2009 ESP Workshop

Summary of Presentations

Woodland Waterway Marriott Hotel

Wednesday April 29 – Friday, May 1, 2009

Prepared by
Cleon Dunham, Oilfield Automation Consulting
May 1 - 12, 2009

Paper	Author(s)	Summary of Discussion
Purpose of this Document		
Purpose of this Document	**Cleon Dunham** **Oilfield Automation Consulting**	The purpose of this document is to summarize the main points of the technical presentations at the 2009 ESP Workshop. If you wish to learn more, please review the actual papers. The papers are included in the Workshop notebook and on the Workshop CD. If you didn't attend the workshop, you can purchase a CD from the ESP Workshop committee. These summaries are based on my notes. If anything is presented incorrectly, the fault is mine, not the authors and/or presenters of the papers. The lead author (or the author who presented the paper) is shown in **bold color** with each paper. Attendance at this year's workshop: • A total of 437 people attended the workshop. This was down slightly from last year, but far better than might have been expected based on the economy. • About 25% were from outside the US. They came from 22 separate countries. • Those from the US came from 17 states, with the majority from Texas and Oklahoma. • About 25% were from Operating Companies. The rest were from Service Supply Companies, Consultants, and Universities.
Opening Comments **Session Chair:** **Chip Ollre --- Schlumberger**		

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Opening Comments	**Chip Ollre**
	Schlumberger
		Chip Ollre, General Chair of the Workshop, gave the opening comments.
		• Chip welcomed the attendees.
		• He gave a safety presentation and made other announcements.
		• He thanked this year's sponsors.
		• He gave a nice testimonial for Jack Blann who recently passed away. Jack was instrumental in formation and perpetuation of the ESP Workshop.
		• He reviewed the schedule of the Workshop.
		• He briefly discussed the breakout sessions which will be:
		  - "Believe it or Not." A presentation by several ESP service companies, in the main ballroom.
		  - Equipment Selection, in Waterway 6 – 7.

	Keynote Address	

Keynote Address – ESP's Provide New Options for Subsea Boosting	**Dr. Stuart Scott**
	Artificial Lift Focal Point / R&D Program Manager
	Shell EP Americas
		Dr. Stuart Scott currently works for Shell EP Americas. Previously he was a professor at Texas A&M University.
		• Shell EP Americas – Areas of Interest
		  - Gas Well Unloading, including wellhead compression.
		  - Gas-lift, including high reliability gas-lift valves.
		  - Sub-sea boosting, including use of twin-screw pumps and a caisson ESP system.
		  - Boosting to increase reserves.
		    o At the sea bed.
		    o In the wellbore.
		  - Looking at new types of pumps for boosting.
		    o Helio-axial.
		    o Twin screw.
		    o ESP's.
		  - Helio-axials – developed by Framo.
		  - Twin screws – being used in Brazil, the North Sea, and the Gulf of Mexico, They are being used in up to 5,000 feet of water, up to 18 miles from the host platform.
		  - ESP's.
		    o Baker Centrilift
		    o Reda
		    o Typically handle GVF < 35%
		    o Looking at installing ESP's on the sea floor.
		      ▪ Using existing ESP technology.
		      ▪ Provide high boost: > 2000 psi.
		      ▪ Install in a caisson to separate gas and liquid.
		        • Basically a 300-ft.deep, 36-inch di-

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		ameter well for gas/liq. separation. ▪ Use large motors. ▪ Looking for 3 – 4 year run life. o All of these need to be tested. ▪ Testing in Norway, Brazil, and in a Shell/Statoil/Hydro facility in Gassmer near Houston, Texas. • Testing at full scale, with gas. • Testing with gas, various viscosities. o Lessons learned: ▪ Testing can save big $$ by saving interventions. ▪ Learn range of GVF's and viscosities that can be handled. ▪ Gain experience with multiple starts/stops. ▪ Gain experience with use of shrouds. ▪ Learn how to control the caisson. o Challenges: ▪ How to reduce intervention costs? ▪ How to redesign the caisson for easier access? ▪ How to handle more gas? ▪ How to handle higher viscosities? ▪ How to improve run life? o Need to step outside the "comfort" zone. ▪ 1st Generation: Standard techniques. ▪ 2nd Generation: Higher boost, higher pressure, more gas. o Conclusions: ▪ ESP's can be used for sub-sea boosting. ▪ A caisson is a good method to obtain sub-sea separation. ▪ Testing and qualification is essential. ▪ 2009 is a "milestone" year. Q. Will Shell's test data be presented to the Industry? A. Papers will be presented after the caissons have been used. Probably in 2010.

Paper	Author(s)	Summary of Discussion
Session I -— Harsh Environments **Chairs:** **Chip Ollre --- Schlumberger** **Tom Van Akkeren --- Production Technology**		
How We Did It Then Or The Evolutionary Growth Of ESP's	**John Bearden** Bruce Brookbank Lyle Wilson **Baker Hughes – Centrilift**	This was a presentation of the history of electrical submersible pumping over the last 82+ years. It presented the history, some of the key technical improvements that have been made in the recent past, and some of the expected future directions. The original inventor of ESP technology was Armais Aratunoff of Russia. He had many of the early patents. He presented his early ideas to Westinghouse who turned him down. His initial success was with a sucker rod company. Phillips field tested his first pumps in Kansas in 1928. • Companies: - REDA started in 1930. - Centrilift in 1957. - ODI in 1966. They are now part of Centrilift. - WoodGroup and Weatherford more recently. • ESP development: - First patents by Aratunoff. - Rotary gas separator by Shell in 1966. - Sand handling in 1958. - Motor patent in 1928. - Seal section patent in 1925, 1929. - Cable patent in 1930. - All current technologies have "evolved" from initial patents and developments. This has been an evolution, not a revolution. • Future? - Improvements for different fluid conditions. - Improvements for higher temperatures, higher viscosities, higher gas, higher sand. - Deeper settings, higher fluid rates. - Higher temperature insulation, elastomers, - Smart downhole ESP's. - No-leak seals. - Improved reliability. - Better monitoring and modeling. Q. ESP's are very big in Russia. Why not highlighted in this presentation? A. This paper was mostly about ESP development in the west. It is large also in Russia, China, etc. Q. Are you working on seal sections? A. Centrilift is looking at modifications for high temperature.

Paper	Author(s)	Summary of Discussion
		Q. What are the plans for API 11S? A. There is no plan to update API 11S at this time. To do so, need feedback and a "pull" from the Operating Companies. Comment: ISO is looking into forming an ESP committee.
The Quest To Understand ESP Performance And Reliability At 220 ºC (Ambient) And Beyond	**Shauna Noonan** **ConocoPhillips** Harryson Sukianto **Mike Dowling** **Schlumberger** **Wayne Klaczek** **CFER**	This was a presentation on development of ESP's for very high temperature use in SAGD (steam assisted gravity drainage) operations. Much of the information in this project is confidential, so it can't be presenter here. • Challenges: - The target is 250 ⁰C and 100 m^3/day. - The ESP must start at a much lower temperature, or about 100 ⁰C. • Have a 250 ⁰C test facility at C-FER in Edmonton, Alberta, Canada. - Can test at 260 ⁰C and 800 psi. - Can use N_2 instead of air. - Can conduct several types of tests: ▪ ESP start up/shutdown. ▪ Develop performance curves. ▪ Extended reliability tests. ▪ System shut-down tests. ▪ Vertical and horizontal vibration. - Tests have been conducted with a Schlumberger (Reda) pump. ▪ Specail materials used for temperature monitoring. • Conclusions: - Test loop worked very well at 24 hrs. per day. - ESP worked as expected. - It failed at 280 ⁰C. - ConocoPhillips is moving to the 2nd phase of the test. - Need to determine what "temperature rating" really means. Q. How is motor temperature measurement different from the normal approach? A. Measuring inside the motor with a thermocouple. Q. Is observed temperature increase consistent with an increase in motor loading? A. Yes. Q. What was the maximum differential temperature observed, and where was it? A. Confidential. Q. Is there a lower differential temperature during start-

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<tr><td></td><td></td><td>up?
A. The temperature during start-up was 220 ^{0}C, but we saw no cooling during the start-up operation.</td></tr>
<tr><td>Advancements in pump stage materials for Abrasive and Corrosive Well Environments</td><td>Tyler H Denham
Yakov A. Gluskin
Borets-Weatherford</td><td>This presentation covered advancements in pump stage materials to better handle abrasion and corrosion.

• ESP population:
- 76,000 ESP's in Russia – 60% of world population.
- USA has about 20% of world population of ESPs.
• Problems:
- Abrasion
- Scale
- H_2S
- Get impeller wear and diffusion.
• Materials:
- High Mn Ni-Resist.
- Spherical Graphite Ni-Resist.
- Co-Resist, using Powder Metal.
- Can address the problems with these materials.
- High MN Ni-Resist is low cost.
- Co-Resist gives excellent wear resistance.
- Powder metal is easily manufactured. It provides:
▪ Higher head per stage.
▪ 10 – 15% shorter pump for same lift.
▪ Reduced vibration.
▪ Longer run life
• These materials cost more than cast iron.
• Have developed a new test stand to test abrasion wear.
- Abrasion is much less than with cast iron.
- Corrosion damage is much less.
• Cost.
- Cost of powder metal is a little more than cost of cast iron.
• Summary.
- Powder metal provides better run lift than Ni-Resist.

Q. Is there a problem with copper corrosion in H_2S?
A. Powder medal performs well.

Q. What is density of the rotor plate?
A. Powder metal provided better run life.

Q. What was % solids test during test?
A. We used 10 gm/liter of solids.

Q. Did you follow ASTM testing procedures?
A. We used Russian standards; they are compara-</td></tr>
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Paper	Author(s)	Summary of Discussion
		ble. Q. Do you have numbers on efficiency improvements with Power metal? A. The actual numbers are available in the boot, but they were around 5 – 10%. Q. What is the basis for the claimed improvements? A. These new metallurgies have been used in more than 1000 wells.
Electrical Sub-mersible Pumps In SAGD Wells – Lessons Learned	**Colin Drever** Dale Serafinchan Ricky Santos **Schlumberger**	There are large challenges in SAGD wells. • Canada's Oil Sands - 173 Billion Barrels in Place - 140,000 Square Km. - 80% must be addressed with in-site recovery, as opposed to mining. - In 2008 – 1.2 MMBOPD. - By 2020 – 3.3 MMBOPD. • Lift methods used. - SAGD – steam assisted gravity drainage. - Gas-lift - ESP - Reciprocating plunger - PCP - Some others - Gas-Lift and ESP are predominant - Conventional ESP – 150 ^{0}C - 1st Generation Hotline – 180 ^{0}C - 2nd Generation Hotline – 218 ^{0}C - 3rd Generation Hotline – Expected in 2009. • ESP advances: - Lower pressure operation. - Higher flow rates – up to 2,000 m^3/day. - Good start-up capabilities. • Reliability - 140 Hotline ESP's in use. - Total of 413 pump years in operation. - 1492 days longest run life - still running. - 1291 days run life for Hotline 550 – still running. • Lessons learned: - High temperature ▪ Experience thermal growth. ▪ Experience thermal shock. ▪ Important to use correct materials. - Wellbore geometry ▪ Wells are highly deviated. ▪ Dogleg severity can be 5 – 15% / 30 meters. ▪ Need an improved drilling program with a slower build rate to kick-off depth. ▪ Need to include a "soft landing" area so ESP can be landed in a straight section of pipe.

Paper	**Author(s)**	**Summary of Discussion**
		▪ Need to include deviation analysis of well-bore. - Steam flashing ▪ Need to minimize steam flashing in wellbore. ▪ Need a better feeder intake. ▪ Need better pump stages, e.g. use AGH, Po-seidon, or multi-stage pump. - Abrasives, scale. ▪ A lot of abrasives (sand) are produced. ▪ Consider use of chemical treatments to ad-dress scale. ▪ Need to improve wellbore design to exclude solids. - General ▪ Need to use downhole monitoring. ▪ Need to measure motor temperature. ▪ Need to size the ESP to match each well's condition. ▪ Need more Operator training. - Future developments; ▪ Handle higher temperatures. ▪ Improve system durability. ▪ Improve downhole monitoring. Q. How can you improve downhole monitoring at high temperatures? A. Need a motor winding device. Consider use of fiber optics. Q. What have been the primary causes of failures? How soon? A. 40 – 50% of failures are due to abrasion. Mostly occur during first 30 days of operation. Q. Is steam break through a problem? A. This is not too large of a problem. Q. Is there a problem with generating enough steam for the field? A. Some Operators have a problem this, but most do not. Q. How do you size the ESP for each well? A. Need to work very closely with the Operator. Normally size for a mid-range production rate, in the middle between the minimum and maximum expected rates. Q. What software do you use for design? A. There are plans to design and develop a new de-sign program. Comment: PDO is using a downhole distributed tem-

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		perature system (dts); it uses fiber-optics to measure temperature and fluid level.
Session II – Alternate Deployed Systems / Surveillance **Chairs:** **Robert Lannom --- Baker Hughes, Inc.** **Noel Putscher --- Murex Petroleum Corp.**		
The Geared Centrifugal Pump - A New High Volume Lift System	**John C. Patterson** **Conoco Phillips** William B. Morrow **Harrier Technologies, Inc.** Michael R. Berry **Mike Berry Consulting LLC**	The Geared Centrifugal Pump (GCP) is a mechanical drive centrifugal pump, driven with rotating sucker rods. There are no electrical downhole components. A speed increaser is used to covert rod rotation speed of 500 RPM to pump speed of 3500 RPM. Components, from bottom up: • Stinger and gas separator. • Pump • Shroud • Transmission speed increaser. • Upper shroud with seal section. • Receiver. • Sucker rod string. Characteristics of "typical" system: • 100 Break Horsepower • 250 psi wellhead pressure. • 7,000 foot well depth. • 1,000 barrels per day production rate. Factors: • Fluid load is carried on the tubing. • There is a low axial load on the rods. • Need to use rod guides on rod string to minimize rod/tubing wear. • There needs to be fluid flow to cool the transmission. • All gears are equal load sharing. Field trial: • Placed the GCP in a well that had been produced with an ESP. • Had bottom rod fatigue due to offset in transmission. • The ESP efficiency was 45%. • The GCP efficiency was 49.5%. Issues: • Rod instability, due at least partly to offset in transmission. • Had a rod failure in the first rod above the receiver. • Plan to re-install with flexible shaft. Results: • Efficiency was better than expected.

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Installation went well.
There was no back spin.
Plans:
Install a flexible shaft above the receiver.
Install the unit in a 60 ft. test well.
Advantages:
Bottom intake ESP.
Better gas handling.
About same cost as for an ESP.
Can be used at high temperature; e.g. 250 ^{0}C in SAGD operations.
Q: Cost difference with ESP.
A. Cost of the prototype was about same as for ESP. With full production, cost should be less than for an ESP.

Q. What is the length of the transmission square rod?
A. Three feet.

Q. What was the depth of the test well?
A. 4,600 feet.

Q. Can this be used in a deviated well?
A. There low axial loads. Rods are guided. Should be OK up to 80^{0} from vertical.

Q. What are the target depths and rates?
A. 7,000 feet at 1,000 B/D. Can have up to 300 BHP in large casing.

Q. What is the temperature limit?
A. Up to 600 ^{0}F.
</td></tr>
<tr><td>The First 3 1/2" Coiled Tubing Deployed ESP In Saudi Aramco</td><td>Somali, Abdullah
Saudi Aramco</td><td>
Production from the wells needs to be pumped to the surface and then to the production facility. Coiled tubing is used to reduce cost and downtime.

Coiled tubing deployment characteristics:
Cable internal in the coiled tubing, vs. external.
With internal cable, pump up the annulus.
Internal cable installation time about 2 days.
External cable installation time about 3 days.
Conventional installation is longer than either.
Challenges:
This method needed to be approved by Saudi Aramco.
Cost:
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The cost with the internal cable is about 20 – 30% less.

Field test:

The field test was in an onshore field, but the eventual target is offshore where rig costs are high.
Well was 6,460 feet deep.
Well produced 2,000 B/D.
Pulled the old ESP and installed the new ESP with coiled tubing.

Results:

Installation time was 30% less than for a conventional installation.

Conclusions:

Running an ESP with 3.5-inch coiled tubing is feasible.
The installation cost is lower.
The downtime is lower.
The test well has been on production for 1.5 years at 2,000 B/D.

Q. How is the external cable system run?
A. The cable is manually attached to the coiled tubing. In the future, this can be automated.

Q. Is 3.5-inch coiled tubing readily available?
A. Yes. It is frequently used due to high production rates in Saudi Aramco.

Q. Did Operations like the idea?
A. Yes.

Q. The coiled tubing was made of carbon steel. Are you concerned about corrosion? Do you have water and CO_2?
A. The fluid in the field is sweet. CO_2 content is low.

Q. Do you plan to continue to install this onshore?
A. Yes, for ESP replacements.

Q. Will you kill and clean wells with coiled tubing?
A. Yes.

Q. Are you familiar with similar experience in Australia?
A. No.
</td></tr>
<tr><td>Dump Water Flooding Trials in Petroleum</td><td>Iqbal Sipra
Ahmed Azkawi
Jan Brinkhorst
Dey Arunangshu</td><td>Water flooding is needed for pressure maintenance. For small fields, “Dump” water flooding costs about one third of the cost for a full scale field water flood.</td></tr>
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Paper	Author(s)	Summary of Discussion
Development Oman	Ibrahim Shaibani **Petroleum Devel-opment Oman** Irina Osipova Fouad Eid Reza Dadrass **Schlumberger**	Injection strategy: • Initially inject at low pressure to avoid fracturing the reservoir. • Then plan to fracture the reservoir. • Produce water from a lower zone and inject it into an upper zone in the same wellbore. Risks: • Aquifer incompatibility. • ESP reliability. • Target injection zone may become plugged with fines produced from source zone. Testing conducted: • Initial tests conducted at the manufacturing plant. • Evaluated the risks. • Set up an installation and evaluation procedure. Conclusions: • Dump flooding is feasible. • The cost is less than a field-wide water flood pro-gram. Q. Is this the only dump flood well? A. Other wells in the field area have a full water flood system. But there are more candidates in small fields for dump water flooding. More pro-jects are planned.
Vibration, What Does It Mean?	Bruce Brookbank **Baker Hughes Centrilift**	This was a tutorial on vibration monitoring. Originally vi-bration monitoring (condition monitoring) has been applied to surface equipment. Initial steps: 1. Set a limit. 2. Conduct frequency analysis. 3. Evaluate eddy current problems. 4. Develop a Fourier Transform to evaluate the data se-ries. 5. Finally develop a portable analyzer. Application to ESP's: • Can measure the overall "G" limit – but which one? • Can't read the frequency spectrum – too much data to obtain from downhole. • A torsional vibration paper was written in 1982. • API RP 11S8 addresses ESP system vibration. • Tests of new and used ESP's were conducted in the 1990's. Reported by Dave Carpenter. • Get vibration spikes at about 60 Hz, 30 Hz, and 120 Hz. • Get pump vibration peaks at 30Hz, 60 Hz, 90 Hz, 120

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<tr><td></td><td></td><td>Hz, 240 Hz, and 460 Hz. Harmonics.
• Create a “waterfall” plot.

How much can an ESP shake?
• Per API 610, less than 0.184 inches/sec.
• Different standards vary on the allowed limits.

Does vibration cause damage?
• It can if there is a flexible housing.
• If there is no support.

What to do?
• Use API RP 11S8 as a guide.
• Need to re-write 11S8 to update it.
• Need to conduct R&D to determine what vibration causes what defects.

Q. Why was Carl Cox of Amerada Hess not cited in this paper?
A. His data was not published. Amerada did a lot to improve run life. But don’t know which things helped.

Q. What is the effect of “critical” speed?
A. VSD’s don’t cause a problem when they are operated at “critical” speed.

Q. Can you use vibration data to evaluate product manufacture? Can you indicated the best way to support equipment to get good vibration data?
A. No.

Q. Is vibration worse in resonance?
A. A Hz by Hz plot is needed to see where the vibration is worst.

Q. What vibration should we look at downhole – radial or axial?
A. Would like to see both.</td></tr>
<tr><td>ESP Monitoring And Alarms</td><td>Clint Olmstead
Jeff Dwiggins
Conoco Phillips</td><td>Field Information:
• Located in Offshore China.
• 200 wells produced by ESP.

The ESP’s:
• The ESP’s are operated by the Platform Operators.
• They are equipped with downhole data.
• Some of the downhole sensors aren’t working.
• There are some natural flow wells with and without downhole data.
• There are some shut-in wells.</td></tr>
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		Control room:
		• The control room is very busy.
		
		Alarms:
		• More than 85% of alarms are ignored by the offshore operators.
		• Onshore, the alarm data is fed into a LOWIS database.
		• Data is captured at 5-minute intervals.
		• There are both analog and discrete alarms.
		
		Alarm strategy:
		• The severity of each type of alarm has been defined.
		• Case History –before setting the alarm severity
		  ○ A well had a high GLR.
		  ○ Well gas locked at 9:45 am.
		  ○ This was finally noticed at 5:00 pm and the pump was stopped.
		
		Conclusions:
		• An alarm philosophy has been defined.
		• This leads to a consistent Operator philosophy for dealing with alarms.
		• Using alarms without an Alarm Philosophy is not good – may lead to ignored alarms that are important.
		• Use of real-time data allows engineering to intervene when necessary.
		
		Q. Can people access the information from Houston?
		  A. Yes, via the internet.
		
		Q. What interventions do engineers perform other than stop the pump? Can they fine tune the ESP operation?
		  A. They may increase the pump speed and then monitor the operation very closely. They don't make changes after 5:00 pm. They use LOWIS to optimize the ESP operation.
		
		Q. Do they use a VSD to control the speed of the ESP?
		  A. They do this to some extent. They try to "optimize" drawdown. They have to be careful about solids production.
		
		Q. How do they monitor the wells that don't have downhole data?
		  A. They monitor surface pressures. They use "dead head" tests to see if the data is on specification. When they have downhole data, they monitor pump intake pressure, pump discharge pressure, motor temperature, differential pressure across

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Q. Have you considered automating the response to certain alarms, instead of using people to make all decisions?
A. No. This could possibly be done via the DCS (distributed control system), but it hasn't been tried yet.</td></tr>
<tr><td colspan="3">Break-Out Session --- Day 1</td></tr>
<tr><td></td><td></td><td>There were two breakout sessions on Wednesday, and two on Thursday.

On Wednesday, I attended the one on Equipment Selection. On Wednesday, there was information on pump selection for different well conditions, and seal section selection.

Other aspects of equipment selection were addressed on Thursday. Chip Ollre sent a summary of the PowerPoints used in the breakout sessions to those who requested one.</td></tr>
<tr><td></td><td></td><td>Pump selection.
• Abrasive wells.
○ Sand is harder than standard Ni-Resist.
○ Can use ceramics
- With a small amount of sand – use on bottom stages.
- With a medium amount of sand – use on more stages.
- With a lot of sand – use throughout the pump.
○ Geometry.
- Radial veins wear more than mixed flow veins.
○ Frequency.
- If run at a lower frequency, wear is less.
- Wear is a function of the square or the cube of the speed.
○ Material.
- Can use harder materials.
- Can use harder coatings.
○ Thrust considerations.
- Use a down thrust washer in the pump.
- Use thrust bearings in the seal section.
• Gassy wells.
○ Leads to head degradation.
○ Gas locking.
○ Loss of efficiency.
○ Depends on the properties of the fluid.
○ Depends on pump stage geometry.</td></tr>
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		○ Gas handling strategy: - Avoid the problem by setting below the perfs with a shroud, or setting above the perfs with an inverted shroud. - Use separation with natural separation, a passive (static) separator, or dynamic (rotary or vortex) separator. ○ Address with pump design - Radial impellers – poor gas handling. - Mixed – better gas handling. - Axial – good for gas but poor for liquid. - Radial can handle up to 10% GVF. - Mixed from 20 – 25% GVF. - Gas Handler from 45 – 55% GVF. - Axial from 70 – 75% GVF. • Seals. ○ Also defined as Penetrator, Seal Section, Seal Chamber, Balance Chamber, or Equalizer. ○ Installed between the motor and the pump. ○ Purpose: - Transfer motor torque to pump. - Handle pump shaft thrust. - Provide for motor oil expansion/contraction. - Equalize motor oil with well bore. - Seals the motor from well fluid. ○ A VSD keeps the torque lower on start-up. ○ This helps protect the up and down thrust bearings. ○ There are various seal section designs: - Labyrinth chamber – equalizes pressure between motor oil and well fluid. - Bags. May be in series or parallel. ○ Sealing the motor. - Shaft seals. - O-rings. - Volumetric expansion chamber.
Session III – ESP Applications in Gassy Environments **Chair:** **John Patterson – ConocoPhillips** **Atika Al-Bimani – Petroleum Development Oman**		
Application Map For ESP Installation In Gassy Wells Below Perforations	**Vitaly Elichev** Rinat Khabibullin Valery Mikhailov Konstantin Litvinenko Alexey Pustovskikh **Rosneft** Mauricio Prado **University of Tulsa**	In the project, the Poseidon and other gas handling tools were tested. The goal was to install the ESP below the perforations. They developed a “map” to guide choice of the method to use. Approaches considered: • Install the ESP below the perforations. • Install the ESP with a shroud. • Install the ESP above the perforations, with a tail pipe extending below the perfs. • A possible combination of these – this idea was re-

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		jected as there were too many problems. Field test goals: • Prove the efficiency of using a shrouded ESP below the perforations. • Evaluate use of a multi-phase flow meter. • Install and evaluate use of downhole sensors for Pressure and Temperature. • Measure gas flow up both the lubing and the casing. Results: • Use of a long tail pipe was not effective; this has not been pursued. • Better results were achieved with an ESP with a rotary separator. • The use of a shroud is also good if there is ample room in the casing. Conclusions. • A Russian application map has been developed. • The use of a shroud is OK, if there is room. • The use of a gas separator is OK. But don't combine this with a shroud. • The use of a tail pipe to reach below the perforations is not OK. Q. What is the problem when you tried a tail pipe with a rotary gas separator? A. There was a significant pressure drop in the tail pipe; this lead to instability. Q. Where was the shroud? A. The shroud was used above the perforations. The tail pipe was extended below the perfs. Q. Did you consider a progressing cavity pump for the lower rate wells? A. No. This project was focused on testing various ESP applications. But we do plan to test PCP's in the future. Q. What software tools did you use to conduct the analysis? A. First we used Mat Lab, and then we used our own ESP sizing program. Q. Is your software available commercially to other companies? A. No, it is for in-house use only.
Poseidon Gas Handling Tech-	**Lawrence Camilleri**	The Poseidon is being used on two offshore wells in Congo. Production is to a wellhead platform. The ESP's are

Paper	Author(s)	Summary of Discussion

nology – A Case Study Of Two ESP Wells Congo	**Schlumberger**
	
	Emmanuel Segui
	Laurent Brunet
	Pierre Valette
	Total
		used to pump fluids to the surface and then on to the production platform.
		
		Conditions:
		• The flowing bottom-hole pressure is below the bubble point pressure.
		• Originally, there was no water injection to provide pressure support, but now there is some injection.
		• The Pwf is approximately 0.5 * Pb.
		• Total vertical depth is about 3,000 feet.
		• The wells have sub-surface safety valves, but there is a gas vent so gas can be produced up the annulus.
		
		Installations:
		• The initial installation was a standard ESP with a gas separator and an “advanced gas handler” (AGH).
		• Then the AGH was replaced with a Poseidon.
		• When the Poseidon was installed on the first well:
		  ○ The flowing bottom-hole pressure was reduced.
		  ○ The production rate was increased by about 10%.
		  ○ Gas production was greater than 60%.
		• When the Poseidon was installed in the second well:
		  ○ The production rate increased.
		  ○ The tubing-head pressure was stabilized.
		
		Analysis
		• They used a model of fluid flow through the pump.
		• They calculated the head degradation per stage.
		• They developed a correlation for casing head pressure degradation when head degradation varies stage by stage.
		
		Conclusions:
		• The Poseidon can handle a gas volume fraction (GVF) of up to 67%.
		• It improves the stability of the operation.
		• Future: Need new work to better understand the head degradation per stage.
		
		Q. How many Poseidon stages were used?
		A. There were 15 stages of Poseidon and 158 stages of a standard ESP. The Poseidon doesn’t reduce the GVF in its stages. It “conditions” the gas to enter the normal stages.
		
		Q. How many pump stages were used with the AGH?
		A. The same number.
		
		Q. Is there any problem with sand production?
		A. No.

<table>
<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
<tr><td colspan="3"></td></tr>
<tr><td></td><td></td><td>Q. Did you integrate pump intake pressure into or with your correlation?
A. No.

Q. Why is gas slugging in the tubing reduced with the Poseidon?
A. The flow regime is changed.</td></tr>
<tr><td>Handling Gas Pump (MVP) In Putumayo Fields; The Latest Technology To Handle High Gas Volumes</td><td>John Fredy Reina
Luis Farfan
Ecopetrol

Arturo Morales
Julio Alban
Baker Hughes de Colombia</td><td>This presentation was given in Spanish. Sandy Williams provided a translation into English.

The field where the test occurred is in South West Colombia, near the Ecuador border. Originally, all wells in the field were on sucker rod pump. The gas pump was used in a test well.

Well conditions:
The well was fractured to improve its productivity.
The sucker rod pump was gas locking.
They tried a 4.5” ESP in 5.5” casing.
They set the ESP above the perforations with a gas separator.
There was a problem with gas locking.
The pump was pulled after 30 days.
Multi-vane pump (MVP):
The multi-vane pump has split impeller veins.
Gas isn’t allowed to accumulate in the impeller veins.
The well has a gas separator.
There are 60 stages with multi-vanes.
There are 195 stages with normal ESP.
The well produces 700 B/D, with 33% free gas.
Production is better than with sucker rod pumping or with a conventional ESP.
Benefits:
Can operate below the bubble point pressure.
Production is about 200 B/D higher than before.
The operation has been stable for 398 days.
A 4” ESP is used in 5.5” casing.
The ESP performance was better than the sucker rod pump.
The MVP is better than a standard ESP.
Q. How would efficiency compare with gas-lift?
A. Don’t know.

Q. If the gas production is the same as before, why is the oil production rate improved?
A. We couldn’t keep the ESP running. With the MVP, we run at a higher frequency and choke the tubing-head.</td></tr>
</table>

Paper	Author(s)	Summary of Discussion
		Q. There is 55% CO_2, and P_{bp} is 1100 psi. Is this a "hydrocarbon" bubble point pressure? A. A separate bubble point pressure for CO_2 wasn't considered. Q. How did the head with the standard ESP compare with the head of the MVP? A. Both used the same number of stages. Both have the same head. Q. How did you measure gas separation efficiency? A. Measured gas separately up the tubing and up the annulus. Q. How does the efficiency of the MVP compare with that of a standard ESP? A. The efficiency of the MVP is less than that of a standard ESP that is handling liquid only.
Experience and Developments with Inverted Shroud	**John Mack** Brown Lyle Wilson Donn Brown **Baker Hughes Centrilift**	This is a review of experience with using inverted shroud in natural gas wells. ESP and conventional shroud. • Encapsulate the motor and seal. • Provide motor cooling by forcing liquid flow past the motor. • Can be installed below the perforations. Inverted shroud. • Can be installed up to 500 feet above the perforations. • The motor is below the shroud. The fluid flows past the motor, for cooling. • Fluid rises above the pump intake. • Gas flows up the annulus; liquid flows back down to the pump intake. • Can be used for gas well dewatering. Examples: • Well has gas "bubbles" of 2 – 3 minutes duration. • Pump shutting down due to gas locking. • Installed a 200 foot shroud. • In another example, well had 12 minutes gas slugs. • Installed a 500 foot shroud. Sizing: • Use a 1.4 safety factor to size the length of the shroud. • Keep the downward liquid velocity between the shroud and the tubing low enough to keep from drawing gas down into the pump intake.

<table>
<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
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<tr><td></td><td></td><td>
Consider perforating the top few feet of the shroud to reduce turbulence at the top of the shroud.
Summary:
Can install a shroud in deviated wells up to 84^0 from vertical.
Provides a good use of annular separation.
A shroud is easy to install.
Q. How do you lock the pump and the shroud together? Can the pump be lost when the shroud is pulled?
A. It is hung on the casing. Instillation is secure.

Q. Is there a plot for the performance of the shroud?
A. Yes.

Q. Why is the top of the shroud perforated?
A. Only about the top ten feet of the shroud are perforated. This is to facilitate fluid entry into the annulus between the shroud and the tubing, and minimized turbulence at the top of the shroud.
</td></tr>
<tr><td>Downhole Fluid Conditioning System For Electric Submersible Pumps. Golfo San Jorge Basin, Argentina</td><td>Roberto Tarabelli
YPF S.A. Argentina

Dolores Ingouville
Olegario Rivas
Schlumberger</td><td>
One way to overcome a low production rate with an ESP is with a circulation system.

Field conditions.
82% of the wells in the field produce less than 40 m^3/day (about 250 B/D).
The water injection wells have been closed, so there is no active pressure support in the reservoir.
So, the ESP's are now producing at low rates.
Strategy.
Use downhole sensors.
Use “compression” pumps.
Set the ESP's as deep as possible.
There isn't enough clearance to use shrouds.
They were not getting good motor cooling.
To address the problem:
Installed a gas-lift mandrel with a recirculation valve.
Inject re-circulated liquid back down below the motor to help with motor cooling.
Liquid is re-circulated down a tube that delivers it to below the motor.
They had to develop a method to size the recirculation tube.
Case study:
The system has been in operation for 17 months.
The motor temperature has been stable.
The pump intake pressure has been stable.
</td></tr>
</table>

Paper	Author(s)	Summary of Discussion
		• The recirculation rate can be changed by changing the recirculation valve with wireline. Injection is through an orifice in the recirculation valve in the gas-lift mandrel. • About 40% of the liquid entering the pump is recirculated liquid. 60% is new production. Benefits: • Can handle low flow rate wells. • Maintenance costs have been reduced. • Instillation costs have been reduced. • There is less deferred production. • The cost is 34% less than the cost of a shroud. • The motor temperature is less than the fluid temperature due to the recirculation. Q. What is the casing size? A. 5.5 inch. Q. What are the recirculation rate boundaries? A. Can control the recirculation rate by changing the size of the orifice in the recirculation valve. Q. Are there problems with scale, solids? A. There was some problems with scale. Can inject chemical if needed. Q. What is the size of the recirculation tube? A. We're using 3/16" stainless steel. May try a slightly larger tube. Q. Is there a problem with plugging of the recirculation tube? A. Recirculation is controlled by the orifice, so plugging materials can't enter the tube.
Field Experience with the Application and Operation Of Permanent Magnet Motors in the ESP Industry: Success Stories and Lessons Learned	A Sagalovskiy **PK Borets** M. Solesa **Borets International** **K. Sikora** **Borets-Weatherford**	This a story about using a permanent magnet motor instead of a conventional ESP rotor. This has been installed in over 900 wells in Russia. Benefits: • Don't need to use conventional magnetism. • This reduces power consumption. • It allows synchronous operation. • It eliminates motor slip. • It permits higher horsepower with a simpler geometry. • It is higher efficiency. • It generates less heat, so motor cooling is easier. • It can run from 200 – 6,000 RPM. • The motor is 40% shorter than a conventional motor.

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<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
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<tr><td></td><td></td><td>
Results:

Uses 27% less power.
If there were to be used worldwide in all ESP’s in the world, the overall savings could be $1.3 Billion.

Need to control properly:

Need proper control system.
Provides improved diagnosis.
Allows pump-off control.
Less cooling is needed for the motor.
Can be used on unstable wells.
Can also be used for progressing cavity pumping.

Advantages with a PCP.

No tubing wear due to use of sucker rods.
Can run at 200 to 2,000 RPM.
No gear box needed as is needed when drive a PCP with a conventional ESP motor.

Advantages relative to industrial motors.

Efficiency up to 93%.
Less current, lower power consumption, lower operating cost.
Longer run life.
Run life is comparable to a conventional motor, but it is in a harsh environment.

Q. What is the size of the magnet?
A. No answer.

Q. What is the temperature limit?
A. 175 ^{0}C.

Q. Are there special considerations for starting the motor?
A. Yes. We use a proprietary controller.

Q. How is the operating cost reduced?
A. The motor runs cheaper at low load.

Q. What is the cost of the motor?
A. Need to ask a salesman this question.

Q. Is a special surface drive needed?
A. Yes.

Q. Is the stator the same?
A. Yes. We use a permanent magnet instead of using a rotor.

Q. Is there a high temperature rise on start-up?
A. No, the frequency rise is less.
</td></tr>
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<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
<tr><td colspan="3"></td></tr>
<tr><td></td><td></td><td>Q. Does the PCP use a 6-pole motor?
A. No, a 10-pole motor is used.</td></tr>
<tr><td colspan="3">Session IV – Power Management
Co-Chairs
Richard Delaloye --- Borets - Weatherford
Kenneth Lacey</td></tr>
<tr><td>Variable Speed Drive Regenerative Type - Lessons Learned</td><td>Guy Descorps
Philippe Espagne
TOTAL

Claudiu Neacsu
Philippe Wesolowski
L. SOMER</td><td>This presentation is about variable speed drives on ESP's on a remote, unmanned platform. The primary goals are to perform remote control and minimize maintenance.

Problems with "standard" VSD's.
• Problems with harmonics in the electrical system.
• Problems with being able to limit the stress on the motor.

The regenerative VSD.
• The regenerative type VSD places one half as much stress.
• Ultra fast.
• Very good power factor (approx. 1.0)

Failure experience in the early tests.
• Had a sudden shut down.
• Fix this with some software changes and physical modifications.

Lessons learned:
• Only access "active" energy.

Compare the regenerative VSD with the APEX motor.
• Compared with "direct on line."
• Compared with regenerative type VSD.
• Compared with 6-pole motor.
• The regenerative VSD outperformed each of the others.
• It had better voltage output.

Q. Are you using an active vs. a passive filter?
A. Yes.

Q. Are you using controls to eliminate harmonics?
A. Yes.

Q. What is the additional cost of the regenerative type VSD?
A. The cost is twice as much as for a 6-pole motor. It is less than for a 12-pole motor.

Q. How is the power quality vs. a 12-pole motor?
A. Between 5 and 10% better.</td></tr>
</table>

<table>
<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
<tr><td colspan="3"></td></tr>
<tr><td></td><td></td><td>Q. The target is a 7-year run life?
A. Yes, for the drive and the downhole system.

Q. Did downhole data better coordinate with motor temperature for the regenerative VSD vs. the 6 or 12-pole motor?
A. Not answered.

Q. How does quality compare vs. the 6 or 12-pole motors?
A. The coating for a 12-pole motor costs more than for the regenerative VSD.

Q. What is the impact on the transmission network?
A. We have no data on this.</td></tr>
<tr><td>Continuous Power Quality Measurements for VFDs Utilizing an Xpert Power Meter</td><td>Keith Fangmeier
Keith Strenge
Hess Corporation

Roger Cox
Bill MacFarlane
David Shipp
Eaton Corporation</td><td>Power quality data was run on a 2200 foot well in Equatorial Guinea. There is a sub-sea umbilical cable that is 7 – 10 km long. The work was done to determine the cause of electrical failures. It was difficult to take measurements due to field safety reasons. The goal is to measure the power quality.

Measure power quality:
• Measure at 1 Mhz rate.
• Need high speed data acquisition to analyze data.
• Running at 722 Hz.
• Could see special problems occurring downhole.
• Could see harmonic disturbances in the vicinity of the resonate frequency.
• Were able to analyze the data to find the problem.

Lessons learned:
• Measurements need to be taken at a frequency of at least 100 Hz.
• Need a predictive tool to forestall problems.
• Can obtain good information with a good SCADA system.

Q. Can you configure the data capture?
A. Yes. But the system is also “self learning.”

Q. Can you configure it from Houston?
A. Yes.

Q. Is this system commercially available?
A. The</td></tr>
<tr><td>Design Considerations for High Voltage</td><td>Cameron Chung
Jeff Frey
Baker Hughes,</td><td>ESP cables and surface cables have differences.

ESP cables:</td></tr>
</table>

Paper	Author(s)	Summary of Discussion

ESP Cables Used in 8kV Applications	**Inc.**	• Solid conductors.
		• Special insulation.
		• Barriers.
		• No ground.
		• Swell resistance.
		• Design life < 10 years.
		
		Surface cables:
		• Stranded conductors.
		• Design life > 30 years.
		
		Special conditions for ESP cables:
		• Limited space.
		• Harsh conditions.
		• Rapid gas decompression.
		• API codes are lagging the needs of the industry.
		
		Problem of partial discharge:
		• Can cause cable failure.
		• This is affected by:
		  ○ Geometry,
		  ○ Void space and what is in the space.
		  ○ Pressure and temperature.
		
		Barriers:
		• There are various types.
		• May be impervious to liquid but pervious to gas.
		• May be impervious to both liquid and gas.
		
		Test to determine effect of permeability:
		• Measure PDIV @ 0 psi – Partial discharge 2.2 KVAC
		• @ 50 psi, 4.0 KVAC
		• @ 155 psi, 9.9 KVAC
		• Measure endurance (breakdown time) at high voltage
		• @ 0 psi, 22 minutes
		• @ 80 psi, 2.5 hours
		• @ 155 psi, 23 hours
		
		Partial discharge is reduced by reducing permeability, so need to reduce partial voids in the cable.
		
		Three tests conducted @ 5.8 KV
		• With no adhesive or tape, bad results.
		• With no adhesive but use tape, better results.
		• With both adhesives and tape, good results.
		
		Conclusions:
		• Cannot use surface cable standards for ESP cables.
		• There is a problem with partial discharge in ESP cables
		• There are ways to reduce partial discharge.

Paper	Author(s)	Summary of Discussion
		Q. During the tests, when the pressure was changed, did the temperature change? A. No. Temperature remained the same. Q. How can I tell if there is a partial discharge failure? A. This depends on the type of cable. Q. Can there be a partial discharge failure in the stator? A. Probably not. Q. What is the basis for the 10-year vs. the 30-year life? A. A 10-year life is typical for an ESP cable. Q. Is partial discharge testing done on used cable? A. No Q. Did you test both leaded and non-leaded cables? A. Yes. Tests are the same. Q. Why did you test 8 KV cable? A. The customer wanted to test greater than 5 KV cable. Q. Why not supply elastomer with the ESDM? A. We are working with swell-resistant EPDM cable.
System Lightning Improvements And Drive Ride-Through Prototype Development And Testing For Progressive Cavity Pumps In The Boscan Field	Aidor Martinez Juan Biternas Jesus Borjas Frank Reinaldo Bustamante **Chevron Texaco** **David D. Shipp** Dan Carnovale Tom Dionise **Eaton Electrical**	There are problems with lightning in Venezuela. There are many progressing cavity pumps used in the Boscan Field. They are served by a large electrical distribution system. When there is a problem in the system, up to 25% of the wells may be affected and go down. The system was redesigned so a maximum of $1/8^{th}$ of the wells are served by any portion of the distribution system. The system needed to be designed for a “ride through” in case of an electrical failure, to protect the PCP’s. The solution was to use direct current (DC) capacitance. This uses a recharge “ride through” to keep the PCP going if there is up 0.7 seconds power outage. The wells need 60 horsepower to start and 40 horsepower for normal operation. Results: • Progressing cavity pumping availability was improved from 95.5% to 99.7%. • Production was improved by 1440 B/D per production unit. • Mean time between failures (MTBF) was improved from 18 to52 days. Conclusions:

<table>
<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
<tr><td colspan="3"></td></tr>
<tr><td></td><td></td><td>• The number of outages was reduced.
• The test proved the good results.

Q. What is the time to recharge?
A. The design provided for up to 0.7 seconds, whereas the actual requirement is 0.25 seconds. The recharge with AC power is about 0.1 seconds. With DC power, it is about 3.4 seconds.

Q. Only 0.1 seconds to recharge?
A. This gives a 0 to 90% recharge.

Q. What is the life of this system?
A. A system life of 10 years is expected.

Q. Why is MTBF only 52 days?
A. This is based on acquired field data. There are still some problems with this.

Q. Are they using old or new drives?
A. They are 5 - 6 years old.</td></tr>
<tr><td>Committee Introduction and Presentation</td><td></td><td>The people who conducted the Continuing Education Courses on Monday and Tuesday were recognized. The courses were:

• Failure Analysis Course - led by John Patterson and Jeff Dwiggins, with many helpers.
• ESP 101 and 102 – led by David Devine
• How to Optimize ESP Production – led by Sandy Williams and Shekha SInha

The people on the ESP Workshop Committee were introduced and thanked for their service.</td></tr>
<tr><td colspan="3">Break-Out Session --- Day 2</td></tr>
<tr><td></td><td></td><td>The same two breakout sessions that were presented on Wednesday were also presented on Thursday, but with different topics covered.</td></tr>
<tr><td></td><td></td><td>On Thursday, I attended the “Believe it or Not” session where a number of Service/Supply Companies made brief (5 minute) presentations on their goods and/or services. There was no discussion of the presentations. The presentations on Thursday were by:

1. Magna Grande – Including a short video.
2. Quick Connect – About electrical connectors.
3. Echometer – About the value of fluid levels.
4. Borets-Weatherford – About integrated services.
5. iWellsite – About information availability on the web.
6. Solvapli – About downhole instruments.</td></tr>
</table>

Paper	Author(s)	Summary of Discussion
		7. Cannon Services – About cable protection.
Session V – Operations / Run Life Improvement **Co-Chairs** **Rafael Lastra --- Occidental Oil and Gas Corp.** **Shauna Noonan - ConocoPhillips**		
First Installation Of 5 ESP In Offshore Romania - A Case Study And Lessons Learned	**Lawrence Camilleri** Danut Tudora **Schlumberger** Dr. eng. Traian Banciu Gheorghe Ditoiu Petrom **S.A. -Exploration & Production Romania**	This is a summary of ESP operations in offshore Romania. Situation: • There are five ESP's being used in offshore Romania. • This is in the Black Sea, in 50 meters water depth. • The wells are about 5,200 feet deep. • The other wells in the area are flowing or on gas-lift. • The ESP's were installed in 2006. • The PI is < 0.5 B/Day/Psi. • For these five wells, there is no gas for gas-lift. • The bubble point pressure is 2,160 psi. Conditions: • The water cut was increasing on these wells; therefore the need for ESP's. • There is a packer set below the ESP, in 7" casing. • There is no gas vent valve. Disadvantages faced: • The wells produce some solids. • They have sub-surface safety valves. Monitoring required: • Use ESP Watcher • Goal to maximize uptime. • Trending changes in flow rate by measuring the differential pressure across the pump and then solving for the flow rate. After installing the ESP's. • The flow rate was stabilized. • In some wells, there was an increase in motor temperature; this was due to a decrease in flow rate which lead to a decrease in motor cooling. • With the estimation of flow rate, they can allocate production back to each well. • This can allow a reduction in well test frequency, and it allows seeing changes that can't be seen with the well test separator. Benefits: • Less downtime for the wells. • Less back pressure in the system to affect the gas-lift

Paper	Author(s)	Summary of Discussion
		wells. • Can address a high GVF in some of the wells. • Have achieved uptime of from 91 – 99%. • Have reduced stops per month down to 0.4 – 2.7 stops per month. • There has been only one failure; it was due to scale. Conclusions: • Good project lifecycle engineering. • Good alarming. • Good use of trending. • Good ESP economics. Q. For flow rate estimate, why tie to the motor? A. Can use volts and amps; don't need to know the specific gravity of the fluid. Q. What is the well test "fudge" factor? A. We compare the estimated flow rate at the pump with the stock tank barrels in the well test system. We use a correction factor to correct the estimate to the measured values. Q. Why have you relaxed the trip settings? A. We have relaxed the underload shutdown trip settings. We can stop the pump remotely if needed. Q. What problems have you had with gas locking? A. We are using an AGH to "ride through" gas problems. Q. How do you train the Romanian operators? A. They are very bright and willing to learn. They like the graphical approach. Q. In the flow estimating, how are you accounting for pump degradation? A. We don't account for degradation. We use the "new" pump performance curves. Q. Have you looked at a combination of Gas-Lift and ESP? A. No. One field has no gas. The others we didn't consider it. Q. Were gas-lift wells optimized before the ESP's were installed? A. Yes. Q. Why do you try to not shut down the pumps? A. We can manually stop the pumps if we need to.

Paper	Author(s)	Summary of Discussion
		We try to minimize shutdowns to protect the pumps and optimize production.
Motor Cooling In Viscous Applications	**Ketan Sheth** Don Cox Bruce Brookbank **Baker Hughes Centrilift** Dustin Gilyard **Shell International E & P**	There are special concerns for cooling ESP motors in viscous production applications. Cooling depends on: • The configuration of the well and the ESP. E.g. where is the ESP installed in the well? • The ESP motor characteristics. • The operating conditions. • The fluid properties. • The fact that oil is << thermal conducting than water. Design considerations: • Reynolds Number • Prandtl Number • Nurrelt number • Turbulent flow (high Reynolds number) is better for heat transfer. • In highly viscous fluid, it is difficult to have turbulent flow. Test set-up: • Produce fluids with different viscosities through the ESP. • When the flow is laminar, the cooling is the same with the different viscosities. Model development: • A model was developed to predict cooling. • The model was verified by using computational fluid dynamics. • The model shows the temperature distribution across the motor. Conclusions: • Laminar flow provides poor cooling. • New correlations can be developed based on the results of the tests and the modeling. Q. What methods can be used to reduce the viscosity? A. Can create turbulence with changes in geometry of the installation. Can use a viscosity reducer. Q. How do you calculate the heat coefficient H? How do you measure heat transfer during the test? A. H is based on fluid properties. Can calculate H based on the differential temperature between the motor skin and the fluid temperature. Q. What is the best geometry for the motor?

Paper	Author(s)	Summary of Discussion
		A. It is best to centralize the motor. Get poorer cooling when motor is not centralized. Q. What is the impact of velocity on cooling? A. There is no impact at high viscosity.

Electrical Submersible Pumping System: Striving For Sustainable Run-Life Improvement In Company's Oil Fields	**Atika Al-Bimani** (SPE)
	Samuel Armacanqui (SPE)
	Buthaina Al-Barwani (SPE)
	Iqbal Sipra (SPE)
	Said Al-Hajri (SPE)
	Halima Al-Riyami, **PDO**
		This is an overview of ESP operations in Petroleum Development Oman (PDO).
		
		Overview of wells:
		• 3200 wells in PDO.
		• The average well produces 85% saltwater.
		• There are 700 wells with ESP's.
		• They produce 25% of PDO's oil and 50% of PDO's gross liquid.
		
		Management of the ESP's:
		• Use an artificial lift selection matrix.
		• Consider well conditions.
		  ○ Hydrates.
		  ○ Corrosion and solids.
		
		Need to recognize problems and develop an operating strategy to optimize lift and outflow.
		• Wells with poor inflow are placed on gas-lift.
		• Use scale inhibition.
		• Use VSD's on the ESP's.
		
		Surveys and troubleshooting:
		• Have had problems making good use of data.
		• Working to improve use of downhole information.
		• Providing on-the-job training for Operators.
		
		ESP optimization and workover planning:
		• Using data to plan workover schedule.
		• Implemented use of a dedicated workover hoist to be able to address workover needs more quickly.
		
		ESP equipment improvements:
		• Using improved shafts
		
		ESP electrical improvements:
		• Improving electrical system stability with work by Sultan Qaboos University (SQU)
		
		Contracts:
		• Using lease contracts.
		• Using a "no blame" culture.
		• Focus on incentives, not penalties.
		
		Case History:
		• Used analysis of real-time data to find a hole in the

Paper	Author(s)	Summary of Discussion
		tubing. • Found a broken shaft. • Performed root cause analysis – found a faulty start-up procedure. Achievements: • The percent failures have been reduced, but it is still not good enough. Challenges: • Solids. • Gas. • Corrosion. Conclusions: • Run lives have been improved. • Failures have been reduced, but needs more work. • The well conditions are harsh. • Need to work with the University and the Vendors. • Need to continue to improve use of real-time data. Q. Do you wait for the results of root cause analysis before you reinstall a failed ESP? A. No, we don't wait, but we try to improve the next time. Q. Is the corrosion related to ground faults? A. There appears to be a correlation. Q. What is your run life target? A. Five years. Q. You reported 25% failures in the North, 21% in the South. Any comments? A. We are counting failures that are related to ESP equipment, not things like tubing failures.
Viscosity Correction Factors For Pumps	**Ketan Sheth** Alex Crossly **Baker Hughes Centrilift**	There are various approaches to determine viscosity correction factors for ESP pumps. Hydraulic Institute Method (1960's) • Single stage pump. • Fluid correction factor. • Used multiple factors for a single stage pump to correlate performance with viscosity. New guidelines in 2004: • Considered new parameters based on viscosity and speed. • The Hydraulic Institute Method over predicts pump performance in viscous applications. • The new method is based on losses. It under pre-

Paper	Author(s)	Summary of Discussion
		dicts head and over predicts efficiency. Use of test data: • There is a significant decrease in head performance at high viscosity. • There is a significant increase in brake horsepower at high viscosity. • Use new data tracking to predict head and BHP. Effect of speed: • Efficiency is better at 60 Hz than at 45 Hz. BHP correction factor: • The factor increases to the left of the best efficiency point on the pump performance curve. Conclusions: • Existing viscosity correction factors are not OK. • The "loss" method is not OK. • Must include the effect of pump speed. • A 3D evaluation is good. Q. What is the 3D viscosity correction approach? A. This is confidential. It is in Autograph. Q. Will it be published? A. No. It is in Autograph. Q. Did you test multiple pumps? A. We tested twelve pumps. The data was all consistent. Q. Is there a special plot of the correction factor? A. There is a plot. It isn't in the paper, but can be shown. Q. When will this be implemented in Autograph? A. As soon as possible. Q. How did you get pump fillage at high viscosity? A. We used a primer pump to pump liquid from a test tank. Q. Was a multi-stage pump used in the test? A. Yes. We measured the temperature at each stage. Q. Does Autograph calculate the motor temperature rise? A. Yes, as a function of the viscosity. Q. Does it include the effects of gas?

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<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
<tr><td colspan="3"></td></tr>
<tr><td></td><td></td><td>A. Yes.</td></tr>
<tr><td>"Fishing For Your ESP? - What Is Your Bait?"</td><td>Gary Robert Lannom, P.E., SPE
Baker Hughes Centrilift

John C. Patterson SPE
ConocoPhillips</td><td>Careful planning is necessary for a successful fishing job in an ESP well.
• Review the equipment in the well.
• No two fishing jobs are alike.
• Understand why fishing is needed:
o Parted tubing.
o Corrosion.
o Scale.
o Stuck pump.

What is the problem?
• Evaluate all available information.
• Communicate with all parties that may have information or experience with the well.
• Know what is in the hole.
• Where is the top of the fish?
• What is the description of the fish?
• Do you have the right tools to fish safety and efficiently?
• Evaluate the economics of the fishing job. Is it worth the cost and risk?

There are many tools for fishing in a cased hole.
• Impression block.
• Tapered mill.
• Junk basket.
• Bumper sub.
• Drill collar to add mass to the bumper sub.
• Chemical cutter.
• Jet cutter.
• Split shot.
• Severing cut.
• Cable spear.
• Fishing guidelines are available.
• Wash over operations.

Summary:
• Use proper tools.
• Use experiences personnel.
• Be safe.

Q. How do you deal with cable?
A. Depends on the type of well.

Q. How do you fish steel bands?
A. A junk basket probably won’t work well. May need to use special tools.

Q. What if the wash over doesn’t work?</td></tr>
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		A. Don’t try to mill out an ESP. This is tough. Q. What are the weakest points in the ESP system to be considered? A. Determine with a system analysis. Try to set the ESP in a straight run of pipe. Q. Do you prefer a chemical or a jet cutter? A. Actually, a mechanical cutter may be best. Q. What is the cause of most fishes? A. Good information is needed to determine the causes? A hole in the tubing is a common cause.
Breakout Session Summary		Chip Ollre, Workshop Chair, reviewed the two breakout sessions that were held on Wednesday and Thursday evening. He offered to send the PowerPoints that were used in the sessions on Equipment Selection to those who want to receive them.
Closing Comments **Chip Ollre - Schlumberger** **ESP Workshop Chair**		
		Chip Ollre, Workshop Chair, summarized the Workshop. There were 437 attendees at the 2009 ESP Workshop. • Twenty five percent came from outside the USA. • They came from 22 different countries. • Those from the USA came from 17 states. • Of the attendees, about 25% were from Operating Companies with the rest from Service/Supply Companies, Consultants, etc. Chip repeated the fact that this Workshop was conducted in honor of the memory of Jack Blann who was very involved in helping to form the Workshop in the first place, and who played a role in helping to organize this Workshop. Chip acknowledged that the next week is the Offshore Technology Conference in Houston, and next year there will be another bi-annual Progressing Cavity Pump workshop. The next ESP Workshop will be in 2011.