2017 SPE ESP Symposium

Summary of Presentations

Woodlands Waterway Marriott Hotel

Monday, April 24 – Friday, April 28, 2017

Prepared by
Cleon Dunham, Oilfield Automation Consulting, Artificial Lift R&D Council
May 3, 2017

Purpose of this Document		
Purpose of this Document	**Cleon Dunham** **Oilfield Automation Consulting, Artificial Lift R&D Council**	The purpose of this document is to summarize the main points of the technical presentations at the 2017 SPE ESP Symposium. If you wish to learn more, please review the actual papers, which can be downloaded from the ESP Symposium website. If you didn't attend the Symposium, you can purchase a CD from the SPE ESP Symposium Committee. These summaries are based on my 46 pages of notes. If anything is presented incorrectly, I may not have heard or recorded it correctly, so the fault is mine, not the fault of the authors and/or presenters of the papers. The lead authors (or the authors who presented the paper) are shown in bold brown color for each paper. The authors are welcome to correct the summaries, if needed. • This would be the 29th ESP Workshop, but now it is called the SPE ESP Symposium. • The first one had 60 people. • Total attendance at this year's workshop was 561, with 159 from operating companies. There were 39 exhibitors and 8 sponsors. • In 2015 there were 491 attendees. • This year's attendees came from 29 separate countries. • They represented many different organizations. • Legend used for Q and A is: Q = Question A = Answer C = Comment

Opening Comments Workshop Co-Chairs: **Barry Lance Nicholson - Oxy Inc.** **Leon Ben Waldner - Nexen Energy ULC**		
Paper	**Author**	**Comments**
Opening Comments	**Barry Lance Nicholson** **Oxy Inc.** **Leon Ben Waldner** **Nexen Energy ULC**	**Barry Nicholson,** the 2017 SPE ESP Symposium Chair, welcomed all attendees. • He said the ESP Symposium is on the SPE Calendar. – All the Technical Presentations are recognized and registered. – There are so many Technical Presentations that there needed to be 3 ½ days to include all the presentations. These were on Tuesday, Wednesday, Thursday, and Friday morning. The event used to be 2 ½ days. – There was one day of Certified Training on Monday. – He thanked all the members of the Committee. – He thanked ExxonMobil for sponsoring the WiFi service. – He mentioned a "trivia" application that will be used throughout the Symposium. • He reviewed the general schedule. – Crawfish Bowl on Thursday evening. – Golf on Friday afternoon. • He introduced David Carpenter of Shell to give the Keynote Address.
Keynote Address		
Keynote Address	**Dave Carpenter** **Shell International EP**	**Dave Carpenter** of Shell International EP gave the Keynote Address. • He shared his thoughts on how we, as an industry, can learn from history and prepare to ride through this economic downturn. – We need experts. – Small details matter. – Oil prices will go up and down. – People change. – We tend to do better when prices are lower, and we need to focus on details to make improvements. – In the 1980s, Shell had over 15,000 sucker rod pumping wells. Shell also had CO_2 injection. – Now Shell focused on subsea and unconventional wells. – "We have lost all our sucker rod pumping expertise." • Experts need to focus on three areas: – Understand system performance. – Analyze results. – Be able to duplicate results.

		• He gave examples of real experts: − John Bearden − Mark Mahoney − James McCoy − Sid Smith • All had common characteristics: − All of them used mentors. − All were active in the industry. − All taught others. − All took a long time (a decade or more) to become an expert. − They received feedback and learned from it. − They had a passion for their area of expertise. • He talked about how to become an expert: − Read technical papers, like from SPE. − Meet with recognized experts and learn from them. • He gave examples from Shell of various levels of experts: − Principal Technical Experts, e.g. Jim Hall for gas lift. − Subject Matter Experts. − Associate Subject Matter Experts. • He gave examples from other companies: − Hosting technical Q&A sites. − Having global troubleshooters. − Some companies hire experts. ▪ He said how experts can be “killed:” − Don’t let them attend conferences. − Don’t give them challenging work. − Make them focus too much on administrative work. − Don’t show them respect. ▪ He discussed how to rebuild expertise: − Work with academia, JIPs. − Work with the service industry, e.g. on new products. − Work with operators. − Work with other operating companies. Q. If a person’s expertise in no longer needed, how can they advance their careers? A. Need to obtain good general skills in addition to expertise. Q. What percentage of the experts are lost? A. Typically, we lose ⅔ to ¾ of our experts. They go into other work, or other fields, or to other companies.

Session I ESP Data Analysis Session Co-Chairs: Barry Lance Nicholson - Oxy Inc. Leon Ben Waldner - Nexen Energy ULC		
ESP Root Cause Failure Analysis in Guatiquia Field, Colombia: A Case Study	**F. Guerra**, Pacific Exploration & Production Corp. N. Cortina, L. Franco, Pacific Exploration & Production Corp. E. Vera, Y. Pineda, Universidad Pedagogica y Tecnologica de Colombia	• This is a story about an unconventional field in Colombia. • Issues addressed: – Stuck pumps. – Sand. – $CaCO_3$ scale. – Tried to use acid – it didn't work. • Focused on analyzing the root cause of failures: – Tried visual inspection. – Chemical analysis. – Micro attack – stress analysis. – Micro structural analysis. – Micro hardness profiles. – X-ray diffraction. – Hydrogen evaluation testing. • Failure mechanism: – Hydrogen embrittlement. – Addressed by changing to stainless steel. Q. How long did it take to go through this process? A. Three months. Q. Can you reduce this time? A. It depends on the number of tests needed. Q. Did you consider using 15% HCl? A. We used this and some other fluids. Q. Have you used X-ray results? A. Saw some scale, and used inhibitors. Q. Did you use the same lab for all the tests? A. We worked with different universities. Q. Had you used acid before? A. Yes, we often use acid. Q. Were the components exposed to the acid? A. We injected the acid through the tubing.

Leveraging Run-Life Data and Industry Collaboration in a Low-Cost Environment	**J.W. Sheldon**, F. Trevisan, C.A. Radke, F.J. Alhanati, C-FER Technologies	• This is about run-life data in a low-cost environment. • ESP experience: – First experience. – Increase operating costs. – Increase replacement costs. • Data Used: – Need good data. – Target cost to collect and devaluate data. • Three-stage strategy: – Obtain quality data – seven parameters. ○ Need information on all systems. – Overcome some challenges. – Identify technical issues. • Leverage industry collaboration. • First Case Study: – High-curvature wells. – Correlate with dogleg severity. – Need to decide where to land the pump to minimize problems. • Second Case Study: – Leaking seals. – Solved with 25% to reduce cost by $40,000. – Conducted lab tests to verify results. – Goal: Quality operation to alleviate problems. Q. Were seal failures due to installation problems? A. We assumed the installation was OK. Q. What are low, medium, and high doglegs? A. This is confidential information. Q. Are doglegs indicated in open hole or cased hole? A. Both. Q. Did you improve the failure rate? A. Too early to tell. Q. What part of the seals failed? A. We only have general results. Don't know the details. Q. What is the general find? A. The failure is due to leakage. Q. Did you look at horizontal wells only? A. Only horizontal wells. Q. Who did the work? A. Work was done at CFER.

<table>
<tr><td></td><td></td><td>Q. Was it difficult to get consistent data?
A. We used standards and best practices.

Q. Are failures near-term or long-term?
A. Don't know.

Q. Can doglegs be corrected with drilling practices?
A. We only looked at crooked wells.</td></tr>
<tr><td colspan="3">Session II
ESP Subsea
Session Co-Chairs:
Miguel Angel Ortega - Cannon Services Ltd.
Keith Russell - GE</td></tr>
<tr><td>Full-Scale Investigation of Gas-Handling Capabilities of High-Flow Helicoaxial ESP Stages for Deepwater Application</td><td>M.D. Rojas, Royal Dutch/Shell Group

L.J. Barrios, Shell

G.T. Harris, K. Cheah, Schlumberger</td><td>• This is about gas handling in deepwater applications.

• This is about testing of a subsea boosting system in the Shell Gasmer testing facility in Houston, Texas.
– The system is used in the Perdido field in the Gulf of Mexico and the BC10 field in Brazil.

• The Gasmer test facility uses an ESP system.
– It uses 1,600 horsepower.
– It can boost up to 2,0000 psi.

• The testing was conducted at Gasmer.
– 30,000 bbl/day.
– Three different VDSs.
– Tests were conducted with oil and N_2 gas.
– The tests varied the gas volume fraction.
– They tested 150 and 300 centipoise.
– They tested helio-axial ESP stages.
– They ran several different tests.
– They can handle greater than 79% GVF.

Q. How did you correct factors for gas?
A. We used stage-by-stage corrections.

Q What was the viscosity?
A. As indicated, the viscosity varied from 150 to 300 centipoise.

Q. Did you monitor at stable GVF readings?
A. Yes, we monitored at stable points.

Q. Did performance improve at increased pump intake pressure?
A. Yes, we got a better mixture of gas and liquids.

Q. Can you go up to 70 Hz?
A. The test loop can only go up to 60 Hz.</td></tr>
</table>

Brazil Field Experience of ESP Performance with Viscous Emulsions and High Gas using Multi-Vane Pump (MVP) and High Power ESPs	**Lisette J. Barrios**, Shell M.D. Rojas, Royal Dutch/Shell Group G. Monteiro, N. Sleight, Shell Brazil	• This is about gas handling in deepwater applications. • It is based on more testing at the Gasmer test facility in Houston, Texas, and the BC10 field in Brazil. • Production conditions: – The crude is up to 1,200 centipoise. – Used demulsifier. – The ESP is used in a subsea caisson system. – In some cases, the gas and oil are separated before being pumped. – In other cases, the gas and oil are pumped together. – Pumped at 3,500 psi. – Up to 55% GVF. – Up to 1,200 centipoise. – Used a head correction factor to model the results. • Field results: – Flow rate was up to 11,000 bbl/day. – Injected demulsifier to reduce the viscosity. – Performance decreased at 60 GVF. – Needed to use correction factors from the manufacturer. – The Gasmer tests gave good predictions of the performance we saw in the field. Q. How suitable is this for smaller casing? A. We can correct for smaller pumps. Q. How did you measure the amount of gas in the fluid? A. This is based on the GOR of the wells and the ESP pump performance curves. Q. What are the correction factors for the pumps? A. Need different factors for different sizes of pumps. Q. How do you evaluate the effect of the demulsifier? A. This is based on each separate condition. Q. Why change the viscosity of the injection of demulsifier? A. We have a mixture of fluids. We can more easily handle lower viscosity fluids.
Session III ESP Field Study / Surveillance Session Co-Chairs: Cyril Girard - Statoil ASA John K. Graham - Suncor Energy Inc.		
Increasing Production with High-Frequency and High-Resolution Flow	**L.A. Camilleri**, M. El Gindy, A. Rusakov, I.H. Ginawi, H.T. Abdelmotaal, Schlumberger	• This is about high-resolution flow measurements with ESPs. • This is in the Khalda field in Egypt. – This based on work in four wells. – The wells are from 4,000 to 13,000 feet deep. – Production is above the bubble point.

Rate Measurements from ESPs	E. Sayed, T. Edrees, M. Karam Abdo, Khalda Petroleum Company	– The flow rate is calculated from well data. – The flow rate measurement is more accurate than using a test separator. – It uses a "Pump Health Indicator" or PHI. – If the PHI is 1.0, there is no degradation in the flow measurement. – This can be used to measure the well's productivity index (PI) "on the fly." – Can use to calculate reserves. – Can use to calculate the well's skin effect. Q. Do you need the downhole pressure? A. Yes, we must have this to make the calculation work. Q. What if the pump is broken? A. Then this method will not work. If the pump is broken, we can't use this method. Q. Does it depend on how the pump is driven? A. We need a filter on the pump. Q. How do you calculate the load factor? A. We need a model to calculate the load factor.
Successful Standardization and Sustainable Well Management System for ESP Well Surveillance & Optimization Across PDO	**Atika S. Al-Bimani**, R. Kulkarni, H.K. Al-Muqbali, A. Mackay, A. Andrade Marin, A. Al-Busaidi, S. Touqi, Z.A. Al-Yazeedi, A. Abdullah, K. Harthy, F. Kharusi, Petroleum Development Oman; N. Kumar, Weatherford International Ltd.; S. Gupta, Weatherford	• This is about well surveillance in Petroleum Development Oman (PDO) using software. – They want all engineers to use it. – 70% of their production is oil. – There is a lot of gas production as well. – PDO is owned 60% by the government of Oman. – It is owned 34% by Shell International. – There are 1,500 ESPs. – All ESPs are monitored by PDO's SCADA system. – All use automatic well models. – They use a LEAN process for analyzing their ESPs. – They use this to design and operate their ESPs. – This leads to a 4% gain in production, and eliminated waste. – They use pattern recognition to detect problems. – Manual work time is reduced by 59%. – They use this to improve their Standard Operating Procedures (SOPs). – All of their engineers are using this. – They want to be able to predict when a well will fail, and what will be the failure mode. Q. How many production engineers do you have? A. We have 85. Q. Are you improving run life? A. Yes, and we use failure data.
Strategy to	**P.V. Mali**,	• This is a story about reducing operating costs in Kuwait Oil

Implement Relevant ESP Technologies for Mitigation of Reservoir Challenges and Reduction of Operating Costs in KOC	Prasanna Mali; H. Al-Abdullah, M.M. Zerai, B.S. Al-Matar, Kuwait Oil Company	Company (KOC). • This is based on pilot tests implemented in KOC. – Goals are to reduce Capex, Opex, improve run life, and increase production. – Have high GOR wells. – Have used alternative deployment methods. – Use power analysis. – Have high water cut wells. – Have heavy oil. – Have problems with asphaltenes in the crude. • High GOR problems: – Have some wells with high GOR. – Have low pump intake pressure and low bubble point. – 75% free gas. – Have tried gas handlers, multiphase handlers on two wells. – This improved run life. • Have used dual ESPs. – Producing two zones in one well. – This reduced drilling costs. – This was pilot tested and it worked OK. • Have tried alternative deployment methods. – Did this to reduce cost and increase production. – Done in 3.5-inch tubing. – Need a workover to install this. • Used permanent magnet motors. – Permits a wide operating range. – Power use is decreased. – We plan to increase use of this gradually. • High water cut wells. – Goal is to reduce load on surface facilities. – Inject the water downhole. – Try inverted ESP to inject water downhole. • Heavy oil. – 9,300 feet deep. – 7,800 centipoise. – Gravity 10° API. – Want to conduct a pilot test with chemical injection downhole. • Have asphaltenes. – 14,000 feet deep. – Gravity 34° API. – Will use downhole chemical injection. – Need a trial test. – Need good project management.

		Q. What is your GOR? A. Sometimes high enough to permit natural flow. Q. Do you use gas separators? A. Yes. Q. Did you consider venting gas up the casing? A. No. Q. Did you look at using jet pumps for heavy oil? A. Yes. Q. How do you inject chemicals? A. We use hot water with chemicals. Q. Have you tried inverted ESPs? A. We haven't tried this yet.
Session IV **ESP High Temperature** **Session Co-Chairs:** **Chris J Scrupa - Schlumberger** **John K. Graham - Suncor Energy Inc.**		
Eliminating Gas Lift by Directly Converting SAGD Wells with High-Temperature ESPs	**S. Shang**, J. Caridad, Schlumberger	• This is a story about the Steam-Assisted Gravity Drainage (SAGD) project in Northern Alberta, Canada. • SAGD focus, problems: – High temperature, scale, sand. – Eliminate need for gas lift by using high-temperature ESPs. – SAGD has two wells in parallel; steam injection in upper well and production in lower well. – The Steam/Oil Ratio (SOR) is important for the economics of the project. – Want to have a low SOR. • There are four phases in the production life cycle of a SAGD well: – Start up. – Ramp up. – Long-term production. – Blow down. – Normally gas lift is used in the ramp up phase. – The temperature is about 250°C. – Now would like to use ESPs in the ramp up and long-team phases. • Production conditions: – Normally sand is produced along with the oil. – "Poor Boy" gas lift is used in the ramp up phase. – There are no gas lift mandrels. – There are some problems with gas lift. ○ There are thief zones.

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<li style="list-style-type:circle">Need more infrastructure to inject the gas and handle the production.
Would like to use ESPs, starting in the ramp up phase.
– Use VSDs to manage the ESPs.
– Use gas handling technology.
– Need to deal with high temperatures.
– Can install ESPs during the start-up phase.
– Can use existing high-temperature ESP technology.
– Can use to reduce the steam/oil ratio (SOR).
– Can increase production rate.
– If can use ESPs starting in the start-up phase, can reduce workover costs.
Q. How can you control temperature and steam breakthrough?
A. Need to avoid high drawdown to avoid breakthrough.

Q. What does perfect sub-cool look like?
A. 5–8°C.

Q. Problems with inflow. Does Schlumberger look at this?
A. Yes. We look at composite models. Look at Equation of State. Look at Steam Void Fraction data.
</td>
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<tr>
<td>Design, Operation, Diagnosis, Failure Analysis and Optimization of ESP Systems in Wells With Great Depths, High Temperature, High GOR, and High Concentrations of CO_2, N_2, H_2S in Samaria Luna Field</td>
<td>M. Ramirez, ESP Oil and Gas Energy, SA DE CV;

J.F. Martinez, Pemex</td>
<td>
This is about a very important field in Mexico.
– The field is in the South of Mexico.
– We use gas lift and ESPs.
– 28–31°API.
– Well depths are 4,150–4,450 meters.
– Temperatures are 130–160°C.
We have 80 ESPs.
– To manage these, we need lots of information:
  ○ Power supply.
  ○ VSDs.
  ○ Use of chokes.
  ○ Chemical injection.
– We have many problems.
– We've had 41 failures in 17 wells.
Q. Do you have problems with your vendors?
A. Most of our problems have been with operations.

Q. What is your plan to improve run life?
A. Improve many aspects of our operations.

Q. What are the manufacturer's responsibilities?
A. Most of the responsibility is with Pemex.
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<tr>
<td colspan="3" align="center">Session V</td>
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<tr><th colspan="3">Graybeards Panel</th></tr>
<tr><td></td><td></td><td>• This was a session for “Gray Beards,” that is, people who are very experienced in ESP troubleshooting and failure analysis, to discuss approaches to improve ESP run life.

• The “Gray Beards” included:
– Jeff Dwiggins
– Peter Oyewole
– Ken Lacy
– And others

• Each person reviewed a “Case History” and discussed how problems were found and addressed.</td></tr>
<tr><th colspan="3">Session VI
ESP Operation / Optimization
Session Co-Chairs:
Albert George Ollre - GE Oil and Gas
Steven C. Kennedy - EOG Resources Inc.</th></tr>
<tr><td>Best Practice on ESP Hands-On Operation: Troubleshooting & Optimization at Well Sites, Oman South Oil Fields</td><td>A. Awaid, Petroleum Development Oman

S.B. Nemecio, A. Al-Oufi, K. Al-Kindy, A.S. Al-Bimani, Petroleum Development Oman</td><td>• This is about troubleshooting and optimization of ESP operations in Petroleum Development Oman (PDO).

• ESPs in PDO:
– There are 1,500 ESPs in PDO.
– The NIRM field has 350 ESPs.
– There are 82 trips every year.
– They have heavy oil.
– Solids.
– Low reservoir pressures.
– Low inflow rates.
– CSR staff.
– CSR Supervisors in all ESP operations.
– Troubleshooting methods.

Q. Do you use Change Management?
A. This is a new term for us.

Q. Do you use “management by exception?”
A. We used the Weatherford LOWIS system to monitor our ESP operations. This provides a “management by exception” capability.</td></tr>
<tr><td>Installation of Electric Submersible Pump as Artificial Lift Method in Low Flow Rate Wells, a Case History</td><td>J.J. Del Pino Castrillon, OXY Colombia

J.L. Martin, H. Vargas, Occidental de Colombia Inc.

J.S. Maldonado, OXY Colombia</td><td>• This is a discussion of using ESPs to produce low rate wells in an Oxy field in Colombia.

• Typical problems we have:
– Sand.
– Scale.
– Corrosion.
– Low GOR.
– Typical production rates are less than 1,000 bbl/day.
– High failure rates:
○ Rod and tubing wear; sand.</td></tr>
</table>

	W. Nunez Garcia, Occidental de Colombia Inc. L.M. Sanchez, OXY	• Sucker Rod Pumping: – Failures due to corrosion. – Sucker rod and PCP failure rates are higher than ESP failure rates. ▪ Started using ESPs. – 50–1,000 bbl/day. – Low flow rates. – Mixed flow stages. – Compression type pumps. – No radial stages because of problems with sand. – Can produce with both down thrust and up thrust. Q. Did you try to solve your problems with sucker rod pumping and progressive cavity pumping? A. Yes, but ESPs work better. Q. Did you consider the value of life cycle? A. We did, and that's why we changed to using ESPs. Q. Could the problem be the difference between low and high rate production? A. They operate better at low rates. Q. What is the focus of your design? A. We design to operate at the "best efficiency point." We do this at low flow rates. Q. What ESP run life are you able to obtain? A. We are getting 4–5 year run life with our ESPs.
Advanced Electric Submersible Pump - Status on Development Towards Superior Reliability	**Cyril Girard**, Statoil ASA F. Marra, Statoil	• This is about ESP status offshore Norway. • Status of ESP operations in Statoil, Norway: – Statoil started using ESPs in 2011. – First ran a pilot test. – Now have 1,600 ESPs offshore Norway. – Also use gas lift. – They want to improve the reliability of their ESPs. – Target is 5-year run life on 85% of their units. – They have high costs offshore in deep water. – They have high intervention costs. – There is often a long wait time for rigs. – Target is to produce 10,000 bbl/day. – They use permanent magnet motors. – They will pilot test this until the end of 2019. – Seeking high reliability. – They use OLGA to model their wells. – They want to work with other operating companies. Q. Do you have best practices? A. Yes, this is our corporate philosophy.

		Q. How do you obtain management buy-in? A. We minimize risk; we use a Statoil team. Q. Will you do lab testing? A. This will be part of the pilot test. Q. How will you focus on reliability and cost? A. We will retrofit in existing 7" tubing.
Session VII **ESP Gassy Applications I** **Session Co-Chairs:** **Thomas J. Van Akkeren - Production Technology Associates** **Roger Brown - XTO Energy Inc**.		
New ESP Gas Separator for Slugging Horizontal Wells	**Steve C. Kennedy**, EOG Resources Inc. **Zach T. Madrazo**, C. Rhinehart, B. Hill, C. Grimm, EOG Resources C. Smith, Mingo Manufacturing	• This is about a gas separator to help mitigate slugging in horizontal wells. • Problems with gas: − Pumps can gas lock. Can't handle fluid. − This can heat the pump to 600°F. − This can heat the motor. − Can cause thermal stress in pot heads, motor windings. • Ways to address these problems: − Reverse flow. − Gas handlers. − Better gas separators. − Inverted shrouded pumps. • Test in an R&D Facility. − Redesign pumps to improve pump fillage. − Use newer trim. − Install Coriolis meter to test flow rates. − Try new "Ninja" design. − Tried on 10 wells in the Bakken field. − Want to test on more wells. Q. Is intake through a slotted shaft? A. Yes. Q. What is the casing size? A. 7" casing, 4" Ninja. Q. Is the ESP setting in the vertical? A. No answer. Q. Can we see a cut-away of the Ninja? A. See the paper. Q. Is this tested with a gas separator? A. We don't need a rotary separator with this.
Maximizing	**J. Chira**, A. Diaz Arias,	• This is about high gas wells in Ecopetrol in Colombia.

Production in High Gas Wells with Electrical Submersible Pumps Utilizing Variable Speed Drives with Intelligent Gas Control Software: Case History in Colombia	C.A. Gonzalez, B. Rodriguez, Baker Hughes H. Serrano, Ecopetrol S.A. J.A. Prada, OXY	• Project outline: – ESPs are controlled with VSDs. – Gas blocks with cycling at the impellers. – Motor temperature rises due to no fluid flow. • Three strategies to address the problem: – Avoid the gas by setting the pump below the perforations and using a shroud. – Separate the gas. – Handle the gas. o Use a Gas Handler. o Use special control modes: • Use PID control logic. • Use gas control software with a “control” module and a “purger” module. • Field experience: – Used in Oxy and Ecopetrol. – 40,000 BOPD. – 21–18°API gravity. – Before: 400 days, 65 BOPD, downtime 28 hours/month. – After: Stable operation, 250 psi pump intake pressure. – 500 days run time, 74 BOPD. – Flow rate increased by 14%. – No downtime. – Improved reliability. – 24/7 operation, no personnel required to operate the system. Q. What does the software do? A. Detects gas lock; changes pump speed; look at the paper. Q. Can the software run on any VSD? A. No, only on the Baker VSD. Q. Can it be installed on other VSDs? A. No, not now. Q. How does it work? A. It is automatic, not manual.
Session VIII		

<table>
<tr><th colspan="3">ESP You Don't Know What You Don't Know
Session Co-Chairs:
Francisco J.S. Alhanati - C-FER Technologies
Shauna G. Noonan - Occidental Petroleum Corp.</th></tr>
<tr><td>You Don't Know Pumps: Myths and Truths About ESP Operation in High-Gas Environments</td><td>M.A. Dowling, Perenco LLC</td><td>• This was an interesting discussion about use of ESPs in high gas environments.

• Sometimes gas is a problem, sometimes it isn't.
– We usually get the normal response.
– We don't get untreated gas out of the formation.

Q. Are there advantages to using gas separation?
A. All wells can benefit from good gas separation.

Q. Did you limit your study to certain types of wells?
A. No.

Q. Were the wells you studied vertical or horizontal?
A. Both.

Q. Can you unravel the myth?
A. Yes.

Q. If the casing valve is closed, can you see the flow path anyway?
A. Maybe we can, in some cases.

Q. How did you figure this out?
A. There were broken pumps.</td></tr>
<tr><td>Understanding Seal Sections and the "Phantom" Failures</td><td>Dan Merrill, Borets

Jeff L. Dwiggins, Dwiggins Consulting LLC</td><td>• This is about seal sections and protectors.

• The seal section:
– Connects the motor shaft to the pump.
– Compensates for oil volume change.
– Some use a labyrinth to separate the oil and water.
– Some use a positive seal to separate the oil from the well fluid.

• There are many rules of thumb:
– What safety factor to use?
– What are the root causes of failures?
o Mechanical; Chemical.
o Thermal. Temperature causes growth of components. Inverted systems have less growth.
– Address root causes of failures in design.
– It is good to use metal bellows rather than bags.
– Important rule: "Give up the good to get to great."

Q. What about use of check valves?
A. They are a big reliability issue.

Q. Oil expands due to high temperature. Should we increase the number of checks?
A. Maybe, but this may be due to shaft seal growth.</td></tr>
<tr><td>Achieving a</td><td>R.A. Lastra,</td><td>• This is a story about the goal of obtaining a 10-year run life</td></tr>
</table>

10-Year ESP Run Life	Saudi Aramco PE&D	on ESP systems.
		
		• This should be goal of both operators and suppliers.
		  – First thing is to overcome infant mortality.
		  – Most ESP systems have a 2–3 year run life.
		  – Chevron has reported 5-year run lives.
		
		• In general ESP reliability is poor.
		  – Human errors.
		  – Environmental factors – mostly downhole.
		
		• 1 – 10 Vision.
		  – Try for 1-day replacement time.
		  – Try for 10-year run life.
		  – Reliability: Go years without failures.
		  – Maintainability: Be able to restore production quickly after a failure.
		  – Availability: Be able to produce all of the time.
		
		• Reliability – three options:
		  – Use redundant systems.
		  – Improve intrinsic reliability through better designs.
		  – Responsible system – better operation before a failure.
		
		• Scheduled maintenance:
		  – Combine with alternative deployment.
		  – Need radical innovations.
		
		• Goal: 10-year run life without unscheduled downtimes.
		  – Need improved workover contracts.
		
		Q. How can we embrace preventive pulls?
		  A. This is a direction we want to pursue.
		
		Q. Will improved well surveillance help?
		  A. All of our ESPs are monitored by dedicated staff in a special room.
		  A. Adding more sensors will help.
		
		Q. You may need a “benign” field to actually get longer run life. Need to develop your people.
		  A. We need more training for our people. We are working on this.
		
		Q. An issue for a 1-day replacement time: dealing with wellhead problems.
		  A. We may need a workover to address well problems. We want to replace the ESP in one day. We are looking at using coiled tubing as an alternative deployment method.

Session IX		

<table>
<tr><th colspan="3">ESP Gassy Applications II
Session Co-Chairs:
Peter Olugboyega Oyewole - Proline Energy Resources
Kenneth Lacey - Custom Submersible & Electrical Service</th></tr>
<tr><td>A Tough, Truly Multiphase Downhole Pump for Unconventional Wells</td><td>A.J. Simpson, J.O. Rhys-Davies, M.J. Husman, E. Youri, Elite Multiphase Solutions</td><td>• This is about using the “V” pump.

• “V” pump characteristics:
– Provides a wide operating range.
– This is not a centrifugal or a progressing cavity pump.
– Can operate from 40–100 Hz.
– Can handle sand: from 5% up to 50%.
– Can handle gas: from 80% up to 95%.
– Can handle viscosity: from 6,000 up to 13,000 centipoise.
– It is a helio-axial pump.
– It looks like an ESP.
– It has the same installation profile.
– It is installed using standard installation practices.
– It has very stable operation – can address slugging.
– It can pump down and can overcome sand bridges.

• Target:
– Greater than a one-year run life in tough environments.
– Normally more than 5-year average run life.
– Can handle high viscosity.
– Uses advanced materials.
– Can operate from 40–100 Hz with very little amperage change.

Q. Sounds good. What problems do you have?
A. When there is a low flow rate, sand can accumulate in the tubing.

Q. What are the failure modes?
A. It can be seized with sand.

Q. Rotor/shaft gap. How does this affect efficiency?
A. Efficiency is similar to that of an ESP, but with different amps. It uses fewer amps than an ESP.

Q. What if there is a lot of scale?
A. Same problem as with an ESP.

Q. How does it handle emulsion?
A. It handles it well.</td></tr>
<tr><td>Subsea Boosting with ESPs in</td><td>L.N. Portman, Baker Hughes</td><td>• This is a story about using an ESP for subsea boosting.</td></tr>
</table>

High-Gas Environments - Full-Scale Prototype Testing Demonstrates Full Capability of New, Low-Cost System	Inc. H.C. Stibbe, Baker Hughes Oilfield Operations G.O. Homstvedt, Aker Solutions Subsea AS M. Farias, Aker Solutions	• It works in a subsea environment. – This will be tested in 2017. – This is a gassy environment. – There is a lot of gas slugging. – The system is installed on the sea floor. – This uses a regular ESP to produce reservoir fluid. • Why are we conducting a test? – High gas environment. – Need to test the software's technical capabilities. – There is low intake pressure. – Initial tests were in Oslo, Norway. – The ESP was installed in a caisson. – It was easy to assemble. – The system is rigid. – Tested from 0–70 GVF at 10 bar inlet pressure. – Operated ad 40–60 Hz. Q. Could you go up to 70 Hz with recirculation? A. Yes. Q. What are your future testing plans with the control system? A. We plan to test at 100% GVF, with gas slugging. Q. Does testing with air and water differ from using gas and oil? A. Yes, we would like to test with gas and oil.
Session X **Breakout Session I**		
Re-Use of ESP Components	**Matt Hackworth,** Oxy Petroleum	• This was a breakout session to discuss re-use of ESP system components. • We discussed re-use of: – Pumps. – Motors. – Cables. – Gauges. • We discussed the following categories: – New. – Remanufactured – like new. – Repaired. – Used. – Re-run. • Matt provided a summary of the Breakout Session on the last day of the Symposium.
Session XI		

<table>
<tr><th colspan="3">ESP Permanent Magnet Motors
Session Co-Chairs:
Tommy D Vineyard - Vineyard ESP Consulting
• Jeffrey Lee Dwiggins - Dwiggins Consulting LLC</th></tr>
<tr><td>Leveraging Energy Efficiency Downhole with Permanent Magnet Motors</td><td>Dennis J. Harris,
Chevron Energy Technology Company

J. English,
Chevron, retired

J. Leemasa-watdigul,
Chevron</td><td>• This is a story about the use of permanent magnet motors.

• Benefits of permanent magnet motors:
– They reduce the power consumption by 10–18% over regular ESP motors.
– The first patent on these motors was in 1916.
– They were first used in Russia.
– They run at synchronous speed with no slip.
– They are shorter, lighter, and can run at higher RPM.
– They reduce operating costs by 20–30%.

• Tests of the Motors:
– They have been tested by two companies in July 2015.
– They were tested in the Houston area.
– The efficiency is increased by 8%.
– There is almost no heat rise.
– The cost is comparable with other motors.
– The number of vendors for these motors is growing.
– They are compatible with alternative deployment methods.
– They work in horizontal wells.

Q. Is the power cable similar to that needed by other pumps?
A. No, it is lower in cost.

Q. Can they be controlled with a VSD?
A. Can’t talk about this; it is proprietary.

Q. Is the PMM as effective in regard to torque?
A. This wasn’t answered.

Q. Is there an issue with cable length, imbalance?
A. This a function of the motor, not of the cable.

Q. Is there an issue with dynamic changes, synchronization?
A. The tests have addressed this.

Q. What is the run life of a permanent magnet motor?
A. It will pay out over time, based on its improved performance.</td></tr>
<tr><td>Ultra-High Speed ESP PMM System</td><td>Alexander Gorlov,</td><td>• This is about an ultra-high speed permanent magnet motor.</td></tr>
</table>

Application in Salym Petroleum Development	Salym Petroleum Development	• Information about the application: – It was installed in western Siberia, Russia. – The field produces 120,000 BOPD. – There are 700 wells on ESP. – 7" casing is used. – The wells are 3000 meters deep. – There are problems with scale and corrosion. • Pilot test: – A pilot test was run in 2015. – Permanent magnet motors (PMM) were used in the test. – The PMM was run at 1200 RPM. – The downhole pump system was shorter. – The power consumption and installation time were reduced. – Installation time was reduced by 40%. – The installation was easy. – The power savings was 40%. – 100 units have been installed. – Run life has been increased by 60%; now at 800 days and counting. Q. Is there an issue with thrust? A. This has not been a problem. Q. How are the wells controlled? A. We use a Russian company. Q. How are power savings calculated? A. We do this on a KWH per m^3 of production basis Q. How do you get the primary savings in power – from the motor, the pump, or the entire system? A. We don't know yet. Q. What is your operating frequency? A. 55 Hz. Q. What is your probable run life? A. We're not there yet. Q. What is your reliability with respect to conventional ESPs? A. We expect the PMM to be better in this regard. Q. When you produce solids, will this increase wear? A. We don't know this yet.
High Efficiency ESP Applications for Slim Wells	**M. Ballarini**, Pan American Energy	• This is a story about use of slim wells in Argentina. • Information on the project. – This in a field that is in the South of Argentina.

<table>
<tr><td></td><td>M.L. Bruni,
D.H. Munoz,
M.E. Colla,
Pan American Energy

R. Teves,
GE Oil & Gas - Artificial Lift

J. Pires,
M. Russo,
GE Oil & Gas

R. Oyarzun,
D.A. Fleitas,
GE Oil & Gas - Artificial Lift</td><td>– There are 3,200 wells.
– There are 622 injection wells.
– There are 961 ESPs.
– We produce 15,000 m³/day of dry oil.
– We produce 182,000 m³/day of liquid.
– We use 5.5” casing.
– Wells are 2,500 meters deep.
– Temperature is 110–150°C.
– 2/3 of our production is by ESP.
– In 2002, our failure index was 0.42.
– Now it is 0.22.

• Our goals:
– Reduce power consumption.
– Increase efficiency from 35% to 60%.
– Reduce cable losses.
– Reduce motor losses – use permanent magnet motors to increase efficiency.
– They have a flat efficiency curve.
– Installation time is 2.55 times faster.

Q. How can you reduce cable losses?
A. Use slim holes; install the pump below the perforations; use flat cable.

Q. Will you be using permanent magnet motors in 10 years?
A. This our goal.</td></tr>
<tr><td colspan="3">Session XII
ESP Reliability Analysis
Session Co-Chairs:
Atika Said Al-Bimani - Petroleum Development Oman
Mark Robert Neinast - Summit ESP</td></tr>
<tr><td>High Density Survey Data and ESP Placement - Case Studies</td><td>A.G. Ledroz,
R. Shoup,
Gyrodata Inc.

B.L. Nicholson,
Oxy Inc.

T.B. Favrot,
Occidental Permian Ltd.</td><td>• This is about using gyroscopic data to evaluate ESP settings.

• ESP data:
– ESPs are long: from 80 to 150 ft in length.
– They are multi-jointed with flanges.
– They should be bent less than 2° when running.
– The bending depends on the dogleg severity and the tortuosity of the wellbore.
– An accurate survey is needed to evaluate the well’s actual deviation.
– A data point once every 100 ft is not good enough, as is obtained with most measurement-while-drilling data.
– Thus, a high-density survey data is needed.

Q. Is there a difference between the dogleg severity in open hole vs. in the casing?
A. The casing may decrease the dogleg severity, but not always.</td></tr>
</table>

		Q. Does the dogleg severity change with a change in azimuth? A. Inclination and azimuth are both critical. A. Oxy has a rule of no more than 2° per 100 ft. A. Some companies don't set the ESP near the kick-off point. Q. Can this be addressed with "best practices" in drilling? A. Oxy does address and determine "best practices" while drilling. Q. Is there a concern with "micro" doglegs? A. Need to evaluate the doglegs after running the casing. A. "Micro" doglegs may be bad, but they are better than kinks.
ESP Motors Reinstall Criteria to Maintain Reliability in Cerro Dragon Field	**M. Marzona**, Panamerican Energy A. Aguila, GE Oil & Gas R.A. Oyarzun, R. Teves, GE Oil & Gas - Artificial Lift	• This is about the reinstallation of motors. • Details on the project: – This is about a field in Argentina. – They re-use motors. – They have 5.5" casing. – They produce from multiple layers. – Typical temperature ranges from 110–130°C. Sometimes it is up to 110–180°C. – There are 930 ESPs. – The failure index is 0.22. – Most use 300 series motors. Some are 375 series. – There have been 3,200 motors running. • Project goals: – Improve reliability. – Reduce failures, Opex and Capex. – Change motor insulation for high-temperature usage. – Redesign the O-rings. – Motors were all tested when they were pulled. – About half of the motors passed the test and can be re-used. – Usually a motor can be installed up to three times. – This depends on the temperature. – We use a temperature indicator to check the temperature. – We can re-use the motor if it has run for less than 2,000 days. Q. You operate at 50 Hz. Has your QA process extended your run life? A. This is a "best practice." Q. What is your power factor mode? Under which conditions will you not re-use motors? A. If we have scale, sand, a large number of perforations, or if we have to change the pump. Q. Do you dismantle the motor and discharge the oil?

		A. We completely flush the motor before it is re-used. Q. If the oil isn't clear, do you re-use the motor anyway? A. This depends on the previous condition of the motor. Q. How do you prepare a motor for re-use? A. We use a plant that is on site for this work.
Session XIII **ESP Alternative Deployment** **Session Co-Chairs:** **Henry Okoro - Hess** **Michael Christopher Romer - Exxon Mobil Corporation**		
Comparative Project Economics: Wireline Retrievable ESP (WRESP) vs. Conventional ESP Systems	**L. Olabinjo**, Chevron S.J. Vierkandt, Chevron Overseas Petroleum Inc. J.C. Patterson, Patterson Consulting	• This is about a comparison between conventional ESP deployment and wireline deployment. • Workover options: – The first wireline ESP installation was in 1967. – Slick line operations are cheaper. – Workover options include: ○ "Heavy" workover with a rig. ○ "Light" workover with coiled tubing. ○ Cable-deployed ESP installation. ○ Wireline-deployed ESP installation. • Advantages of wireline: – Wireline installation is cheaper. – Less downtime. – More production. – Maintenance is easier. – Better than waiting a long time for a workover rig. • With wireline, need more hardware for docking the system. Q. What is the payback time? A. This hasn't been determined. Q. Are cable-deployed and wireline-deployed ESP installations affected by dogleg severity? A. People need to see proof of the benefits of wireline-deployed ESP systems. Q. Do you need to look at the cost of "Light" workover vs. cost of "Heavy" workover for ESP deployment? A. We haven't looked at this.
Well Control Strategy for ESP Rigless Deployment with Power Cable	**J. Xiao**, B.A. Roth, R.A. Lastra Melo, Saudi Aramco EXPEC ARC	• This is about rigless deployment of ESPs with power cable. • Deployment methods: – Tubing-deployed. – Coiled tubing-deployed, using 3.5" coiled tubing. – Coiled tubing, with the cable inside the tubing – this won't work.

	Y.S. Sarawaq, Baker Hughes, Saudi Arabia	– Coiled tubing with the cable strapped to the outside of the coil – this can work.
		– Power cable-deployed – with the ESP and cable run together.
		  o This reduces the cost.
		  o It is faster.
		  o Can deploy inside 4.5" tubing.
		
		• HSE issues:
		– Well control is challenging.
		– Need two barriers.
		– Need to keep well safe.
		– With two barriers, the safety is better than the normal workover process.
		
		Q. Can you use a deep-set barrier?
		A. This would be redundant.

Live Well Deployment of ESP Systems, Case Histories	**J. Greg Nutter**, D. Malone, AccessESP J.C. Patterson, Patterson Consulting	• This is about deploying an ESP system in a "live" well. • Project description: – This uses through-tubing deployment. – The ESP is deployed on slick line. – Don't need to kill the well. – Use a slick line blowout preventer (BOP). – This provides two barriers. – Can be used with any ESP. – 7" casing and 4.5" tubing. – The ESP cable is clamped on the outside of the tubing. – Install the power unit on the bottom of the tubing. – Use wireline to install the ESP. – This required four wireline runs. • First run: – Install the motor. – Install the seal. – Lower the motor onto the motor acceptance unit. • Second run: – Install the pump intake. – Install the pump. • Third run: – Install the pack-off. • Fourth run: – Install the tubing slip. • Summary: – Can complete the ESP change out in three days. – After the installation, can start the ESP and establish production. Q. Could you use a tractor in a high deviation well?

<table>
<tr><td></td><td></td><td>A. Yes.

Q. What can you do if the unit is stuck?
A. Pull the upper part and clear the tubing.

Q. What is the life of the external unit? Life of the wet connect?
A. They are filled with oil to protect them.</td></tr>
<tr><td colspan="3">Session XIV
ESP New Technologies
Session Co-Chairs:
Keith Terretta - Nexen Energy ULC
Alexander John Williams - Artificial Lift Performance Ltd.</td></tr>
<tr><td>Geared Centrifugal Pump Performance in an Enhanced Oil Recovery Field</td><td>Garret Best, Occidental Petroleum

R.J. Delaloye, ConocoPhillips Co.

B.L. Nicholson, Occidental Petroleum

W.B. Morrow, Harrier Technologies Inc.</td><td>• This is about using a geared centrifugal pump in lieu of a conventional ESP.

• Project description:
– These can be used in enhanced oil recovery (EOR) fields.
– Currently Oxy has 1,900 ESPs.
– They can be effective in providing efficient gas handling.
– They are used for CO_2 tertiary recovery operations, which experience gassy production.

• Description of the geared centrifugal pump:
– This is a rod-driven ESP, like a progressing cavity pump (PCP).
– The system uses a gear reducer (actually a gear increaser) to allow the pump to operate at 3,500 RPM.
– There are no downhole electrical components.
– Two of these pumps have been used in the Permian.
– Five have been used in Petroleum Development Oman (PDO).
– The ESP is a 456 unit.
– Three separate units have been tried.
– The drive runs at 60 HP, 6 Hz.
– The pump can produce more than 300 bbl/day.

• Pump operation:
– The pump is set above the perforations.
– There is a fiberglass intake below the perfs.
– The pump intake is just like that of a normal ESP.
– The rod string that is used to drive the pump is guided, with three guides per rod.

• Failures:
– First failure:
○ The sucker rod parted, due to poor quality rod material.
○ While the unit was running, there was good efficiency, and it used 74% less power than for a conventional ESP.</td></tr>
</table>

		– Second failure:
		  ○ There was some cycling on this well.
		  ○ The seal section failed.
		  ○ During operation, the power was reduced by 41%.
		– We still need to improve the system reliability if this is to see more use.
		
		Q. What was the cause of the failures?
		A. Poor material quality.
		
		Q. Is there differential heating?
		A. The unit should be stable.
		
		Q. Was there a pre-indication of the failures?
		A. The failures were sudden with no pre-indication.
		
		Q. What about heat dissipation?
		A. This shouldn't be a problem.

First Successful Experience of Hardened Stages for Sandy Wells at Northern Llanos Field, Case History	**Louise M. Sanchez**, J.S. Maldonado, J.L. Martin, H. Vargas, W. Nunez Garcia, J.J. Del Pino Castrillon, Occidental de Colombia LLC E. Rubiano, Occidental Oil & Gas Intl. C.H. Leon, J.L. Villalobos, J.S. Miranda Fernandez, Schlumberger	• This is about using hardened stages to help with sandy wells in Colombia. • Project description: – We are producing sandy wells. – Need more hardness to deal with erosion caused by sand. – The field produces 2.2 MM bbl/day fluid, 52,000 BOPD. – We get failures due to erosion caused by sand. – We get about 100 days run life. – Our target is to produce 200,000 BOPD. • Achieving hardness: – We use Ni-Resist to obtain hardness. – We use Zirconium bearings. – We install the pump low to minimize the amount of sand in the pump. – With this, we have increased to 20,000 bbl/day. – We have achieved 800 days of run life. – Workovers have decreased. Q. Have you tried backflushing? A. Yes. Q. When this is done, is sand reduced? A. Yes, this is normal in this field. Q. Have you tried running the pumps more slowly? A. Yes. Q. If you increase the Hz, does this increase the amount of sand production? A. Yes.

<table>
<tr><td></td><td></td><td>Q. Have you needed vibration from your downhole measurements?
A. We don't run downhole sensors on these wells.</td></tr>
<tr><td colspan="3">Session XV
Breakout Session III</td></tr>
<tr><td>Panel Session – Downhole Gauges and Data Acquisition</td><td>Thomas J. Van Akkeren, Production Technology Assoc.

Brian Hicks, Julian Credmore</td><td>• This was a panel session on downhole gauges.

• Considering downhole gauges, the following items were discussed:
– Gauge reliability.
– Value.
– Compatibility, standards.
– New technology.

• Reliability:
– Has been improving over time.
– Measure: PIP, PIT, motor T, leakage, vibration
– Failure modes: leakage, high temperature, contaminants.

• Value:
– Failure prediction.
– Well performance.
– Using a vibration spectrum – need high bandwidth data transmission to surface.

• Standardization:
– There are already some standard formats for handling data.
– More standardization would be a good thing.</td></tr>
<tr><td colspan="3">Session XVI
ESP Unconventional Applications I
Session Co-Chairs:
Matthew Roy Hackworth - Oxy Oil & Gas Corp.
Lorne Simmons - Borets US Inc.</td></tr>
<tr><td>Well Trajectory Impact on Production from ESP-Lifted Shale Wells: A Case Study</td><td>G. Yuan, Diego Narvaez, H. Xue, S. Nagarakanti, Schlumberger</td><td>• This about well trajectory and a software approach to artificial lift.

• Project challenges:
– Wells exhibit a steep decline in production rate.
– They produce slugs.
– They suffer from abrasion.

• Impact of well trajectory:
– This is from experience in the Bakken formation in North Dakota.
– Experience over 10,000 days.
– Some wells are toe up, some are toe down, some are hybrid (i.e., undulating).
– Primarily looked at wells in "hybrid" formations.</td></tr>
</table>

		– Use of ESPs increased the production rates. – Toe up and toe down wells had similar production rates. – The undulating wells experienced slugging. – The toe down wellbore is better for handling gas. Q. Did you use OLGA for your evaluations? A. We are not allowed to answer this. Q. Did you model sand production? A. We would like to do this. Q. What is your gas/volume fraction (GVF)? A. 400–1,500. We didn't get a good match. Q. Did you use test strips? A. Yes, 5 seconds. Q. Did you see the same effect on all of the stages? A. Yes. Q. Are you evaluating the slugging effect? A. We will do this on future tests.
Implementation of Torque and Drag Analysis to Simulate Forces while Running in Hole Electric Submersible Pump - ESP Assemblies, to Reduce Power Cable Mechanical Damages	**J.J. Del Pino Castrillon**, OXY Colombia W. Nunez Garcia, Occidental de Colombia Inc. J.S. Maldonado, OXY Colombia J.L. Martin, H. Vargas, Occidental de Colombia Inc. L.M. Sanchez, Universidad de America Bogota E. Rubiano, Occidental Oil & Gas Intl. J.A. Prada, Occidental de Colombia Inc. S. Gomez, Baker Hughes	• This is looking at the torque and drag while running ESPs in the hole. • This is based on work in a field in northeast Colombia, near the border with Venezuela. – Field has 3,600 wells. – 24% of the wells have greater than 99% water cut. – 17 had failed ESPs. – 31 had failed cable. – 39 failed due to other reasons. – Failures were greater due to cable installation problems. – These wells had severe dogleg severity. – We did a torque and drag analysis. – We identified several causes for failures. – One was due to the clamping pressure used to clamp the cable to the tubing. – We changed to flat cable with thickened armor. – We upgraded the cable spooler. – We upgraded the cable sheaves. – The new cable has a 0.15 failure index. Q. The torque and drag were not corrected at the first? A. Correct. Q. What is the competence of the people? A. This is being improved with more training. Q. Do you evaluate the torque and drag to determine the failure location? A. Yes,

	N. Sarkis, Baker Hughes Solutions A. Gonzalez, M. Jimenez, Baker Hughes E. Villamizar, UIS	Q. What database do you use to keep track of your failures? A. We use an Excel Spreadsheet. A. We take pictures of the failures. A. We take videos. Q. You have changed to flat cable? A. Yes. Q. Did the change increase the harmonics? A. No.
Session XVII **ESP Unconventional Applications I** **Session Co-Chairs:** **Barry Lance Nicholson - Oxy Inc.** **Leon Ben Waldner - Nexen Energy ULC**		
Improving ESP Application for Unconventional Wells in the Bakken	**James Britvar**, Oasis Petroleum LLC A.J. Williams, Artificial Lift Performance Ltd.	• This is about improving use of ESPs in unconventional wells. • This experience is from the Bakken Shale, in the Williston Basin in North Dakota. – The goal is to increase run time. – ESPs are used to increase the production rates from the wells. – Want to address limiting factors: ○ Dealing with reduced prices. ○ Dealing with other non-aligned factors. • Benefits desired: – Increase the wells' uptimes. – Reduce the workover costs. • Identify the failures: – Use proprietary software. – Failures in cables, pumps, and tubing. – Failures due to corrosion, abrasion. • Solutions: – Train the staff – both engineers and operators. – Train on the use of VSDs. – Train on the use of capillary injection to address corrosion problems. – Use a third party to conduct audits, perform teardown analysis. – Implement mandatory programs to make improvements. – Improve equipment selection. • Solutions: – Improve tenders. – Use capillary injection to address corrosion. – Use heavy lead cable. – Use better clamps. – Consolidate on one monitoring system, rather than several different ones.

		– Implement incentive contracts. Provide rewards for long run life. – Conduct well reviews using integrated software. Q. What is your tear down approach? A. Use to identify the cause of failure. Q. Do you use tear down for root cause analysis, or an ad-hoc approach? A. We use a team for this from the Cedar Creek Anticline. Q. What is your run life target? A. 18 months. Q. Does your gas separator handle 75% free gas? A. This is our estimate. Q. Do you tear down all pumps, or only those that have failed? A. We tear down all of them. Q. What are your before and after improvements? A. Our run time is improved. Q. Does your incentive contract consider tubing issues? A. This is an ESP contract. It doesn't consider the tubing. Q. How are you addressing problems with corrosion and scale? A. We did this through the use of improved metallurgy. Q. Who did your enhanced training? A. We used a third-party training company.
Breaking the 800 psi ESP PIP Barrier: How a Proven Flow-Conditioning Technology Can Dramatically Improve ESP Performance in Horizontal Wells	**Dave W. Kimery**, Production Plus Energy Service Inc. J.C. Saponja, Production Plus Energy Services Inc. R.C. Chachula, Chachula Consulting Inc. C. Jensen, Scribe Solutions Inc.	• This is about understanding multi-phase flow in horizontal wells. • Issues with multi-phase flow: – This leads to failures caused by gas and sand. – It can be addressed by beefing up the components. – However, this has a cost. – Pumps "see" the slugs of gas and liquid. – Slugs often occur after a shutdown. – Can use chokes to help address the slugging problem, but this causes high pressure losses. • Use the HEAL system to help address slugging. – This is installed below the pump to help stabilize the flow into the pump. – The gas goes up the annulus, and liquid goes through the pump. – The ESP pump is installed above the HEAL system. – In a field trial, this helped to reduce the drawdown and increase the flow rate. – This works on large casing. – We are looking at designing a system to work in smaller

		casing. Q. Have you tried setting this below the perforations? A. We would need a shroud above the pump. Q. When will the system fail in the life cycle? A. We are trying to optimize the full life cycle of the well. Q. Can you scale this up to 5,000 bbl/day? A. We want to try to do this. Q. What sizes are you considering? A. We are looking at multiple field models. Q. Do you use a choke? A. We try to minimize pressure losses that would be caused by using a choke.
Session XVIII **Symposium Wrap-Up**		
		• First, each of the leaders of the Breakout Sessions presented a brief review of their session. • Power Quality – Michael Romer: – We use long cables. – Small conduits. – Long motors. – High temperatures. – Failures shorten run life. – Need to avoid improper handling. – Use sine wave filters. – Need new specifications. • Equipment Re-Use – Matt Hackworth: – This was addressed in Session X on Page 19 of these notes. • Downhole Gauges – Tom van Akkeren: – This was addressed in Session XV in Page 28 of these notes. • Permanent Magnet Motors: – This was addressed in several papers in Session XI starting in Page 20 of these notes. • Symposium Summary – Leon Waldner: – Leon first thanked Barry Nicholson for the job he did as the General Chair this year. – He then acknowledged that he will be the General Chair for the next ESP Symposium in 2019. – He reviewed the following statistics from this year's ESP Symposium:

		- There were 561 attendees. - They came from 29 countries. - There were 159 attendees from operating companies. - There were 39 exhibitors. - There were 8 sponsors. - There were two Session Chairs for each Technical Session. – He acknowledged David Carpenter for giving the Keynote Address. • The Program Committee members were: – Barry Nicholson, Chairperson – Leon Waldner, Vice-Chair – Atika Al-Bimani – Amy Coombs – Karen Draper – Jeff Dwiggins – Carol Grande – Matthew Hackworth – Geoffrey King – Cheri Vetter • The Sponsors were: – Alkhorauef Petroleum – Baker Hughes – C-FER – Dover Artificial Lift – ExxonMobil – Schlumberger – BIW – PFT Power Feed-Thru • The Exhibitors were: – Access ESP – Alkhorayef Petroleum LLC – Artificial Lift Performance Ltd. – Baker Hughes Inc. – BCP Group Artificial Lift Inc. – Borets – CoorsTek – D&S Engineered Products – Dover Artificial Lift – Downhole Products USA – Echometer Company – ESP Completion Technology LLC – Fohama Electromecanica – Forum Energy Technologies Inc. – GE Oil and Gas – Gyrodata Inc. – Halliburton Co. – ITT BIW Connector Systems – Magnetic Pumping Solutions – Magney Grande Inc.

		– Marmon Engineered Wire and Cable LLC – Mingo Manufacturing – MultiLift Well Tec – Nix Electric Co. – Novomat USA Inc. – Pemser – SSAP Systems – PFT Systems and Connectors – Production Plus Energy Services Inc. – Production Tool Solution – Quick Connect Inc. – RMSpumptools – Schlumberger – Scientific Drilling International – Sercel-GRC – Summit ESP – Taurus Engineering – Triol Corporation – Zeus Inc. – Zhejiang Kete Pump Industry (RKT)