling (LWD) acoustic tool containing ultrasonic transmitters. This LWD acoustic tool operates over a wide frequency range centered at 250 kHz and contains an array of sensors having a 2-in. receiver aperture.

Numerical modeling of the microsonic tool indicates the tool can primarily detect refracted compressional waves and surface-mode waves related to the pseudo-Rayleigh mode. These waves contain information about the formation compressional and shear slowness, respectively. To validate the new LWD tool's measurement capabilities, the tool was run in a test well, which was previously evaluated with the standard quad-combo wireline logging suites and a formation resistivity imaging tool. Slownesses obtained from the semblance processing of the waveforms acquired with the microsonic tool show characteristic features corresponding to the formation lithology and structure. The variations of those slownesses clearly correlate with the contrast of the resistivity image, especially where thin beds are present. While the receiver aperture of the microsonic tool is far smaller than that of the standard sonic tool, by applying spatial smoothing to the microsonic slowness log, a comparison of the microsonic slowness log with the sonic slowness log was obtained to validate the measurement.

This study demonstrates the outstanding capability of the microsonic technology. It also corroborates the effectiveness of expanding the use of ultrasonic frequencies for probing the fine features of formation acoustic properties that cannot be resolved with traditional methods. The effectiveness of using ultrasonic pitch-catch technology for probing fine features of the formation compressional and shear slownesses is presented in this paper, in addition to the modeling study results and field data analysis obtained with this novel LWD acoustic tool.

Improvements of Fast Modeling of LWD Neutron Logs Acquired in Enlarged Boreholes With a Commercial Tool

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In complex formations and geometries, interpretation methods based on fast modeling and inversion deliver better estimates of petrophysical properties than conventional methods. Neutron measurements are affected by nonlinear formation and borehole effects. Their depth of investigation is also very sensitive to porosity, borehole size variations, fluid and rock properties. Consequently, reliable petrophysical interpretation of neutron logs under complex rock and geometrical conditions requires fast modeling methods.

We developed a fast forward algorithm for a commercial LWD neutron tool. The algorithm is based on perturbation theory, flux sensitivity functions (FSFs), and diffusion flux-difference (DFD) approximations. The DFD method interpolates between Monte Carlo (MC)-derived, base-case FSFs using one-group diffusion models and Rytov approximations. Diffusion approximations successfully capture sensitivity flux perturbations as neutron porosities derived using DFD-perturbed and MC-derived FSFs agree within 2 porosity units (p.u.) in highly deviated wells, in the presence of tool eccentricity and invasion. They significantly outperform linear interpolation approaches, improving accuracy by as much as 10 p.u. Even when diffusion approximations are applied, perturbation theory may still yield inaccurate results when compared to neutron porosity estimated from MCNP counts for regions exhibiting contrasting properties, particularly those with enlarged boreholes. We introduce a new two-step algorithm to improve neutron-modeling accuracy to MCNP counts in the presence of standoff. The algorithm is based on two sets of base cases: sensitivity functions base cases, and detector counts base cases. On one hand, DFD approximations are used to compute perturbed sensitivity functions for any tool, borehole, and formation configuration. On the other hand, count base cases obtained for 8.5-, 9.5-, and 10.5-in. boreholes extend the validity of the Taylor series expansion by minimizing the size of the perturbation.

Compared to neutron porosity derived from MCNP counts, the new algorithm yields relatively low errors in enlarged boreholes. Comparison benchmarks against synthetic and field cases in vertical and high-angle wells confirmed good agreement with Monte Carlo simulation results and field logging data, respectively. For the synthetic case, a high-angle well was assumed with the tool penetrating several bed layers with contrasting hydrogen Index. Monte Carlo simulations were carried out to simulate neutron-detector counts and to compare against results obtained from our fast forward algorithm. The fast forward algorithm was then applied to a field case featuring a high-angle well penetrating a Norwegian sandstone with light hydrocarbons; good agreement was obtained with field logs. Results obtained in the synthetic and field cases show that our fast forward modeling approach can be a good candidate for geosteering applications.

Introduction of a Faster Through-Tubing Pulsed-Neutron Carbon/Oxygen Logging Instrument

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Pulsed-neutron instruments are widely used for reservoir monitoring applications for cased wells. The common practice is to use thermal-neutron capture cross section (sigma) measurement if the formation water is highly saline, and carbon/oxygen (C/O) measurement if the formation water salinity is low or mixed. Sigma is not sensitive enough to distinguish between oil and fresh water; thus, C/O data are required. One significant limitation of the pulsed-neutron C/O measurement is its low measurement precision, requiring very slow logging speeds and multiple pass acquisitions.

This paper introduces a new pulsed-neutron C/O tool designed to provide improved measurement precision while allowing faster logging speeds and fewer passes. The C/O measurement precision is highly influenced by the fact that the amount of the carbon in the logging environment is relatively small compared to the oxygen that roughly makes up half of the formation. The only solution for what nature imposes on the measurement is development of tools that can make best use of what nature provides. Improving the precision is related to increasing the detector count rate, which is limited by neutron output, choice of scintillator, detector size, and electronics. The measurement is especially challenging in slim tools for through-tubing deployment, where, due to space constraints, the scintillator size is limited. To increase the precision, the measurement is traditionally done at low logging speeds with multiple passes. The new 1-11/16-in. multidetector pulsed-neutron tool described here overcomes this shortcoming by using lutetium yttrium orthosilicate (LYSO) scintillation detectors. The high density of LYSO ($\rho = 7.1$ g/cm^3) increases its gamma-ray detection efficiency at the especially high-energy region where the carbon and oxygen gamma rays are emitted. The detector count rate exceeds that of lanthanum bromide ($LaBr_3$, $\rho = 5.1$ g/cm^3) and sodium iodide (NaI, $\rho = 3.67$ g/cm^3). Compared to heavy scintillators like bismuth germanate (BGO, $\rho = 7.13$ g/cm^3) and gadolinium orthosilicate (GSO, ρ = 6.71 g/cm^3), LYSO offers better energy resolution and temperature stability. The high-efficiency detector is combined with a high throughput field-programmable gate array (FPGA) based digital pulse processing system to take full advantage of the increased count rate. The digital pulse processing reduces deadtime and pulse pile-up effects.

The paper discusses the technologies that enable improved measurement precision and reduced logging operational time and cost. LYSO detector count-rate performance is compared to NaI and $LaBr_3$ detectors. Stability of C/O response in the temperature range up to 150°C is demonstrated. Interpretation is based on a comparison of the measured log response with completion- and reservoir-specific Monte Carlo simulations. The C/O measurement response characterization is discussed based on experimental data and Monte Carlo model development.

Lateral-Motion Correction of NMR Logging-While-Drilling Data

Radu Coman, Holger Thern and Tobias Kischkat, Baker Hughes, a GE company

Although the total porosity obtained from nuclear magnetic resonance (NMR) logging-while-drilling (LWD) data is typically not affected by lateral motion of the NMR-LWD tool, some other deliverables (e.g., bound water, movable fluid, permeability, viscosity) might be affected. This paper introduces a data-based lateral-motion correction (LMC) that uses a four-parameter function to quantify and correct potential lateral-motion effects.

The objective of the LMC is to improve the accuracy of the final T_2 porosity distribution. The LMC therefore extends the operational domain of the NMR-LWD method and enables more advanced petrophysical NMR applications at high data quality. In addition, the LMC approach can be used to quantify the lateral-motion effect and to mark intervals where the motion effect is too severe to be fully corrected.

The LMC was developed by analyzing the potential lateral-motion effect on numerous NMR-LWD data in combination with numerical simulations. Using drilling dynamic simulations of a complete bottomhole assembly (BHA) under realistic drilling conditions, motion paths of an NMR sensor were calculated, which were then used to simulate NMR signals. Real data and the NMR simulation indicate that lateral-motion effects can be adequately described by a four-parametric function. Two parameters describe an exponential decay, while the other two parameters describe a periodic variation of the amplitude. The motion-effect function was integrated into the forward matrix of the NMR inversion, and a nonlinear optimization algorithm was used to determine the four motion parameters and to compensate for lateral-motion effects, if present.

Although motion paths are typically complex, the characteristic period of the identified tool motion relates to the revolutions per minute (RPM) of the BHA. The amplitude of the motion mainly depends on the drilling regime (e.g., from “smooth” drilling to whirl), the gap between the BHA stabilizers and the borehole, and the borehole inclination. Numerical simulations show that the NMR motion effect is small to negligible if an NMR-LWD tool with a low magnetic-field gradient and with adequate stabilization is used.

The correction method was tested on synthetic and real NMR-LWD data from more than 30 runs with different realizations of lateral motion. The approach is robust and works for all datasets. The magnitude of the lateral motion effect is reliably shown by the implemented quality-control (QC) indicator. Some examples of synthetic and real NMR data, with and without LMC, are included.

The inversion that includes the LMC improves the quality of the T_2 spectrum, which is important for standard and advanced NMR applications, such as accurate calculation of volumetrics (e.g., movable fluid, bound/irreducible fluids) and pore-size distribution, as well as improved estimation of fluid viscosity and formation permeability.

Monte Carlo Modeling of Thorium Blankets: A Digital Alternative for the API Gamma-Ray Calibration Facility

James Galford, Halliburton

The deteriorating condition of the American Petroleum Institute (API) gamma ray calibration facility on the University of Houston campus was highlighted in two papers presented at the 2017 SPWLA Annual Logging Symposium. Now that awareness of the API facility’s rapidly approaching end of life has been raised, the search for a suitable replacement should include a variety of ideas. The ultimate solution must be readily accessible to service companies regardless of size or market share, and it must be applicable to wireline and logging-while-drilling (LWD) tools, which had not been thought of when the API facility was built. Construction of a new, physical replacement for the API facility that would accommodate both types of gamma-ray instruments is an obvious solution. However, there is little interest among the major service providers and oil companies to embark on such a complex and expensive undertaking in the current business climate.

Monte Carlo modeling of nuclear logging tool responses has become a widely accepted and cost- effective practice during the last 40 years. The future replacement for the API calibration facility will probably involve Monte Carlo modeling because of these features. For this to be a viable option, a normalization to measured data obtained from a test pit, tank, or fixture is necessary to obtain accurate results.

This paper proposes a new method that uses calibrated Monte Carlo models to obtain counting rate-to-API unit sensitivity factors for new hardware designs by modeling their responses to thorium-blanket calibrators. Most, if not all, service providers have thorium-blanket field calibrators that have been characterized with existing natural gamma-ray tools that were calibrated at the API calibration facility. The new technique, which can be applied to wireline and LWD tools, is advantageous because it uses existing field equipment to calibrate the Monte Carlo models instead of bulky, fluid-filled tanks or other constructions, such as man-made or natural rock formations. However, Monte Carlo techniques that have not been used previously for well-logging applications are necessary to accurately simulate tool responses to thorium-blanket calibrators. Results for several tool configurations are presented that show the new technique produces results, which are typically accurate to within a few tenths of a percent. The paper also includes sufficient details to enable anyone with modest nuclear-modeling experience to apply the technique to their equipment.

New Laboratory Setup for Ultrasonic Borehole Logging

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Technology; Tonni Franke Johansen and Idar Larsen, SINTEF; Rune Martin Holt, SINTEF & Norwegian University of Science and Technology

The increasing need of P&A of old wells in the North Sea has led to new involvement and financial spending in the petroleum companies for optimizing and finding new methods for saving time at this operation. Shale has proven to seal off the annulus in longer well sections; however, the detection and qualification of the sealing ability can be improved.

As a response to this, a laboratory setup has been built that can perform pressurized measurements on shale cores. The laboratory setup consists of a steel casing inside a vessel, and the hollow shape represents a well section, where the tool is inside the casing together with a drilling fluid. The measurements are carried out using the pulse-echo method with a 5-MHz focused transducer. The transducer is attached to a toolstring, and the string is locked at a rotation board at top for steadily handling of the logging procedure. The backside of the casing is separated, so if there is an annulus it can contain any fluid independently, and a constant fluid flow can be maintained to measure the permeability. The casing can be cast with cement under pressure to differentiate good and bad bonding, or the vessel can be filled with a rock sample.

The first objective is to consistently test the laboratory setup with different materials behind the casing, and verify the results with numerical simulations. By combining the simulations and the laboratory results, the goal is to document and qualify the laboratory setup. This involves investigating an eccentric tool, the effect of oblique incidence, and the effect of using a focused transducer. The focusing of the transducer enables more energy to be transmitted into the casing, and the high frequency increases the resolution for improved evaluation of debonding and determination of the material behind the casing. The main result is to deliver a comprehensive study the laboratory setup, and so far, the laboratory results and the numerical simulations show good correlation. This provides confidence in the measured data, and by exploiting the numerical simulations, we can evaluate the displacement at the casing and the pressure field at any given point. This has allowed us to interpret the different waves being excited and thereby extend our understanding of the reflected signals.

Further, a laboratory experiment with a larger shale core with the casing in the middle is under development. The shale core will be exposed to an external pressure, so the core will start to creep towards the casing. The permeability in the annulus will be constantly measured so we can determine if the shale will creep and eventually function as a sealing barrier. The experiment will be monitored by the ultrasonic pulse-echo method, and this allows us to measure the third-interface-echo (TIE), which provides information about the creeping shale. In addition, we will obtain measurements over a larger time window, where we can observe the shrinkage of the annulus results in the first contact between the casing and the shale, and ultimately completely sealing off the zone.

New Multiphysics, Multiscale Inversion for Imaging Petrophysical Properties in Anisotropic Laminated Formations

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We present a new inversion that integrates multiphysics, multiscale borehole data, new effective-medium petrophysical models, and 1D or 2D tool response models, to characterize formations with anisotropic thin laminations containing radially varying saturation of up to three fluid phases. Sonic data, such as Stoneley- and flexural-wave dispersion, compressional transit-times, slowness logs, together with triaxial induction and density logs, are integrated into a self-consistent petrophysical model that honors the multiscale radial sensitivities of all the data. As output, the inversion provides images of radial distribution of water, oil, and gas saturations, porosity, and shapes of different pore types, for a thinly laminated medium, which can guide formation evaluation decisions in challenging scenarios.

We previously developed an inversion framework that integrates sonic, induction, and density data based on radially heterogeneous, isotropic layers with a thickness of 1 to 2 ft dictated by the axial resolution of the data. The inversion solves for radial distribution of three fluid phases, pore shape and porosity, extending up to 3 ft radially from wellbore. Under the previous framework, intervals with axial heterogeneity from adjacent layers can be identified and characterized with 2D tool-response models that include both radial and axial sensitivity. However, if the layers contain laminations much thinner than the tool axial resolution, with contrasting properties and pore types, then the previous framework can lead to bias in the estimated petrophysical properties.

Therefore in this work, we expand the framework by developing new effective-medium petrophysical models for a thinly laminated medium, which are combined with 1D or 2D tool-response models for a TIV medium to simulate the data. The inversion estimates petrophysical formation properties for a TIV medium such that the simulated data match the measured data at each log depth. Additional to the sonic flexural-wave dispersion and induction data included in the previous framework, here we include the Stoneley-wave dispersion and triaxial induction logs to characterize both radial and axial properties of the TIV formation at different radial depths from the borehole.

We apply the new inversion to two field datasets for a gas-bearing formation drilled with oil-based mud in an interval with thin laminations of shale and sand. The shale laminations have intrinsic TIV anisotropy from grains and boundwater-filled pores aligned with layer boundaries, whereas the sand laminations are isotropic because of randomly oriented grains and fluid-filled pores. Results from the new inversion a show significantly more accurate estimate of fluid saturations and porosity in gas-bearing sand laminations, and more accurate pore shape in bound-water-filled shale laminations. The results are compared with traditional interpretation of high axial resolution data from dielectric, NMR, and applied in conjunction with Thomas-Stieber workflow and net-to-gross analysis from image logs. The combination of triaxial induction, density, and sonic Stoneley, flexural and compressional wave data, which is demonstrated here for the first time, allows more accurate, efficient, and robust imaging of radial distribution of petrophysical properties in TIV formations, as compared to traditional workflows.

New Triaxial Induction Quality Indicators (QI) to Aid in the Understanding of the Validity of the Triaxial Induction Answer Products

Ahmed Fouda, Junsheng Hou, David Torres, John Quirein and Sandeep Ramakrishna, Halliburton

Triaxial induction (TI) borehole-correction algorithms are based on an eight-variable borehole formation model, namely horizontal resistivity (R_h), vertical resistivity (R_v), relative-dip angle, relative-dip azimuthal angle, borehole diameter, tool-eccentric distance (or standoff), tool-eccentricity azimuthal angle, and borehole mud resistivity (R_m). Actual data, however, do not always conform to the model; the most important inverted results, such as R_h, R_v, relative-dip angle, and relative-dip azimuthal angle, may be highly affected by these model nonconformities. The quality of the fit of the data to the model has been generally characterized with a single misfit function constructed by summing the difference squared of all measured and reconstructed conductivity tensors. Attempts to estimate errors of the modeled parameters have generally proven to be inadequate, requiring modification by "rules of the thumb" to determine good vs. poor inversion-predicted parameters.

This paper describes a series of quality indicators (QI) that show when the predicted data deviates from the model assumptions to better understand the conformity of the model to the real data, and consequently, the validity of the results. These QI address the degree of noncircularity of the borehole, excessive eccentricity of the tool that affects the inverted results, whether the formation conforms to the assumption of being a TI formation, and validity of the inverted R_h, R_v, relative dip, and relative-dip azimuthal angle. This is accomplished using a previously benchmarked 3D electromagnetic forward solver, based on a finite-difference method, to solve the vector-coupled potential equations to generate and invert synthetic tool tensor data. This paper shows the inversion results on both synthetic and actual data, and demonstrates how the QI aid in explaining the unusual triaxial induction tool responses.

Next-Generation LWD NMR for Slim Holes

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Nuclear magnetic resonance (NMR) is now a firmly established formation evaluation service available in logging-while-drilling (LWD) mode. Key NMR products including lithology-independent porosity, fluids, and producibility answers are broadly accepted in the industry. Existing commercial services focus either on T_2 or T_1 acquisition modes, each of which has its own advantages and disadvantages. This paper presents initial results of a new-generation LWD NMR service for slimholes, which offers the benefits of both T_2 and T_1 measurements.

The new slimhole NMR technology introduced in this paper has been designed with service efficiency as a primary objective, along with hardware reliability, data quality, and answer products objectives. Using novel acquisition electronics and an optimized magnet configuration, the sensor is highly tolerant to variations in borehole salinity and operates with a short echo spacing. The new tool delivers simultaneous T_1 and T_2 distributions while drilling, along with all derived NMR answer products in real time. This includes T_1 and T_2 distributions and the associated answer products, all while the BHA is either rotating or sliding. The simultaneous T_1-T_2 capability allows good definition of both slow- as well as fast-relaxing components, enabling more accurate distinction of different fluid environments. Because of the high-quality raw data and an efficient T_1-T_2 acquisition scheme, NMR answers are delivered at high resolution even at moderate drilling speeds, with formation features on the order of 1 ft being accurately identified. A common processing workflow ensures that all real-time answers are equivalent to post-acquisition recorded-mode products.

The potential effects of lateral motion, a concern for all LWD NMR tools, are largely mitigated in the new slimhole tool through optimization of the magnet and antenna design. The standard acquisition of T_1 data also helps to minimize the risk of motion effects compared with T_2-only measurements. In addition, a workflow has been developed which integrates NMR physics with drilling dynamics so that BHA configurations may be optimized to minimize motional modes at the NMR sensor, as part of the overall job-planning exercise.

Results are presented from two field tests. The first was in a vertical hole at a test facility. Multiple runs were acquired while drilling both with, and without a motor and in washdown mode. The second field test was performed in an operator well on the North Slope, Alaska. Here, the new NMR tool was run in a horizontal 6.75-in. hole drilled through a sand-shale formation with the primary objective of identifying permeable pay zones in real time as targets for subsequent wireline fluid sampling. Additionally, this dataset was used to understand the complex fluid distributions and properties within an isolated fault block.

Novel Smart Cement for Improved Well-Integrity Evaluation

Hani Elshahawi, Shell International Exploration and Production Inc.; Jacob Pollock and Vinod Veedu, OceanIt

Wells can experience integrity failure during the production cycle. Improved knowledge of cement-bond strength and distribution enables lifetime well-integrity monitoring thus improving HSSE and environmental sustainability and enhancing life cycle economics.

In this paper, a novel solution to well integrity is presented. We have developed a smart well cement with specific enhanced acoustic signatures that can be detected by traditional sonic logging tools. This smart acoustically responsive cement uses a specially engineered particulate filler that acts as an acoustic band gap filter and contrast agent at specific frequencies. The acoustic signature of the cement can be analyzed to determine the integrity of the cement, contamination in the cement, and, importantly, mechanical loading on the cement. During the development of this technology, finite-element modeling and simulation were used to determine the acoustic response of the novel material and guide the design of the particle additive.

The material was produced on the laboratory scale, and the acoustic-band gap features were confirmed using vibrational measurements. Ultrasonic measurements were used to determine the acoustic response of subscale composite structures, including under mechanical load and in simulated environmental tests. Shallow buried pipes with cemented annuli and engineered voids were constructed at a field site. A slimhole monopole sonic logging tool was then used to map the cement location and determine the location and relative degree of mechanical loading. Stress was applied using a variety of methods and mapped along the wellbore. The results indicated improved acoustic detection using sonic bond-log tools including uniquely identifiable cement placement, enhanced void discrimination, and localization of loaded regions. This provides significant value for a smart acoustically responsive cement in detecting and thereby reducing well integrity risks due to cementing. The acoustically responsive cement allows distinguishing between fluids and lightweight cement, monitoring of formation depletion and reservoir compaction, and increased knowledge of wellbore stresses in the oil field. Furthermore, the material has the potential to be continuously monitored with an acoustic interrogation system for remote real-time indication of cement stress and integrity on a zone-by-zone basis.

Predicting Reservoir Fluid-Sample Contamination Using an Advanced Equation-of-State-Based Model

Peter Olapade, Mehdi Alipour Kallehbasti, Bin Dai and Christopher Jones, Halliburton

It is well known that the acquisition of representative formation-fluid samples is essential for reservoir management and development. However, because of overbalance pressure in the mud column, mud filtrate invades and contaminates the reservoir fluid during the drilling process, before the mudcake around the wellbore is properly formed. Although water-based mud (WBM) is immiscible with formation fluid, oil-based mud (OBM) is miscible with it. Samples with OBM contamination levels greater than at least 10%, if not 15%, for oils and 3% for volatile oils and gas condensates, may be considered unusable because the OBM contamination alters the formation-fluid properties; this alteration prevents an accurate characterization of the reservoir fluid. Despite a large body of research, it is very difficult to avoid contamination. Unfortunately, openhole sampling is usually a single opportunity event; by the time the laboratory analysis is complete, it is not possible to acquire additional samples. Consequently, it is important to be able to measure the contamination level of the reservoir fluid, as accurately as possible in real time, before taking the sample. In addition, by knowing the contamination level in real time, the optimal timing of sampling can easily be determined, which reduces rig time/cost and reduces fishing risks. Current techniques to estimate contamination nearly ubiquitously rely on curve fitting of measured properties, such density, fluid compositions (including gas/oil ratio (GOR) and asphaltene content), or color. These techniques, however, suffer from several shortcomings, such as tool drifting, dependence on the endmember filtrate, and formation-fluid properties. In all techniques, those measured properties are assumed to asymptotically approach clean fluid properties.

This paper proposes a method to estimate the drilling-fluid contamination levels and characterize reservoir fluid in real time by using the formation-tester tool measurements of the fluid. Although equation-of-state methods have been previously proposed, in this approach, a combination of a multipoint equation-of-state, distribution function of formation fluids, inherent geochemistry principles, and empirical correlations are used. This advanced equation-of state-method has been validated with several laboratory data sets.

The algorithm developed uses an inverse method to compute the reservoir-fluid contamination. It takes as inputs the downhole fluid composition, including C_1, C_2, C_3, C_4-C_5, C_6 saturates aromatics resins and asphaltenes fractions and fluid properties, such as GOR, density, and bubblepoint pressure, and mud-filtrate composition. Using an iterative process, an optimum combination of formation and filtrate fluids whose properties best match the fluid properties supplied to the algorithm is determined.

Sensitivity Study and Uncertainty Qualification of Azimuthal Propagation Resistivity Measurements

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Since LWD deep azimuthal resistivity service was first introduced a decade ago followed by ultradeep azimuthal resistivity a few years ago, the new service has been under the spotlight and drawn great attention from operators. The azimuthal propagation resistivity tools all use the concept of multispacings, multifrequency and multicomponents. The measurement acquired by the tool is much richer than traditional omnidirectional propagation resistivity.

The application of the new service is widely used, ranging from well placement, reservoir mapping, geostopping, landing, fault detection and salt-edge detection. However, due to the complexity of the measurement physics, tool-response characteristics and data processing, many operators do not have sufficient confidence to use the service more often.

In order to promote the understanding of the service and clarify the various questions in the industry, we systematically study the sensitivity and quantify the uncertainty of the inverted parameters. We use various 1D and 2D formation models with both deterministic and Monte Carlo-based statistical inversion methods to quantify the uncertainty.

A set of 1D formation models proposed by SPWLA Resistivity-SIG chapter is used to characterize the sensitivity and quantify the uncertainty of the bed-boundary position, formation resistivity, dip angle, directionality and anisotropy. The algorithm is robust in that it is able to quantify the importance of each measurement (or the combination of the measurements) to the final answer. The information content of the measurement and the proper use of the measurements is clearly observed when using this algorithm. It provides a guideline for BHA design, proper selection of the inversion algorithm, the optimum data channels to be pulsed in real-time and the expected error bar on the inversion outputs. It is more realistic and practical than the Picasso-style plot currently offered by service providers. Both synthetic data and field examples are used to validate this work.

Slimhole NMR T_1 Logging-While-Drilling Enhances Real-Time Petrophysics

Gabor Hursan and Andre Silva, Saudi Aramco; Johathan Lee and Ahmed Taher, Halliburton

This paper presents the first while-drilling acquisition of nuclear magnetic resonance (NMR) polarization buildup data in slim boreholes in the Middle East. NMR logging data are paramount to the petrophysical evaluation of complex rocks, such as silty sands, heterogeneous carbonates and reservoirs with variable hydrocarbon viscosity in many fields of the region. Fractionalized porosity obtained by NMR logs can discern bound fluids and free fluids, reveal otherwise hidden pore-size variations and determine hydrocarbon composition and viscosity with unique sensitivity. The real-time availability of this valuable information from logging-while-drilling (LWD) measurements significantly improves drilling decisions to place the well into favorable zones. In addition, under some circumstances, it is safer to perform logging operations with sensors mounted on a bottomhole assembly (BHA) than with pipe-conveyed wireline tools.

Most NMR logging tools, including wireline and LWD devices, record the transverse magnetization signal and its decay rate (T_2), because of the simplicity and rapidity of the measurement. Other instruments observe the formation's magnetization buildup rate (T_1) upon exposure to a permanent magnetic field. While this acquisition mode is more time consuming, it requires less electrical power and data storage to obtain the same petrophysical information. Furthermore, the T_1 measurement is insensitive to tool motion associated with drilling. The new tool discussed in this paper is the industry's first LWD NMR sensor that performs T_1 measurements in boreholes with diameters ranging from 5-7/8 to 6-1/4 in.

The verification of the new tool followed a three-step testing plan to ensure hardware integrity and data quality. The first testing step checked the consistency between while-drilling and relog datasets including the T_1 spectra and the volumetric deliverables such as total and bound-fluid porosity. Real-time logs were compared with post-processed memory data to evaluate downhole processing and data transmission capabilities. The second testing objective was to monitor the consistency among density, neutron and NMR porosities in known lithology (e.g., clean limestones) for the evaluation of tool calibration, activation and echo-level preprocessing. Finally, the new tool was run back-to-back with a wireline NMR logging tool with high-quality T_1 logging capabilities to validate the accuracy of the LWD T_1 spectrum and partial porosities.

The new tool is the latest addition to the industry's LWD NMR technology. It was run in three wells with hole sizes of 6-1/8 in. in three different fields without incidents. Two of the wells were drilled in carbonate reservoirs, whereas, the last test was conducted in sandstone. The tool met all expectations as described for the three-step consistency test. In the carbonate wells, real-time NMR logs provided pore size information in both limestones and dolomitic intervals and helped optimize subsequent formation testing operations whose result was in excellent agreement with the logs. In the sandstone well, the tool revealed grain-size variations and provided total porosity, bound-water volume and reservoir permeability. These were key inputs for petrophysical interpretation, model calibration, and completions design.

Systematic Optimization Approach for High-Resolution NMR Logging

Songhua Chen, Lilong Li, Wei Shao, Arcady Reiderman and Ron Balliet, Halliburton

A preferred nuclear magnetic resonance (NMR) logging tool should possess the following features: (1) high vertical resolution at reasonable logging speeds; (2) high spectral resolution to resolve fluid constituents embedded in relaxation time distributions; (3) capacity to acquire data with a short interecho-time (TE) to capture fast decay components and increase data density; (4) adequate field gradient to enable diffusivity sensitivity; and (5) robust data quality that is immune to tool motion, borehole rugosity, and environment variations. The realization of these comprehensive requirements is possible with substantial sensor, environment, and spin-dynamics simulations.

Meeting the requirement of high vertical and spectral resolutions of NMR logging best illustrates the need of a systematic approach for optimization. First, the antenna aperture is optimized to be sufficiently short for static resolution, but long enough to avoid the need of substantial motion correction for high-speed logging. Second, broadband multifrequency with narrow, shaped RF pulses are used to ensure high dynamic resolution with robust logging speed and to increase the frequency-band packing density to boost the overall signal-to-noise ratio (SNR) with the minimal need of vertical stacking. Narrow pulses also enable short-TE data acquisition, which increase the time-domain data density. Third, a highly focused antenna minimizes the sensitivity to borehole salinity, enabling adequate SNR, even in high-salinity boreholes. Fourth, a combination of narrow, shaped RF pulses and intermediate gradient range results in wider sensitive volumes, which reduce motion sensitivity, even at higher logging speeds.

Sensor optimization is necessary, but is not all-encompassing, to achieve high-resolution NMR logging. The systematic approach relies on spin-dynamics simulation for a data-acquisition design that optimizes spectral resolution for targeted fluid or pore typing. Three novel data-processing methods were investigated to improve vertical and spectral resolutions. Method 1 uses a two-step inversion. In Step 1, inversion is applied to heavily stacked echo data to obtain high-relaxation time spectral resolution, but a low vertical resolution. In Step 2, maximum-a-posteriori (MAP) inversion is applied to minimally stacked data; the priors for the MAP inversion are the T_1 or T_2 distribution from Step 1. The resultant high-vertical-resolution T_1 or T_2 distribution will have comparable spectral resolution of the stacked data. Method 2 applies joint inversion of data stacked at 2, 4, 8… levels, similar to a deblurring image processing technique. Method 3 applies to a data-acquisition sequence that yields a large number of repeats of partial-recovery echo bursts that can be stacked together (PR), and a nonstacked, normal-SNR fully polarized echo train (FR) per depth. In this method, high-resolution stacked PR is inverted first, then the corresponding bound-water bin porosities are forward-modeled and subsequently subtracted from time-domain FR data; inversion is applied to the latter using a reduced bin range, thereby reducing the effects of high-frequency random noise in the inversion results.

The paper presents NMR logs acquired with multiple logging speeds over varying thin-bed formations. Simulation results representing a wide-range of scenarios with actual logging activations further demonstrate the effectiveness of the systematic optimization approach for obtaining robust high-resolution NMR logs.

Visualizing the Mechanism of Azimuthal Shear Anisotropy With Broadband Frequency Analysis

Rachel Confer, Mark Collins and Philip Tracadas, Halliburton

A new log-visualization approach uses the frequency-domain azimuthal anisotropy algorithm of Collins to provide insight into the anisotropy mechanism using a continuous log presentation. Conventional crossed-dipole azimuthal anisotropy is processed routinely in the time domain, providing the direction of the formation fast shear and the magnitude of difference (in percent) between the fast- and slow-shear velocities. These standard log curves do not provide clues to the underlying mechanism that caused the shear splitting. A common method of determining the azimuthal anisotropy mechanism is through the use of fast- and slow-shear-dispersion curve overlay analysis. This approach requires a two-dimensional graph analysis per depth acquisition, which usually results in report presentation at coarse depth intervals and is not as visually intuitive as a log plot.

The basis of this new approach compares the fast angle from time-domain processing to the fast angle measured as a function of frequency over a wide band from formation cutoff to up above 6 kHz. In the case of crossed-dipole azimuthal anisotropy being caused by imbalanced horizontal stresses, the hoop stress at the borehole wall will cause the fast angle to rotate away from the formation's maximum stress direction as the frequency increases. This angle flip is plotted visually as a shaded vector of angle rotation value versus frequency in a track alongside another visual representation of crossover from the fast- and slow-shear-dispersion curve value differences versus frequency termed signed percent anisotropy. A back rotation similarity output is also generated as a quality control measure to assess whether the anisotropy mechanism obeys the Alford rotation assumptions. This measure uses the resulting matrix of fast- and slow-shear waveforms, sets the cross-axis waveform response to zero, and takes the matrix backward through the Alford rotation to compare with the original matrix of waveform response. If the result is a close match, the answer is considered to obey horizontal transverse isotropy (HTI) assumptions; a large misfit indicates that the environment does not meet HTI conditions. Instead, an orthorhombic environment may be present.

The paper presents field data to demonstrate an integrated approach to investigate the azimuthal anisotropy mechanism in both the time and frequency domains to distinguish stress-induced anisotropy from intrinsic anisotropy within the same well on a single log plot. The integration with resistivity and acoustic image logs distinguishes between dipped bedding and fractures to fully characterize the intrinsic anisotropy and complete the mechanism analysis.

What's New in Borehole Nuclear Modeling? (A Lot!)

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Nuclear borehole instruments are ubiquitous in well logging—from bare-bones logging-while-drilling (LWD) gamma to conventional triple-combo and more esoteric neutron-gamma capture (Σ) and spectroscopy tools. Now, more than ever, nuclear modeling is being used instead of physical experiments to relate nuclear measurements to formation properties, petrophysical parameters, and even to generate "digital" calibration standards.

This paper discusses significant improvements in software and hardware used to model measurements acquired with borehole nuclear instruments. These advances make nuclear modeling more accurate, more efficient, and substantially less expensive to perform.

For qualitative interrogations of complex rock formations, the University of Texas developed UTNuPro, a successor to the venerable SNUPAR program, that supports more elements and yields better matches with Monte Carlo calculations. Given a material description of the formation and its pore-space fluid, UTNuPro computes macroscopic nuclear properties that predict how nuclear tools will respond. An inversion-based interpretation involves adjusting formation properties until a predicted nuclear log matches what was measured; UTNuPro provides first-order trends without requiring proprietary knowledge of the tool geometry.

If the user possesses details of the tool geometry, then nuclear Monte Carlo simulations can provide quantitative results. Wondering whether a nuclear log makes sense in shale when drilling with an unusual mud? Model the shale (or bed boundaries or layers, etc.) before and after invasion. Designing a new tool? It is straightforward to model different nuclear sources and detector types.

This paper explores recent and forthcoming changes in the nuclear Monte Carlo n-particle code (MCNP) that are useful to the industry. Modeling the tool geometry is much easier because MCNP now supports an "unstructured mesh" geometry that can be rendered (almost) directly from a computer-aided design (CAD) file for the tool. An "importance map" of the geometry is constructed simultaneously to speed up simulations. (Such maps can be used for fast, quasilinear modeling to implement reliable inversion-based interpretations in real-time, akin to borehole resistivity, resulting in better rock compositional assessments.) New helper tools improve detector processing and particle tracking (MCNPTools), compute more realistic post-processed detector spectra (DRiFT), and produce source descriptions for complicated decay chains such as those for U and Th required for natural gamma modeling (ISC). New physics includes alpha particle tracking (vital for modeling 10B-based neutron detectors) and correlated fission event generators (CGMF and FREYA). Pulsed-neutron spectral interpretation is simplified because MCNP can now "tag" each photon with its element of origin. Borehole nuclear Monte Carlo requires some type of computer cluster; accordingly, this paper provides best practices for choosing appropriate hardware or cloud service, as the latter is now an option, and constructing and maintaining the cluster with minimum effort while satisfying the strict US Department of Energy requirements for MCNP clusters. MCNP relies on high-quality nuclear data, hence reviewing recent evaluated nuclear data file (ENDF) cross sections, including the new generalized nuclear data (GND) format, new versions of NJOY for processing the cross sections, and the introduction of photon-production cross sections from the TENDL libraries (for modeling nuclear mineralogy tools).

OIL AND GAS DATA SCIENCE AND ANALYTICS

Accelerating and Enhancing Petrophysical Analysis With Machine Learning: A Case Study of an Automated System for Well-Log Outlier Detection and Reconstruction

Ridvan Akkurt, Schlumberger; Tim Conroy, Woodside Energy; David Psaila and Andrea Paxton, Schlumberger; Jacob Low and Paul Spaans, Woodside Energy

Recent advances in data science and machine learning (ML) have brought the benefits of these technologies closer to the main stream of petrophysics. ML systems, where decisions and self-checks are made by carefully designed algorithms, in addition to executing typical tasks, such as classification and regression, offer efficient and liberating solutions to the modern petrophysicist. The outline of such a system and its application in the form of a multilevel workflow to a 60-well multifield study are presented in this paper.

The main objective of the workflow is to identify outliers in bulk-density and compressional slowness logs, and to reconstruct them using data-driven predictive models. A secondary objective of the project is to predict shear slowness in zones where such data do not exist.

The system is fully automated, designed to optimize the use of all available data, and provide uncertainty estimates. It integrates modern concepts for novelty detection, predictive classification and regression, as well as multidimensional scaling based on inter dimensional scaling based on interwell similarity.

Benchmarking of ML results against those created by human experts show the ML workflow can provide high-quality answers that compare quite favorably to those produced by humans. A second validation exercise, that compares acoustic impedance logs computed from ML answers to actual seismic data, provides further evidence for the accuracy of the ML-generated results. The ML system supports the petrophysicist by easing the burden on repetitive and burdensome quality control (QC) tasks. The efficiency gains and time-savings created can be used for enhanced effective crossdiscipline integration, collaboration and further innovation.

Advanced Fractal Modeling of Heterogeneous and Anisotropic Reservoirs

Paul W.J. Glover, Piroska Lorinczi, Saud Al-Zainaldin, George Daniel and Saddam Sinan, University of Leeds

Paradigms are shifting in the hydrocarbon industry. Large, relatively uncomplicated reservoirs are obsolescent, and those resources, which remain will be increasingly smaller, deeper, more difficult to access, more heterogeneous and more anisotropic. Unfortunately, conventional reservoir modeling, which uses statistical techniques to populate the interwell volume, use upscaling and interpolation of sparse datasets with a resolution of at least 50 m. Conventional approaches have difficulty modeling heterogeneous and anisotropic reservoirs because such reservoirs exhibit extreme interwell variability, making them less reliable for reservoir management and development. This paper focuses on the modeling and simulation of heterogeneous and anisotropic reservoirs using a new fractal approach, which includes data at all scales such that it can represent the heterogeneity of the reservoir correctly at each scale. These three-dimensional advanced fractal reservoir models (AFRMs) can be used in generic modeling in order to understand the effects of heterogeneity and anisotropy, and can also be conditioned to represent real reservoirs.

This paper will show (1) how 3D AFRMs can be constructed and normalized to represent porosity, cementation exponent and grain size, and (2) how these models can be used to calculate permeability, synthetic porosity-permeability crossplots, water saturation maps and relative permeability curves. Finally, (3) we will show how these initially generic models can be conditioned to represent the variability found in real reservoirs. Results of generic modeling and simulation with AFRMs will be given, which show how total hydrocarbon production, hydrocarbon production rate, water cut and the time to water breakthrough all depend strongly on heterogeneity as represented by the fractal dimension the reservoir, and also depend upon anisotropy.

Further work also shows that in heterogeneous reservoirs, the best production data are obtained from placing both injectors and producers, counter-intuitively, in the most permeable areas of the reservoir. In addition, modeling with different degrees and directions of anisotropy have also shown how the critical production data dependent anisotropy over the lifetime of the production of the reservoir. The real test of AFRMs is their capacity to be conditioned to real reservoirs. Initial results will be presented where fractal interpolation has been used to match AFRMs to reservoir data across a wide scale range. Results comparing the production characteristics of such an approach to a conventional kriging and upscaling approach will be presented, showing a remarkable improvement in production modeling when AFRMs are used. The use of AFRMs in moderate to high heterogeneity reservoirs was always within 5% of the reference case, while the conventional approach often resulted in systematic underestimations of production rate by over 70%.

Artificial Intelligence for Prediction of Severe Fluid Losses in Presalt Carbonates

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Severe fluid losses while drilling carbonate reservoirs have considerably increased well construction time and costs. Such extra expenses are mainly related to wasted time while struggling with such losses, material costs and its delivery/availability logistics. Besides the economic impact, severe circulation losses have HSE impacts since there is a risk of well control when losses can evolve to hydrocarbon inflow and simultaneous loss and gain issues. Extreme situations may lead to temporary or even definitive abandonment.

Fluid-loss predictions are usually performed by a specialist with knowledge of the geological model and the drilling history of the field. Such approach has proved to be a hard task, with limited success, especially in the presalt carbonate reservoirs due to their high structural and facies heterogeneity. Focusing on uncertainty reduction of critical resources allocation, such as managed pressure drilling (MPD) and loss-control materials (LCM), this study aims to improve prediction (as compared to the conventional expert-based approach) of the geological structures that might lead to severe fluid losses with impact on well construction costs.

Artificial Intelligence (AI) techniques have proved to be useful with a high success rate in complex problem solving in many industrial segments. The focus of the present study was to search for AI algorithms to correlate seismic attributes, well logs, fluid-loss occurrences and information from geologic and reservoir flow models. A pilot area comprising 38 wells drilled in Santos Basin (Brazil) was chosen for the present analysis. The first step was to use this dataset to map the search space of the algorithms, i.e., to identify the critical intervals for severe losses. Information gain tests related to the fluid-loss rate (dependent variable) were performed aiming to identify the most relevant independent variables for the case of severe losses prediction and to discard the ones with minor contribution.

Among the tested classifiers, an ensemble of Naive Bayes & Perceptron Neural Network had the best performance at predicting severe fluid losses for the pilot area. A global hit rate of 84% was achieved for metrics evaluated under a well-based standpoint. A blind test with 11 wells (from a different set) returned 82% of global hit rate. These results are considered superior than the ones obtained through the conventional approach. It is important to mention that due to the great uncertainty of the related variables, the output cannot be more accurate than the precision of the original data employed.

These results show a great potential for the use of AI techniques on severe fluid-loss predictions in presalt carbonates. Therefore, the AI approach is being incorporated as a new tool to support the field experts on improving the performance of the predictions.

Statistical Methods to Enable Practical Onsite Tomographic Imaging of Whole-Core Samples

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X-ray computerized tomography (CT) allows initial inspection of the internal structure of whole-core and it is a valuable technique to efficiently select subsamples for further analysis. Additionally, whole-core tomographic imaging is an effective tool for stratigraphy characterization, categorizing geological horizons, visualizing coarse sedimentary features, and core-log correlation. Although conventional X-ray scanners are available with most core analysis laboratories or neighboring medical establishments, this measurement practice remains in the laboratory domain and is rarely performed onsite. This is primarily due to the instrumentation complexity and limited portability as well as measurement time demands. Consequently, important operational petrophysical decisions for core analysis are delayed for days or weeks after coring a well.

We show that statistical methods enable the use of portable industrial scanners (with sparse measurements), suitable for fast onsite whole-core X-ray CT, as opposed to conventional (medical) devices (with dense measurements). This accelerates an informed first-stage general assessment of core samples, even before these are extracted from the core barrel liner. Conventional X-ray CT systems use dense projections (radiograms), which rely on back-projection image reconstruction algorithms. Alternatively, with sparse radiograms, statistical methods yield superior tomographic images than those derived from standard back-projection. This distinct imaging principle enables using more robust and portable industrial equipment with limited measurement acquisition. To that end, we show that this novel industrial tomographic measurement principle is feasible for rock-sample imaging, in conjunction with suitable forms of priors in Bayesian inversion algorithms. We assess the performance of the inversion with Gaussian, Cauchy, and Total Variation (TV) priors. In so doing, we consider, in discrete form, conditional mean (CM) estimators, via Markov Chain Monte Carlo (MCMC), and maximum a posteriori (MAP) estimators, via optimization in noise-contaminated measurements.

To benchmark the reliability of whole-core imaging with sparse radiograms via Bayesian inversion, we consider X-ray CT from numerical simulations and test it with actual tomographic measurements of whole-core samples. To that end, we acquire tomographic measurements of fine-grained core samples from the Kevitsa area in northern Finland, and serpentinite-clorite schist from the Kainuu region, characterized by layered structure and elongates minerals. Bayesian inversion results show that with only 12 radiograms, foliated texture and fractures of approximately 2-cm long by 0.1-cm wide are detectable. Additionally, images show approximately circular concretions of 1.3-cm diameter. We show that to achieve similar results, filtered back-projection (FBP) techniques require hundreds of radiograms, only possible with conventional (medical) scanners.

This paper shows that Bayesian inversion on whole-core X-ray CT is capable of imaging coarse sedimentary features that, with faster measurement principles, would aid in more efficient operational petrophysical decisions for planning further core analysis. Its applicability in high-resolution micro-CT is left for a subsequent study.

Using Machine-Learning for Depositional Facies Prediction in a Complex Carbonate Reservoir

Nadege Bize Forest, Lucas Lima, Laura Lima, Victoria Baines and Austin Boyd, Schlumberger; Frances Abbots and Andrew Barnett, Shell

A geomodel is the framework for propagating reservoir rock types and petrophysical properties in 3D to build the static model, which is fundamental to setting up the dynamic model to understand reservoir quality and performance during the field development phase. The first step in constructing a reliable 3D geostatistical model for depositional facies, only available and described from wells that have been cored, is to predict them for the uncored sections using clustering methods or neural networks on continuous downhole measurements. The next challenge is to model depositional facies geometries between the wells.

In carbonate reservoirs, the challenge to identify the original depositional facies is a notorious issue, as the same depositional facies can be affected by different diagenesis processes, leading to rock-types with different petrophysical properties. The interrelationships between depositional facies and petrophysical logs are not straightforward and conventional training or supervised methods are usually not successful for depositional facies prediction. This is particularly true for the heterogeneous lacustrine carbonates of the Brazilian Presalt carbonates where facies cannot be predicted with more than a 40% accuracy using conventional training techniques.

Our paper describes an innovative new workflow to predict complex carbonate depositional facies from logs using multiple clustering methods combined with probability techniques, or machine learning. The workflow was developed using a dataset with 250 m of core and 25 logs covering a 5-km interval of oil-bearing reservoir.

The new workflow for facies prediction focuses on data management, supervised, unsupervised learning methods and probabilistic algorithms:

1. Data management and preparation includes an automatic removal of the top and bottom of the facies boundaries to exclude log shoulder effects from the training dataset, a normalization of log data correcting for outliers, and the option to generate blocked logs. For all supervised methods tested, the new data management workflow increases accuracy of the results by 5%.
2. Several supervised learning methods including SVM Gaussian, Random Forest, neural network, Naïve Bayes, KNN, MLP etc. are run simultaneously using the full suite of available logs. For each method, accuracy scores (mean, variance) are generated by testing the model well-by-well. The objective is to

identify which training method clusters the best against the depositional facies, and to define the optimum combination of logs to use.

3. An unsupervised clustering method equivalent to the best supervised method previously identified, and using the best set of input logs, is run to define petrophysical clusters. The optimum number of petrophysical clusters is generated, which carries the maximum information.
4. The petrophysical clusters generated are then compared to the core depositional facies in order to find the rules of frequency, stratigraphic distributions and likely patterns. Petrophysical clusters are then automatically assigned to the corresponding depositional facies.

Fifteen petrophysical clusters were identified for the dataset used and reassigned to five main depositional facies described from core. The integrated supervised-unsupervised clustering approach increased accuracy tests for facies prediction by over 20%, which makes the final model more accurate.

RESERVOIR AND PRODUCTION SURVEILLANCE

A New Formation Evaluation Philosophy to Integrate Production Surveillance Petrophysical Interpretation Results With Reservoir Model Simulation; A North Sea Case Study

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This paper introduces a new petrophysical interpretation philosophy for the evaluation of cased-hole saturation logs and PLT data. This new petrophysical interpretation technique has been developed to reduce the significant uncertainty that is typically inherent in the quantitative interpretation of cased-hole sigma and inelastic capture spectra (Carbon/Oxygen) data. This new interpretation technique has been specifically designed to create interpretation products that can be seamlessly integrated with subsurface workflows in a robust and quantitative way. Examples from a North Sea case study highlight how the new petrophysical interpretation products are integrated with 4D seismic interpretation and also included in the objective function of reservoir simulation history match. It is demonstrated how robust monitoring of sweep patterns can support effective field development decisions.

Monitoring the location and timing of the movement of the waterflood front, or sweep, in oil and gas reservoirs is a key source of information required to make effective reservoir management decisions. Knowledge of sweep in a reservoir facilitates several key field development activities including the identification of opportunities to add perforations to unswept zones; the derisking of infill-drilling well locations; the support of 4D seismic interpretation; the calibration of reservoir model simulations.

Water saturation has been estimated in cased-hole development wells by the use of pulsed-neutron logging technology for many decades. However cased-hole saturation interpretations contain much higher uncertainty than typical openhole interpretation results, particularly where the salinity of the water in the flood front is unknown. It is questionable if accurate estimates of water saturation are possible to achieve routinely from cased-hole pulsed-neutron logs.

In order to mitigate this significant uncertainty, a new interpretation philosophy has been developed that produces a quantitative interpretation result that may be used with confidence by subsurface teams. An interpretation method has been developed that involves creating a Boolean interpretation of the breakthrough of the flood front, or sweep. This sweep interpretation is a simplification of the true petroleum physics at work in the reservoir; however it can be demonstrated to be a valid characterization of the style of sweep of the specific oilfield discussed in this paper in several ways. The case study presents several types of information that support this interpretation method from a rich dataset with 10 years of production surveillance data. This includes reservoir zones with several time-lapse RST datasets, coreflood experiments and the PLT interpretations of dry and swept zones.

The new production-surveillance petrophysical interpretation products have been used to support field development operations and 4D seismic interpretation. The ultimate objective has been to quantitatively integrate the production-surveillance interpretation with reservoir simulation results. This paper shares the method with which these interpretation results are successfully integrated with the simulation history match objective function. This allows the reservoir model to be conditioned to match cased-hole saturation data, and support effective field development decisions.

Determination of Residual Oil Saturation in a Water- and Gasflooded Giant Oil Reservoir Using Core, Conventional and Pulsed-Neutron Logs

Mike Davenport, Adrian Zett, Kasim Sadikoglu, Xiaogang Han and Pavel Gramin, BP

The understanding of residual saturation in an oil field in mid-development is essential for estimating the cumulative production achievable, optimizing the future production mechanisms planned for infill targets, development of adjacent reservoir levels and optimizing the design of future facilities. The ACG (Azeri, Chirag, Gunashli) field is a giant oil field located about 120 km offshore in the South Caspian Sea, Azerbaijan. The field consists of multiple stacked clastic reservoirs including the Fasila and Balakhany formations, each with variable oil-water contacts, and variable presence and fill level of gas caps. The Fasila reservoirs have been nearly fully developed. Both down flank water injection and crestal gas injection have been employed to drive oil towards producers. These two processes result in different residual oil-trapping mechanisms, which have been explored by logging and coring. Future development of overlying reservoirs can be optimized if we understand the effectiveness of these mechanisms to improve oil recovery and understand produced-fluid compositions to enable facilities optimization to handle them.

Established techniques to measure the residual oil saturation in a live field depletion, such as conventional openhole logging, pulsed -neutron logging and direct core measurements have been employed. This paper investigates the methodology of each technique and the comparison of the magnitude and uncertainty of the saturations obtained.

The sands in the ACG main reservoirs are relatively massive and high net-to-gross, however their clay content and distribution is quite variable leading to a range of rock types which behave differently under fluid sweep, and the presence of both intrareservoir sealing shales and lateral sand quality variations lead to a complex pattern of sweep behavior.

It was considered that conventional core would be the principle measurement, with the most direct estimation of downhole fluid conditions. Core was acquired on two pilot wells, one behind the waterflood front and another behind the expanding crestal gas cap. Several innovative core analysis techniques were employed. A full conventional log suite was acquired in both wells as well as an openhole pass of a multi-detector pulsed-neutron log in the crestal gas swept well.

The analysis of all this data has led to some interesting conclusions. Previous coreflood experiments had led the team to believe gas is more efficient than water in terms of lowering residual oil saturation and reaching higher recovery factors. The new core demonstrated that such low residual oil saturations are achieved more slowly than originally thought, though it didn't change the view of efficiency of gas displacement relative to water. It is also likely that reservoir heterogeneity has had a bigger impact on the variation in residual oil saturation between layers than reservoir quality itself.

Identification of Bypassed Hydrocarbon Through the Integration of 3D Resistivity Mapping and Pulsed-Neutron Logging

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Reservoirs are spatially heterogeneous. Nevertheless, conventional approaches to the exploitation of oil and gas reservoirs have assumed a certain level of homogeneity to identify drill locations, sweep and injection patterns, and ultimately recoverable volumes. The obvious consequence of such an approach is the inevitable presence of bypassed hydrocarbon, where natural or induced fluid-rock dynamics have been unfavorable. The presence of such bypassed zones has been acknowledged throughout the years, and numerous technologies exist to identify and map their occurrence. These technologies, however, are either too insensitive (spatially or temporally) to resolve fluid substitution, such as seismic imaging, or ignore the natural tortuous paths of fluid flow through porous media, such as tracer surveys and 2D crosswell resistivity imaging. This paper proposes a workflow that integrates water saturation as inferred by pulsed-neutron logs with 3D resistivity imaging. 3D resistivity imaging of fluid saturation around a borehole can be achieved if the fluids surrounding the borehole have distinct physical properties that are sensitive to an appropriate source-sensor combination. Such contrast exists between the resistivities of brine, hydrocarbon, and/or CO_2 in porous formations. Log analysis is used to determine the appropriate rock physics relations between resistivity and saturations. The imaging source consists of an electrode for current injection into the wellbore casing at or near the target reservoir depth, with a surface counterelectrode. A surface array of electric and magnetic sensors is deployed around the wellbore, such that the far-field volume of interest may extend to several kilometers from the wellbore. 3D petrophysically constrained inversion of the resistivity data yields 3D resistivity models that can be transformed to 3D saturation models. The high-resolution, near-field calibration of the saturation model comes by means of pulsed-neutron logging, which is also salinity dependent. At low, unknown or variable water salinities, the carbon/oxygen ratio is preferred; whereas, at high salinity, the sigma value is used. These logs may be upscaled and used to constrain the 3D inversion. The workflow of this interpretation methodology is presented with synthetic examples of bypassed-pay identification.

Monitoring a Unique Field Through Depressurization; A Cased-Hole Logging Plan to Optimize Blowdown Performance

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Machar, a fractured waterflooded imbibition-dominated carbonate reservoir has been subject to a phase development throughout its lifetime. As the field's waterflooded phase comes to an end, Machar will move into a depressurization (blowdown) phase at the beginning of 2018. With limited depressurization examples of this type of field, cased-hole surveillance is key to understand oil recovery and behavior under blowdown conditions. Pulsed-neutron and production logs have been used in the past to manage waterflooding and understand S_{orw} (residual oil saturation to water). Moving into depressurization understanding critical gas saturation becomes the primary uncertainty in delivering oil volumes. Critical gas saturation is a more complex parameter to measure and unlike S_{orw} it is not an endpoint but rather a transition point.

A proposed surveillance program has been designed to monitor oil recovery performance during blowdown: low critical gas saturation, mobile water movement post-gas-breakthrough and maintaining well integrity. The surveillance program will also identity downdip production adding opportunities.

In this paper, we will discuss the team's surveillance plan for monitoring the depressurization in support of reservoir management. A wide variety of cased-hole sensors have been reviewed, modeled and proposed. These include pulsed-neutron logging, production logging sensors, caliper logging and a new sensor for gravimetry logging. The discussion will also talk about key factors including model results, well selection and timing. The broad selection of sensors will help understand the PVT change in-situ as well as the saturation change near and away from the borehole.

New Ruggedized Electromagnetic Tool Achieving Quantitative Azimuthal Casing Inspection

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In the harsh environments of oil and gas wells, steel well casings are subject to corrosion. Starting with pitting and thinning at either external or internal wall, casing corrosion may propagate more seriously turning into holes or splits, which cause leaks and environmental damage, seriously affecting production operations. Therefore, corrosion monitoring and timely detection of casing integrity issues is considerably important. In direct response to demand by independent wireline companies for a quantifiable, reliable and cost-effective intelligent solution to accurately evaluate casing integrity, a new ruggedized mandrel-based electromagnetic (EM) casing inspection tool has been developed to provide quantitative measurements of casing thickness and inner diameter (ID).

The tool also provides a comprehensive analysis of casing material properties. A patented four-segment (quadrant) receiver incorporated within the tool mandrel measures the casing thickness with a 90° circumferential sensitivity based on remote-field eddy current (RFEC) principles. The EM field attenuations and phase shifts from transmitter to receivers are precisely measured by using innovative electronics and then quantitatively translated to single-layer casing thicknesses after corrections on material EM property variations. In addition, the axial differential measurements, in quadrants as well, deliver enhanced axial resolutions of small defects on the casing wall. Meanwhile, the precise casing ID and material EM properties, such as magnetic permeability and electrical conductivity, are derived from a dual-frequency measurement and real-time inversion while the EM caliper sensor arrangement is satisfying the near-field eddy current (NFEC) conditions. Consequently, inner or outer casing-wall defects can be identified by combining casing ID with quadrant thicknesses during interpretation. In conjunction with a mechanical caliper, the EM caliper is also applicable to further determine the nonmetallic deposition on the casing. The newly developed intelligent algorithm significantly simplifies the calibration procedures, consistently delivering reliable results. To provide a relative tool orientation and monitor shock and vibration, the tool features a triaxial accelerometer. Furthermore, an auxiliary temperature sensor in the electronics sub enables complementary monitoring of the tool's overall operating condition. The tool operates in high-pressure wellbores, including those in highly deviated and horizontal wells, up to 20,000 psi, in temperatures as high as 175°C. Laboratory verification has been performed by logging casing samples which are precisely machined with design features simulating corrosion events. The fundamental interpretation has been derived from the corresponding tool responses. The field examples demonstrate quantitative assessment of casing conditions and identification of corrosion damage from the quadrant sensitivity.

Petrophysical Surveillance—The Key Driver In Optimizing Well Performance

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Reservoir quality and completion efficiency are important factors that interrelate with well performance. They become more subtle for the particular case of cased-hole gravel-pack and frac-pack completions. Most of the time, completion quality and reservoir description were treated in isolation, by different disciplines deploying dissimilar surveillance methods. This can negatively impact the decision-making and the cost of data acquisition. The evolution of multidetector pulsed-neutron (MDPN) technology and the improvement of nuclear attributes extraction (spectral processing) enabled us to simplify the data-acquisition program while expanding the applications to both reservoir and completion evaluation. Our paper will describe a case study from Gulf of Mexico where deployment of MDPN technology saved significant rig time and reduced the production deferment.

In this case study, various nuclear attributes were used to extract information about connate-water distribution, something that has been observed to be variable in the field. This will reduce the uncertainty in MDPN derived saturation and impact further the reservoir model when reconciled with other data.

Data acquired with the same MDPN instrumentation has been used to evaluate the quality of the ceramic proppant packing these wells. This approach introduces rigor in acquisition, processing and evaluation, offering a robust answer over traditional methods such as density based and radioactive tracer logs.

The development of memory conveyance broadens the application of MDPN for reservoir and completion evaluation.

Using Temperature Measurements From Production Logging or Distributed Temperature Sensors (DTS) to Diagnose Multistage Fractured Well Flow Profile

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The temperature log as a part of a production logging package has been used in the industry for many years. Recent developments in downhole fiber-optic sensing technology introduced a more continuous measurement of temperature both temporally and spatially for flow diagnosis. One of the powerful applications of temperature measurements is to diagnose multistage fracture treatments. Because the fiber-optic temperature measurements can be available during fracturing, during shut-in, and during production, the integrated interpretation provides information of fracture/flow distribution. This information helps to understand what happened during the fracture treatment stages, to identify problems in treatment design and execution, and to improve the efficiency of multistage fracture stimulation.

The key component of fracturing diagnosis by temperature measurements is the interpretation models. In this paper, we will introduce the models developed for the purpose of fracture diagnosis. The mathematical models are built on mass, momentum and energy balances of each component (reservoir, fracture, well completion and wellbore) in the system, and the components are linked through the boundary conditions. All models can be solved numerically, but for computational efficiency, analytical/semi-analytical solutions are preferred when available. To correctly simulate heat transfer during fracture propagation, a fracture geometry model with appropriate leakoff description is integrated in the model buildup. For flow problem in a fractured well, analytical model, streamline approach and reservoir simulation can all be the solution methods.

The paper compares the advantages of each approach. Field cases from the Eagle Ford, the Marcellus, and the Vaca Muerta shale formations will be presented in the paper to illustrate how the models can be used to generate the fracture/flow distribution. The results show that temperature measurement is a comprehensive tool for fracture diagnosis.

Well-Based Monitoring of a CO_2 Plume in a Carbon Dioxide Storage Project

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Carbon dioxide (CO_2) capture and storage is the subject of ongoing research in which various techniques are being assessed to monitor the progress of the injected CO_2 through the selected formation(s). Of the formation properties desirable for CO_2 storage, one of the most important is the presence of an effective trapping mechanism to ensure the CO_2 remains in place and does not escape to neighboring formations or to the surface. Therefore, to confirm that the CO_2 plume can be detected and leaks outside the target formation identified, various monitoring techniques need to be assessed. One such technique was tested at the CO2CRC Otway Research Facility in southwest Victoria and is the subject of this paper.

Pulsed-neutron logging has been used for reservoir monitoring in the oil business for over 40 years; conventional techniques rely on the measurement of the thermal-neutron capture cross section (sigma) in saline formation water of known or assumed salinities and/or the salinity-independent carbon/oxygen (C/O) ratio in oil densities and/or porosities of sufficient magnitude to allow calculation of the oil and water saturations.

Prior to 2004, the limited sensitivity of sigma and C/O measurements to gas precluded both quantitative gas saturation and the differentiation of gas from oil and fresh water. Recently developed pulsed-neutron gamma-ray ratio-based measurements overcome these limitations and allow salinity-independent quantification of gas saturation in fresh water, oil and three-phase environments.

This paper and associated poster will present the results of a program conducted in late 2015 and early 2016 to monitor an injected CO_2 plume which comprised a base log and two post-CO_2-injection logs, one in the injection well and the other in the neighboring monitoring well. The results show that the combination of the pulsed-neutron capture measurement, Monte Carlo tool response modeling and the salinity independent interpretation technique is able to locate and quantify the CO_2 plume. In the injection well, this was accomplished in the presence of complex completion hardware. The data also shows that the measurements allow the location of leaks within the completion, in this case, by detecting CO_2 trapped under a packer.

Well Diagnosis Using Pulsed-Neutron Logs to Investigate the Effect of Propellant Stimulation in Gravel-Pack-Completion Wells

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Field B is a prolific hydrocarbon-bearing mature field discovered in 1970, wherein most of the wells have been producing for more than 25 years. These wells are primarily dual-string completions with multiple packers and zones completed with a gravel pack. Over the production lifetime, fines migration across the gravel pack has plugged packs and screens. Acidization was the conventional measure to address this challenge. However, acidization poses a risk of screen damage and probable gravel-pack failure, which, in turn, can lead to costly repairs. Additionally, acidization to clear the fines plugging the gravel pack can weaken the formation matrix and further aggravate sanding tendency. This paper presents a new technique using pulsed-neutron logging (PNL) to evaluate well-stimulation results in this mature field.

Stimulation was conducted in December 2014. A propellant stimulation device was fired across the gravel pack to enable the high-pressure stimulation to shake the gravel-pack matrix, thus leading to even redistribution and repacking of the entire gravel pack according to theory/assumptions. To validate this methodology, two cased-hole spectroscopy data runs, along with production logging and silicon activation (an established method to assess gravel packing), were recorded. The emphasis was on analyzing raw yield and the changes in yields across the logged interval.

This paper presents conceptual prejob planning, operation execution, and the method outcome. This novel methodology measured relative changes in the silicon activation value (before and after stimulation) and showed a decrease in silicon content across the zone stimulated with propellants. This can be attributed to cleaning of the silica/fines that were clogging the gravel-pack area. The stimulation successfully increased the production rate, and PNL helped determine the possible screen clogging causes and the propellant stimulation effect on gravel packs. A second stage treatment using a slimhole PNL tool (post-stimulation in shut-in conditions) is recommended to corroborate the theory.

This method provides a more efficiently engineered technique that can be used for future similar applications. The study and subsequent results provide an alternative cost-effective gravel-pack cleanout technique.

RESERVOIR CHARACTERIZATION CASE STUDIES

Advanced Coal Reservoir Quantitative Characterization Based on Low-Field Nuclear Magnetic Resonance Experiments

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Coalbed methane reservoirs typically have a special and complex pore-fracture network. They contain both pores (mostly nanopores) and fractures. The pore structure of coal reservoirs has an important influence on gas storage and gas production capacity. The traditional experimental techniques cannot fully describe the pore structure of coal reservoirs. To address this problem, we have developed a novel method using low-field NMR, cryogenic nitrogen adsorption and isothermal adsorption experiments, which have been systematically carried out and will be described in this paper.

We have studied the effects of changing TE (echo spacing) and TW (wait time) on the T_2 spectrum and NMR porosity in order to accurately describe the pore structure of a coal reservoir. We found that TE should be less than 0.2 ms and TW should be greater than 6 s. Because the coal is very brittle, it is difficult to measure porosity with a coal plug. Through the comparison of the NMR porosity of coal cuttings with different mesh sizes, we found that a 90-mesh number minimizes the error between NMR porosity and plug porosity. Based on NMR and cryogenic nitrogen adsorption experiments, a new method is proposed to convert the T_2 spectrum into a pore distribution. The NMR measurement of the pore structure in a coal plug has improved results compared to the cryogenic nitrogen adsorption experiment of macropores (100 to 1,000 nm). The relationship between nanopore volume, Langmuir volume and Langmuir pressure of a coal is established, and the adsorption capacity of the coal reservoir is predicted by the NMR T_2 spectrum. We then used this data to calculate the adsorption gas content of coal using the NMR T_2 spectrum at different pressures, which is consistent with the isothermal adsorption experiments result. We have therefore developed an innovative petrophysical experimental technique that has been established for coal reservoirs to evaluate pore structure, porosity and adsorption capacity by NMR while providing a novel approach for understanding coal reservoir properties.

Constraining Uncertainty in Complex Reservoir Description—A Case History Applying Magnetic Susceptibility to Estimate Permeability From Core Samples and Cuttings

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The accurate prediction of development-well productivity and zonal contribution depends on robust reservoir permeability characterization. Establishing permeability models for heterogeneous and heterolithic reservoirs can be extremely challenging due to complex relationships between the depositional environments, lithologies, grain-size distributions and diagenetic history. Permeability descriptions of the Central North Sea Triassic sandstone reservoirs require multivariable relationships with wide ranges in uncertainty of each input. The challenge is compounded in the absence of comprehensive core coverage. The consequence is a significant increase in well-productivity prediction uncertainty. To improve the productivity prediction, a quick and independent estimate of permeability was sought for the entire development well perforation interval. The solution has been the application of magnetic susceptibility measurements on core and cuttings to estimate permeability. A rigorous phased acceptance process was undertaken to prove the robustness of applying the magnetically derived permeability estimates to the available material and datasets. This culminated in the technique being applied throughout the reservoir interval, providing an independent permeability profile which favorably compared to the existing overburden core plug datasets and permeability predictions. Initially, the technique was used over just the cored interval but was later extended to cover other permeable zones of interest. Permeability values were derived from published correlations with magnetic susceptibility. Initially these were compared to high-quality core-plug and slabbed core measurements, as well as existing permeability predictors, and later applied to the cuttings. Samples of wet-cuttings were provided at 10-ft intervals throughout the reservoir interval. A number of improvements to the technique were developed at an early stage, such as the use of high- rather than low-field magnetic susceptibility measurements. These developments were then applied to the later stages of the study. The result of this applied research and development has been a significant reduction in uncertainty on permeability prediction throughout the reservoir interval, and thus much greater confidence in the prediction of permeability and well productivity of the complex Culzean Triassic reservoir. The method is quick, cost effective and uses material that is readily available. From the successful results of this study the technique has been applied to other zones of interest within the Culzean field where permeability is relevant. The results have provided insights in how to judiciously apply the magnetic susceptibility technique to develop permeability profiles in other wells where core coverage is poor or absent.

Improved Petrophysical Rock-Type Prediction by the Integration of Probability Derived From Sequence Stratigraphy

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In petrophysical rock-typing projects most techniques commonly applied do not directly integrate vertical information in predictions. In carbonate fields in particular, the sequence stratigraphy concept holds valuable information that is underused in petrophysics, although used extensively by geologists in the geomodeling stages. This paper discusses a number of directly applicable, new techniques that support the petrophysical prediction of geological rock types (i.e., depositional environment and facies) and their subsequent (dynamic) petrophysical rock types.

Petrophysical rock-typing projects typically have a 'definition' and a 'prediction' stage. Rock types are usually defined based on mercury injection capillary pressure data, thin-sections, and core descriptions of environment and facies. The prediction stage distributes the defined rock types to uncored intervals and wells. This latter stage is normally driven to a large extent by logs and based on multivariate statistics techniques like self-organizing maps (SOM) and neural networks. Weaknesses of these techniques are that they use input data from a single depth; hence, there is a significant challenge when there is overlap between the log responses of different petrophysical rock types. In the case of overlap, support of external data is required for prediction to be successful. The application discussed in this paper integrates probabilities derived from sequence stratigraphy with probability derived from the multivariate prediction by SOM.

The sequence stratigraphy probabilities are computed from a similarity of the vertical sequence to the sequences observed in the core-derived calibration data. Already in 1987, Busch et al. described the use of the stacking sequences identified from core data to drive and optimize predictions. In this application, the stacking sequences are captured in transition matrices from which probability can be extracted. During the development of the application, different workflows for the integration have been devised and tested. The investigated workflows range from overruling unlikely transitions to the use of transition probability as input in the multivariate predictions, and includes combinations and variations of these. All workflows will be described in detail with an overview of their strengths and weaknesses. The achievable improvement of the success rate in blind test predictions is about 10 to 15%.

Production Petrophysics in Liverpool Bay Asset—the Driver for a Successful Rejuvenation Strategy

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Lennox field is a clastic reservoir with an oil rim and primary dry-gas cap, located in Liverpool Bay Asset and characterized by weak aquifer support. Discovered in 1992, the oil production has been managed by the previous operator, reinjecting the produced and associated gas in order to maintain the position of the oil-water contact. In 2014 Eni acquired the operatorship; according to the progressive field depletion, the exploitation strategy moved from oil production towards the gas-cap blowdown. The dual effect of stopping gas injection and starting to produce from the gas cap induced a sharpening of the reservoir pressure decline and increase in water cut, strongly affecting the production performance in most of the wells.

The challenging scenario characterized by a faulted reservoir with an increasing and undesired water production which led to the shut-in of gas-cap producers has been addressed with a comprehensive cased-hole log campaign in several wells. The integration of the acquired data with the existing petrophysical model, fluid distribution and the historical reservoir production

allowed a detailed and robust update of the fluid distribution and their relationship at reservoir scale.

In particular, uncertainties over the well-completion integrity, the current reservoir fluid distribution, the strategies to optimize the gas deliverability, reduce water production and the liquid-loading issues have been managed integrating the production logging data, P&T profiles and pulsed-neutron capture (PNC) outcomes.

The results of the PNC campaign showed a progressive rising of the bottom fluid contacts. Furthermore, a lateral waterfingering phenomenon has been observed on the western flank of the field. This unexpected and sudden water movement was probably triggered by the combined effect of extensive 'shale baffles' within the reservoir and the exploitation strategy (most of the wells are drilled on the western flank with a horizontal trajectory in the best reservoir facies), and was supported by a structural setting unaffected by faulting.

The analysis, carried out by way of an extensive logging campaign (more than 50 acquisitions in the last three years) focused on optimizing the production intervals and water shutoff operations, resulted in an increase in gas production of about 40% with respect to the "do nothing" scenario.

Reservoir Characterization of Compartmentalized, Turbidite Lobes in the GOM Using Real-Time While-Drilling Magnetic Resonance

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Deepwater lobe turbidites are difficult to model geologically, but they are known to be very prolific producers, once their stratigraphic setting and lobe stacking architecture are understood. Variability in rock-quality distribution, permeability, and flow barriers strongly impact productivity and development strategy for economic hydrocarbon recovery. Additional complexity is imposed with structural faulting. After the discovery well in one of the faulted blocks for the Gulf of Mexico (GOM) example presented, additional appraisal close-proximity penetrations were planned to fully understand the geology setting.

Advanced evaluation technologies were deployed, including a combination of while-drilling magnetic resonance to fully understand porosity, permeability, and fluid composition independent of anisotropic effects in laminate-turbidite setting. High-resolution geological borehole imaging, nuclear-porosity measurements, formation pressures while drilling, wireline evaluation, core data, and seismic data were integrated.

The integrated study showed the sand lobes to have similar reservoir characteristics of the discovery and existing offset wells. Gathering data early via the logging-while-drilling (LWD) combination of gamma ray, resistivity, density, neutron, nuclear magnetic resonance (NMR) and pressures enabled better data-gathering decisions post drill. The permeability profiles of the sands reservoirs were found to be consistent with the lobe-turbidite geologic model. A real-time permeability profile from the NMR helped define the lobe stack sequence. Hydrocabon identification in a laminated margin section, which extended the proved hydrocarbon limits, was also achieved using a new real-time compression of the NMR T_2 spectrum distribution. A perched-water feature was observed at the base of a lobe sequence, not previously observed in other sand compartments. In addition to providing a framework to model the geologic setting, reservoir connectivity was also evaluated by integrating pressure measurements and dynamic fluid sampling.

Reservoir Realization of Fluid Geodynamics With the Integration of Petrophysics and Downhole Fluid Analysis

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The Jurassic and Triassic Conglomerates reservoirs encountered in the central part of the North Sea are mineralogically complex and highly heterogeneous across the field. In addition, fluid complexities associated with heavy oil and tar formation from specific reservoir fluid geodynamic processes have also been identified in these reservoirs and have significant impact on development strategies. An Integrated approach is applied where the advanced petrophysical evaluation delineates the likely mobile fluids versus viscous oil or tar, which can subsequently be validated by downhole fluid analysis (DFA) and core analysis.

Petrophysical methods described herein accurately describe and quantify the fluid volumes and types, which are needed to anticipate the fluid movability in the near-wellbore region of the oil column. The work described in this paper shows the sequential refinements of individual, yet collective petrophysical interpretation with the use of advanced measurements, leading to enhanced understanding of the atypical reservoir. Nuclear spectroscopy helps resolve an accurate porosity and matrix permittivity, enabling dielectric to solve accurately the shallow zone saturation ($S_{w\text{—}Xo}$), rock textural parameter (MN), salinity and shallow zone resistivity. The combined dielectric and spectroscopy results are directly used to resolve the undisturbed zone saturation (S_{w_Deep}) on formation resistivity. This sequential integration constrains fluid dynamics descriptions of immovable fluids by analyzing the shallow versus undisturbed zone saturations. In hydrocarbon-bearing formations with water-based muds used here, if the saturation profiles indicate $S_{w\text{—}Xo} = S_{w\_Deep}$, there is no invasion and the hydrocarbons are immobile, while if $S_{w\text{—}Xo} > S_{w\_Deep}$, then the hydrocarbons are mobile. Additionally, NMR data mark zones of immobile fluids showing missing porosity, thereby indicating the presence of heavy oil of asphaltene/tar. Even if the zones have some mobile hydrocarbon yet still have missing porosity from NMR and this could also indicate some asphaltene/tar in the formation.

The petrophysical interpretation guides DFA investigation of the reservoir to validate reservoir fluid geodynamic (RFG) scenarios that yield tar deposition; here, gas charge into oil. Core analysis is then targeted to confirm these RFG scenarios. This powerful combination of petrophysics, DFA, and core analysis (of uncleaned cores!) clarifies the importance of immobile hydrocarbons on well placement and aquifer sweep in field development planning.

The Detection and Imaging of Igneous Intrusive Bodies At, and Away From the Wellbore in Complex Structures Associated With a Volcano in Neuquina Basin, Argentina

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In complex hydrocarbon fields associated with the Auca Mahuida volcano in the Neuquina basin, Argentina, igneous dikes are detrimental to the reservoir, creating hydraulically isolated bodies or compartments, and restricting fluid flow. The effects are confirmed from pressure testing and the changing distribution of fluids throughout the stratigraphic column. The use of borehole imaging is important for understanding and identifying these dikes and their orientation in the vicinity of the borehole wall. Image interpretation suggests that dike emplacement tends to follow pre-existing natural fracture trends, and the recognition of near borehole fracture attitude is very important to help predict intrusion locations in nearby offset wells. The behavior of these intrusions far from the wellbore is unknown and difficult to predict. The addition of acoustic deep shear-wave imaging, using data from the conventional cross dipole acoustic logging tools already being run in these wells, has provided a new way to confirm the orientation of these dikes and image them far from the borehole wall. It also allows detection and orientation of those dikes that do not cut the wellbore but may have an influence on the production and fluid distribution up to 30 m away. This case study shows an integration of the datasets at different depth scales, at and away from the wellbore, and how they complement each other in understanding the reservoir structure, compartmentalization, and fluid flow.

Using Innovative Petrophysics in the Canadian Oil Sands

Kevin Pyke and Jeff Taylor, Nexen CNOOC

The Canadian oil sands hold vast reserves and development will continue for many years to come, however evaluation of the reservoir and its fluids is not without challenges. The fluvial estuarine Cretaceous McMurray formation can change rapidly laterally and vertically both in facies and fluids. Formation water variations within the McMurray can also be frustratingly complex with salinity varying spatially and vertically by orders of magnitude. SAGD technology is used to produce these wells, which relies on steam chamber growth and dynamic changes within the reservoir, creating an additional dimension of variability in the fluid and rock properties.

Nexen CNOOC's Long Lake property is a challenging reservoir and this case study will highlight some of these challenges. These include bottom water, top water, top gas, low-resistivity gas (fizzy water), lean zones, facies variation, and changing R_w.

The McMurray reservoir has been cored extensively to help characterize the deposit, but this can be very costly when drilling hundreds of wells to find the sweet spot. Along with this, Dean-Stark analysis of the core is often found to be unreliable due to various factors that will be discussed. After drilling thousands of wells with about 14,000 m of McMurray core, we have a huge dataset that has contributed to understanding the reservoir and developing our petrophysical models. Operators must look for new methods to evaluate the reservoir and reduce development costs, while reducing uncertainties to make oil sands projects more competitive.

Logging programs and integrated analysis were used to overcome some of these challenges of reservoir characterization while eliminating costs of coring, core analysis and core handling. We will show examples of why we designed logging programs to include microresistivity imaging and nuclear magnetic resonance. We will also show examples of using pulsed-neutron logging to monitor steam-chamber growth and reservoir sweep efficiency.

We have had considerable success logging microresistivity imaging tools to get a high-resolution characterization of the reservoir along with facies identification. Nuclear magnetic resonance has been proven to be a robust tool for saturation prediction that is independent of formation water salinity. An annual pulsed-neutron logging campaign has also been implemented to make steam injection more efficient and maximize oil production.

Understanding the true benefits and weaknesses of acquiring core and core analysis can save a lot of money in a SAGD delineation program. Our workflow shows how to save money and still reduce reservoir uncertainty with the correct evaluation program and petrophysical routine.