2004 ESP Workshop
Summary of Presentations

Prepared by
Cleon Dunham, Oilfield Automation Consulting
May 4, 2004

Paper	Author(s)	Summary of Discussion
Purpose of this Document		
		The purpose of this document is to summarize the main points of the technical presentations, panel discussions, and breakout sessions at the 2004 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 / presenters of the papers. Attendance at this years workshop was: • A total of 290 people. • From 19 countries. • 30% from Operating Companies. • 13% from five largest Operating Companies. • 70% from Service/Supply Companies. • 33% from three largest Service/Supply Companies.
Opening Comments **Chair: Shauna Noonan**		
		Shauna Noonan, ConocoPhillips, opened the 22nd annual SPE Electrical Submersible Pumping Workshop. She covered several items: • Reconstruction activities were underway at the Adams Mark Hotel. All attendees were encouraged to "make the best of the situation." • Next year's workshop will be held in the Woodlands Conference Center in The Woodlands, Texas, north of Houston. • After next year, the ESP Workshop will move to an "every other year" schedule. There will be workshops in 2005, 2007, etc. The Aberdeen Workshop, which also features ESP's, along with other artificial lift tech-nologies, will be held on even years --- 2006, 2008, etc.

<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>Workshop registration was conducted by the SPE. It seemed to go very well.
Extra security was present. All attendees were required to wear badges to attend all Workshop events.
Each attendee's Workshop notebook contains a CD with copies of the actual presentations. All papers are included in the notebooks.
CD's with the last 20 years of proceedings are available for purchase.
Jack Blann, Consultant, paid a tribute to Buford Neely. Buford, who passed away on December 10 2003, was instrumental in helping to start the ESP Workshop. This year's workshop was dedicated to his memory.</td></tr>
<tr><td colspan="3">Keynote Address</td></tr>
<tr><td>ESP's – New Horizons</td><td>Dr. James F. Lea, Department Chair, Petroleum Engineering, Texas Tech University</td><td>Dr. James F. Lea, chairman of the Department of Petroleum Engineering, Texas Tech University, gave this year's keynote address. Jim's focus was on the challenges that face the ESP industry in the upcoming years.

His opening thought was, 'I wish we could know the additional barrels of oil and reductions in failures that have occurred because of the learnings from the ESP Workshops over the years."

He made the following points:
75% of the total world's oil will be produced in the period from 1950 – 2025.
Currently, world oil production is expected to peak in 2010.
Very significant amounts of technology will be needed to produce the remaining reserves.
World population is expected to grow to about 10 billion before it levels off. It was 6.1 billion in 2000.
There are about 2 million oil and gas wells in the world.
About 1 million of these currently require some form of artificial lift with the number continuously growing.
There are about 533,000 wells in the US, with 90% needing to be pumped – beam, ESP, or PCP.
PCP is the fastest growing with 60,000 in the world.
There are 90,000 ESP's in the world, with 60.000 in Russia.
ESP challenges / opportunities:
Deepwater.
Gas-lift replacement.</td></tr>
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		– New developments. • Deepwater: – If artificial lift isn't used in the deepwater wells, up to 33% of producible reserves are lost. – There are subsea wells with wet wellheads. Interventions can cost up to $10 million. – There are platform wells with dry wellheads. Interventions can still cost $1-2 million. – Deepwater wells required sub-surface safety valves. – Many of them are fractured and production of frac sand is an issue. – Many must be produced at very high rates – over 10,000 B/D. – For all of them, reliability is essential. • Efforts to improve reliability: – Pressured motor oil for improved cooling. – Materials to handle high temperatures. – Use of advanced downhole monitoring systems. – Advanced deployment methods – coiled tubing or wireline. – Use of fiber optics. – Subsea lubricators. • ESP competition with gas-lift. – ESP's have several advantages over gas-lift --- very high production rates, lower operating bottom-hole pressures. – A big disadvantage is high workover costs. – Gas-lift has many advantages --- handle gas, solids. – Its big disadvantage is inability to achieve low operating bottom-hole pressure. • ESP retrievability options: – Cable – Through tubing – Coiled tubing – Coiled tubing with cable inside tubing – More development of rig-less systems is needed. – Need better wireline deployment options. – Need to consider a pump-in/pump-out system that might be called a "Free Hydraulically Deployed ESP." – Might consider use of robots for ESP deployment.

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<tr><td></td><td></td><td>• Q/A Session:
– Shell:
○ In deep offshore, Shell is using riser gas-lift.
○ Is considering use of multiphase pumps on seabed.
○ Needs “utterly reliable” ESP’s for deployment in subsea wells.
– Petroleum Development Oman:
○ Expressed concern about high voltage. Response was that industry does a good job of providing systems for electrical safety.</td></tr>
<tr><td colspan="3"></td></tr>
<tr><td colspan="3">Session I -— High Horsepower / High Volume Systems
Chairs: John Patterson and Steve Breit</td></tr>
<tr><td>High Volume Applications - Tutorial</td><td>Gumersindo Novillo, Petrobras Energia, SA

Dr. James F. Lea, Texas Tech University</td><td>This was a story about planning and implementation of ESP systems to produce very high rates. It was presented by Gumersindo Novillo, Petrobras Energia, SA.

• Goal is to produce more than 10,000 B/D.
– Primary problems are very high velocities, corrosion, and sand production.
– Designs are required for 7-inch and 9 & 5/8-inch casing.
– Production may be up to 95% water.

• Questions:
– Which pump(s) to use?
– Horsepower needed?
– Maximum torque?
– Maximum thrust?

• Considerations:
– Produce 10 – 28,000 B/D in 7” casing.
– Produce 10 – 35,000 B/D in 9 & 5/8” casing.
– Use 250 – 1170 HP in 7” casing.
– Use 333 – 1500 HP in 9 & 5/8” casing.

• Risks:
– High frequencies.
– Erosion due to high velocities.
– Corrosion: H_2S, CO_2.
– Sand.

• Alternatives in 7” casing:
– Looked at producing through 3.5”, 4.0”, and 4.5” tubing.
– 3.5” is best – less risk for fishing operations.
– Friction loss is less then 2.5%. Use internal plastic coating on tubing.</td></tr>
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		– There are concerns about erosion and corrosion. – Considered producing up annulus. o Have lower friction. o But have problems with gas, sand, corrosion, sand, and safety. • Sand issues: – As production rate increases, sand production tends to increase. – As water production increases, sand production tends to increase. – However, if rate is reduced, sand production rate may not decrease. – Sand measurement methods: o Most still rely on samples. o Some are considering use of sand measurement technologies – probes, clamp-on devices, etc. – Sand control: o Can limit sand if produce below “critical” production rate. Obtain this by using more perforations, avoiding sudden changes in production rates, using slow start-up, using surface backpressure or VSD control. o Another option is use of sand exclusion devices such as wire-wrapped screens and gravel packs. o Another is using special pump materials designed to withstand sand abrasion.
Novel Application of ESP’s in the Brent Field: The Challenge of Back-Producing Water using High Horsepower ESP’s	John Blanksby and Steve Hicking, Shell Exploration and Production Willie Milne, Centrilift	This is a story about producing high volumes of down dip water to reduce reservoir pressure to enhance gas desorption and increase gas recovery in the Brent Field. John Blanksby, Shell Exploration and Production, presented it. The Shell Brent Field is located 100 miles northeast of the Shetland Islands, in the Northern North Sea. It was discovered in1971 and has recently celebrated 25 years on production. It was an oil field, with some associated gas production. Now, it is a gas field with some “tail end” oil production. High volumes of water need to be produced to depressure the reservoir. This depressurization allows gas release. It will allow production of up to 1.5 trillion extra cubic feet of gas. ESP’s are used to produce the water to permit reservoir pressure depletion. • ESP strategy: – Use soft starters. – Draw reservoir pressure down to 1200 psi.

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		• ESP testing protocol: – Focus on detailed ESP design / development. – Conduct factory acceptance test. – Conduct site installation test. – Conduct pump endurance test. – Conduct start-up test. – Use floating stages in HC19000, HC27000, and HC35000 pumps. – Upthrust is a “hard constraint. It cannot be allowed. – Downthrust is a “soft” constraint. Some downthrust can be tolerated. – Use 6” tubing. – Use tandem motors. • Run lives: – In Phase I (first three pumps), run lives were short: 15, 42, and 230 days. – In Phase II (after design improvements), run lives are improving with best up to 381 days. – Failures have occurred with the packer and with the motor interconnections. • Work is needed on: – Improved temperature performance – both for high and for low temperatures. – Improved pump monitoring and operating procedures. • Learnings: – Many of the problems are on the surface. – Need to focus on design of the seal section. – It is important to accurately predict the GLR. There is gas in the water zone. – Must have a reliable check valve to keep the tubing full of liquid on a pump shutdown. – Use control by surface choke – don’t use a VSD. – However, in hindsight, use of a VSD could be beneficial. – High ESP motor temperatures are being experienced. – Need to have a good idea of the well’s productivity index. – Expect project delays, especially in the North Sea environment. – Concluding comment: “ESP run life is a long as the weakest link.”

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<tr><td></td><td></td><td>• Q&A Session:
– Q. Did you consider using fiber optics?
– A. Considered but thought it was too complex.

– Q. What is source of produced gas?
– A. Solution gas in the water.

– Q. What are future plans?
– A. Must make ESP's work. Other artificial lift methods not pertinent for this application.

– Q. What is source of check valve?
– A. Had to design a special check valve for this project.</td></tr>
<tr><td>Production Performance Evaluation of a 2000 Horsepower Oilwell ESP System for 30,000 BFPD Production Capability</td><td>Dana Pettigrew, Nexen Petroleum International Ltd.

David Ling, Centrilift</td><td>This is a story about using ESP's to produce up to 30,000 B/D in Yemen. Dana Pettigrew, Nexen Petroleum International Ltd., gave it.

• Description:
– Project in Yemen, in Middle East.
– Wells are 5,700 feet deep.
– Have 9 & 5/8" casing.
– Sand stone reservoir.
– Low GOR, bubble point is 50 psi.
– Productivity index is 50 B/D/Psi.

• Initial ESP's:
– 1000 HP.
– Use tandem ESP's.
– Produce 25,000 B/D.
– Water cut not proportional to drawdown.

• New ESP's:
– Use two tandem ESP's.
– Called TUT-Tandem: Tandem upper tandem.
– Two 500 HP motor systems and one 640 HP motor to yield total of 1640 HP in double tandem system.
– Have size limits – shaft.
– Have shaft HP limits.
– Have limit of 1000 HP at surface.
– Have limits in Y tool – friction.
– Use double systems to achieve needed HP and pump capacity:
○ Two common main cables.
○ Two common wellhead penetrators.
○ Two common sets of surface equipment, including VSD's.
○ Two common electrical generator sets.</td></tr>
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Paper	Author(s)	Summary of Discussion
		• Q&A session: – Q. What is run life? – A. For 1000 HP system – up to 800 days. For 2000 HP system, we don't know yet. – Q. What type of seal section? – A. Use parallel bags. – Q. How do you coordinate the VSD operation? – A. Use common start, common target rate, and common stop. However they are not synchronized. – Q. What size equipment. – A. Basically, the largest equipment that will fit in 9 & 5/8" casing. – Q. What is strategy if a VSD fails? – A. Run as one system until it can be repaired. – Q. Would this work offshore? – A. Don't know, but don't see why not.
Session II –-- ESP Run Life and Reliability **Chairs: Shauna Noonan and Nasser al-Rawahy**		
A Quest to Improve ESP Run Life in High Rate, Multilateral Water Flood Fields; Qarn Alam, PDO Oman	Atika Said al Bimani, Petroleum Development Oman	This is a story about Petroleum Development Oman's efforts to improve ESP run life in the Qarn Alam Business Unit in Oman. Atika Said al Bimani, Petroleum Development Oman, gave it. • Oman – 75% of the income of the country comes from production of oil and gas. • Qarn Alam – Has three large carbonate fields. – Has several smaller sandstone fields. – 90% of the oil in the business unit is produced by ESP. • ESP statistics: – Average ESP run life is 467 days. – Lost production amounts to 600 M3/Day (about 3,600 B/D) when an ESP fails. • Project goals: – Reduce well downtime. – Improve field/well management.

Paper	Author(s)	Summary of Discussion
		– Improve relationships with stakeholders. – Improve ESP design. – Improve ESP run life. • Process: – Use dedicated field staff and teamwork with contractors. • Progress: – Have been able to reduce premature failures. – There are no more premature failures. • Problems with solids: – Most of wells are multi-laterals. – In many cases, the drilling trajectory enters into shale zones. – PDO attempts to control production of solids with use of wire-wrapped screens. – They also use “solids tolerant” pumps. • Problems with corrosion: – Corrosion is caused by CO_2, H_2S, high temperature, and silt. – Stray currents may also cause it. – PDO is coating pumps with Monel to prevent corrosion. – Whenever a well is pulled, new tubing is run. – A study of the stray current issue is underway. • Problems with poor reservoir pressure support: – PDO is making an effort to size the ESP pumps to just equal the reservoir off take rate. – Where necessary, they are using special gas handling stages or components. – They are injecting water – water flood – to maintain reservoir pressure. • Progress with monitoring: – PDO has improved the use of downhole alarms and trips. – They have improved use of downhole information. – This results in better information for ESP design. – And better problem diagnosis. • Training: – PDO has recognized staff training as an essential issue. – They have trained 48 staff in the Qarn Alam Business Unit. – They have established Key Performance Indicators (KPI’s) to track ESP performance improve-

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		ments. – They are using ESP design software. • Results – Run life has been improved to +12% relative to PDO average performance (it was -5% relative to PDO average performance). – Premature failures have been eliminated. – The problem with solids (shale) still exists, but drilling programs have been improved. – Better use is being made of downhole data. – The next step is to focus on evaluation and improvement of the electrical systems. • Q&A session: – Q. What is % of wells with VSD's? – A. About 10%. VSD's are only used when they are needed. – Q. Where have the biggest improvements come from: new technology or staff development/training. – A. Both are equally important. – Q. What forms of contracts are used with suppliers? – A. PDO is using a lease contract approach.
Designing Electrical Submersible Pumps for the Chad Project While Managing Uncertainty	Thomas Paez, ExxonMobil Production Company Thomas J. van Akkeren, Production Technology Associates	This is a story about design and development of a new field in Chad, Central Africa. Thomas Paez, ExxonMobil Production Company, presented it. • Chad: – Chad is a land-locked country in central Africa. – Production is exported via a 660-mile pipeline, through Cameroon. • New Field in Chad: – The new field has (will have) 220 wells. – Target production is 225,000 B/D. – A 30-year production life if expected. – A lower zone produces gas. This is used to run electrical generators. There is no "public" source of electricity. – The upper zone is oil bearing. – The oil ranges from 17 - 27 ^{o}API. – The wells are completed with 9 & 5/8" casing. – Sand control is used. – The wells must be pumped initially. – PCP's are used for the wells that are expected to produce at lower rates; ESP's for the higher rate

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		wells. • Expected reservoir performance: – Expect reservoir pressure to decline, at least initially. – Expect high water production rates later on; reservoir has a large aquifer. – When water hits, problems with emulsions are anticipated. – The field is in a very remote location. This presents many logistical problems. • Equipment selection: – Pumps must be abrasion resistant. – The system must be designed for high horsepower to produce high rates. – Use of VSD’s is expected to be minimal; most wells with use FSD’s. – Check valves will be used to prevent back flow. – Downhole monitoring will be used; especially pump intake pressure. – A capillary tube will be used for chemical injection. – A Y tool will be used to permit production logging. – Adjustable chokes will be used at the surface for well control. – Design of the well system is performed in Houston. – Design of the ESP equipment is performed in Chad. • Initial well testing: – Only have portable well test system for initial well evaluation. – Use a portable VSD for initial well tests. – Obtain a good match between measured performance and performance predicted by use of the SubPump design program. • Well start-up protocol: – Use a conservative approach. – This prevents (at least reduces) solids production. – Start-up takes 5 - 7 days. • Initial implementation: – Initial 50-well field has 47 ESP’s, 3 PCP’s. – Have had a few failures of surface controllers, downhole data readouts. • Challenges: – Power distribution. – Well testing; there are no permanent well test

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		separators. – Operating the wellhead chokes. • Conclusions: – Focus on detailed planning and follow-up. – Be conservative in approach. – Use gradual field ramp-up. • Future plans: – Plan to use more VSD's. – Plan to use emulsion breakers. • Q&A session: – Q. How many manufacturers are used? – A. One. Have single source contract. – Q. Do you plan to allow competition in the future? – A. Right now, we are only Operator in Chad. Competition may come in the future. – Q. How do you choose between use of ESP's and PCP's? – A. PCP's for wells less than 2,500 B/D. ESP's for higher rate wells. – Q. Is a water flood being planned? – A. Water injection may be used in a few areas for reservoir pressure maintenance. – Q. What are expectations for high viscosity? – A. Don't know. Need well test data. – Q. How many ESP's are now on line? – A. 75 – 90 are currently on line. – Q. Isn't your run life target of 2 years a bit optimistic? – A. Well, so far so good. – Q. You mention good agreement with SubPump. How is this done without well test data? – A. We use a portable well test unit for initial testing. This is where we correlate with SubPump. – Q. Are you considering multi-phase metering? – A. We are considering use of Coriolis Meters where we don't have free gas. – Q. What type of contract do you have? – A. Production contract.

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<tr><td>Making Sense of Mean Time Between Failure (MBTF) and Other Run Life Statistics</td><td>Bruce Brookbank and Ken Bebak, Centrilift</td><td>This is a story about how to calculate and use mean time between failure statistics. It was presented by Bruce Brookbank, Centrilift.

• Introduction – issues to ponder:
– How to perform reliability analysis?
– How to measure mean time between failures (MTBF)?
– Challenge: Is 5% MTBF improvement possible in a 10-year old field?

• Options to define MTBF:
– Time the ESP system is in the well?
– Time from initial start to final stop?
– Actual number of operational hours?
– Different people use different definitions.

• Options to define failures:
– Does any type of failure count?
– Or only failures that occur below the wellhead?
– Or only failure with the pumping system itself?

• Example:
– Define run lift as “total operating time.”
– Can MTBF be improved by 5%?
– MTBF = Total Run Time / # Failures.
– MTBF approx. = # Wells * Run Time / # Failures.
– If MTBF= 2 years, 50% fail per year.

• Options:
– Calculate a “moving” MTBF.
– Calculate an average MTBF.

• Recommendations:
– Agree on a definition of failures.
– Count # failures per # wells.

• Q&A Session:
– Q. What are best ways to calculate MTBF?
– A. There are at least four different ways. Choose the one that fits your case the best.

– Q. What if it is early in a project and there have been no failures?
– A. Then MTBF is undefined.

– Q. Should infant mortality be counted in determining MTBF?
– A. This adds to the numbers of failures. So it should be counted. But it is appropriate to classify failures into different classes. Might have a class</td></tr>
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		for infant mortality; a different class for other types of failures. – Q. Is it possible to determine an inherent MTBF for a particular condition of class of equipment? – A. Unanswered.
Case Study: A Review of Production Optimization Results using ESP's in the Samotlor Field, Western Siberia, Russia	Gary Oxley, Wood Group Run Krupa and Sergey Yakimov, Halliburton Sergey Sviderski and Mark Seitz, TNK-BP	This paper was not presented. The authors could not attend the workshop. In its place, the following panel discussion was held
Panel Discussion – Ways to Improve Run Time	This was an open panel discussion, open to question and answers from the entire audience.	• Q&A session: – Q. Why do we care about MBTF? – A. To help improve reliability by focusing on the right problems. – Q. In the PDO story, what does it mean for the run time to be improved from -5% to +12%? – A. This is an indication of the relative change in run life over time. It is a measure of performance in the Qarn Alarm Business Unit vs. the overall performance in PDO. – Q. Does the ESP-RIFTS (ESP Reliability Information and Failure Tracking System) provide enough data to help in understanding run life and MTBF? – A. To make this type of analysis, good quality date is needed. Must analyze this information. Only looking at changes in cumulative run time is not enough. Some interesting analyses are being performed on the ESP-RIFTS database. – Q. Should a "sacrificial" pump be counted in MTBF statistics? – A. A separate class of "sacrificial" pumps can be created, so the MTBF of this class can be monitored over time and it can be compared with other classes of pumps. – Q. If mean time between pulls a better measure than MTBF? – A. This depends on your objectives and purpose.

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		– Comment. There is a significant difference be "system" reliability and "mission" reliability. System reliability refers to the reliability of an ESP system. Mission reliability refers to the reliability of the entire production mission – well, pumping system, operation, etc. – Q. How does PDO evaluate its improvement in performance? – A. By using differential improvements in reliability, vs. looking at cumulative changes in reliability. – Q. What are problems in looking at failures per well per year? – A. These can vary a great deal. Must be careful in using short-term measures of reliability.
Session III –-- Cables and Competency Chairs: Mark Johnson and Mark James		
Design and Application of Electrical Submersible Pump Cables for Extremely Harsh Environments	Carlos Alberto Fereira Godinho, Edvaldo Chaves Mendes, and Valeria Garcia, Pirellie Energia Cabos E Sikstemasdo Brazil, S.A.	This is a story about the design, development, manufacture, and testing of cables in Brazil. It was presented by Carlos Alberto Fereira Godinho, Pirellie Energia Cabos E Sikstemasdo Brazil, S. A. This was a very "commercial" presentation – not well in keeping with the spirit for technical, non-commercial presentations. • High voltage cables are needed for harsh environments. – High cable reliability is needed. • Specific cable needs: – Thermal stability. – Low amount of swelling when immersed in oil. – High resistance to blistering. – Good aging resistance. – Insulations that are resistant to high operating temperatures. • Cable material: – An EPDM-based rubber compound is used to meet these needs. – It depends on finding the optimum chemical formulation. • A special testing program is needed to: – Select and evaluate new cable compounds for low swelling. – Materials to resist blistering. This is a function of the solubility of gas in the cable compound.

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		– Long-term electrical stability (aging). • Test evaluation methods: – Use a Weibull distribution to establish cable life. – Developments are leading to new cable compounds with four times longer lives. • Test to simulated operating conditions: – Immerse cable in 450 ^{o}F, 3000 psi, for one week. – Tests conducted at Southwest Research in San Antonio, Texas. – Field tests are being conducted in Brazil. • Q&A Session: – Q. What is the make-up of the cable to prevent swelling? – A. Only use insulation compound and a jacket. – Q. Are pressure cycling tests run? – A. Yes. – Q. What are conditions of field test? – A. 150 ^{o}C, gas is present. – Q. Is thermal cycling used in the testing? – A. Yes, in long-term tests. This is done by cycling from AC to DC to simulate operations in the field. – Q. Why is AC used in the tests? – A. To simulate normal operations. – Q. Does the practice of using DC for the tests give good results? – A. Use of DC alone is not sufficient. Need to cycle between AC and DC. – Q. Were the various EPDM compounds all the same hardness? – A. Yes.
API Update on 11S5: Application of Electrical Submersible Pump Cables	Tom van Akkeren, Production Technology Associates	This is a story about the status of API 11S5, for the application of electrical submersible pump cables. Tom van Akkeren, Production Technology Associates, presented it. • Introduction: – The American Petroleum Institute (API) has over 400 member companies. – All work on API documents is performed by industry volunteers. – API is based in the U.S.A., but API documents are used around the world.

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		– API seeks to produce specifications and recommended practices that lead to equipment that can be used in a safe, HSE-friendly manner. (HSE = health, safety, environment.) – There is a strong alignment between the API and the ISO (International Standards Organization). In some cases, the API and ISO share common documents. • API Committee 11: – API Committee 11 addresses ESP's, gas-lift, and beam pumping. – API documents must be reviewed every five years. They must be confirmed, revised, or revoked. – So, any document with a date older than five years is not up to date. – There are nine (9) API 11 documents for ESP's. • API 11S5 for ESP cables covers: – Design. – Description of all cable components. – Applications. – Limitations. – Conductors. – Insulation. – Jackets. – Braids. – Armor. – Auxiliary components (e.g. monitoring systems, back-spin relays, etc.) – Splicing. – Terminating. – Power / cost Issues. – An application selection guide.
ESP Training and Competency Development in PDO	Atika al-Bimani and Nasser al-Rawahy, Petroleum Development Oman Alastair Baillie and Sandy Williams, Engineering Insights Limited	This is a story about ESP training and development of staff competencies in Petroleum Development Oman. It was given by Nasser al-Rawahy, Petroleum Development Oman. • Introduction: – PDO is divided into two main business units. – The North Unit has mostly carbonate reservoirs. Gas production is an issue. – The South Unit has mostly sandstone reservoirs. Issues are heavy oil production and sand production. • ESP run life: – ESP run life is trending in the right direction:

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		○ 563 days average run life n 1995. ○ 893 days in 2003. ○ Target is 1190 days in 2006. • Challenges: – Currently 46% of production is by ESP's. – The target is 70% of production in 5 years. – Target is to improve run life by 10% over next 5 years. – There are several production challenges: ○ Gassy production. ○ Solids production. ○ Corrosion. ○ High power requirements. ○ Need to minimize production deferments. • Skills gaps: – There is high degree of staff turnover. – There is more and more reliance on outsiders (non PDO staff). – Classroom training is not sufficient. People must gain hands-on skills. • Staff development targets: – Extend staff competencies. – Develop local Omani expertise. – Develop the ability to train trainers. – Share best practices across PDO. – Extend the technical progression ladder. Make it possible for technical experts to be recognized and rewarded. • Implementation plans: – Continue classroom training. – Use coaching. – Develop measures of competency. – Develop in-house experts. • Pilot use of this approach in the Qarn Alam area: – Focus on selecting important wells. – Model these wells. – This obtained good results. As a result, the staff were: ○ Integrated. ○ Motivated. ○ And the results were sustained. • Plans: – Use on the job training. – Focus on interpreting well performance. – Incorporate use of downhole information.

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		– Make good use of the SCADA system. – Upgrade more company Production Technologists and Production Programmers to become ESP experts. – Recognize that not all staff need or can use the same level of training. – Tailor the training to meet the needs of the person(s) being trained. • Results so far: – Eliminated initial (infant) failures. – Gained strong management support for the process. – Have received good cooperation from Service/Supply Companies. • Goals: – Develop 16 Omani experts. – Develop 2 trainers who can maintain expertise and develop new experts. – Have 0 accidents. • Q&A Session: – Q. How important is the technical progression ladder? – A. It is critical. People need to see that they can grow. – Q. Will the electrical component of the training be increased? – A. Yes, and Service/Supply Companies will be involved. – Q. What is the role of PDO management? – A. It is very strong and very supportive.
Panel Discussion		
"Is There an Expert in the House? Addressing the Future Artificial Lift Competency Crisis"	Facilitator: David Carpenter, Shell International EP Panel: Howard McKinzie, OGCI PetroSkills Shauna Noonan, ConocoPhillips Mark Johnson,	This was a combination of presentations by the panel of experts and Q&A session from the audience. • Shell production - challenge: – Shell produces 3.6 million B/D. – 55% of this is by natural flow, 45% by artificial lift. – 23% is produced by ESP's. – Shell U.S. used to dominate artificial lift technology for the Shell Group. – Now, there is almost no artificial lift left in Shell U.S. – Shell expects to loose 50% of its engineers in the

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	ExxonMobil Nassar al Rawahy, Petroleum Development Oman	next 10 years. A huge gap is coming in the number of engineers. • ExxonMobil, ChevronTexaco, and PDO reported that the situation has been as follows: – There has been a lack of company support for a career development ladder for technical experts. – There has been a lack of technical mentorship. – This has lead to a lack of experienced personnel. – This has resulted in heavy use of consultants. – The push from management has been for people to broaden their experience, rather than deepen their expertise, so they can move into management positions. – There has been less focus on R&D for artificial lift. – Where to obtain and encourage people to be mentors? – Involvement in API and ISO is one way. – Companies have recently recognized the value of membership and cooperation in such groups. – It has been hard to stop the exodus of people. – There has been some focus emerging on developing ways to retain experts in the company. • Q&A Session: – Q. What is the effect / impact of alliances? – A. Service/Supply companies also have a problem in attracting and keeping good people. – Q. What about consultants? – A. Where will they be in the future? – Q. Why not involve Service/Supply Companies in sharing their expertise at the ESP Workshop. – A. They are invited to participate. – Q. How is training implemented in PDO? – A. It requires good coordination. – Q. What are other companies doing about it? – A. Shell is developing a path for technical and operational excellence. There is a focus on developing measures of competence through testing. – A. ExxonMobil is recognizing artificial lift as a critical skill. – Q. What are Service/Supply Companies doing? – A. Schlumberger is providing in-house training. Tolerance is needed from the Operating Companies to be willing to use less experienced Service Company people, so they can learn by doing.

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		– A. Centrilift is using internal training. They support a technical development path. They too need to develop young people and have the Operating Companies willing to use them. – A. Wood Group is hiring new engineers. Providing internal training. – Q. What are other approaches? – A. PDO recognizes that Operating Company staff must cover a wide range of experiences and expertise. It may be easier for Service/Supply Company staff to concentrate on one area – artificial lift. – A. Schlumberger has a three-year competency development program for new engineers. – A. ExxonMobil is focusing on training, development and sharing of best practices, participation on artificial lift joint industry projects (JIP's), and technical career development. – A. PetroSkills has training as its sole mission. o It has ten member companies. o Training is approved by curriculum advisors. o It develops competency maps whereby people can evaluate their progress. o This highlights the skill levels that are needed: ▪ Awareness. ▪ Basic application of the technology. ▪ Skilled application of the technology. ▪ Mastery. o Dr. Jim Lea of Texas Tech University and Cleon Dunham of Oilfield Automation Consulting provide current artificial lift training. – Q. What is an expert? What are the expectations of an expert? – A. An expert can: o Handle non-routine problems. o Pass on knowledge to others. o Participate in industry – help lead in the particular area of technology. – Q. Do we re-learn the same things over and over? Are we trying to "off load" too much to the Service/Supply Companies? – A. The Artificial Lift R&D Council (ALRDC) is an organization set up to share artificial lift knowledge and expertise across the world. – A. PDO proposes that a license or charter be created to recognize artificial lift experts. There could be a process whereby a person could become a licensed or chartered artificial lift expert and could

Paper	Author(s)	Summary of Discussion
		be so recognized both in his/her company and in the industry. Is there support for this idea?
Session IV -— Got Gas? Chairs: Jack Blann and Chip Ollre		
New Positive-Seal Shroud Hanger Design Solves Production Problems in New Mexico Gas Wells	Art Pena, Yates Petroleum Paul Wang, Mark Neinast, and Eddie Stewart, Wood Group ESP, Inc.	This is a story about a new positive seal shroud hanger in New Mexico gas wells. Art Pena, Yates Petroleum, and Eddie Stewart, Wood Group ESP, Inc., gave it. • Introduction: – The project is in Eddy County, New Mexico. – The application is de-liquification of gas wells. – Former approach was to set the ESP system below the perforations. – Shrouds were used to force liquid by the motor, for cooling. – Problems with this included: ○ Scale build-up. ○ Poor prevention of heat build-up. ○ Gas locking due to poor gas separation. – There was a problem with leaks at the top of the shroud. ○ As leaks increased, flow down past the shroud decreased, and heating increased. • New shroud hanger: – A new shroud hanger was designed to significantly reduce gas leaking into the annulus between the shroud and the pump. – Results of this were: ○ Fluid was forced to flow down past the shroud. ○ This reduced the motor temperature by 30 – 50 ^{o}F. ○ Scaling was reduced. ○ Required horsepower was reduced by 50%. ○ There was less downtime and more production. • Results in the field: – The wells are now operating 24 hours per day. – 46 of these re-designed shroud hangers are in the ground. – Run time was about 8 weeks. – Now they've been in operation for 8 months and are still going. • Example well: – Well in Southeast New Mexico. – 7" casing.

Paper	Author(s)	Summary of Discussion
		– 99% water. – 1500 MCF/day. – When the new shroud hanger was installed: o Installed a smaller pump. o Horsepower decreased from 150 to 50 HP. o Electrical costs reduced by $2,500 per month. o Scale formation stopped. o High gas production was maintained. • Q&A Session: – Q. Does pump-off cause a problem? – A. It causes severe downthrust. It is sometimes done to maximize production. – Q. What's next? – A. Will stimulate some of the wells. – Q. Do you run any wells without a shroud? – A. Yes, wells that don't pump off. – Q. How hot is motor temperature? – A. We try to keep the motor temperature below 200 ^{o}F to avoid problems. – Q. You have downthrust. Do you use a compression pump? – A. The problem is with thrust on the seal section. – Q. How do you know that you have reduced scaling? – A. By observation of pulled equipment. – Q. Have you tried a re-circulation system? – A. Yes. Heat caused a scale build-up.
Keeping ESP's Primed in High Volume Gas Wells	John Mack, Centrilift Greg Robl, New Dominion	This is a story about use of a long, inverted shroud to handle very long gas slugs from wells with horizontal completions. John Mack, Centrilift, presented it. • Introduction: – Wells with long horizontal legs often produce long slugs of gas. – The gas slugs may last 3 – 5 minutes or more. – This was causing very frequent cycling on underload shutdown, with cycle frequencies of about five minutes. • Inverted shroud: – The shroud is installed above the ESP system. – It is connected above the motor and below the

Paper	Author(s)	Summary of Discussion
		pump, so fluid flows up past the motor. – The liquid and gas slugs are produced up the annulus between the casing and the shroud. – The liquid runs down between the shroud and the pump while the gas continues up the casing / tubing annulus. – The size of the shroud controls the flow of liquid up and down and the volume of liquid stored in the shroud / pump annulus. – When a gas slug passes the pump, this volume of liquid is pumped, keeping the pump primed with liquid at all times. – This is referred to as a “gas avoidance” system. • Equipment used: – The system uses all standard equipment. – No gas intake separator is used. • To calculate shroud size, must know: – The estimated gas bubble duration. – The estimated liquid production rate. – Calculate the length of the shroud to contain the needed amount of liquid. – Use a safety factor of 1.4. • Specific applications: – The pumps were set at 74 – 81 degrees from vertical in the horizontal section of the well. – The wells were producing very long gas bubbles. – The shrouds were from 250 – 400 feet long. – If the shroud is too short, the well will still cycle. • Advantages: – More gas production. – Fewer off/on cycles. – Fewer failures. – Lower workover costs. • Q&A Session: – Q. Amps before and after. – A. No data is available to answer this. – Q. Did wells use an FSD or a VSD controller? – A. Had a VSD, but got immediate underload shutdown. – Q. Did you try to use pump intake pressure to control the wells? – A. No. – Q. What is the impact on system components?

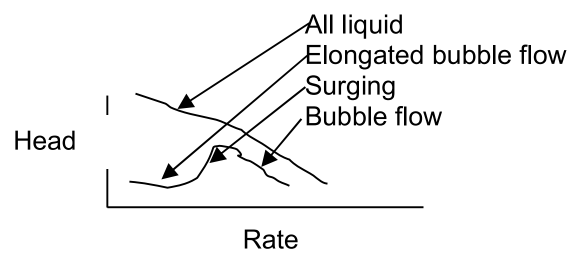
Paper	**Author(s)**	**Summary of Discussion**
		On radial wear in the seal section? – A. We are using a tapered pump. – Q. What are the downsides of this approach? – A. Need at least 7" casing. Need enough fluid production to keep the pump primed. – Q. How do you build / install a long shroud? – A. Install a special seal below the pump intake. Then connect one section of shroud at a time. – Q. What is the key to a successful design? – A. Must get the downward fluid flow rate below 0.5 feet/second. In this case, reduced it to 0.3 feet/second and got good gas separation.
ESP Stages Air Water Two Phase Performance - Modeling and Experimental Data	Javier Duran, Ecopetrol Mauricio Gargaglione Prado, The University of Tulsa	This is a story about the development of ESP gas handling models at the Tulsa University Artificial Lift Project (TUALP). Mauricio Gargaglione Prado, The University of Tulsa, presented it. • Introduction: – ESP's work very well to pump single-phase liquids. – There are problems with handling gas: o Gas degrades the pump performance. o It can lead to gas locking. – New mathematical models are needed to better predict the impact of free gas on ESP performance. • Forces acting on the pump: – There is a pressure gradient across the impeller from the intake to the discharge. – The forces can approach 900 – 1000 G (times the force of gravity). – There are drag forces. – There is slip, which increases as the gas void fraction increases. – As the gas fraction increases, it can form large, elongated bubbles. • Objective of research: – Develop a better mathematical prediction model to predict the effects of gas on pump performance. • Various models: – Homogeneous model: no head degradation. – Work of Lea and Bearden: found that homogeneous model is not OK for liquid / gas mixtures. – Work by Turpin: Defined the range where too

Paper	Author(s)	Summary of Discussion

much free gas can lead to gas surging problems.
- Work by Dunbar: Used real world data to calculate the range where gas surging problems begin.
- Work by Schneider: Developed the first "real" mathematical model of two-phase flow through an ESP.
- Work by Estevam: Worked with the experimental test facility at the University of Tulsa to "see" the flow of a gas / liquid mixture through an ESP.

- Test facility at the University of Tulsa:
  - Liquid flow rates from 0 – 9,500 B/D.
  - Pump intake pressures of 100, 150, 200, and 250 psi.

- Tests by Duran:
  - Duran conducted 88 tests.
  - He used from 150 – 8,300 B/D liquid (water).
  - He used 9,000 SCF/D gas (air).
  - He found three distinct regions:
    - Elongated bubble flow region at low liquid flow rates.
    - Bubble flow region at high liquid flow rates.
    - Surge region in transition from elongated bubble flow to bubble flow regions.
  - He used the test data to generate a mathematical model to describe when each region will occur.
  - The model fits the test data very well.
  - The three regions appear as follows:



- Q&A Session:
  - Q. Why did you use 2450 Hz. for the tests?
  - A. We were using a 50 HP motor, degraded to 42 HP.

  - Q. Do you plan to conduct tests at different speeds?
  - A. At lower Hz, bubble flow area decreases and have a larger elongated bubble region.

  - Q. Do you plan to conduct future tests at specific

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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>speeds?
– A. Yes. Tests are planned at lower specific speeds.</td></tr>
<tr><td>Management of ESP’s in the Yibal Cluster of PDO – North Oman</td><td>‘Leste O Aihevba, Hamad H. al-Sharji, Buthaina B. Bar-wani, and Terek A. Amri, Petroleum Development Oman</td><td>This is a story about the use of ESP’s in the Yibal Field, in Petroleum Development Oman. It was presented by ‘Leste O Aihevba, Petroleum Development Oman

• Introduction:
– The Yibal area consists of two fields: Yibal and al-Huwaisah.
– The production is about 1,300 meters deep.
– Oil is light: 30 – 37 ^{o}API.
– The fields are under waterflood.
– Artificial lift is required.
– Originally gas-lift was used.
– The first ESP was installed in al-Huwaisah in 1991.
– The first ESP in Yibal was in 1996.
– Currently, if a well produces less than 1,000 B/D, it is produced by gas-lift; if more than 1,000 B/D, it is produced by ESP.
– Currently 47% of the wells are on ESP. They produce 64% of the total liquid.
– They are on a lease contract.

• ESP Design:
– Design is performed in house, with reservoir information provided by PDO and ESP information by the Service/Supply Company.
– Nodal analysis is used in the design.
– Obtaining a high quality design is essential.
– Wells have 9 and 5/8” casing; 4.5” tubing.

• Strategy:
– Formerly new wells were started on gas-lift and converted to ESP if necessary.
– Now new wells are started on ESP from day #1, if the expected rate is sufficient.

• Problems:
– Production of debris.
– Low PI’s.
– High BS&W, and water production is increasing
– Expect 2-year run life, but not always achieved.

• Monitoring:
– Use downhole gauge to measure pump intake pressure and temperature.
– Have a team review each problem well.
– Reporting to team is on exception basis.</td></tr>
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Paper	Author(s)	Summary of Discussion
		• When an ESP fails it may be due to: – Incorrect design / installation. – Incorrect data used in the design. – Faulty equipment. – Faulty operations. • PDO is focusing on the entire ESP system: – Current average run life is 587 days. – Target is 700 days. • Approach to improve run life: – Use good, "fit for purpose" equipment. – Run new tubing when a well must be pulled. – Strive for improved ESP design. – Work for improved ESP operations. • Efforts to minimize downtime: – Have plans ready for an ESP replacement, before it fails. • Strategy to evaluate reservoir: – In some wells, use pump intake pressure and extrapolate to reservoir. – In some wells, use a Y tool so can run tools below the ESP. • Q&A Session: – Q. You mentioned failures due to solids. Where do the solids come from? – A. Shale in open-hole completions.
Session V -— New Technology and Applications **Chairs: Mike Parker and Tom van Akkeren**		
Total Otter – A Small Field with a Big Output Through the Use of Dual Subsea ESP's	Paul Kelmen, Total Eugene Bespalov, Centrilift	This is a story about production from a small, sub-sea field in the Northern North Sea. Eugene Bespalov, Centrilift, presented it. • Introduction: – This is a paper about the use of dual, sub-sea ESP's. – The Otter Field is located 150 miles northeast of the Shetland Islands, in the Northern North Sea. – Production from the field flows via sub-sea pipeline to Shell's Eider Platform. – The field has 3 oil wells and 2 injection wells. – It has a 21 km. long ESP tieback to the "host" platform. – It uses the world's first dual ESP system in sub-

Paper	Author(s)	Summary of Discussion
		sea operations. – The oil is 36 °API. – Reservoir pressure is 2900 psi. – Wells are 6,600 feet deep with horizontal completions. • The ESP's: – ESP's are sized for 20,000 B/D. – They use 684 HP motors. – A Y tool is used to allow access to the bottom dual ESP. – The ESP's are installed at 55° from vertical. • Well design: – The wells have a wire-wrapped screen; no gravel pack. – Two, tandem ESP's are used; one as primary and one for back up. – Production is from below a packer. – The wells have 10 & ¾" casing. – Power can be switched to either ESP. • Problems / Issues: – Had drilling and completion problems in the winter. – Needed to use nitrogen injection for initial well clean up. – Have real-time data available on the "host" platform, and at the Centrilift and Total offices. – Have had some problems with water slugging in the horizontal legs. – Had 0 accidents and 0 lost time days during the drilling, completion, and start-up processes. • Operating strategy: – Run the lower ESP until it fails. – Then switch to the upper ESP. – Begin planning for a workover. – Only do workovers in the summer months. – They credit much of the success to excellent teamwork between Total, Shell, and Centrilift. • Q&A Session: – Q. What is the cut-off between winter and summer for workover operations? – A. We can perform workovers from mid May to mid September. – Q. How did you conduct deadhead testing? – A. We tested before installation. The deadhead testing was conducted for 10 minutes, in the well.

Paper	Author(s)	Summary of Discussion
		– Q. How did you obtain updates to the VSD software? – A. The Supplier was able to e-mail updates to us. – Q. How is power distribution handled? – A. Power comes in three cables, buried in one trench, from the host platform. Voltages are at 5000 and 3600 volts. – Q. Do you have water production? – A. Water production is currently at 10% and rising. – Q. What do you do to protect your standby pump? – A. Standby pump is operated and tested every three months. We have an automatic Y tool. It is normally closed.
Injection Well Testing Utilizing Standard Production ESP Equipment and an Injection ESP Adapter Kit	Dana Pettigrew, Nexen Petroleum International Ltd. Andy Liwanowka, Canadian Advanced Inc.	This is a story about using an ESP to conduct an injection test in a well in Yemen. Dana Pettigrew, Nexen Petroleum International Ltd., and Andy Liwanowka, Canadian Advanced Inc., presented it. • Introduction: – Needed to establish and test injectivity into a reservoir in Yemen. – Needed information to justify purchase of “normal” injection system. – Used and “upside down” ESP to inject water into an oil formation to test the injectivity. • Conditions: – Injection would require between 3,000 and 5,000 psi at the surface. – Wells have 9 and 5/8” casing. • ESP equipment: – Inverted ESP system. – Standard motor, seal section, pump. – Used labyrinth and bag design in seal section. • Results: – The test of injection was successful. – Can now specify and order “normal” injection equipment. – The approach could also be used to dispose of water downhole. • Q&A Session: – Q. Did you have up thrust on start-up?

Paper	Author(s)	Summary of Discussion
		– A. We are using a floater pump design. We had no up thrust problems on start-up. – Q. Do you use a VSD or FSD drive? – A. VSD. – Q. Could you have installed the "injection" ESP system at the surface and injected from the surface? (Not sure the question was understood.) – A. We didn't have surface injection pumps. We couldn't generate enough power to inject form surface.
A Low Cost Method for Improved VFD Reliability on Distorted and Unregulated Power Lines	Kurt LeDoux, Toshiba Mario Lanaro, Semirca Venezuela Aido Martinez, ChevronTexaco	This is a story addressing problems caused by distorted and unregulated power in VFD operations in Venezuela. Kurt LeDoux, Toshiba, gave it. • Power input problems: – Lightning. – Short circuit faults. – Harmonic voltage distortion. – Poor power line regulation. – Poor power factors. • Damage caused: – Capacitors stressed by abnormal voltages. • New design: – Installed new resisters and changed timing of contactors to protect capacitors. – This was a low cost solution, using existing equipment. • Q&A Session: – Q. How do you protect against momentary power sags? – A. The transformer protects against these. Can withstand (ride through) sags of up to 5 cycles. – Q. Does each unit need to be custom designed? – A. No, one standard design is used.
Breakouts		
Gas-Lift to ESP Conversion	Chip Ollrey, Diamould Ltd.	This is a summary of the two breakout sessions on conversion of gas-lift to ESP. Chip Ollrey, Diamould Ltd gave the summary. • Issues or potential barriers to conversion from gas-lift to ESP: – Cost.

Paper	Author(s)	Summary of Discussion
		– Lack of familiarity with ESP's. – Handling of abrasive materials. – Economics. – Water cut. – Surface water handling problems. – Information uncertainly – PI, static bottom-hole pressure. – Power needs. – ESP investment costs. – Well bore trajectory issues. – Well completion issues – drawdown limits. – Emulsion problems. – Slug flow problems. – Pressure assurance in the riser. – Reservoir surveillance procedure changes. • Factors in favor of conversion: – High flow rate. – Low flowing bottom-hole pressure. – No need for a packer – in some instances. – Can still use gas-lift as a back up. – Gas-lift gas that was used on this well can be re-allocated to other wells. – Can use various ESP deployment methods. – Can handle waxy crude oils. – Avoids some HSD issues with gas in the annulus. – Avoids issue of NOX emissions from compressors. – Handles wells with high water cut. – A workover to convert to ESP gives opportunity to make other necessary changes. • Conclusions: – Make a very careful evaluation before moving ahead. – Perform evaluation on a well-by-well basis. – Look very closely at the economics. – In "green" fields, can drill and complete wells initially for more effective implementation of ESP's, where appropriate.
Downhole Data Analysis: Usage in ESP Troubleshooting and Performance Improvements	Tom van Akkeren, Production Technology Associates Panel members: Sandeep Suchdeva, Schlumberger (Phoenix)	This is a summary of the two breakout sessions on downhole data analysis. Tom van Akkeren, Production Technology Associates, gave the summary. • Use of downhole data: – This is now well accepted. – Costs are down, and reliability is up. – Approximately 40% of ESP installations now include downhole data.

Paper	Author(s)	Summary of Discussion
	Tor Kramer, Weatherford Mark Roberston, Autonomous Well Mike Whitaker, Wood Group Inc. Some notes added by Cleon Dunham, based on notes taken during actual breakout session.	• Items measured: – Pump intake pressure. – Pump discharge pressure. – Well and motor temperature. – Vibration. – Current leakage. – Other measurements: flow rate, seismic, temperature profiles with fiber optics. • Most important items: – Pump intake pressure. Use to optimize well performance, detect fluid level change. – Motor temperature. Use to protect motor. • Other measurements: – Vibration. Get maximum "shock" G vibration, not vibration spectrum. Can use in trend mode to recognize onset of sand, gas, and a bad VSD operation. – Current leakage. Most feel that this has no value. It may be used to detect a fault in the ESP cable. – Flow rate. This is normally done with a spinner. Some are using a venturi meter method. There are more accurate, more expensive methods available for critical applications. • Data transmission: – Normally this is done via the ESP cable, at about 3 bits per second. – So not all values can be read simultaneously. – It may be possible to use fiber optic cables, but this will cost more. – Some are claiming being able to transmit up to 10 bits per second up the electrical cable. – Some are claiming being able to "buffer" downhole data so it might be possible to gather information for a spectrum analysis of vibration data. • Accuracy: – Good enough for well performance. – May not be accurate enough for evaluation of reservoir performance. • Temperature limits: – Most systems are good up to 150 ^{o}C (302 ^{o}F). Higher temperature components can be used, at higher cost. • Data management: – Primarily downhole data systems have been sold

Paper	Author(s)	Summary of Discussion
		as part of the pump protection system. – Operators want to use the information for other things such as well performance, well control, reservoir management, etc. – Since huge amounts of data can be generated, data compression and exception reporting are needed. People can't review all of the data, all of the time. – This information can be used as part of an "intelligent" well management system. • Q&A Session: – Q. Shouldn't pump discharge pressure also be included in the measurement pack. It can be added for a low cost. – A. Yes. And some systems can also include downhole flow rate measurement and measurement of the % water in the produced fluid. – Q. Can this information be used to predict failures? – A. Most Operators will run an ESP until it fails. This information can be used to detect deteriorating performance and allow pre-planning for an upcoming workover. – Q. How is this data used to trend pump performance. – A. Can see pump performance degradation over time. – Q. What do you do if you see temperature increasing over time? – A. Can control the speed of the pump, or the production rate, to keep the pump operating inside the safe operating envelope. – Q. Can trends in vibration be used to predict the need for a workover? – A. Guidelines are needed on how to use vibration information, how much vibration is too much, etc.
ESP Failures	Ken Lacey, Custom Submersible Electrical Services	This is a summary of the breakout session on ESP failures. Ken Lacey, Custom Submersible Electrical Services, gave the summary. • Summary of breakout session: – Need to perform analysis to determine the "root cause" of each failure. – For this, need good information on: o Design.

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Installation.
Operation.
Failure.
Tear down.
Tear down.
There is a tear down reporting form available in the API documents.
But the industry needs a new tear down reporting form.
Need to be very open-minded when performing the tear down review and analysis.
Root cause analysis:
Need to determine how deep to go into root cause analysis. How far “back” to look.
Need to be careful about inappropriate “finger pointing.”
A step-by-step process is needed to assure that the root cause analysis is performed correctly and completely.
Guidelines are needed on how to use the results of the root cause of failure analysis.
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<tr><td>Gas Handling and Separation</td><td>Mike Berry, Wood Group ESP, Inc.

Lyle Wilson, Schlumberger

Some notes added by Cleon Dunham, based on notes taken during actual breakout session.</td><td>
This is a summary of the breakout session on gas handling and separation. Mike Berry, Wood Group ESP, Inc. gave the summary.
Four ways to deal with gas:
Avoid it.
Separate it.
Pump it.
Design well to address it.
Methods to avoid it:
Increase the pump intake pressure so free gas isn’t present at the pump intake.
Lower the pump intake depth.
Lower the pump flow rate.
Increase the well’s productivity index.
Increase the fluid level by reducing the casing pressure.
Use an inverted shroud. Can use a separate tube for the liquid to by-pass the shroud. Can insert “fighting” in the by-pass to get vortex separation of liquid and gas as fluid rises in tube. Can use two “flights” in the tube. This produces large bubbles that tend to rise easier.
Don’t set pump underload shutdown so low that pump will trip on a gas lock.
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Paper	Author(s)	Summary of Discussion
		• Methods to separate it: – Use a shroud. Have sizing problems. Need slow enough flow rate so gas can separate from liquid. – Use a rotary separator. No one really knows how much gas it can separate. – Use a vortex separator. Liquid is forced to outside. The fluid be “routed” into pump intake and the gas up the annulus. – Use a static separator. • Methods to pump it: – Use mixed flow impellers. – Tapered pump. Better gas compression in lower stages but they produce little head. Upper stages produce head on more compressed or homogenized fluid. – Use a gas handler system. – Use a VSD. Control intake pressure. May be able to temporarily increase stage capacity by changing speed. However, don’t go below 30 Hz. • Well design options: – Use large casing. – Include a “rat hole” in the well. – Include a sump above horizontal sections. • Q&A Session: – Q. What can you do if a well is gas locked? – A. Use a choke or VSD at the surface to control the flow rate.
Closing Comments		
Closing Comments	Shauna Noonan, ConocoPhillips, General Chair of the Workshop	Shauna thanked everyone for his or her participation.