Learning Objectives

By the end of this lesson, you will be able to:

- Use well performance analysis to finalize production targets
- Explain the ESP principles, advantages and limitations
- Describe the various components of an ESP system
- Identify how to select the right ESP equipment to meet the production targets
- Review the ESP completion design options
- Identify how to perform ESP surveillance and troubleshooting
- Review the factors influencing ESP run-life
Module Contents

- Introduction
- When to Select ESP as Lift Method
- Inflow and Outflow Evaluation
- ESP Theory, Advantages and Limitations
- Various Components of ESP
- The ESP System
- Design Example
- Surveillance and Troubleshooting
- Conclusions

Module Schedule

<table>
<thead>
<tr>
<th>S. No.</th>
<th>Topic of Discussion</th>
<th>Activity</th>
<th>Time (mins)</th>
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<tbody>
<tr>
<td>1</td>
<td>Pre Assessment</td>
<td>Evaluation</td>
<td>30</td>
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<tr>
<td>2</td>
<td>Module Introduction and Learning Objectives</td>
<td>Narrated Slideshow</td>
<td>10</td>
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<tr>
<td>3</td>
<td>Operating ESP Completions</td>
<td>Videos</td>
<td>2</td>
</tr>
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<td>4</td>
<td>Downhole ESP Operations</td>
<td>Videos</td>
<td>2</td>
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<td>5</td>
<td>Evaluate Well Inflow</td>
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<td>2</td>
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<td>6</td>
<td>Total Dynamic Head (TDH)</td>
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<td>7</td>
<td>ESP Head/Pressure Exercise</td>
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<td>8</td>
<td>ESP Downhole Components</td>
<td>Virtual Session 1</td>
<td>90</td>
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<td>9</td>
<td>ESP Power Cable and Accessories</td>
<td>Narrated Slideshow</td>
<td>14</td>
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<td>ESP Surface Systems</td>
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<td>ESP Cable Voltage loss Exercise</td>
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<td>ESP Completion Options</td>
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<td>ESP Design Example</td>
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<td>14</td>
<td>ESP Start Up</td>
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<td>ESP Monitoring and Diagnostics</td>
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<td>ESP Run Life Enhancement</td>
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<td>17</td>
<td>ESP Case Study</td>
<td>Exercise</td>
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<td>Post Assessment</td>
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<td></td>
<td><strong>Total Duration</strong></td>
<td></td>
<td><strong>6 Hrs</strong></td>
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</tbody>
</table>

VS1 = Virtual session 1
VS2 = Virtual session 2

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ESP Introduction

Large Volume Artificial Lift

Typical ESP System
ESP with Packer

Lift / Rate – High Volume

2. Elimination Process

High Volume
Hydraulic Jet Pumps, Pumping, and Gas Lift
ESP Advantages

- High volume and depth capability
- High efficiency over 1,000 BPD
- Low maintenance
- Minor surface equipment needs
- Good in deviated wells
- Adaptable to all wells with 4-1/2” casing and larger
- Use for well testing

ESP Limitations

- Available electric power
- Limited adaptability to major changes in reservoir
- Difficult to repair in the field
- Free gas and/or abrasives
- High viscosity
- Higher pulling costs
- Run life
## ESP Considerations

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Typical Range</th>
<th>Maximum*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating Depth TVD</td>
<td>1,000' - 10,000' TVD</td>
<td>15,000'</td>
</tr>
<tr>
<td>Operating Volume</td>
<td>200 - 20,000 BPD</td>
<td>30,000 BPD</td>
</tr>
<tr>
<td>Operating Temperature</td>
<td>100° - 275° F</td>
<td>400° F</td>
</tr>
<tr>
<td>Wellbore Pump Pump Deviation</td>
<td>10°</td>
<td>0 - 90°</td>
</tr>
</tbody>
</table>

*Special Analysis Required

- Corrosion Handling: Good
- Gas Handling: Poor to Fair
- Solids Handling: Poor to Fair
- Fluid Gravity: >10° API
- Servicing: Workover or Pulling Rig
- Prime Mover Type: Electric Motor
- Offshore Application: Excellent
- System Efficiency: 35%-60%
Well Inflow Evaluation

Determine the Production Target

- Pwf and hence the Target liquid production rate is determined using Inflow calculations

<table>
<thead>
<tr>
<th>Pressure, psi</th>
<th>Flowing Qliq, m³/day</th>
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</thead>
<tbody>
<tr>
<td>158,987</td>
<td>115.967</td>
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<tr>
<td>206,842.37</td>
<td>195.967</td>
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<tr>
<td>241,398.66</td>
<td>275.967</td>
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<tr>
<td>276,954.94</td>
<td>355.967</td>
</tr>
<tr>
<td>312,511.22</td>
<td>435.967</td>
</tr>
<tr>
<td>348,067.51</td>
<td>515.967</td>
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<tr>
<td>383,623.79</td>
<td>595.967</td>
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<tr>
<td>419,179.97</td>
<td>675.967</td>
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</table>

<table>
<thead>
<tr>
<th>Pressure, kPa</th>
<th>Flowing Qliq, m³/day</th>
</tr>
</thead>
<tbody>
<tr>
<td>4694.757</td>
<td>115.967</td>
</tr>
<tr>
<td>6894.757</td>
<td>195.967</td>
</tr>
<tr>
<td>9094.757</td>
<td>275.967</td>
</tr>
<tr>
<td>11294.757</td>
<td>355.967</td>
</tr>
<tr>
<td>13494.757</td>
<td>435.967</td>
</tr>
<tr>
<td>15694.757</td>
<td>515.967</td>
</tr>
<tr>
<td>17894.757</td>
<td>595.967</td>
</tr>
<tr>
<td>20094.757</td>
<td>675.967</td>
</tr>
</tbody>
</table>

Electrical Submersible Pumps Fundamentals
Back to Work Plan

☑ Discuss with your reservoir engineers how they estimate the liquid production rate target and the expected Pwf for their wells
Total Dynamic Head (TDH)

Determining the TDH

Defining the Requirement

- The job of an ESP system:
  - To deliver the desired flowrate
  - To deliver the required lift for that flowrate

- The head generated by the ESP \((\text{Pump discharge} - \text{Pump intake})\) will help deliver the fluids to the surface production system.
**Total Dynamic Head (TDH)**

- TDH = Total Dynamic Head in feet (or meter) delivered by the pump when pumping the desired flow rate
- $H_d = \text{vertical distance between the wellhead and the estimated producing fluid level at the expected flow rate or "net dynamic lift"}$
- $F_t = \text{the head required to overcome friction losses in tubing}$
- $P_d = \text{wellhead pressure, the head required to overcome friction in the surface piping & elevation changes}$

$$TDH = H_d + F_t + P_d$$

---

**Net Dynamic Lift**

- Knowing the Pwf and pump setting depth, Fluid Level Over Pump (FLOP) and hence $H_d$ can be calculated
- $H_d = \text{Pump Setting Depth – FLOP}$
- Specific gravity of fluid mixture can be calculated if water-cut (WC) and specific gravities of oil and water are known
  $$\text{SpGr}_{(w+o)} = WC \times \text{SpGr}_{w} + (1-WC) \times \text{SpGr}_{o}$$
- The pump intake pressure (PIP) can be calculated as:
  $$\text{PIP} = \{\text{FLOP(ft)} \times \text{SpGr}\} / 2.31 \text{ft/psi}$$
  **Assuming the surface casing pressure is zero.**
Frictional Head

- Frictional loss in pipe (Ft) can be calculated using Nodal Analysis programs or using Hazen-Williams equation or chart

\[ Tfloss = 0.015 \left[ \frac{BPD^{1.85} (Tlen)}{Tid^{4.87} (C)^{1.85}} \right] \]

- Where:
  - \( Tfloss \) = the tubing friction loss in feet
  - \( BPD \) = flow up the tubing (also \( Q_{liq} \))
  - \( Tlen \) = tubing length in feet
  - \( Tid \) = tubing inside diameter (in.)
  - \( C \) = 120 for new steel pipe and 94 for 10 year old steel pipe

Frictional Loss using Chart

- Chart for calculating frictional loss in feet per 1,000 feet of tubing.
Calculate TDH

- $P_d = \text{Wellhead pressure (PSI)} \times \left(\frac{2.31}{\text{Sg}}\right)$

- Calculate TDH (feet) as

$$TDH = H_d + F_t + P_d$$

Back to Work Plan

- Check with your artificial lift team if there is any ESP well with a high flowing tubing pressure, either due to a throttled choke or plugged up flowline (an excessive head demand may put the pump on downthrust)
ESP Cable and Other Accessories

Estimating the Voltage Loss

Cable

- Cable is a critical downhole component of the ESP system
- Cable can be round or flat depending upon the allowable clearance
- Upper and lower pigtails can be spliced on to allow for packers and wellhead connections
Cable Size (AWG)

- American Wire Gauge (AWG): A standardized wire gauge system for the diameters of round, solid, nonferrous, electrically conducting wire
  - The smaller the AWG number, the larger the physical size of the wire:
    - The smallest cable size is AWG40 and the largest is 0000 (4/0)
  - The smaller the AWG number, the lower the electrical resistance (hence less voltage drop) and larger its current carrying capacity (amps)

<table>
<thead>
<tr>
<th>American Wire Gauge (AWG)</th>
<th>Diameter (inches)</th>
<th>Diameter (mm)</th>
<th>Cross Sectional Area (mm²)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0000</td>
<td>0.46</td>
<td>11.68</td>
<td>107.16</td>
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<td>000</td>
<td>0.4096</td>
<td>10.40</td>
<td>84.97</td>
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<td>00</td>
<td>0.3648</td>
<td>9.27</td>
<td>67.40</td>
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<td>0</td>
<td>0.3249</td>
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<td>53.46</td>
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<td>1</td>
<td>0.2893</td>
<td>7.35</td>
<td>42.39</td>
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<td>2</td>
<td>0.2576</td>
<td>6.54</td>
<td>33.61</td>
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<td>3</td>
<td>0.2294</td>
<td>5.83</td>
<td>26.65</td>
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<td>4</td>
<td>0.2043</td>
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<td>21.14</td>
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<td>5</td>
<td>0.1819</td>
<td>4.62</td>
<td>16.76</td>
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<td>6</td>
<td>0.162</td>
<td>4.11</td>
<td>13.29</td>
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</tbody>
</table>

Cable

- Three copper conductors, one for each phase (can be stranded or solid)
  - A layer of electrical insulation
  - A layer of barrier tape to protect the electrical insulation from well fluids
  - A layer of braid to physically protect and contain all of the above around each conductor
  - A nitrile jacket enclosing the three insulated conductors
  - Metal armor to provide the main physical protection and give some extra tensile strength
    - Sometimes an expensive lead sheath is used to keep out H₂S gas

Note: Insulation with polypropylene is sufficient for downhole temperatures 205 – 225 F max, but higher wellbore temperatures will require insulation with ethylene propylene diene monomer (EPDM) synthetic rubber
Cable

### Ranking of insulation materials

<table>
<thead>
<tr>
<th>Model</th>
<th>Max T deg. F</th>
<th>Min T deg. F</th>
<th>Flat Round</th>
<th>Insulation</th>
<th>Jacket</th>
<th>Application</th>
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<td>CTT</td>
<td>190</td>
<td>-40</td>
<td>F</td>
<td>Thermo-plastic</td>
<td>Thermo-plastic</td>
<td>Shallow wells, Water wells, Low CO₂ Light ends</td>
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<tr>
<td>CPN</td>
<td>205</td>
<td>-30</td>
<td>F/R</td>
<td>Poly-propylene</td>
<td>Nitrile</td>
<td>General</td>
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<tr>
<td>CPL</td>
<td>225</td>
<td>-40</td>
<td>F</td>
<td>Poly-propylene</td>
<td>Lead</td>
<td>Gassy Wells, High CO₂ H₂S</td>
</tr>
<tr>
<td>CEN</td>
<td>280</td>
<td>-30</td>
<td>F/R</td>
<td>EPDM w/Tape</td>
<td>Nitrile</td>
<td>Low to Moderate Gassy Conditions</td>
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<tr>
<td>CEE</td>
<td>400</td>
<td>-60</td>
<td>F/R</td>
<td>EPDM</td>
<td>EPDM w/Tape, Braid</td>
<td>Moderate Gassy</td>
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<tr>
<td>CEB</td>
<td>300 or 400</td>
<td>R</td>
<td></td>
<td>EPDM w/Extruded Fluoro-polymer</td>
<td>EPDM</td>
<td>Gassy Wells</td>
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<tr>
<td>CEL</td>
<td>450</td>
<td>-40</td>
<td>F/R</td>
<td>EPDM</td>
<td>Lead w/Bedding Tape</td>
<td>Hot Gassy Wells</td>
</tr>
</tbody>
</table>

### Cable protection

- Cast clamps, Lasalle, Canon, Winterhawk
- Pressed clamps
- Banding, black iron, super bands
- Cable saddles
### Cable

- **Banding – at unit and tubing**

```
6" Sub
Pump
Intake
Motor

2 Bands 6" above splice
Splice
Cable guards

Band 4" on other side of coupling or at low profile tubing or where upset tubing, band 2-3" on each side of collar

Cable encapsulating guards are available for collar locations

No bands in center of tubing
```

### Cable

- **Banding, near surface**

```
UPPER PIGTAIL
O-RING
MANDREL & PIGTAIL SYSTEM

WELL HEAD
TUBING HANGER
TUBING

LOWER PIGTAIL
LEAVE 6" OF SLACK FROM MANDREL CONNECTION TO 1ST BAND 6" DOWN HOLE
1ST & 2ND DOUBLE BAND

3rd BAND
PIGTAIL TO CABLE SPLICE 10" NOT BAND OR SPLICE

4th BAND

5th BAND

NOTE: SLACK IN CABLE MAX. SHALL BE WRAPPED AROUND TUBING BELOW 5TH BAND.
```
Potheads

Plug-in
Tape-in

Cable Voltage Drop: Industry: 30 v/1000 ft
Correct Preceding Chart with Below

Temperature Correction Factors

![Temperature Correction Table]

Accessories / Check and Bleeder

- Check valve
  - Used to prevent backfall of fluid when pump shuts down
  - Minimises downtime after a shutdown
  - Prevents sand falling back down inside pump
- Bleeder valve
  - To circulate fluid above pump to kill well
Accessories: Y-Tool

- Y-Tool or ESP bypass system
  - Offsets ESP in wellbore
  - Provides access using bypass tubing to perforations
    - PLTs
    - Logging
    - Perforation
  - Blanking plug in top of bypass tubing to prevent recirculation

Accessories: Instrumentation

- Downhole sensor
  - Installed on bottom of motor
  - Powered through ESP cable
  - Panel at surface to receive signal
  - Typical parameters
    - Intake pressure
    - Discharge pressure
    - Intake temperature
    - Motor temperature
    - Vibration

<table>
<thead>
<tr>
<th>Parameter</th>
<th>E6</th>
<th>E7</th>
<th>Units</th>
<th>Range</th>
<th>Resolution</th>
<th>Accuracy</th>
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<tr>
<td>Intake Pressure</td>
<td>yes</td>
<td>yes</td>
<td>Pa/Bar</td>
<td>0-5,000 Pa</td>
<td>0.1 Pa</td>
<td>0.1%</td>
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<tr>
<td>Discharge Pressure</td>
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<td>yes</td>
<td>Pa/Bar</td>
<td>0-5,000 Pa</td>
<td>0.1 Pa</td>
<td>0.1%</td>
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<td>°C/°F</td>
<td>0-125 °C</td>
<td>0.1 °C</td>
<td>1 °C</td>
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<tr>
<td>Motor Temperature</td>
<td>yes</td>
<td>yes</td>
<td>°C/°F</td>
<td>0-755 °C</td>
<td>0.1 °C</td>
<td>1 °C</td>
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<tr>
<td>Vibration - x axis</td>
<td>yes</td>
<td>yes</td>
<td>G</td>
<td>0.1 G</td>
<td>0.0005 G</td>
<td>0.0%</td>
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<tr>
<td>Vibration - y axis</td>
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<td>yes</td>
<td>G</td>
<td>0.1 G</td>
<td>0.0005 G</td>
<td>0.0%</td>
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<td>Current Leakage</td>
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<td>yes</td>
<td>mA</td>
<td>0-29 mA</td>
<td>0.001 mA</td>
<td>0.07%</td>
</tr>
</tbody>
</table>
Back to Work Plan

- Discuss with your Artificial Lift team if they have had ESP failures due to Cable faults. How this has been addressed in your asset?
- What has been the feedback on the actual reliability of ESP bottom-hole gauges in your asset?
ESP Surface Systems

Power Supply and VSD

Wellhead

- ESP surface and wellhead assembly
Wellhead

- Wellhead options
  - Mandrel feedthrough
  - Packoff, low pressure

ESP Surface System

- Switchboard

  - Generation System
  - Step-down Transformer
  - Switchboard
  - Junction Box
  - ESP

  - Input power:
    - High voltage (11-15 kV)
  - Input at fixed frequency (50/60 Hz)
  - Output voltage:
    - 250 – 4000 V

- Variable Speed Drive (VSD)

  - Generation System
  - Step-down Transformer
  - Variable Speed Drive
  - Step-up Transformer
  - Junction Box
  - ESP

  - Input power:
    - High voltage: 380V or 480V
    - Input at fixed frequency (50/60 Hz)
  - Output voltage at desired frequency
  - Output voltage for ESP at desired frequency
Vented Junction Box

- Due to time and constant exposure, some gas may enter the power cable and migrate to surface

- Junction box (located between the wellhead and switch board) allows any gas migration to be vented to atmosphere, and eliminates possible danger of explosion in the switch board

- Normally located 15 ft. (4.572 m) from wellhead and mounted 2-3 ft. (0.609-0.914 m) above ground level

Common ESP Surface System
ESP Surface System

- **Transformers**
  - Note voltage drop from 12,500 to about 1000 volts as typical:
  - For VSD would drop to 480 (60 Hz) or 380 V (50 Hz)

ESP Surface System

- **Switchboard is combination of**
  - Motor starter
  - Overload / underload protective device
  - Recording instrument
- **As part of switchboard unit may have**
  - Nema 3R Enclosure
  - Load Break Disconnect
  - Fuses
  - Vacuum Contactor
  - Control Power Transformer 50/60 Hz
  - Recording Ammeter
  - Motor Controller
    - Backspin protection or timer
    - Protection for low amps
**Surface System/ VSD**

- Variable Speed Drive Controller
  - Takes fixed frequency input and converts to variable frequency output
  - Using a VSD allows the speed of the ESP downhole motor to be varied

**Surface ESP System: Variable Speed Drive**

![Diagram of Surface ESP System: Variable Speed Drive](image-url)
VSD

- Provides flexibility for:
  - Uncertain well performance
  - Changing well conditions with time (WC, THP, PR, PI)
  - Producing the well down to the limit of drawdown (sand, gas, water influx)

- Added advantages:
  - Allows soft starting - reduces start up current
  - Limits the initial rate and permits gradual increase of drawdown as required
  - Permits control of intake pressure
  - Keeps power below power constraints
  - Helps test and produce well at different rates

Back to Work Plan

- Discuss with your ESP team how frequently they use the VSD controller in ESP operation
- Has the VSD been useful for limiting water cut or controlling gas or sand production in any well in your area?
ESP Completion Options

Based on Well Requirements

- Decide on additional downhole equipment in ESP well completion based on specific well requirements / value addition:
  - Downhole production packer
  - Sub-surface safety valve
  - Downhole intelligent control systems
  - What to do with the separated gas (if separator included)
  - Distributed temperature systems
  - Large diameter pump set inside casing vs. smaller pump inside liner?
  - Y-Tool with ADV (Automatic diverter valve)?
  - System to flush the pump with treated water for startup
ESP Design Special Cases

- Special products/solutions are available for the following situations:
  - Excessive gas production
  - High temperature
  - Sand production
  - High viscosity
  - Corrosion
  - Deposition/scaling
  - Well deviation (dogleg severity, DLS) at the proposed pump set depth
  - Any other concerns

- Select the most cost effective solution as applicable, after consulting with the ESP supplier

A Few ESP Completion Options

- Single ESP (Packerless)
- Single ESP with Packer
- Single ESP with Shroud
A Few ESP Completion Options (2)

- Single ESP with Y-Tool
- Smart Completion Selective System
- Dual ESP Completion with POD System**

**ESP System in a sealed environment

Back to Work Plan

Would you prefer to incorporate gas lift mandrels with dummy valves in an offshore ESP completion as back-up (in case ESP fails)? Why or why not?
ESP Monitoring and Diagnosis

ESP Surveillance Program

- A good surveillance system
  - Monitors key surface and sub-surface parameters that indicate the health of operating ESP systems;
  - Is ably supported by well performance modeling to identify problem areas
- Useful tools
  - Amp charts
  - Real-time ESP data, well production test data
  - Good record keeping
  - Failure analysis and sharing lessons learned
  - Expertise from ESP companies
  - Use of comprehensive data in the analysis process
Measurements for ESP Systems

<table>
<thead>
<tr>
<th>What's measured</th>
<th>What it can help with</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pump discharge pressure</td>
<td>Water cut, tubing GOR estimation and well shut in protection</td>
</tr>
<tr>
<td>Well head pressure</td>
<td>Water cut and tubing GOR</td>
</tr>
<tr>
<td>Pump intake pressure</td>
<td>Gas locking ($P_{bg}$ and free gas volumes), reservoir drawdown, sand control, coning</td>
</tr>
<tr>
<td>$\Delta$Ppump</td>
<td>Upthrust and downthrust protection; flow estimation, pump performance (wear, viscosity, materials)</td>
</tr>
<tr>
<td>Motor temperature</td>
<td>Overheating</td>
</tr>
<tr>
<td>Motor amps</td>
<td>Overload/underload protection</td>
</tr>
<tr>
<td>Current leakage</td>
<td>Overheating – insulation breakdown</td>
</tr>
<tr>
<td>Vibration</td>
<td>Fatigue, loading</td>
</tr>
</tbody>
</table>

Inflow vs. Outflow problem

- Less intake pressure, less rate may indicate inflow problem
- More intake pressure, less rate, may indicate deteriorating pump performance, scale, asphaltene, wear, etc.
- Use all the available data for analysis:
  - Surface and downhole parameters, Amps, well test data
  - Measure fluid level if the intake pressure gauge is not working
Monitoring

**Surveillance Process**

- Is the pump on?
  - How is downtime captured?
- Is it producing?
- Is the system protected?
  - Alarms and trips
- Has it lost production
  - Suddenly
  - Gradually
- Do we understand the well inflow?
  - Flowrate / watercut / PI validation
- Can we gain production (existing/new system)?
- Do we need remedial action?
Discuss with your Production engineering team on how frequently they review the ESP field data along with the well production data to evaluate the combined performance of the ESP, the well and the reservoir.
A detailed database that contains the performance information of all ESPs will give the vital clue: *the area that requires attention*.

- An ESP Failure distribution chart as reported by a Major Operator is reproduced below. This chart highlights the major areas causing pump failures.
- The factors may be different for other assets.
Key Factors Impacting Run Life

- Ten (10) key factors having the most impact on system run life - Need to understand and then effectively manage these:
  1. Equipment sizing, selection and operation
  2. Power quality
  3. Well deliverability and inflow performance
  4. ESP operating temperature
  5. Solids production
  6. Free gas in pump
  7. Depositions
  8. Corrosion
  9. Equipment monitoring & surveillance
  10. Continuous improvement processes

Continuous Improvement Program

- Make ESP run life improvement a team goal
  - Measure, record and communicate run life performance
  - Use down-hole sensors with surface monitoring and surveillance
  - Inspect “short runs” and apply root cause analysis techniques
  - Engage the ESP service company
Back to Work Plan

- Discuss with the Artificial Lift team about the average ESP run life achieved in your company, compared with the industry average (+/-2.5 years)
- Investigate the major factors contributing to ESP failure in your company
In this module:

- We have shown that the ESP design starts with the reservoir performance analysis to finalize production targets.
- We learned the principles, advantages and limitations of the ESP lift method.
- We learned how to calculate the total dynamic head (TDH) that is required for ESP design.
- We described in detail various components of the ESP system, at both the surface and the sub-surface, and emphasized how each component can contribute to enhance the run life of the ESP completion.
- We learned how to select the right ESP equipment to meet the production targets and to achieve a long service life, while working as a part of the system.
Summary (Continued)

In this module:
- We reviewed various completion options with ESP based on well requirements and local regulations
- We performed a ESP design for an example well, starting with basic reservoir, fluid and well parameters
- We presented guidelines to be followed for commissioning and routine start up of ESPs
- We discussed the need and ways of performing surveillance and troubleshooting using well production data and ESP performance data
- We summarized the factors that affect ESP run-life
- We have done various exercises and a case study to demonstrate important concepts presented in the module

PetroAcademy™ Production Operations

- Production Principles Core
- Well Performance and Nodal Analysis Fundamentals
- Onshore Conventional Well Completion Core
- Onshore Unconventional Well Completion Core
- Primary and Remedial Cementing Core
- Perforating Core
- Rod, PCP, Jet Pump and Plunger Lift Core
- Reciprocating Rod Pump Fundamentals
- Gas Lift and ESP Pump Core
- Gas Lift Fundamentals
- ESP Fundamentals
- Formation Damage and Matrix Stimulation Core
- Formation Damage and Matrix Acidizing Fundamentals
- Flow Assurance and Production Chemistry Core
- Sand Control Core
- Sand Control Fundamentals
- Hydraulic Fracturing Core
- Production Problem Diagnosis Core
- Production Logging Core
- Production Logging Fundamentals