2007 ESP Workshop
Summary of Presentations
Woodland Waterway Marriott Hotel

Prepared by
Cleon Dunham, Oilfield Automation Consulting
May 1, 2007

<table>
<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
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<tr><td colspan="3">Purpose of this Document</td></tr>
<tr><td>Purpose of this Document</td><td>Cleon Dunham
Oilfield Automation Consulting</td><td>The purpose of this document is to summarize the main points of the technical presentations at the 2007 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 at least the author who presented the paper) is shown in bold color with each paper.

Attendance at this years workshop was:
A total of 476 people attended the workshop.
They came from 27 separate countries.
30% were from Operating Companies. The rest were from Service Supply Companies, Consultants, and Universities.</td></tr>
<tr><td colspan="3"></td></tr>
<tr><td colspan="3">Opening Comments
Session Chair:
Noel Putscher, Medallion Exploration</td></tr>
<tr><td>Opening Comments</td><td>Noel Putscher
Medallion Exploration</td><td>Noel Putscher of Medallion Exploration, General Chair of the Workshop, gave the opening comments.
Noel welcomed the attendees.
He gave a safety presentation and made other announcements.
A special recognition to Boyd Moore who passed away on June 4, 2006. Recognition Boyd's contributions to the ESP Workshop is included in the ESP Workshop Notebook.</td></tr>
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<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
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<tr><th colspan="3">Keynote Address</th></tr>
<tr><td>Breathing New Life into a Maturing California Asset</td><td>Frank Komin
President and General Manager, Oxy/THUMS Long Beach Company</td><td>Frank Komin gave a very interesting keynote address.

A. Introduction
• THUMS Long Beach is now owned by Oxy.
• Oxy’s proven reserves are 2.9 MM Bbls.
• It is a world-wide operator in North America, South America, the Middle East, North Africa, and other locations.
• Production is about 730 MMB/Day with 350 MMB/Day in the US.
• Oxy is big in California, with major assets in THUMS, Elk Hills, and other location. This accounts for 25% of Oxy’s production.

B. History of THUMS Long Beach
• THUMS is in Long Beach Harbor, one of the busiest in the US.
• It is part of the Wilmington Field, discovered in 1932.
• This is one of the largest fields in the US.
• After early production, there was up to 30 feet of subsidence.
• Local residents opposed further development and production.
• A water flood was started in the 1950’s to arrest the subsidence.
• When subsidence was arrested, further development was approved under very strict rules.
• In 1965, a consortium of Texaco, Humble, Union, Mobil, and Shell (thus the name THUMS) bought the field.
• By 1969, production was 150,000 BOPD.
• The wells are all drilled from islands in Long Beach harbor. The wellheads are all below grade so they can’t be seen from shore.
• Today there are 1100 wells, with 2/3 producers and 1/3 injectors. All of the producers are artificially lifted by ESP.
• The original architecture of the islands was by the same people who originally developed Disneyland.

C. Operations
• The field is operated by Oxy in cooperation with the City of Long Beach and the State of California.
• Currently production is about 30,000 BOPD, with 96% water cut.
• There is about 1.0 MMB/Day water injection.
• There are 740 producers, 375 injectors, and 70</td></tr>
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Paper	Author(s)	Summary of Discussion
		megawatts of electricity is generated. **D. Growth Plan** • For the last several years, the focus was on cost reduction. • Today it is on growth in both reserves and production. • The current expected life is 40 years. • The current strategy has been nicknamed G^3 for Smart Growth, Strong Growth, Long-term Growth. **E. The Reservoir** • The field is small but very thick. • Net pay is up to 1000 feet, with 5000 – 6000 feet of gross pay interval. • There are many individual intervals. • Water flooding is a challenge. • Reservoir modeling is very important. **F. Drilling** • Some 380 drilling prospects have been identified. • Some of these are on additional property that Oxy has acquired in the Wilmington Field. **G. Technology Plan** • Plan to drill mostly horizontal wells to find pockets of bypassed oil, attic oil. • Using extended reach drilling. • Need to be concerned with using anti-collision technology to avoid drilling in to existing well-bores. • Most completions use frac packs to limit sand production for the benefit of ESP operation. • There is a concern with mechanical integrity of the wells and flowlines. The major lines are inspected for corrosion and leaks using smart pigs on an annual basis. • They are using guided ultrasonic inspection of lines. • Water flooding of the multiple layers is a large challenge. They are using profile control. **H. Artificial Lift** • ESP's have been used in the field for 42 years. • There are 740 wells in ESP; 700 are provided by Centrilift and 40 by Reda. • The ESP's produce 1260 B/D average • Run lives vary from 3 – 5 years, with 55 month average. • They focus on well failure analysis.

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<tr><td></td><td></td><td>Their primary ESP challenges are: sand, temperature, corrosion, low rates on some wells, scale, electrical costs, and the need to perform “root cause of failure.”.
I. Community Relations
Maintaining good relations with the community is essential.
The focus is on community awareness (partly through field visits), education, and maintaining a good environment.
They commissioned an ecological study. As might be expected, the islands are a favorite habitat for much sea life.
J. Work Force
THUMS has 225 employees.
32% are over 49 years old.
47% are between 40 and 49.
8% are under 30.
THUMS is actively recruiting new staff.
Question: What is THUMS doing in the area of artificial lift innovation?
Answer: Looking to improve electrical efficiency. Focusing on understanding causes of problems and addressing the root causes.</td></tr>
<tr><td colspan="3"></td></tr>
<tr><td colspan="3">Session I -— Alternate Deployed and Specialty Applications
Chairs:
Noel Putscher – Medallion Exploration
Sandy Williams – ALP Limited</td></tr>
<tr><td>The World’s First Wireline Retrievable ESP System</td><td>Neil Griffiths, Vishal Gahlot, Steve Sakamoto, Frank Claborn
Shell International Exploration and Production B.V.

Wood Group ESP Inc. Limited</td><td>This is a story about the world’s first wireline retrievable ESP system. There are other systems where the pump can be retrieved, but in this system the entire pump system (motor, protector, pump, etc.) can be installed and retrieved by wireline.

A. Business Case
Be able to conduct preventive maintenance on an ESP, rather than wait until it fails. This can be done if the ESP can be retrieved by wireline. For example, can do this to service the oil in the motor and seal section.
Can quickly and easily replace a failed component of the system.
Can replace sub-optimal ESP systems.
Can replace sacrificial ESP’s if they are used, for example, for initial unloading of frac sand, etc.
Can be used to install and replace test ESP’s</td></tr>
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Paper	Author(s)	Summary of Discussion
		used to conduct initial productivity tests on wells. • Can be pulled to allow well inferential below the pump setting depth. **B. Existing ESP Deployment Technologies** • ESP's installed on tubing • ESP's installed with coiled tubing. • ESP's installed with powered coiled tubing, with the electrical cable installed inside the coiled tubing. • ESP's deployed through the tubing using wireline, with the ESP motor and protector permanently installed in the well. **C. Existing ESP Failure Data from ESP-RIFTS** • There are currently some 25,000 ESP systems documented in the ESP-RIFTS (ESP Reliability Information and Failure Tracking System). • 32% are identified as having failed motors (although the motor is often not the "root cause" of failure. • 30% are associated with pump failures. • 21% are associated with cable failures. **D. Wireline ESP (WRESP) Design** • There ESP cable is permanently installed on the tubing. • The ESP motor, protector, and pump are installed on wireline. • Currently the system required 9-5/8" casing. **E. Testing of the System** • The test is being conducted by Shell and Diamould Ltd. • The system is designed to withstand up to 5000 psi, and 121 ^{o}C. • The motor will be about 800 horsepower. • The system has been developed in conjunction with Wood Group. • It has been tested in the lab and in a test well. • The plan was to test it in a Petroleum Development Oman (PDO) well in the Rima Field: Rima 18. • This well is 854 meters deep and has 9-5/8" casing. • The test had to be postponed due to a leak in the casing. • A new test well has been identified and the test will be conducted in mid May, 2007.

Paper	Author(s)	Summary of Discussion
		F. Future Plans • Develop a version to run in 7" casing. • The system will soon be commercialized. **Question**: What are the depth and weight limits? **Answer**: We don't expect any limits other than the limits on the wireline itself. **Question**: What is the expected differential pressure across the connector? **Answer**: 5000 psi. **Question**: What are the expected problems with solids? **Answer**: Solids should be able to fall through the system. **Question**: What are the expected wellbore deviation limits? **Answer**: The deviation limits should be similar to any wireline operation. A deviation of up to 60^o from vertical should be OK.
The First Riser Deployed ESP in the Gulf of Mexico	**David Cocciolone**, Mike Parker, **Anadarko Petroleum Company** Tiffany Pitts, Mark Ohl **Baker Hughes Centrilift**	This is a story about an ESP deployed in a riser that brings production from a sub-sea flowline to a production platform. **A. Introduction** • The ESP is installed in a flexible steel riser. • The well flows into a sub-sea flow loop, then up the riser. • The well conditions: unstable, liquid loading, hydrate formation, 6000 psi static bottom-hole pressure. **B. Artificial Lift Options That Were Considered** • Use a velocity string inside the riser. • Gas-lift in the riser. • Use a sub-sea multi-stage pump. • Use an ESP in the riser (this option was chosen.) **C. Challenges to be Addressed** • 50% free gas production. • Need a special wellhead to accommodate the ESP system in the riser. • Need an ESP power supply. • Need to determine how to install an ESP in the riser. **D. The Application** • Used a gas separator on the ESP. • Designed a new wellhead.

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Installed a new power supply on the platform.
Selected a hydraulic workover unit to install the ESP in the riser.
Selected stainless steel tubing to handle CO_2.
Installed a system on the surface to collect production that comes up the annulus and keep and measure it separately from the production up the tubing.
Installed a VSD.
Installed a 91-stage pump.
Implemented a SCADA system to monitor pump data.
Initially turned of the Overload and Underload shutdowns. Controlled the pump by monitoring the current and using the VDS to control the current draw of the motor.
The motor temperature is about 140 °F.

E. Conclusions

The well produces about 3200 B/D. It was 1400 B/D before.
They expect up to 700,00 Bbls. of oil extra production.
The GOR is gradually reducing.
The water cut is stable.
There is enough power on the platform to run the system.
The riser is more than 2000 feet high.

Question: How much dogleg can be accommodated:
Answer: The dogleg can be no more than 2°. The deviation can not be more than 45 °.

Question: What is the diameter of the pump?
Answer: 4.5 inches.
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<tr><td>Electric Submersible Pumps in Low Volume Rod Pump Applications</td><td>Jeff Finnell, Chesapeake Energy Corporation

Malcolm Rainwater
Wood Group ESP Inc.</td><td>
This is a story about using ESP’s in low production rate wells that might otherwise be produced by sucker rod pumping systems.

A. Introduction

The company was looking for an option to sucker rod pumping.
Previously they used a 912 sucker rod pumping unit with 1.5 – 2.0” downhole pumps. They used an 87 rod string, running at 7.0 strokes per minute.

B. Limits to be Overcome

Limited casing size.
Rod strength.

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Paper	Author(s)	Summary of Discussion
		• Able to produce less than 350 B/D. • Excessive number of rod failures. **C. Limits to use of ESP's** • Gas. • Pressure. • Solids **D. ESP Design** • 100 psi Pump Intake Pressure. • 5.5" casing, 2-7/8" tubing. • 200 oF. • 10,400 feet depth. • Use a rotary gas separator. • Use a high temperature design. • Use a downhole measurement system: Pressure, Temperature, and Vibration. • Design with 485 pump stages. • Use a new pump stage design • Use a new thrust washer design with two washers. • Use a new housing capable of withstanding 10,000 psi. • Designing for up to 18,000 feet TVD, at 600 B/D. • Chesapeake has obtained approximately 2 years run time with this system. **Question**: Did you compare ESP and Sucker Rod efficiency and cost? **Answer**: For systems less than 75 HP, the sucker rod system cost is about $120 per month less expensive. **Question**: Why not use a smaller ID pump? Answer: We have done a re-design with a 4" pump. We haven't looked at a 3" pump. **Question:** Have you looked at 4.5" casing? Answer: Yes, but this is not as good at handling gas. **Question**: Have you seen an advantage in increased production in using continuous production vs. pump-off control on sucker rod pumping? **Answer**: We have not seen an improvement in this case.
Development of an Integrated Solution for Perforation, Production, and Reservoir Eval-	A. Mejias, **RepsolYPF** **J. Jaua** and O. Rivas (SPE), **Schlumberger**	This is a story about an integrated approach to perforate and evaluate a reservoir and then place it on production. This was run in Venezuela, east of Lake Maracaibo. **A. Wish List** • Obtain good reservoir information. • Reduce well interventions.

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<tr><td>uation</td><td></td><td>
Acidize the well without needing to pull the ESP.
B. Objectives
Integrate three technologies:
TCP – through tubing perforating
DST – production formation evaluation
ESP – produce the well with an ESP.
Use a “Y” tool to allow access past the ESP.
C. The Completion
ESP
Phoenix data sensor
“Y” tool.
Packer
Perforations for testing the formation.
D. Testing the Well
Run the completion equipment in one trip.
Run the ESP and perforate under balanced.
Acid treat the formation using the “Y” tool to by-pass the ESP.
Produce the well with the ESP.
Can run wireline via the “Y” tool to perform downhole operations.
E. Options
The system can also be run without a packer.
Can also perforate an upper zone with wireline..
.
F. Results
Have produced between 700 and 1350 Bbls. per Day.
Expect production to average 1150 B/D.
This process saved 36 hours of rig time.
Question: How do you retrieve the perforating guns?
Answer: In this test the guns weren’t retrieved. They were dropped in the hole. In the future they can be re-trieved with a special tool.
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<tr><td colspan="3" align="center">Session II –-- Specialty Applications
Chairs:
Rafael Lastra – Occidental
Steve Kennedy – Weatherford</td></tr>
<tr><td>Powered Dump-flood Wells Provide Pres-sure Support for ExxonMobil Chad Reser-</td><td>Tom Van Ak-keren, E. Jake Kamps, Production Tech-nology Associ-ates</td><td>This is a story about using an ESP to “dump flood wells to provide pressure support for production in the Bolobo Field, Chad, central Africa.

A. Field Conditions
Production is from poorly consolidated sands.
Oil is between 18 – 23 ^{o}API.
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Viscosity is 56 cp.
Water injection is used to maintain the reservoir pressure, not to sweep or move oil to the producing wells.
Injection is performed off of the main structure.
The Fields don’t have many separation facilities.
The wells are produced with ESPs and PCPs, depending on the well conditions.

B. Water Flood Project

Looked at various options.
Chose to use a “powered” dump flood approach.
Use produced water and inject into the production zone, off of the main production structure.
Target to inject into 4 – 6 wells; target to inject 100,000 Bbls. per Day.
The wells have 9-5/8” casing. The producers have gravel packs. There is no sand control in the injection zones.
Plan is to use existing equipment that is already in Chad due to difficulty in importing equipment.
Target is to inject 15,000 B/D per well.
The selected ESP’s have a Best Efficiency Point of 12,000 B/D.
A Variable Speed Drive will be used so the injection rate can vary from 8,000 – 20,000 B/D.
Tandem 400 HP motors will be used.
Standard pump components will be used.
A downhole measurement system will be used to measure pump intake pressure, pump intake temperature, pomp discharge pressure, and vibration. This will be linked into a SCADA system.
A hydraulic set packer will be used to avoid movement that could damage the cable or downhole sensors.

Question: Did you compare the economics of this approach with other options?
Answer: Yes. This is less expensive then drilling other wells for injection. We also looked at other types of injection systems. This is the most economical.
</td></tr>
<tr><td>ESP in Caisson --- A novel application of ESPs for “Deep Water” Artificial Lift</td><td>Dustan Gilyard
Shell International Exploration and Production,

Norman Ritchie
Link Project Services</td><td>
This is a story about installing an ESP in a caisson for use in deep water.

A. Target

To be used for deepwater applications such as the Gulf of Mexico, Brazil, etc.
Target production rates of 80,000 – 100,000 B/D.
Target water depths of 6,000 – 9,000 feet.
Target well depths of 8,000 – 14,000 feet TVD.

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Paper	Author(s)	Summary of Discussion
		• Temperature: 115 -170 °F. • GOR: 190 – 4,000 CF/Bbl. • Oil gravity: 15 – 35 °API. • Viscosity: 1 – 1,000 cp. • Water cut: 0 – 85%. **B. ESP Installation** • ESP installed in a caisson. • Pump intake pressure: 500 – 1,500 psi. • Pump discharge pressure: 2,500 – 3,600 psi. • Pump motor: 700 – 1,500 HP; high temperature motor. • Pumps: 6 – 10" OD. • Install a ESP inlet separator to separate gas from the liquid. **C. The Caisson** • Outside diameter: 32 – 36 inches. • Level measurements in caisson; use a VSD to control the level to maintain pump intake. • Use make-up fluid to provide a slow start method for the pump. • Use a downhole measurement system to measure pump intake pressure, pump discharge pressure, pump discharge temperature, flow rate, and vibration. • Use a shroud to assist with motor cooling. **D. Risks** • Need to match pump performance to ability of surface separator to handle produced fluids. • Start up and shutdown at low temperature. • Using a 1500 HP motor. • Having high temperature during operation of the system. • Gas decompression, emulsions, sand. • Complexity of the system; need to achieve 3 – 5 year run life to meet economic targets. **E. Risk Mitigation** • Work closely with system manufacturers. • Work closely with operating staff. • Use a VSD to control the pump rate. • Plan ahead for intervention work. • Plan for wellhead interference. • Plan to use a state-of-the-art monitoring system. • Conduct a full-scale performance test at the Shell lab in Gasmer, Houston. **Question:** How do you plan to handle debris? **Answer**: It must be produced.

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<tr><td></td><td></td><td>Question: What are your lifetime expectations?
Answer: We are planning on an MTBF of 3 years.</td></tr>
<tr><td>Experiences of Occidental Colombia using the Automatic Diverter Valve</td><td>Juan Carlos Trujillo,
Occidental Colombia

Paul Shotter
Pumptools Limited</td><td>This is a story about use of an automatic divert valve to prevent sand from falling back into the ESP when it is stopped.

A. Problem
ESP's are used to produce sandy wells in Colombia.
.When the ESP is stopped, sand in the tubing can fall back into the pump.
This can cause pump failures.
And/or the pump can have difficulty in restarting.
B. The Automatic Diverter Valve
It prevents solids from falling back into the pump when it is stopped.
It prevents back-spin caused by flow back through the pump when it is stopped.
It prevents the tubing from being plugged with an amount of sand held in the tubing.
It allows treatments to bypass the ESP.
If the well can flow, it allows the flow to occur past the ESP, with no flow back into the ESP.
C. Testing of the System
It has been tested in a flow loop, and in a test well.
It has been tested is a "slurry" loop with 1 – 2% sand.
A pre-install test was run in Venezuela.
D. Actual Experience to Date
It has been installed in five wells.
There have been several stops and starts.
The run time has been increased.
All five wells are still running OK.
Question: What are your expansion plans.
Answer: We plan to use this in China, the North Sea, Oman, Yemen, and Thailand. Our target is to accommodate over 100 stops and starts.

Question: What is the differential pressure across the automatic divert valve?
Answer: It is less than one bar (15 psi). It is no more than with a standard check valve.</td></tr>
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<tr><td></td><td></td><td>Question: What happens if there are paraffin deposits?
Answer: We haven’t seen any paraffin deposits.

Question: What are the variations in run life? What is the standard deviation in run life?
Answer: It is too early to tell. Currently all five wells are still running.

Question: How is this better than a conventional check valve?
Answer: Sand does not stay in the tubing so it can’t plug the tubing. Can treat the well by pumping down the tubing.

Question: Have you compared the economics of the automatic diverter valve vs. a conventional check valve?
Answer: We are using the automatic diverter valve since a check valve didn’t work in our conditions.</td></tr>
<tr><td>Local Experiences Gained Through The Application of Dual Y Tool ESP Systems in Qatar</td><td>Emmanuel Pradie, Joanes Bertin
TOTAL

Khaled Elsheikh, Reza Dadrass, Brian Scott, Remi Arseneault
Schlumberger</td><td>This is a story about use of a dual “Y” tool for an ESP system in Qatar.

A. Field Conditions
• The field is offshore, Qatar.
• Qatar is a peninsula north of Saudi Arabia.
• Production is 42,000 BOPD, 170,000 BWPD.
• There are 33 production wells and 3 injection wells.
• Most of the wells are horizontal wells.
• The average life expectance of the ESP’s is 34 months.

B. ESP Design
• Dual ESP’s are installed in the wells.
• The goal is to minimize downtime.
• The dual ESP’s are installed with a dual “Y” tool system.
• Work can be performed through the “Y” tool to access the reservoir.
• There is an automatic flapper to open/close the sides of the “Y” tool depending on which ESP is being operated.
• All components of the system were pre-tested.
• They use 13-chrome, since CO_2 corrosion is an issue.
• A special packer penetrator design is used.
• A pre-job space out is conducted.
• This saves 15 hours of rig time.

C. Operating Philosophy
• Use the lower ESP, with the upper ESP held in</td></tr>
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<tr><td></td><td></td><td>reserve as back-up.

Test the back-up ESP once every four months.
The primary and back-up ESP’s are still operating OK
The average ESP run life is 34 months.
A workover is planned when one ESP fails. Don’t want to have a double ESP failure and associated well downtime.
Plan to install seven more dual ESP’s.
The wait time on a workover rig can be up to six months.

Question: How do you plan to increase run life?
Answer: By performing preventative maintenance.

Question: What problems have you had?
Answer: So far we haven’t had any real problems.

Question: Does the start/stop of the back-up pump limit its run life?
Answer: We don’t know yet.

Question: Do you do anything special with the design of the back-up pump?
Answer: No.</td></tr>
<tr><td>Induction Motor Starting for ESP System Applications</td><td>Joe Liu (SPE),
Ryan Laughy,
Xiaodong Liang,
Schlumberger</td><td>This is a tutorial on the issues with starting an ESP with an induction motor.

A. Options for Starting the Motor

Across the line start.
Variable speed drive.
Soft start.

B. Across the Line Start

In this case, you must take what you get.
You can’t actually change anything during the start.
You can adjust the voltage during running operations.

C. Variable Speed Drive

The frequency of the electrical current can be adjusted to adjust the start-up speed.
The VSD can start an ESP with a lower start-up torque than with an across-the-line start.
Cable size and length are very important in evaluating the choice between across-the-line and VSD.
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Answer: This was not considered.

Question: What type of VSD are you considering?
Answer: A VSD with pulse width modulation.

Question: What do you think about using a soft start? Does it protect the ESP motor?
Answer: There are two types: one to limit voltage and one to limit current. Use of a soft start should help to improve run life.

Question: Did you consider the type of transformer?
Answer: This was not included in the study.</td></tr>
<tr><td>Breakout Sessions for Day 1</td><td>Three Breakout Sessions were held on Wednesday.

Future – What is needed for the Future of ESPs?
Craig Stair and Rebecca Larkin

ESP Jewelry and Add-On's.
Julian Cudmore

Production Optimization and Well Surveillance.
Sandy Williams</td><td>I attended the breakout session on the future needs for ESP systems.   The overall summary of all of the breakouts was presented on Friday morning and is shown at the end of this document.

A. Downhole Water Separation
• This was an issue for a while.
• Some work was done on it but it seems to have lost impetus in the last few years.
• Schlumberger is currently doing some work on this.
• An issues is how to measure (and limit) any oil that may be injected into disposal zones downhole.
• A major issue is finding a suitable injection/disposal zone in the well.

B. Handling Sand
• This will continue to be an important need for the future.
.
C. Dewatering Gas Wells
• Typically only a small amount of water (and sometimes condensate) must be produced to deliquify gas wells.
• So, low horsepower is needed.
• A complication is that some wells must haves sub-surface safety valves.

D. Heavy Oil
• Some redesign of pumps is needed to pump heavy oil.
• A Recommended Practice is needed for ESP motor used to operate heavy oil ESP pumps.
• There can be significant temperature issues..</td></tr>
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An issue here is the slugging of liquid and gas that may occur in the horizontal wellbore upstream of the pump intake.
This may be addressed in some cases by improving the way horizontal sections are drilled and completed, to avoid “hills and valleys” in the horizontal sections.
There is also a significant pump control issue when there can be alternating slugs of liquid an gas entering the pump.
Some form of downhole pump control is needed.
F. Other Issues that will Continue to Need Attention in the Future
High pressure installations.
High voltage requirements.
Use of sealed motors.
Pump deployment – consider development of a way to deploy ESP’s by pumping them into and out of the well. This could be very useful in casers where well interventions are very expensive due to deep water or sub-sea locations.
Interventions in “live” wells.
Design is enhanced, multi-phase ESP’s.</td></tr>
<tr><td colspan="3">Session III –-- Harsh Environments
Chairs:
Atika al Bimani, Petroleum Development Oman
Chip Oilre, Schlumberger</td></tr>
<tr><td>Using the Calibrated-Tested Pumping Instrument (ELECTRICAL SUBMERSIBLE PUMP) for Continuous Fluid Measurement When Producing Heavy Oil Wells</td><td>William D. Bolin,
KerrMcGee</td><td>This is a story about using the electrical submersible pump to measure the liquid production rate in heavy oil wells.

A. Alternatives to Measure Production Rate
Production separator. This can have problems due to emulsions between 30 and 100%, sand, no gas to help operate the separator, etc.
Tank. This can be very messy.
Multiphase meter. This can be expensive and problematic. Also, it can be difficult to calibrate the meter.
Orifice and turbine meters. These don’t work with heavy oil.
B. Using the ESP to Measure Production Rate
This turns out to be a good solution.
It can be easily calibrated.
Accuracies of 2% can be achieved.</td></tr>
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<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
<tr><td></td><td></td><td></td></tr>
<tr><td></td><td></td><td>C. How This Works
Use the tested pump equations – not the ones from the catalog.
Need to measure pump intake pressure, pump discharge pressure, motor amps, motor frequency, and water cut.
ESP pump performance degrades when pumping heavy oil.
Therefore, need to use a correction factor.
Downhole date is acquired once every 45 seconds.
Determine motor load.
Use affinity laws and tested equations for the pump.
Obtain a water cut from a shake out taken by the operating staff.
D. Using the Information
The calculated flow rate is entered into a SCADA system.
Can compare the sum of the calculated production rates from the wells with the total production measured from the field production facility.
Can use this to allocate “actual” production back to each well.
This can be thought of as a “true digital oilfield” with real-time surveillance of the wells.
Question: Do you need pump intake temperature and pump discharge temperature?
Answer: We are planning to measure these temperatures.

Question: How do you test the ESP to get the actual equations?
Answer: We use computer aided design.</td></tr>
<tr><td>Challenges and Solutions during ESP Application in Harsh Environment: With high output of mechanical impurities and with scaling</td><td>Sergei Rusakov, Alexander Kaplan, Mr. Ali Nagiev, Sergey Anufriev, Gazprom NEFT</td><td>This was a story about using ESP’s in harsh environments in Russia. The presentation was given in Russian, with an interpreter.

A. Overview of Operations
These fields are being operated by NEFT, U91.
They operate 24 fields in Western Siberia.
There are 4000 wells. Most of them are operated with ESP’s.
They produced 27,000,000 pounds of oil in 2006.
ESP run life has been improving since early 2005.
They have done this while maximizing production and minimizing downtime.</td></tr>
</table>

Paper	Author(s)	Summary of Discussion
		B. Steps to Improve MTBF • Work with the manufacturers. • Use unique materials. • Use variable speed drives. • Eliminate problems with scale and solids. • Use better technical support services. **C. Steps to Reduce Scale** • Use chemical injection. **D. Steps to Handle Solids (65 Micron Size)** • Use a slotted filter with a stainless steel screen. • Use "V" shaped slotted wire. • The filter has a "self cleaning" capability. • The filter is placed between the seal section and the pump intake. • More than 1000 of these units have been installed. **E. Problems** • Damage to screens during transport and installation. They have addressed this by using centralizers when the units are installed in the wells. • Gas interference. They use dispersers instead of gas separators. **F. Other Approaches** • They use a combination of domestic and Western ESP's. • They use Western Manufacturers to service Western ESP's. **G. Well/Pump Designs** • Wells are up to 2,600 meters deep. • They use VSD's for ESP start-up. • They use Tungsten Carbide, Ni-Resist, Duplex Stainless Steel. • Motors are designed to operate up to 200 ^{o}C. • They use Tungsten Carbide bearings. • They design for flow rates of more than 1,000 M^3/Day. **H. New R&D Plans** • They are working on new gas separators capable of separating 75 – 80% free gas. • They are working on multiphase pumps for 500 M^3/Day, 1000 M^3/M^3 GOR, and high solids content. • They are planning to work with packers in wells with bad casing.

Paper	Author(s)	Summary of Discussion
		• They are looking at using Progressing Cavity Pumps in some cases. They are planning to design a PCP to operate at 3,000 RPM. **Question**: Does sand fall off of the screens? **Answer**: The sand if actually proppant from frac jobs that is produced back into the well. **Question**: What is the status of the 3,000 RPM Progressing Cavity Pump? Has it been tested? What is its run life? **Answer**: This is still in the R&D stage.
TCP-DST-ESP Powerful Configuration to Test Exploratory Heavy-Oil Wells in Block 39 of Peru	Antonio Prioletta, Jaime Cadena, Rafale Cachutt **Repsol YPF** Mateo Sersen, **Jose Flores**, Manual Lokli, Juand Watanabe, Carlo Sanabria **Schlumberger**	This is a story about use of a special tool set to test heavy oil exploratory wells in Block 39 in the Amazon Jungle in Peru. **A. Introduction** • The field is in the Amazon Jungle, a long way from any cities. • The production is heavy oil. • Oil: 12 ^{o}API. • Reservoir pressure: 2,350 psi. • Depth: 5,500 feet. • Temperature: 195 ^{o}F. • Water cut: 0%. • GOR: very low. **B. Challenges** • Reservoir evaluation. • Obtain good pressure data. • Eliminate wellbore storage effects when running pressure build-ups. • Obtain good reservoir fluid samples. • Currently don't know the rock and fluid properties; don't know the well potentials. **C. Program Development** • Obtain production data. • Run a pressure build-up to evaluate the reservoir properties. • Compute the well's inflow performance relationship (IPR). • Several approaches were tried. **D. 1st Well** • Made two runs: one to perforate and a second one to test the well. • The results were not good. **E. 2nd Well** • Used a packer.

Paper	Author(s)	Summary of Discussion
		• Had no wellbore storage effects. • This still required two runs. • Rig time was too long. **F. 3rd Well** • Performed the perforation and test with a one run. • Had no wellbore storage effects. • Obtained a good pressure build-up. • Obtained good production data. • Used the TCP, DST, ESP tool for perforating through tubing, conducting an evaluation of the reservoir conditions and fluids, and producing the well. • This required much less rig time than for the first two wells. **G. Comparison of Rig Times** • 1st well: 89.5 hours rig time. • 2nd well: 88 hours rig time. • 3rd well: 63 hours rig time.. **H. Conclusion** • The TCP, DST, ESP tool is good for evaluation of exploratory wells. **Question**: What is your ESP efficiency? **Answer**: Not sure. **Question**: How did you reduce rig time? **Answer**: By making one trip rather than two trips.
Operations of Multistage Surface Pumping Systems	**William D. Bolin** **KerrMcGee**	This is a story about use of a multi-stage surface pumping system. This paper was substituted for the scheduled paper. The original author was not able to attend the workshop. A copy of this paper can be obtained by contacting the author. **A. History** • This technology came from use of ESP's for downhole pumping. • The project started in 1987 by Amerada Hess. • The surface installed ESP's are used to transfer large volumes of oil. **B. Benefits of this Approach** • Cost. • Availability as compared with other transfer pumps. • Flexibility. • Efficiency.

Paper	Author(s)	Summary of Discussion
		• Rugged. • Low maintenance. • Pulsation is OK. • Horsepower. • High flow rates. • Low weight. **C. Instrumentation** • Measure vibration. • Pump intake pressure. • Oil level. • Pump discharge pressure. • Flow rate. • Motor temperature. • Bearing temperature. • Amps. **D. Bearings** • Use Silicon or Tungsten Carbide. **E. Operation** • Must maintain fluid flow to the pump. • Avoid low pressures. • Avoid running to the "right" on the pump curve; avoid running in upthrust. • Be careful if using two pumps in parallel. • Verify that the pump is running in the right direction. • Keep vibration below 0.156 in/sec. • Perform a laser alignment. This is running at 3600 RPM. • Check for thermal growth. • Start slowly, **Question**: How does the cost of this compare with the cost of other surface transfer pumps? **Answer**: Often the costs of these other pumps are 2 or 3 times more expensive.
Field Performance Evaluation – Advanced Gas Handler (AGH)	Zhizhuang Jiang**ConocoPhillips China Inc.** **Zhou Zhen Guo** **Schlumberger**	This is a story about efficiency improvements that come from effective gas handling using an "Advanced Gas Handler" or AGH. **A. Effects of Gas on ESP Performance** • An ESP is not designed to pump gas. • Gas will reduce the head generated by the pump, may cause surging,, may cause gas locking, and may make it more difficult to cool the motor. • Gas locking occurs when the flow of liquid through the pump is blocked by build-up on gas in the pump stages.

Paper	Author(s)	Summary of Discussion
		• A typical ESP can handle up to 15% free gas. • An ESP with mixed stages can handle up to 30% free gas. **B. Potential Solutions** • Avoid getting gas into the pump by placing the pump intake below the perforations. This requires use of a shroud to force the fluid to flow past the motor for motor cooling. • Separate the gas from the liquid before it enters the pump by using a static or rotary gas separator. The separated gas must be able to flow up the annulus and not through the pump. • Treat the gas so it can be pumped by the ESP. **C. Gas Conditioning** • The idea here is to produce a gassy fluid that can be pumped by the ESP without gas locking. • This is done by reducing the gas bubble size and increasing the pressure of the fluid. • A homogeneous mixture of liquid and gas is created. **D. ConocoPhillips Data in China** • They are operating 21 wells in the subject field. • All of them use ESP's. • All of them use Advanced Gas Handlers. There are three types of AGH's in use. **E. Data Analysis** • Separate analyses were run for each type of AGH. • Well tests were conducted on each well. • Each well was modeled with the SubPUMP program. • The GOR and water cur were adjusted to match the predicted Pump Discharge Pressure with the measured pressure. **F. Results** • Case I: Used an AGH and a radial design pump. The average gas was 48% free gas. • Case II: Used an AGH and a mixed stage pump. The average gas was 45% free gas. • Case III: Used an AGH and a different mixed stage pump. The average gas was 56% free gas. **Question**: Did you evaluate at different pump intake pressures? **Answer**: In most cases the pump intake pressure was 800 – 1,000 psi.

Paper	Author(s)	Summary of Discussion
		Question: What SubPUMP correlations were used? **Answer**: Will provide an answer to this offline. **Question**: The GOR seems to have changed on these wells. Why has it changed? **Answer**: The gas production rate is measured with well tests. The change in GOR is related to changes in the reservoir pressure. **Question**: What is the water cut? **Answer**: It changed a lot during the test. There is an active water flood being used. **Question**: Does water cut have an effect? **Answer**: Water cut is taken into consideration in the SubPUMP model. **Question**: Are all wells produced below a packer, with no gas separator. **Answer**: An AGH is used in lieu of a separator.
Evaluation of Electric Submersible Pumps for heavy oil. Well CIB 260 – Morichal District	**Ana Sosa**, Emmaris Manrique, Marcelo Ramos, Juan Brown **PDVSA**	This is a story about the evaluation of using ESP's for heavy oil production in the Morichal District in Venezuela. **A. Field Description** • This in the area of the Orinoco heavy oil fields in Eastern Venezuela. • The field conditions are: • SBHP: 1,270 psi. • Temperature: 133 °F. • Oil gravity: 8 °API. • Productivity Index: 4 bpd/psi. • Depth: 3,000 – 3,500 feet. • Viscosity: 5,000 cp. • Oil production rates: 1,000 – 2,000 B/D. • Efficiency: 20%. **B. ESP Design** • Special pump design for high viscosity crude. • It uses short veins, high angles. • Efficiency of this is more than 5%. • Design for 1,000 – 2,000 B/D at 10% efficiency. **C. Benefits** • Small equipment. • Low CAPEX cost. • Low maintenance costs. • Low operating costs.

Paper	Author(s)	Summary of Discussion
		D. Test Well • Test well is CIB 260. • Pump has 86 stages. • Motor sis 340 HP; using a VSD. • Using a downhole sensor. • Observed efficiency from 19 – 26%. • Due to efficiency being higher than expected, can downsize equipment to save costs. **E. Conclusions** • Efficiency higher than expected; up to 26%. • Flow rate higher than expected; up to 15% more flow. • Cost lower than expected; down by as much as 11%. **Question**: What is the viscosity of the oil? **Answer**: It is 5,000 cp at 3,000 feet, with out use of diluent. It is about 800 cp with use of diluent. **Question**: Did you compare the efficiency of a Progressing Cavity Pump vs. that of an ESP? **Answer**: We compared with other ESP's. **Question**: Did you make any comparison with a PCP? **Answer**: We only looked at ESP's. **Question**: Is there a "best" operating frequency? **Answer**: We didn't see a "best" frequency. **Question**: What is the typical spread in operating frequencies? **Answer**: We operate at 40 Hz. **Question**: Why do you operate at 40 Hz? **Answer**: We could operate at 50 Hz, but 40 Hz is better for the wells. **Question**: How much diluent do you use? Where is it injected? **Answer**: WE use 600 B/D of diluent. We inject it below the pump intake. **Question**: Where do you inject the diluent? **Answer**: We inject it below the pump; not in the area of the motor.

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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 colspan="3">Session IV -— Electrical, Surveillance, Optimization
Chairs:
Amanda Rovira, ExxonMobil Production
Kenneth Lacey, Custom Submersible</td></tr>
<tr><td>CMB (Controlled Motor Behavior) Soft Start Optimizes Submersible Motor Performance</td><td>Rebecca Larkin
Kinder Morgan

Salvatore F. Grande
Magne Grande

Kenneth Lacey,
Custom Submersible and Electrical Services</td><td>This is a story about use of a soft start approach (controlled motor behavior) to optimize ESP motor performance.

A. Why Consider Soft Start
• The wells in the SACROC Field are produced by a WAG (Water alternating with Gas, e.g. CO_2) process.
• There is a vast difference in load when the pumps are handling a high water fraction vs. when they are handling very gassy production.
• CO_2 is in the gaseous state at the pump intake.
• This causes a reduction in the load on the motor and on the efficiency.
• The power grid in the field is old and in poor condition. This often causes imbalances.
• An imbalance reduces the horsepower that can be generated. This leads to a 3 – 10% drop in efficiency.
• Temperature is also a concern. Higher temperature reduces motor life. A 10 ^{o}C increase in temperature can reduce motor life by 50%.

B. The SACROC Unit
• Production started in 1972.
• The field has an old, poor power grid.
• It uses short WAG cycles.

C. Controlled Motor Behavior (CMB)
• Monitor the power factor.
• Control the voltage to maintain the desired power factor.
• Do this in real time.
• Limit current to just meet the motor's needs.

D. Testing the System
• This was tested first in a Sucker Rod Pumping well.
• Then, it was tested in an ESP well that was experiencing significant unbalance.

E. The Controlled Motor Behavior Design
• It has a built-in soft start capability.
• It reduces start-up "in rush" amps.
• It reduces overall current draw and current unbalance.
• It reduces voltage.</td></tr>
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It reduces unbalance by up to 11%.
It reduces motor temperature.
F. Next Steps
Look at the impact on vibration.
Look at the impact on power factor.
Look at using with higher voltages.
Question: Is there harmonic distortion?
Answer: There was no change in frequency.

Question: Did you actually measure frequency?
Answer: No. We operated at 60 Hz. We saw no decrease in production rate.

Question: Are you using voltage regulation?
Answer: This is being evaluated.

Question: How did you obtain the 11% reduction in unbalance?
Answer: We use flat cable.

Question: How are you monitoring the system?
Answer: We are currently doing it manually. We plan to use a SCAD System but it's not yet hooked up.
</td></tr>
<tr><td>Stray-Current Corrosion Study of PDO's ESP Systems</td><td>I. A. Metwally
H. M. Al-Mandri
A. Gastli
Sultan Qaboos University

Art Al-Bimani
Petroleum Development Oman</td><td>
This is a story about a study that was conducted in Petroleum Development Oman (PDO) to determine the effects of stray electrical currents on corrosion.

A. Introduction
Stray electrical currents are caused by ESP's.
The impact of this has been studied in PDO.
PDO uses ESP's by all three major vendors: Centrilift, Reda, and Wood Group. All there were included in the study.
B. Questions Studies
How much of a problem are the stray currents?
Does these cause corrosion?.
C. Measurements Taken
Measured stray currents.
Measured motor to ground voltages.
The alternating current leakage is small.
Saw up to 60 volts elevation in voltage.
Saw no serious current unbalance.
D. Looked at Cathodic Protection
There are no DC (direct current) currents.
The current is not pulsating as expected.
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<tr><td></td><td></td><td></td></tr>
<tr><td></td><td></td><td>More study is required to fully evaluate if cathodic protection is needed.
E. Used a BEASY Simulator System
This is a galvanic cell simulation.
See up to 1,000 milli-amps even with the ESP turned off.
Get a comparable rate with Sucker Rod pumps and ESP's.
Sucker Rods use four grounding rods vs. one rod for ESP's.
The grounding rods could be improved by replacing iron with aluminum or zinc for better performance.
High eddy currents increase corrosion.
Round cables work better than flat cables.
ESP's do produce stray currents.
Stray currents do cause corrosion.
Question: Does the current loop in a well have an impact on corrosion?
Answer: There is no effect.

Question: How high will the temperature get?
Answer: Don't know, but it will increase.</td></tr>
<tr><td>ESP Process Optimization Results in Longer Run Lives and Incremental Production – A Case History from Block 1AB in Northeastern Peru</td><td>Luis Pantoja
Renato Alegre
Marcial Cruz
Pluspetrol Peru S.A.,

Manuel Loli
Mateo Sersen
Jose G. Flores
Schlumberger</td><td>This is a story about using process optimization to improve ESP run life and increase production in Block 1 AB in Northeastern Peru.

A. Introduction
The fields are in the Peruvian Jungle.
There are 180 wells in the twelve fields.
Production is 30,000 BOPD and 750,000 BWPD.
The field was discovered in 1981.
It is operated by water drive.
There are two primary reservoirs. One is at 10,000 feet with a pressure of 4,000 psi. The other is at 13,000 feet with a pressure of 2,800 psi.
B. Operating Problems
High corrosion.
High temperature.
Scale.
Sand.
High viscosity.
C. Optimization Process
Data acquisition.
Engineering.</td></tr>
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Paper	Author(s)	Summary of Discussion
		• Testing equipment and procedures. • Root cause of failure analysis procedure. **D. New Pump Technology** • Tandem ESP pumps. • Follow good installation and operating practices. • Use two protectors. • Use an improved motor design. • Use improved cable. • Replace use of VSD's with across-the-line starters. • Use SCADA to monitor the wells. • Use sine-wave drives. • Make miscellaneous other improvements: a "Y" tool, a training program, and a technical audit. • A downhole sensor. • Use "Pump Watcher." • Use the Phoenix "Select" Sensor. **E. Results** • Increased run life up to 1,000 days. • Increased to 31 months in 2006. • This is a 20% increase. • Saw benefits from teamwork. • Saw a reduction in vibration. • Moved support of axial loads to the lower protector. • Improved the cable design. **F. Future Plans** • Use a VSD. • Use a Reda Maximus. • Use Phoenix Select Sensor. • Use an Advanced ESP Lifting System. • Use a Poseidon Pump. **Question**: Please explain the Phoenix Sensor. Is it for high temperature? **Answer**: The Phoenix Select Sensor can be used up to 312 ^{o}F. **Question**: How do you plan to reduce vibration? **Answer**: Will use a compression pump to reduce vibration. Will move the load bearing to the bottom protector. We ran hundreds of tear downs to detect the causes of the vibration. **Question**: Do you plan to use rubber cable banding? **Answer**: Not sure.

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<tr><td colspan="3"></td></tr>
<tr><td></td><td></td><td>Question: Does your chemical injection damage cable splices?
Answer: WE use lead spices to avoid chemical damage.</td></tr>
<tr><td>Focus ESP Surveillance in Sensitive Conditions: Benefits and Challenges</td><td>Ibrahim Al-Siyabi
Hamed Al-Sharji
Atika Al-Bimani
Petroleum Development Oman</td><td>This is a story about use of an improved surveillance system in Petroleum Development Oman.

A. Introduction
• ESP's are used to lift 60% of the liquids in the Fahud Field.
• The field is under water flood.
• The wells were on natural flow from 1969 – 71.
• Gas-lift started in 1971.
• The waterflood started in 1972.
• Use of ESP's started in 1996.
• 50% of wells have a GOR of 100 M^3/M^3.

B. Goal of the Surveillance Program
• Increase production.
• Improve ESP performance.
• Identify deferred oil.
• Validate well tests.
• Validate Static Bottom-Hole Pressures.

C. Surveillance Tools
• Downhole sensors.
• SCADA.
• PI database.
• SAP.
• Special ESP surveillance teams with 50 wells per team.
• Use of PDO's "Schrooq:" system.
• Use of analysis tools: Prosper, PVT data, Tubing Pressure.

D. Case Histories
• No. 1: The water cut increased when a nearby well went on water injection. Water injection was stopped and the well recovered good production.
• No. 2: The production rate dropped. The well was re-modeled and re-tested. Now it is OK.
• No. 3: The production rate dropped. A hole was found in the tubing; the pump was worn and plugged. The pump was replaced to minimize losses.

E. Challenges
• Obtain and use accurate downhole sensors.
• Obtain accurate well tests.
• Improve staff competence.
• Create good well models in Prosper.</td></tr>
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<tr><td></td><td></td><td>
Obtain good PVT data.
Enhance the organization to focus on surveillance.
Obtain a production pressure traverse for each well in the SCADA system.
F. Expected Benefits
Increased production, reduced costs, improved efficiency, improved understanding, reduced deferment.
Question: Why did the tubing failure occur?
Answer: Corrosion.

Question: Originally PDO planned to replace all gas-lift wells with ESP's. What is the status of this?
Answer: Some wells are still on gas-lift, primarily in the North of Oman.

Question: Is there a problem with running both ESP's and gas-lift?
Answer: Yes, there are some problems. Mostly since operating, control, surveillance, and optimization requirements are different.
</td></tr>
<tr><td>Committee Introductions</td><td>Noel Putscher
Medallion Exploration</td><td>Noel Putscher gave special mention to David Devine for teaching ESP 101 and ESP 102 on Monday and Tuesday. He also gave special mention to John Patterson and his team for their course on teardown analysis.

He then introduced the ESP Workshop Committee and had each of them come forward to be recognized. The committee is listed in the front of the Workshop notebook.</td></tr>
<tr><td>Breakout Session for Day 2</td><td>Three Breakout Sessions were held on Wednesday.

Harsh Environments
Lyle Wilson and William Bolin

Electrical
Ken Lacey

Alternative Deployment.
Neil Griffiths</td><td>I attended the breakout session on alternative deployment methods. The overall summary of all of the breakouts was presented on Friday morning and is shown at the end of this document.

A. Challenges
Alternative deployment is defined as any method other than use of a rig and a tubing-deployed ESP system.
B. Why Consider Alternative Methods
One of the main objectives is to not have to run an ESP to failure. It can be changed to prevent an ultimate failure, to fine tune the design, etc.
C. Options
Install with or without a rig.
Install with or without a service company.
</td></tr>
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Paper	Author(s)	Summary of Discussion
		• Consider the need for upside down installations with the motor on top and the pump on the bottom. **D. Business Drivers** • Reduce CAPEX. • Reduce production deferment. • Reduce downtime. • "Do it right." • Perform preventive maintenance. • Provide redundancy. • Use hybrid systems. **E. Discussion** • Cable deployed systems moved to coiled tubing deployed systems. It is often difficult to obtain coiled tubing units. • A new initiative is to use wireline installed systems. • ConocoPhillips uses wireline to install ESP pumps where the motor and seal section are already installed. If necessary the pump can actually be pumped downhole, e.g. in highly deviated wells. • Shell is planning a complete wireline installation in Oman. • The possibility of a capability to install and retrieve an ESP system by pumping it into the well and out of the well was discussed. **F. Summary** • A set of standards are needed so people can obtain and make use of the right system for the right application.
Session V -— Operations, Run Life Improvement **Chairs:** **Gabriel Diaz – ChevronTexaco** **Tom vanAkkeren, Production – Production Technology Associates**		
ESP Operation, Optimization and Performance Review; ConocoPhillips China Inc. Bohai Bay Project	Zhizhuang Jiang **Conoco Phillips** **Bassam Zreik** **Schlumberger**	This is a story about optimization of ESP operations in China. **A. Summary of Problems** • They have a problem with sand production, with a sand cut of up to 10%. • This causes a number of problems including: broken shafts, eroded gas handlers, plugged pumps, eroded bearings, and eroded surface equipment. • This results in many well interventions. 24 or 28 interventions were due to sand.

Paper	Author(s)	Summary of Discussion
		• They also have problems with gas. They have a packer above the pump so all gas must pass through the pump. This leads to Underload shut-downs • This leads to deferred production, and overall production is below target. **B. The Field** • Production started in 1999. • This is the 2nd largest field in China. • Per well production is 5,000 – 6,000 BOPD. • The production is gassy and heavy. Production is below the bubble point. **C. Phase I** • The wells produce up to 40% CO_2. They produce below a packer. • They use gas handlers, tandem protectors, and VDS'. • Production is characterized by high sand production, high gas production. • They have a water flood and experience sand control failures. • To improve the situation, they operate the ESP's at a slow speed and use a gradual start-up to avoid pressure surges across the sand control system. • To deal with the gas, they operate on the right-hand portion of the pump curve. • They use a SCADA system to monitor the well data and find this an invaluable tool. **D. Phase II** • They have installed a new sand control system. • They have installed a new packer that can allow gas venting up the annulus. • They use a gas separator. • They control the speed of the ESP to limit the drawdown during start-up. **E. Improvements** • The venting system has helped reduce the gas problems. • The new sand control system has reduced the sand production to about 0.01%. • They are using a team approach to enhance the overall operation • They are focusing on teardown analysis to determine the root causes of failures.

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<tr><td colspan="3"></td></tr>
<tr><td></td><td></td><td>F. Reasons for Improvements
They have installed a check valve above the pump to prevent sand from settling back into the pump.
Thus use an upgraded VSD approach on start-up to avoid pressure surges.
They are using an improved protector design and improved seals on their shafts.
Run life has been improved.
Question: How have you reduced sand production?
Answer: We have installed a screen for sand control.

Question: How are you calculating run life?
Answer: We are using a new method.

Question: Can you describe your method?
Answer: We are using the method recommended by ConocoPhillips (John Patterson).

Question: What have you learned from your teardown of the vortex gas separator?
Answer: This needs to be evaluated.

Question: Do you have corrosion problems?
Answer: We haven’t seen corrosion due to CO_2.</td></tr>
<tr><td>How to make your ESPs last longer</td><td>Luud W. Dor-restijn
Chevron Explora-tion & Production Netherlands</td><td>This is a story about ways to make ESP’s last longer, off-shore in The Netherlands.

A. Introduction
This work has resulted in a large increase in run life. We are now averaging 5.5 years. We were averaging 1.2 years. Our longest run life is 12.75 years.
We produce 5 fields, with 36 ESP’s in the North Sea, offshore The Netherlands.
The wells produce between 500 and 12,000 B/D. Water cuts are up to 99.3%.
We have 24 years experience with ESP’s.
Our workover costs are between $100,000 - $150,000.
Some fields produce below the bubble point.
Some fields don’t require use of a sub-surface safety valve.
B. Our Approach
We conduct teardowns to understand the root cause of failures.
We design our systems using a design simulation program.
We design to operate our pumps at 44 Hz. We</td></tr>
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Paper	Author(s)	Summary of Discussion
		find that operating at slower speeds helps the ESP's to last longer. • When we design, we try to look ahead to future conditions. • We design to operate above (to the right of) the best efficiency point. • We like to operate on the steep portion of the pump curve. We don't like "flat" pump curves. • We use a VDS and an over-sized pumping system so we can run it slow. • We use soft start with less than 350 HP during start-up. • We limit voltage to less than 3 kV. • We use a 5 kV cable. • We find that Underload shutdowns don't always work. • If we have a trip of our electrical generator, we shut down some ESP's. We shut down different ones each time to avoid shutting down any one ESP too many times. • We avoid abrasion by operating at 44 Hz, a slow speed. • We try to keep our pump intake pressures at about 50 – 100 psi. • We use inlet gas separators when needed to handle the gas production. • We try to operate above (to the right of) the Best Efficiency Point, but we avoid moving into upthrust. • We use check valves to avoid upthrust and to avoid sand settling in our pumps. • We use a tail pipe that extends down inside the sand screen to assist in the production of sand and gas. • Corrosion problems are addressed in our designs. We use corrosion resistant materials such as 9 CR, 1 MO tubing and casing. • We use stainless steel when we can get delivery; otherwise we use monel. • We find teardown and failure analysis to be very important. • We need to maintain good ESP engineering. **Question**: How stable is your power supply? **Answer**: WE get about one trip of the generation system per month. This hasn't caused failures due to shutdown and restarts.
ESP Analysis and Optimization by Opera-	**Iqbal Sipra** **Petroleum Development Oman**	This is a story about using plots generated in the SCADA system in Petroleum Development Oman to assist with analysis of ESP operating problems and optimization of

<table>
<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
<tr><td></td><td></td><td></td></tr>
<tr><td>tional Trends</td><td>Steve Beattie
Zenith Oil Field Technology</td><td>the systems.

A. Gradient Traverse Plot (GTP)
This plot is generated by the SCADA system.
It shows the pressure traverse in the tubing above the ESP pump discharge and the pressure traverse in the casing below the pump intake.
They use these plots to help spot operating problems.
With the gradient traverse plot, they compare actual well/pump performance vs. performance predicted by the design program.
B. Trend Plots
They use trend plots (plots of operating variables vs. time) to determine when to proactively work over a well to avoid production deferment.
C. Size of the Prize
This surveillance process has helped PDO to improve ESP run life from 615 to 914 days.</td></tr>
<tr><td>Streamline Operation of ESP Systems in ECUADOR TLC</td><td>Edison Bedoya
Isaac Flores
Dalton Muñoz
Petrobras

David Amores
Jose Leon
Diego Narvaez
Schlumberger</td><td>This is a story about methods to streamline ESP operations in Ecuador.

A. Introduction
The field is in the Ecuadorian portion of the Amazon Jungle.
The field was discovered in 1999; production started in 2002.
They operate 28 ESP’s and produce 40,000 B/D.
This is a very bio-diverse area.
B. Challenges
The area is very remote.
It rains much of the time.
There are community issues with the local indigenous people.
The reservoir conditions change dynamically.
C. Operating Philosophy
There must be minimum impact on the community.
Want to use ESP’s to minimize the impact on the surface.
The wells are drilled from PAD’s to minimize the overall “footprint” in the area.
The improve the well productivity, they use under balance perforating with the assistance of the ESP’s.
Flexibility is very important due to uncertain res-</td></tr>
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Paper	Author(s)	Summary of Discussion
		ervoir conditions. • Reliability is very important; they use a quality control program. **D. Design of the ESP System** • They use a variable speed drive, and advanced gas handler to handle high gas production, and a downhole sensor to measure pump intake pressure, pump discharge pressure, temperature, vibration, and current. • They use abrasion resistant bearings. • They use tandem protectors and compression type pumps. • The follow the recommended practices of API RP 11S3. • They install their pumps in 9 hours. They use a very careful process, closely following the guidelines. **E. Dealing with Severe Conditions** • They use several special methods to deal with severe conditions. • They have to deal with gas, high temperatures, high flow rates, and large horse powers. • .They use materials that are abrasion resistant and special protectors. • They control pump rates with VSD's. • They use a SCADA system for system monitoring. • They special well servicing practices to deal with the severe weather (lots of rain). • They need special procedures for handling and installation. **F. Goals** • They would like to have a system that can be installed using a "plug and play" method to minimize steps required in the field. • They have reduced the number of steps required in the field from 69 to 38 and they want to reduce to 4 steps. With this they can reduce their installation time by 40%. **Question**: Do the motors have more horsepower? Doe this affect reliability? **Answer**: We want to improve reliability. We are doing more testing. We are also testing a rotary bearing. We have used a plug-in pot head for 20 years.
COTL Block B8/32 ESP Pilot	**Gary G. Thompson**	This is a story about an ESP pilot program in the Chevron Offshore (Thailand) Limited (COTL) B8/32 Block in off-

Paper	Author(s)	Summary of Discussion
Program	St, Crower (SPE) **Chevron Thailand** Ra Mastellar **Baker Hughes Centrilift**	shore Thailand. **A. Introduction** • The field for the ESP pilot test is in offshore Thailand. • The field is in 250 feet of water. • An ESP feasibility study was performed in November, 2004. • In November, 2005, four ESP's were installed using a jack-up workover rig. • In 2006, six ESP's were installed using a hydraulic workover rig. • Another twenty ESP's are scheduled for installation in 2007. • There are multiple reservoirs vertically stacked on one another; there are 3 – 20 reservoirs, with depths ranging from 4,300 – 9,500 feet. • They tried "in-situ" gas-lift by producing a gas reservoir to lift oil production. • To reduce drilling costs, they place 7" casing down to 2,000 feet and then drill the wells with 2-7/8" monobores. • They use a well automatic flow valve (WAFV). • They use VDS's to drive the ESP's. They use modular skids with transformers. • A goal is to reduce pump intake pressure from 400 to 80 psi. **B. Operation** • They have between eight and twelve stops/starts per month due to power surge problems. • They use SCADA and downhole monitoring. • They have developed a screening process to select candidates for use of ESP's. • They use a hydraulic workover rig to reduce costs. • They have worked to improve the safety of this operation. **C. Pilot Results** • They have produced 1.7 millions barrels of oil by ESP since the pilot began. • They have averaged 16 months run life. • They have had three failures: one was a broken shaft and two were electrical. **D. Lessons Learned** • It is important to minimize the wellhead back pressure. • They need to continue use of the sub-surface safety valves.

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It is very important to use clean fuel gas.
They have seen many benefits by bringing the SCADA date to the home office.
They have benefited from use of the hydraulic workover rig.

E. Conclusions

The development cost with the ESP operation is about $7.00 per barrel.
They have added reserves by being able to reduce the pump intake pressures.
SCADA is a useful tool to help optimize the wells.
Training is very important.

Question: How have you reduced the free gas at the pump intake?
Answer: WE have seen some drop in the GOR. And, we feel we are successfully separating 80 – 90% of the free gas at the pump intake.
Question: Will you perform teardown analysis?
Answer: This has been hard to do so far. We plan to attend teardowns in the future.
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<tr><td>Breakout Session Summary</td><td>
There were a total of six breakout sessions.
Future – What is needed for the Future of ESPs?
Craig Stair and Rebecca Larkin
ESP Jewelry and Add-On’s.
Julian Cudmore
Production Optimization and Well Surveillance.
Sandy Williams
Harsh Environments
Lyle Wilson and William Bolin
Electrical
Ken Lacey
Alternative De-
</td><td>
The leaders of each breakout session gave a brief overview summary of the discussion in their session.
A. Future – What is needed for the Future of ESPs?
Summary provided by Rebecca Larkin

58 people attended this session.
Discussion topics included:

- Downhole oil/water separation.

- Sand separation and production.

- Gas well dewatering.

- Installing electrical line through tubing.

- Producing heavy oil, for which there are no existing API recommended practices or standards.

- Motor performance, for which there are no standards.

- Methods to handle multi-lateral wells.

- The possibility of downhole adjustments/control to combat slugging.

- High (really high) horsepower motors.

- High temperatures.

- Dealing with small casing sizes.

- Working in permafrost areas.

- Consideration of pumpable deployment systems.

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Paper	Author(s)	Summary of Discussion
	ployment. Neil Griffiths	**B. ESP Jewelry and Add-On's** Summary provided by **Julian Cudmore** • Discussion topics included: - Devises to prevent back-spin. - Devices to allow access to the reservoir. - Corrosion. - Handling solids. - Metering flow. - Providing a back-up ESP system with a 2nd ESP or with gas-lift. - Using shrouds to enhance motor cooling. - More new technologies are needed. **C. Production Optimization and Well Surveillance** Summary provided by **Sandy Williams** • 20 people attended this session. • Discussion topics included: - There is a need to evaluate ESP operations daily. - A process is needed for surveillance. - There is not enough focus on surveillance, need to focus more on $/Bbl vs. run life.. **D. Harsh Environments** Summary provided by **Lyle Wilson** • It's easier to define what is "not harsh." Good pressure, clean water, low temperature. • Everything else is harsh. • In all situations, very close communication is needed between the Operator and the Supplier to they have a mutual understanding of the conditions to be addressed. **E. Electrical** Summary provided by **Ken Lacey** • The following topics were discussed: - The electrical distribution system. - Electrical problems. - Use of VSD's and soft start systems. - Grounding. - Need to perform root cause of failure analysis to know what actually caused the problems. **F. Alternative Deployment** Summary provided by **Neil Griffiths** • 40 people attended the session • The following topics were discussed: - Alternative deployment is any deployment without a rig and the ESP system run on tubing. - In some forms or alternative deployment,

Paper	Author(s)	Summary of Discussion
		ESP's must be run "upside down" with the motor on top. - Alternative deployment can be without a rig; it can also be without the direct involvement of a Service Company. - Alternatives include coiled tubing deployment, cable deployment, wireline deployment, and possibly pumpable deployment. - Goals include: reduced CAPEX, reduced deferment, improved run life, no time waiting on the availability of rigs. - The majority of ESP deployments are and will likely continue to be the conventional type with a rig. - Use of alternative deployment methods is a niche operation although use of this approach is likely to grow in the future. .
Closing Comments	**Noel Putscher** **Medallion Exploration**	Noel Putscher gave a few closing remarks. **A. Attendance** • There were 476 registered attendees at this year's Workshop. • Of these 30% were from Operating Companies. • Therefore, 70% were from Service Companies, Consultants, Universities, etc. • There were representatives from 27 countries. **B. Thanks Very Much** • Noel closed by thanking everyone for their attendance and participation. • See you in two years.

Wednesday

01	02	03	04	05	06	07	08	09	10	11

Thursday

12	13	14	15	16	17	18	19	20	21	22	23

Friday

24	25	26	27	29	29	30