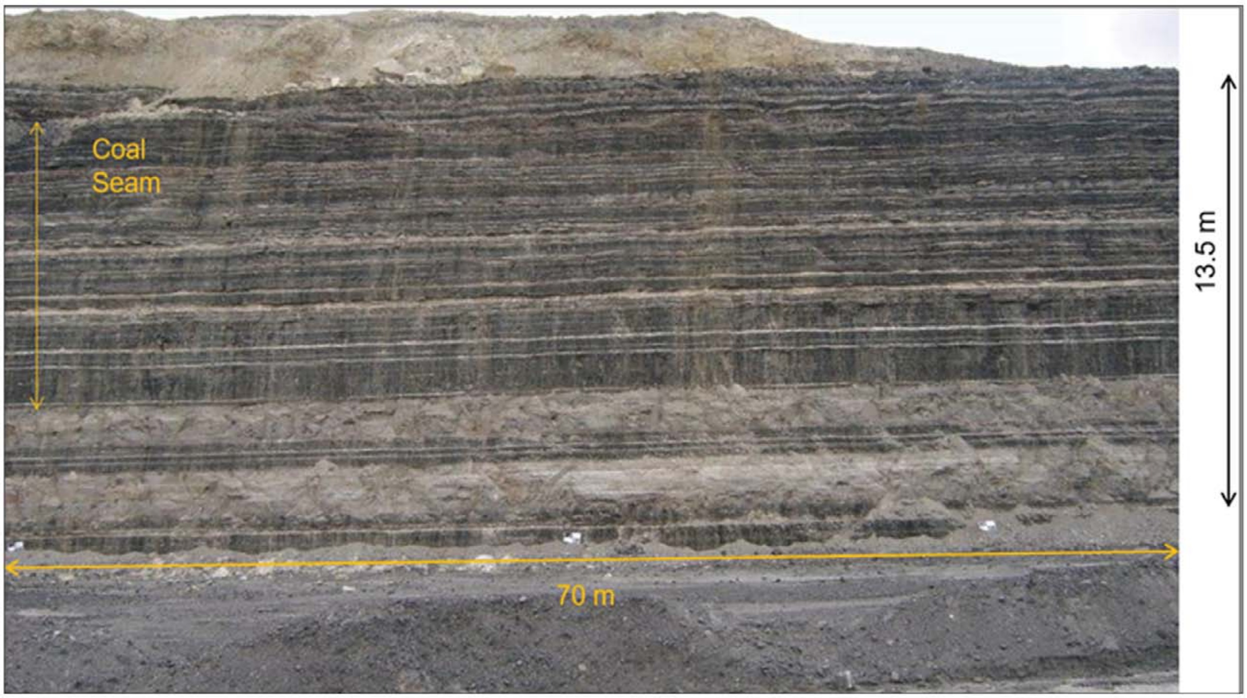
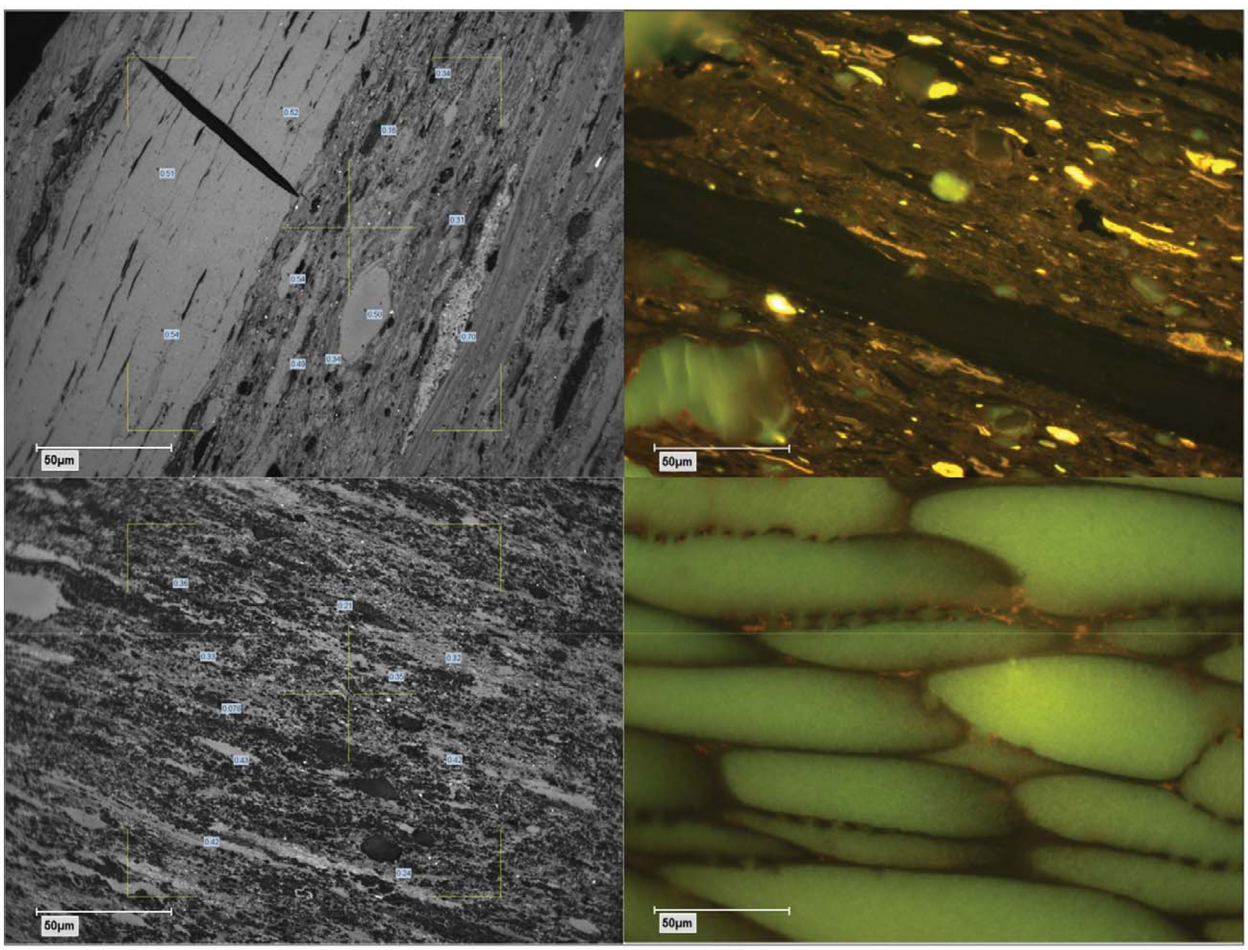
ISSUE 5 | VOL 1 | NOVEMBER 2018

THE SPWLA TODAY

NEWSLETTER





INSIDE THIS EDITION

SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS

CALENDAR OF EVENTS

November 7–8, 2018

SPWLA Asia Pacific Technical Symposium 2018
Bogor, West Java
Indonesia
www.spwla-indonesia.org

November 26–27, 2018

SPWLA Monthly Webinar (Two identical sessions offered)
"Experimental Quantification of Kerogen Wettability as a Function of Thermal Maturity"
Speaker: Arachna Jagadisan, The University of Texas at Austin
www.spwla.org

November 28–29, 2018

Digital Rocks and Unconventional Petrophysics Workshop
Hosted by the Boston Chapter of SPWLA
Cambridge, MA, USA
www.spwla.org

December 5–7, 2018

Training Course on "Machine Learning Techniques for Engineering & Characterization"
Course Instructor: Dr. Siddharth Misra
Frank S. Millard SPWLA Training Center Houston, Texas
www.spwla.org

March 6, 2019

Formation Testing SIG Technical Meeting
BP Westlake Campus in Houston.
An agenda will be posted before the end of the year on the SPWLA FT SIG webpage.

June 15–19, 2019

SPWLA 60th Annual Symposium
The Woodlands Waterway Marriott
The Woodlands, TX
www.spwla.org

About the Cover

Top: Outcrop of New Acland seam, equivalent to the basal Walloon Coal Measures (WCM). Coal quality varies rapidly laterally, often transitioning into carbonaceous mudstone. Small reverse thrust fault visible. Photo taken at New Acland Mine, Queensland, Australia.

Bottom: Photomicrographs of WCM coals taken using oil immersion at 500X magnification. B&W images (left) taken in reflected white light and color images (right) taken in blue-light fluorescence. Numbers indicate reflectance values. Complex assemblages of mostly vitrinite and liptinite, mineral matter and rare inertinite.

Notable features-

- Top left: a thick, cleated clean band of vitrinite contains a large slit infilled with generated bitumens
- Bottom left: intimate mixture of vitrinite, liptinite (suberinite) and mineral matter
- Top right: A complex mixture of mostly liptinites, with strongly yellow fluorescing spores and resins
- Bottom right: Plant cell tissues preserved by mineral infillings, fluorescing a strong green color and vitrinite + resins fluoresce weak-brown to orange.

From the President

Zhipeng "Z" Liu
2018–19 SPWLA President
zliu@spwla.org

Dear SPWLA members and friends,

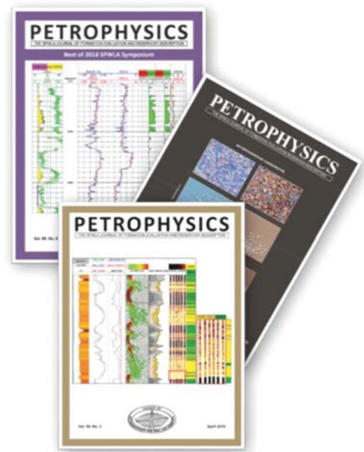
Greetings! Another month has come and gone and we are on the countdown to holiday season. I guess it's true—time flies when you're having fun. 2018 is on pace to be a fruitful year for SPWLA:

- We hosted a successful symposium in London.
- Great progress was achieved in the SPWLA with the formation of new professional chapters, new SIGs, and new student chapters.
- And, last but not least, the SPWLA financial situation has been stabilized via a set of actions to improve efficiency without reducing core membership benefits.

All of these accomplishments were challenging during the continued slow recovery of the oil and gas industry, which brings me to next item—advertisements.

Advertisements, exhibitions and sponsorships pay for a substantial part of SPWLA membership benefits. It is not surprising the multiyear downturn has taken its toll on that revenue stream and could eventually jeopardize SPWLA as a whole, in its continuing efforts to provide benefits for our members. With the slow but steady recovery, it presents an opportunity for our community to help by recruiting advertisers and sponsorship for SPWLA. When you meet a potential advertiser, exhibitor, or sponsor for SPWLA, please mention the SPWLA opportunities available to them and follow up by forwarding your lead to the SPWLA business office (sharon@spwla.org).

The 2019 symposium abstract submission is coming to a close. Under the leadership of Vice President Technology Jim Hemingway, abstract review and selection process will soon commence. Prompted by feedback from our membership, the selection process will include new procedures, including anonymous abstract review. This will improve transparency and reduce potential bias in the abstract selection process. SPWLA leadership strives to listen to our members and is committed to fair and balanced publication.



Last but not least, I feel obliged to communicate and explain to our members about the upcoming changes to printed publication of Petrophysics journal. Over the last two years, under the successful management of Vice President of Publications Carlos Torres-Verdin, Petrophysics has substantially increased the number of papers published in each issue. The journal's influence has also greatly improved (JIF almost doubled since 2015). Cutting-edge technology papers were added as well as review and tutorial papers to better serve the diversified member body of SPWLA. We have received very positive feedback. Digital delivery of a high-resolution PDF is the mainstream delivery option for our members and is always included free of charge with SPWLA membership. The number of additional professional papers per issue has increased the printing and shipping cost of the printed issue. For the members who choose to receive a printed journal, the average cost is $84 per member (free digital PDF). If members prefer to read the journal on paper, the high-resolution PDF can be immediately printed at a fraction of the cost on your choice of color print methods. With that said, SPWLA board feels that heavily subsidizing printing and shipping journals is no longer the most efficient use of our limited funds. The board voted to increase the surcharge for printed journal from $25 to $65 starting 2019. Library-level subscribers will continue to receive printed journal at no additional cost.

Best,
Zhipeng "Z" Liu, P.E.
2018-2019 SPWLA President.
zliu@spwla.org

Carlos Torres-Verdín
2018–19 VP Publications
cverdin@mail.utexas.edu

I hope that you enjoy reading through the pages of this new installment of *SPWLA Today*. For the first time, we are introducing what we refer to as “soft technical papers” in *SPWLA Today*. These papers, two of them included here, are subject to some technical and editorial scrutiny but not to the same extent that *Petrophysics* papers are. The intent is to showcase brief and relevant accounts of technology, interpretation methods, and field applications of general interest to SPWLA members. You may want to think about penning one such paper to share your work and insights with SPWLA colleagues; the sky is the limit! This is just one more example of how *SPWLA Today* is designed to evolve under a very flexible format.

We would love to showcase more stories from SPWLA’s Regional Chapters to expand our communications and interactions across the world. Let us know how your local Chapter is facing the formation evaluation challenges of today and the future…

As always, please be kind enough to e-mail us comments and suggestions to improve and adjust the *SPWLA Today*. The success of the SPWLA depends on all of us; everybody has a voice and every voice counts! Thanks for your continued support.

Sincerely,
Carlos Torres-Verdín

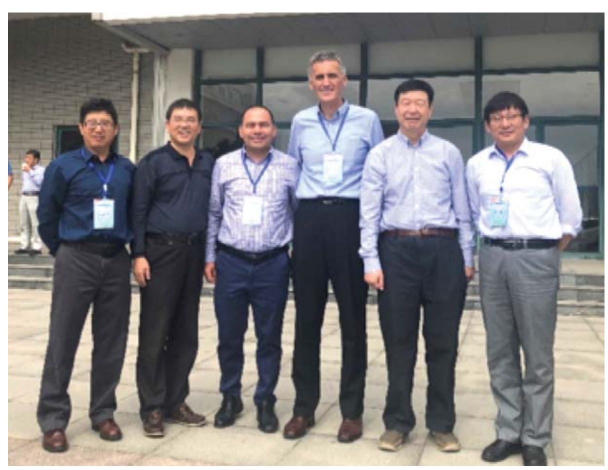
Jesús M. Salazar
2018–19 SPWLA President-Elect

I'd like to continue reporting some of my activities as President-Elect. One of the coolest treats of this position is to be able to solicit bids for the Annual Symposium, in my case, for the year 2020. Traditionally, we host the Annual Symposium in an international location biannually. However, there could be exceptions in case we could not secure a chapter able to host it outside the United States. In 2018 we had an extremely successful Symposium in an international location, London, England. Next year we'll have a US-based symposium at The Woodlands, a beautiful suburb right outside Houston's second loop, or Beltway 8. For 2020, I'm encouraging both US-based and international chapters to bid for the 61st Symposium. Hosting a symposium is no small thing—it requires commitment from the hosting chapter and a determined group of volunteers. So far, we have seen interest from one city in South America, one in the US, one in Canada, and one in the Middle East. This is sort of a nice problem to have—it'll be a fierce competition among four wonderful locations. I can tell you that only one of these cities has held the symposium before and it was over a quarter century ago.

Another important task is to keep in touch with the chapters. I was cordially invited by the East China SPWLA Chapter as one of the keynote speakers of the 10th UPC International Symposium on New Well Logging Techniques, held in Qingdao, China September 26–29. This was an event, organized jointly by the China University of Petroleum and the East China SPWLA Chapter, where the focus was the status and challenges in electrical logging, the event brought together experts from three continents. My keynote speech reflected on the role of petrophysics, the SPWLA and its benefits, and electrical resistivity modeling and mud-filtrate invasion to assess rock properties, quite the mix. During the same trip I stopped in Beijing where I also visited the Student Chapter of the China University of Petroleum (Beijing) and delivered a brief talk about the SPWLA and its benefits and a technical presentation on unconventional reservoirs petrophysics. Both visits were great opportunities to interact with students and professional members of our society. This trip was graciously organized by Hanming Wang from Houston and by Professors Fan Yiren and Zhang Feng in Qingdao, and Guangzhi Liao in Beijing. I want to thank the graduate students that made my stay easy, Fei Hu (Qingdao) and Jiang Jia (Beijing), great SPWLA volunteers. The food in both places was just spectacular, I loved the veggies in Beijing and the seafood in Qingdao. I even had an afternoon available to sightsee in Qingdao—we went to the Beer Museum. Little did I know that Qingdao is home to the second largest brewery in China and that every summer they host one of the largest beer festivals in the world, I guess I missed it by a couple of weeks. The beer culture started during the German occupation before the Great War (WWI).

Finally, during a business trip to Brisbane, Australia, I visited with the FESQ SPWLA Chapter Secretary Marcel Croon, Asia-Pacific regional director Rick Aldred, and other members of the local chapter. I also attended a joint SPE/SPWLA presentation by Distinguished Speaker and BOD member Jennifer Market, and got to mingle with the larger SPWLA membership in Brisbane. It was interesting to see how the local membership is composed of professionals dealing with coalbed methane and mining, perhaps two topics not very well known to members in the Americas and Europe. Meeting the membership around the world in person is a great opportunity for the BOD to understand the needs of our members, how they want us to improve our society, what they want to see a few years down the road, and how to continue modernizing our SPWLA.

Giving the keynote speech at the 10th UPC International Symposium on New Well Logging Techniques held in Qingdao, China.



International guests posing with the faculty of China University of Petroleum (Qingdao). From left to right, Hanming Wang (Chevron), Professor Fan Yiren, your writer, Dzevat Omeragic (Schluberger), Professor Xiaoming Tang, and Professor Zhang Feng.

After giving a talk at the China University of Petroleum in Beijing on unconventional reservoirs I had a photo session with the students majoring in Well Logging (a real major here).

Ready for Qingdao's amazing seafood and more.

Society of Petrophysicists and Well Log Analysts

8866 Gulf Frwy., Suite 320 ♦ Houston, Texas 77017 USA ♦ 713-947-8727 ♦ www.spwla.org

SPWLA International Student Paper Contest 2019

Dear Students:

SPWLA would like to announce the guidelines for participation in the 2019 international student paper contest. Due to the increase in student involvement across the international SPWLA community, the SPWLA board of directors and the 2019 SPWLA annual symposium student paper committee have decided to conduct Internal Student Chapter Paper Contests (ISCPC) as a pre-selection step for participants of the 2019 SPWLA International Student Paper Contest (2019 SPWLA ISPC). Both of the ISCPC and the 2019 SPWLA ISPC will have separate categories for undergraduate, M.Sc., and Ph.D. level students. In order to compete in the 2019 SPWLA ISPC, students should either win the nomination of their SPWLA student chapter, or submit an abstract.

Students who have a local student chapter at their university must win the nomination of their SPWLA student chapter per each degree level, undergraduate, M.Sc., and Ph.D. Student Chapters must finish their competitions, submit their abstracts and deliver their nominations to the SPWLA Student Paper Contest Committee at *papercompetition@spwla.org* on or before **March 31st 2019**. Each Student chapter is allowed three nominees for each degree level. The guidelines for the internal paper contests can be found in **Appendix A**, attached to this announcement. You may contact the Student Paper Contest Committee for more information about the ISCPC.

Students who do not have a local student chapter at their university are also welcome to participate in the international paper contest. To be eligible to compete in the international competition, these students must submit an abstract and the abstract submittal form to *papercompetition@spwla.org* on or before **March 31st 2019**.

When submitting an abstract, please follow the guidelines on the attached Student Paper Contest Entry Form and submit the completed form with your abstract. The student paper contest committee will announce the list of participants in the ISPC by **April 15th 2019**. Students may be selected to participate in either an oral or poster contest. The 2019 SPWLA ISPC will take place during the annual symposium in Woodlands on Sunday, **June 16th, 2019**. Monetary awards will be given to the top presenters within each category undergraduate, M.Sc., and Ph.D. for both oral and poster contests.

For more information about the 2019 SPWLA ISPC, please contact *papercompetition@spwla.org*.

We would like to thank you for your time and interest in the SPWLA organization and we look forward to seeing you at the 2019 SPWLA Annual Symposium in Woodlands, TX.

Sincerely,

Jiaxin Wang, Chair of the Student Paper Contest Committee
Katerina Yared, SPWLA VP-Education

Appendix A: Guidelines for the SPWLA Internal Student Chapter Paper Contests

The guidelines for the Internal Student Chapter Paper Contests are listed as follows:

- SPWLA Student Chapters are expected to hold internal paper contests.
- SPWLA Student Chapters are expected to share their plans for holding internal paper contest with the SPWLA VP of Education.
- Each SPWLA Student Chapter should submit a plan for the use of this financial support to the SPWLA VP of Education to gain approval before receiving the funds. The financial support of $500 USD is reimbursed for approved plans. The plans should be submitted to the SPWLA VP of Education no later than **November 30th 2018** to qualify for the financial support.
- Each SPWLA Student Chapter has the responsibility of announcing the internal paper contest within their university. This includes a call for abstracts.
- Each SPWLA Student Chapter must also select at least three judges for their internal contest. The judges assigned for internal student paper contests should include at least one professor and one member from the local SPWLA chapter or from the industry. Students are not allowed to serve as a judge for the internal student contests.
- Each SPWLA Student Chapter is required to send a list of the three top student presentations within each category of Ph.D., M.Sc., and Undergraduate to the SPWLA VP of Education and the Chair of the student paper contest committee.
- The SPWLA VP-Education and the student paper contest committee will select among the nominees from each school for participating in either oral or poster presentations in the SPWLA International Student Paper Contest, upon availability of the spots and based on the technical content of the submitted abstracts.
- Financial support to those selected to present at SPWLA 2019 may be available to help students attend. This will be discussed with students once they have been selected.

Student Paper Contest Entry Form

Return by March 31st, 2019

Date:____________________

Full Name:____ SPWLA Member Number:________

Address:____

Telephone:_________________________________ E-Mail:_______________________________________

Are you a full-time Student?________ College/University:_______________________________

Citizenship:______________ Non US Citizen Passport Number:______________________

Passport Issuing Country:________________ Passport Expiration Date:____________________

Degree(s) Completed:______________________ Date Degree(s) Awarded:____________________

What is your current status? (Field of study, Degree pursued, and anticipated completion date)

____

Division entered: Undergraduate (BS)____ Masters (MS)____ Doctoral (PhD)____

Paper Title or Topic:____

Has this paper been accepted for publication? Yes ___ No ___

Has this paper been presented elsewhere? Yes ___ No ___

If yes to either of the above, please explain: ____

____

____

By completing this form, I confirm that the information given is correct to the best of my knowledge. The work completed in my paper/presentation is that of my own and has not been plagiarised. If my work is found, to have been copied, from another person or source, or is the work of more than one author, I may be disqualified from participating in the 2018 SPWLA Student Paper Contest.

Signature: _________________________ Printed Name: _______________________ Date:________

Sponsoring Professor

Full Name:____ SPWLA Member Number:____________

Address:____

Telephone:_________________________________ E-Mail:_______________________________________

College/University:_________________________________Department:________________________

I confirm that the above Student will present the paper, described below, if accepted for presentation.

Signature: _________________________ Printed Name: _______________________ Date:________

Student Paper Contest
Entry Form

Student Paper Contest Abstract Information

Please make sure that the abstract includes the following:

1. **Problem Statement:** describe the problem that motivates the paper proposal
2. **Methodology:** describe approach to problem solution, with particular emphasis on innovative procedures that differentiate the method
3. **Results and Conclusions**: describe significant results and major technical contributions, lessons learned from the study, application of findings, and opportunities to further deploy methods
4. Abstract should be more than 200 words and no more than one page.
5. **Return your abstract on or before March 31st, 2019 to *papercompetition@spwla.org***

Attach Abstract by Separate File

Regional Understandings – Middle East and Africa

S. Mark Ma
SPWLA Middle East and Africa
Regional Director

Dear Colleagues,

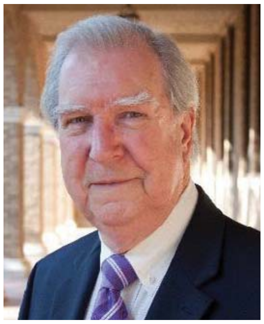
As mentioned in the September 2018 issue SPWLA Today, a virtual Learning and Practicing Petrophysics Together LinkedIn group has been set up with mains objectives of attracting and mentoring young professionals in the areas of petrophysics. In the first two months of establishing this group, we have registered over 800 professionals including many top-notch subject matter experts in key areas of petrophysics;

- Coring operations including special purpose coring and sidewall coring
- Petrology and rock geological description and analysis
- Conventional and special core analysis
- Rock and geomechanics
- Openhole logging, log processing and interpretation
- Logging while drilling
- Geosteering
- Surface logging
- Casedhole logging, log processing and interpretation
- Petrophysical modeling and integrated petrophysical studies.

At the same time, it is encouraging to observe that some meaningful knowledge sharing and technical exchanges have been conducted on the website. I am calling all SPWLA members to actively participate in professional development through this website or through other means.

Looking forward to reporting to you with more results in two months.

Great Moments in Formation Evaluation, Part 3: How to Sell a Dog



Richard Bateman

On a trip to Calgary, Canada, I attended an oilpatch convention. An invited speaker at one of the luncheons told a great story about a boy who was trying to sell his dog. The story has stuck in my mind, but I can't, for the life of me, remember the name of the kind gentleman who originally told the story, but I send him my thanks now.

According to the aforementioned raconteur a small boy stood somewhat forlornly by the side of the road with a dog and a sign saying: "**Dog for Sale 25¢**". A passing businessman, who happened to be a marketing expert, stopped his limousine and gave the boy some words of advice.

"Son, you are never going to sell the dog that way. To begin with, both you and the dog look scruffy. Why don't you take the dog home and give it a good bath—and while you are about it get cleaned up yourself and put on your Sunday-Go-To-Church outfit. Furthermore, nobody wants a 25-cent dog, why don't you put a higher price on the animal?"

The lad agreed to the plan and thanked the magnate for his kind suggestions. The next day, on his way to work, the businessman noticed that the boy had indeed heeded his advice. With pride he noticed the clean white shirt and tie, the shined shoes, the neatly combed hair and the immaculate dog with its fur brushed and a red bow around its neck. What he was not expecting to see was the sign that the boy now held. It read: "**Dog for Sale $4,000**".

Shaking his head, the businessman went on about his business. On his way home he was astonished to see neither the boy nor the dog, but the sign was still there with a line drawn through it and the word "**SOLD**" in bold capital letters underneath.

The businessman was so intrigued with this marketing coup that he took the trouble to inquire where the lad lived and having tracked him down he congratulated him on selling a dog for $4,000.

"Did you really get $4,000 for the dog?" he asked.

"Well, actually," replied the lad, "I swapped the dog for two $2,000 cats."

Surprisingly often, the deals made in the oilpatch are embarrassingly similar, except that we deal in wildcats and prospects that sometimes turn out to be real dogs.

Petrophysical Software (again): Some Thoughts on Enhancements

Dan Krygowski
Senior Petrophysical Advisor
The Discovery Group,
Denver, Colorado, USA

My thoughts in this issue of *SPWLA Today* continue around petrophysical software, from my perspectives as both a development team member and a user of software. In the last issue, I related my experiences in gaining interface clarity and efficiency through lean manufacturing principles, where each interface component could be regarded as a tool (like a hammer or a table saw), and interface improvements could be made by having the right "tool" at the right place at the right time, clean and ready to use.

In this note, I'd like to look behind that interface to the functionality, petrophysical in this case, that drives the development of those interfaces, and which also impacts the efficiency and utility of those interfaces.

If we lump changes to the software under the broad category of "enhancements," we can go off in at least three different directions (and probably more, if I give my few remaining neurons a chance to fire…).

I've covered the first direction that came to mind, at least in part, in the last issue: creating more efficient interfaces. We can also go down that road a little further in improving interface efficiency, and that can be done in a variety of ways, including having the interface tools:

- Suggest general default parameter values for parameters;
  - A first-order value of the Archie porosity exponent, *m*.
- Suggest specific default parameter values based on other assumptions;
  - A suggested matrix density value based on a previous general lithologic input or calculation result.
- Alert the user if the entered parameter values are outside of "usual" limits (and allowing the user to change those limits as well as the input value);
  - A value for formation water resistivity, R_w, that is unreasonable for salinity and temperature information.
- Alert the user if calculated values are outside of reasonable or expected limits.
  - Calculated values for water saturation, S_w, that are consistently unreasonably high, or low.

A second direction in which we've all been involved is increasing functionality. In one approach, it may be the addition of a new algorithm or a display that has gained wide acceptance or usage, especially if the internal programming capabilities of the software make it difficult to implement and to test. However, one of the pitfalls that the development team must avoid is building more and more functional detail, which is used less and less and by fewer and fewer people. Sometimes a few very vocal people will demand, and get, very specific functionality at the expense of a broader functional package that benefits more users.

It is largely up to the software company to balance the needs of the many with the desires of the few. Perhaps they, and their user community, should keep in mind the words of Mick Jagger, "You can't always get what you want…"

A third, and for now final, direction for enhancements has not so much to do with the increased functionality of the software as much as the transparency of the software. This means exposure of the underlying algorithms and their sources, or some clear indication of proprietary techniques, through easy-to-access (and preferably online) focused 'help' systems.

Once again following the road in this direction, a fit-for-purpose 'help' system can answer user questions and take some burden off of the software support staff, at least for often-asked questions. Such a system might include, but not be limited to:

- Accessible information specific to each software "tool" on the interface, both for how the tool functions and its petrophysical utility;
- A multilevel system that answers, in different layers, specific questions, informs users of the associated physics or interpretive process, and provides specific references and where to access them;
- Hyperlinks to related information for the measurement/analytical method in question or for similar measurements or interpretive methods, which might help in user understanding;
- Hyperlinks to short tutorials related to the 'help' information. These could be part of an agreement between the software company and a third-party organization with subject matter and training capabilities (like SPWLA?).

I hope that my ramblings here have raised more questions than they have answered. If the topics that I've exposed cause dialog, rather than confrontation, between software development teams and software users, then my efforts have not been in vain.

In my next chapter, if the editors approve, I'll take a last look at the topic of software and focus on when it is time to leave one package and go to another.

The Application of Petrophysics in Coal-Seam Gas in the Surat Basin, Queeensland, Australia

Rachael Ilett
Senex Energy, Australia

Rodney J. Sime once said, “Adsorption by a solid is not a very important process unless the solid has a very large surface area compared to its mass.” One cubic meter of high-rank coal can contain a surface area of up to 200 m^2 within the porosity, cleat and fracture systems. For this reason, Australia’s coal-seam gas (CSG) industry is a globally significant supplier of liquefied natural gas (LNG), producing 20.4 million tonnes from six trains in FY 2018 (EnergyQuest, 2018). Data-driven studies have been at the forefront of successful development of the East Coast LNG industry and will continue to be of significance to meet growing domestic and international demand.

The Surat is one of two key coal basins in Eastern Australia, covering 24,000 km^2 in Queensland and Northern New South Wales. Over 9,500 wells have intersected the Walloon Coal Measures (WCM), the zone of economic interest. 30 TCF of 3P reserves remain in the Jurassic-aged CSG plays (petroleum and gas reserves statistics December 2017) (Queensland Government, 2017). The sheer volume of data and its baselining requirements provide a unique challenge for petrophysicists working in this sector. The highly heterogeneous nature of the subbituminous coals and inability to accurately measure key properties, such as coal fracture porosity, presents a series of complex and unresolved characterization problems.

The Walloon Fairway subcrops along the northern basin margin and sediments dip toward the NS-trending Taroom Trough. In commercially viable regions, the coals constitute 5 to 9% of the gross 180- to 350-m interval thickness. As the coal formed in a fluviolacustrine depositional environment, abrupt and uncontrolled avulsion of the river systems led to frequent inundation of coal swamps, often resulting in high mineral content and an average seam thickness of just 40 cm. The lithologies and fluvial architecture of the interburden changes rapidly, leading to irregularly shaped coal geobodies that have highly variable maceral composition, ash and moisture content. The relative density ranges between 1.25 and 1.8 g/cm^3 with moisture values between 2.5 and 10%. (database of 4,757 core samples, <50% ash). A great deal of well and core data is required to ascertain the property ranges in a single development area.

Thousands of log suites have been acquired across the basin by numerous service contractors over five decades, and many remain undigitized. Varied logging objectives, evolving tool technologies, contrasting borehole environments, variable acquisition parameters and independent tool calibrations have yielded a Pandora’s box of disproportionate electrical information that requires standardization prior to the most basic quantitative analysis. Of particular interest, are the bulk-density measurements, which are heavily used for gas-in-place (GIP) determination. Density is used to define initial net coal thickness, in-situ coal density and quite often gas content, before upscaling these properties for facies modelling into 3D static models. Raw log densities are a bulk response of the coal matrix density (controlled by organic composition and rank), dry mineral densities, water-filled porosity, free-gas and adsorbed-gas content.

Disparate systems to standardize raw data are prevalent and the lack of industry standards can be attributed, in part, to the labor requirements to design and implement a series of time-consuming normalization steps. Ren et al. (2016) proposed a novel workflow comprising a seven-stage normalization process. The absence of a regionally extensive marker layer is the crucial missing link in the Surat Basin for decoupling true geological heterogeneity from detection-based variability. The large number of wells and complex normalization issues make such tasks quite daunting and expensive to justify in the context of plays with marginal commerciality.

Considerable effort has been expended by operators to understand the most representative density cutoffs, as these have a considerable impact on GIP estimation. Density cutoffs between 1.72 to 1.8 g/cm^3 yield on the order of a ± 8% variance in net pay. Studies have been hampered by poor core retrieval, core interpreter bias and thin seams below log resolution, which all contribute to discrepancies in the resultant net-pay criteria. Furthermore, high-density pay, defined as 1.8 to 2.0 g/cm^3, is treated differently across the industry. Carbonaceous shale is discounted on the basis that production testing has not yet verified commercial rates of recovery, while major proponents carry it as a 3 to 4.5% uplift on resource volumes. With many projects being commercially marginal, these variances are a major concern that may impact the future viability of CSG resource development.

Calibration to core and integration of multiple datasets is the gold standard for validation of derived rock properties in the conventional realm. Its application in CSG faces problems of representativeness, scale, sample stability and an inability to measure every property essential for characterization. CSG core calibration is similar to the thinly laminated clastic pay problem. Coal bright bands hold higher vitrinite and gas content and are interbedded with dull bands, tuffs and mineral-rich layers. Vertical log resolutions do not capture the fine-scale lamination changes. Core samples are not taken with a regularly spaced vertical origin; they are instead homogenized from individual seams. For example, relative density is measured using a 50-g crushed and milled sample, which is itself split from a larger 2 to 3 kg desorption sample. As a result, an average of the coal properties always underpins static representations. Furthermore, relatively predictable thermogenic processes work alongside the geographically variable contribution of biogenic sources to make depth-trending in discrete geodomains difficult. The sources of production behavior differences at the seam level are seldom distinguished and impossible to model at a large scale. A lack of fine-scale, dynamically relevant characterization is one of the reasons production forecasting on a well-by-well basis is not yet practical.

A multitude of variables overlap in unconventional CSG plays and can change at the nanometer to structural region scale. Core-to-log relationships must consider vertical resolution problems, sample representativeness, measurement accuracy and repeatability, meaningful binning and like-for-like reporting bases. Companies in Queensland have funded several reputable research centers, such as CSIRO and the University of Queensland Centre for Coal Seam Gas, to carry out academic studies to address convoluted coal characterization problems. Density normalization is one crucial issue that operators can address internally to reduce uncertainties in geomodelling. Collaboration among petrophysicists will aid the establishment of standards and allow more consistency in the methods underpinning resource estimation.

REFERENCES

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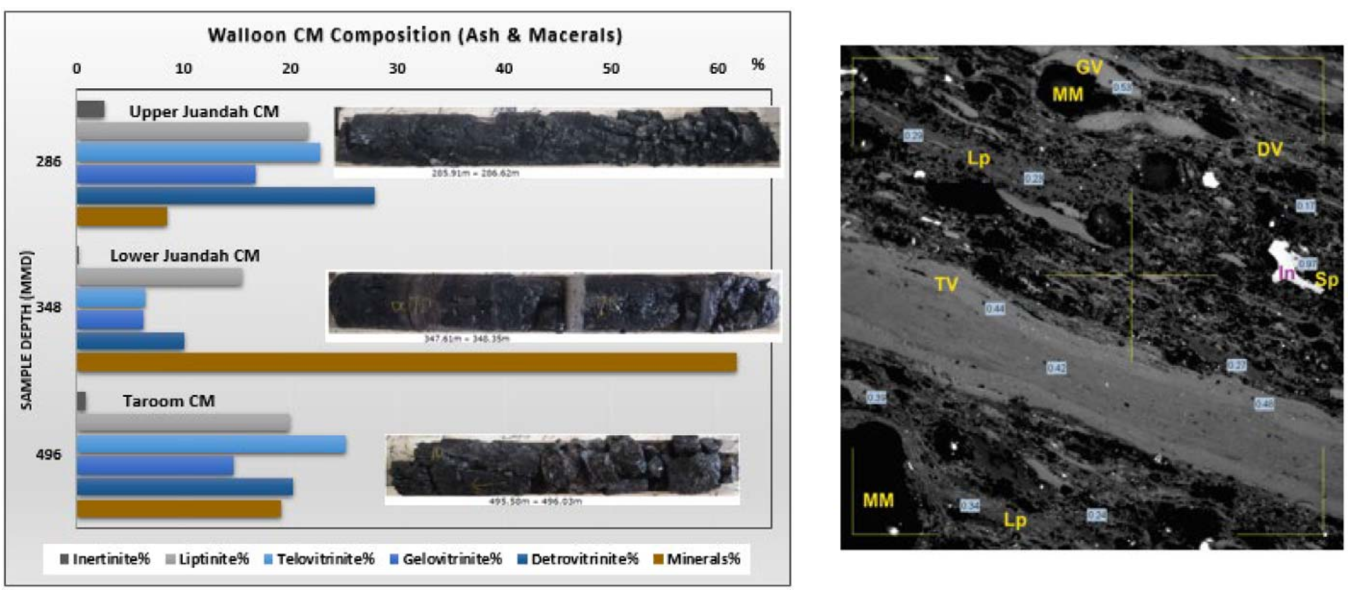
ABOUT THE AUTHOR

Rachael Ilett is a geologist and petrophysicist with Senex Energy in Brisbane, Australia. She has experience in exploration, appraisal and development and has worked



(a)

(b)

Fig. 1—Photomicrograph of Walloon CM illustrating its strongly heterogeneous nature. Annotations show maceral groups and reflectance of selected areas. (a) The field is dominated by liptinite group macerals (Lp and Sp), which are closely associated with vitrinites (DV and GV) and minerals (MM) and rarely inertinites (In). The band of telovitrinite (TV) would make a very thin band of bright coal in hand specimen. TV = telovitrinite, DV = detrovitrinite, GV = gelovitrinite, In = inertinite; Lp = liptinite, Sp = sporinite (a type of liptinite); MM = mineral matter. (b) The black and white image was taken on a polished surface in reflected light using an oil-immersion technique. Width of the field of view = 175 μm; total magnification = 500X.

across a wide range of conventional and unconventional assets in Australia and New Zealand. Rachael received a BSc (Hons) from the Queensland University of Technology, and is a committee member of FESQ, a chapter of the SPWLA. The author wishes to acknowledge the valuable contributions of Kevan Quammie, Senior Reservoir Engineer, Senex Energy, Brisbane and Peter Crosdale of Energy Resources Consulting Pty Ltd, Brisbane, who provided the photomicrograph and maceral interpretations.

Automated Workflows for Planning Formation Testing and Sampling[1]

Mark Proett
Mark Proett Consulting

INTRODUCTION

A primary source of dynamic data for formation evaluation is available from wireline and LWD formation testing. In a typical exploration or appraisal well, the formation testing can provide definitive data for the identification of flow units, fluid types, contacts, composition and even EOS models. In the process of pressure testing and sampling, the dynamic data also provides a link to the static open hole logging data that can be integrated to enhance the formation evaluation. However, this dynamic data is frequently overlooked due to the uncertainty created by the wide variability of the tool technology, measurement options and interpretation methods available. Most openhole logs produce standardized results that are readily accessible and accepted. In the case of formation testing, the data is normally analyzed and the results are reported by the service provider's analysis, which can be subjective. Recently, reporting standards have been instituted enabling the relative quality of the measurements to be assessed objectively and uniformly (Proett et al, 2015). This has led to the development of automated analysis methods that have progressed to the point where an entire testing run's dynamic data can be analyzed automatically.

While the interpretation of the dynamic data is being addressed, there is still a need to automate the job planning process. The tools and measurement options available are numerous and can be daunting to someone not familiar with the technology. In addition, the formation testing is typically the most expensive portion of the openhole logging program, which puts considerable focus on this task with competing objectives by all the parties involved. Current job-planning methods do not have a well-defined workflow and typically rely heavily on the availability of highly skilled specialists, and due to time constraints, a detailed job plan is rarely done. However, by implementing a systematic approach, a job-planning workflow can be defined that is highly automated, enabling formation testing jobs to be optimized. This article provides an overview of the new methods currently being developed and how they can be made accessible to a wide audience.

JOB PLANNING

Formation testing can be separated into two stages: pressure testing and sampling. In most cases pressure testing is conducted initially to further delineate potential flow units and select the most favorable sampling locations. Most pressure tests are called "pretests" since they are typically short duration tests with limited drawdown volumes lasting less than 5 to 20 minutes. Most pretests consist of several drawdown buildups, which are performed to confirm the data quality (see Fig. 1). A pretest is almost always performed before any type of testing, including sampling and more advanced testing methods, such as a longer duration drawdown buildup test (miniDST). When pretests are monitored in real time, changes in the testing controls can be made to obtain the highest quality data in the shortest time with the tool being used. In the planning process it is desirable to select the testing technology and anticipate the testing control settings, such as drawdown rates and buildup times that optimize the test quality.

Sampling can be the most difficult to plan and have confidence in obtaining the desired objectives while considering the uncertainties. Depending on the formation conditions and the sampling objectives, the pumpout or cleanup stages can take over 10 hours to reach the contamination level considered to be representative. Drilling conditions may cause tool-sticking risks requiring operational constraints that could interrupt and shorten the desired cleanup time. Optimization of sampling objectives requires tradeoffs to be made between sample quality, operational constraints and available technology. While sampling can be simulated, it is a very time-consuming task and requires the consideration of many variables that are uncertain. Some sensitivity analysis is required to consider these variables and obtain an understanding of the potential impact they can have on the sampling time required to meet the objective. New algorithms have recently been introduced that enable the automation of FTS job planning (Proett et al., 2017). Furthermore, Monte Carlo simulations were introduced that can provide statistics on the uncertainty in obtaining the testing and sampling objectives.

[1]This article contains highlights of paper SPE 187040, Proett, M.A., Ma, S.M., Al-Musharfi, N.M., and Berkane, M., 2017, Dynamic Data Analysis with New Automated Work Flows for Enhanced Formation Evaluation," originally prepared for the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, 9–11 October.

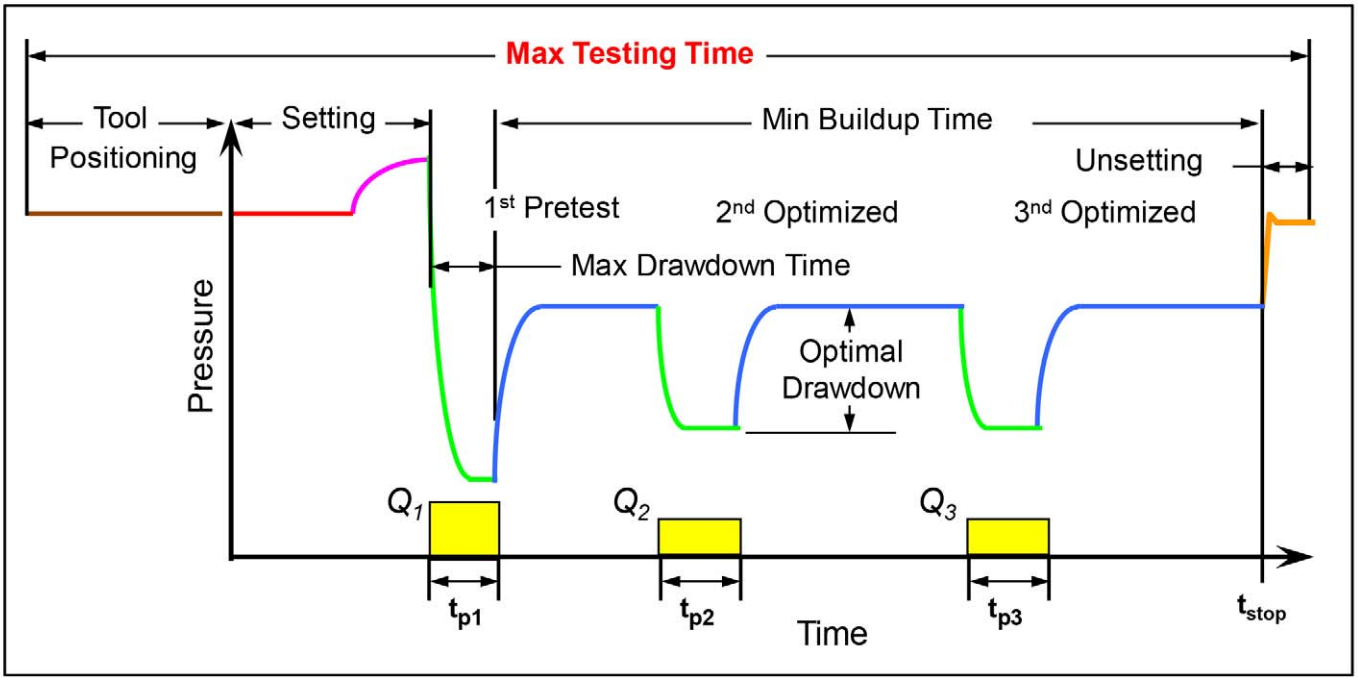


Fig. 1—Time line for a complete pretest sequence. When the tool is positioned with a wireline or drillpipe at the test depth point, a command is given to deploy the probe-packer to the borehole. After this tool positioning time, the pressure gauge starts reading the hydrostatic borehole pressure until the flowline valve is closed. Then, as the probe is set against the borehole, a pressure change may be observed in the flowline (setting time). The first pretest drawdown is performed by moving the pretest piston, which draws fluid from the formation into the probe and flowline, lowering the pressure at the probe to the drawdown pressure. After the pretest stops, the buildup occurs and the pressure increases until it stabilizes within the specified level or the maximum buildup time is reached. The process is normally repeated at least once to confirm that the final buildup pressure is close to the previous buildup pressure. Additionally, the second flow rate can be modified to optimize the test for the best results in obtaining a stable buildup and estimate of the formation mobility (mD/cP). After the final drawdown-buildup sequence the tool is unset from the formation and the probe retracted. The entire test pretest sequence must be within the "Max Test Time" allowable to be within the "Operational Control Parameters" specified (see Table 1).

PRESSURE TESTING

The test control parameters are shown in Table 1 with the quality parameters highlighted in light green and the control parameters highlighted in yellow. The pressure stability (i.e., psi/min) is the primary quality parameter that determines the length of the testing time. Quality standards can vary over a wide range, depending on the testing objective. For example, in drilling operations, a DFT can have a limit of 0.1 to 1.0 psi/min that is sufficient for a reasonable estimate of formation pressure. Another parameter that is often not considered is the depth of investigation. While there is no definitive estimate for the depth of investigation it is recognized that the volume produced is the primary controlling factor and should be a consideration in the test design (Kuchuk et al., 2009). For example, in most conditions the flowrate can be controlled to obtain the desired drawdown pressure and extending the drawdown time to a practical limit (< 1 min) in order to maximize the test volume without significantly impacting the total test time.

Another important factor often reviewed and specified for operation is the maximum time allotted for each test. In Table 1, the maximum time is set at 60 minutes (shown in red text), which includes the tool position time and probe setting time (which in turn consists of time required to extend the probe and start the first drawdown). Therefore, a maximum of 54 minutes would be allowed for a buildup with a single drawdown, as shown in Fig. 1, considering the control parameters highlighted in yellow in Table 1. Table 2 shows the operational constraints highlighted in light red with the formation and drilling constraints shown in a light olive background. The minimum testing time of 10.5 minutes shown in Table 2, considers the case when three drawdown/buildups are performed in a high-permeability formation and stability occurs within the minimum buildup time (i.e., T_{bmin} of Table 1). Other important parameters are the stability time and the radius of investigation (Proett, 2014). Control parameters also include the number of drawdown/buildups allowed, the optimal drawdown pressure differential, and initial drawdown times and rates. Every test starts with an initial rate and time (i.e., volume) and if the tool is capable of adjusting the rate to attain the optimal drawdown differential then the drawdown can continue but not exceed the maximum drawdown time.

For a formation interval, the parameters for consideration are shown in Table 3. The buildup time required for job planning purposes can be estimated using this closed-form expression (Proett et al, 2017):

$$\Delta t \cong \left(t_p q_o \frac{3}{8} \frac{\sqrt{\phi c_t}}{dp/dt} \right)^{\frac{2}{5}} \left(\frac{14{,}696 \mu}{\pi k_s} \right)^{\frac{3}{5}} \tag{1}$$

The storage factor can extend the buildup station time. This delay can be approximated for a storage-dominated buildup using the following closed-form solution (Proett, et al., 2017):

$$\Delta t \cong -\alpha \ln\left(\frac{dp}{dt} \frac{\alpha}{\beta} \right) \tag{2}$$

The relationships of the buildup derivative versus time are best demonstrated in Fig. 2a. In this figure, the formation parameters shown in Table 2 were used and it was assumed that the drawdown time was at least 10 seconds. The storage factor is also shown in Fig. 2a with the long-dashed line above estimated derivative curve. In this case, the storage factor would add about 6 minutes to the buildup time for 0.1 psi/sec of stability for a 0.1-mD formation and a typical probe formation tester. Table 3 shows the typical specification for a probe formation tester with a flowline volume of 180 cm^3 and a 0.25-in. radius probe with a probe flow coefficient of 4,984 (mD-psi-sec/cm^3) used for the storage time estimates. It is interesting to note that while storage can be a contributing factor to increasing the buildup time, it may not be as significant as expected in all cases.

Figure 2b illustrates how the operational parameters can affect the total testing time. The dashed curve in this plot is an estimate of buildup time to reach a stability of 0.1 psi/min considering the tool parameters (Table 3) and the formation parameters (Table 2) where the formation spherical mobility (k_s/μ) is varied. If the basic operational parameters are added to this buildup time from Table 1 the dash-dot curve shows the time required for a single drawdown test to be performed.

Using the other operational constraints shown in Table 1, the solid curve shows an optimized testing time when more than one drawdown is possible. In the lower limit of mobility, the pretest is limited to one drawdown/buildup due to the total testing time limitations (i.e., 60 minutes). There is a transition to two drawdown/buildups at about 0.05 mD/cP. When the testing time drops to 45 minutes, three drawdown/buildups are activated within the maximum testing time and then the time reduces until it reaches the minimum testing time of 10.5 minutes at about 20 mD/cP.

These algorithms have been implemented to demonstrate the automated testing planning process. The formation intervals and testing properties are shown in Table 4**,** where formation intervals are highlighted with different colors. The number of testing stations are determined considering the

Table 1—Test Quality and Operational Control Parameters

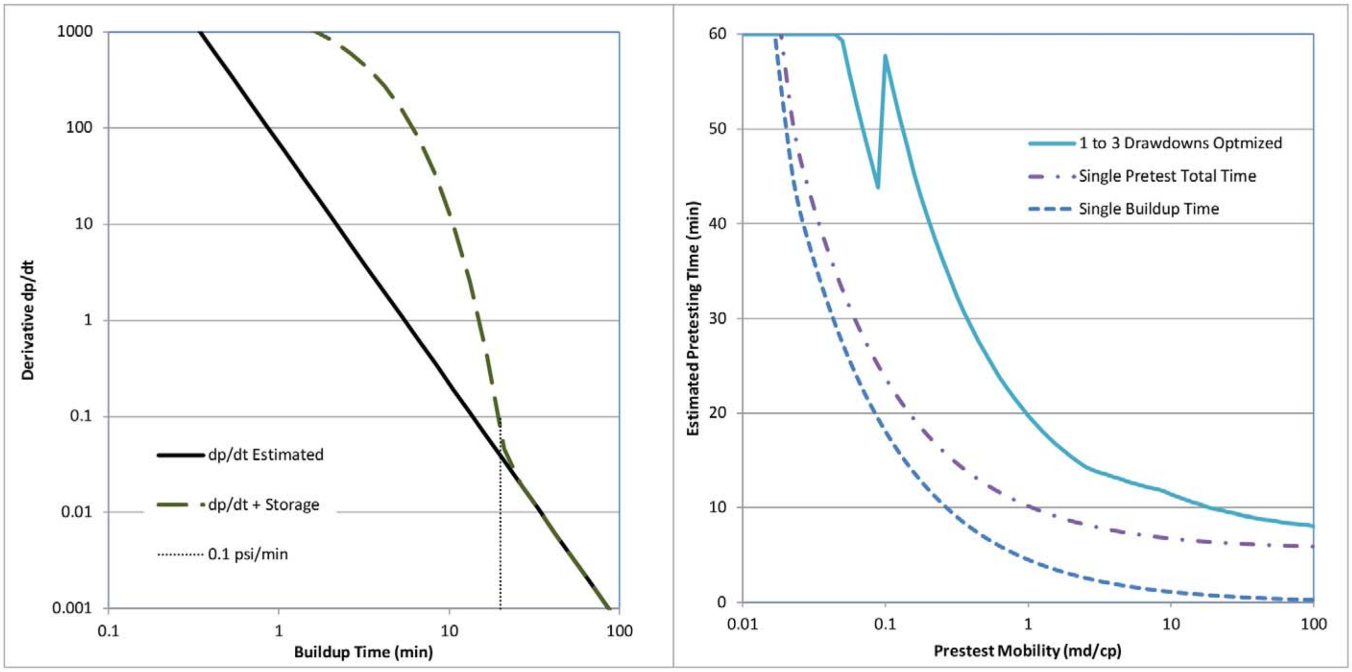
Test Quality Parameters						Test Control Parameters					
Max, DD Time (sec)	Min Buildup, Tbmin (min)	Max Test Time, Ttmax (min)	Stability, Time (min)	Stability, dp/dt (psi/min)	Ri Index (#)	Max No. Draw-downs (#)	Optimal DD ΔP (psi)	Initial DD Time, Tdd (sec)	Initial Flow Rate, q (cm^3/sec)	Test Spacing (ft/test)	Tool Position Time (min)
30	1	60	0.5	0.05	5	3	500	10	1	6	5

Table 2—Operational and Drilling Constraints

Constraints			Formation and Drilling			
Min Test Time, Ttmin (min)	Max Buildup Time (min)	Min DD Pressure (psia)	Wellbore Radius (in.)	Overbalance ΔP (psi)	Mud Weight (lbm/gal)	c_t (1/psi)
10.5	54	1000.00	8.5	500	10	3.00E-06

Table 3—Formation and Testing Parameters

Depth (ft)	Mud Weight (lbm/gal)	Wellbore Pressure (psi)	Overbalance, ΔP (psi)	Filtrate Viscosity, μ (cP)	Spherical Perm, k_s (mD)	Flowline c_{fl} (1/psi)	Formation c_t (1/psi)	Porosity, ϕ (V/V)
12,000	10	6068	500	1.0	0.1	1.0E-5	3.0E-6	0.1



(a) (b)

Fig. 2—(a) The plot shows the estimated pressure derivative (i.e., stability) versus buildup time. The dashed line shows the additional time added due to the fl owline storage eff ect. (b) The solid line shows the estimated testing time, considering multiple drawdowns. The logic increases the number of drawdowns when the total testing time is less than 45 minutes. At lower mobilities, only one drawdown buildup is used and as the mobility increases there are two sharp increases in the estimated time when additional drawdowns are introduced.

interval height and the test spacing from Table 1, which can be modified as needed.

Using the inputs from Tables 1 to 4, the testing time and quality estimates are shown for the FTS logging job in Tables 5 and 6 based on the tool technology chosen. For each interval defined in Table 4 the quality parameters are estimated and shown in Tables 5 and 6 using the algorithms presented previously and based on Proett (2015). The quality parameters are defined in a range from 0 to 4 with a progressive color spectrum from red to green. Uncertainties are also determined based on Monte Carlo simulations considering the range of variability in the formation parameter inputs in Table 4 and the tool's probe sealing efficiency. For example, in Table 5 a typical small probe tool technology is chosen (TYP) which resulted in a total testing time of 46 hours with an expected variance of 21.5 hours. The overall quality is good based on a four-point scale where quality values above 1.5 are considered acceptable (Proett et al., 2014). However, the quality for Interval A is very low and it is unlikely that valid data will be obtained. Changing operational parameters may improve the testing in this interval but to keep the testing time and cost within budget and maintaining safe operational best practices, another technology can be evaluated, as shown in Table 6.

A much larger oval-shaped elongated probe is chosen for the estimates shown in Table 6. The overall logging time is reduced by only 1 hour, but more importantly, the expected variance is reduced, and the quality parameters indicate that testing will be successful in Interval A. The reason for the total testing time being nearly the same is primarily due to operational constraints. The oval pad has a much larger volume pretest, probe area and a wider range of flow rates enabling it to be more effectively used within the time allowed for testing, particularly of Interval A.

It is interesting to note that the quality for the oval pad in the high-permeability zones is slightly lower than the small-diameter probed tool. This is because the volume of the pretest is reduced over the oval pad which actually reduces the time to pressure stabilization. However, a larger volume pressure test is optimal since it increases the radius of investigation, which is the case for the oval pad. Also, the oval pad has much better pressure stabilization in the low-permeability intervals. Therefore, one technology may be better suited for formation conditions in a particular formation interval.

Table 4—Formation Interval and Testing Properties

Interval Name	Tops Depth	Interval	Testing Stations	P*	Overbalance	Phyd	Porosity Min	Porosity Nominal	Skin	Mobility Min	Mobility Nominal	Success Rate
	(ft)	(ft)	(#)	psia	(psi)	(psia)	(V/V)	(V/V)	(#)	(mD/cP)	(mD/cP)	(%)
A	A,841	120	20	3574	500	4074	0.04	0.12	1.00	0.005	0.150	95%
B	B,366	200	33	3867	500	4367	0.06	0.16	1.00	0.020	0.600	95%
C	C,060	60	10	4190	500	4690	0.08	0.20	1.00	0.080	2.400	95%
D	D,934	180	30	4674	500	5174	0.10	0.24	1.00	0.32	9.60	95%
E	E,862	100	17	5134	500	5634	0.12	0.28	1.00	1.28	38.40	95%
F	F,257	70	12	5331	500	5831	0.14	0.32	1.00	5.12	153.60	95%
Average		121.67	20.33					0.22	1.00	1.138	34.125	0.95
Totals		730.00	122									

Table 5—Pressure Testing Estimate Summary with Typical Small Probe Tool

Selected FT Tool and Options					TYP				
Interval Name	Ri Radius QC Rating (#)	Stability QC Rating (#)	Testing QC Rating (#)	Average Testing Time (hours)	Total Testing Time (hours)	Testing Time Variance (± hours)	Draw-Down Buildups (#)	Opt DD Rate (cm³/sec)	Opt DD DP (psi)
A	0.89	0.74	0.81	0:39	13:11	6:44	2.5	0.20	2411
B	1.39	2.10	1.74	0:28	15:37	9:04	2.8	0.26	1671
C	1.76	2.34	2.05	0:20	3:20	1:37	3.0	0.62	1232
D	2.12	2.78	2.45	0:15	7:30	1:55	3.0	1.13	697
E	2.52	3.18	2.85	0:13	3:49	0:30	3.0	1.43	326
F	3.07	4.00	3.53	0:12	2:31	0:04	3.0	1.69	177
Averages	1.84	2.40	2.12	0:22	9:17	4:14	2.9	0.8	1183
Totals	Job Efficiency		0.84		46:16	21:47			

Table 6—Pressure Testing Estimate Summary With Typical Oval-Shaped or Elongated Probe Tool

Selected FT Tool and Options					TYP-OP				
Interval Name	Ri Radius QC Rating (#)	Stability QC Rating (#)	Testing QC Rating (#)	Average Testing Time (hours)	Total Testing Time (hours)	Testing Time Variance (± hours)	Draw-Down Buildups (#)	Opt DD Rate (cm³/sec)	Opt DD DP (psi)
A	1.02	1.99	1.50	0:35	11:56	5:10	2.8	0.32	1240
B	1.45	2.00	1.72	0:27	14:55	6:31	3.0	1.38	807
C	1.86	2.06	1.96	0:19	3:13	0:57	3.0	3.82	468
D	2.25	2.30	2.28	0:16	8:12	2:38	3.0	5.94	342
E	2.75	2.65	2.70	0:13	3:53	0:52	3.0	7.58	241
F	3.26	3.10	3.18	0:12	2:29	0:17	3.0	8.91	155
Averages	1.95	2.27	2.11	0:21	9:03	3:29	3.0	4.1	593
Totals	Job Efficiency		0.93		45:08	16:54			

SAMPLING

Sampling estimates based on simulation are even more complex than those for pressure testing. This is because the mud filtrate invasion needs to be estimated, requiring mudcake properties, fluid properties (mud and formation fluids) and multiphase rock properties (Cig, et al., 2014). Accurate estimates of these properties are rarely available and, therefore, sensitivity studies are run to assess the variability of the sampling times based on the assumptions. Due to the complexity, these sampling simulations are only done for special cases, particularly when evaluating one technology against another (Beik, et al., 2010). The practical approach normally taken is to simply estimate the total pumpout volume based on previous jobs in a similar reservoir.

This approach is best demonstrated in a recent paper (Deering et al., 2015) where the sampling time was estimated assuming a fixed volume was required to achieve the sample quality needed. The time for the pumpout depends on the technology employed. This is illustrated in Fig. 3, which shows the relationship that the pumping capacity and probe packer size have on the optimum pumping rate. As shown in Fig. 3, the wellbore overbalance must first be overcome by the pump and then the probe or packer creates an additional pressure drop based on their size and shape (Larsen et al., 2017). Assuming a linear relationship for flow rate and pressure based on the probe flow coefficient (C_{pf}) and formation mobility, the optimal pumping rate can be estimated when the pump curve intersects the probe curve, as shown in Fig. 3. Assuming the rock properties are constant, then mobility changes during the pumpout due to fluid property changes can be considered and an average optimal rate may be estimated.

While the pumping rate can be estimated, the pumpout volume is still needed to determine the pumping time. Additionally, there needs to be considerations for sample quality and changes in borehole and formation conditions. The following development shows how these factors are considered to determine the required pumpout volume. Consider the pump and probe curves shown in Fig. 3, the volume pumped is determined as a function of the pumpout time (i.e. t_{po}):

$$V_{po} = Q_{po} t_{po} = \left(\frac{\Delta P_{\max} - \Delta P_{ob}}{\dfrac{\Delta P_{\max}}{Q_{\max}} + \dfrac{C_{pf}}{M_{sph}}} \right) t_{po} \tag{3}$$

In one of the earliest papers concerning estimating sample contamination, it was demonstrated that contamination could be estimated using a power law relationship (Hammond, 1991) and was later generalized for contamination estimates (Mullins et al., 2000):

$$C = -\beta_f V^{-\chi} \tag{4}$$

The formation coefficient β_{f1} applies to a specific formation condition. One of the primary factors is the invasion volume. If conditions allow more filtrate invasion, then the pumpout volume would increase to reach the same contamination level. When formation conditions change, the invasion volume would change and, conversely, the formation coefficient.
By assuming that the volume of invasion is related to the volume required to pumpout, the following expression can be used as a first order estimate (Proett et al., 2017):

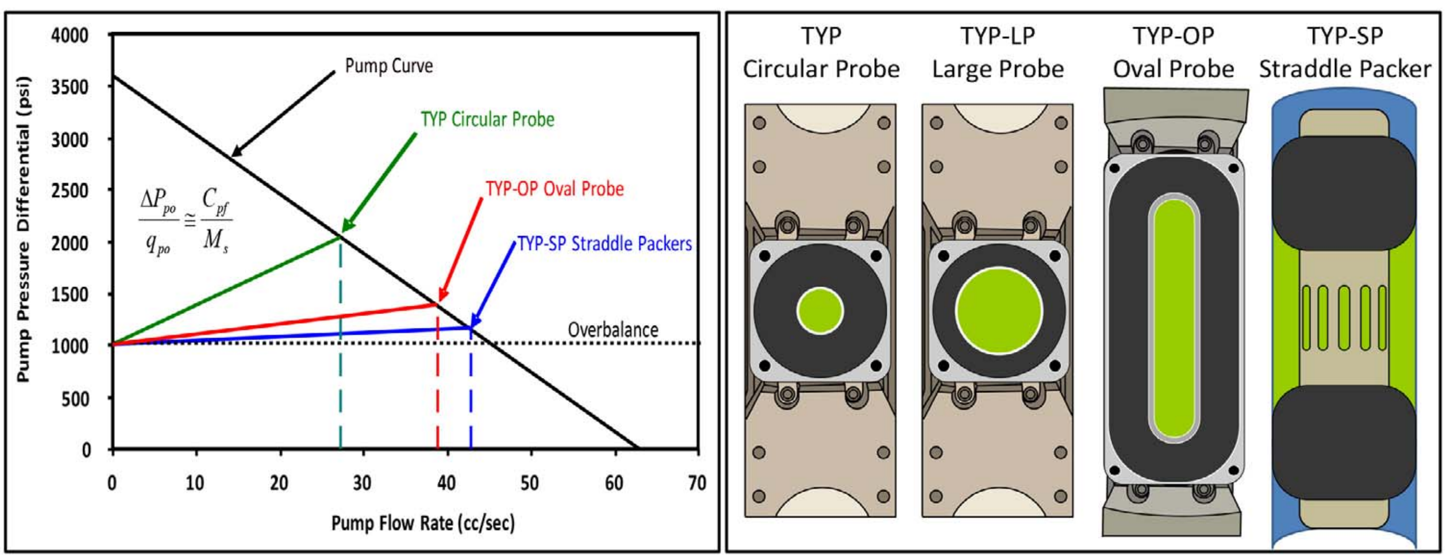


Fig. 3—Performance comparison of a typical probe, oval (pad) probe and straddle-packer systems. The simulations assume a 100-mD/cP formation with the pump curve shown. The green areas show the area and volume affected by the different probes and straddle packer. The straddle packer has a considerable area in communication with the borehole compared to the probes. However, the volume between the inlet and the borehole slows the buildups due to storage and sampling because of the additional trapped borehole volume that needs to be pumped.

$$\frac{V_{f2}}{V_{f1}} = \frac{v_{inv2}}{v_{inv1}} = \frac{\Delta P_2 k_{f2} t_{inv2}\left(\frac{1}{2}\ln\left(\frac{8k_{f1}t_{inv1}}{\phi\mu c_t r_w^2}\right) - \gamma + \left(\frac{k_{f1}}{k_{mc}} - 1\right)\ln\left(1 + \frac{l_{mc}}{r_w}\right)\right)}{\Delta P_1 k_{f1} t_{inv1}\left(\frac{1}{2}\ln\left(\frac{8k_{f2}t_{inv2}}{\phi\mu c_t r_w^2}\right) - \gamma + \left(\frac{k_{f2}}{k_{mc}} - 1\right)\ln\left(1 + \frac{l_{mc}}{r_w}\right)\right)} \quad (5)$$

Now, by using the Mullins Relationship (Mullins et al., 2000) for volume and contamination, variations in invasion volume can be estimated based on formation properties and overbalance conditions.

$$V_{f2}(C) = \left(\frac{\beta_{f2}}{C}\right)^{\frac{1}{\chi}} = \left(V_{f1}\frac{v_{inv\_2}}{v_{inv\_1}}\right)\left(\frac{C_{f1}}{C}\right)^{\frac{1}{\chi}} \quad (6)$$

The algorithms developed were implemented to estimate sampling time in multiple zones using the log example from the Deering paper (Deering et al., 2015) and are shown in Table 7 with the test intervals highlighted with different colors. When this example was estimated, using a fixed volume of 200 liters for each pumpout, the total estimated pumping nearly matched the actual pumpout results. In this new estimate, the optimized rates were kept the same and the results show the pumping time would be reduced by 7 hours. This is due to the fact that the optimal pumping rates are much higher than the actual average pumping rates, while the total volume was about the same. As is the case for the pressure testing job planning, Monte Carlo simulation methods can be used to estimate the uncertainties for expected variabilities in formation properties and contamination resulting in a standard deviation for the pumpout times.

In this case, the base case was a normalized version of this sampling run using the averages shown for porosity, overbalance, mobility and volume. The contamination was also assumed to be unchanged. Assuming the original contamination was 0.07% and it was desirable to improve the samples to 0.05%, the total pumping time would increase to 55.5 hours.

Because different technologies are used in the estimate, the χ exponent should be changed based on the source types. For example, a single circular probe cleanup has been observed to be matched with a 5/12 exponent in Eq. 13 (Mullins et al., 2000) and was used for the oval-pad cases. A 3D radial-probe cleanup matches with a 2/3 exponent (Zuo et al., 2015). For the straddle packer, a 2/3 exponent was assumed since the geometry was similar to a 3D radial probe.

CONCLUSIONS

This article documents methods used to automate and optimize the job planning process. New algorithms were developed to automate the pressure testing job planning that include combining one or more tool technologies into a toolstring to obtain the optimal job design. New algorithms were also developed for the sample planning function where either experience or a few simulations can be used to estimate sampling times for the entire job that considers the changes in formation conditions and sample quality. The complete job-planning process is demonstrated by comparing field results with the job plan. The example shows how the automated job planning for sampling compares with results and the

Table 7—Pumpout Estimates and Results

Formation Properties				Pumpout Estimates						Pumpout Results					
Interval	TVD (ft)	Porosity (V/V)	Overbal (psi)	Fluid Type	Probe Type	Pretest Mobility	Rate (cm/sec)	Volume (liters)	Est Time (hours)	Time (hours)	Rate (cc/sec)	Volume (liters)	Flowing Mobility	Probe Type	Fluid Type
C1	a362.7	0.24	311.3	Oil	Oval	111.0	56	125	0:37	1:15	32	144	71	Oval	Oil
C2	a403.4	0.36	310.5	Oil	Oval	599.0	63	124	0:32	1:00	49	178	520	Oval	Oil
G4	a741.3	0.23	732.8	Oil	Oval	322.0	54	293	1:30	2:00	33	236	331	Oval	Oil
I	b263.2	0.15	436.2	Oil	Oval/SP	27.20	63	174	0:45	2:00	38	270	92	Oval	Oil
J2	b608.3	0.18	253.7	Water	Straddle	0.29	5	83	4:31	7:00	0.5	12	0.2	Oval	Water
K1	b670.1	0.18	622.5	Oil	Straddle	3.48	51	244	1:39	4:00	5.7	82	6.7	Oval	Oil
K2	c227.6	0.21	626.5	Oil	Straddle	1.03	11	234	7:23	5:30	7.0	139	0.3	Straddle	Oil
L	d082.9	0.24	612.3	Water	Straddle	21.00	56	244	1:29	3:00	28	301	165	Oval	Water
M	d148.5	0.22	600.4	Water	Straddle	3.00	34	234	2:25	2:30	33	300	11	Straddle	Water
M	d912.1	0.15	564.4	Water	Straddle	0.75	9	206	8:14	5:15	11	215	0.5	Straddle	Water
M	d991.1	0.12	572.9	Water	Straddle	15.30	56	228	1:25	2:30	15	135	14	Oval	Water
N1	e111.7	0.14	519.1	Water	Straddle	6.74	53	205	1:24	3:00	22	233	1.3	Straddle	Water
N2	e197.1	0.22	522.2	Water	Straddle	2.46	31	203	2:19	2:00	37	266	30	Straddle	Water
Averages		0.20	514			86	42	200	2:38	3:09	24	193	96		
Totals								2,597	34:19	41:00		2,511			

sensitivity that contamination has to the total estimated sampling time. Monte Carlo job-planning simulations are introduced to demonstrate how uncertainties in the planning parameters can be considered to quantify the uncertainty of critical job-planning measurements, such as total rig time, test quality and probability of a successful test. These new methods can also be applied to automation of the real-time operations to optimize the data acquisition for testing and sampling which would complete the automation of the entire FTS workflow.

NOMENCLATURE

C = contamination by volume fraction (V/V)
$C_{f(i)}$ = formation sample contamination by volume fraction (V/V)
c_{fl} = flowline fluid compressibility (1/psi)
C_{pf} = probe flow coefficient (md-psi-sec/cc)
c_t = total compressibility (1/psi)
dp/dt = Pressure derivative (psi/min)
DD = drawdown
$k_{f(i)}$ = formation permeability (mD)
k_{mc} = mudcake permeability (mD)
k_s = spherical formation permeability (mD)
l_m = thickness of mudcake (cm)
M_{sph} = spherical mobility (mD/cP)
Q = pumping flow rate (cm3/sec)
Q_{max} = maximum pumping flow rate (cm3/sec)
Q_{min} = minimum pumping flow rate (cm3/sec)
q_o = pretest flow rate (cm3/sec)
Q_{po} = pumpout flow rate (cm3/sec)
t = time (sec)
t_{inv} = invasion time (sec)
tp = production time (sec)
t_{po} = pumpout time (sec)
V = volume pumped (cm3)
$V_{f(i)}$ = formation pumpout volume (cm3)
$v_{inv(i)}$ = invasion volume (cm3/cm)
V_{po} = pumpout volume (cm3)
ϕ = porosity
x = probe cleanup exponent
σ = standard deviation
β = storage drawdown constant (sec)
$\beta_{f(i)}$ = formation cleanup coefficient (cc%)
α = storage time constant (sec)
μ = viscosity (cP)
ΔP_{ob} = wellbore overbalance pressure (psi)
Δt = buildup time (sec)
ΔP = pressure differential (psi)
λ = Euler's Constant (0.5772)

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Borehole-Image-Based Characterization of Reservoirs Targeting Draining Features (Fluid Pathways)

Dr. Abdelkader Saadallah
Consultant in Geosciences,
Stavanger Norway

ABSTRACT

The methodology, presented here, has been used for several years for the study of reservoirs around the world by making full use of borehole image data (Prensky, 1999).

1. Statistical analyses of populations as well as the preliminary results, such as differentiating structural dip from paleohorizontal dip, constitute the next step.
2. Sedimentological objects determined, especially those related to fluid flows.
3. The determination of the SHmax (maximum horizontal stress) direction, at three different scales: well, reservoir and regional.

The association of essential characteristics would highlight potential drains (e.g., natural fractures or faults) to correlate with production results, such as flowmeter data, to estimate the drains that could be targeted for intersection by future drilling.

INTRODUCTION

The initial acquisition of borehole images took place at the end of the 1980s (Boyeldieu and Jeffreys, 1988; Pöppelreiter, et al., 2010). These images, which had their technological and scientific origins in the dipmeter tools (Schlumberger and Doll, 1933) that preceded them, were considered a major development for geoscientists. The treatment of multiple types of data has presented petroleum geoscientists with new challenges. The multitude of measurements recorded within the well can be processed, quality controlled and delivered in interpretable formats. It is important to treat the basic data rigorously to move to a step-by-step interpretation to identify likely drains.

BASIC PROCESSING OF THE RAW DATA

It is clear that the quality control of the data, the primary, as well as the subsequent output data, occurs at different stages of the analyses, while at any time the key question to be kept in mind is: "Do the data make geological sense?"

Prior to systematic measurements of geological surfaces (sedimentological and structural) It is often important, to retain a nonexhaustive list of geological surfaces but well-differentiated to not only facilitate correlations within the formations of the same section of the reservoir, but also with other wells in the reservoir, from the same block or other blocks. Compare what is comparable!

FIRST STANDARD RESULTS: STRUCTURAL AND PALEOHORIZONTAL DIPS

Once the bedding surface populations have been analyzed statistically by the classical stereographic projection (Phillips, 1971), two fundamental results emerge: the structural dip and the paleohorizontal dip (Fig. 1), which must be clearly differentiated.

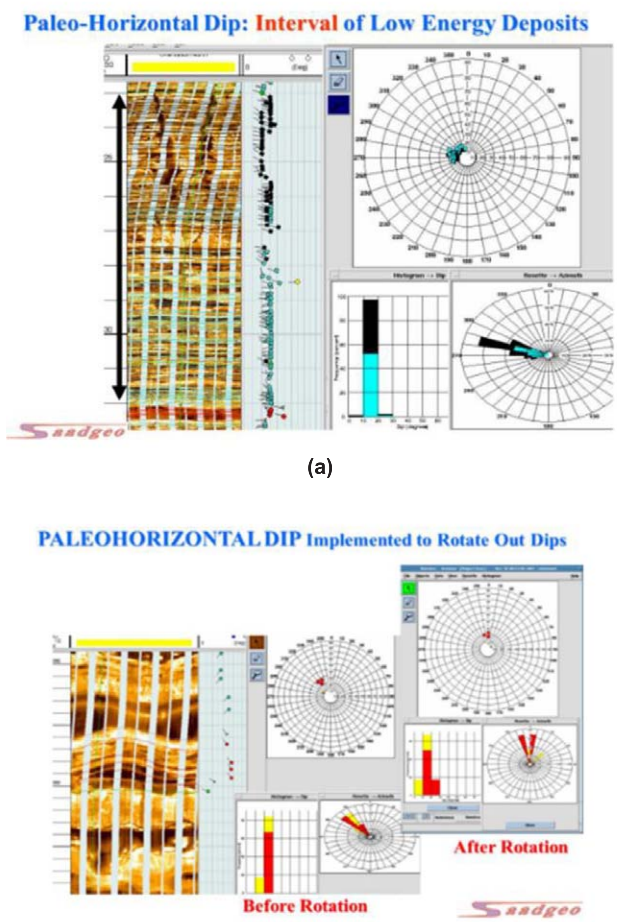


Fig. 1—Determination of the paleohorizontal dip based on an adequate interval (a), and its implementation to rotate back or flatten the paleocurrent directions (b).

From the beginning, a confusion was "hidden" deep within the definition of the structural dip. Serra (1985) defined structural dip as "... Dips with constant magnitude and azimuth in a low energy environment can be selected. They correspond to the groups of beds, whose bedding planes have not undergone any biogenic or tectonic alteration. It can reasonably be assumed that these beds were deposited on nearly horizontal surfaces and that their present dips are the results of tectonic stresses." A decade later, Rider (1996) proposed the following definition "... .By structural dip is intended the 'general attitude of beds'. It is the dip that would be measured at outcrop. It is usually seismic reflectors, themselves a generalization. It avoids any sedimentary structures of any size and is generally considered to represent the depositional surface which is also considered to be horizontal."

I therefore propose the following definitions:

- Paleohorizontal dip—as the name suggests it is the dip of the bedding surfaces originally deposited horizontally (Fig. 1). These dips are of low-energy sediments, such as clays, planktonic and some carbonaceous sediments, to be considered as deposited horizontally, solely under the force of gravity. These bedding surfaces are implemented to deduce tectonic events such as uplift, tilting and especially fault-block rotation. This definition is need to make the necessary rotations required to rotate back to the prior flat position in order to highlight the rotations of the fault-blocks; or the true directions of the flow currents at the origin of slope deposits, such as cross-bedded sandstone (Fig. 1).
- Structural dip—the actual mean dip of a formation, or a lithologic unit, used in structural tasks for a specific section or a marker that could be correlated with seismic data. It can be used to infer the geometry of the units for smaller scale structural purposes and unconformities (Fig. 2), regardless of its origin and the events recorded by these units.

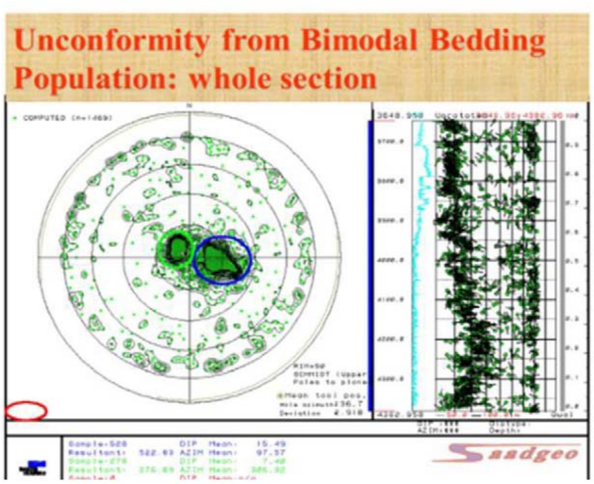


Fig. 2—Implementation of structural dip to highlight an unconformity.

This methodology would make it possible to determine the structural dips of a section for the different reservoir units and the paleohorizontal dip of the reservoir section of interest. Such results may be correlated across the entire block, entire reservoir, and at field scale.

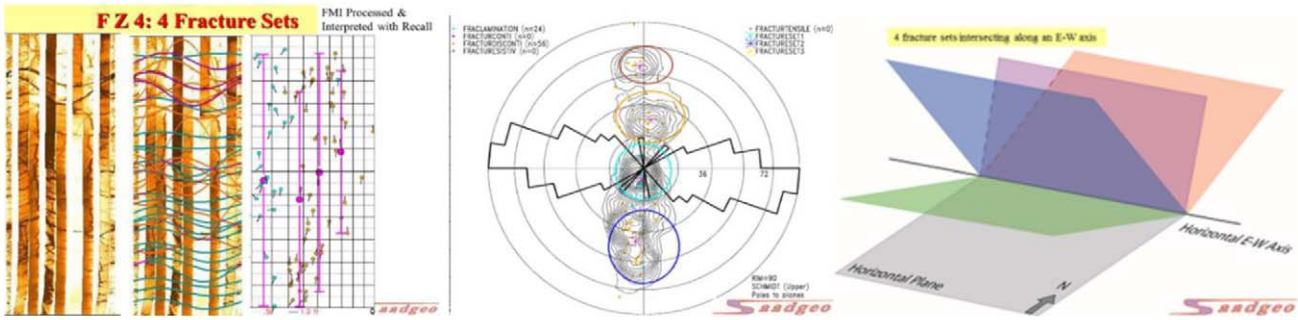
The Necessary Step of the Population Analyses of the Whole Measured Surfaces

The statistical analyses of the populations based on the stereographic projection makes it possible to discriminate the most typical types, like the concentrations, i.e., unimodal, bimodal (Fig. 2), and multimodal, while making sure to differentiate the major concentrations from the minor ones, the dissemination, the distribution of the poles in girdles, (Fig. 3) i.e., plans, and the intersection of these to highlight intersecting axes.

The listing of surface types at the reservoir scale should include (1) sedimentological surfaces, and (2) tectonic surfaces. Among the main sedimentological surfaces, the current bedding surface occupies the first place. It must be differentiated from slumping surfaces, unconformities and foreset boundaries. The presence of sandstone beds makes it necessary to highlight at least two types of surfaces: the foreset boundary of a channel and cross-bedding surfaces.

Regarding the tectonic surfaces, it is important to differentiate between fracture and faults on the basis of objective criteria. A fault displaces a marker, like a bedding surface, while a fracture shows no indication of displacement, at the visual scale. It is very useful to distinguish minor faults, underlined by centimeter-scale displacements; these are sometimes described in the cores as fractures. The measured faults are visible surfaces, open or closed, and different from the faults inferred from the population analyses of the bedding surfaces. Regarding the fractures it is very useful to differentiate discontinuous vs. continuous fractures, large fractures, open and closed (Fig. 4). The stylolite surfaces are of great importance, and they are measurable and must be of particular interest by adding the associated structures to them, such as tensile fractures (Fig. 4).

It is well known that the SHmax direction helps to open or close some fractures, depending on whether the stress direction is parallel to or perpendicular to the stress, respectively. The shear directions, that is to say at 30° of the SHmax, support fluid flows (Rogers, 2003). These are the tensile drilling fractures and the borehole breakouts, considered to be deformations caused by the actual stress, (Bell and Gough, 1979; Peska and Zoback, 1995; Aadnøy and Bell, 1998; Barton and Zoback, 2002). Once confirmed, it is possible to deduce the SHmax direction at three scales: well, reservoir and regional.



(a) (b) (c)

Fig. 3—FZ4 (fracture zone 4). (a) Track 1, the basic image; Track 2, image with interpreted sine curves; and Track 3, tadpole presentation. (b) Stereographic projection highlighting a girdle built up by four fracture sets. (c) The geometric model illustrating the directional drain.

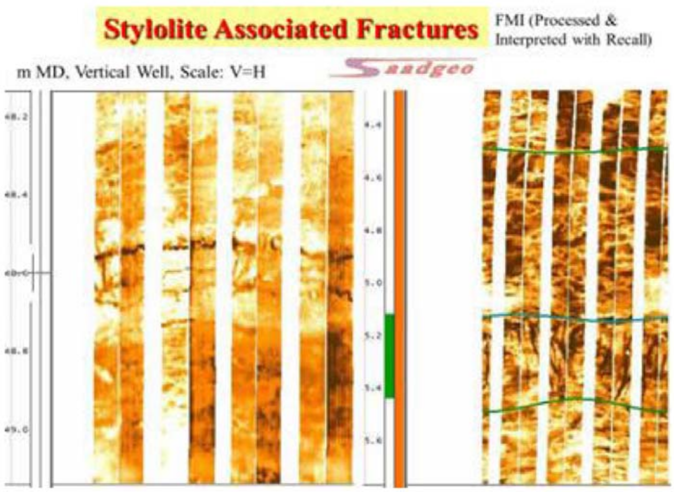


Fig. 4—Stylolites associated with tensile fractures.

KEY GEOLOGICAL FEATURES TO REPORT IN SPECIFIC ZONATION

It is also important to identify and characterize, by appropriate zonation, geological features of sedimentary origin, alteration and tectonics, associations of such features, and their accumulation in particular intervals of the reservoir formations. These are karsts, stylolite zones associated with tensile fractures (or not) (Fig. 5), vugs, fossil-bearing intervals (and therefore probably vugs created by dissolution of fossils). The vugs must be characterized as precisely as possible, this includes distinguishing whether they are isolated or interconnected.

The nonmeasurable fracture intervals are indicated by specific zonation, differentiating the fracturing type (cataclase, short fracture networks, vertical fractures etc.), and in this latter case how they are associated and the nature of the lithological interval.

FOCUSING ON FRACTURE ZONES

The fracture population has to be carefully analyzed at different levels: the total population, the intervals involved and fracture zones. The fracture zones have to be discriminated by several parameters to differentiate the fracture sets in order to correlate them from one lithological unit to another one, and from one borehole to another. The minimum parameters usually acquired are fracture density, orientation parameters and relation to lithology. The fracture zones have to be categorized as FZ1 (containing one set), FZ2 (containing two sets, such as conjugate fractures) and so on, up to FZ4 (Fig. 3), as I had the opportunity to observe it.

INFERRING POTENTIAL AND ACTUAL DRAINS

The results of these analyses have to be correlated at the well scale, then at the reservoir level of the fault block and finally up to the whole reservoir. The most representative support is the composite plot form shown in Fig. 5.

To understand the idea of a drain (Saadallah, 2010), we need to think that at the moment the borehole reaches the reservoir, the trapped fluids inside the matrix are attracted to the well, because of the activation of the differential pressure gradient between the reservoir to the bottom of the well. One could then have an image with radiating gradients in all directions converging towards the bottom of the well. This image would reflect the hydrodynamic reality of the reservoir if the reservoir rock is isotropic, i.e., the scalar and vector properties of the reservoir, such as porosity, permeability, conductivity, and rock texture have the same values in all points and in all directions; which is never the case in any reservoir. Fluids behave like electric currents attracted by the easiest path, offering less resistance, and therefore not necessarily in a straight line. These easiest fluid paths are the drains. I think that two types of drains can be differentiated by modeling them to plans of a certain thickness and directions. For convenience of communication, the first will be called ‘planar drains’ and the second ‘directional drains.’

Planar Drains. It has been known for some time that tectonic surfaces, fractures and faults in some cases, are pathways taken by fluids. They are said to be open, in contrast others that are obstacles to fluid flow, i.e., ‘closed’. In the case of faults, they are typically impermeable, which, in some case, makes them exploration targets because they are associated with accumulation of fluids below the fault, in the footwall block. If a simple fracture is can serve as a drain, then a fracture zone would serve even more so. Planar drains can be of lithologic or tectonic origin, or both. An interval bearing karst or vugs is a potential planar drain, if in addition, it is intersected by a fracture zone, it is clear that this fracture zone is also a potential planar drain (Fig. 6).

This could be the case of a layer bearing stylolites, especially if they are associated with perpendicular tensile fractures. The stylolite, impermeable film is acting as a minicap accumulating fluids while the tensile fractures will drain the trapped fluid drops, such as pipes, all constituting a planar drain. In the same way, the lithological interval bearing vugs (isolated or interconnected) resulting from dissolution of fossils for example, are planar drains, and thus also the zone of fracture which cuts it. There are many examples. It is important to define the planar drains as much as possible and

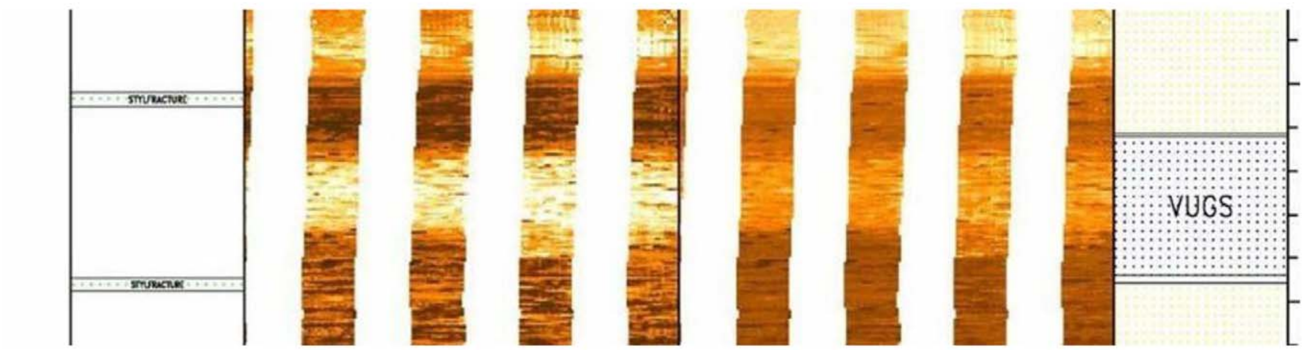
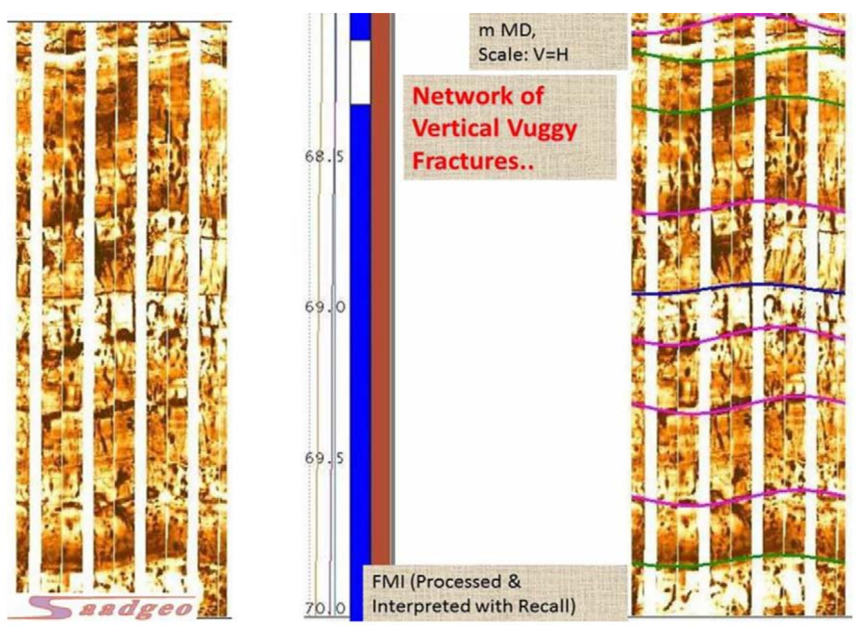


Fig. 5—Section of a composite plot displaying the correlation of the results by the projection of the results along tracks. This display makes it possible to highlight the interesting intervals, such as a zone of vugs bounded at top and bottom by fracture zones that is shown here.



(a) (b)

Fig. 6—Example of a planar drain of about 2-m thickness consisting of a network of vertical fractures intersecting a range of interconnected vugs. (a) The borehole image without interpretation; (b) the borehole image with the interpretation.

to specify the orientations as well as the exact location within the reservoir formations.

*Directional Drains***.** Directional drains result from the intersection of two or more planar drains. The most common case is the intersection of two conjugate fracture sets, so the two populations define a preferred direction by their intersection. One case studied is the result of four fracture sets building a girdle in the stereographic projection (Fig. 5), which has an intersection axis that is a potential directional drain.

Potential Drains Defined by Including Data From Other Sources and Integrating With Stress Data. Potential drains are defined at a first approach, based only on the characteristics of sedimentological, tectonic features and their association. The first result of this analysis, i.e., going from the well to the reservoir, will establish a hierarchy of potential drains. With the integration of data from other sources, especially the SHmax direction, the hierarchy may deserve another look.

Highlighting Actual Drains. The step forward from potential to effective drains requires the integration of production data, such as production tests, flowmeter and sometimes also those of fluid injection wells that experience unexpected water supply.

CONCLUSIONS

This methodology involves a lot of rethinking, going backward into the huge amount of data available for some fields, because we are at the beginning of the last century of hydrocarbons, which are still the engine of the world, and will remain so for several decades. The approach is to develop new methods to process data seeking to retrieve and keep only what is of interest to sort quickly, and then devote the necessary time to think and test.

ACKNOWLEDGMENTS

I thank Sonatrach for inviting me to JST11 (Scientific and Technical Days organized in Oran, Algeria) from April 16 to 19, 2018, where I presented part of this methodology.

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Society of Core Analysts International Symposium
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Abstracts

(The full papers can be downloaded from the SCA website www.SCAweb.org)

ORAL PAPERS

SCA2018-001. Reconsidering Klinkenberg's Permeability Data

Douglas Ruth[1] and Rasoul Arabjamaloei[1]
[1]University of Manitoba

The foundational paper by Klinkenberg contains a very rich dataset for gas flow in porous samples over a range of mean pressures from 1 to 2,000 kPa. Based on his data, Klinkenberg proposed a correlation between pressure drop and flow rate that depends on both the Darcy permeability (the permeability at infinite mean pressure) and the ratio of a coefficient, now generally termed the Klinkenberg coefficient, and the mean pressure. Klinkenberg's approach to analyze his data was to determine the Darcy permeability at a high mean pressure, then calculate Klinkenberg coefficients at lower values of mean pressures. He found that values of the calculated Klinkenberg coefficient remained constant for a certain range of mean pressures, but changed significantly at low mean pressures. Klinkenberg clearly stated that his results did not show a strictly linear function of effective permeability with the inverse of mean pressure—it appears that this observation has never been studied in detail.

Based on an approach published by Arabjamaloei and Ruth, Klinkenberg's data have been reanalyzed using three methods: (1) by optimizing the Darcy permeability and the Klinkenberg coefficient simultaneously; (2) by holding the Darcy permeability constant but optimizing the value of the Klinkenberg coefficient to obtain a single value for all mean pressures; and (3) by optimizing Darcy permeability, the Klinkenberg coefficient, and a second Klinkenberg coefficient divided by mean-pressure-squared. It is shown that the last approach is successful in correlating all of Klinkenberg's data to within ± 5%. However, the improvements due to the modified Klinkenberg equation are marginal and do not explain all the disagreement. For this reason, a second dataset, published by Ash and Grove, was explored. This dataset, which has been largely ignored in the literature, provides convincing evidence for Klinkenberg's ideas, once the data are reanalyzed to account for shortcomings in the ranges of experimental pressures. Based on ideas documented by Carman for mixed viscous/ diffusive flows, the results are used to derive estimates of an effective pore diameter and the tortuosity.

SCA2018-002. Validation of Permeability and Relative Permeability Data Using Mercury Injection Capillary Pressure Data

Rasoul Arabjamaloei[1], David Daniels[2], Einar Ebeltoft[3], Egil Boye Petersen[3], Richard John Pitman[3], and Douglas Ruth[1]
[1]University of Manitoba
[2]Equinor Canada Ltd.
[3]Equinor ASA, Norway

This paper reports on a study with the objective to validate a set of core analysis data using a combination of mercury injection capillary pressure (MICP) data and statistical correlation techniques. The dataset is from an offshore reservoir in Atlantic, Canada. Analysis of this reservoir was complicated by the fact that the permeabilities of the samples were high, greater than 2,400 mD. The analysis was done using an existing dataset, not a dataset specifically tailored for the techniques used in the analysis. The data analyzed included samples that represented seven zones in a single well. Porosities and permeabilities were available for the MICP samples. Electrical properties, along with porosities and permeabilities, were available on samples from each zone, but not from the same depths as the MICP samples. Steady-state relative permeabilities (SSRP) were available for stacked samples in each zone; one of the samples in the stack was a companion sample for one of the MICP samples from that zone. The MICP results were used to validate the permeability measurements using both the Swanson method (SM) and the Ruth-Lindsay-Allen (RLAM) method. The SM, using published correlation parameters, significantly underpredicted the permeabilities; the RLAM, which uses no correlation parameters, gave predictions within a maximum error of just over 33% and a mean error of -12%. The MICP data were used to validate the shapes of the SSRP curves using the Gates and Tempelaar-Lietz method (GT-LM), the Burdine method (BM), and a modified Burdine method (MBM). The GT-LM, which uses no correlation parameters, provided good predictions of the wetting-phase SSRP curves but very poor predictions of the nonwetting-phase SSRP curves. The BM, using published correlation parameters, provided poor predictions of the wetting-phase SSRP curves but improved predictions of the nonwetting-phase SSRP curves. The MBM provided good predictions of the wetting-phase SSRP curves and acceptable predictions of the nonwetting-phase SSRP curves. The MBM method does use a correlation parameter but a single value was used for all seven zones. This work provides a protocol for validating core analysis data that can be implemented in a straightforward manner to determine the "quality" of the data. The results emphasize the importance of MICP as an experimental technique. A proposed modified workflow is presented that would optimize the validation protocol.

SCA2018-003. An Investigation of Three-Phase Recovery Mechanisms for Oilfield Optimization by Three-Phase Coreflood and Simulation Studies

C. Jones[1], J. Brodie[1], M. Spearing[1], S. Lamb[1], and K. Sadikoglu[1]
[1]BP, Sunbury on Thames, United Kingdom

Two potential recovery mechanisms are being considered for a major field which required laboratory measurements to investigate the efficiency of the two scenarios: gasflood followed by waterflood and waterflood followed by gasflood. Although simply stated, the recovery scenarios involved complex three-phase processes that had to be replicated in the laboratory at reservoir conditions to provide reliable data upon which reservoir development decisions could be made.

The first sequence consisted of water displacing oil to residual oil saturation (S_{orw}), oil displacing water to residual water saturation (S_{wro}) and gas displacing both oil and water to $S_{or3,g}$ and $S_{wr3,g}$. The second sequence consisted of gas displacing oil to residual oil saturation (S_{org}), oil displacing gas to trapped gas saturation (S_{gto}) and water displacing both oil and gas to $S_{or3,w}$ and S_{gt3w} respectively.

Composite cores of four well-matched plugs at S_{wi} were used and all measurements were made at bubble point conditions. A vertical core holder was housed inside a reservoir condition facility equipped with gamma attenuation saturation monitoring (GASM). Temperature stability and the use of GASM were paramount for

the accurate measurement of produced fluids, especially trapped gas saturation. Oil, gas and water produced volumes were also measured using a separator housed inside the core flood oven to provide optimum temperature stability.

The laboratory results were modeled in a compositional simulator using an equation of state tuned to conventional PVT data and both swelling and multiple contact experiments. The objective was to build a three-phase predictive model from the constituent two-phase relative permeability data. The paper details the experimental methods and presents results for each section of the two sequences.

SCA2018-004. Determination of Electrical Parameters in Carbonates with Micro-CT, NMR and Gas Displacement Experiments

Wang Kewen[1], Li Ning[1,2], Wu Hongliang[1], Zhang Gong[2], Feng Zhou[1], and Yu Jun[1]
[1]Research Institute of Petroleum Exploration & Development, PetroChina, Beijing 100083, China
[2] Yangtze University, Jingzhou, 434023

Understanding the electrical characteristics of carbonate formation and accurately determining the electrical parameters (cementation exponent m and saturation exponent *n* in Archie equation) are very important for carbonate formations evaluation. However, the study of electrical characteristics faces great challenge because of the variable pore types, the complicated pore structure and the big heterogeneity in carbonates. We selected representative carbonate cores to carry out experiment research based on newly developed technologies in digital core analysis and resistivity test. Three types of cores were selected: the void space is mainly intergranular and intercrystalline; the vugs are developed; the fractures are developed. Firstly, the porosity and permeability of the selected cores have been tested. Then micro-CT with high resolution is used to scan the cores and NMR T_2 spectrums of the cores both in water-saturated state and in bound-water state are obtained. Finally, the resistivity of the cores in different water saturation is tested by using gas-displacement technology. The analysis results of the experimental data show that the intergranular and intercrystalline pore and the fracture both have great influence on R_0 while the influence of secondary vug on R_0 is slight. Cementation exponent m and saturation exponent *n* have great difference between different cores and there is no obvious relation between *m*, *n*, and reservoir parameters (ϕ or *K*). However, if we classify the cores based on the pore type, and the values of both *m* and *n* have good relationship with bound-water saturation.

SCA2018-005. Insights, Trends and Challenges Associated With Measuring Coal Relative Permeability

Dylan Shaw[1], Peyman Mostaghimi[1], Furqan Hussein[1], and Ryan T. Armstrong[1]
[1]The University of New South Wales, Sydney, Australia

Due to the poroelasticity of coal, both porosity and permeability change over the life of the field as pore pressure decreases and effective stress increases. The relative permeability also changes as the effective stress regime shifts from one state to another. This paper examines coal relative permeability trends for changes in effective stress. The unsteady-state technique was used to determine experimental relative permeability curves, which were then corrected for capillary end-effect through history matching. A modified Brooks-Corey correlation was sufficient for generating relative permeability curves and was successfully used to history match the laboratory data. Analysis of the corrected curves indicates that as effective stress increases, gas relative permeability increases, irreducible water saturation increases and the relative permeability crosspoint shifts to the right.

SCA2018-006. Dos and Don'ts When Developing a System to Investigate Spontaneous Imbibition in Unconsolicdated Porous Media

Bergit Brattekås[1], Tore L. Føyen[1], Trond Vabø[1], Håkon Haugland[1], Simon I. Reite[1], Anders S. Saunes[1], and Martin A. Fernø[1]
[1]Deparment of Physics and Technology, University of Bergen, Norway

This paper describes the development of a consistent model system to measure spontaneous imbibition and determine saturation functions in unconsolidated porous media. Sand grains or glass beads were packed in up to 0.5-m long, transparent glass tubes with optical access to local saturation development during spontaneous imbibition processes. The two-ends open-free spontaneous imbibition (TEOFSI) boundary condition was used, where one end-face is exposed to the wetting fluid and the other end to the nonwetting fluid. Dynamic measurement of the advancing displacement front and volumetric production from each open end-face enabled estimation of capillary pressure and relative permeability for the system.

A range of wetting- and nonwetting-phase viscosities and viscosity ratios was used during spontaneous imbibition in unconsolidated sand or glass packs. Wetting-phase (water) viscosity was increased using water-soluble glycerol or polymers. Air or mineral oil of varying composition provided a wide range of nonwetting-phase viscosities. High-permeable systems are extremely sensitive to laboratory properties, which may dominate the viscous resistance and determine flow behavior. Systematic discrepancies observed in early testing indicated that end-effects were present, even in long systems, in the filters at each end of the glass tube to maintain the grains or beads in place. Different filters were tested (no filter, glass, paper and microporous discs) to determine the impact of the filter on spontaneous imbibition. In addition to slower oil recovery than anticipated, development of a nonuniform displacement front was observed, demonstrating the large influence from minute heterogeneities within the packs, and at the end-faces. A standard sand grain packing procedure, using a custom-designed packing device, was therefore developed to ensure homogeneous properties throughout the porous media, and limited the spread in porosity and permeability values. Homogeneous sand packs with reproducible properties are necessary, to systematically investigate flow parameters and changes in wettability in unconsolidated porous media.

SCA2018-007. In-Situ Saturation Monitoring (ISSM)—Recommendations for Improved Processing

Jules Reed[1] and Arjen Cense[2]
[1]Lloyd's Register, Aberdeen, UK
[2]A/S Norske Shell, Stavanger, Norway

In-situ saturation monitoring (ISSM) using X-rays or gamma rays, has become a common method to determine fluid saturations in commercial coreflood experiments. The most common method in commercial laboratories entails 1D saturation measurements as a function of core-plug length and of experimental time. Laboratories often employ ISSM as the only method of determining fluid saturations, assuming an almost infallible accuracy of 1 to 2

saturation units (s.u.). However, as for all measurement methods, there are possible sources of uncertainty in ISSM data. Previous papers have discussed some of these uncertainties, such as X-ray drift, and inappropriate calibration scans or changes to core or fluid properties during testing. Despite this evidence, some laboratories continue to use ISSM measurements alone, assuming negligible uncertainty.

In the authors' experience, uncertainties not only exist in measurement errors, but also may be introduced by inappropriate processing and interpretation methods. This paper first considers the stipulated 1 to 2 s.u. accuracy and the necessary signal-to-noise ratio, i.e., counts required, to achieve this; as well as providing a suggested approach, where plausible, to correct saturation data compromised by incorrect calibration scans. It also considers the uncertainties in use of ISSM production volumes in determining unsteady-state relative permeability; specifically, pre- and post-breakthrough data and the assumptions surrounding selection of breakthrough from flood-front scans. In addition, ISSM profiles are often used in coreflood simulation of relative permeability to aid correlation of the capillary end-effect; incorrect data processing may compromise this correlation. In conclusion, the paper considers several sources of error in ISSM data and provides a recommended approach to acquisition, processing and interpretation of ISSM data for calculation of fluid saturations.

SCA2018-008. Characterization of Hysteretic Multiphase Flow From the Millimeter to Meter Scale in Heterogeneous Rocks

Samuel J. Jackson[1] and Samuel Krevor[1]
[1]Department of Earth Science and Engineering, Imperial College London, UK

Incorporating millimeter- to meter-scale capillary pressure heterogeneity into upscaled numerical models is key to the successful prediction of low-flow potential plume migration and trapping at the field scale. Under such conditions, the upscaled, equivalent relative permeability incorporating capillary pressure heterogeneity is far from that derived conventionally at the viscous limit, dependent on the heterogeneity structure and flow rate, i.e. dependent on the capillary number.

Recent work at the SCA 2017 symposium demonstrated how equivalent functions can be obtained on heterogeneous rock cores from the subsurface under drainage conditions; going beyond traditional SCAL. Experimental observations using medical CT scanning can be combined with numerical modeling so that heterogeneous subsurface rock cores can be directly characterized and used to populate field scale reservoir models.

In this work, we extend this characterization approach by incorporating imbibition cycles into the methodology. We use a Bunter sandstone core with several experimental CO_2–brine coreflood datasets at different flow rates (2x drainage, 1x imbibition and 2x trapping) to demonstrate the characterization of hysteretic multiphase flow functions in water-wet rocks. We show that millimeter- to meter-scale experimental saturations and equivalent, low-flow potential relative permeabilities can be predicted during drainage and imbibition, along with trapping characteristics. Equivalent imbibition relative permeabilities appear as a function of capillary number, as in the drainage cases. We also find that the form of capillary pressure function during imbibition has a large impact on the trapping characteristics, with local heterogeneity trapping reduced (or removed), if the capillary pressure drops to zero, or below at the residual saturation.

SCA2018-009. Measurement of Spontaneous Imbibition Capillary Pressure, Saturation and Resistivity Index by Counter-Current Technique at Net Reservoir Stress and Elevated Temperature

Stefano Pruno[1], Hans Erik Rodvelt[1], and Ola Skjæveland[1]
[1]Weatherford Laboratories (Norway) AS, Stavanger

Capillary pressure and resistivity index spontaneous imbibition experiments by the porous-plate method, in a core holder at elevated temperature and net reservoir stress, are both difficult and time-consuming special core analysis measurements to perform. In this type of experiment, low capillary forces act against a low-permeable porous plate and only one face of the cylindrical core sample is in capillary contact with the fluid-saturated porous plate.

In this paper, core samples having different lithology, petrophysical properties and wettability are analyzed by countercurrent spontaneous imbibition, starting at initial water saturation (S_{wi}), at net confining pressure and elevated temperature. Synthetic brine is used as the wetting phase and Isopar L mineral oil as the nonwetting phase. This methodology is applied to investigate and evaluate how to obtain more reliable, more efficient and faster saturation imbibition data combined with electrical measurements, during spontaneous imbibition measurements.

Resistivity index (*RI*), saturation exponent (*n*) (by single saturation equilibrium point using Archie's second law $RI = S_w^{-n}$) and wettability information using representative fluids, confining pressure and temperature are also obtained by applying this specific counter current imbibition technique and improved procedural approach.

SCA2018-010. An Investigation into Different Correlation Methods between NMR T_2 Distributions and Primary-Drainage Capillary Pressure Curves Using an Extensive Sandstone Database

Adam K Moss[1], Tim Benson[2], and Tony Barrow[3]
[1]AKM Geoconsulting
[2]Advanced Magnetic Resonance
[3]Weatherford Laboratories

Many workers have recognized the link between nuclear magnetic resonance (NMR) derived T_2 distributions and pore-size distributions in reservoir rocks. This property has been used to develop models to obtain primary-drainage capillary pressure curves from T_2 distributions. These models often assume that the rocks pore space resembles a simple bundle of capillary tubes. They do not consider the existence of multiple pore-body connections and pore-body restrictions/throats. The most successful models utilize variable scaling factors to convert T_2 times to pore diameters and hence, capillary pressure. The variable scaling factor approach recognizes the existence of variable surface relaxivity throughout the pore space due to variations in mineralogy and pore topography.

This investigation uses SCAL data from the ART NMR Sandstone Rock Catalogue to obtain core-calibrated variable scaling factors for 174 reservoir sandstone samples. The depositional environments for these samples include; aeolian, fluvial, coastal and shallow and deep marine. The samples used have a wide variety of mineralogy, diagenetic overprints and cover six orders of magnitude in absolute permeability. Three different methods for obtaining the scaling factors are presented and the relative merits of each discussed. A global model to predict capillary pressure from NMR T_2 distributions in reservoir sandstones has been developed using correlations between the variable scaling factors and permeability.

SC2018-011. A Fast Method for Trapped Gas Determination

Pierre Faurissoux[1], Moeata Lutui-Tefuka[1], Cyril Caubit[1], Bruno Lalanne[1], and Benjamin Nicot[1]
[1]TOTAL

Gas reservoirs are mainly produced by depletion with an aquifer rise; reservoir simulation requires two main SCAL inputs: the amount of trapped gas by the aquifer (residual gas saturation: S_{gr}) and the relative permeability to water due to aquifer flooding. As it is quasi-impossible to predict aquifer strength, the primary SCAL input for reservoir simulation is the S_{gr}. The recovery factor is directly defined by initial and residual gas saturations.

In fact, the residual gas saturation S_{gr} highly depends on the initial gas saturation S_{gi} and there is no universal petrophysical parameter governing the shape of this curve. This relationship can be described by several different models (Land, Aissaoui…). While Land's model is widely used, the Aissaoui model better fits the experimental results, at least for homogeneous sandstones. For a given threshold of initial gas saturation S_{g0}, this relationship typically exhibits a plateau at high $S_{gi} > S_{g0}$ and an increasing linear trend at low $S_{gi} < S_{g0}$. The challenge here is to properly estimate the value of the S_{g0} threshold. Classical laboratory method would require one experiment per point in the S_{gr}/S_{gi} plot, and therefore can be achieved in a matter of months.

Here, we propose a laboratory method allowing the acquisition of the S_{gr}/S_{gi} curve in a few days. The proposed method combines centrifugation and capillary rise under imaging. First, the centrifuge allows creating a saturation profile along a sample; measured by NMR. Then, capillary rise is used to capture S_{gr} under NMR monitoring. By adding NMR imaging, this technique allows combining the benefits of centrifugation to explore a wide range of S_{gi}; and the ease and cost effectiveness of capillary rise to measure the resulting S_{gr}. Therefore, at a timescale close to a traditional capillary rise, the proposed technique avoids Land extrapolation and provides a direct measurement of S_{gr} in a wide range of S_{gi}.

As an additional benefit, the combination of NMR and centrifuge can provide at the same time a direct measurement of capillary pressure, providing information on the gas in place and potential imbibition process in the reservoir.

SCA2018-012. Exponential Capillary Pressure Functions in Sedimentary Rocks

Armin Afrough[1], Mehdi Bahari Moghaddam[2], Laura Romero-Zerón[1], and Bruce J. Balcom[1]
[1]University of New Brunswick, Fredericton, Canada
[2]Petroleum University of Technology, Ahvaz, Iran

The Brooks-Corey power-law capillary pressure model is commonly imposed on core analysis data without verifying the validity of its underlying assumptions. The Brooks-Corey model, originally developed to model the pressure head during the drainage of soil, is only valid at low wetting-phase saturations. However, such models are often applied in petroleum production simulations and may lead to erroneous recovery factors when the saturation range of interest is far from the endpoints. We demonstrate that exponential models work much better for capillary pressure compared to the Brooks-Corey model over a wide saturation range.

Mercury injection porosimetry, petrographic image analysis, and magnetic resonance studies suggest that the pore- and throat-size distribution in many rocks are log-normally distributed. This fact was previously employed to calculate the capillary pressure function as a function of saturation for pore-size distributions described by a truncated log-normal distribution. Employing a Taylor series expansion, we simplify the random fractal capillary pressure model of Hunt to $P_c = \exp(a{-}bS)$, where S is the wetting-phase saturation, and a and b characteristic of the porous medium.

An extensive dataset of 17 centrifuge capillary pressure measurements were used in this research to demonstrate the merit of the new method. For both sandstones and carbonates, the logarithm of capillary pressure showed a linear relationship with saturation as observed by magnetic resonance imaging centrifuge capillary pressure measurements over a wide saturation range. This work demonstrates that: (a) in semilog plots of capillary pressure as a function of saturation, capillary pressure will vary linearly over a wide saturation range, (b) such a plot as described in (a) will show the uni- or bimodal pore-size distribution of the rock, (c) the exponential capillary pressure function simplifies analytical models that use the capillary pressure function, for example oil recovery models for fractured reservoirs.

SCA2018-013. Impact of Brine Composition and Concentration on Capillary Pressure and Residual Oil Saturation in Limestone Core Samples

F. Feldmann[1], A.M. AlSumaiti[1, 2], S.K. Masalmeh[2], W.S. AlAmeri[1], and S. Oedai[1]
[1]Department of Petroleum Engineering, Khalifa University of Science and Technology, SAN Campus, Abu Dhabi
[2]Abu Dhabi National Oil Company (ADNOC)

Low-salinity waterflooding (LSF) is a relatively simple and cheap EOR technique in which the salinity of the injected water is optimized (by desalination and/or modification) to improve oil recovery over conventional waterflooding. Extensive laboratory experiments investigating the effect of LSF are available in the literature. Sulfate-rich, as well as diluted brines have shown promising potential to increase oil production in limestone core samples. To quantify the low-salinity effect, spontaneous imbibition and/or tertiary waterflooding experiments have been reported. For the first time in literature, this paper presents a comprehensive study of the centrifuge technique to investigate low-salinity effect in carbonate samples.

The study is divided into three parts: At first, a comprehensive screening was performed on the impact of different connate-water and imbibition-brine compositions/combinations on the spontaneous imbibition behavior. Second, the subsequent forced imbibition of the samples using the centrifuge method to investigate the impact of brine compositions on residual saturations and capillary pressure. Finally, three unsteady-state (USS) corefloodings were conducted in order to examine the potential of the different brines to increase oil recovery in secondary mode (brine injection at connate-water saturation) and tertiary mode (exchange of injection brine at mature recovery stage). The experiments were performed using Indiana limestone outcrops.

The main conclusions of the study are: Spontaneous imbibition experiments only showed oil recovery in case the salinity of the imbibing water (IW) is lower than the salinity of the connate water (CW). No oil production was observed when the imbibing water had a higher salinity than the connate water or the salinity of the connate water and imbibing brine were identical. Moreover, the spontaneous imbibition experiments indicated that diluting the salinity of the imbibing water has a larger potential to spontaneously recover oil than the introduction of sulfate-rich sea water.

The centrifuge experiments confirmed a connection between the overall salinity and oil recovery. As the salinity of the imbibing brines decreases, the capillary imbibition pressure curves showed an increasing water-wetting tendency and simultaneous reduction of the remaining oil saturation. The lowest remaining oil saturation was obtained for diluted seawater as CW and IW.

The coreflooding experiments reflected the results of the spontaneous imbibition and centrifuge experiments. Injecting brine at a rate of 0.05 cm^3/min, seawater, and especially diluted seawater, resulted in a significant higher oil recovery compared to formation brine. Moreover, when comparing secondary mode experiments, the remaining oil saturation after flooding by diluted seawater, seawater and formation water was 30.6 , 35.5 and 37.4%, respectively. In tertiary injection mode, seawater did not lead to extra oil recovery while diluted seawater led to an additional oil recovery of 5.6% in one out of two tertiary injection applications.

SCA2018-014. Monitoring Core Measurements With High-Resolution Temperature Arrays

James J. Howard[1] and Keith C. Hester[2]
[1]University of Tulsa,
[2]Eni S.p.A.

While distributed temperature sensing (DTS) has become a commonly used tool in reservoir studies, the technology has not seen widespread use in SCAL projects. Most core-scale experiments attempt to control temperature at a constant value rather than monitor temperature changes within a sample during a test. High-resolution temperature arrays are available that measure changes in temperature of 0.1°C at 1-mm resolution. The optical backscatter reflectance (OBR) fiber senses both temperature and strain that can be separated through experiment design and signal processing. These OBR fibers are sensitive enough to monitor temperature changes associated with endo- and exothermic chemical reactions associated with mineral dissolution/precipitation, or fluid-front movements in steam-assisted gravity drainage of heavy oil tests. An example of the use of a distributed temperature array is in the monitoring of natural gas hydrate formation and dissociation in a sand pack as CO_2 is exchanged with the naturally occurring CH_4 in the hydrate structure. A fiber optic array was placed within a narrow diameter PEEK tube as the sandpack was constructed. The PEEK tube held the fiber optic in place so that the sensed signal was temperature only and did not include any strain effects. The OBR was set up to acquire a temperature array every 30 seconds during the test at 5-mm spacings. The core holder was placed in a MRI that provided additional spatial information on hydrate formation during the test that was compared with the OBR results. Initial hydrate formation resulted in a several degrees increase in temperature at the inlet end of the cell that with time progressed down the length of the cell. The temperature array and MRI images both showed the nonuniform nature of hydrate formation and subsequent dissociation of the hydrate when N_2 was injected into the cell as a permeability enhancement step. The faster response of the OBR array compared to the time required to acquire MRI images provided additional detail in the sequence of hydrate formation and dissociation during CH_4-CO_2 exchange. The limitation to the OBR array was that it only sensed temperature fluctuations proximal to the fiber as a function of the hydrate system's thermal conductivity.

SCA2018-015. Obtaining High Quality SCAL Data: Combining Different Measurement Techniques, Saturation Monitoring, Numerical Interpretation and Continuous Monitoring of Experimental Data

Yingxue Wang[1] and Shehadeh K. Masalmeh[2]
[1]Shell International E & P, Inc. Houston, USA,
[2]Shell Abu Dhabi BV

SCAL parameters (i.e., relative permeability and capillary pressure curves) are key inputs to understand and predict reservoir behavior in all phases of development. Techniques to measure relative permeability and capillary pressure have been well established and applied to a wide variety of core samples from both sandstone and carbonate reservoirs. On the other hand, we frequently encounter quality-compromised data due to challenges in experimental procedures, lack of understanding of measurement techniques, and poor quality of raw data. As a result, relative permeability is often viewed as a parameter with large uncertainties and a fitting parameter in history matching.

A special core analysis program was recently carried out on selected core samples from a deepwater sandstone reservoir in the Gulf of Mexico. In this frontier, relative permeability has been ranked among the top subsurface uncertainties. It greatly impacts the production forecast and field development plan. However, due to the high temperature, high salinity and fluid compatibility issues, the core measurements faced very specific challenges and a good relative permeability dataset has not been obtained in the past for this area. In this work, we demonstrate that a quality set of relative permeability data can be obtained through close collaboration across disciplines, a properly designed protocol, adequate engagement with the laboratory, timely QA/QC of experimental raw data, and appropriate interpretation incorporating numerical simulations. Well-defined and constrained relative permeability curves have been derived with the combination of steady-state and centrifuge techniques. The average trend can be described by a residual oil saturation of 22%, endpoint relative permeabilities of 0.6 and 0.2 to oil and water, respectively and Corey exponents between 2 and 3.

SCA2018-016. In-Situ Investigation of Aging Protocol Effect on Relative Permeability Measurements Using High-Throughput Experimentation Methods

Matthieu Mascle[1], Souhail Youssef[1], Hervé Deschamps[1], and Olga Vizika[1]
[1]IFP Energies nouvelles, 1&4 avenue de Bois-Préau, Rueil-Malmaison, France

In this study, we have investigated the effect of two aging protocols (static and dynamic) on oil/water relative permeabilities. Experiments were conducted on a set of initially strongly water-wet outcrop sandstone samples (Bentheimer). The same measurements were also conducted on altered samples using the two different aging protocols. Steady-state relative permeabilities were measured using a state-of-the-art experimental setup (CAL-X). The setup is equipped with an X-ray radiography facility, enabling monitoring of 2D local saturations in real-time and thus giving access to fluid flow paths during the flooding. Aged samples relative permeability curves show clear differences when compared to water-wet relative permeabilities, hence suggesting that the wettability has been effectively altered. However, the two aging protocols were unable to produce the same results. The dynamic aging has led to an inversion of the original relative permeability curves asymmetry, suggesting a strongly oil-wet system, whereas the static aging protocol has altered the wettability to a lesser extent. The differences can be explained by analyzing a 2D saturation map. In the case of dynamic aging we observe a homogeneous distribution of fluid saturation during fractional flow. On the opposite, the static protocol results in heterogeneous flow paths, confirming that this protocol did not alter uniformly the wettability of the sample and generates a patchier mixed-wettability system.

SCA208-017. A Review of 60 Years of NMR Wettability

Andrea Valori[1] and Benjamin Nicot[2]
[1]Schlumberger SDCR, Saudi Arabia
[2]TOTAL CSTJF, France

Wettability is a key parameter in the development of an oilfield as it strongly affects oil saturations, capillary pressures, electrical properties, relative permeabilities and oil recovery. Despite attempts that have been made to evaluate wettability downhole, the standard methods to quantify it are still laboratory based; the two most commonly used are Amott-Harvey (AH) and U.S. Bureau of Mines (USBM). These techniques are expensive and very time consuming, requiring a sample to be retrieved from the well and analyzed in the lab. In several cases, the results are obtained late and only after several decisions regarding the reservoirs had already been made, without this important piece of information.

It is ubiquitously recognized that nuclear magnetic resonance (NMR) is very sensitive to the strength of the fluid-rock interactions, and therefore has been considered as a good candidate for wettability determination since the 1950s. The NMR signal, however, is also sensitive to several other fluid and rock properties, for example, viscosity and pore-size distribution, making the practical extraction of wettability information from NMR data not straightforward. NMR has, however, two considerable advantages compared to AH and USBM: it is much faster, allowing much faster turnaround of laboratory measurements; and can be measured in-situ downhole, with the result of the measurement being available in real time. These extreme advantages fuelled the research on the topic of NMR wettability despite the abovementioned difficulties.

There are at least three main NMR parameters measurable downhole: T_1, T_2 and diffusion; with additional information extractable from the correlation between these three. Wettability affects all of these parameters, and the correlation between them. This means that there is not a single way to extract wettability information from NMR data, but there are different options.

Here, we review 60 years of literature on the topic of NMR and wettability, from the first experimental observations in the 1950s to the most recent advancements. Also, this work aims at presenting the strength and limitations of the techniques being developed nowadays, to help the audience make the best choice for each specific case. In this paper, we focus mostly on the laboratory applications, while we focused more on the downhole applications in another recent paper.

SCA2018-018. Spatially Resolved Wettability Measurements Using NMR Wettability Index

M.J. Dick[1], D. Veselinovic[1], and D. Green[1]
[1]Green Imaging Technologies, Fredericton, NB, Canada

Wettability is a crucial petrophysical parameter for determining accurate production rates in oil and gas reservoirs. However, industry standard wettability measurements (Amott test and USBM) are expensive and time consuming. It is known that NMR response varies as a function of wettability change in rock core-plug samples. This information was used to develop an NMR wettability index (NWI) based on T_2 distributions. This NWI is capable of measuring changes in wettability as a function of oil/water saturations, unlike traditional methods, which are based on measurements at S_{wi} and S_{or} only. In addition, these oil/water saturations are determined without the aid of any special oil or brine, such as D_2O. This allows the NMR method to nondestructively monitor changes in wettability in real time (i.e., during a flooding experiment or an aging procedure). In this work, we have coupled this T_2-based NWI to spatially resolved T_2 NMR measurements to monitor changes in wettability and saturation along rock core plugs.

In order to derive an NMR wettability index, NMR T_2 spectra of 100% brine saturated, 100% oil saturated, bulk oil and bulk brine are needed. These spectra are then mixed to give a predicted T_2 spectrum which is compared (via a least squares fit) to a T_2 spectrum recorded from a sample partially saturated with both water and oil and whose wettability is to be determined.

For initial testing, three sandstone samples were employed along with 2% KCl brine and dodecane. To achieve sample states of mixed wettability, 100% brine-saturated samples had dodecane pushed into them via centrifugation. Centrifugation at different speeds resulted in samples of varying bulk and spatial wettabilities from which NWI parameters and oil/water saturations were determined. The bulk wettabilities were compared to measurements done using the standard Amott test and oil/water saturations were confirmed by repeating experiments using NMR invisible D_2O.

SCA2018-019. The Role of Ferrous Clays in the Interpretation of Wettability—A Case Study

Velazco, M.A.[1], Bruce A. [1], Ferris M.[1], Reed J. [1], and Kandasamy R.[1]
[1]Lloyd's Register Energy Consultancy, Rock Properties Group, Aberdeen, UK

Clean sandstone, with minimal clay content, is expected to be strongly water-wet once the rock has been through an effective cleaning process. Even samples containing significant clay minerals are usually expected to be water-wet after appropriate cleaning. However, tests carried out on core samples from fields in three different global locations show mixed indices, even for clean-state samples where no aging with crude oil has taken place. A few hypotheses for this behavior considered herein are: whether the cleaning method was adequate, whether wettability was altered by an external factor, or if wettability was due to mineral composition.

This paper presents the results obtained from wettability studies on fresh, clean and restored-state core-plug samples from three different fields. Wettability indices were obtained by using the combined Amott-USBM method. Petrography was performed on sample end-trims to investigate the possible presence of halite or barite in the clean-state samples, thought to be from drilling-fluid infiltration, which should have been removed by the methanol cleaning cycle. This showed no organic material or salt (halite), negating wetting change from inefficient cleaning. From a reactive-clays model perspective, these rock samples are considered clean sand (i.e., illite/smectites as total clay content), determined by XRD analysis, are lower than 10%. SEM and XRD results showed the presence of grain-coating chlorite in one sample set and glauconite grains in the others. Only once the unusual wettability indices were obtained was the grain-coating chlorite identified as chamosite by SEM/EDX, which is an iron-rich form of chlorite. The presence of chamosite or glauconite appears to influence the wetting tendency. In summary, USBM vs Amott wettability indices of the analyzed samples are consistent between both methods, showing a mixed-to oil-wet tendency for all samples where chamosite was identified, regardless of the initial test condition. Samples with glauconite appeared to be more mixed-wet after wettability restoration. The results suggest that iron-rich clay/mineral content is the main contributor to the oil-wet tendency of the evaluated rocks.

SCA2018-020. A Laboratory-Scale Approach to Wettability Restoration in Chalk Core Samples

Jaspreet S. Sachdeva[1,2], Edison A. Sripal[3], Anders Nermoen[1,2,4], Reidar I. Korsnes[1,2], Merete V. Madland[1,2], and Lesley A. James[3]
[1]The National IOR Centre of Norway
[2]University of Stavanger
[3]Department of Process Engineering, Memorial University of Newfoundland
[4]International Research Institute of Stavanger

Wettability in chalk has been studied comprehensively to understand fluid flow mechanisms impacting coreflooding experiments. Wettability becomes paramount in understanding the parameters influencing chalk-fluid interactions. The main objective of this work is to evaluate the degree to which the wettability in chalk core samples can be controlled in the laboratory. Kansas chalk samples saturated with brine (1.1 M/64284 ppm NaCl) and an oil mixture (60 to 40% by volume of Heidrun oil and heptane) were aged at a constant temperature of 90°C with aging time as the laboratory control variable. A multimodal method incorporating contact-angle measurements, wettability index via USBM test, and SEM-MLA analysis was applied in evaluating wettability. A systematic approach was applied with the three different methods to quantify the degree of uncertainty linked to (a) wettability estimation, and (b) the aging procedure to control wettability alteration of Kansas chalk. With a comprehensive suite of samples, we were successfully able to alter the wettability of chalk cores.

SCA2018-021. Toward a Mechanistic Understanding of Wettability Alteration in Reservoir Rocks Using Silica Nanoparticles

Saeed Jafari Daghlian Sofla[1], Lesley Anne James[1], and Yahui Zhang[1]
[1]Memorial University of Newfoundland, St. John's, Canada

Traditional concepts of simple liquid spreading may not apply to nanoparticle fluids. Most investigations pertaining to the wettability alteration of solid surfaces due to the presence of nanoparticles in the fluid are oversimplified, i.e., nanoparticles dispersed in DI-water and smooth, homogeneous, and clean surfaces have been used. From a practical enhanced oil recovery (EOR) point of view, the nanoparticles must be dispersed in either seawater or high-salinity formation water containing diverse types and concentrations of ions. These ions interact with the electrostatic properties of the nanoparticles. Likewise, the oil phase may contain many surface-active components, like asphaltene and naphthenic acids, which can interact with nanoparticles at oil-water and oil-rock interface. In reality, the rock sample is a heterogeneous, nonsmooth, mixed-wet substrate with a diverse mineralogical composition. The electrical charge of minerals can vary when contacted with an ionic fluid. This can alter the electrostatic repulsion between substrate and nanoparticles and consequently the substrate can either attract or repel charged particles, including nanoparticles. Hence, the role of nanoparticles must be evaluated considering multicomponent complex fluids and real formation rock.

Despite numerous reports regarding the wettability alteration of reservoir rock from oil-wet to water-wet by nanoparticles, some inherent limitations in the wettability-alteration experiments prevent conclusions about the performance of nanoparticles in practical complex conditions. For instance, the wettability alteration by nanoparticles is often determined by contact-angle measurements. In this method, the substrates are either aged with (immersed in) nanoparticle-fluids before conducting the experiments or contacted with nanoparticle fluids before attachment of the oil droplet on the rock surface. Hence, in both cases, before initiating the contact-angle measurements, the nanoparticles would already exist at the oil-rock interface possibly giving inaccurate measurements.

The objective of this work is to investigate the mechanism of wettability alteration by silica nanoparticles pre-existing on the rock interface (conventional contact-angle measurements) and using a new displacement contact-angle method to better mimic the scenario of injecting a nanoparticle fluid into the reservoir already containing formation brine. The impact of pre-existing nanoparticles at the oil-rock interface (in the conventional contact-angle measurements) on the contact-angle measurements is examined for simple (n-decane, NaCl brine, and pure substrates) and complex (crude oil, seawater, and reservoir rock) systems on various wetting conditions of substrates (water-wet and oil-wet). The nanoparticles are dispersed in seawater using our H+ protected method. Then, the effect of surface and nanoparticle charge on the contact angle is evaluated by adjusting the aqueous-phase salinity. We also differentiate between the disjoining pressure mechanism and diffusion of silica nanoparticles through the oil phase by testing the attachment of nanoparticles on the rock surface.

SCA2018-022. Links Between Geochemistry, Total Organic Carbon, Magnetic Properties and Anisotropy in Shale Core Samples From the Horn River Group, British Columbia, Canada

Vivian T. Ebufegha[1] and David K. Potter[1,2]
[1]Department of Physics, University of Alberta, Edmonton, Canada
[2]Department of Earth and Atmospheric Sciences, University of Alberta, Edmonton, Canada

Geochemical analyses of shale core samples from the Muskwa, Otter Park and Evie formations of the Horn River Group were undertaken using inductively coupled plasma mass spectrometry (ICP-MS), and total organic carbon (TOC) was determined via combustion analysis. The results were compared with bulk volume magnetic susceptibility and anisotropy of magnetic susceptibility (AMS) measurements on the same samples. Strong positive correlations were observed between the bulk volume magnetic susceptibility and the weight percent of each of the following metallic oxides: Fe_2O_3, Al_2O_3, K_2O and MnO. Furthermore, strong positive correlations between Al_2O_3 and Fe_2O_3 and between K_2O and Fe_2O_3 indicated that paramagnetic clays (especially illite), and not ferrimagnetic minerals like magnetite, are the main source of iron in the Horn River Group shales. In contrast, strong negative correlations were observed between bulk volume magnetic susceptibility and TOC, and between bulk volume susceptibility and SiO_2 (i.e., magnetic susceptibility decreased as TOC and quartz content increased). The correlation between TOC and bulk volume magnetic susceptibility has not, to our knowledge, been reported in any other studies. Higher TOC and quartz concentrations in the Upper Muskwa and Evie formations are responsible for their lower bulk volume magnetic susceptibilities. The study suggests that in these shale samples bulk magnetic-susceptibility measurements can be used as a proxy to rapidly and nondestructively estimate TOC content and metallic oxide content.

Significantly, a strong positive correlation was also found between TOC and anisotropy of magnetic susceptibility (AMS). This unexpected relationship has not been reported in any previous studies. The data suggested that organic matter content controls the preferred orientation of other key matrix minerals in the shales, especially paramagnetic clays, such as illite. Further independent support for this came from thin-section analysis of the samples. The relationship between AMS measurements and TOC can potentially be used to estimate TOC content, as well as providing insights into

the controls on anisotropy.

SCA2018-023. Loading Effects on Gas Relative Permeability of a Low-Permeability Sandstone

F. Agostini[1], P. Egermann[2], L. Jeannin[2], E. Portier[3], F. Skoczylas[1], and Y. Wang[1]
[1]LamCube CNRS FRE 2016, and Centrale de Lille, CS20048, F-59651 Villeneuve D'Ascq Cedex, France
[2]Storengy, 12 rue Raoul Nordling - Djinn - CS 70001 92274 Bois Colombes Cedex
[3]ENGIE EPI, 1 Place Samuel de Champlain, 92930 La Défense Cedex, France

This paper deals with a study of the gas relative permeability of tight sandstones under loading. Specific experiments have been designed and the experimental measurements obtained show that, not only the absolute permeability but also the gas relative permeability are sensitive to confinement and that the residual gas saturation (through permeability "jail") increases with loading. This observation consists in an additional source of complexity in the evaluation of low-permeability sandstone gas reservoirs.

SCA2018-024. First Step in Evaluating the Role of Diffusion in EOR in Tight Shale Formations

Son T. Dang[1], Carl H. Sondergeld[1], Chandra S. Rai[1], Ali O. Tinni[1], and Nicholas Drenzek[2]
[1]Melbourne School of Petroleum and Geological Engineering, University of Oklahoma
[2]Baker Hughes, a GE Company

Miscible gas injection has been proven to be amongst the few successful enhanced oil recovery (EOR) techniques, which can be applied in unconventional reservoirs. Recent reports from operating companies suggested this process can enhance current recovery from 30 to 70%. An effective and economical project depends on the understanding of gas transportation during both injection and flowback. Previous modeling and theoretical investigations have shown that diffusion could be one of dominant transport mechanisms in low-permeability shales (microporous media). Despite the importance of diffusion as a transport mechanism in shales, direct measurements of diffusion coefficients in shales are not currently available. The main reason for the lack of currently available techniques is due to the fact that pore volume in shale is generally small.

This work summarizes a novel approach to measure the diffusion coefficient of injected gas components into shale samples. The effective diffusion between methane versus nitrogen was simultaneously measured with infrared spectroscopy (IR) methods. IR captured the change in methane/nitrogen concentration at the outlet of the sample as function of time. The difference in effective diffusion without and without microporous media, provide sample tortuosity. In the end, a simulation model was established based on the experimental setup to back-calculate diffusion rate.

SCA2018-025. Monitoring Gas Hydrate Formation with Magnetic Resonance Imaging in a Metallic Core Holder

Mojtaba Shakerian[1], Armin Afrough[1], Sarah Vashaee[1], Florin Marica[1], Yuechao Zhao[2], Jiafei Zhao[2], Yongchen Song[2], and Bruce J. Balcom[1]
[1]MRI Center, University of New Brunswick, Fredericton, NB, E3B 5A3, Canada
[2]Key Laboratory of Ocean Energy Utilization and Energy Conservation of the Ministry of Education, Dalian University of Technology, Dalian, 116024, China

Methane hydrate deposits worldwide are promising sources of natural gas. Magnetic resonance imaging (MRI) has proven useful in previous studies of hydrate formation. In the present work, methane hydrate formation in a water-saturated sandpack was investigated employing an MRI-compatible metallic core holder at low magnetic field with a suite of advanced MRI methods developed at the UNB MRI Centre. The new MRI methods are intended to permit observation and quantification of residual fluids in the pore space as hydrate forms.

Hydrate formation occurred in the water-saturated sand at 1,500 psi and 4°C. The core holder has a maximum working pressure of 4,000 psi between −28 and 80°C. The heat-exchange jacket enclosing the core holder enabled very precise control of the sample temperature.

A pure phase encode MRI technique, SPRITE, and a bulk T_1-T_2 MR method provided high-quality measurements of pore fluid saturation. Rapid 1D SPRITE MRI measurements time-resolved the disappearance of pore water and hence the growth of hydrate in the sandpack. 3D π-EPI images confirmed that the residual water was inhomogeneously distributed along the sandpack. Bulk T_1-T_2 measurements discriminated residual water from the pore gas during the hydrate formation. A recently published local T_1-T_2 method helped discriminate bulk gas from the residual fluids in the sample.

Hydrate formation commenced within two hours of gas supply. Hydrate formed throughout the sandpack, but maximum hydrate was observed at the interface between the gas pressure head and the sandpack. This irregular pattern of hydrate formation became more uniform over 24 hours. The rate of hydrate formation was greatest in the first two hours of reaction. An SE-SPI T_2 map showed the T_2 distribution changed considerably in space and time as hydrate formation continued. Changes in the T_2 distribution are interpreted as pore level changes in residual water content and environment.

SCA2018-026. Rheology-Based Method for Calculating Polymer Inaccessible Pore Volume in Coreflooding Experiments

Ferreira, V.H.S.[1] and Moreno, R.B.Z.L.[1]
[1]Department of Energy, School of Mechanical Engineering, University of Campinas

Polymer flooding is an enhanced oil recovery (EOR) method that reduces the mobility ratio between the displaced oil and the displacing injected water. The flow of polymer solutions through porous media is subject to some process-specific phenomena, such as the inaccessible pore volume (IAPV). Due to IAPV, polymer molecules move faster through the porous medium than smaller ones. Thus the IAPV value needs to be accounted for in experiments and field projects. Recent reports found that polymer in-situ rheology correlates with the IAPV. The objective of this paper is to develop a method for estimating IAPV based on the in-situ rheology of polymers.

The methodology proposed here can be used in both single- and two-phase experiments. The technique requires measurement of polymer resistance factor (RF) and residual resistance factor (RRF) at steady-state conditions. Core permeability, porosity, and residual oil saturation, as well as water and polymer bulk viscosities, also need to be taken into account. Correlations for polymer in-situ viscosity and shear rate are solved simultaneously, to wield an estimative for the IAPV. Aiming to prove the method, we report 16 coreflooding experiments, eight single- and eight two-phase experiments. We used a flexible polymer and sandstone cores. All the tests were run using similar rock samples. In the single-phase experiments, we compare the alternative method with the classic tracer method to estimate IAPV. The results show an average relative difference of 11.5% between the methods. The two-phase results display, on average, an 18% relative difference to the IAPV measured in the single-phase experiments. The difference between single- and two-phase results can be an effect of the higher shear rates experienced in the two-phase floodings since, in these cases, the aqueous-phase shear rate is also dependent on the phase saturation. Additionally, temperature, core length, pore pressure, and iron presence on the core did not show any influence on the IAPV for our two-phase experiments.

The method proposed in this paper is limited by the accuracy of the pressure-drop measurements across the core. For flexible polymers, the method is valid only for low and middle shear rates, but, according to literature, for rigid polymers the method should be accurate for a broad range of shear rates. The method proposed here allows the measurement of polymer IAPV on two- and single-phase coreflooding experiments when a tracer is not used.

SCA2018-027. Impact of injection Rate on Transient Oil Recovery Under Mixed-Wet Conditions: A Microfluidic Study

Magali Christensen[1], Xanat Zacarias-Hernandez[1], Yukie Tanino[1]
[1]School of Engineering, University of Aberdeen, UK

Lab-on-a-chip methods were used to visualize the pore-scale distribution of oil within a mixed-wet, quasi-monolayer of marble grains packed in a microfluidic channel as the oil was displaced by water. Water injection rates corresponding to microscopic capillary numbers between Ca = 5×10^{-8} and 2×10^{-4} (Darcy velocities between 0.3 and 1,100 ft/d) were considered. As expected, early-time water invasion transitions from stable displacement to capillary fingering with decreasing Ca, with capillary fingering observed at Ca ≤ 10^{-5}. Endpoint oil saturation decreases with Ca over the entire range of Ca considered, consistent with the canonical capillary desaturation curve. In contrast, S_{or} derived from approximate numerical simulations using reasonable $P_c(S_w)$ do not display a strong dependence on Ca. These results suggest that the Ca dependence of endpoint oil saturation is largely due to capillary end effects, which, under conditions considered presently, affect the entire length of the packed bed.

SCA2018-028. Effects of Ions on the Characteristics of Monolayer at Brine/Oil Interfaces

Mohammed B. Alotaibi[1], Dongkyu Cha[1], Karam Chand[1], and Ali A. Yousef[1]
[1]Saudi Aramco

The advanced waterflooding technologies through salinity and ionic content adjustment can make favorable impacts on rock wettability and oil recovery. In carbonate reservoirs, SmartWater at low ionic strength showed strong chemical interactions with carbonate minerals and oil components. As a result, several hypotheses are proposed in literature, such as as ionic exchange, rock dissolution, surface charges etc. The applied macroscopic and microscopic technologies have certain limitations in identifying the structures at interfaces especially at monolayers.

In this paper, advanced sum frequency generation (SFG) spectroscopy is used for the first time to characterize the chemical structures of molecules at the brine/oil interfaces. Different brines recipes and model oils are tested to determine the effects of individual and combined ions on the monolayer structures. Stearic acid is also mixed with hydrocarbons to mimic the acidity condition of fluids in the reservoir. The change in the chemical structure is monitored with time at a broad wavenumber ranging from 1,000 to 3,800 cm^{-1}. Distinct spectral signatures of oil components and water ions are detected at different pH conditions.

The SFG data is compared with the previous macroscopic wettability results to predict the components that are highly affected during waterflooding and enhanced oil recovery (EOR) processes. This study brings new insights to understanding the chemical structures at the thin monolayers of flat and curved geometric at different aqueous interfaces. The measured spectra, coupled with a wide range of laser polarization settings, and signal intensity trends are discussed in terms of composition, and structure of organic and inorganic components. For example, the intensity for SmartWater at certain wavenumber is three times higher when compared to high-salinity water. This indicates that the interactions at oil/water interfaces are enhanced at lower ionic strengths. In addition, these findings are also confirmed with similar behaviors at a higher salinity brine, such as connate formation brines.

The novelty of this interfacial study can provide better understanding of the reaction mechanisms altering the ionic strength and salinity of injection water and its impact due to the changes in geometric interfaces. Such understanding is also crucial to optimize the chemistry of injection water and its interaction with oil components and carbonate rock, to ultimately alter wettability toward water-wet.

SCA2018-029. A Novel Experimental Approach for Studying Spontaneous Imbibition Processes With Alkaline Solutions

T. Chevalier[1], J. Labaume[1], A. Delbos[1], T. Clemens[2], V.M. Waeger[2], B. Bourbiaux[1], and M. Fleury[1]
[1]IFPEN, Rueil-Malmaison, France
[2]OMV, Vienna, Austria

Spontaneous imbibition processes can play an important role in oil production. It can be enhanced or influenced by wettability changes generated by properly designed chemicals or by the natural surfactants resulting from reactive crude oils in the presence of alkaline solutions. The reaction of basic salts with some components of oil can, indeed, lead to the formation of natural soaps that reduces the interfacial tension between oil and brine. The latter scenario is studied herein on samples and oil from the St. Ulrich oil field in the Vienna basin. To that end, spontaneous imbibition experiments were performed with two brines differing by the absence or presence of alkali. We first present a general novel technique to monitor saturation changes on small rock samples for the purpose of assessing the efficiency of a given recovery process. Samples of 15-mm diameter and 20-mm length and set at irreducible saturation were fully immersed in the solution of interest, and the evolution of the samples' saturation with time was monitored using a dedicated NMR technique involving the quantification of the sole oil phase present within the sample. A fully 3D imbibition configuration was adopted, involving countercurrent flows through all faces of the sample. The experimental method is fast for two reasons: (1) the kinetics of capillary imbibition process is proportional to the square of sample size, i.e., very rapid if accurate measurements can be acquired on tiny samples; and (2) the present 3D situation also involves faster kinetics than the 1D configuration often used. The NMR technique was crucial to achieve such conditions that cannot be satisfied with conventional volumetric methods.

The kinetics of oil desaturation during spontaneous imbibition is interpreted with the help of an analytical 3D diffusion model. For the alkaline solution, the diffusion coefficient is reduced by a factor of only two compared to the nonalkaline brine, although the interfacial tension between the oil and the imbibing solution is reduced by a factor of 10. Hence, a wettability change to a more water-wet state has to be assumed when the alkaline solution replaces the nonalkaline solution in the imbibition process. However, no significant impact on the final saturation was observed.

SCA2018-030. Review of the Intercept Method for Relative Permeability Correction Using a Variety of Case Study Data

Jules Reed[1] and Jos Maas[2]
[1]Lloyd's Register, Aberdeen, UK
[2]Independent Consultant

In 2014, Gupta and Maloney introduced a novel method of measuring steady-state relative permeability, called the intercept method (IM). This method entails a modification of a standard steady-state procedure that incorporates multiple total flow rates at each fractional flow rate. The objective of the method is to measure data at each fractional flow rate that will permit simple analytical calculations to correct differential pressure (hence relative permeability) and saturation data for the effects of capillary pressure. The IM is intended to provide a corrective technique without the need for additional supportive analyses, such as capillary pressure and in-situ saturation monitoring (ISSM), or as an alternative approach to the current considered best practice of numerical coreflood simulation, which generally requires the specified additional data.

Consequently, the IM is of interest to the global industry in regions and/or laboratories that do not possess state-of-the-art equipment, or for its cost-saving potential. However, before employing this new method, it was important to the authors to investigate its validity across the range of rock properties, sample dimensions and wettabilities experienced in commercial SCAL coreflood experiments. This study thus draws on a variety of relative permeability curves (and supporting data) from various global core studies, originally derived by typical relative permeability methods plus coreflood simulation. From these data, we use SCORES to simulate the expected results of multiflow-rate steady-state experiments and use the IM to derive and compare the corrected relative permeability curves. Results highlight criteria under which the method does not provide fully corrected data. The paper explores these criteria in more detail.

SCA2018-031. CO_2-Brine Injectivity Tests in High CO_2 Content Carbonate Field, Sarawak Basin, Offshore East Malaysia

A. Giwelli[1], M.Z. Kashim[2], M.B. Clennell[1], L. Esteban[1], R. Noble[1], C. White[1], S. Vialle[3], M. Ghasemiziarani[3], M. Myers[1], A. Saeedi[3], and S. Salwani Md Shah[2]
[1]CSIRO, Australia,
[2]PETRONAS Research Sdn Bhd, Malaysia
[3]Curtin University

We conducted relatively long duration coreflooding tests on three representative core samples under reservoir conditions to quantify the potential impact of flow rates on fines production/permeability change. Supercritical CO_2 was injected cyclically with incremental increases in flow rate (2 to 14 ml/min) with live brine until a total of seven cycles was completed. To avoid unwanted fluid-rock reaction when live brine was injected into the sample, and to mimic the in-situ geochemical conditions of the reservoir, a packed column was installed on the inflow accumulator line to pre-equilibrate the fluid before entering the core sample. The change in the gas porosity and permeability of the tested plug samples due to different mechanisms (dissolution and/or precipitation) that may occur during scCO_2/live brine injection was investigated. Nuclear magnetic resonance (NMR) T_2 determination, X-ray CT scans and chemical analyses of the produced brine were also conducted. Results of pre- and post-test analyses (poroperm, NMR, X-ray CT) showed no clear evidence of formation damage even after long testing cycles and only minor or no dissolution (after large injected pore volumes (PVs) ~200). The critical flow rates (if there is one) were higher than the maximum rates applied. Chemical analyses of the core effluent showed that the rock samples for which a precolumn was installed do not experience carbonate dissolution.

SCA2018-032. A New Waterflood Initialization Protocol for Pore-Scale Multiphase Flow Experiments

Q. Lin[1], B. Bijeljic[1], S.C. Krevor[1], M.J. Blunt[1], S. Berg[2], A. Coorn[2], H. van der Linde[2], A. Georgiadis[1], and O.B. Wilson[2]
[1]Imperial College London, London, SW7 2AZ, United Kingdom
[2]Shell Global Solutions International BV, The Netherlands

In the context of digital rock analysis, pore-scale imaging of multiphase flow experiments using X-ray microtomography can be used to obtain fundamental insights into pore-scale displacement physics. This provides a basis to better calibrate numerical pore-scale simulators, or it can be used to understand local fluid distributions, while simultaneously measuring average properties, equivalent to a traditional SCAL experiment.

Imaging studies in the literature have historically been conducted on water-wet microplugs, using kerosene, or another refined oil, as the nonwetting phase. Prior to conducting waterflood experiments, the initial water saturation has been established by dynamic flooding. The disadvantage with this is that a nonuniform saturation profile is established due to the capillary end effect. This will result in a higher average initial water saturation compared with, for instance, standard SCAL techniques, such as the porous-plate method or centrifugation.

In this paper, a methodology for initializing multiple microplugs to connate water saturation has been developed by adopting best SCAL practices, namely the porous-plate method or centrifugation using crude oil, followed by aging. We drill multiple microplugs from a full-size SCAL core sample, without losing capillary continuity with the base of the original sample. In the example presented, for Bentheimer sandstone, the initial saturation was established using centrifugation. The experiment is designed to prevent a nonuniform saturation profile in the microplugs. We use in-situ imaging to determine the water saturation after primary drainage and show that it is indeed uniform across the microplug with a value consistent with large-scale SCAL measurements and the measured mercury injection capillary pressure. We also show that a significant wettability alteration had occurred by measuring in-situ contact angles.

SCA2018-033. Added Insight From Image-Based Wettability Characterization

Rudolf Held[1], Norbert Schleifer[1], Luis Genolet[1], and Andrew Fogden[2]
[1]Wintershall Holding GmbH, Germany

[2]Thermo Fisher Scientific, Canberra ACT 2600, Australia

Microtomographic rock and fluid imaging under in-situ conditions is applied for reservoir wettability characterization. The investigation entails careful sample preparation and cleaning of miniplugs, operation with reservoir fluids, wettability restoration, centrifuge wettability testing cycles, repeated sample scanning and image analysis, parametrization of wettability and digital rocks simulation for input into reservoir modeling. The results are compared to conventional Amott testing performed in core laboratories. Determination of saturations from image analysis, instead of centrifuge production, allows the use of stock-tank crude, rather than exchanged mineral oil. Doping of the synthetic formation water (here with 1 M sodium iodide) was applied for enhancement of the X-ray contrast. The digital imaging workflow offers insight on the liquid distributions from the plug-scale down to the pore-scale, linked to applied pressure gradients and resulting pore-fluid occupancies in the sequence of displacement states. An example is given with the investigation of a North Germany oil field, where the image-based workflow led to a revised view of the reservoir conditions for spontaneous imbibition and drainage, and the overall wetting behavior.

SCA2018-034. Uncertainty Quantification in Image Segmentation for Image-Based Rock Physics in a Shaly Sandstone

James Howard[1], Sam Lin[1], Shawn Zhang[1]
[1]DigiM Solution LLC

Image processing of high-resolution 3D images to create digital representation of pore microstructures for image-based rock physics simulations remains a highly subjective enterprise, despite the seeming precision associated with improving imaging resolutions and intensive parallel computations. The decisions on how to identify pore space, both macro- and micropores, and various mineral components remain very much dependent upon user choices and biases. A set of shaly sand samples with a significant amount of authigenic chlorite/smectite that lines the larger pores was tested to identify uncertainty quantification (UQ) requirements associated with image-processing steps, segmentation in particular. This sandstone provides several challenges in that the dominant clay mineral lining the pores has a high surface area and cation exchange capacity, which in turn influence hydrocarbon mobility, reservoir quality, and stimulation approach. Two segmentation strategies, conventional thresholding-based and artificial intelligence (AI) -based, are employed with different UQ parameter space. The pore structure extracted from these different iterations is the basis of simulations of basic petrophysical properties. Upon cross-validation with measured core properties, a UQ framework is proposed to assess the differences between the different measurements from three angles: sampling, numerical and physical.

SCA2018-035. Digital Rock Physics Approach to Effective and Total Porosity for Complex Carbonates: Pore-Typing and Applications to Electrical Conductivity

Christoph H. Arns[1], Han Jiang[1], Hongyi Dai[1], Igor Shikhov[1], Nawaf Sayedakram[1], and Ji-Youn Arns[2]
[1]School of Petroleum Engineering, University of New South Wales, Sydney, Australia
[2]Department of Applied Mathematics, Research School of Physics and Engineering, Australian National University, Canberra, Australia

Recent advances in micro-CT techniques allow imaging heterogeneous carbonates at multiple scales and including voxel-wise registration of images at different resolution or in different saturation states. This enables characterizing such carbonates at the pore-scale targeting the optimizing of hydrocarbon recovery in the face of structural heterogeneity, resulting in complex spatial fluid distributions. Here we determine effective and total porosity for different pore types in a complex carbonate and apply this knowledge to improve our understanding of electrical properties by integrating experiment and simulation in a consistent manner via integrated core analysis.

We consider Indiana Limestone as a surrogate for complex carbonate rock and type porosity in terms of macro- and microporosity using micro-CT images recorded at different resolutions. Effective and total porosity fields are derived and partitioned into regions of macroporosity, microporosity belonging to oolithes, and microporosity excluding oolithes' rims.

In a second step we use the partitioning of the microporosity to model the electrical conductivity of the limestone, matching experimental measurements by finding appropriate cementation exponents for the two different microporosity regions. We compare these calculations with calculations using a single cementation exponent for the full microporosity range. The comparison is extended to resistivity index at partial saturation, further testing the assignment of Archie parameters, providing insights into the regional connectivity of the different pore types.

SCA2018-036. Capillary Desaturation Curves and Insights on Trapped Oil at the Pore Scale in Water-Wet and Oil-Wet Sandstones

Hélène Berthet[1], Prisca Andriamananjaona[1], Sandra Barbouteau[1], Mathilde Hebert[1], Remi Farwati[1], Redouane Meftah[1], Gerard Quenault[1], Jean-Philippe Chaulet[1], Regis Brugidou[1], and Richard Rivenq[1]
[1]TOTAL SA, Avenue Larribau 64018 Pau Cedex, France

Capillary desaturation experiments are combined with high-resolution microtomography imaging to understand the impact of wettability on the global and local distribution of fluids in the pore space of sandstone outcrops. Small cylindrical rock samples are cored, imaged in dry state then successively prepared at irreducible water saturation before steps of waterflood. Several samples also go through a wettability-alteration phase in order to expand the range of wettability conditions: namely, oil-wet to mixed-wet. Waterflooding is done at various capillary numbers and injected brine volumes, depending on the case. The entire rock is imaged at voxel resolutions of typically 2 or 4 µm, to ensure a high-quality segmentation.

Global oil saturation results show how the wettability impacts the shape of capillary desaturation curves, in particular the existence of a critical capillary number. In the nonwater-wet experiments, oil saturation is controlled by a large, highly connected oil cluster percolating from the inlet to the outlet of the sample. Such results are important for pore-scale flow-modeling strategy and validation. We demonstrate that the wettability is not always uniformly distributed along the core despite of the use of classical wettability alteration protocols, highlighting potential biases in traditional SCAL tests.

POSTER PAPERS

SCA2018-037. Nondestructive Pore-Scale Approach to Evaluate Elastic Properties of Shale Samples by Imaging, Modeling and Simulation

Weifeng Lv [1] and Langqiu Flora Sun [2]
[1]Research Institute of Petroleum Exploration and Development, Beijing, China
[2]China University of Petroleum, Beijing, China

Elastic moduli are among the most important parameters to assess the shale plays and to instruct the hydraulic fracturing. However, due to extremely high brittleness of shale and very limited samples available, the conventional methods used to obtain elastic properties, such as uniaxial or triaxial compression tests, often generate early breaking of shale samples, which leaves significant uncertainties on accurate evaluation of the elastic properties of shale samples.

In this project, a new workflow to estimate the elastic moduli of shale samples is established with the aid of scanning electron microscopy (SEM) and numerical methods. A 2D mineralogical map of the external surface of a shale sample is obtained by energy-dispersive X-ray spectra (EDS), from which not only the volumetric fraction but also the spatial correlation of each minerals is displayed. Finite-element methods (FEM) are applied to this mineralogical map to simulate compression tests based on the principle of least elastic potential energy. Taking advantage of the flexibility of this simulation, anisotropy and other represented from the mineral map are also presented to clarify some aspects of the controversial debate on the representative volume of this work flow associated with its microscopic scale, and the potential upscale of the elastic properties from microscopic scale to core-analysis-scale. Also presented in this work are comparisons of the calculated elastic properties with some existing models that evaluate the effective moduli at macroscopic scales.

SCA2018-038. Rock Electrical Properties From Porous Plate and Resistivity Experiments: Tips to Maximize Data Quality

F. Pairoys[1]
[1]Schlumberger

Oil and gas reserve estimates based on measurements by downhole electrical tools require input data such as the cementation factor *m* and saturation exponent *n* obtained from core measurements in the laboratory. Thus, the quality of both the laboratory measurement and downhole measurement determines the overall uncertainty of the data interpretation. The uncertainty associated with the laboratory measurement can be minimized by designing an adequate special core analysis (SCAL) program and taking care of quality assurance.

There are several parameters to be controlled to ensure good data quality during a porous-plate test with resistivity measurements, such as representative applied net confining stress, equilibrium criteria, corrections of sleeve conformance and brine squeeze off, pore volume compressibility, resistance contribution of the porous plate, excess of conductivity due to clay, temperature variation, or even saturation derived from the material balance. Moreover, comprehensive quality control of these tests requires knowledge of rock characteristics, such as mineral composition and routine core analysis data.

This paper presents a description of the porous-plate experiment combined with measurement of the rock resistivity at capillary equilibrium. A sensitivity analysis of the resistivity measurement with respect to the various parameters evaluates the degree of impact on the cementation factor and the saturation exponent. Some parameters have a small effect on data quality whereas others can lead to significant error in the calculation of the Archie's exponents *m* and *n*. Precautions are necessary in the laboratory to obtain good data quality and avoid large errors in water saturation calculated from electrical logging techniques.

SCA2018-039. Insights into Low-Salinity Waterflooding

Hasan N. Al-Saedi[1], Ralph E. Flori[1], and Patrick V. Brady[2]
[1]Missouri University of Science and Technology, Rolla, Missouri, 65409-0140, United States
[2] Sandia National Laboratories, Albuquerque, New Mexico 87185-0754, United States

In our previous work, we examined the potential of divalent cations (Mg^{2+} and Ca^{2+}) in formation water (FW) for low-salinity (LS) EOR effect, where the increase in divalent cations in FW lowered the impact of LS water EOR.

In this paper, we demonstrate the importance of the same divalent cations in the injected water (both FW and LS water). We also try to relate the percentage of the divalent cations in the injected water to that in the FW to engineer the optimum concentration of the injected water and obtain the maximum oil recovery from sandstone reservoirs.

Berea sandstone cores were successfully flooded with FW and LS water at 90°C. While injecting both brines, samples of the effluent were analyzed for pH. Oil recovery experiments with a double Ca^{2+} and Mg^{2+} concentration showed a lower LS water effect, inferring that the cores became more water-wet; however, the LS water effect was much greater when the amount of Ca^{2+} and Mg^{2+} in the HS water was decreased by half. The results of this work relate oil recovery with LS water chemical compositions, temperature, ion exchange, and pH.

SCA2018-040. Residual Oil Saturation Under Mixed-Wet Conditions: Optimal Wettability Revisited

Magali Christensen[1] and Yukie Tanino[1]
[1]School of Engineering, University of Aberdeen, UK

We present laboratory measurements of imbibition capillary pressure and residual oil saturation established by centrifuge in mixed-wet Indiana limestone cores. The capillary pressure curves were combined with previously reported waterflood data to extract relative permeability curves by history matching. Both centrifuge and waterflood data suggest that residual oil saturation decreases monotonically as contact angle increases from ϑ_a = 110° to 150°, in contrast to the nonmonotonic dependence displayed by core-averaged oil saturation at the end of waterfloods. The results indicate that capillary end effects may be significant even in rock of relatively low permeability, and highlight the importance of using simulation to interpret coreflood data under capillary-dominated conditions.

SCA2018-041. A New Chemical Remediation Product to Prevent Sand Production From Unconsolidated Porous Media

B. Marchand[1,2], C.A. Davy[1,2], F. Agostini[1,3], F. Skoczylas[1,3], A. Lange[4], L. Jeannin[4], and P. Egermann[4]
[1]Ecole Centrale de Lille, CS 20048, F-59651 Villeneuve d'Ascq, France
[2]UCCS UMR CNRS 8181, F-59650 Villeneuve d'Ascq, France
[3]LAM3, F-59650 Villeneuve d'Ascq, France
[4]Storengy, Centre d'Expertise, 12 rue Raoul Nordling, 92274 Bois-Colombes, CS 70001, France

A new chemical remediation product to prevent sand production in unconsolidated formation is studied. This binder shows a similar strengthening to that of common binder such as PAM (PolyAcrylaMide) and does not induce permeability decrease. Moreover, its performance is not reduced by water injection; it is thus a good candidate to prevent sand production.

SCA2018-042. Measurement of the Organic Saturation and Organic Porosity in Shale

Qian Sang[1,2], Shaojie Zhang[1], Yajun Li[1], Mingzhe Dong[1?1,2], and Steven Bryant[2]
[1]College of Petroleum Engineering, China University of Petroleum (Huadong), Qingdao, China 266580
[2]Department of Chemical and Petroleum Engineering, University of Calgary, Calgary, AB, Canada T2N 1N4

Shale formations are fine-grained, clastic sedimentary rocks composed of a mix of clay mineral flakes and tiny fragments of quartz and calcite, with both inorganic and organic content and porosities. The inorganic content, such as clay minerals, is hydrophilic, while the organic pores are largely hydrophobic and therefore form the main ad- and absorbed sites for hydrocarbons. The complex wettability of shale formation has a significant impact on fluid storage and flow behavior of shale oil reservoirs. Oil content in a given shale oil formation includes free oil, which is primarily contained in inorganic pores and ad- and absorbed oil in kerogen. Assessment and quantitative evaluation of oil content in shale is challenging. Oil saturation in a given shale oil formation consists of two components: inorganic saturation (free-oil-dominated) and organic saturation (ad- and absorbed oil-dominated). Shale porosity includes inorganic and organic porosity. There is no reported research that identifies the two porosities and saturations. We therefore recently performed, for the first time, two types of vacuum-imbibition tests—water imbibition and oil imbibition—on 20 shale oil core samples to distinguish these two saturations.The final imbibed oil volume represents the total oil saturation, the final imbibed water volume is the inorganic saturation, and the difference between the two represents the organic oil saturation. Helium saturation tests were conducted to determine the total pore volume in shale. The amount of ad- and absorbed oil can be obtained from the difference between the total imbibed oil volume and pore volume. The difference between organic saturation and absorbed oil represents the organic pore volume, thereby obtaining the organic and inorganic porosity. Our results indicate that, for the shale core samples tested, the oil saturation in organic matter ranges from 6 to 55% of the total oil saturation in shale, and 50 to 90% of the organic saturated oil is ad- and absorbed in kerogen. The organic porosity ranges from 2 to 50% of the total porosity. Both the organic oil saturation and the effective organic porosity exhibit positive correlation with total organic carbon.[2]

SCA2018-043. Formation Damage in the Interwell Zones: Experiments and Advanced Analytics

Denis Orlov[1] and Dmitry Koroteev[1]
[1]Skolkovo Institute of Science and Technology, Skolkovo Innovation Center, Building 3, Moscow, 143026, Russia

We present a predictive model of formation damage in Vendian deposits based on the analysis of rock properties and flooding conditions. We have studied all the features of the self-colmatation process and arrange them in accordance with their importance. We have used two approaches to obtain the results. The first one was to discover all possible 2D crossplot correlations between colmatation characteristics and features (manual analysis). The second is based on machine learning algorithms. The benefits and disadvantages of both approaches are discussed in details.

SCA2018-044. Continuous Core Measurements: Applications for Optimized Petrophysical and Geomechanical Modeling in SNE Field, Senegal

C. Germay[1], T. Lhomme[1], C. McPhee[2], and Mike Starcher[3]
[1]Epslog
[2]Pelican Rocks
[3]Cairn Energy

An enhanced core analysis workflow, which integrates conventional core-plug analysis with continuous direct core measurements and wireline log data, was developed to optimize petrophysical and geomechanical modeling of the reservoir intervals in the deepwater SNE field, offshore Senegal. An extensive, continuous core scratch-testing campaign was run on core from two wells. The scratch tests produced a continuous profile of uniaxial compressive strength (UCS) and P-wave velocity values that were correlated with available core-plug strength and porosity data. The sample site selection protocol based on the upscaled scratch-test data resulted in fewer plug-sample failures during plug preparation for geomechanical testing. The rock mechanical tests (RMT) results were also found to be in excellent agreement with the scratch strength profile. By integrating the scratch-test results with core porosity and wireline logs, a centimeter-scale profile of estimated porosity was derived. The continuous rock property profiles created with the scratch test could be used to systematically check both routine core analysis (RCA) and RMT plug results. The robust multivariate relationships established between the rock strength profile and selected wireline logs enabled reliable upscaling of plug rock properties to predict rock strength in noncored intervals and wells. In comparison, rebound strength index tests run over the same core scratch interval produced limited and potentially misleading strength data. Plug sampling in thin-bedded heterogeneous formations may lead to an irreducible bias in test results unless it is based on a-priori knowledge about the rock small-scale heterogeneity. The heterogeneity assessment methodology based on the scratch test enables the selection of more representative plug site and more robust core property-log calibration at different length scales. This leads to a significant reduction in uncertainty in petrophysical and geomechanics models, and better decision-making in well design and field management.

SCA2018-045. Numerical Simulation of Nanofluid Injection in Oil Saturated Porous Media With Environmental Applications

Alexandra Sikinioti-Lock[1], Katerina Terzi[1], Maria Theodoropoulou[1], and Christos Tsakiroglou[1]
[1]Foundation for Research and Technology Hellas – Institute of Chemical Engineering Sciences, Stadiou str., Platani, 26504 Patras, Greece

A macroscopic numerical model is developed to simulate the flow, mass-transfer, and reactive processes when a suspension of zero-valent iron nanoparticles (nZVI) is injected in a porous medium, polluted by a chlorinated nonaqueous-phase liquid (NAPL) at its residual saturation. The nanoparticles transport is coupled with their nonequilibrium deposition in a porous medium, and the parameters quantifying the kinetics of nanoparticle attachment/detachment in sand grains are estimated with inverse modeling of experimental

results from nZVI flow tests in a sand column. The kinetics of the reaction of nZVI with dissolved tetrachloroethylene (PCE) is based on the numerical predictions of the statistical shrinking-core model that couples the mass transfer with reactive processes at the nanoparticle scale. Then, the NP transport model is extended to reactive flows by combining the dynamics of PCE ganglia dissolution and nZVI reactions with mass balances for residual PCE saturation, dissolved PCE concentration, and nZVI concentration in the aqueous phase. Numerical predictions of the residual PCE remediation efficiency as a function of injected NP mass is compared with experimental results of a PCE source zone remediation test performed in a sand column. The PCE source zone remediation efficiency is maximized, as the injected nZVI maintains its reactivity for a long period of time, and along the longest length of the porous medium. If updated to 3D media, and accounting for the real hydrogeology and contaminant reaction kinetics, the simulator might be used as a tool to predict the spatial and temporal evolution of the NAPL source zone during the in-situ nanoremediation of heavily contaminated aquifers.

SCA2018-046. A Methodology to Predict the Gas Permeability Parameters of Tight Reservoirs From Nitrogen Sorption Isotherms and Mercury Porosimetry Curves

Christos D. Tsakiroglou[1], Adnan Al Hinai[2], and Reza Rezaee[2]
[1]Foundation for Research and Technology Hellas – Institute of Chemical Engineering Sciences, Stadiou str., Platani, 26504 Patras, Greece
[2]Department of Petroleum Engineering, Curtin University, Perth, WA, Australia

For the explicit computation of the absolute permeability and Knudsen diffusion coefficient of tight rocks (shales) from pore-structure properties, a methodology is suggested. The pore space is represented by a pore-and-throat network quantified by bimodal pore- and throat-size distributions, pore-shape factors, and pore accessibility function. With the aid of percolation theory, analytic equations are developed to express the N_2 adsorption/desorption isotherms and Hg intrusion curve as functions of all pertinent pore-structure parameters. A multistep procedure is adopted for the successive estimation of each set of parameters by the inverse modeling of N_2 adsorption, N_2 desorption, and Hg intrusion datasets. With the aid of critical path analysis of percolation theory, approximate relationships are developed allowing the explicit calculation of the absolute permeability and Knudsen diffusion coefficient, from estimated pore-network properties. Application of the methodology to the datasets of several shale samples enables us to evaluate the predictability of the approach.

SCA2018-047. Avoiding Routine Core Analysis Plug Damage by Proper Evaluation of Core Gamma-Ray, Core Description and Wellsite Core Sampling

Norbert Schleifer[1], Emmanuel Kesse[2], and George Lawrence[3]
[1]Wintershall Holding GmbH
[2]Wintershall Norge AS
[3]DEA Deutsche Erdöl AG

Great effort and care is exercised to select proper cleaning methods for special core analysis (SCAL) plugs. In contrast, selecting the proper cleaning methods in routine core analysis (RCA), which deliver the majority of information for the static reservoir model and whose plugs act as backup samples for SCAL, is often neglected. Mild and more expensive cleaning methods are often avoided in RCA as the large sample number would lead to a considerable cost increase.

In this paper, two case studies from oilfields in Germany are presented where massive plug damage while cleaning took place during RCA, leading to a biased distribution of petrophysical data in the cored reservoir and a lack of backup plugs for SCAL. This plug damage would have been avoided by a proper evaluation of existing data, such as total core gamma-ray, geological core description, Dean-Stark fluid extraction, and results from “hot shot” as well as tracer plugs taken at the wellsite. So-called “hot shot” plugs are sampled to receive porosity and permeability data within two weeks by limiting the cleaning time to a few days. Integration of the information from these sources can be used to identify core sections where cleaning should be avoided or short-list plug samples requiring a more selective and milder cleaning method compared to conventional approaches. Considering a closer look at the available data offers a proactive means of avoiding damaged plugs during RCA and the loss of valuable data for the reservoir model.

SCA2018-048. Liquid Vapor Isotherms in Nano-Porous Media Under NMR Observation

Aleksandr Denisenko[1]
[1]Schlumberger Moscow Research Center

Conventional experimental approaches and current understanding of low-permeability reservoir rocks are based on the models of hydrocarbon storage and transport in rather large pore systems (several microns and larger) where the properties of bounded fluids are close to the bulk ones and fluid flow in the rock complies with Darcy’s law. This concept is not straightforward or useful for complex reservoirs with nanoscale pores. Instead, their characterization requires revisiting available petrophysical techniques.

This work delivers a modern consideration of sorption processes of liquid vapor in porous media with a leading role given to nuclear magnetic resonance (NMR) phenomena. The high accuracy of the NMR method to hydrogen nuclei volume, and especially its sensitivity to the surface properties of confining media, enable discovering new potential adsorption-desorption mechanisms. This study presents the first step in experiments with artificial solid porous models and synthetic liquids, which could then be transposed to natural and more complex oil- and gas-bearing rocks.

SCA2018-049. X-Ray Computed Tomography Supported by Nuclear Magnetic Resonance and Mercury Porosimetry as Novel Approach in Pore-Space Characterization of Tight Sandstones

Krakowska, P. [1], Puskarczyk, E.[1], Jędrychowski, M.[2], Habrat, M.[1], Madejski, P.[3], and Dohnalik, M.[4]
[1]AGH University of Science and Technology in Krakow (Poland), Faculty of Geology, Geophysics and Environmental Protection
[2]AGH University of Science and Technology in Krakow (Poland), Faculty of Physics and Applied Computer Science
[3]AGH University of Science and Technology in Krakow (Poland), Faculty of Mechanical Engineering and Robotics
[4]Oil and Gas Institute – National Research Institute (Poland)

Tight, gas-bearing formations from Paleozoic basins in Poland were carefully analyzed using nuclear magnetic resonance spectroscopy, NMR, mercury porosimetry, MICP, and computed X-ray tomography, CT. Results of laboratory measurements were used to calculate advance petrophysical parameters, such as clay-bound, capillary-bound and moveable water for nonstandard T_2 distribution interpretation from NMR. Swanson parameters for fracture-porous systems were derived from MICP and sphericity and pore-throat diameters from CT. Innovative approach in estimating pore-throat diameter was introduced on the basis of best-fit ellipsoid radii. Moreover, application of semivariogram for pores location allows assessing the heterogeneity in pore-space structure as well as the qualitative interpretation of 3D objects (pores).

SCA2018-050. Corefloods Onsite: Assessing the Options for Water Treatment in Fields With Active EOR Applications

T. Gumpenberger[1], P. Toplack[2], Ch. Pripfl[1], W. Vollnhofer[3], Ch. Einzinger[1], M. Marx[1] and R. Grillneder[1]
[1]OMV Upstream AG
[2]Technisches Büro für Verfahrenstechnische Simulation
[3]OMV Downstream AG

We report on a new mobile coreflood system to assess the impact on injectivity of different treatment processes for oilfield waters used in enhanced oil recovery (EOR).

Oil-in-water (OIW) and the amount of total suspended solids (TSS) are traditional parameters for assessing water quality, be it for secondary or tertiary recovery methods or simple disposal. Typically, these values are obtained by analysing water samples taken at discrete intervals at a water treatment plant or from process streams inside a testing facility for a novel water treatment technology.

In our experience OIW- and TSS-values alone will provide limited information to properly assess risks and injection-well performance of chemical packages that are employed during the water treatment process. These additives can interact with traces of EOR-fluids (e.g. polymers) or the matrix of the target formation. This in turn can lead to damage and even the loss of an injection well, despite the fact, that initial screening based upon OIW or TSS content indicated good injectivity.

To directly asses the water quality in terms of actual injection performance, we employ a continuous “permeability reduction test” (PRT). A 10-ft container equipped with two identical coreflood rigs allows continuous monitoring of injectivity of produced water from different stages of the treatment process. The injectivity behavior of the produced water is evaluated in terms of pressure buildup across a core sample. A short latency, on the order of only five minutes, allows us to correlate the pressure response of the core with operating parameters and/or the chemical consumption in the upstream water treatment plant. Testing two cores in parallel (e.g., inlet vs. outlet) corrects for variations in the inlet water quality caused by unsteady operating conditions. The PRT-container is designed for road transport and can be deployed at any desired locations within an oilfield. Once the core samples have been mounted monitoring and control can be done remotely.

We present results from a test campaign that evaluated a novel flotation technology for treating water containing back-produced polymer from a polymer pattern in the Matzen field in the Vienna Basin, Austria.

SCA2018-051. An Experimental Setup for the Assessment of Effects of Carbonate Rock Dissolution on Complex Electrical Conductivity Spectra

Matthias Halisch[1], Sarah Hupfer[1], Andreas Weller[2], Raphael Dlugosch[1], and Hans-Peter Plumhoff[3]
[1]Leibniz Institute for Applied Geophysics (LIAG), Dept. 5 Petrophysics & Borehole Geophysics, Stilleweg 2, D-30655 Hannover, Germany
[2]Clausthal University of Technology (TUC), Institute of Geophysics, Clausthal, Germany
[3] Westphal Präzisionstechnik GmbH & Co. KG, Celle, Germany

Investigating complex electrical properties of natural rocks and soils by using spectral induced polarization (SIP, i.e., low-frequency impedance spectroscopy, typically measured from 1 mHz up to 100 kHz) is of high research interest for all pore-space and boundary-surface specific processes and properties between the matrix and the pore fluid. The deduction of hydraulic and pore-space-related structural properties, as well as the correlation of SIP-data with core and special core analysis data is recently in the focus of research.

In the first stage of this project, a case study is presented that investigates the complex electrical conductivity of carbonate samples using low-frequency electrical impedance spectroscopy. Within the next phase, a specifically designed experimental setup for temperature controlled acidizing of carbonate rock samples was constructed. The setup features a special core holder for saturating the samples with a retarded (i.e., temperature activated) formic acid, which is connected to adjacent fluid reservoirs by high-precision piston pumps. Fluid type can be easily switched for flushing/ cleaning of the material after acidification without removing the sample from the core holder. The core analysis program includes a multimethodological and interdisciplinary approach, combining petrophysical, mineralogical and geochemical techniques. Before and after each core acidification step, porosity, specific surface area, nuclear magnetic resonance (NMR) T_2 distributions as well as complex conductivity spectra and data from 2-D and 3D imaging techniques were obtained. In this manuscript, the authors present the experimental setup, the workflow as well as first results of the SIP and petrophysical investigations on selected carbonate samples.

SCA2018-052. High-Field MRI of Hydrate Phase Transitions in Sandstone

S. Almenningen[1], J. Gauteplass[2], V.F. Veland[1], G.L. Aastveit[3], P. Fotland[3], and G. Ersland[1]
[1]Department of Physics and Technology, University of Bergen, Norway
[2]Department of Chemistry, University of Bergen, Norway
[3]Statoil ASA, Bergen, Norway

This paper reports a methodology for high-field magnetic resonance imaging (MRI) and nuclear magnetic resonance (NMR) T_2 spectroscopy of hydrate-bearing porous media. We used a 4.7-Tesla MR scanner with connected high-pressure and high-precision pumps to facilitate direct visualization of gas-hydrate phase transitions in sediments. Experiments were designed to measure the correlation between water saturation in Bentheimer sandstone cores and obtained MR signal intensity. Gas hydrates were formed from 65% of the pore volume occupied by water (0.1 wt% NaCl) and 35% by gas (78% methane and 22% propane). The specific gas mixture was chosen to provide hydrate stable conditions at room temperature (21°C) and moderate pressures (above 5 MPa). Both hydrate formation and dissociation events were initiated and monitored by pore pressure control. Two types of MR pulse sequences are reported: (1) RAREst, used to image and analyze the spatial development in the pore volume of the core*;* and (2) CPMG to map T_2 relaxation changes during hydrate growth and dissociation. Phase transitions of gas hydrate in Bentheimer sandstone cores were successfully imaged by high-field MRI, and benefits from reduced measuring time and enhanced spatial resolution compared with experiments using lower field strengths. Obtained T_2 distributions during hydrate formation indicate pore-filling hydrate growth in the largest pores.

SCA2018-053. Characterization of Fluid-Rock Interaction by Adsorption Calorimetry

D. Korobkov[1], V. Pletneva[1], and E. Dyshlyuk[2]
[1]Schlumberger, Moscow Research Center
[2]Schlumberger Dahran Carbonate Research Center

We continue our study on rock characterization by calorimetry. In this study, differential scanning calorimetry (DSC) and the gas-sorption techniques were used to characterize fluid/rock interaction, which is related to the wettability state of the surface of the formation. The paper presents an approach for surface characterization by measuring the change in enthalpy associated with adsorption process. Using calorimetry, it is possible to obtain the variation of state function-enthalpy, due to interaction between molecules of a fluid and a surface. DSC adsorption enthalpy measurements were used in a combination with the gas-sorption technique, which allows one to measure the amount of adsorbed media. Comparison of the adsorption isotherms for different fluids (for example water and hydrocarbons) can provide valuable information on wettability of powder, cuttings, conventional and tight rocks, that cannot be obtained by any other existing methods. For conventional rocks, it can be used for characterization of the wetting state (i.e., for evaluation of contact angle).

In the paper, we discuss the approach and results of tests that have been conducted using an artificial porous media and powders with predefined composition, surface state, and size of pores.

SCA2018-054. Measuring Relative Permeability With NMR

M.J. Dick[1], D. Veselinovic[1], T. Kenney[1], and D. Green[1]
[1]Green Imaging Technologies, Fredericton, NB, Canada

Whether they are used to complement existing measurements, or completely replace traditional methods of data acquisition in lieu of speed, accuracy, cost-effectiveness and/or other benefits, NMR techniques have become an indispensable tool in oil and gas exploitation. This project uses NMR capabilities in unsteady-state relative permeability measurements.

In conventional relative permeability measurement, fluid saturations, pressure differences and fluid flow rates are monitored and, from these values, relative permeability can be calculated. Typically, the fluid saturation monitoring relies on mass or volume measurements acquired using acoustic and/or optical instruments. We propose a more elegant technique to monitor the saturations via NMR T_2 distributions. This NMR relative permeability measurement should be more accurate than the conventional method since the saturations are measured directly in the rock rather than from mass or volume measurements. An NMR relative permeability measurement has been developed and is presented in this paper.

To test the feasibility of this method, a carbonate initially saturated with dodecane was confined in an NMR overburden probe. NMR invisible D_2O-based brine was then pushed through the rock at a fixed rate. A T_2 spectrum was recorded every few minutes and the resulting pore volumes were employed to retrieve the oil produced from the rock as a function of time. Simultaneously, the pressure drop across the rock was also measured as a function of time. The resulting dataset was then employed to determine a relative permeability plot for the rock. An overview of how this experiment is conducted, how the pressure drop across the rock is recorded simultaneously with the NMR T_2 distributions and other experimental hurdles in this measurement is presented.

SCA2018-055. Supercritical Methane Diffusivity in Porous Media

Nicholas J. Drenzek[1], Prem K. Bikkina[2], Jarred H. Kelsey[2], Clint P. Aichele[2], and Jeffery L. White[2]
[1]BHGE Oil & Gas Technology Center, Oklahoma City, OK 73104 USA
[2]Oklahoma State University, Stillwater OK 74078 USA

The self-diffusion coefficients and transverse relaxation rates of supercritical methane at temperatures and pore pressures up to 60°C (140°F) and 62.1 MPa (9,000 psig) were measured in sandstone (SS) and limestone (LS) microplugs at dry and irreducible brine saturation in zirconia tubes using 400 MHz nuclear magnetic resonance (NMR) spectroscopy. Diffusivities in the tube annuli, whose 0.3-mm apertures approximate that of subsurface fractures, were on the order of $10^{-8}m^2s^{-1}$. These values were up to three times higher than those in the network of pores, whose volume-distributed mode CT-derived diameters were 35 and 5 µm for SS and LS, respectively. All diffusion coefficients decreased exponentially by a factor of 2 to 3 from 13.8 to 62.1 MPa in SS and LS, respectively, and all decreased by a factor of 1 to 3 across an 8 to 64 ms increase in echo spacing. Corresponding annular and pore relaxation rates generally increased with pressure from 42 to 139 ms and 37 to 71 ms for SS, and 46 to 144 ms and 90 to 217 ms for LS, respectively. These trends compare reasonably well against quantitative model predictions of the progressive disruption of spin-rotation proton relaxation with increasing pressure.

SCA2018-056. Overview of the LET Family of Versatile Correlations for Flow Functions

Frode Lomeland[1]
[1]Orec AS, Stavanger, Norway

The LET family of correlations for flow functions is gradually gaining foothold among core analysts, reservoir engineers and scientists due to their flexibility, accuracy and ease of communication. This makes LET excellent for interpretation of flow experiments, for upscaling of flow functions and for history matching models of fields in production. The LET family of capillary pressure correlations avoids singularities when approaching residual saturations. The family includes several capillary pressure correlations available to suit various needs. The LET family of correlations, parameter trend functions, recommended workflow and some applications has been presented in previously and denoted LET and LETx. An overview of the 2018 version of the LET family of correlations for flow functions is displayed together with comments and explanations. An overview of selected flow parameters, such as L_o, L_w, S_{orw} and $K_{rwr} = K_{rw}(S_{orw})$, is also displayed. New elements in the family are invertible correlation for primary drainage P_c (LETh) and imbibition P_c (LETs) correlation with independent spontaneous and forced P_c-branches.

SCA2018-057. Probe Magnetics as a Rapid, Nondestructive Screening Tool for Consolidated and Unconsolidated Core in Conventional and Unconventional Reservoirs

Toan H. To[1], David K. Potter[1,2], Aminat Abiola[1,2], and Vivian T. Ebufegha[1]
[1]Department of Physics, University of Alberta, Edmonton, Canada
[2]Department of Earth and Atmospheric Sciences, University of Alberta, Edmonton, Canada

A comprehensive study using probe magnetic susceptibility measurements has been used to characterize a wide range of slabbed core from different types of conventional and unconventional reservoirs. The probe magnetic device was small and very portable, and allowed high-resolution, nondestructive screening to be undertaken very rapidly. The technique is particularly useful for unconsolidated core, where some other more conventional techniques can be destructive. The results allowed rapid acquisition of high-resolution clay profiles, which correlated with other independent established methods, such as X-ray diffraction. Furthermore, the magnetic profiles also correlated with grain-size variations, determined independently from laser particle-size analysis, and probe permeability (where the latter was possible). Some of the key probe magnetic results in different types of reservoir are as follows:

(1) The probe magnetic technique has been particularly useful in a number of oil sands reservoirs in northern Alberta as a nondestructive screening tool for these unconsolidated samples. In particular, it has allowed the main oil-sand intervals to be differentiated from the more clay-rich shale and inclined heterolithic stratification (IHS) beds better than conventional gamma-ray techniques.

(2) The technique has allowed one to distinguish different types of unconsolidated turbidite samples in some Middle East gas reservoirs that were difficult to differentiate visually. This included quantitatively differentiating "uniform" turbidites from "graded" turbidites, where the grain size subtly fines upwards, but which is quite difficult to identify qualitatively from mere visual inspection.

(3) The technique has been able to easily distinguish different types of shales (due to the varying amounts of clay minerals and organic matter that they contain) in some shale-oil and shale-gas reservoirs in western Canada. Increased paramagnetic clays, such as illite, result in higher magnetic susceptibility, while increased organic matter and quartz content result in lower magnetic susceptibility values.

The results suggest that probe magnetics could be used as proxy for rapidly and nondestructively estimating high-resolution clay content, grain-size and permeability profiles in consolidated and unconsolidated samples in several different types of conventional and unconventional reservoir.

SCA2018-058. Dynamic Adsorption-Diffusion Model for Simulating Gas Production in Shale

Zehao Yang[1,2], Qian Sang[1], Yajun Li[1], Steven Bryant[2], and Mingzhe Dong[2]
[1]College of Petroleum Engineering, China University of Petroleum, Qingdao, China 266555
[2]Department of Chemical and Petroleum Engineering, University of Calgary, Calgary, Canada T2N 1N4

Reliable mathematical models for analysis of shale-gas production require consideration of gas-storage forms in shale rocks: free gas in micro- and nanoscale pores, adsorbed gas on surfaces of organic matter and clay minerals, and dissolved gas in kerogen. In this paper, a dynamic (delayed) adsorption-diffusion (DAD) cylindrical model is presented to analyze the gas-production process in shale rocks. This model considers that the adsorption/desorption process of adsorbed gas is time-dependent instead of instantaneously reaching equilibrium. Meanwhile the diffusion process of dissolved gas in kerogen is also taken into account. The exact solution for the DAD cylindrical model is derived. The dynamic adsorption/desorption parameters are estimated through fitting the exact solution of DAD cylindrical model with the experimental results of the shale-gas production process under constant production pressure conditions. The parameter estimation method is realized by a global optimization method, called multilevel single-linkage (MLSL) method. The critical points, which distinguish the three domination stages of free gas, adsorbed gas, and dissolved gas, are determined by using the DAD model and dissolved-gas model. The production characteristics of these three stages are analyzed. The percentage of free gas, adsorbed gas and dissolved gas are also obtained from the DAD cylindrical model analysis.

SCA2018-059. Topological Persistence of Heterogeneous Sandstone

Anna L. Herring[1], Vanessa Robins[1], Mohammad Saadatfar[1], BenjaminYoung[2], Mark Knackstedt[1], and Adrian Sheppard[1]
[1]Department of Applied Mathematics, Research School of Physics & Engineering, The Australian National University, Canberra, ACT, Australia
[2]Thermo Fisher Scientific, Brno, Czech Republic

Quantitative topological analysis of the internal pore-space architecture of porous rocks, and of the fluid distributions within the pore space, has recently been used to inform understanding and predictions of petrophysical properties, such as permeability, fluid relative permeability, and nonwetting-phase capillary trapping capacity and efficiency. So far, this type of analysis has only been used effectively for relatively homogenous media, partially due to the intrinsic nature of topology: topological analysis inherently disregards geometry and size of features; it provides quantification of the connectivity and interconnectivity of a phase (i.e., pore space or fluid), but no information on the relevant length scales of connections or isolated components. This presents problems for analysis of heterogeneous media, where fluid flows are strongly influenced by the relative size and spatial variation of preferential pathways.

Persistent homology is a technique that complements standard topological analysis because it measures the size of topological features (disconnected components and redundant connections) as well as the frequency of each kind of feature. This capability to link topology and geometry results in a powerful analytical tool; for example, this type of analysis has recently been used to develop a universal capillary trapping relationship that describes nonwetting phase trapping during capillary-dominated imbibition flows for a variety of homogenous sandstones.

Here, persistent homology analysis is applied (via the open-source image analysis program Diamorse) to a drainage-imbibition experiment in a heterogeneous reservoir sandstone exhibiting, notably, a high-density cement layer in the lower quarter of the core and a lateral fracture above the layer. Steady-state drainage and imbibition processes were carried out in a vertical fluid injection (flow from bottom to top), and 3D internal phase distributions were measured after each flow process using pore-scale helical trajectory X-ray computed tomography (CT) via the CTLab at the Australian National University (ANU). Nonwetting-phase (octane) saturation levels after drainage and after imbibition were measured for subsections of the core as well as for the entirety of the core, and are shown to relate to persistent homology signatures measured for the pore space and the initial octane distribution.

SCA2018-060. Universal, Flow Dependent Relative Permeability Scaling for Steady-State Two-Phase Flows in Porous Media

Marios S. Valavanides[1]
[1]Dept. of Civil Engineering, University of West Attica, Campus 1, Ag. Spyridonos, Athens, GR-12210, Greece

The phenomenology of steady-state two-phase flow in porous media is recorded in the well-known relative permeability curves. Conventionally, relative permeabilities are considered as functions of saturation. Yet, this has been challenged by theoretical, numerical and laboratory studies of flow in artificial pore-network models and real porous media that have revealed a significant dependency on the flow rates—especially when the flow regime is capillary to capillary/viscous and part of the disconnected nonwetting phase remains mobile. These studies suggest that relative permeability models should include the functional dependence on flow intensities.

Here, we present the outcome of extensive simulations implementing the DeProF true-to-mechanism model algorithm, in flow setups spanning five orders of magnitude, both in the capillary number, Ca, and the flow rate ratio, *r*, and for different favorable/unfavorable viscosity ratio systems in a typical pore network. The systematic dependence of the pressure gradient (and of the relative permeabilities) on the local flow-rate intensities is revealed. This systematic dependence can be described analytically by a universal scaling functional form along the entire domain of the true independent variables of the process, Ca and *r*.

The proposed scaling opens new possibilities in improving SCAL measurements and implementing true-to-mechanism (flow-dependent) relative permeability maps in simulators.

SCA2018-061. Experimental Investigation of Stability of Silica Nanoparticles at Reservoir Conditions for Enhanced Oil Recovery Applications

Shidong Li[1], Nanji J. Hadia[1], Ng Yeap Hung[1], Hon Chung Lau[1,2], Ole Torsæter[3], and Ludger P. Stubbs[1]
[1]Institute of Chemical and Engineering Sciences, Agency for Science, Technology and Research (A*STAR), Singapore
[2]National University of Singapore,
[3]PoreLab Research Center, Department of Geoscience and Petroleum, Norwegian University of Science and Technology (NTNU)

To be effective enhanced oil recovery (EOR) agents, nanoparticles must be stable and transported through the reservoir. However, the stability of a nanoparticle suspension at reservoir salinity and temperature is still a challenge and how it is affected by reservoir rock and crude oil is not well understood. The objective of this study is to investigate ways to stabilize nanoparticle suspensions at reservoir conditions for EOR applications.

The stability of nanoparticle suspensions was screened in test tubes at 70°C and 3.8 wt% salinity in the presence of rock and crude oil. Rock and oil samples used included Berea sandstones, shale, chalk, and limestone and crudes with different properties. Fumed silica nanoparticles in suspension with hydrochloric acid (HCl), polymer modified fumed nanoparticles and amide functionalized silica colloidal nanoparticles were studied. The size and pH of nanoparticle suspension in contact with rock samples were measured to determine the mechanisms for stabilization or destabilization of nanoparticles. A turbidity scanner was used to quantify stability of nanoparticle suspension.

Results showed that both HCl and polymer surface modification can improve nanoparticles stability under synthetic seawater salinity and 70°C. Suspensions of polymer modified nanoparticles were stable for months. It was found that pH is a key parameter influencing nanoparticle stability. Rock samples with carbonate destabilized unmodified nanoparticles. Crude oils have limited effect on nanoparticles stability and no obvious trend was observed. Some components of crude oil migrated into the aqueous phase consisting of amide functionalized silica colloidal nanoparticles suspension.

This is the first time the effect of rock and crude oil on the stability of silica nanoparticle suspension has been reported. The feasibility of using a low pH environment to stabilize a nanoparticle suspension in a porous medium will be further investigated. This study constitutes part of a continuing effort to determine the feasibility of using nanoparticle suspensions as EOR agents.

Japan Formation Evaluation Society (JFES)
24th Formation Evaluation Symposium of Japan
Chiba, Japan, October 11–12, 2018
Abstracts

NOTE: Tentative Program. The 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.

Paper A. Production Data Analysis Using Rate Transient Analysis and Mini-Frac Test Report Review

Hiroko Kozawa[1], Hiroaki Kadono[2], Yoshiharu Ito[2], and Sunao Takagi[2], Ayae Goto[1]
[1]Japan Petroleum Exploration Co. Ltd.
[2]Japan Oil, Gas and Metals National Corporation

The objective of this study is to create a production forecast and optimize the completion design at the North Montney area through the development of a complex fracture model and analyzing flow simulation.

In this article, we focus on the mini-frac test report, production and pressure data to review the present completion design as follows;

- $Ac\sqrt{k}$ estimation from rate transient analysis (RTA)
- Permeability estimation from mini-frac test.

The effective fracture length and effective fracture area can be evaluated based on these production results. We focused on the parameter that shows an influx from the matrix to the fracture then calculated the value using a square-root-time plot. The term Ac refers to the summation of the fracture surface area, and k is the matrix gas permeability.

For the calculating the fracture surface area from RTA, the permeability is needed therefore the permeability was estimated from mini-frac test records. Two methods were adopted (1) after closure analysis, and G-function plot. The calculated values for the three wells showed the same trend of productivity.

The evaluated permeability has room for improvement. The potential exists for permeability estimation from the core or log analysis. We compare all of the data to find the lowest uncertainty, and then calculate the fracture surface area. Furthermore, we construct a complex fracture model and compare the calculated surface area to show the validity of this model.

Paper B. Investigating the Influence of Organic Matter Composition and Connectivity on Organic Matter Porosity Development in Duvernay Formation Organic-Rich Mudstones

Levi J. Knapp[1], Takashi Nanjo[1] Shinnosuke Uchida[1], Omid Haeri Ardakani[2], and Hamed Sanei[3]
[1]Japan Oil, Gas and Metals National Corporation
[2]Geological Survey of Canada
[3]Aarhus University

Organic matter exerts a fundamental control on porosity and permeability in organic-rich tight-oil and -gas reservoirs. The complexities of these relationships are not well defined, however, and may be influenced by a variety of factors, including organic matter abundance (TOC), thermal maturity, kerogen type, original kerogen structure and primary organic-hosted porosity, compositional fractionation of migrated and solidified hydrocarbons (solid bitumen), interaction with mineral catalysts, compaction, and occlusion by generated products such as solid bitumen.

This study attempts to explain the large range of pore sizes and morphologies that are commonly observed even at the micrometer scale. Our hypothesis is that organic matter composition causes local heterogeneity in organic matter porosity due to differences in porosity generation, expulsion, and occlusion processes. The study presented here aims to advance the science in this field by integrating advanced organic geochemical analyses (Raman spectroscopy, Rock-Eval with extended slow heating cycle and pyrolysis-GC-MS, organic petrology) with robust mineralogical (ICP-MS, XRD, SEM-EDS) and porosity (He-porosimetry, MICP, NMR, FIB-SEM) quantification. The study target is the Devonian Duvernay Formation of western Canada, which is a prolific source rock and rising star as an unconventional reservoir.

Distinct porosity morphology groups have been observed in SEM and ongoing work has shown that organic matter porosity morphology may be influenced by organic matter connectivity, composition, and the ability for hydrocarbons to migrate in and/or out of macerals. Integration of porosity calculated from 2D and 3D FIB-SEM with other laboratory-based porosity analyses has demonstrated that a significant portion of the porosity is below typical SEM imaging resolution and that even methods such as He-porosimetry are challenged to access nanometer-scale pores. Variations in sample preparation and analysis procedures can significantly alter porosity results.

Paper C. Impact of Small Fractures on Porosity and Permeability: Implications From Dolomite Veins in Onnagawa Tight Formation

Tetsuzo Fukunari[1], Takashi Tsuji[2], Kentaro Takeda[2], Tetsuya Tamagawa[2], Shigehiro Kitamura[1], and Yoshiharu Ito[1]
[1]Japan Oil, Gas Metals National Corporation (JOGMEC)
[2]Japan Petroleum Exploration Co., Ltd. (JAPEX)

The Onnagawa Formation is Miocene biosiliceous shale tahat is known as major source for hydrocarbon accumulation in the western Tohoku region, Japan. Acid stimulation was tested in the source rock in 2012. The result shows dramatic improvement of oil production at the tested interval, from 1,500 to 50,000 liters per day. One of the possible phenomena having caused the exceptional improvement is considered to be dissolution of dolomite veins, which locally developed in the siliceous shale. It is, therefore, a key issue of the project to characterize the dolomite veins in terms of both estimations of appropriate acid injection amount and post-acidizing fracture permeability.

Geological model construction and reservoir simulation are ongoing work. Here, we focus on scale problem of the vein characterization, which we faced in the project. The dolomite veins were characterized in both core-scale and image log-scale in a 12-m interval. The total numbers of veins counted in core and image log are 1,181 and 117, respectively. Comparison of the two datasets indicates many small veins shorter than 10 cm are visible only in the core. In order to investigate the effects of the small veins, veins are separated into two groups: Group 1, veins shorter than 10 cm; Group 2, veins longer than 10 cm. Since mineral veins generally preserve subsurface fracture geometry, constant aspect ratio among vein thickness, dip-length and strike-length is assumed based on core observation. Subsequently, post-acidizing fracture intensity, fracture porosity and fracture permeability are examined with the two groups.

The results show Group 1 accounts for 83% of fracture intensity and 56% of fracture porosity, and Group 2 controls 85% of fluid flux in the system. Simple discrete fracture-network models also demonstrate that shape factor increases nearly 20 times by Group 1. These results suggest that small fractures can have a significant impact on reservoir simulation if matrix permeability is very low or negligible (dual-porosity single-permeability model) in which fluid flow requires high fracture connectivity and matrix production requires high fracture-matrix interaction. In addition, the porosity of small fractures should be taken into account if matrix has no or negligible porosity. In the current study case, fractal features of the dolomite veins obtained from core might be applicable to correlate the volume of dolomite veins and post-acidizing fracture permeability in future modeling work.

Paper D. Case Study: Productivity Evaluation of Pronounced Heterogeneous Gas Reservoir Drilled at High Overbalance

Liu Jian Xin[1], Bei Gao[2], Chen Jichao[2], and Shim, Yen Han[2]
[1]CNOOC
[2]Schlumberger

Reservoir heterogeneity is the key factor that impacts production, waterflooding efficiency and ultimate hydrocarbon recovery during the reservoir development. Reliable productivity evaluation from the early stage is needed to understand reservoir characteristics and minimize the uncertainty of production potential so that a suitable solution can be prepared to address the technical challenges during the development phase. The main challenges in evaluating wells drilled at high overbalance conditions came from severe near-wellbore formation damage and complex pore structures due to the complex lithology. These circumstances contributed to a large discrepancy among computed permeability from different measurement sources. The productivity analysis becomes complicated and affected by the interpretation methods under different measurement environment.

A comprehensive case study is presented in this paper for productivity evaluation in highly heterogeneous reservoirs at high overbalanced drilling. An integrated approach is elaborated to overcome the challenges by integrating all available data from different sources. Flow-based rock typing with neural network is used to identify the flow units from complex lithology, and capillary pressure and relative permeability based on different rock types are the key parameters input to control the model. Different scaled permeability from openhole logs, MDT pretests, mini-DST and DST is integrated systematically to understand the vertical and horizontal direction of reservoir heterogeneity. From the integrated data analysis, the interpreted reservoir properties are upscaled and populated into numerical models and validated through history matching by dynamic tests. This integrated methodology or study provides an attractive and efficient way to evaluate the productivity in the early stage of reservoir life cycle, and minimizes the uncertainty of production potential. In the end, the suggestions are concluded according to this comprehensive study.

Paper E. Lithology Characteristics and Logging identification of Basement Rocks: Taking Buried Hills in Chad, Bongor Basin as an Example

Linhui Yan[1], Yuwen Chang[1], Zhongyuan Tian[1], Xianbing Li[1], Li Wang[1], and Xuerui Zheng[1]
[1]Petrochia Research Institute of Petroleum Exploration and Development

Lithology identification in basement rock reservoirs is one of the most important basic works for reservoir evaluation. The identification results can directly influence the evaluation of reservoir physical properties, oil-bearing properties and the identification of effective reservoir. Taking buried hills in Chad, Bongor basin as an example, the characteristics of lithology, chemical composition, and mineral composition were analyzed using core observation, slice identification, geochemical analysis. Based on lithology characteristics, the classification criteria of the basement rock were determined. The logging response characteristics were summarized and the corresponding logging identification method was established. The results show that the basement rocks of the research area are composed of metamorphic rocks and magmatic rocks. With the decrease of the content of light minerals, the contents of silicon and potassium decrease, and the of Fe, Al, Ti, Mg and Ca content increases. According to the mineral composition and content, the lithology can be divided into two categories and 10 subclasses. The logging response characteristics of basement rocks can be divided into six kinds combined with the form of density and compensated neutron. Meanwhile, there are brecciated structures, clasfic structures, gneissic structures, banded structures, net veined structures, massive structure and intrusive structure in electrical imaging logging. The established crossplots and summarized characteristics of logging curves and response values provide a basis for lithology identification.

Paper F. An Object-Based Modeling and Simulation of CO_2 Plume Dynamic in Saline Formation in Nam Vang Field, Cuu Long Basin, Vietnam

Vo Thanh Hung[1], Yuichi Sugai[1], and Kyuro Sasaki[1]
[1]Kyushu University

In recent years, Carbon capture and storage technology (CCS) has been recognized as one of the potential methods to reduce greenhouse gas emission and for mitigating global climate change. This practice can be done in depleted reservoirs as well as in saline aquifer reservoirs. Geological modeling is an important process to prove the suitable geologic formation in CCS project. The CO_2 plume behavior depends on geological structure of the storage formation. This study focuses on geological modeling and on the simulation of CO_2 plume behavior in saline sandstone of fluvial deposits, Nam Vang field, Cuu Long Basin, Vietnam. Channel sands and floodplain are defined based on well-logging data. Fluvial facies are distributed in the three-dimensional grid using the object-based method with consideration of lateral continuity, vertical range and orientation in each facies. The porosity and permeability are modeled stochastically to conditioning to facies. The advantage of object-based modeling constrained the petrophysical model to facies model to assign the high porosities and permeability distributed within channel sand-dominated facies. The low porosities and permeability populated within floodplain-dominated facies. CO_2 injections were simulated using ECLIPSE300-CO2STORE. Sensitivity analysis was been conducted to investigate the behavior of the CO_2 plume for reservoir saline sandstone. Simulation results indicate the extent of CO_2 plume dynamic is sensitivity to the geometry and sinuosity of the fluvial channel. Object-based modeling can construct the geological model to relate with fluvial channel facies correctly. This method is effective to support for geological CO_2 storage modeling in the fluvial deposits. As a general evaluation, this study can contribute to CO_2 storage in an offshore area in Vietnam.

Paper G. Development of Double-Permeability Type Compositional Simulator for Predicting Enhanced Coalbed Methane Recovery

Hiroaki Sakai[1] and Masanori Kurihara[1]
[1]Waseda University

Due to the reduction of conventional oil and natural gas resources, unconventional resources have attracted a lot of attention. Coalbed methane (CBM) is one of such unconventional resources, a part of which has been already commercialized. In the past, during extraction of coal from coal mines, coalbed methane (CH_4), which has 25 times larger greenhouse effect than CO_2, had been released into the air to avoid a danger of large gas explosions. The development of CBM has the advantages from the viewpoints of both resources development and environmental protection. By injecting CO_2 and/or N_2 gas into a CBM reservoir, the more CH_4 can be recovered due to the decrease in the partial pressure of CH_4, which is called an enhanced CBM (ECBM). In the case of CO_2 injection, we can fix CO_2 underground and can increase CH_4 production at the same time. Thus, ECBM is drawing attention not only as energy resources but also as a method for carbon dioxide capture and storage (CCS). In the actual CBM development projects, reservoir simulation is practically used. Especially to simulate ECBM performances accurately, the simulator that can deal with the phase equilibrium for the multiple components including CH_4, CO_2 and N_2 and with the fluid flow specialized in coal reservoirs is required. Furthermore, we need to consider the changes in permeability and porosity caused by coal swelling/shrinkage.

In this study, we developed the double-permeability type compositional simulator (ECBM simulator), which deals with two phases of gas and water composed of four components of H_2O, CH_4, CO_2 and N_2. The phase behavior/equilibrium is calculated by solving the equation of state (EOS). Hence in this simulator, the phase behavior is determined in accordance with thermodynamic equilibrium. In addition, this simulator can predict the behavior of each component taking the Darcy flow, dispersion and adsorption/desorption into consideration.

After developing this ECBM simulator, we verified the simulator by comparing the simulation results with those obtained by GEM (commercial simulator of Computer Modelling Group Ltd.). Through the comparison, we confirmed that this simulator worked accurately. We then conducted case studies using ECBM simulator to evaluate the effects of the injection of CO_2 and/or N_2 gas on the CH_4 production. It was revealed that N_2 gas enhanced CH_4 production from the early stage of the injection by reducing the partial pressure of CH_4, while CO_2 gas increased CH_4 production slowly by replacing CH_4 adsorbed on the coalbed surface.

Paper H. Case Study: Uncertainty Analysis of Reservoir Parameters in Low-Resistivity Heavy-Oil Reservoir to Understand Reservoir Performance

Wu Yiming[1], Bei Gao[2], Chen Jichao[2], Huigeng Li[2], and Zhang Wei[2]
[1]CNOOC
[2]Schlumberger

With the fast pace of technology use, the South China Sea has been experiencing continuous exploration success, especially in shallow heavy-oil reservoirs with low resistivity contrast. The big uncertainty in this type of reservoir in the South China Sea is the well performance in the development stage due to formation laminations, various viscous fluid distribution, high water saturation and two-phase flow from the initial state of reservoir. To understand the key parameters that impact the later reservoir performance, comprehensive analysis is needed from different advanced reservoir measurements, such as NMR, dielectric measurement etc. to evaluate the uncertainty of the production potential so that the field development plan can be in place to address these technical challenges and minimize this large uncertainty on production during the development phase.

A case study from an appraisal well in offshore China is presented in this paper for the productivity uncertainty analysis in a shallow heavy-oil reservoir with low-resistivity-contrast formation. By analyzing the different reservoir measurements from various sources, an integrated approach is conveyed to tackle the challenges by integrating all available data in a numerical model, and the sensitivity study on water saturation, various viscous fluid, permeability, formation thickness and well skins was carried to understand the impact severity to reservoir production in the model. In this study, the dielectric logging tool is not of significant help to understand the water saturation profile in a low-resistivity-contrast formation, but also was useful to validate the formation thickness. Integration with NMR measurements, allow systematic identification of the bound water to help predict water production. Using the heavy-oil PVT data from different neighboring wells, the viscosity uncertainty was investigated. Last, but not the least, permeability sensitivity analysis was a key to be evaluated on how much the permeability impacts on well production potential. Based on the sensitivity result, the production prediction was provided with the certain level of uncertainty instead of one figure, and this paper provides a new way of thinking to demonstrate he reservoir management with uncertainty in the very early stage of the reservoir life cycle.

Paper I. Effects of Matrix Properties on Surfactant Enhanced Oil Recovery in Fractured Reservoirs

Xiaoqian Cheng[1], Jon Kleppe[1], and Ole Torsæter[1]
[1]Norwegian University of Science and Technology

The properties of rocks have effects on surfactant efficiency. One objective of this study is to analyze the effects of rock properties (permeability, porosity, initial water saturation) on surfactant spontaneous imbibition at the laboratory scale. The other objective is to evaluate existing upscaling methods, and establish a modified upscaling method.

A core is put in a container that is full of surfactant solution. We assume there is no space between the bottom of the core and the container. The core is modeled as a cuboid matrix 3.5 × 3.5 × 5 cm. The initial matrix, brine and oil properties are set as the properties of the Ekofisk Field.

The simulation results of matrix permeability show that the oil recovery rate has a strong positive linear relationship with matrix permeability. Higher oil recovery is obtained from the matrix with higher permeability. One existing upscaling method was verified by this model. The study on matrix porosity shows that the relationship between oil recovery rate and matrix porosity is a negative power function. However, the relationship between ultimate oil recovery and matrix porosity is a positive power function. The initial water saturation of matrix has negative linear relationships with ultimate oil recovery and enhanced oil recovery. However, the relationship between oil recovery and initial water saturation is more complicated with the imbibition time because of the transition of dominating force from capillary force to gravity force. Modified upscaling methods were established.

This work could be used as a reference for the surfactant application in fractured reservoirs. And the description of the relationships between properties of matrix and the oil recovery rate and ultimate oil recovery helps to improve upscaling methods.

Paper J. Development of Optimization Program for Estimation of Three-Phase Relative Permeability From Unsteady-State Coreflood Experiments by Genetic Algorithm and Iterative Latin Hypercube Sampling

Kenta Takahashi[1], Hideto Utsunomiya[2], Masanori Kurihara[1]
[1]Waseda University
[2]Hitachi, Ltd.

It is essential to estimate the three-phase (oil-water-gas) relative permeability accurately in the numerical simulation for the three-phase flow behavior in porous media. The most common approach currently used in modeling three-phase flow is to calculate the three-phase relative permeability from the set of two-phase (oil-water and oil-gas) relative permeability data measured in a laboratory using empirical correlations, such as Stone and Baker. However, these existing three-phase relative permeability models may lead to highly erroneous simulation results. On the other hand, it is unrealistic to obtain three-phase relative permeability data directly from three-phase coreflooding experiments in the steady-state condition, because they require a great deal of time and cost.

The objective of this research is to develop a new method to estimate three-phase relative permeability as functions of oil, water and gas saturation, through automatic history matching of unsteady-state coreflooding experiment results. In this study, the programs for estimating three-phase relative permeability were developed, applying the genetic algorithm (GA) and iterative Latin hypercube sampling (ILHS), which are nongradient optimization methods, as optimization tools. These programs enable the estimation of the oil-phase relative permeability in the three-phase condition, and that of the relative permeability to water and gas phases as functions of water and gas saturation, respectively, by automatically matching the calculation results with experimental results. The black-oil type simulator was modified so that it could read the oil relative permeability as a complicated function of oil, water and gas saturation, which was adopted as an engine of these optimization programs.

The hypothetical unsteady-state coreflooding experimental results (oil, water and gas production rates and inlet/outlet pressure) were prepared by numerical simulation instead of actually conducting experiments. Three-phase relative permeability was then tuned so as to strictly reproduce these hypothetical experiment data by numerical calculation. In all the trial cases with different conditions, three-phase relative permeability was successfully estimated using the above optimization programs. These programs are also expected to be extended to the estimation of the relative permeability in the steam-water system, gas-water-gas-hydrate system and microemulsion-oil-water system in which the rigorous measurements of relative permeability in the steady-state condition are difficult due to the complex phase equilibrium.

Paper K. Development of Program Coupling Flow Simulator With Geomechanics Simulator Using Adaptive Mesh Refinement Model and Analytical Solution for Simple One-dimensional Rock Deformation

Masaru Sawata[1], Shigeki Iwata[2], and Masanori Kurihara[1]
[1]Waseda University
[2]Japan Oil, Gas and Metals National Corporation

In general, conventional oil and gas reservoirs are not deformed significantly. However, some unconventional reservoirs, including those of methane hydrate and heavy oil/bitumen, are soft and deformable. Therefore, it is important to introduce the geomechanical effects, such as the changes in porosity/permeability associated with the deformation of a reservoir, for accurately predicting production performances for these unconventional reservoirs.

Recently, the reservoir fluid flow behavior has been simulated in conjunction with geomechanics simulation, using various coupling methods, such as fully implicit method, explicit method, iterative method, etc. All of these methods have both advantages and disadvantages. For example, the fully implicit method, which solves flow and geomechanical behavior simultaneously, is accurate, but requires considerable computer time. In addition, it is difficult to use existing flow simulators and geomechanics simulators in this method. Meanwhile, the explicit method does not require much computational time, but is not accurate since the geomechanical behavior is predicted without being reflected enough in flow simulation. The iterative method is accurate because geomechanical information and flow information is transferred to each other until the flow performances become consistent with geomechanical behavior. However, this method also requires considerable computer time. Therefore, we conducted this research seeking for a new method coupling fluid flow with geomechanics that enables the accurate prediction in a reasonably short computer time.

In this research, after developing the 3D, three-phase black-oil type simulator and the elastic type geomechanics simulator, the programs combining these two simulators by various methods were developed. To shorten the computational time, the geomechanics simulator developed in this research has the function of computing stress-strain field using the adaptive mesh refinement (AMR) model. In addition, the program that roughly calculates the formation deformation applying the analytical solution for simple one-dimensional deformation was coded. Furthermore, the flow simulator solving the one-dimensional deformation equation implicitly with flow equations was constructed. Case studies using these simulators/programs revealed that:

1. The solutions given by the explicit method were unreliable;
2. The application of the analytical solution of one-dimensional deformation was very fast, but might not be accurate in the complex 3-D case;
3. The iterative method could provide accurate solutions, but was slow; and
4. The best method was to couple the flow simulator with the geomechanics simulator equipped with AMR model, which could reduce the computational time to less than a half of the conventional iterative methods without reducing the accuracy of prediction.

Paper L. Evaluation of Horizontal Layers by Crosshole Borehole Radar

Tsogtbaatar Amarsaikhan[1] and Motoyuki Sato[1]
[1]Tohoku University

Crosshole ground penetrating radar (GPR) is being used for high-resolution characterization of subsurface structure. At Tohoku University we conducted fundamental research of borehole GPR, which includes parallel measurement and fixed transmitter measurement. Crosshole GPR is an efficient tool for characterization structure due to the sensitivity to water content in soil and rock. We concentrated the first-arrival time of the direct wave and refracted wave in both methods. The first-arrival time indicated velocity changes which depends on electromagnetic properties of a different soil layers. We figured out simulated travel times that indicate an arrival time in an ideal layer at each fixed transmitter measurement. Then, we tried to fit measurement data to the simulated travel time. In high-attenuation media, the signal-to-noise ratio was much lower than in low-attenuation media. The simulated travel time did not fit radar cross sections due to the variation of velocity. As separating point of simulated travel time and measurement data, we could define an interface between two layers. The slope of refracted signals depended on a velocity of refraction layer. We overlapped radar data and simulated travel time of the refracted signal. The fixed transmitter measurements illustrated the variation of velocity along a vertical and horizontal direction. The simulated signal provides velocity with high accuracy. As the result of parallel measurement, we could get signal at horizontal intervals. The amplitude of the first-arrival signals was quite different in some intervals. Then, we calculated dielectric permittivity and volumetric water content using empirical model at each particular layer.

Paper M. Bayesian Kriging for Reproducing Reservoir Heterogeneity in a Tidal Depositional Environment of a Sandstone Formation: A Case Study

Watheq Al-Mudhafar[1]
[1]Basra Oil Company, Iraq

Spatial permeability modeling is an important step in reservoir characterization as it directly affects heterogeneity and fluid flow modeling. Thus, it is crucial to look for an efficient algorithm that captures the most realistic spatial continuity. Many conventional kriging algorithms have been adopted for spatial petrophysical property modeling, such as simple, ordinary, and universal kriging. These algorithms are linear, unbiased estimators because covariance structure is first estimated, and then adopted for interpolation, leading to disregarding the impact of uncertainty in the covariance structure on subsequent predictions. To prevail over the restrictions of unbiased prediction in conventional approaches,

Bayesian kriging has been recently presented to take into account the uncertainty about variogram parameters on subsequent predictions. Bayesian Kriging incorporates knowledge about observations, such as expert grasp and outcome from neighboring data, to be considered as a prior distribution to improve the spatial estimation. Specifically, the prior distribution is classified in terms of the variogram parameters: coefficients, data variance, range, and nugget, to be incorporated as a qualified guess in the spatial estimation. The qualified guess allows a reduction in uncertainty estimation to preserve realistic spatial correlation and to improve reservoir characterization. Additionally, the uncertainty about model parameters in Bayesian kriging is represented in a form of posterior probability distribution to attain optimal unbiased linear interpolation, which then leads to avoid unrealistic small regions within the reservoir.

The efficiency of Bayesian kriging was justified through simulating the reservoir heterogeneity in terms of spatial permeability continuity in a tidal depositional environment of heterogeneous sandstone reservoir in South Rumaila oil field. The Bayesian kriging simulation was implemented in extensive comparison with other conventional geostatistical algorithms, such as simple, ordinary and universal kriging. A statistical sampling approach was considered to rank and select the three quantiles P10, P50, and P90 of the created equiprobable reservoir stochastic images simulated by Bayesian kriging. Consequently, the Bayesian kriging algorithm can be considered as an efficient geostatistical simulation approach for reproducing reservoir heterogeneity. The entire work was implemented through R, the powerful open-source statistical computing language, and R codes can be used as fast vehicles to conduct the geostatistical simulation in various formations.

Paper N. Comprehensive Production Evaluation for Gas Condensate at Early Exploration Stage by Using Downhole Fluid Analysis (DFA) and Numerical Simulation: Case Study From China Bohai Bay

ZhaoYa Fan[1], Ji Chao Chen[1] and Bei Gao[1]
[1]Schlumberger

Gas condensate has been discovered recently in Bohai Bay China, and due to the complexity of the fluid behavior in nature, appropriate characterization of the in-situ fluids and relevant flow testing can provide valuable insight into gas condensate reservoir forecasting. This paper discussed a comprehensive methodology for reliable productivity evaluation with the aid of in-situ fluid characterization and interval pressure testing, and the results of the methodology are key factors not only in DST design and equipment optimization for better production evaluation design, but also can be optimal production prediction for reserve booking. Based on the efficient and reliable productivity evaluation, operators can make the real-time decision on whether to carry on a DST and which DST equipment should be chosen and where to test it. However, the local operator has been dealing with heavy oil for very long time, and the DST equipment common in the Bohai Bay is for heavy oil not condensate reservoirs, plus there were no published case studies in China about DST modification from heavy oil to gas condensate, and what can be done for production forecasting in gas condensate reservoir. In this paper, a new solution is proposed based on the problem elaborated above.

To overcome challenges, an integrated approach was conducted by using all available data from wireline formation tester (WFT) and conventional log data. An accurate permeability is always the foundation of a good prediction, a single-well model was built by taking full advantage of all permeability information. A compositional model is the best way to simulate the condensate phase change. In this paper, a calibrated composition was deduced by combining with semiquantitative DFA composition and PVTi (PVT analysis software) via calibrating downhole measured GOR and density. The black-oil model is the most common and popular method used to evaluate single-well productivity, however, the uncertainty of condensate viscosity usually leads to large errors. Based on the results of the calibrated composition the downhole fluid viscosity was evaluated. Correct evaluation of the downhole fluid viscosity enables the black-oil model to be applied in condensate productivity evaluation.

Four DST results were used to validate the results using this approach, the error percentage range is 10 to 20% compare with DST results. This new solution has the following benefit: An accurate gas condensate production forecast becomes possible even without PVT laboratory results. A quick gas condensate production workflow has been set up for this field; and the methodology applied is not limited to this specific field but applicable to other fields with condensate fluid type.

Paper O. A Comprehensive Workflow Using Nuclear Magnetic Resonance (NMR) Data to Evaluate and Characterize Low-Resistivity Low-Contrast Reservoirs

Tianmin Jiang[1], Michiko Hamada[1], Yuki Maehara[1], Samira Ahmad[1], Aldrick Garcia Mayans[1], Niranjan Aryal[1], and Hanatu Kadir[1]
[1]Schlumberger

A novel integrated workflow to evaluate laminated low-resistivity low-contrast (LRLC) clastic formations in offshore deepwater wells using nuclear magnetic resonance (NMR) data is developed and presented in this paper. Traditional interpretation methods, such as laminated sand analysis (LSA) require a high resistivity contrast between sand and shale laminations to be able to estimate resistivity and volume fraction corresponding to sand, which is then used to compute total hydrocarbon in place. In the LRLC environment, the method fails because of insufficient resistivity contrast. Moreover, the traditional methods lack the ability to output other important quantities of interest, such as sand facies, hydrocarbon properties, and reservoir quality indicators.

The proposed workflow uses NMR data and incorporates modern techniques of factor analysis and fluid substitution to fully evaluate and characterize LRLC formations by (1) accurately quantifying the sand fraction, porosity, permeability and water saturation using a modified laminated sand analysis with NMR factor analysis, (2) analyzing poro-fluid facies from NMR factor analysis to separate shale, block pay sand, laminated pay sand and wet sand intervals, (3) estimating hydrocarbon properties, grain-size distribution and corresponding reservoir quality using fluid substitution, which removes hydrocarbon contamination from the NMR signal to simulate a 100% water-filled formation.

In this paper, we present examples of the successful application of the proposed workflow in the LRLC environment to determine hydrocarbon in place, hydrocarbon properties and reservoir quality, in addition to a more accurate sand fraction and corresponding resistivity and water saturation. Furthermore, we demonstrate how the new workflow can help reveal additional pay in such reservoirs which was missed using traditional workflows, such as laminated sand analysis.

Paper P. Automated Seismic First-Break Picking Using Image-to-Image Translation With Full Convolution Neural Networks

Mitsuyuki Ozawa[1], Shinji Kawasaki[2], Motonori Higashinaka[2], Hiroshi Sato[3], and Susumu Abe[1]

[1]Japan Petroleum Exploration Co., Ltd
[2]JGI,Inc
[3]The University of Tokyo

First-break picking, the process of determining the onsets of the first seismic signal arrivals at receivers, is essential in seismic data-processing flow, because the picked arrival time is a necessary input to the estimation of seismic velocity and the static correction.

The authors developed a new method of automatic first-break picking, which is based on image-to-image translation with fully convolutional neural network (CNN). The application of our method to a land seismic data volume achieved 90% agreement with manual picking, demonstrating its robust performance.

CNN is a well-known deep-learning architecture, which has achieved a high performance in a wide variety of tasks in computer vision. The CNN learns the sensitive attribute and/or feature of first break from manual picking results prepared as supervised data (“first-break image”). The first-break image is organized by the pixels, its value is 1 when the pixel position corresponds to first break position, and 0 otherwise. Our CNN model learns the mapping from seismic amplitude image to first-break image.

CNN takes advantage of spatial coherence in the input over the conventional neural networks. Therefore, while conventional picking methods seldom preserve global information of shot gathers, this image-to-image translation strategy enables users to recognize visual patterns of the first arrivals using global information, similar to human picking.

Paper Q. Marine Airgun Sources: Sound Levels and Minimizing Their Environmental Impact

John Tulett[1]
[1]Schlumberger

Marine seismic exploration uses airgun sources for emitting sound energy into the earth. With seismic waves from the airgun source, geologic structures are mapped by recording with receivers the arrival time and shape of the waves reflected from acoustic-impedance contrasts in the rock strata.

Typically, several airguns are configured together to form an array to boost the emitted signal amplitude and improve the spectral content of the source signature. With seismic exploration searching for deeper targets, higher-energy sounds from seismic airgun arrays have contributed to more noise in the ocean.

In this paper we first review the important conceptual difference between the source level, which the airgun array emits, and the received level, which the marine mammal experiences. Different airgun source levels are explained and the scientific terms dB, peak pressure (PP) and sound exposure level (SEL), ae discussed together with some common misunderstandings of the acoustics and relationships of the sound levels.

This paper then discusses the benefits of using a new airgun design for marine seismic exploration that preserves the crucial low frequencies required for imaging, while minimizing the unwanted high frequencies that are not useful for seismic imaging. We explain how the new airgun design suppresses the unwanted high frequencies that can affect marine mammal’s hearing, with examples showing the new airgun source producing a significantly lower sound exposure level (SEL) compared to standard airgun sources.

Finally, we show a geophysical case study comparing a standard airgun source with the new airgun source, demonstrating the quality of the final seismic image was unaffected using the new airgun source.

Paper R. Fracture Extension Behavior Dominated by Geologic Features of Preexisting Natural Fractures and Stress Barriers—An Interpretation of Microseismicity at the North Montney Unconventional Shale Gas Field, British Colombia

Yuto Sasaya[1] and Yusuke Kumano[1], and Isao Kurosawa[2]

[1]Japan Petroleum Exploration Co.,ltd. (JAPEX)
[2]Japan Oil, Gas and Metals National Corporation (JOGMEC)

Fracture extension behavior during a hydraulic fracturing job in the Montney shale gas formation was clearly revealed by reprocessed microseismic monitoring data.

Microseismic monitoring was conducted by using the receiver array deployed on the surface around the target well pad. In our reprocessing, the static and anisotropy corrections in the velocity model were carefully refined by successive workflow based on the stack amplitude of moveout-applied waveforms of selected microseismic events with high signal-to-noise ratio. Source mechanism estimation process is involved in the successive velocity model refinement workflow as well as in the event detection and location process. The estimated source mechanisms were referred to compensate the polarity variation of the microseismic waveform associated with the source mechanism and relative position of receivers to the hypocenter. This polarity compensation was the key to drastically increase the resolution of migration image and consequently to achieve more accurate velocity model calibration, higher event detection, and more reliable hypocenter location and source mechanism estimation.

The improved spatiotemporal distribution of microseismic hypocenters and source mechanism solutions were compared with some other field data, such as logging data and seismic attributes. The findings and interpretation through the observations are listed below.

1. The vertical extension of microseismic distribution was clearly blocked at layers with higher Young's modulus and Poisson's ratio relative to the surrounding layers. The authors consider this microseismicity is reasonable from the viewpoint of geomechanics, because, the higher Poisson's ratio and Young's modulus could be associated with the higher closure stress in the formation.
2. Microseismic events with strike slip focal mechanisms tend to occur in the vicinity of minor subvertical faults with the strike along the ENE-WSW indicated by the seismic attribute of Ant-Track. The orientation of the minor faults is favorable orientation for shear slip in the local stress regime.
3. Strike-slip events rarely observed in some fracturing stages in which more viscose fracturing fluid was used, suggesting the lower viscosity of fracturing fluid is more favorable to effectively stimulate preexisting natural fractures.

Paper S. Unraveling Complex Resistivity Responses, A Comparison of Low-Frequency LWD Laterolog to High-Frequency Propagation and Wireline Dielectric

Shim Yen Han[1], Wang Xian Nan[2], Xiao Dong[2], David Maggs[1], Carlos Maeso[1], Fabienne Legendre[1], Richard Leech[1], Olivier Moyal[1]
[1]Schlumberger
[2]CNOOC

During field testing of a logging-while-drilling (LWD) laterolog resistivity and imaging tool, formation resistivity differences were observed between the new laterolog and standard propagation resistivity. This paper compares the measurement acquired in the same borehole using different tools in both sand and shale formations.

The laterolog resistivities were higher in the shales and lower in the sands than the propagation resistivity values. The data were acquired while drilling in two water-based mud, subvertical exploration wells in the South China Sea. While the main objective of the data acquisition in the siliciclastic formations was high-definition resistivity borehole images, the radial laterolog resistivity response was also of interest. An advanced wireline multifrequency dielectric measurement was also acquired in one of the wells and its response was used for comparison and validation.

In this paper, we associate the differences in resistivity response for varying formation properties to the tool physics, vertical resolution, depth of investigation, and time after bit between the measurements. In the sands, a resistivity inversion was applied to correct the logs for invasion effects and forward modeling used to resolve the resolution differences. The resistivity of the invaded zone obtained from the shallow laterolog measurements and inversion compares well with the dielectric measurements acquired at wireline time. The inverted formation resistivity from the LWD laterolog matches the deeper reading LWD propagation resistivity. The shale response was initially found to be more difficult to explain. It is commonly and historically accepted that due to resistivity anisotropy the laterolog reads higher than propagation resistivity in low-angle wells with laminated formations. Advanced forward modeling was used to investigate the laminations observed on the high-definition images and high-resolution laterolog resistivity curves. Although a model could be created to match both sets of resistivity measurements, the level of anisotropy required was considerably higher than expected, and supplementary information was required to validate the model. The wireline multifrequency dielectric measurements provided the additional information required to confirm the anisotropy contrast observed by the resistivity modeling and confirm the LWD tool responses.

This paper presents the workflows required to examine and compare the tool responses, and to determine the correct sand and shale resistivity. It shows how by combining different measurements, additional insight can be obtained into the nature of the formation and its properties.

Paper T. "Gas Effect" Revisited

Yuhei Aihara[1] and Hideo Komatsu[1]
[1]INPEX Corporation

Conventional log interpretation methods implicitly assume a certain model for the reservoir. For instance, lithology should be (shaly) sandstone, limestone, or dolomite, and pore-filled fluid should be water, oil, or HC gas. Almost all logging tools can be regarded to sense either (1) density, (2) the amount of hydrogen nucleus, or (3) electrical conductivity.

When a formation is gas bearing, the presence of gas has an impact on tool response ("Gas effect"), for example gas reduces bulk density, resulting in a high apparent density porosity. It is common that a gas correction is applied before or during the petrophysical formation evaluation, due to the significant differences of density and amount of hydrogen. There are several methods to correct the gas effect, which were proposed a half-century ago (e.g., Gaymard and Poupon, and Segesman and Liu). These methods have been widely adopted in the petrophysical community.

However, there was case of the gas-bearing formation where it was not possible to reconcile porosities derived from different tools (e.g., density, neutron, and nuclear magnetic resonance), even though the gas effect was corrected with these methods using appropriate parameters. To examine which porosity was correct, we employed several methods and combination of tools (density-nuclear magnetic resonance, dielectric tool, and so on), and performed forward-modeling studies, such as a well log simulator and an invasion-profile simulator.

In this paper, we share our insights on the accuracy and limitations of the existing gas-correction methods as a result of our revisit of the "Gas effect".

SPWLA Young Professionals Newsletter

the bridge

November 2018

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SPWLAYP@SPWLA.ORG

My Journey: From Physics to Electrical Engineering to Physiology to Petrophysics

Lalitha Venkataramanan

I come from a small town in the South of India. It was a rather unique town. Almost everyone was a scientist or an engineer! This small town housed India's third nuclear power plant and the town's people all worked in the plant. Needless to say, all the kids in our school knew about nuclear power in elementary school. On reflection, all the dads worked in the power plant or the neighboring research center. I don't recall any women scientists in our town.

It was hard to grow up in this town. There were high expectations from parents, teachers and peers. Regardless, I grew up with a love for sports (swimming, volleyball, girl scouts, and badminton), fictional books and school, in that order. At school, I liked and enjoyed many subjects but excelled at few. Due to my love for reading, I could see myself growing up to be a writer or a journalist. Since I did not see women scientists around me, I certainly did not envision myself as a scientist.

I enjoyed physics and mathematics at school and earned my bachelor's degree in physics from a small college in the neighboring city. I did well and continued to do a Master's in electrical engineering and was then admitted into the PhD program in electrical engineering at Yale University. By the end of my first year, I was not challenged in my classes and had decided to go into the real world and get a job. I found a computer science internship at the Mayo Clinic in Rochester. While developing a graphical user interface for this group, I became fascinated by the laboratory techniques used by the graduate students to study proteins in the cell membrane called ion channels. I learnt more about this technique and came up with ideas on how I could perhaps help in analyzing the data from the proteins. Although I had taken this summer job with the intention of leaving school, I returned to school, this time with a clear passion on what I wanted to do for my PhD.

I did my thesis work with two professors—one in the Department of Electrical Engineering and another in the Department of Cellular and Molecular Physiology at the school of Medicine. I studied day and night for many years. I mostly worked by myself in the Department of Electrical Engineering but would go over to the Medical School to discuss my work with my advisor and other graduate students in his laboratory every 3 to 4 days. It was an amazing experience—I learned a lot about a subject I knew little about. I learned to read papers and frame questions. I learned how what it was to do good research. I grew as a scientist. I learned to make good presentations and learned that writing a paper was like telling a story. I could have continued as a postdoc in the same laboratory and continued to do excellent science. However, during a career fair, Schlumberger came on campus and interviewed me and offered me a job in their Electromagnetics Department. I was hesitant to take this job since my knowledge of electromagnetics was limited to my courses in my bachelor's degree; but I figured it could be interesting and I would learn quickly on the job.

I joined Schlumberger a year after I was given an offer letter. In the meantime, Schlumberger-Doll Research Center had been reorganized, and the Electromagnetics Department did not exist anymore. On my first day at work, I was told to go to the NMR group. I innocently asked, 'what is NMR?' When I went to the NMR group, I was told that I had been loaned to the petrophysics group. Since I did not know anything about NMR or petrophysics, I figured it didn't matter what group I belonged to. I was going to learn something interesting in a new field and that was exciting enough.

I soon learned the basics of petrophysics and NMR and started to work with scientists and going to internal meetings. At one of the meetings, two of my colleagues excitedly discussed their new NMR pulse sequences and their issues with the two-dimensional inversion, which they performed as multiple one-dimensional inversions. They were hoping to use these pulse sequences to study diffusion-relaxation maps and T_1-T_2 maps. I spent a few months studying and analyzing the data and developed a method to do two-dimensional inversion. I soon moved onto many other fields including permanent monitoring of wellbores, fluid analysis with optical data and then learnt more about petrophysics. The start of each scientific discipline is an adventure. It begins with a lot of reading and asking questions. I am fortunate that I am surrounded by many good scientists and can always go to someone to get my questions clarified. I have had one excellent female mentor. She has retired now, but not before, she taught me the power of mentoring. I have attempted to follow in her footsteps and mentor many female interns and younger scientists today.

I have now been with Schlumberger-Doll Research for over 20 years. I enjoy going into work every day. I literally leap out of bed to go into work and I love interacting with my colleagues, the freedom to choose my research problems and my work. Good universities such as MIT, Harvard, Boston University, Northeastern and WPI are within walking/driving distance on my lab and I love going to lectures or classes being hosted by these universities. Many graduate students from these and neighboring universities have come to do their research with me and have gone back to finish their PhDs and move onto a job in the industry.

I continue to be actively involved with Universities and visit often to make presentations of my work. During the discussion session, I am sometimes asked by students to discuss the merits of an academic versus an industry career. Very often, students are surprised to hear that I publish a lot of papers and have multiple patents and my work sometimes leads to a commercial product. I share my rich and varied experiences with them and encourage them to apply their skill sets to the industry.

The smart, vibrant, multicultural, multinational, diverse group of colleagues make my every workday interesting. I am grateful for this opportunity and I look forward to my next adventure in learning something new!

Lalitha Venkataramanan is a Scientific Advisor in the Applied Math and Data Analytics Department at Schlumberger Doll Research, Boston. She manages a program on Automated Log Interpretation. Her interests include petrophysics, machine learning, mathematical modeling and inversion, optimization, probability and stochastic processes. Trained as an Electrical Engineer, she obtained her MSc and PhD degrees from Yale University in 1998. She has published over 25 research papers, and holds more than 14 US patents. She is currently an active member of SPWLA, SPE and a board member of Society of Industrial and Applied Math (SIAM) industry Committee.

Interviews With the Recipients of the 2018 SPWLA Distinguished Technical Achievement Award

The SPWLA Distinguished Technical Achievement Award (DTAA) is presented in recognition of exceptional contributions in one or more specific areas of formation evaluation technology. In 2018, three individuals were selected to receive this award. Dr. Daniel T. Georgi, Dr. Chandra S. Rai, and Mr. John Rasmus.

The Bridge Newsletter team feels that the SPWLA Young Professional (YP) community can learn a lot from the experiences of the three award recipients and will be inspired to create new technologies and techniques that will impact formation evaluation and petrophysics in the future.

The Bridge Newsletter team prepared a questionnaire for an interview with the SPWLA DTAA recipients. A part of the questionnaire focused on the motivations and accomplishments of the awardees and the rest covered their suggestions and recommendations on topics and issues relevant to the SPWLA YP community.

Dr. Daniel T. Georgi
Google Scholar: https://scholar.google.com/citations?hl=en&user=bO3vRbUAAAAJ
LinkedIn: https://www.linkedin.com/in/daniel-georgi-3463b01b/

When did you first learn about petrophysics and formation evaluation as important disciplines for a technical career in oil and gas industry?

Working at Exxon Production Research Company, now Exxon Mobil Upstream Research, I had the opportunity to meet top geophysicist and geologist and petrophysicists, including Howard Yorston, Will Hoyer, Don Luffel, Bill Grives, Richard Glanville, and others. What impressed me was the way they brought together results based on very different measurement physics to answer critical questions. A few years later, working at Esso Resources Canada, now Imperial Oil Limited, I saw the need to answer difficult questions (e.g., is the oil secondary or tertiary? What is the oil saturation during cyclic steam injection, before, during and after production? …) that had large financial implications for capital-intensive projects.

Who all had the strongest influence in your career as mentors, guides, and inspirational figures?

Many names come to mind, but my early supervisors and several senior scientists at Exxon Production Research Co., foremost, Howard Yorston (geophysics), Will Hoyer, and Don Luffel (petrophysicists). Another person who influenced me was Joe Zemanek,who worked for Mobil, that I met at an SPWLA annual symposium. During the last 20 years, my good friends and coworkers but especially Professor Jürgen Schön and Lev Tabarovski guided and helped me.

What are the most important concepts (technical, management, professional, or personal) that have helped you throughout your career?

Two things come to mind:

Practice the Scientific Method especially when trying to fix a new tool or design. If you think you know the solution to a problem try to devise a test to make sure that you really have solved the problem and not coincidentally changed something that makes it appear you fixed the problem. N.B., it is often difficult to isolate things well enough to really determine the problem.

Treat all your coworkers with respect; you will feel better and together you can solve more problems.

What is the best piece of advice you have ever received?

When things don't work out the way you would like, put your head down, "nose to the grindstone," and focus on your work.

Share with us few petrophysics and formation evaluation projects that you were involved with early in your career.

I had the good fortune early in my career to be involved in an internal ultrasonic borehole imager project for fractured reservoirs evaluation, especially in the Austin Chalk. I worked to understand the measurement and gained familiarity with fractured reservoirs from a geological and petrophysical point-of-view. This led to interactions with many operations geologist and reservoir engineers who freely shared their vast knowledge with me.

Another project I had the good fortune to be involved in was a detailed evaluation of the Cessford shallow gas fields in Saskatchewan. This gave me insight into evaluation of very-tight shale reservoirs with both core and log data. Equally important for me was my realization that core did not just provide calibration points and log interpretation parameters, but that it could provide data that were not available from log data.

What are some of your technical contributions and achievements that you are most proud of?

- Application of time series analysis to quantify log data signal and noise, vertical resolution and log repeatability. (Kerford and Georgi, 1990; Georgi, et al., 1991; Georgi, 1991; Georgi et al., 1995)
- The miscible pilot flood monitoring done in the Leduc Age carbonates (Redwater and Judy Creek) in Alberta. (Pritchard and Georgi et al., 1990; Georgi et al., 1991)
- My involvement in the development of the Pulse-Decay Profile Permeameter at Core Laboratories. (Georgi and Jones, 1992)
- My involvement in the development of the Multi-Capacitance Flow Meter for logging horizontal wells for Western Atlas logging Services. (Chase et al, 1998; Wang et al, 1999; Georgi et al., 2000)
- My involvement in the integration of MRIL into a fully combinable logging tool at Western Atlas. Georgi et al 1995; Georgi, 1997)
- My involvement in the development of Formation Rate Analysis for interpreting Formation Test data. (Kasap and Georgi et al., 1996)
- This theory later enabled the downhole unsupervised, real-time optimization of LWD formation testing. (Meister et al, 2003; Lee et al., 2005).
- My involvement in the development of the wireline Magnetic Resonance Explorer Tool
- Work on unconventionals at the Aramco Services Houston Technology Center

What are few significant transformations that the industry has experienced since you started your career?

Managerially/organizationally teamwork and asset teams became the norm for dealing with complex development projects and for seeking technical solutions.

Probably the most significant technical formation evaluation change that occurred since I entered the industry was the introduction and acceptance in the industry of borehole imaging technology. This was enabled by the addition of arrays of button electrodes that transformed dipmeter tools to electrical borehole imaging tools. In retrospect, it should not have surprised us that geologists preferred the borehole images to the 4- and 6-arm dipmeters' tadpole plots, after all "seeing is believing."

Before starting graduate school, I did a three-month internship in Switzerland working on rare-earth based synthetic magnets. That proved to be the first of what turned out to be a career long involvement with magnets and NMR. During my first days in the industry, just after I joined Exxon Production Research Co., I was attending a meeting in Houston where a well-known service company was asking what it would take to save the Nuclear Magnetic Log (NML). Shortly thereafter, I participated in a test with the tool to see whether we could locate a heavy-oil contact in an offshore reservoir. Then in Canada, I used the tool to distinguish between heavy oil and movable fresh water. After joining Western Atlas, I led a capable and dedicated team to integrate the Numar technology into the standard logging suite. Today all service companies have NMR tools and NMR provides many unique answers, yet I believe much more can still be extracted from the downhole NMR measurements.

Finally, I believe the 3D induction tools represent a major step forward in the measurement of resistivity; arguably as large a step forward as the 6FF40 tool of the 1960s.

How do you see the disciplines of petrophysics and formation evaluation evolving in the next 5 to 10 years?

Unconventional source-rock reservoirs present a critical challenge that requires significant re-education. It is my impression that traditional logging has not contributed much and, hence, many operators forgo traditional logging. I think that cuttings are a probable source of "answers;" however, one will need to rethink generating and collecting cuttings. Further, to really understand unconventionals, it is critical to find reliable means to determine source type and maturity. High-field NMR has promise in the laboratory (Clough et al., 2015) allowing us to quantify the hydrogen content, hydrogen-carbon ratio and determine the degree of double bonding, which might be a means of determining critical source-rock parameters. Petrophysicists must take a strong interest in petroleum geochemistry; in addition to sourcing the hydrocarbons they also affect the rock properties, including the traditional properties of interest to petrophysicists (i.e., density, resistivity, porosity, permeability) and also rock strength and seismic velocities.

I fear that big data and data analytics will take us a step backwards, especially when applied to a limited number of wells (e.g. "small" data). The technology likely will provide some answers, but likely it will also minimize the physics in petrophysics. It reminds me of past efforts to predict other logs from a limited suite of measurements. The approach appears useful for predicting other logs in shales and water zones but not at predicting "anomalous" responses; hence, we likely will miss hydrocarbon zones. I do see large potential for big data and data analytics for the interpretation of initial production and long-term production from wells in unconventional reservoirs based on detailed production along the wellbore derived from DTS and DAS data. Unfortunately, there is a significant cost associated with installation of the DTS/DAS and the technical challenge that the fiber-optic sensor package needs to survive the frac operation.

A photo of me enjoying the scenery on Elephant Island, Antarctica. We were very close to the beach that Shackleton wintered-over after his ship was crushed by the sea ice. I was doing my graduate research on mixing in the Antarctic water masses with oceanographic sondes that were lowered on a single-conductor cable, essentially logging the oceans to depths of 5,000+ meters. We measured temperature, salinity (based on conductivity), and dissolved oxygen. The independent variable was pressure.

What advice can you give to those starting their careers in the oil industry, especially to those in the formation evaluation and petrophysics area?

I'm sure there is no single approach appropriate for all. However, I found being an "expert" in one thing opened the door to projects where I was able to learn from other team members all the while earning my keep. It is critical for the petrophysicists to be versed in the technical language of the geologists, reservoir engineer and the production engineers. Early in one's career one needs to learn a lot about many different subjects. Ideally the petrophysicists integrates inputs from all disciplines to solve the formation evaluation problems.

For researchers there has always been a struggle between delivering "useful" results in the short term that operations can use immediately, and long-term research. Some companies use their "research" personnel to do mostly short-term on-demand service work and leave the long-term research to time left over. Others isolate their researchers from operations to focus exclusively on breakthrough research. I have worked in both environments, but honestly believe that there is a lot of truth in the saying that if you want a lot of research isolate your scientists in an ivory tower and you will get lots of useless research; if you want practical results put your researchers in operations and you will get lots of results; unfortunately there won't be much research. Still given the choice, I would rather pursue research in operations than in an isolated corporate research laboratory.

What advice do you have for those affected by the downturn, especially when just starting in the business?

I am thankful that I did not have to face such a challenge during my career. If one is lucky enough to have a job, I believe one should focus on doing a good job and being sensitive to the financial constraints imposed by market conditions. If getting a permanent position is difficult even a second or third internship should result in additional experience and, hopefully, will make the young professional more marketable.

More education may be another option perhaps in Reservoir Engineering, Production Engineering or Geology as these are the technical disciplines that Petrophysicists so often have to interface with. Another possible degree option would be an MBA to enhance one's understanding of the financial side of our business.

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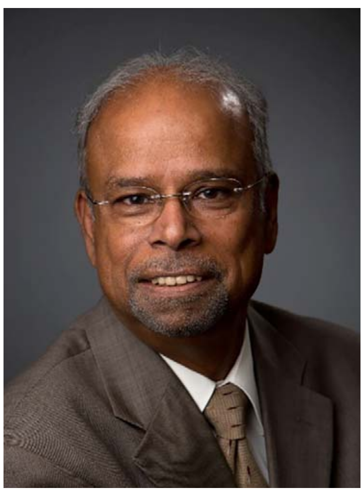


Dr. Chandra S. Rai, Director, Mewbourne School of Petroleum and Geological Engineering, University of Oklahoma
OU Profile: http://www.ou.edu/mcee/mpge/people/rai

When did you first learn about petrophysics and formation evaluation as important disciplines for a technical career in oil and gas industry?

My introduction to petrophysics came after joining Amoco Production Company Research Center in Tulsa. During that time, Amoco started a one-year training program called Petrophysics School. Employees from different assets (engineers, geologist and geophysics) were assigned for one year to work on technical problems relevant to their asset. The participants were given a wide range of courses from all disciplines while they were doing the project work. They also had numerous research scientists and engineers who were full-time employees at the Research Center with whome they could have discussions, consultations, and collaborations. This led to development of best petrophysicists in the industry.

Who had the strongest influence in your career as mentors, guides, and inspirational figures?

It is hard to name one as there are many. On the top are the numerous graduate students with whom I had the good luck to work with. They always inspire you to think and see things in a different light. I had been lucky to have many tremendous colleagues, in particular Carl Sondergeld, with whom many discussions have led to new ideas.

Share with us the toughest technical challenge you have faced in your career.

During my doctoral work, I undertook the task of measuring seismic velocity and attenuation of molten rock. In principle, it was straightforward but making the apparatus from the ground up was a horrendous task. It took me more than a year to come up with a design and fabricate the apparatus.

What are the most important concepts (technical, management, professional, or personal) that have helped you throughout your career?

Listen to others; everyone has good ideas.

What is the best piece of advice you have ever received?

From my dad, who always used to say, “work hard and do your best in everything you do, no matter how small the task may be.”

How and where do your best ideas come from?

Technical papers and in discussions with others.

What are some of the technical contributions and achievements that you are most proud of?

What comes to mind are developing quantitative FTIR for mineral identification, developing a mobile core characterization lab, and unlocking the petrophysical properties of organic mudstones.

What are a few significant transformations that the industry has experienced since you started your career?

The most important change was going digital, which put massive amount of data available at our fingertips.

What are some of the issues facing the petrophysics and formation evaluation community?

Petrophysics is continuously evolving. I remember that at one time SPWLA was mainly focused on traditional log analysis, then it got into bright spot and amplitude variation with offset (seismic modeling). Now I see more and more core-based log interpretation. Challenge, as I see it, is integrating various datasets based on physics to minimize uncertainty in our interpretations.

How do you see the disciplines of petrophysics and formation evaluation evolving in the next 5 to 10 years?

We have moved from producing from 'simple' reservoirs to very complex reservoirs; just knowing how to obtain porosity and water saturation is not enough. We have to know and understand interrelationships between mechanical properties, mineralogy, geochemical properties, microstructure, hydrocarbon phase behavior etc. to fully exploit the reservoirs. It is unacceptable that the recovery from such complex reservoirs is currently no more than 10%, at best. Improving this is going to be a big challenge for the next decade.

What advice can you give to those starting their careers in the oil industry, especially to those in the formation evaluation and petrophysics area?

Petrophysics /formation evaluation is a multidisciplinary science that requires critical thinking. It is not simply applying equations to solve problems, learn how to be a 'detective' and develop the capability to put one and one together to make something much larger than two. Be creative and open-minded.

What advice you have for those affected by the downturn, especially when just starting in the business?

Keep on building your skills. Be proactive to learn new things as technology is evolving very rapidly.

John C. Rasmus

LinkedIn: https://www.linkedin.com/in/john-rasmus-a3a7a730/
Research Gate: https://www.researchgate.net/profile/John_Rasmus

When did you first learn about petrophysics and formation evaluation as important disciplines for a technical career in oil and gas industry?

It was when I was at the Schlumberger training center for new field engineers. I was fascinated with the log interpretation exercises.

Who had the strongest influence in your career as mentors, guides, and inspirational figures?

Fellow petrophysicists and managers, both good and bad.

Share with us a few of the petrophysics and formation evaluation projects that you were involved with early in your career.

The first issue I dealt with was evaluating limestone formations having large amounts of secondary porosity in the Big Horn Basin in Wyoming. We applied moveable oil overlay plots to determine zones with moveable hydrocarbons. After that, we started applying sonic measurements to identify the zones with secondary porosity that were creating overly optimistic saturations.

What are few significant transformations that the industry has experienced since you started your career?

I started in 1975, when the data acquisition was by analog electronics and the interpretation was done by hand for each zone using basic Archie calculations, log-based overlays, such as the F-overlay, moveable oil plots and crossplots, like the Pickett plot. The computerization of the data acquisition and interpretation process allowed us to write programs for more sophisticated interpretation techniques and faster analysis, both of which are significant advances.

What are the most important concepts (technical, management, professional, or personal) that have helped you throughout your career?

Be persistent but know when you've hit a dead end and need to try another technique to solve a problem. Being persistent is first on the list; sometimes you will miss the second goal and work too long on something that's not working, but that's ok, better than the opposite.

What is the best piece of advice you have ever received?

Proverbs 3:5–8
Trust in the Lord with all your heart and lean not on your own understanding;
in all your ways submit to him, and he will make your paths straight.
Do not be wise in your own eyes; fear the Lord and shun evil.
This will bring health to your body and nourishment to your bones.

How and where do your best ideas come from?

Contemplation while taking a long, hot shower.

What are some of your technical contributions and achievements that you are most proud of?

Pride is a bad disease overall and it hinders you from learning from others.

What are some of the issues facing petrophysics and formation evaluation community?

Keeping petrophysics focused on the rocks and new interpretation techniques as new measurements become available as opposed to machine learning techniques using only the basic measurements.

How do you see the disciplines of petrophysics and formation evaluation evolving in the next 5 to 10 years?

There will be a trend to use more automated techniques with less technically skilled people. This will succeed for a "big picture" analysis, and easy to interpret rocks, but fail for formations with more complex pore geometries and in exploration frontiers.

What advice can you give to those starting their careers in the oil industry, especially to those in the formation evaluation and petrophysics area?

Learn to be a generalist in all areas of petroleum engineering and a tower of excellence in one or two areas of petrophysics that interest you and have an aptitude for. To help do this, become a member and be involved with several professional societies and read to comprehend some of their technical papers that interest you.

Strive to understand and learn the measurement physics for each particular type of logging tool.

Learn to recognize a good log from a bad log. Knowing the measurement physics will help tremendously —as well as experience. I think more progress needs to be made in the logging tools themselves with respect to self-healing tools, i.e., tools that tell you when a sensor fails and gives you a recommendation in real time. For example, if one of two antennas on a resistivity tool fail, use the remaining good transmitter and send uphole uncompensated measurements and their associated error bars. The petrophysicist can then decide if he needs to pull out of the hole to replace the tool or keep drilling based on risk factors.

Don't criticize other people's work just to make yours look better.

What advice you have for those affected by the downturn, especially when just starting in the business?

While you are employed, be familiar with the different areas of expertise within your own company and understand it's personality. Be friendly and genuinely concerned about your fellow workers. Don't turn discussions into heated arguments, stay calm and professional.

If you've been laid off, keep your chin up, don't take it personal especially in this downturn. Take it as a chance to find a job you like better than the last one.

What would you do differently if you started your career today?

I spent 43 years with Schlumberger working on various projects, which I liked or learned to like so I wouldn't do anything different. Regarding other things, I would have taken time to rodeo a bit. I had a chance in Cody, Wyoming, but didn't do it. Learned a lesson from that.

SPWLA Networking Happy Hour – October 2018

SPWLA members have continued hosting well-attended events this year. Our most recent social activity in the Greater Houston area was not the exception, with fellow petrophysics enthusiasts joining current and former society global and regional leadership. Faculty and student members from the University of Houston also participated in this activity. Around 20 SPWLA members from the Houston area gathered in a convenient place to network and had a great time in a relaxed atmosphere. New and familiar faces in attendance included 2018–2019 SPWLA President-Elect Dr. Jesus Salazar, SPWLA YP Chairman Javier Miranda, SPWLA Houston Chapter VP Emmanuel Oyewole and SPWLA UH Student Chapter president Naveen Krishnaraj.

Some of the participants in SPWLA's Happy Hour at Houston's Fuego Saloon, October 2018

Proud SPWLA members and petrophysics enthusiasts having a great time in a relaxed atmosphere.

Excellent food and drink, and good conversation can ease your tension after a long day. An excellent sports bar in Houston, Texas, was the venue for this event. Professionals from operating (major and independent), service, and consulting companies, in addition to academia, were delighted with drinks and food onboard in a beautiful evening with nice weather. The majority of the participants have attended in the past and continue to participate in these social events with increasing frequency. There are opportunities to sponsor these events, please let us know if you are interested.

SPWLA members enjoyed a great evening in a baseball post-season atmosphere with the local Houston Astros team playing on the big screens.

SPWLA's recent social events have all been well attended and have included current and former SPWLA global and regional leaders and student members.

Don't miss our next event!

Join us for our next event to end on a high note this year. We have partnered with the SPWLA Houston Chapter to organize our upcoming social event. Our last SPWLA Networking Happy Hour in 2018 will be held right after the Houston Chapter Software Show on December 12, at a venue nearby. Learn about recent innovations and technology advancement in software for formation evaluation and data interpretation during the day and join us for networking right after. We will meet in a location convenient for all our members in the Greater Houston Area. The entire SPWLA community is invited, no need to RSVP, come at your own leisure, no payment required. Come and mingle with fellow petrophysics enthusiasts. Recent social events have been well attended by petrophysicists, geologists, geophysicists, engineers and managers!

Everybody is welcome!

When: Wednesday, December 12, 2018, 5–8 PM

Where: McCormick & Schmick's Seafood & Steaks, 1151 Uptown Park Blvd #01, Houston, TX 77056

What is your favorite science or math joke?
Please, send us some nice jokes, memes or comic strips at spwlayp@spwla.org or through SPWLA social media, and we'll choose some responses to publish in the next issue!
Thanks for your participation.

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.

AUSTRALIAN 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.

The 2018 FEAus Committee Members are

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/Intersociety Liaison/Social Coordinator/ Special Events and Awards	Leanne Brennan
Past President	Nariman Nouri
Monthly Meeting Coordinator	Meretta Qleibo
Membership Coordinator	Siobhan Lemmey
New Technology Forum Coordinator	Ben Van Deijl
New Technology Forum Coordinator	AbdelRahman Elkhateeb
Paul Pillai Education Group Leader	Matthew Josh
Audio Visual Coordinator	Nigel Deeks
Audio Visual Coordinator	Yang Xingwang
Sponsorship Coordinator	Andrea Paxton
Victoria Representative	Matthew Durrant
NSW Representative	Harris Khan

Recent Events

06 September 2018 – This year's FESAus New Technology Forum, with the theme "Hardware Solutions for Formation Evaluation," was conducted by representatives from Schlumberger, Halliburton and Weatherford. The topics were

- Advances in High-Temperature LWD and Cased-Hole Saturation Measurement (Weatherford)
- An Innovative Slim Pulsed-Neutron Logging tool (Schlumberger)
- Illuminate Your Reservoir – EarthStar™ Ultra-Deep Resistivity Service (Halliburton)
- New Azimuthal Resistivity and High-Resolution Imager (Schlumberger)
- Two New-Generation Leading Wireline Technologies (Halliburton)
- Looking Ahead for Your Reserves (Schlumberger)

FESAus 2018 New Technology Forum. Left to right: Hew Hugh James (Halliburton), James Kloos (Weatherford), Ashish Datey (Schlumberger), and Ben van Deijl (Woodside).

FESAus 2018 New Technology Forum. Ben van Deijl (Woodside) (left) and Adrian Manescu (President FESAus).

FESAus 2018 New Technology Forum. (Left to right): James Dolan (Schlumberger), Mohamed Raouf (Halliburton), Mauro Viandante (Schlumberger), and Ben van Deijl (Woodside).

Upcoming Events

30 October 2018 – Master Class in collaboration with SPE "Brown Fields/Production"

13 November 2018 – Technical Meeting, Matt Shaw presenting on "Uncertainty in Petrophysical Properties for Reservoir Modelling"

11 December 2018 – End of Year Event TBA

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

BANGKOK CHAPTER

Recent Events

26 September 2018 – SPWLA Distinguished Speaker Alexander Belovich (Regional Petrophysics Advisor, Baker Hughes, a GE company) presented his work on "The Problem With Silt in Low-Resistivity Low-Contrast (LRLC) Pay Reservoirs." Alexander's work on clastic laminated reservoirs is very pertinent to the offshore fields in The Gulf of Thailand, and his suggestions on appropriate data acquisition programs generated strong discussion in the small and attentive audience. Thank you Alexander for traveling up to Bangkok.

25 October 2018 - SPWLA Bangkok hosted a "Student Evening" with talks by students Waita Sanglee and Mai Thi Huyen Trang from the Asian Institute of Technology. More information can be found at the chapter webpage on the main SPWLA website

SPWLA Bangkok September 2018 meeting. Speaker Alexander Belovich (left) receiving an appreciation plaque from Andrew Cox (right).

BOSTON CHAPTER

Recent Events

August 17, 2018 –The Boston Chapter wrapped up the 2017–2018 speaker cycle by hosting our second "Future of Energy Symposium." The well-attended event had lively and engaged conversations with energy experts on topics that included; the future role of fossil fuels in the energy industry; carbon dioxide capture; and how to improve the interfacing of energy-water-food resources in our continually growing societies.

Boston Chapter 2018 Energy Symposium flyer.

Boston Chapter August 2018 Energy Symposium. Christopher Knittel (MIT) presenting his talk “Will We Ever Stop Using Fossil Fuels”.

Boston Chapter August 2018 Energy Symposium. Drew Pomerantz (Chapter Past President) quizzing the speakers on energy technology and policy. (Left to right): Michael Oristaglio (Yale), Christopher Knittel (MIT), Jacqueline Ashmore (Boston University), and David Keith (Harvard; Carbon Engineering).

The Boston Chapter was well represented in the October issue of *Petrophysics* recognizing the “Best Papers of the 2018 Symposium.”

“An Unsupervised Learning Algorithm to Compute Fluid Volumes From NMR T1–T2 Logs Unconventional Reservoirs,” by Lalitha Venkataramanan, Noyan Evirgen, David F. Allen, Albina Mutina, Qun Cai, Andrew C. Johnson, Aaron Y. Green, and Tianmin Jian.

“Proxy-Enabled Stochastic Interpretation of Downhole Fluid Sampling Under Immiscible Flow Conditions,” by Morten Kristensen, Nikita Chugunov, Koksal Cig, and Richard Jackson.

“Integrating Measured Kerogen Properties With Log Analysis for Petrophysics and Geomechanics in Unconventional Resources,” by Paul R. Craddock, Laurent Mossé, Romain Prioul, Jeffrey Miles, MaryEllen L. Loan, Iain Pirie, Erik Rylander, Richard E. Lewis, and Andrew E. Pomerantz.

“Downhole Fluid Analysis and Gas Chromatography; a Powerful Combination for Reservoir Evaluation,” by Oliver C. Mullins, Julia C. Forsythe, Andrew E. Pomerantz, Tim Wilkinson, Ben Winkelman, Vinay K. Mishra, Jesus A. Canas, Li Chen, Richard Jackson, Soraya S. Betancourt, Julian Y. Zuo, Armin Kauerauf, and Ken E. Peters

Upcoming Events

02 November 2018 – Nicholas Bennett (Schlumberger-Doll Research) will present on “Borehole Acoustic Imaging using 3D STC and Ray Tracing to Determine Far-field Reflector Dip and Azimuth.”

28–29 November – SPWLA and the Boston Chapter will host a workshop “Digital Rocks and Unconventional Petrophysics Workshop,” chaired by Lizhi Xiao (CUP) and Yi-Qiao Song (SDR).

SPWLA general and Boston-affiliate members are invited to browse our chapter website http://boston.spwla.org for up-to-date information of our mission and events, including event information and registration.

CALIFORNIA CHAPTER
(San Joaquin Well Logging Society, SJWLS)

General News

The SJWLS will continue to hold its monthly lunch-and-learn meetings at the CRC’s conference room at 10000 Stockdale on the third Wednesday of the month.

Recent Events

19 September 2018 – The SJWLS annual Fall Kickoff BBQ for 2018–2019 was held at the CoreLab facility.

17 October 2018 – David Barnes gave a presentation on temperature logging guidelines and factors that affect measurement accuracy

Upcoming Events

14 November 2018 – The next technical meeting was moved up one week due to this year’s early date for the Thanksgiving holiday.

19 December 2018 – Dr. Ping Zhang (Schlumberger) will give a presentation on “Extracting Rock Cation Exchange Capacity From EM Measurements.”

16 January 2019 – Dr. Avto Tkabladze (Schlumberger) will give his SPWLA Distinguished Speaker presentation “A Revolutionary X-Ray Tool for True Sourceless Density Logging With Superior Performance”

20 February 2019 – Dr. Saini (Cal State University Bakersfield) will discuss local research projects with emphasis on EOR.

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, Colorado. 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 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

18 September 2018 – Pavel Syngaevsky (Noble Energy) presented his talk, "Pore Structure Characterization of Some North America Carbonate Mudstones." He spoke on the importance of understanding pore structure in the development of unconventional reservoirs, and the resulting petrophysical challenges and potential solutions. The talk was well attended.

At the luncheon, The Bob Cluff Award was presented to Antony (Tony) and Dominic Holmes of Digital Formation, in recognition of their outstanding commitment to DWLS and the Denver petrophysical community. They were also made DWLS Lifetime Members. The award was presented by 2017 DWLS President, Sam Fluckiger (SM Energy).

DWLS September 2018 meeting. Antony (Tony) Holmes (left) accepting the Bob Cluff Award, presented by 2017 DWLS President Sam Fluckiger.

02 October 2018 – DWLS and RMAG cohosted the Fall Workshop, "Conventional Evaluation Methods for Unconventional Reservoirs and Vice-Versa," which was held at the American Mountaineering Center in Golden, Colorado. The workshop featured nine speakers and was well attended.

16 October 12018 – Karthik Srinivasan (Schlumberger) presented a lecture titled "The Changing Oil Price Landscape: A Case Study Breaking Down Liquid-Rich Basins in the Rockies." Low oil and gas prices since 2014 caused a paradigm shift in the oil and gas landscape in North America. Companies adapted by changing operating strategies and field development plans. Mr. Srinivasan shared his conclusions about the transformation in operating philosophies caused by the 2014 downturn in the Williston, DJ, Uinta, and Powder River basins. The talk was well attended.

DWLS October 2018 meeting. Karthik Srinivasan (Schlumberger) was the speaker.

Upcoming Events

13 November 2018 – Paul Devine (Resource Analytics, LLC) will present a lecture on incorporating information theory into petrophysics as a new tool for assessment of resource plays. His talk is titled “Information Theory as a Guide to Probabilistic Log Evaluation Without Petrophysics: Focus on Effective Porosity and a Revised Volumetric Paradigm that Eliminates Recovery Factor.”

DWLS November 2018 meeting. Paul Devine (Resource Analytics, LLC) will be the speaker.

EAST CHINA CHAPTER

Recent Events

26–29 September 2018. The 10th UPC International Symposium on Well Logging Technology was held in Qingdao, China. China University of Petroleum (UPC) was one of the organizers of the event. The East China Chapter of SPWLA hosted the symposium. World famous scholars from the US, Russia, and China gave presentations on the topics on the current status and challenges in electrical logging. In recent years, with the fast changing developments and wide applications of new electrical logging techniques, like multicomponent array electrical logging and electrical logging-while-drilling, electrical logging has shown its unique and irreplaceable role in complex underground environments, leading to continuous attention from the well-log analysts and geologists. We are looking forward to the 11th UPC International Symposium on Well Logging Technology in 2019.

East China Chapter September Well Logging Technology Symposium.

JAPAN CHAPTER
(Japan Formation Evaluation Society, JFES)

General News

JFES is actively working to achieve our mission, which supports formation evaluation committees in Japan: The success of these efforts can be seen in the success of the recent annual symposium. There is no annual fee required for chapter membership. Please feel free join us!

Recent Events

11–12 October 2018 – The 24th JFES annual symposium was held at JOGMEC-TRC, Chiba, Japan. Approximately 70 people from various companies, universities and countries joined the symposium and discussed formation evaluation.

JFES 24th annual symposium at JOGMEC-TRC.

JFES 24th Annual Symposium. Adam Haecker presents the SPWLA Student Award (left) to Hiroaki Sakai (right).

As the SPWLA representative, Adam Haecker (Regional Director North America I) gave the keynote address about the recent trends in global formation evaluation, which included a future vision of the petrophysicist. It was very valuable to hear about formation evaluation challenge from the global point of view. Following the keynote address, we had three invited talks presented by Drs. Tatsuo Shimamoto (INPEX), Satoru Yokoi (JAPEX) and Ridvan Akkurt (Schlumberger) about the technical contribution of petrophysics to local oil and gas field development and recent digital technology applications in petrophysics. We enjoyed the discussion from the local to global petrophycis.

This year, six of the 20 papers presented at the symposium were by students. We thank all the students for your active participation! Following the symposium, the committee evaluated the student presentations and presented two papers with awards for their high level of technical and presentation contents: The SPWLA Student Award to Hiroaki Sakai (Waseda University) for his presentation on "Development of Double-Permeability Type Compositional Simulator for Predicting Enhanced Coalbed Methane Recovery" and the JFES Student Award to Tsogtbaatar Amarsaikahn (Tohoku University) for his presentation "Evaluation of Horizontal Layers by Cross-Hole Borehole Radar."

JFES 24th Annual Symposium. Takehior Minawa (left) presents the JFES Student Award to Tsogtbaatar Amarsaikahn (right).

A ceremony was held at the end of the symposium to present two awards for their special contribution to JFES. The Best Presentation Award of the 2017 23rd Formation Evaluation Symposium was made to Shim Yen Han, Qu Change Wei, Cai Hui Min, Liu Bo, Yang Sheng Xiaong, Liang Jin Qiang, Lu Jing An, for their "Petrophysical Evaluation of Gas Hydrate in Shenhu Area, China." In this study (1) the petrophysical properties and habitat of gas hydrates have been investigated using a new evaluation technique that combines logging while drilling data and core data; and (2) hig-resolution resistivity image data were used to evaluate gas-hydrate volumes, determine hydrate occurrence modes, and hydrocarbon accumulation sequence. JFES recognized that the authors clearly and concisely presented their research results, which demonstrated the benefit of the petrophysical evaluation of gas hydrates. Congratulations! The Distinguished Service Award was presented to Tatsuki Endo in Recognition of "Outstanding Service To The Society." Tatsuki Endo has worked on JFES board for more than 12 years and has made special a contribution to the JFES organization. Thank you, Endo-san!

JFES 24th Annual Symposium. Best Presentation Award of the 2017 23rd Formation Evaluation Symposium by Tetsuya Yamamoto (left) to Shim Yen Han (right).

JFES 24th Annual Symposium. Tetsuya Yamamoto (left) presents the Distinguished Service Award to Tatsuki Endo (right).

Upcoming Events

Early December 2018 - The 105th JFES chapter meeting will be held at the Mitsubishi Corporation Exploration Co., Ltd. (MCX), Tokyo office

17 December 2018 – The 2017–2018 Distinguished lecture will be held at Waseda University on the topic of Low-Resistivity Low-Contrast (LRLC) formation evaluation with Silt

Please visit http://jfes-spwla.org/ for more detail.

MALAYSIA CHAPTER
(Formation Evaluation Society of Malaysia, FESM)

General News

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

Recent Events

26 September 2018 – Thanapala Singam (Petronas) delivered a talk entitled "Data Reconciliation at Various Scales: Do You See What I See?" He explained the workflow and challenges of integration of the reservoir properties such as porosity, permeability and saturations in core, and followed by upscaled the data into the reservoir model for further evaluation. The importance of the integration on knowledge of geosciences, petrophysics and flow dynamics across the various scales were discussed as well.

FESM September 2018 meeting. Thanapala Singam (Petronas) (right) receives a token appreciation from Chapter Officer Grant Heavysege.

LONDON CHAPTER
(London Petrophysical Society, LPS)

General News

The LPS helped to support the third Petrophysics Summer School hosted by the University of Leicester. Building on the success of the previous summer schools, this year's course brought together 21 participants from 10 countries from as far away as the Philippines. Over two-thirds of the 2018 cohort were women, which was a significant increase on the previous two years in which women made up less than half of the groups. The participant group comprised mainly graduate students but also included post-docs and an undergraduate, all of whom had little or no experience with petrophysics. The six-day school combined lectures, practicals, software training, and site visits to Weatherford and the British Geological Survey Core Store, to provide a solid introduction to the fundamentals and applications of petrophysics.

The LPS has also recently given financial support to four students at the Universities of Durham, Leicester and Imperial College, London.

Recent Events

04 September 2018 – SPWLA Distinguished Speaker, Steve Cuddy gave a thought-provoking talk on "Using Fractals to Determine a Reservoir's Hydrocarbon Distribution," putting new life into his Foil function.

27 September 2018 – Our "Seismic Rock Physics" seminar had an agenda of 10 speakers from service companies and consultancies. The audience consisted of professionals, young professionals and students.

23 October 2018 – David Maggs gave a presented on "Application of Borehole Images in OBM From LWD tools."

Upcoming Events

20 November 2018 – The LPS AGM will be held at 6:30 pm. Once the business has been concluded we will have a talk on "Richard III: His Life From his Bones," from Professor Jane Evans MSc, PhD, FGS, C.Geol.

13 December 2018 – Our next one-day seminar is themed "Resistivity-Free Saturation."

See our website www.lps.org.uk for details of all our events.

THE NETHERLANDS CHAPTER
(Dutch Petrophysical Society, DPS)

Recent Events

20 September 2018 – The DPS had a technical seminar preceded by a chapter board meeting. The speakers Maciej Kozlowski (Haliburton) and Sergey Vorobiev (Wintershall) seminar focused on "Quantitative interpretation and Geomechanics". The titles of the presentations were: "Quantitative Interpretation of Sonic Compressional and Shear Logs for Gas Saturation in Medium Porosity Sandstone," and "Rock-physics Anisotropy and its Applications in Geomechanics." The presented material can be found on http://www.dps-nl.org/. The well-attended meeting was held at the KIVI and was followed by a social event.

Upcoming Events

06 December 2018 – The next DPS technical seminar will be held at KIVI The Hague, The Netherlands.

DPS September meeting. Maciej Kozlowski (Halliburton) (left) receives speaker's gift from DPS President Iulian Hulea.

DPS September meeting. Sergey Vorobiev (Wintershall) (left) receives speaker's gift from DPS President Iulian Hulea.

QATAR CHAPTER

General News

After a period of low activity from the SPWLA Qatar, Doha, the recently formed committee is seeking to revive the society by promoting technical talks in close partnership with our sister and well-established QSPE section (Qatar SPE). The committee is formed by a diverse range of petrophysicists and geoscientists working in Doha and has a good balance between operators, academia and service companies. We are currently seeking enthusiastic professionals to join us as Vice President and Treasurer.

Quatar Chapter 2018 Board of Directors. (Left to right) Nayef Alyafei (TAMUQ); Ali Zwali (Halliburton); Ahmed Mokhtar (Schlumberger), Walid Abu El Nor (Occidental Petroleum), IT Coordinator; Sharon Finlay (NOC), President; Calvin Myers (Qatargas); Jose Oliveira Neto, Secretary; Magdy Samir (Schlumberger); Shehab Ahmed (not present).

Recent Events

10 October 2018 – Faris Mahgoub (Ingain/Halliburton) gave a well-attended talk on "Digital and Conventional Techniques to Study Permeability Heterogeneity." This was an interesting technical talk that delved into the relationship between Kv/Kh and the use of advanced 3D X-ray CT scan imaging for digital rock characterization at a plug-scale and whole-core samples.

Qatar Chapter October 2018 meeting. Faris Mahgoub giving his technical talk in which he presented some images of core and CT scans.

Upcoming Events

05 November 2018 – Steve Adams (The Petrophysicist Limited) will give a presentation on "Saturation Height Modeling and Imbibition Zones." The talk invitation and further details will be available soon.

If you want to connect with SPWLA Qatar Chapter, please email us at QSPWLA@gmail.com or talk to any of the committee members! We look forward to meet you!

SAUDI ARABIA CHAPTER (SAC)

Recent Events

29 August 2018 – Shahid Haq (Schlumberger Reservoir Domain Global Lead) gave a talk titled "Reservoir Engineering While Drilling in Horizontal Wells." The talk started by defining reservoir engineering while drilling horizontal wells, the evolution of placing horizontal wells, and then described the evolution of logging-while-drilling (LWD) versus geometric, geological, structural and reservoir steering. The talk stressed key enablers for "productivity steering," reservoir mapping workflow and fluid mapping while drilling. During the Q&A session, the following topics were further discussed: (1) key parameters contributing to uncertainty analysis and difficulties of obtaining effective permeability distribution in order to model the near-wellbore in real time while drilling; (2) the importance of geomechanics while drilling; and (3) challenges related to underbalanced drilling.

SAC August 2018 meeting. Shahid Haq (Middle left) receiving the SAC chapter speaker’s award from the SPWLA SAC Committee.

SAC September 2018 workshop participants.

19 September 2018 – SPWLA SAC conducted a topical workshop on “Well Integrity Evaluation: Challenges and Best Practices.” This workshop was an opportunity to review and discuss important aspects of well integrity; i.e., producing our field safely, environmental consciously, efficiently, and cost effectively. This workshop covered all aspects of well integrity, from well design and completion to production and abandonment, but the focus was on well-integrity evaluation and monitoring of pipe corrosion and cement-bond evaluation with existing technologies.

This one-day workshop was opened by Chapter President Dr. Faisal Alenezi, who introduced the event keynote speaker, Mr. Khalid A. Zainalabedin (Manager of Reservoir Description & Simulation Department in Saudi Aramco). Both Faisal and Khalid emphasized the importance of well integrity in upstream business and the critical roles petrophysicists play in ensuring producers and injectors are in good health while in operation. Workshop consisted of 11 presentations in four sessions and concluded with a presentation on emerging technologies in well-integrity evaluation given by Mohamed Larbi Zeghlache (Saudi Aramco well integrity subject matter expert), and an interactive quiz-game conducted by Marie Van Steene. S. Mark Ma provided a workshop recap. More than 120 professionals from the industry and academia participated in this event.

22 October 2018 – The presentation at the technical luncheon was on advancements in production logging.

Upcoming Events

November 2018 – A workshop on Formation testing will be held.

Please stay tuned to our chapter website for details (www.spwla-saudi.org) and event announcements will be sending as usual.

STUDENT CHAPTERS

CHINA UNIVERSITY OF PETROLEUM (BEIJING) STUDENT CHAPTER

General News

By absorbing the students majoring in well logging at CUPB (China University of Petroleum, Beijing), the 2018 working group of the SPWLA Student Chapter of CUPB was formally established on September 21. The new members will continue to organize academic activities related to well logging for teachers and students of CUPB and expand the influence of SPWLA at CUPB with the support of SPWLA.

CUPB September 2018 organizing meeting. The new chairman of the Student Chapter, Jiang Jia, introducing the Student Chapter.

CUPB September 2018 meeting. Dr. Jesús M. Salazar (third from the right in the first row) with the audience at CUPB.

Recent Events

25 September 2018 – Dr. Jesús M. Salazar, SPWLA President-Elect, was invited to give a presentation at CUPB (China University of Petroleum, Beijing). Jesús first give a brief introduction to the situation of the SPWLA and then give an academic presentation on the topic of “A Practical Petrophysical Model For a Source Rock Play: The Mancos Shale.” The audience was very interested in Jesús’ presentation and had a heated discussion with him. Later, Jesús was invited to visit the State Key Laboratory of Petroleum Resources and Prospecting in CUPB and conducted in-depth exchanges with researchers.

CUPB September 2018 meeting. Dr. Jesús M. Salazar, SPWLA President-Elect, during his presentation.

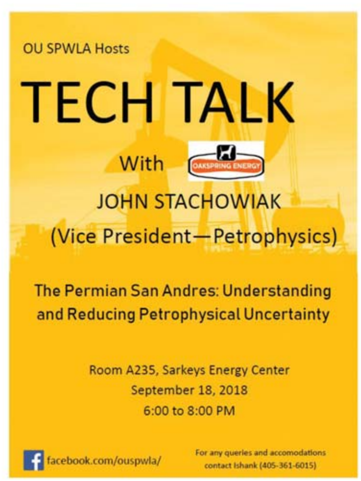
UNIVERSITY OF OKLAHOMA STUDENT CHAPTER

General News

The chapter conducts one techni talk every month for the undergraduate and graduate students in the Mewbourne School of Petroleum and Geological Engineering (MPGE) department. The topics vary widely, encompassing innovative downhole logging tools, integrated petrophysics workflows, case studies etc. The chapter currently has 101 student members.

Recent Events

18 September 2018 – The first tech talk of the Fall 2018 semester hosted John Stachowiak (Vice President of Oakspring Energy and Secretary/Treasurer of SPWLA OKC chapter). Below is the flier for the talk. The talk was well attended by students and professors alike.



09 October 2018 – Jason Gendur (Schlumberger Petrophysics Domain Champion) gave a talk on Schlumberger’s latest spectroscopy tool.

TEXAS TECH UNIVERSITY STUDENT CHAPTER

General News

The newly elected officers for the 2018–19 academic year are:

President	Daniel Owusu-Ansah
Vice-President	Ibe Ezisi
Treasurer	Elizabeth Reeder
Membership Chair	Rushil Pandya
Secretary	Garrett Payne
SORC Representative	Kristofer Aasen

Recent Events

31 August 2018 – Our Fall Engineering Kick-Off was a great turn out for the organization as we were able to sign up several new members and introduce them to what SPWLA is all about.

06 September 2018 – Following our Kick-Off, was our first monthly meeting on September 6th with guest speaker Mr. James Hawkins. Mr. Hawkins, who was the former SPWLA president of the Midland Chapter, discussed the benefits of being involved with student organizations, specifically, SPWLA. It was great exposure for our new members to learn about the organization not only at the local chapter level, but international as well.

05 October 2018 – Guest speaker Kent Newsham (Director of Petrophysics for Unconventional Reservoirs at Occidental Petroleum Corporation) discussed the petrophysical workflow of for evaluating unconventional wells. The meeting was a great learning experience as we gained knowledge from an industry point of view.

TTU SPWLA September 2018 meeting. Past and current officers posing with the speaker James Hawkins (center).

07 October 2018 – Our organization participated in a joint service event with American Rock Mechanics Association (ARMA) TTU student chapter. We participated in a 5K marathon, 'The Race for the Cure,' for the Suzan G. Komen Organization to raise funds for a cure for breast cancer. It was great for TTU SPWLA to be involved in such a great cause.

TTU SPWLA October 2018 race participation.

26 October 2018 – A tailgate joint event hosted by AADE, SPE, and SPWLA student chapters was held prior to the home football game against Oklahoma University. A multidisciplinary group of engineers from Diamondback Energy discussed the workflow used in an unconventional well project.

Upcoming Events

08 November 2018 – A guest speaker from Weatherford International will discuss "No Pay Left Behind," which will cover some of the new technology the company has developed.

FEDERAL UNIVERSITY OF RIO DE JANEIRO (UFRJ) STUDENT CHAPTER

General News

After successfully completing our biggest event of the year (Petroleum Geology Week) we are already organizing for 2019, with new ideas and events to keep sharing knowledge and fueling the exchange between the University and industry.

Recent Events

24–28 September – In association with the AAPG Student Chapter, we held the 2nd Petroleum Geology Week (SEGEP) at UFRJ. It was a five-day event with minicourses and presentations, with the participation of undergraduate and graduate students, professors and guests from industry. Our goal was to tighten bonds and disseminate knowledge between companies and the university. It's our Chapter's biggest event and we are proud to say that it was a successful one!

We would like to thank all our sponsors (Repsol Sinopec, Earth 4Geo, Geosoft and SPWLA) and especially, SPWLA Brasil and SPWLA International. It's very important to have your support on every event helping us reach our goals. Thank you so much!!

UFRJ SEGEP 2018 logo.

Part of the SEGEP 2018 team.

SPWLA THIRD BOARD OF DIRECTORS MEETING
Kinder Morgan Office, Houston, Texas
October 8, 2018

President Zhipeng Liu called the meeting to order at 8:00 a.m. In attendance Executive Director, Sharon Johnson, Attending remotely President-Elect, Dr. Jesus Salazar, VP Technology, Jim Hemingway, VP Education, Katerina Yared, VP Finance, Secretary and Administration, Jennifer Market, VP Publications, Dr. Carlos Torres-Verdin, VP IT, Mehrnoosh Saneifar, Regional Directors, NA 1, Adam Haecker, Latin America, Dr. Nadege Bize Forest, NA 2, Doug Patterson, Europe, Mike Webster and, Middle East/ Africa, Mark Ma.

A motion made by Doug Patterson to approve the 2018–2019 Foundation Board members Matt Bratovich, Vice President 2 years, Thaimar Ramirez, Secretary 3 years, Luis Quintero Treasurer 4 years, Brett Wendt, New Member 5 years as presented by Elton Frost, Jr., was seconded by Dr. Jesus Salazar. All approved, and the motion passed.

A motion made by Doug Patterson to approve Philip Tracadas as SPWLA Foundation S&G committee chair as proposed by Elton Frost, Jr., was seconded by Katerina Yared. All approved, and the motion passed.

A motion made by Mehrnoosh Saneifar to approve SPWLA London Chapter by-laws revision was seconded by Mike Webster. All approved, and the motion passed.

A motion made by Adam Haecker to approve the printing and shipping of *Petrophysics Journal* through 2019 was seconded by Doug Patterson. The motion passed by majority vote.

Discussion and Vote item: An electronic vote from the Board for individual member subscription of *Petrophysics Journal* print surcharge of $65 was decided by an average number proposed by each board member.

Discussion and Vote item: An electronic vote from the Board to redesign the financial support for the *Petrophysics Journal* Editing/Production Fees beginning January 2019 as submitted by the financial committee in the following structure:

- $1200 for each article if the lead author is an SPWLA member
- $1800 for each article if the lead author is not an SPWLA member
- $600 for non-profit/academic papers
- Possible hardship waiver upon request to the Finance Chair

Was passed by majority vote.

Vote results:

- As proposed, starting January 1, 2019 (6 votes)
- 50% of proposed amount starting January 2019, then 100% of proposed amount starting after June 2019 (2 votes)
- Abstain (1 vote)

A motion made by Dr. Jesus Salazar to adjourn the meeting was seconded by Jennifer Market. All approved and the motion passed. Meeting adjourned 12:25 p.m.

Respectively Submitted by
Sharon Johnson
Executive Director

Next BOD meeting: December 5, 2018 in Houston, Texas, at the Kinder Morgan Offices Downtown Houston.

Welcome New Members — August 22, 2018 – October 23, 2018

Abdou , Ali E., Halliburton, Houston, TX, United States
Acuna, Nicolas, University of Houston, Houston, TX, United States
Agarwal, Saurabh, University of Oklahoma, Norman, OK, United States
Agbonayinma, Eghosa Rodney, University of Houston, Houston, TX, United States
Aghaei, Arash, Thermo Fisher Scientific, Houston, TX, United States
Al Abri, Ahmed, LSU, Baton Rouge, LA, United States
Al Shehri, Fahad Hassan, King Fahd University of Petroleum and Minerals, Saudi Arabia
Alexandra, Maria, BP, Jakarta, Indonesia
Aliev, Murad, RNG, Moscow, Russian Federation
Almahadhour, Anisa Nasser, Ara Petroleum Oman B44, Muscat, Oman
Al-Mudhafar, Watheq J., University of Texas at Austin, Austin, TX, United States
Alwarda, Fahad, University of Houston, Houston, TX, United States
Andono, Widyanto, Gowell Oilfield Technology FZE, Jakarta, Indonesia
Arapakis, Lake, Petroleum Development Oman, Mina Al Fahal, MAF, Oman
Babooram, Ashama Prabha, University of Houston, Katy, TX, United States
Bamisile, Toluwalope, Texas A&M University – Kingsville, Kingsville, TX, United States
Batamula, Frank, University of Houston, Richmond, TX, United States
Bauer, Matthew William, Anschutz Exploration Corporation, Golden, CO, United States
Binate, Hadja M. Latifa, Texas Tech University, Lubbock, TX, United States
Boyen, Johnathan Bailey, Texas Tech University, Helotes, TX, United States
Jurczyk, Brian, Starfire Industries, Champaign, IL, United States
Chan Tack, Simon, Sheridan Production, Sugar Land, TX, United States
Donahoe, Thomas, TD Geologic LLC, Cecil, PA, United States
Furnica, Maria Adriana, University of Bucharest, Bucharest, Romania
Ganguly, Eliza, University of Oklahoma, Norman, OK, United States
González Sánchez, David, Universidad Industrial De Santander, Piedecuesta, Santander, Colombia
Goodwin, Trent, Matador Resources, Dallas, TX, United States
Green, Hunter, Texas Tech University Geosciences, Lubbock, TX, United States
Hardwick, Jeffrey William, University of Oklahoma, Norman, OK, United States
Ibrahim, Mohamed, Heriot Watt, Salford, Manchester, United Kingdom
Imanovs, Elhans, Imperial College London, United Kingdom
Javid, Sanaz, Neptune Energy, Oslo, Norway
Kendrick, Alexander, Stanford University, CA, United States
Kolawole, Oladoyin, Texas Tech University, Lubbock, TX United States
Laurence, Ashley, Allied-Horizontal Wireline, Midland, TX, United States
Mahato, Tushar Kanti, ONGC, Dehradun, Uttarakhand, India
Marinho, Paulo, CGG
Marky, Tomas Humberto, REPSOL, Lima, Peru
Matous, Marek, University of Houston, Tomball, TX United States
Mauck, Justin, Schlumberger, Midland, TX, United States
Melani, Leandro Hartleben, University of Campinas (Unicamp), Brazil
Meraz, Devan, SageRider West, San Joaquin, Bakersfield, CA, United States
Mihályka, János, Eötvös Loránd University, Budapest, Hungary
Mirzaahmadian, Yaser, NAED/UIS, Sandnes, Norway
Mortley, Henry James, Schlumberger, Tunbridge Wells, Kent, United Kingdom
Murillo Silva Sr., Julio Cesar, University of Miskolc, Miskolc, Hungary
Naides, Claudio Hugo, Pampa Energia, Buenos Aires, Argentina
Narduzzo, Nicholas Vincenzo, Texas Tech University, Magnolia, TX, United States
Ortiz, Alberto Cesar, YPF, Argentina
Ouzzane Sr., Abderrahmane, Schlumberger, Doha, Qatar
Ramirez, Nelson Xavier, Halliburton, Quito, Pichicnha, Ecuador
Ranade, Saurabh Padmanabh, University Of Portsmouth, Portsmouth, Hampshire, United Kingdom
Rickert, David, EGeoMobile.Com, Urbandale, IA, United States
Rosero Cepeda Sr., Viviana Yajaira, University of Miskolc, Miskolc, Hungary
Rowell, Daylon, Allied Horizontal Wireline, Oklahoma City, OK, United States
Simonov, Kirill Viktor, Skoltech, Moscow, Russia
Slade, Jonathan, Woodside, Perth, WA, Australia
Suarez Bolivar, Valeria Andreyna, Colorado School of Mines, Golden, CO, United States
Tang, Huan, University of Houston, Houston, TX, United States
Tay, Mawuli, Petroleum Commission, Ghana
Topchii, Maria, Lomonosov Moscow State University, Moscow, Russian Federation
Trombin, Gianluca, ENI Spa, San Donato Milanese, Italy
Vogt, Andreas, Baker Hughes, a GE Company, Celle, Lower Saxony, Germany
Wevill, Jessica Laure-May, Imperial College London, London, United Kingdom
Williams, Gareth Wyn, CGG, Llandudno, Conwy, United Kingdom

Formation Testing SIG

The 2019 Formation Testing SIG Technical Meeting will take place on March 6th at the BP Westlake campus in Houston. The event will have speakers from operators, service companies and universities. The meeting agenda will be posted on the SPWLA FT SIG webpage before the end of 2018.