**The Welltesting Network**

**MULTI-TOPIC MEETING (MTM) No. 16**

**Houston, TX**

**Thursday 7th** & **Friday 8th May 2015**

**MEETING NOTES**

The meeting introductory remarks included an anti-trust reminder to ensure that all of the participants conform to the applicable laws and regulations during the course of the meeting.

* *The meeting participants are reminded that the participants are competitors, and are subject to antitrust laws*
* *The parties are committed to compliance with all applicable antitrust laws and other applicable laws and regulations*
* *Discussions which might be misconstrued as price fixing, customer or market allocation, attempts to alter the competitive open bidding season, or boycott suppliers and customers are not allowed*
* *Discussions of other competitively sensitive subjects such as marketing strategies, supply and demand forecasts, open season bids, specific suppliers, and customer information are not allowed*
* *If any meeting participant has any questions/concerns regarding these antitrust considerations with respect to the meeting, he/she will consult his/her counsel*

**Clean Productive PErforations with Minimal Underbalance - Alan Salsman, Schlumberger**

Tubing conveyed perforating (TCP) for DST has been an established industry standard for the last couple of decades. The wellbore pressure conditions at the time of perforation are a key parameter for determining the well productivity. The concept of static underbalance was developed beginning in the 1980s, with a typical target of 500-1000 psi underbalance.

The two primary issues with static underbalance include:

1. The difficulty of achieving the target underbalance condition due to wellbore conditioning,
2. This technique has proven to be ineffective due to the mix of over pressured gas and liquids that occurs during perforating which negatively impacts the quality of the cleanup.

Introduced in 2001, dynamic underbalance (DUB) is a proven technique that is the de facto method in some parts of the world. By its nature, perforating creates localized damage, with the sand grains broken up and a reduction in permeability. Cleaning up the perforations reduces this near wellbore damage, with unloading the well as quickly as possible a way to increase the amount of cleanup. DUB is typically applicable for all well testing situations.

The DUB technique is most successful when perforating formations with rock quality such that they produce naturally (“competent formations”). When perforating unconsolidated sands, there may be a concern if the job design includes a lot of stages, with the potential in this case for sand to flow into the wellbore and to stick the gun. Caution should be exercised in this situation.

In hard rock formations, the use of DUB may be helpful pre-frac to establish initial flow, but perforation clean-up may be limited. In carbonate formations, the use of DUB may help to increase injectivity into a lower permeable zone. The number of applications of DUB in unconventional reservoirs is limited.

One OpCo rep indicated that they had never seen DUB used in their operations. DUB still lacks full adoption globally due to a lack of awareness across the industry (including the exploration community) and a general aversion to the perceived risk of new or different techniques.

Additional barriers to gaining adoption of DUB include difficulty in measuring or quantifying the benefits, and the fact that in the early days of DUB development and implementation, the service companies withheld detailed information on DUB for intellectual property (IP) reasons. Now the service companies have less concern about IP, and are much more open in sharing technical information and lab testing results. It was suggested that the operators consider conducting their own lab work to verify the results of DUB.

One large OpCo conducted an internal study which indicated that utilizing DUB perforating resulted in a significant increase in productivity. A member shared a situation where DUB was applied for a high permeability gas well. The perforations were shot accidentally in an overbalanced condition, with the engineering and operations team concerned that the results would be negative for this reason. However, a DUB response was achieved, and the results were excellent, with better results than anticipated. In this case, the use of DUB stood out as one of the reasons for the positive results.

An OpCo member asked what production time or volume is required as a rule of thumb to achieve adequate clean-up of the perforations before the initial reservoir shut in pressure can be obtained. Alan responded that perforations clean up well with DUB, but it is difficult to determine the extent of clean-up further into the reservoir. There has also not been any attempt to estimate the required clean-up volume using lab testing data.

A member also commented that the location of the pressure gauge relative to the perfs may be an issue if the distance is ten feet or more, and that this is difficult to determine precisely.

A member noted the initial positive pressure surge after perforation that occurs with DUB, and wondered if this would negatively impact the clean-up. Alan responded that these overbalance peaks do not affect the quality of the clean-up, and used the analogy of a vibrator to describe the effect on the perforations.

**Overview of the Marine Well COntainment Company (MWCC) Response System - Doug BLalock, BP**

Doug provided an overview of the MWCC, how it compares to the OSRL/SWRP, with a view on what the role of Well Testers would be in a response that deployed this equipment. The MWCC is GoM specific, and includes over 20 members that are active in this region. The MWCC provides both an Interim and Expanded Containment System (ECS), with the ability to sustain response operations for up to six months. This contrasts with the approach taken by the OSRL/SWRP containment system.

This partnership originated when the IOGP established the Global Industry Response Group (GIRG) following the Deepwater Horizon incident. Major oil and gas companies then joined together to commence the Subsea Well Response Project (SWRP). The SWRP is responsible for designing and overseeing the building of the integrated intervention system. OSRL is responsible for owning, storing and maintaining the equipment. SWRP/OSRL also has global response capability with equipment storage centers in Stavanger, Singapore, South Africa, and Brazil. The SWRP/OSRL system design relies on the use of equipment that is generally available in the industry, and is therefore less equipment intensive than the MWCC.

All of the scenarios used to design the MWCC system are based on the Deepwater Horizon incident. Phase 1 of the response involves the use of ROVs and dispersant. Phase 2 involves the deployment of the containment dome to collect the leaking oil. The equipment on board the Marine Capture Vessels (MCV) resembles a well test, so it is likely that Well Test Engineers (WTE) would be involved at this point. In a response, the WTE would have a matter of days to rig up the equipment. Additional equipment would then be added, including the capping stack if the well has the required integrity from a pressure standpoint. If pressure limitations prevent the capping and closure of the well, then a longer term effort will be required to collect and dispose of the leaking oil. This scenario is where the ECS is designed to operate for up to six months before the relief well is drilled and is capable of killing the well. MWCC has equipment shore bases in Ingleside, Texas, and Mobile, Alabama.

An OpCo member asked about securing vessels for the response, indicating that this was a real issue in Europe. Doug responded that this has been addressed for GoM. SWRP looked at four rig classes, and completed mock-ups on where the equipment on deck would be located.

**Use of Multiple Gauges in Testing Saturated Oil Reservoirs - Bill Roberts, OPC**

The use of multiple downhole pressure gauges (DHPG) delivers a much better well test interpretation.

The first two slides in the presentation make the point that the delta Pressure (P) and derivative curves are the most dominant way to interpret well tests. The delta P curve is the most basic, with the derivative curve very valuable to uncover patterns in the data that would not be revealed with just the delta P curve. The use of these two curves has become the dominant way to interpret well tests.

Slide three indicates radial flow in the pink case and non-radial for the blue. The blue case may reflect the pressure transient hitting a barrier. This case also reinforces the value of having both plots for an improved interpretation. The resolution of the data is critical to provide an accurate interpretation.

The case study beginning is slide four is for a reservoir that is near the bubble point (pb). The well is perforated near the gas/oil contact, and a high flow rate was required during the well test. If both the fluids in the reservoir and those produced in the drill string never cross the pb, then single phase flow is present. However, if the reservoir is near the pb at static conditions, then once the well test is initiated and drawdown occurs, the fluid may go below the pb, with gas breaking out of solution which impacts the pressure drawdown curve. If the pressure gauge is not located at the sand face, which is typically the case, then two phases may exist at the gauge location but not in the reservoir. In this case, the drawdown curve will be influenced by changes in the fluid phases in the wellbore, and will not be reflective of conditions in the reservoir.

The example DST BU 1 and 2 reflects transient depletion, which indicates improving reservoir conditions away from the wellbore which is viewed as a positive indication. This case demonstrates, however, how the data can be distorted by the use of only one DHPG when phase changes are occurring. The case study as detailed in the slides illustrates the value of two DHPG when testing near the pb.

Given the uncertainty of BU 1 and 2, DST BU 3 was proposed to the operator and was initially met with skepticism due to the extra cost and additional kit required. This initial reluctance was overcome, however, with full buy-in to a long term test for more than 30 days. Surface pressure readout was provided which was critical to achieve an accurate interpretation.

A ServCo member commented that they had a similar situation where a downhole temperature gauge was also run. The temperature held steady until gas breakout occurred, at which time a temperature drop was observed when the gas was released. Bill commented that the operator typically misunderstands the value of two DHPG as primarily providing redundancy should one gauge fail. Bill agreed that there is value in this, but dual gauges should also be separated in the optimum configuration to better interpret any wellbore effects due to phase changes.

Another common mistake is to run dual DHPG and then only think about how to use them most effectively until after the test data is collected. When deployed properly, dual gauges can prevent making a significant error in the interpretation. A multi-phase flowmeter is also helpful to measure the GOR. If the surface value of GOR is constant throughout the test, this is an indication that only solution gas is present.

An OpCo rep commented that each BU case needs to be consistent with each other in order to allow a fair comparison from one to the next. In the case study, BU 1 and 2 are not consistent due to wellbore effects, whereas BU 1 and 3 are consistent. Also, the use of the phrase ‘transient depletion’ is frowned upon in his company due to the negative perception associated with the term ‘depletion’. Bill indicated that he is aware of a couple large OpCos that use the term.

**Reducing Risk and Cost in DST Operations - MAdhi Baklouti, Schlumberger**

Wireless telemetry is being used successfully and provides a way to have flexibility in the data sampling rate and resolution based on the BU results. For example, the sampling rate can be varied from 1 data point per minute to 1 per second, and the resolution can range from 1-3 significant digits.

One member commented that they like to receive the data as early as possible, with high resolution in the first hour. Bandwidth limitations can be an issue. The use of wireless may also eliminate the need to run wireline in the hole and avoid the mechanical risk associated with that. The ability to secure continuous measurements including temperature data is also recognized as an advantage over conventional methods.

A member commented that this could make closed chamber testing more viable, but another member noted that once the upfront time for planning and initial investment is made, the incremental effort for a full DST is still typically justified.

A member commented that in addition to the use of data obtained via wireless telemetry quantitatively, there is also value from a qualitative standpoint in terms of allowing a determination of whether the test time needs to be extended.

An OpCo rep supported this view by stating that wireless is helpful to support the business case to extend a test interval, and provides more data to help convince Management to agree to do this.

Another member noted that he always insists on getting real time data which provides the ability to tailor the test, and avoid being asked questions after the test that you can’t answer.

**Well Test Guidelines - Charles He and Gurinder Singh, ABS**

ABS is a non-profit organization with an HSE orientation. ABS classification related to well testing was initiated beginning in 1990 and has since progressed to the current Well Test Guide. The classification system was initially started to support underwriting requirements. Equipment manufacturers and Drilling Contractors (DC) utilize the notation to demonstrate that good principles and practices have been applied.

One OpCo rep noted that the DC is required to be in classification in order to operate. Coastal and flag states regulatory agencies (e.g. BESE and USCG for GoM) depend on third party certifications such as that provided by ABS to assess and manage the level of industry risk. For example, BESE recently issued a 250 page document on BOPs that includes a requirement for third party verification. ABS worked with BESE behind the scenes on the development of this document, with the longer term direction to extend this requirement beyond just BOPs.

An OpCo member challenged the value of certification from their perspective, and it was recognized that certification does offer less direct benefit for OpCos, which address their needs primarily through internal quality and risk management standards as well as industry standards such as those provided through API.

The current 30 month maximum time interval for a facility to be considered temporary is now seen by ABS as too long, and will be reduced to 12 months in the future. ABS clarified that this is 12 calendar months.

An OpCo rep noted that the well testing equipment is not used during all of that calendar time, but rather on a temporary basis. If a time extension is required, the ABS reps advised that the governing regulatory body for that flag state can be consulted on granting an extension. A factor in well testing that impacts the time frame for certification is the uncertainty associated with defining hazardous areas on the deck when the exact equipment list is not yet unavailable and/or may change over time.

An OpCo rep cautioned that all of the involved parties need to work to the spirit of the regulations. An incident was recalled where a DPS-1 OSV was engaged in well testing and lost position and drifted off. There were no serious consequences in this case, but it reinforced the mandate that a DPS-1 OSV should not be utilized for well testing operations.

A member raised an issue with the ambiguity associated with the Well Testing Guide which results in differences of interpretation from one surveyor to the next and from rig to rig. The ABS reps responded that enhancements are in progress to add additional definition on equipment standards, area boundaries, and other topics. Further OpCo comment suggested that there would be a lot of opportunities to use the survey feedback and lessons learned for the many similar vessel classes that are out on the water. Given the similarity between WT layouts it would be good for ABS and DNV to provide more details on acceptable and unacceptable layouts or configurations that have been proposed. For example, it would be good to have all the relevant survey feedback with regard to Samsung series or Enterprise class drillships. If the feedback is more specific to a vessel and highlights the safety intent, there may be greater application of the lessons learned into future submittals. This approach would also build more consistency among the surveyors. Past experience indicates that the outcome is not good when you have many different focus areas and potential interpretations by the surveyors.

One OpCo rep commented that he advises caution when a DC wants to remove notation. The driver to do this in some cases may be to reduce the equipment maintenance requirements associated with notation. The same OpCo rep also suggested that arranging for DNV and ABS reps to meet with the DC, major equipment suppliers, and operators in a workshop environment to agree on overall objectives and best practices can be very effective to develop a shared understanding and improve the business outcomes for all parties. This approach is more effective than each party working independently and "throwing paperwork back and forth".

Another OpCo rep also suggested that a collaborative approach be taken to drive increased learning for all parties, including the inspectors. It was noted that in marine operations the Master is ultimately responsible and can shutdown testing operations very quickly if they are unhappy with the situation.

**Real-Time Well Testing - Vince Zeller, Halliburton**

The use of acoustics in wells has evolved over decades to better understand how to generate and receive signals and manage the signal to noise ratio. However, it is still in its infancy, with a current focus on applying this technology to depth correlation to help ensure that the perforating guns stay on depth when you fire them.

This research area has been active for 20 years, with the ability to conduct field trials constrained by the risk associated with a live fire situation required to test the technology, as well as the overall historic slow adoption rate of new technology in the industry.

The OpCos request a 5 year track record before deploying technology, which is difficult to achieve while still in development. POB limitations have also been a barrier to conducting field trials. The potential benefits of the technology are huge, but more development is needed to increase the bandwidth and enable higher data transfer rates. Currently, the technology is capable of verifying that a downhole sample has been received and determining the basic sample composition (e.g. black oil, gas). From this information, a determination can be made if some sort of intervention may be required. Electromagnetic (EM) technology also has potential applications, but its development is currently limited by technical issues associated with the electrical flow path. There is also potential for the use of acoustics in production applications, but because acoustic devices are currently battery powered, a longer term alternative power source or enhanced battery life is required to enable this.

An OpCo member confirmed the value of moving to wireless systems like this. Some field trials are in motion, but additional field trials by operators is required to advance the technology development.

A ServCo member lamented that the OpCos all like the idea of wireless telemetry, but the first question they ask is where it has been run before. Extensive testing of the equipment is being conducted now prior to field testing.

An OpCo member noted that the forthcoming approval and use of API 19TT will help to drive the qualification of the equipment and increase the confidence level in conducting field applications. The key concern by the OpCos is to prevent a train wreck in a deepwater well. Demonstrating that the tools have a low risk of failure will also allow greater exposure and help to speed adoption in the industry.

**Update on WTN Success STory Template and Risk REgister Library - DOn Dressler, Enterprise PErformance Group, LLC**

An overview of the Success Story template and submittal process was shared with the members. The value of collecting and sharing Success Stories was endorsed, with one member commenting that case studies that are now presented as part of industry publications can be moved to this format. A member requested that a list of categories be created so that the different Success stories can be indexed by type (e.g. mechanical, sampling, subsurface analysis). This was taken as an action by Fiona Curley and Don Dressler.

An overview of the Risk Register Library, the process to submit and cleanse the registers, and the eight registers received to date was also shared with the members. The member feedback endorsed the value of the Library, and that the registers would be valuable as a checklist to review prior to and during risk review sessions. This may identify additional risks and mitigations that could be missed. An action was taken by Fiona Curley to post and communicate the location of the Risk Register Library to the membership.

**Compensator Lockup Mitigation: Update Based on the WTN Virtual Meeting conducted on 24 March 2015 - Arild Fossa, Expro**

Arild make the point regarding Slide 3 that this is not weighted by rig days while conducting locked to bottom (LTB) operations. Weighting the graph by rig days would further indicate the increase in LTB operations across the Norwegian Continental Shelf (NCS), and the corresponding increased risk exposure to potential heave compensator failure. He also noted that Slides 4 and 5 only address the risk of failure in tension, and excludes buckling. The current risk mitigation being applied in the NCS is the use of an open water instead of a subsea system. This is a more costly alternative, however, and typically adds a week of rig time when it is deployed.

A member noted that there are numerous situations in the North Sea where an open water system cannot be used. An OpCo rep responded that the use of the open water system does help, and eliminates the chimney effect that potentially drags all of the hydrocarbons to surface.

Slides 10-15 summarize some known heave compensator failure related incidents. Arild noted that one consistent element in all of the incidents was the need for the Driller to physically intervene (run across the rig floor) as part of the response. Arild indicated that there is little evidence of incident reports documented in the public domain, with most of the incidents documented internally within companies. Arild asked that members prepare and send additional incident case studies for inclusion.

A member noted that they were aware of a failure where coffee was spilled on the active system control screen which caused the system to fail.

Slides 17-23 portray equipment based mitigations that have developed beginning ca 2005. Arild speculated that NORSOK may address this issue in their standards, but this will likely not come to fruition for a couple of years. Arild mentioned that another risk to consider is the bending forces on the flowhead. The flowhead should be kept a minimum distance from the floor to allow room for it to bend sideways.

An OpCo member asked about the preference for an active versus a passive system. He noted that his company tends to go with a passive system. Arild noted that some rig personnel are reluctant to go offshore when there is only an active system present. There does seem to be a growing recognition by the DC of the need for a passive system during LTB operations. Given this, OpCos may want to consider including a requirement for a passive system. An OpCo rep noted that a DC operating manual indicates that in LTB operations, additional protection beyond an active system should be provided.

**Compensator Lockup Mitigation - Steven Plain, Icon Engineering**

Steven reviewed how computer simulations are being developed and compared against unit test results to correlate and validate the accuracy of the computer modelling. He indicated that an ARTP system was deployed offshore very recently.

**WellSafe Explorer Update - Haavar Sortveit, WellPArtner AS**

Haavar noted that over tension protection alone is adequate if the riser is free standing. The design basis for the WellSafe Explorer is not to provide perfect heave compensation, but rather to mitigate and prevent a large scale disaster. A unit is being deployed next month in offshore East Canada.

**New Technology Developments - Richard Broad, Halliburton**

The current industry downturn has created a healthy pressure to challenge standard approaches and determine how we can do things differently to lower the costs of conducting well testing. Mobile manuals are being implemented to ensure that even seasoned engineers and technicians adhere to required maintenance procedures.

**Roundtable Session**

**API 19TT1 UPDATE - TOPIC RAISED BY VINCE Zeller, Halliburton**

The Downhole Test Tools standard API 19TT1 is now submitted for ballot. Voting appears to be positive, with a meeting planned for June or July to review comments, after which the standard will be sent back to API for balloting a second time. By the end of the year, the standard may be fully approved and live. For the majority of ServCos, certification to the standard will be achieved relatively easily. OpCos will have the option to require adherence to the standard in their tenders. Review and revision of the standard is required in three years after approval.

**OUTLOOK FOR H2S - TOPIC RAISED BY VINCE Zeller, Halliburton**

The presence of H2S in well testing has historically been limited. Some recent inquiries suggest that the presence of H2S may be on the rise. NACE has recently revised their H2S industry specification, with more stringent requirements on material specifications. An example of a region where H2S is present is Kazakhstan, with 20-30k ppm H2S in the produced fluids. One OpCo rep responded that he has not heard of any new well testing prospects with H2S present. Another indicated that some well testing regions have a range of 50 to 1500 ppm H2S. The Middle East typically has high H2S, ranging from 0.5 - 12%. Surface equipment specifications for the Middle East will typically require that the equipment is qualified for H2S, but may be unclear on the specific amount of H2S to expect in the produced fluids.

**20K TECHNOLOGY DEVELOPMENT - TOPIC RAISED BY RICHARD BROAD, HALLIBURTON**

Several large OpCos have active development programs in this space. However, given today’s economic climate, how viable is this in the near term?

One OpCo member commented that many questions remain in this area. Another OpCo member indicated that this is not a focus area at this time for his company, and that OpCo investment would not materialize in the near term. The need for 20K pressure differential tools is a key issue, and how this impacts the BHA. A ServCo member noted that he is unable to envision a scenario where an Operator would expect to have 20K pressure differential on equipment. Meanwhile, 15K will remain the standard.

An OpCo member indicated that he agrees with this view of 20K differential pressure, but absolute pressure up to 20K would be possible. So a design basis of 20K absolute and 15K differential may be a more realistic choice. However, another OpCo member noted that the potential for 20K pressure differential could exist in extreme load cases, such as depleted tubing. Also, it would be undesirable for the DST tools to be the weak link in the system.

**Subsea Well Response and COntainment System Production Risers - Adam Tusing, Schlumberger**

A review of the response equipment indicated that the interface adaptor at the flow spool needs to be machined to fit the specific application at the time of the response. This provides flexibility to adapt to any new equipment that is developed in the future. One OpCo member questioned this dependency, but it was noted that this is a feature of the SWRP approach which is to hold less hardware in reserve, and instead leverage equipment that will be available commercially. The Responsible Party (RP) for the spill will be accountable to engage commercial parties to secure the equipment.

**POINTS FOR ACTION -** *key issues, improvements and steers on technology development*

* Engage/bring Drilling Contractor rep(s) to WTN meetings – Fiona Curley coordinate efforts to identify and invite as a guest to the Fall 2015 and 2016 workshops.
* Develop draft Success Story categories and share with the members for feedback - Fiona Curley/Don Dressler.
* Establish Well Testing Risk Register Library on Win Cubed website - Fiona.
* Send additional heave compensation failure related incident summaries - all members. Post incident summaries to Win Cubed web site - Fiona.

**INPUT ON FUTURE WORKSHOP TOPICS**

* API 19TTI Downhole Testing Tools approval update
* API 17G SS Intervention revision update
* Advanced data topics such as free sampling while drilling
* Broader data topics (not just PTA related) - ideally one day data related, one day hardware related

**Dates for Fall 2015 WTN meeting**

* Aberdeen – Thursday and Friday September 10-11, 2015 (Offshore Europe week) Host: to be identified.

END