Weatherford®

Drilling Evaluation Completion Production Intervention

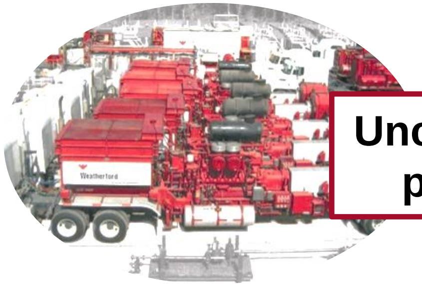
Introduction to Artificial Lift

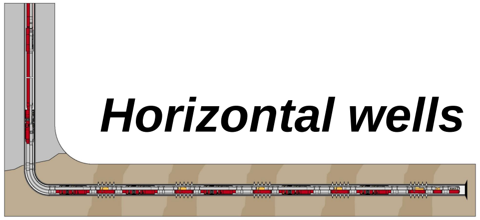
March 2013

What are your Artificial Lift ***challenges***?

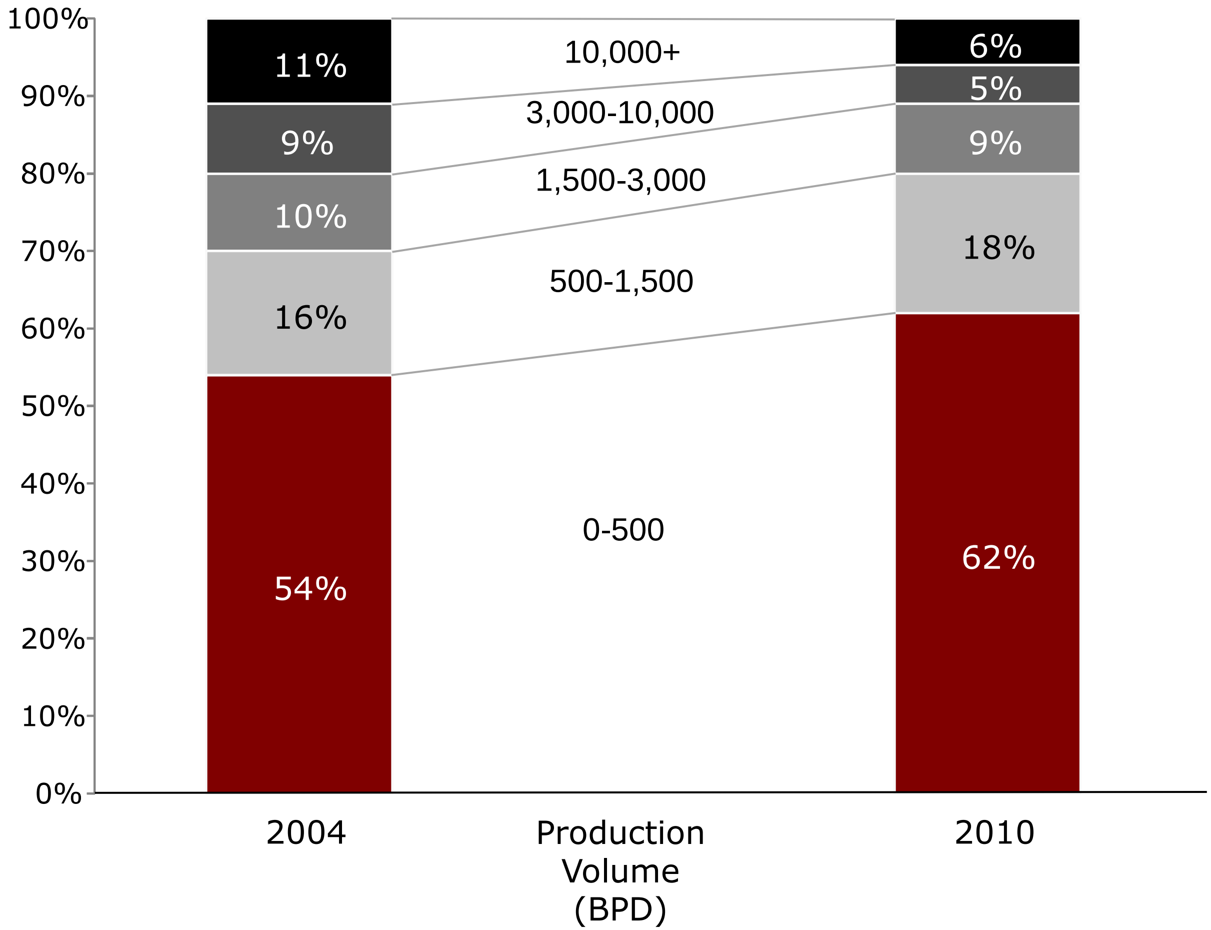
- Gassy oil
- Heavy/viscous oil
- Sandy oil
- High water cut
- Dewatering gas wells
- Deep
- Hot
- Low fluid levels
- Offshore
- Uncertainty
- Production optimization

Global Trends





The shift toward lower volume mature wells



Source: Welling & Company 2010, Worldwide Survey of the Market of Artificial Lift Equipment

The case for Production Optimization

Major producer operating 26,000 wells

Plunger Wells	**16,000**
PCP Wells	**4,000**
ESP Wells	**3,000**
Rod Lift Wells	**1,000**
Other / Natural Flowing Wells	**2,000**
Gas/Oil Meters	**33,000**
RTU/PLC Automation	**24,000**
Oil / Water Production Tanks	**12,000**
Compressors	**3,000**
Water Meters	**6,000**

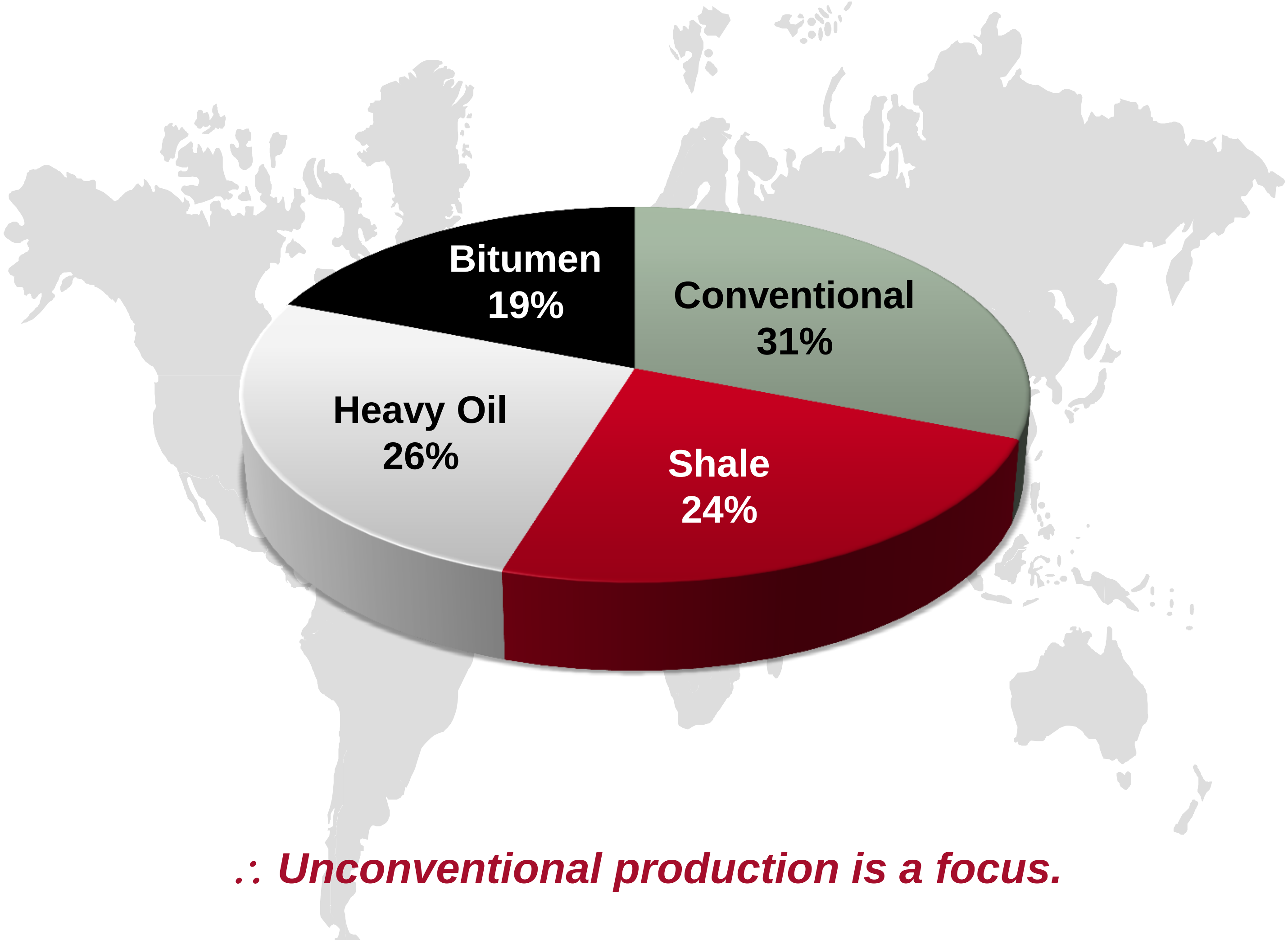
Integrated Field Management:

5 billion data sets every 24 hours

∴ A field management system is required for production optimziation.

The increasing role of unconventional oil

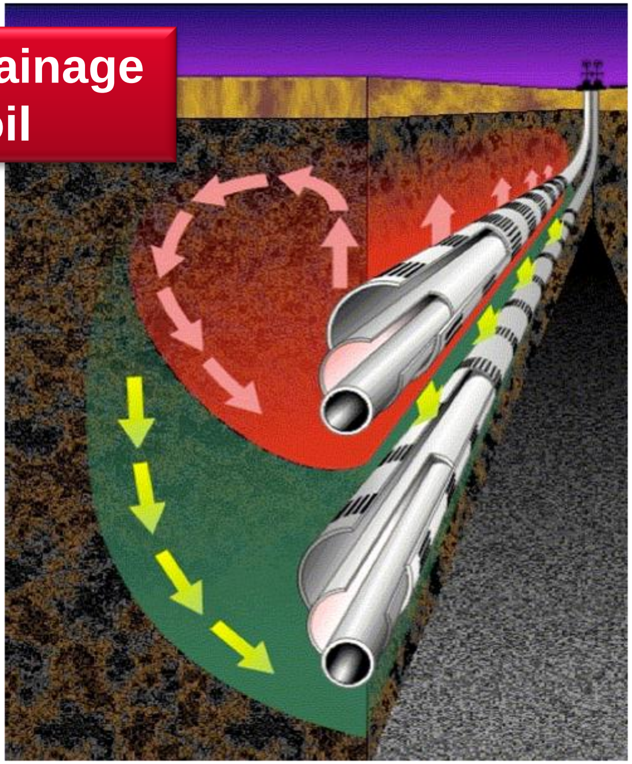
World estimated recoverable oil reserves

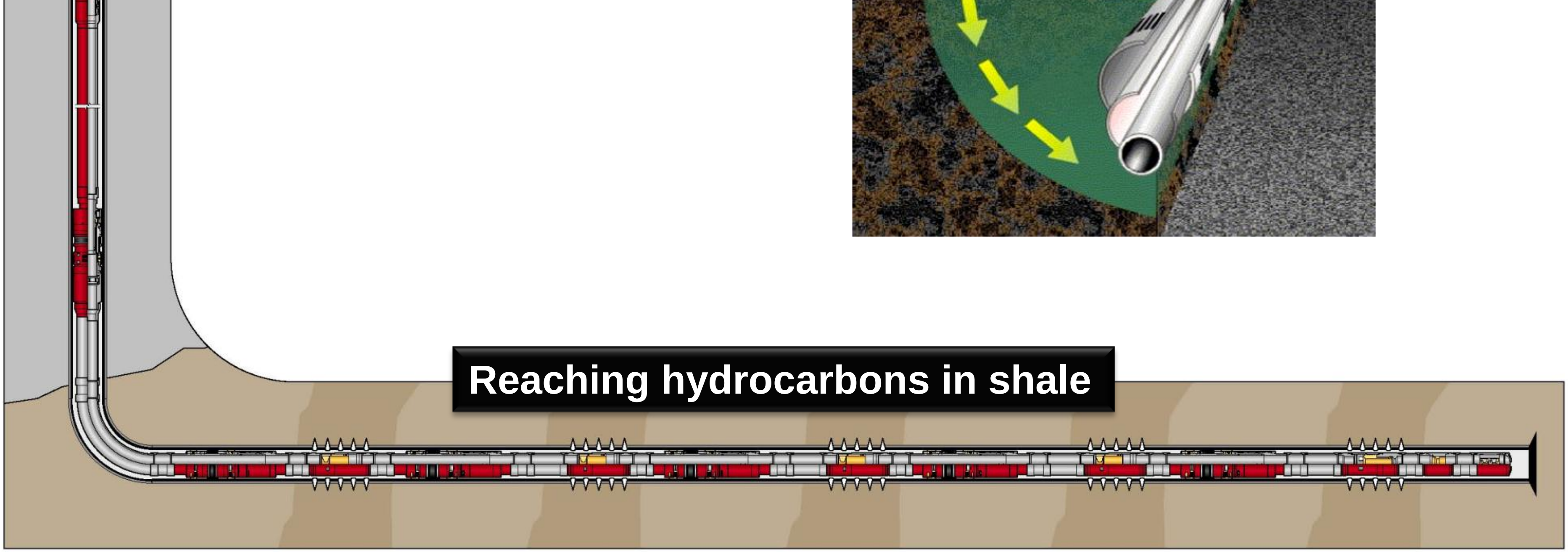


∴ Unconventional production is a focus.

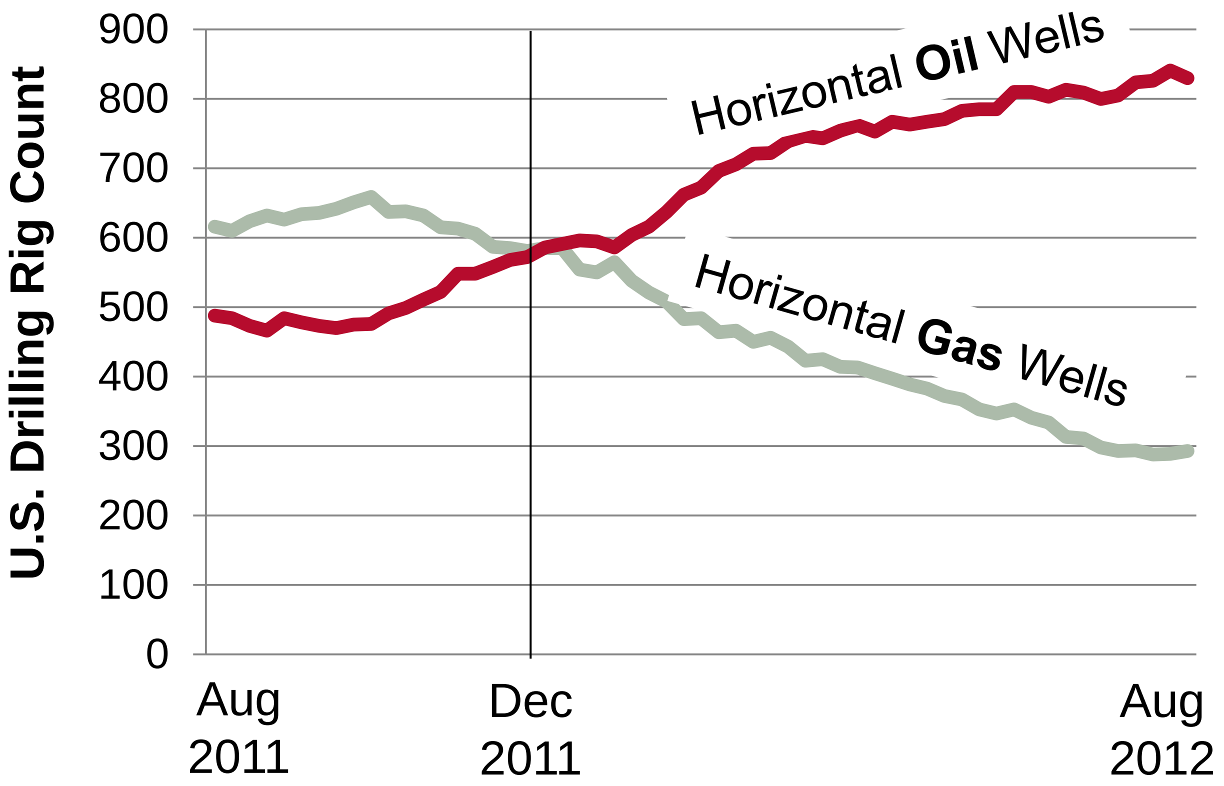
Source: *IEA World Energy Outlook 2011, 2010*

The shift from *vertical* to *horizontal* wells

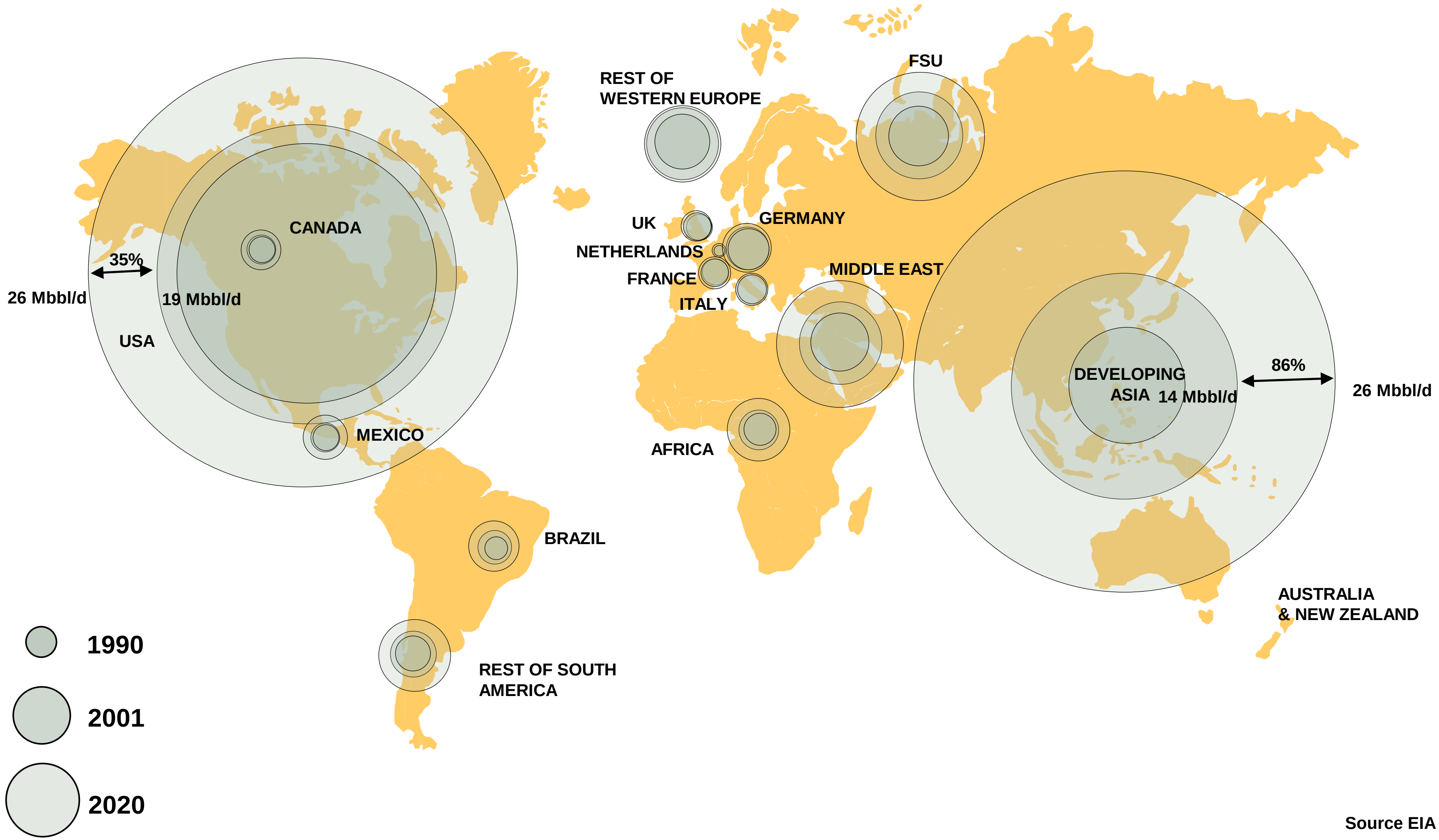




The shift from *gas* to *oil*

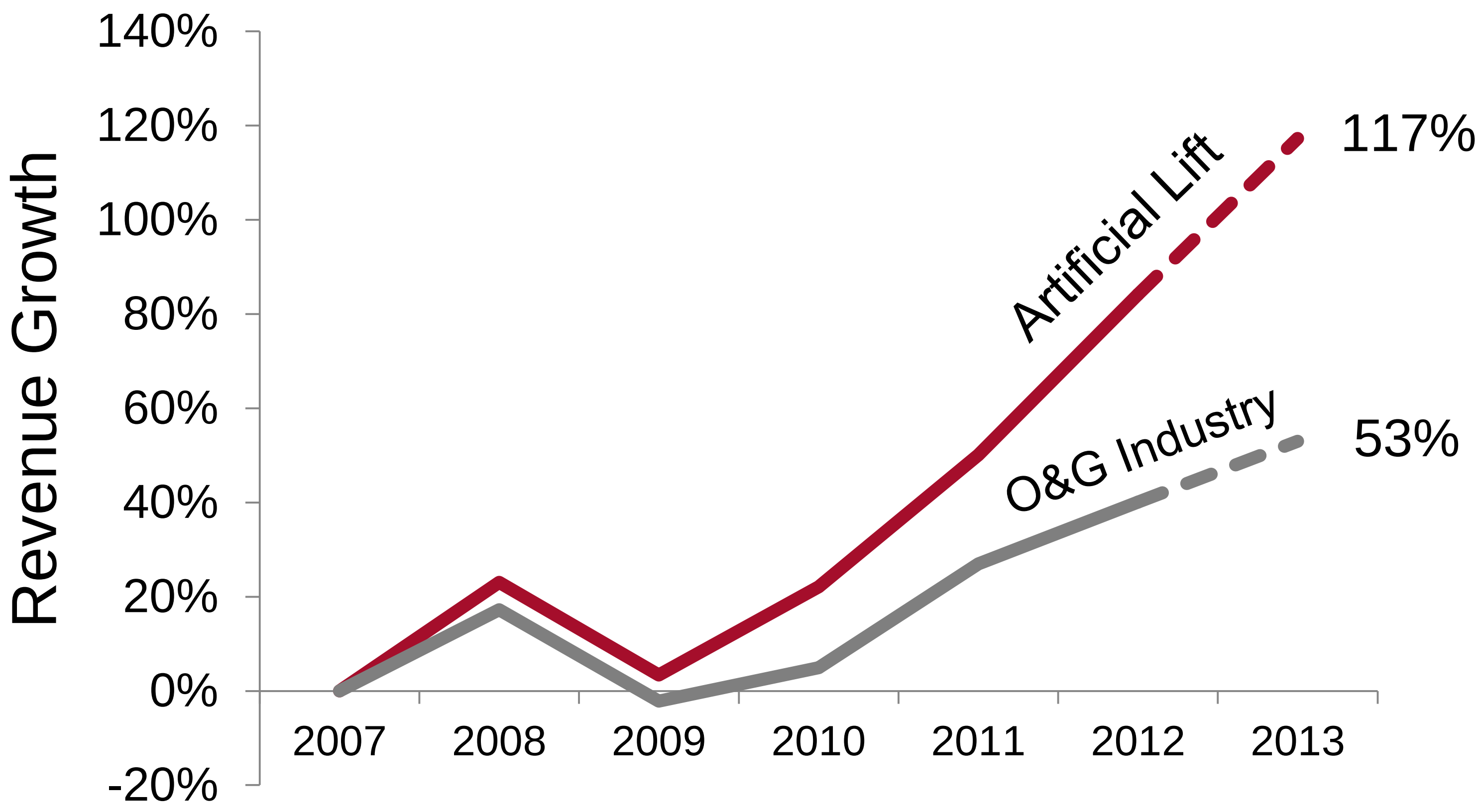


Global oil demand shifting to the east



Source EIA

Increasing focus on production technologies



[3]Oilfield Market Report 2005-2013, Spears & Associates, Inc.

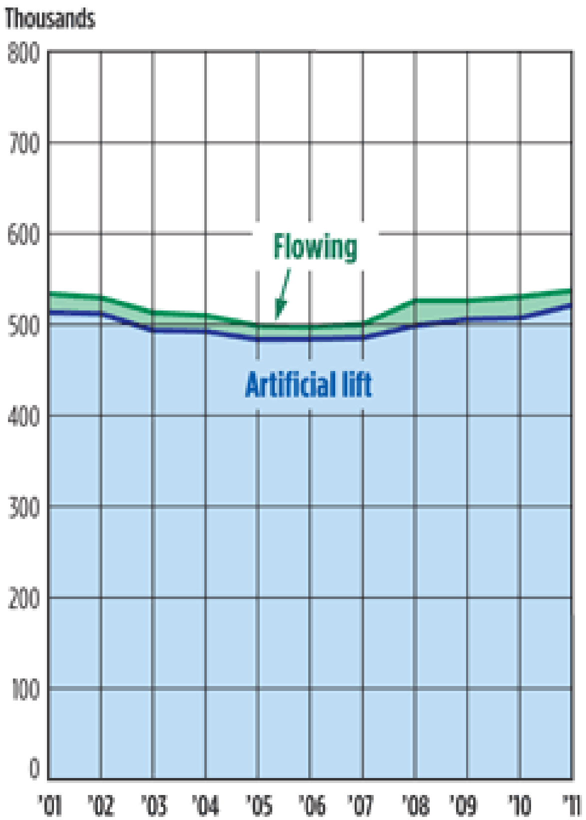
The Challenge…

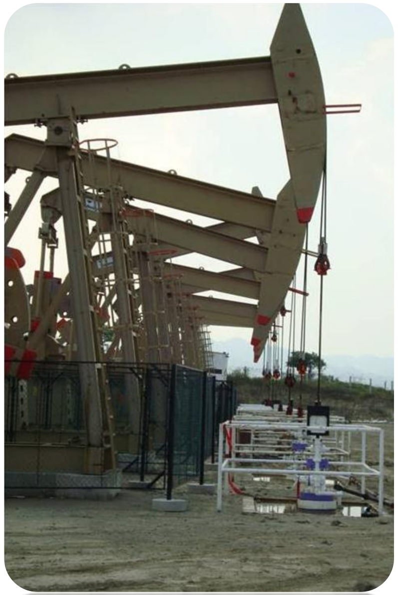
Find and produce ***more*** oil and gas assets

Maximize ***productivity*** of existing assets

Naturally Flowing *versus* Artificial Lifted Oil Wells

5%



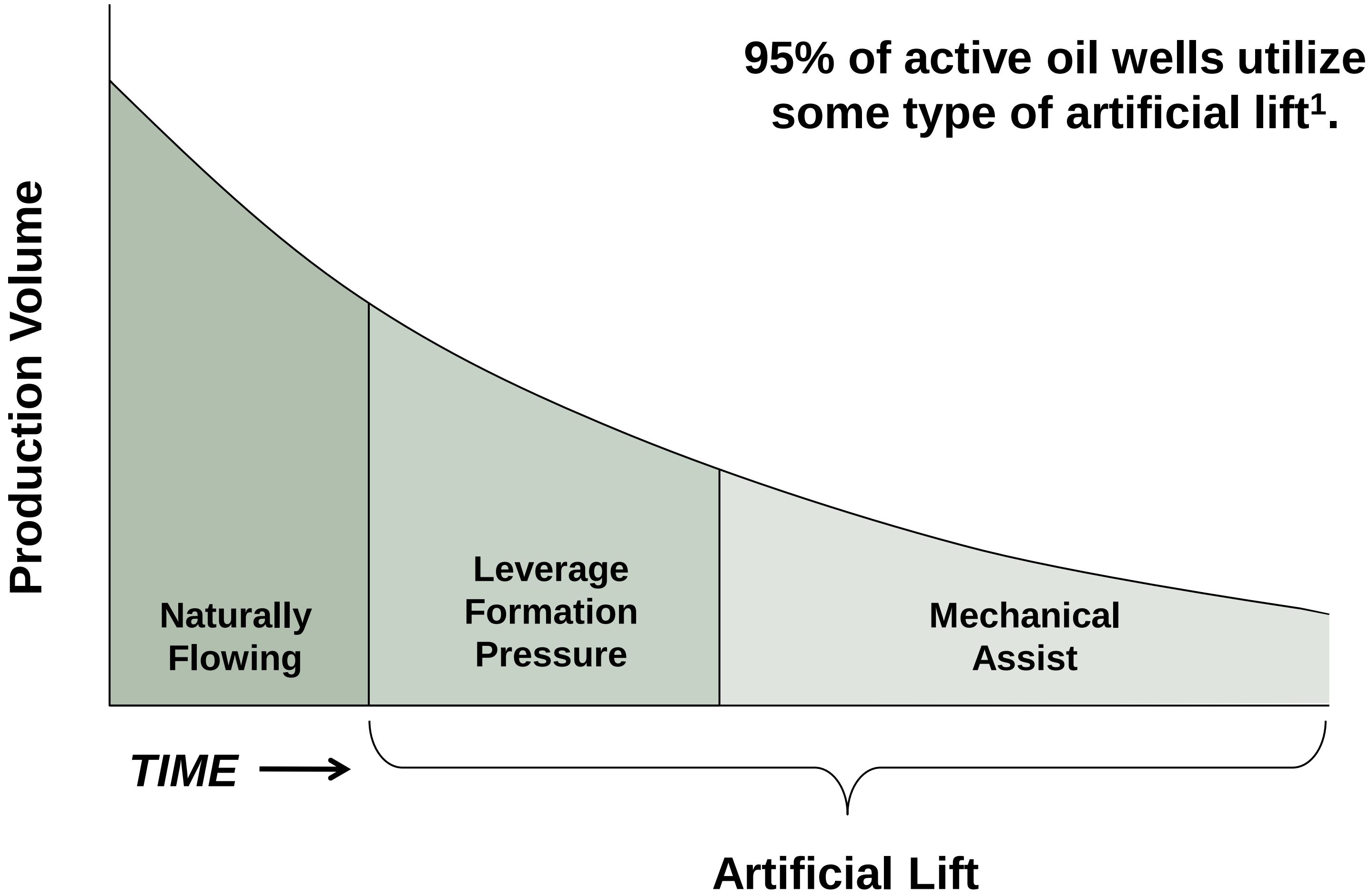


95%

Source: World Oil, Feb 2012

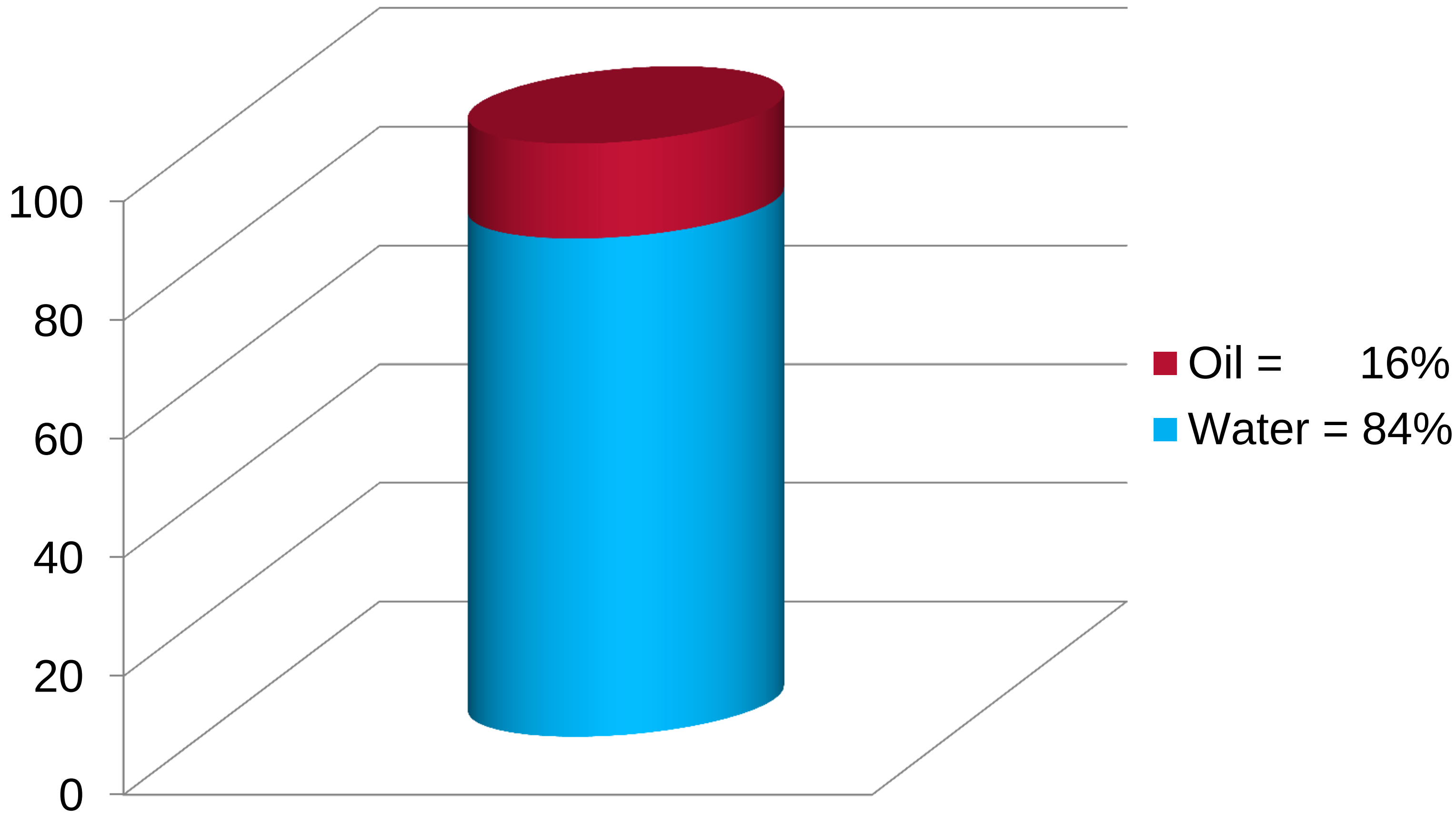
"Based on the states for which the World Oil was able to obtain a breakout of flowing wells versus those on artificial lift, the percentage of U.S. oil wells produced by artificial lift is staying steady at about 95%. That ratio has remained fairly constant throughout the past 10 years."

The Life of an Oil Well



[1]From World Oil, February, 2012.

What liquids are being lifted?



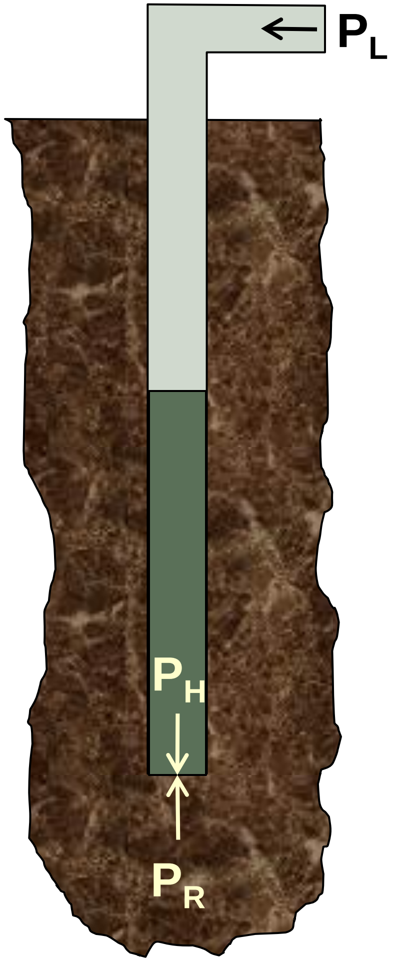
Ref: Produced Water Volumes and Management Practices in the United States (2007), Argonne National Laboratory; Sept, 2009

When is Artificial Lift needed?

1. To raise fluids to the surface when:

   $$P_{Reservoir} < P_{Hydrostatic} + P_{line}$$

2. To increase the production rate of flowing wells by reducing the producing bottom hole pressure (PBHP = $P_H + P_L$)



Solutions:

A. Reduce hydrostatic head pressure

B. Reduce the amount of fluid lifted per cycle

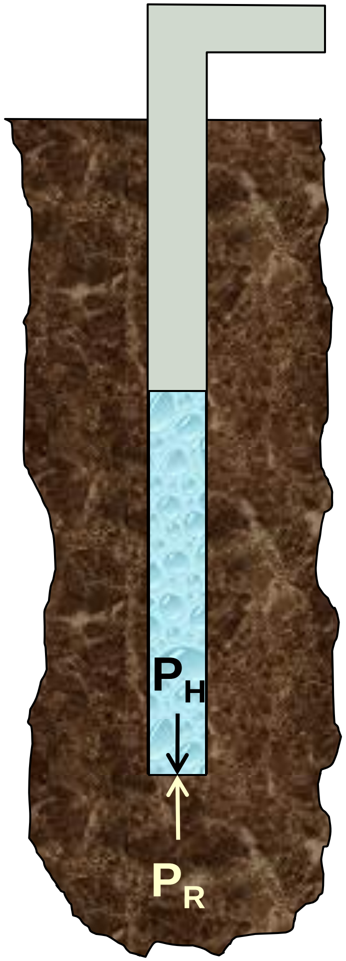
C. Reduce line back-pressure

D. Add *Energy*

Liquid Loading

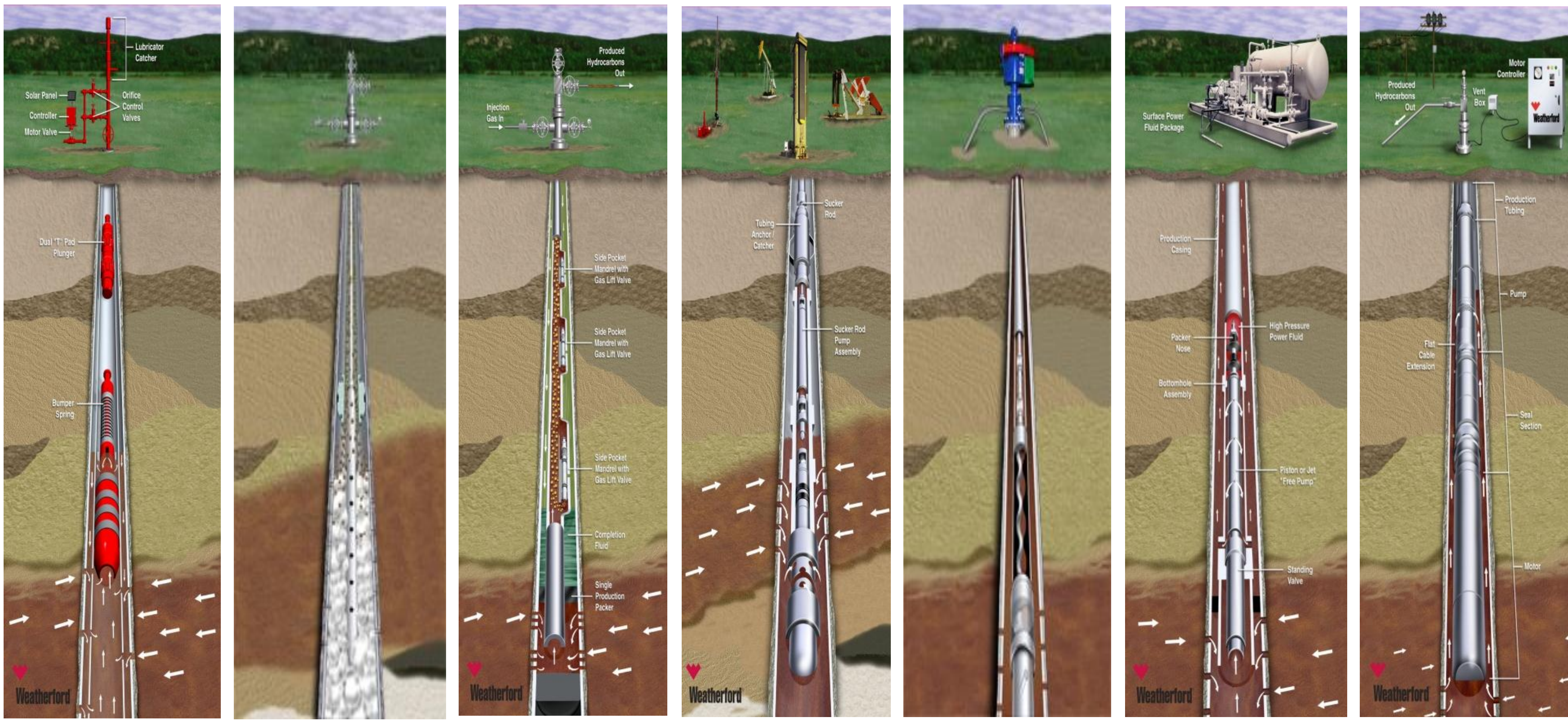
When the pressure of the liquid column keeps gas from entering the well:

$$P_{Reservoir} < P_{Hydrostatic}$$



Lift Technologies by Energy Source

Plunger Lift | **Foam Lift** | **Gas Lift** | **Rod Lift** | **PCP** | **Hydraulic Lift** | **ESP**

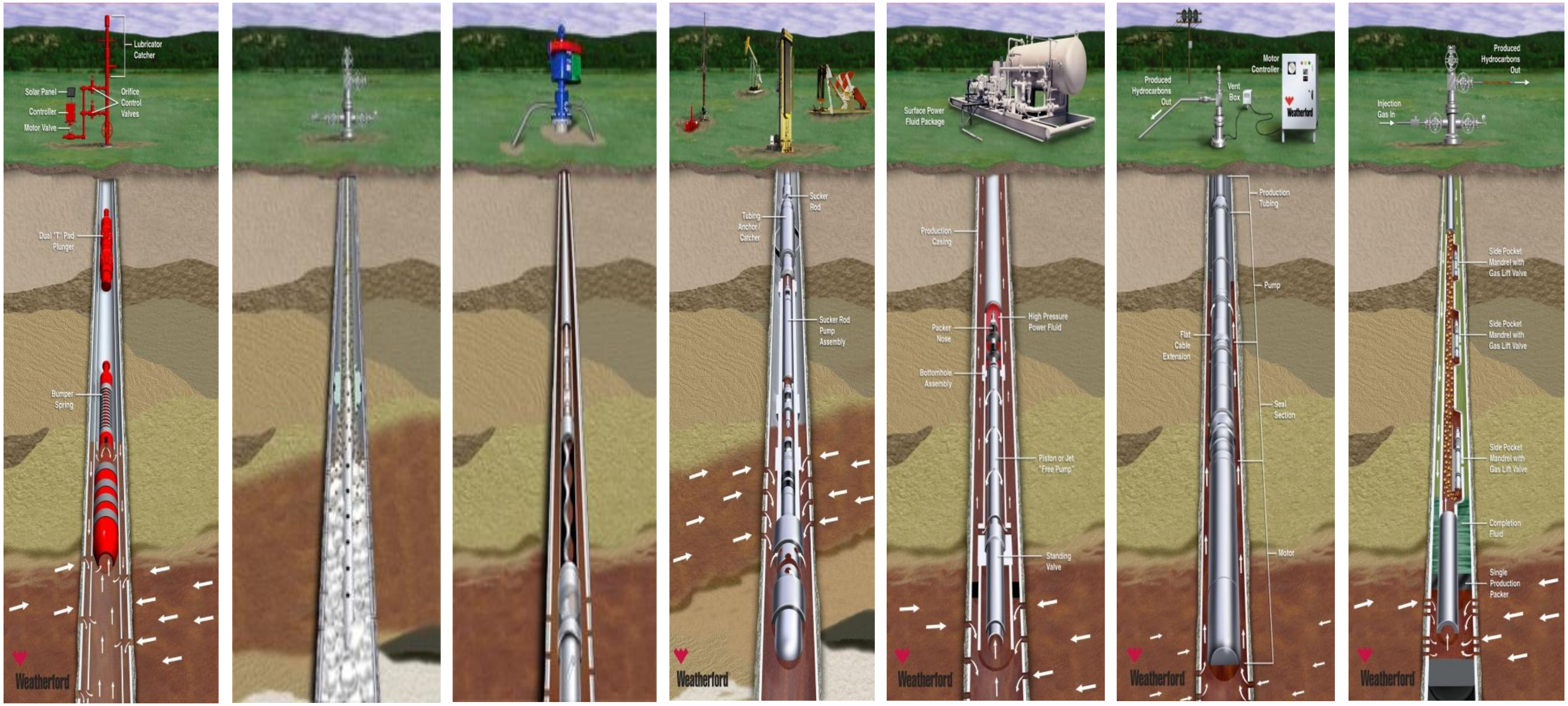


Formation Pressure (Plunger Lift, Foam Lift, Gas Lift)

Mechanical Assist (Rod Lift, PCP, Hydraulic Lift, ESP)

Lift Technology by Lift Capacity (BPD)

Plunger Lift	Foam Lift	PCP	Rod Lift	Hydraulic Lift	ESP	Gas-Lift

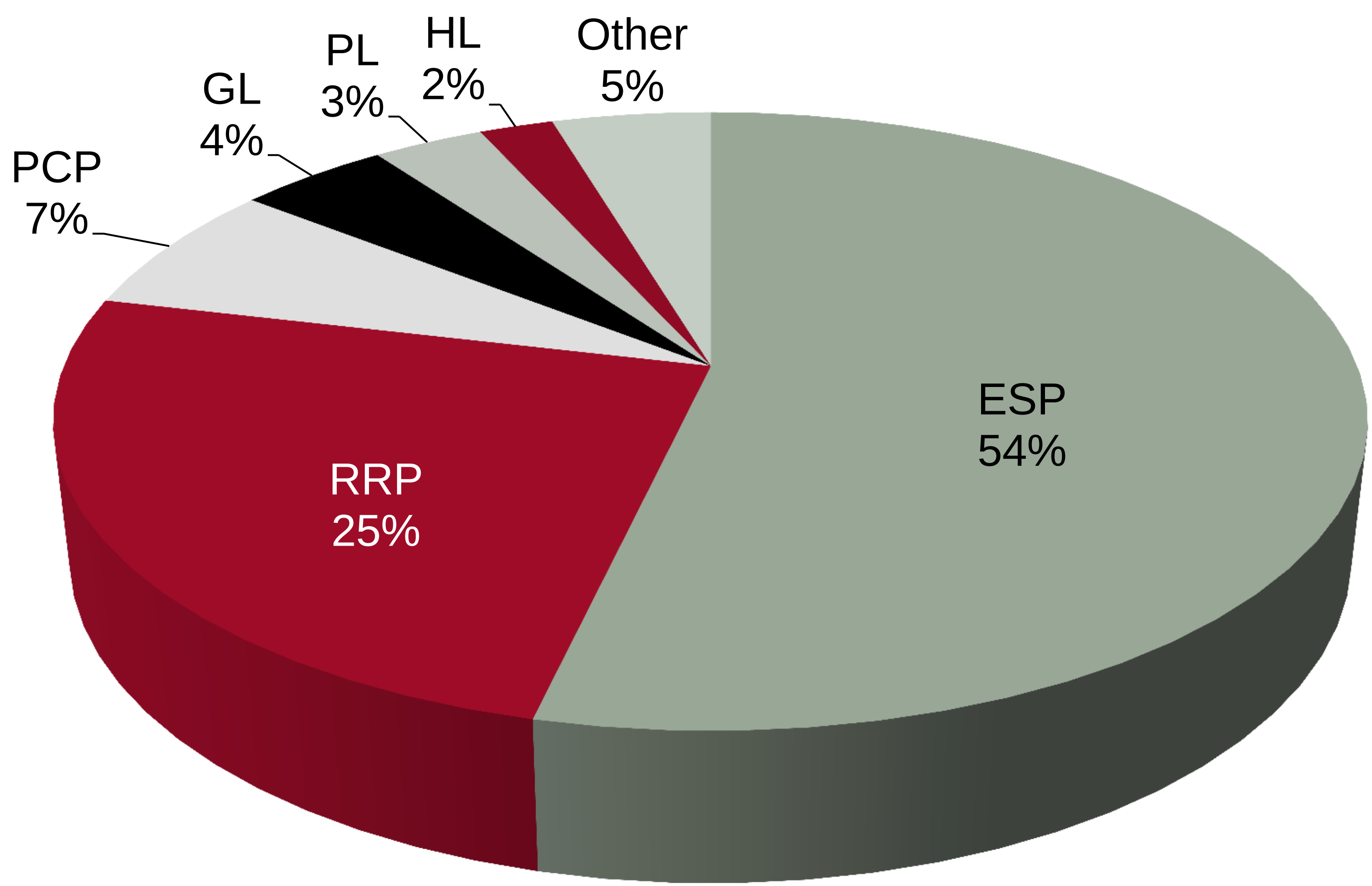


200	500	5000	6000	35000	60000	75000

Low (200–500)	Medium (5000–6000)	High (35000–75000)

Low **Medium** **High**

Artificial Lift Market Share by Type
(based on dollars spent)



From Spears Oilfield Market Report, Oct, 2011

What do you want out of your lift system?

- Maximum production?
- Flexibility in production rates?
- Lowest purchase cost?
- Lowest operating cost? (Efficiency, consumables)
- Reliability and up-time (Mean-Time-Between-Failures)
- Least Energy Consumption? (Best Efficiency?)
- Minimum noise and visual impact?
- Minimum footprint? (Offshore)

ALS Application Screening Values

This is just a starting point!

	Gas Lift	Foam Lift	Plunger	Rod Lift	PCP	ESP	Hyd Jet	Hyd Piston
Max Depth	18,000 ft *5,486 m*	22,000 ft *6,705 m*	19,000 ft *5,791 m*	16,000 ft *4,878 m*	8,600 ft *2,621 m*	15,000 ft *4,572 m*	20,000 ft *6,100 m*	17,000 ft *5,182 m*
Max Volume	75,000 bpd 12,000 M^3/D	500 bpd 80 M^3/D	200 bpd 32 M^3/D	6,000 bpd 950 M^3/D	5,000 bpd 790 M^3/D	60,000 bpd 9,500 M^3/D	35,000 5,560 M^3/D	8,000 bpd 1,270 M^3/D
Max Temp	450°F 232°C	400°F 204°C	550°F 288°C	550°F 288°C	250°F 121°C	482°F 250°C	550°F 288°C	550°F 288°C
Corrosion Handling	Good to excellent	Excellent	Excellent	Good to Excellent	Fair	Good	Excellent	Good
Gas Handling	Excellent	Excellent	Excellent	Fair to good	Good	Fair	Good	Fair
Solids Handling	Good	Good	Fair	Fair to good	Excellent	sand<40ppm	Good	Fair
Fluid Gravity (°API)	>15°	>8°	>15°	>8°	8°<API<40°	Viscosity <400 cp	≥6°	>8°
Servicing	Wireline or workover rig	Capillary unit	Wellhead catcher or wireline	Workover or pulling rig	Wireline or workover rig		Hydraulic or wireline	
Prime Mover	Compressor	Well natural energy		Gas or electric		Electric	Gas or electric	
Offshore	Excellent	Good	N/A	Limited	Limited	Excellent	Excellent	Good
System Efficiency	10% to 30%	N/A	N/A	45% to 60%	50% to 75%	35% to 60%	10% to 30%	45% to 55%

ALS Technology Application Process

1. **Understand** and predict reservoir potential performance.
2. **Establish** target production levels and conditions.
3. **Eliminate** technically infeasible lift technologies.
   - Required performance
   - Support infrastructure (power, skill base, etc.)
4. **Economic evaluation**
   - Acquisition, installation, & training cost
   - Operating cost
   - Reliability
   - Repair/replacement

Artificial Lift Design Software

Lift Technology	Software
Reciprocating Rod Lift	Rod Star, SROD, XROD, QROD, others, WFT csBeamDesign
PC Pump	CFER PC Pump, Prosper, WFT proprietary
Gas Lift	Well Evaluation Model (WEM), VALCAL, Valve Performance Clearinghouse (VPC), Prosper, PIPESIM, Dynalift, WellFlo
Hydraulic Lift	Guiberson Piston Pump, SNAP, Prosper, JEMS
ESP	Dwight's SubPUMP, WEM, Prosper, PIPESIM, supplier proprietary, Borets-WFT proprietary
Capillary/Plunger Lift	WEM, WFT proprietary

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What is Production Optimization?

Managing production of hydrocarbons *as things change over time*

- Surveillance and measurement – ***What** is happening?*
- Analysis – ***Why** is it happening?*
- Design of solutions – ***How** can performance be improved?*
- Asset management – ***When** and **where**?*
- Reporting – ***KPI's** and **feedback***

Real Results from Production Optimization

SPE study group surveyed PO literature, June, 2010[1]:

- *Production Improvements = 3% to 20% (avg = 3,000 BPD)*
- *CAPEX savings = $42,000 to $345,000 (avg = $200,000)*

Value of PO to Shell[2] from *increased production & reduced costs*:

- 70,000 BPD
- $5 billion accumulated value

[1]Ref: http://www.spegcs.org/attachments/studygroups/4/DE%20Workshop%20Literature%20Review%20Slides.pdf

[2]Cumulative value, SPE#128245, March, 2010.

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Key Concepts for Understanding ALS

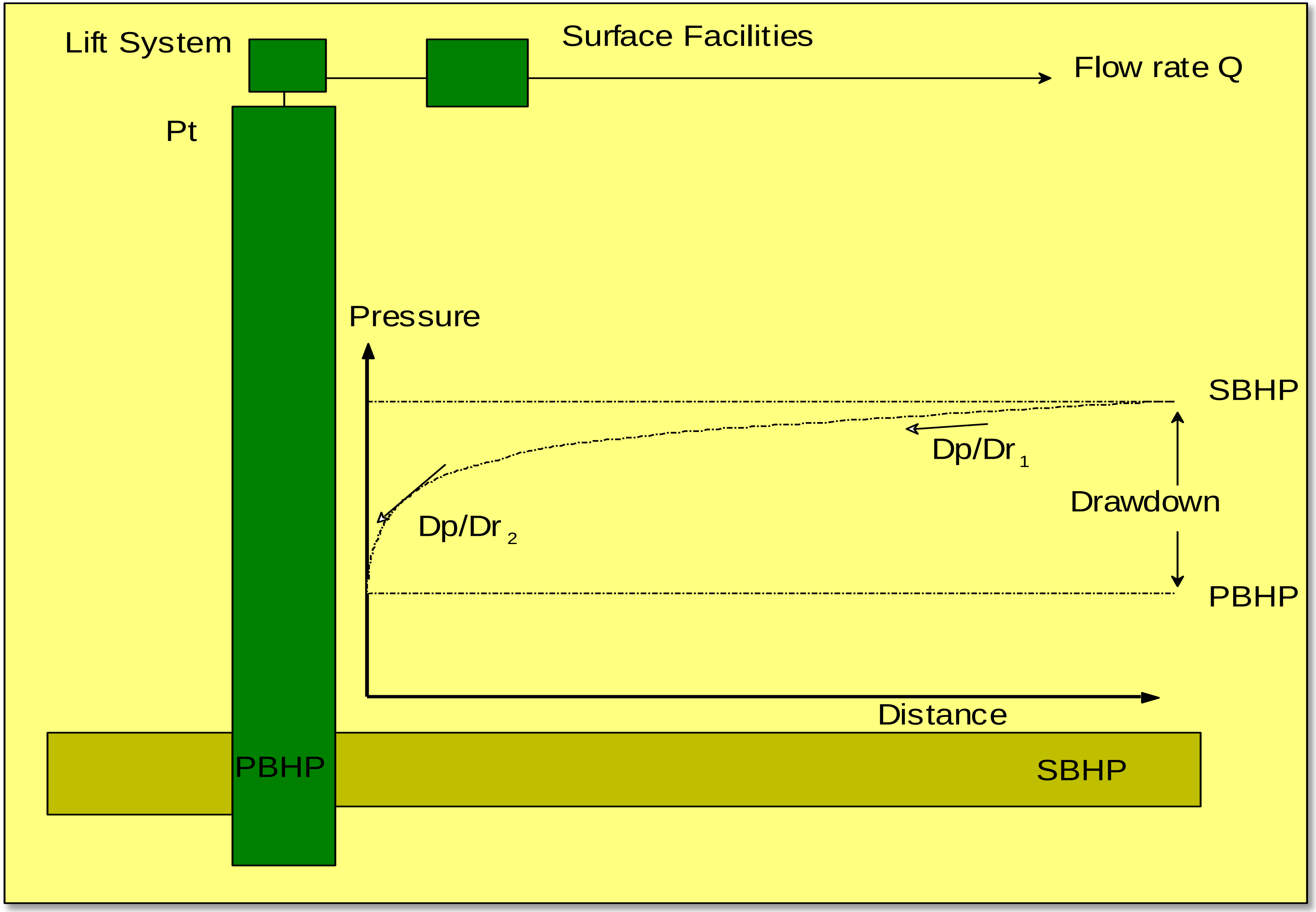
Inflow Performance Relationship (IPR)

Gas Lock

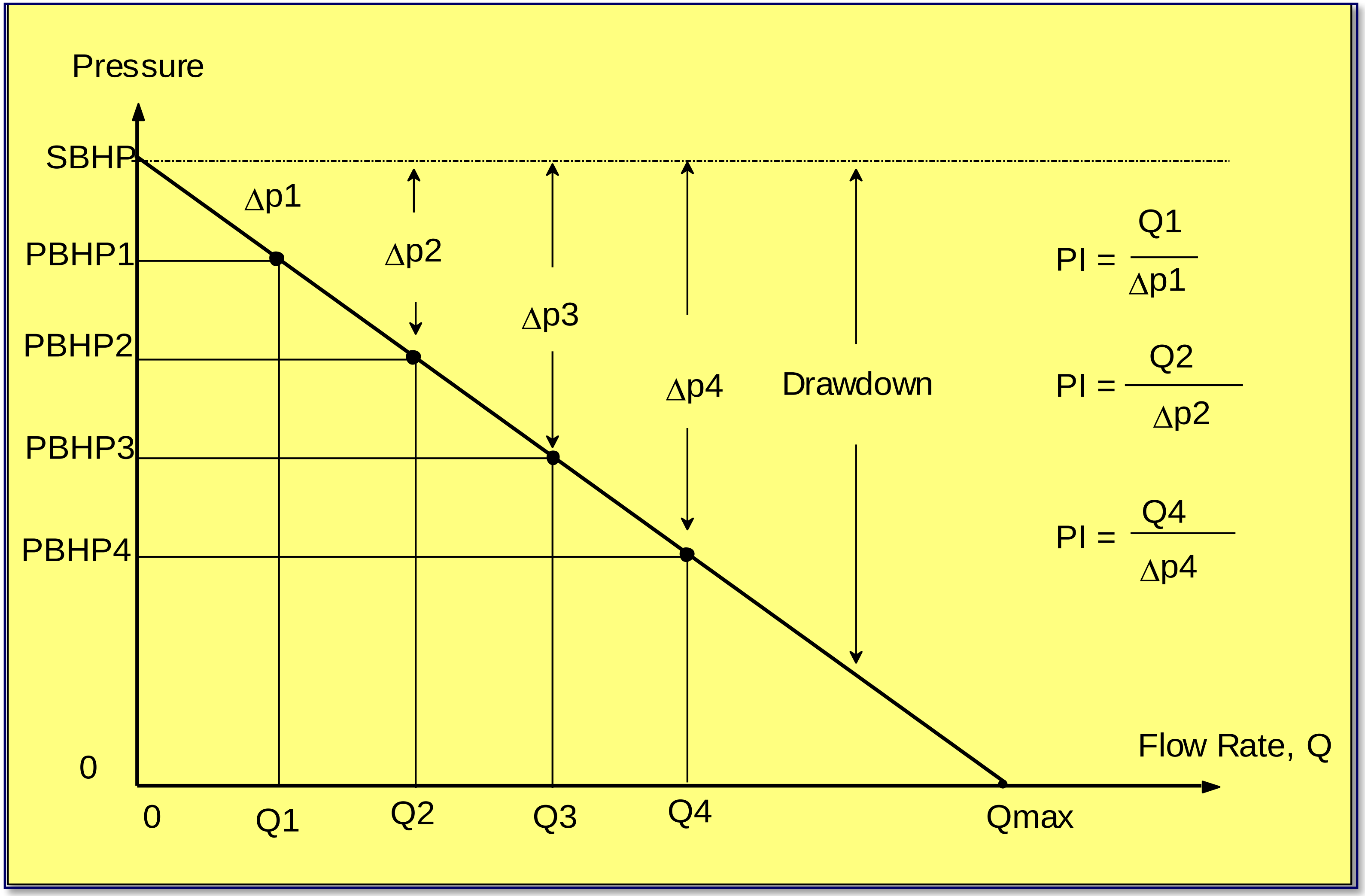
Cavitation

Pump Turndown Ratio

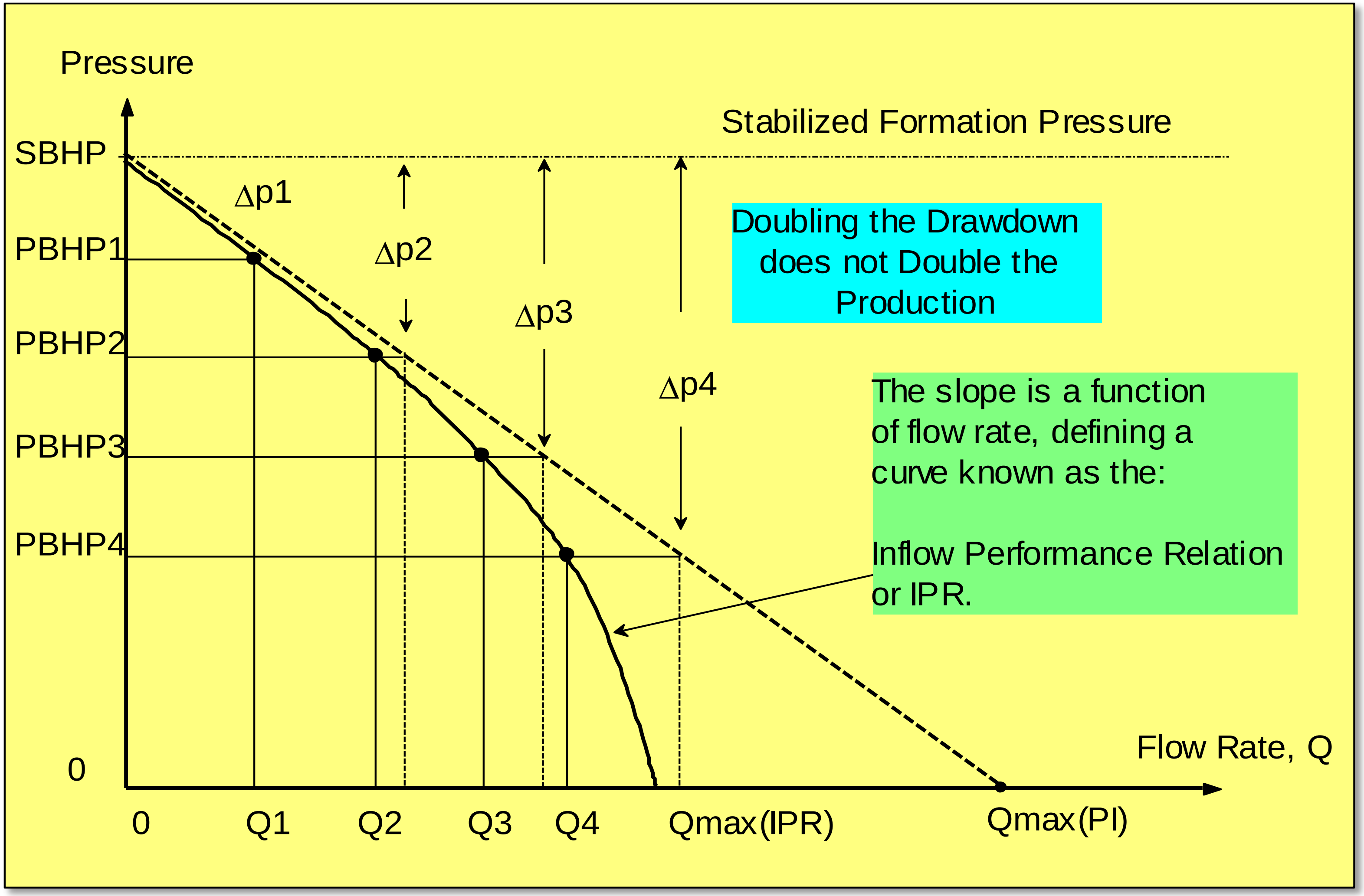
Formation Pressure = *f*{distance from well}



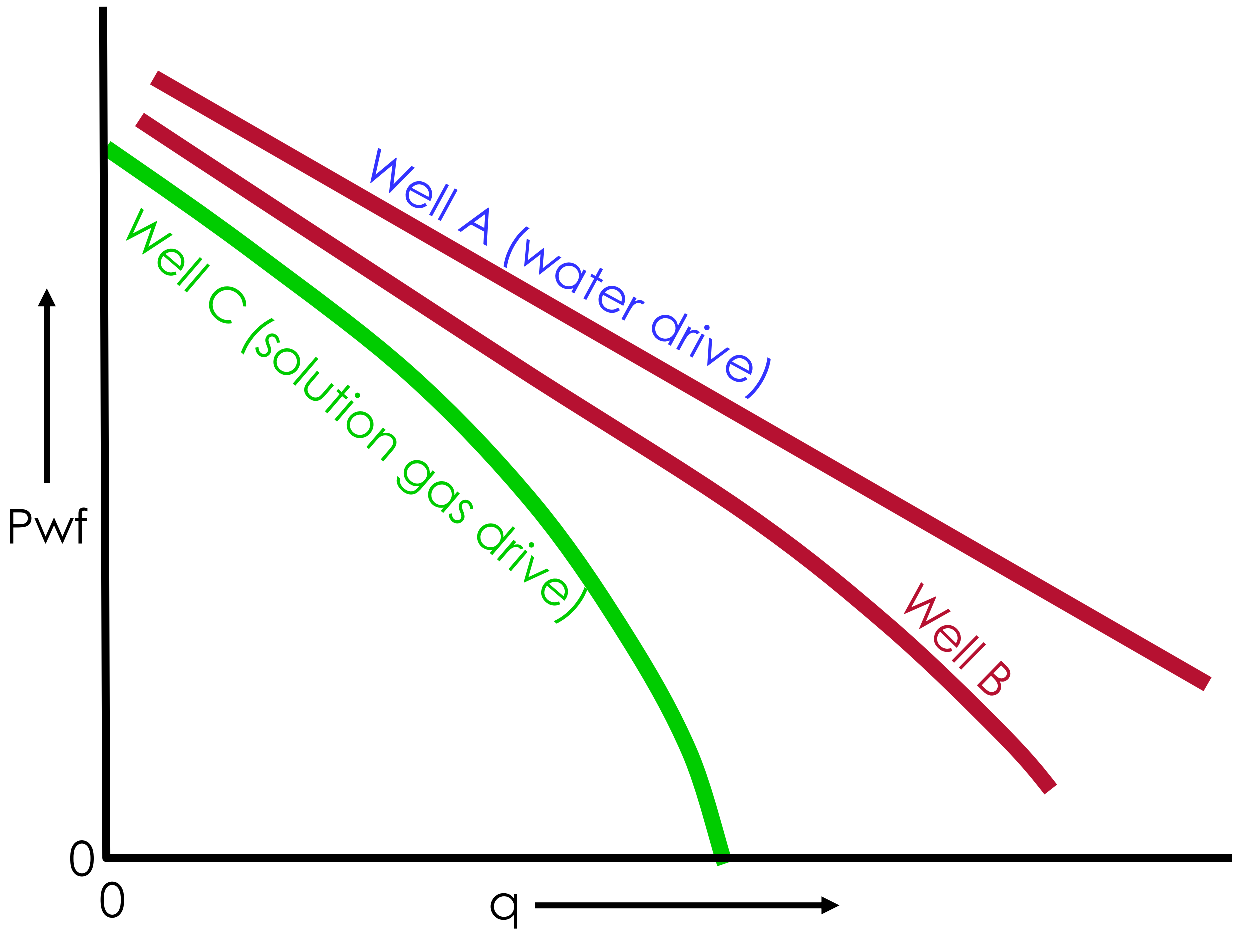
Productivity Index (PI) = $\frac{\text{Flow Rate}}{\text{Drawdown}}$



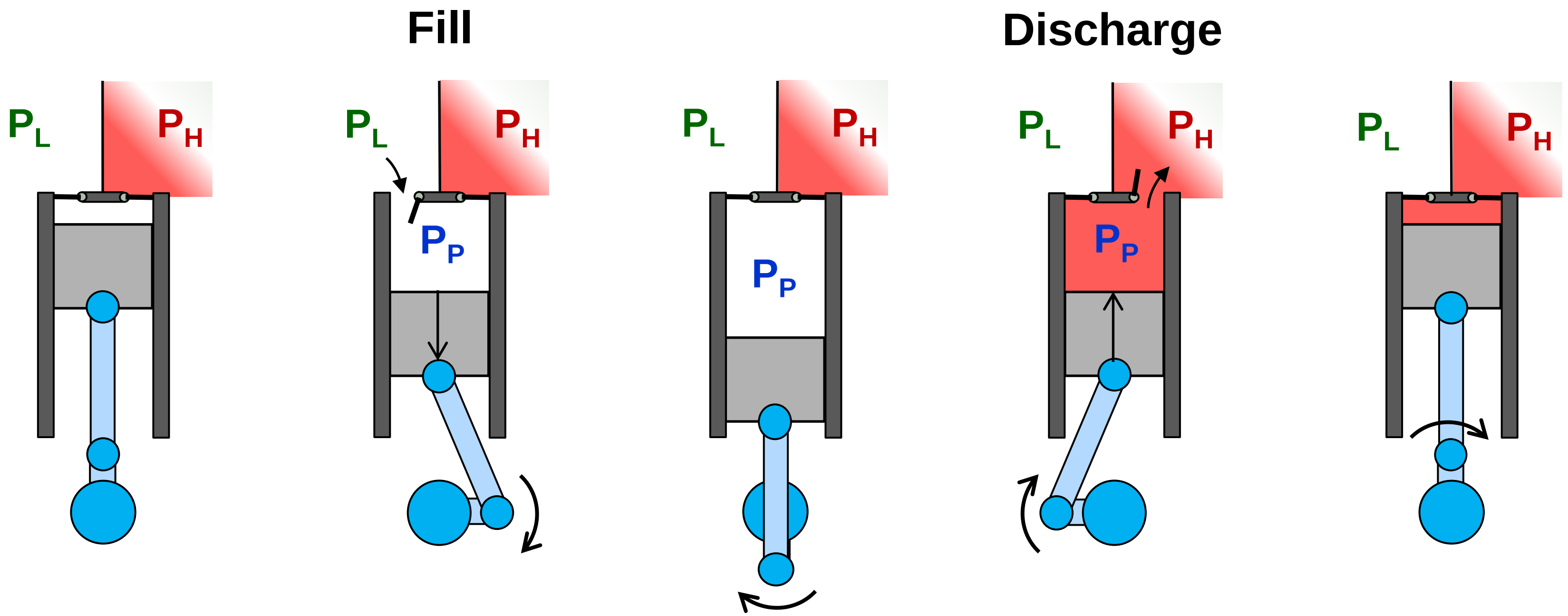
Inflow **P**erformance **R**elation (IPR)



Typical IPR versus Reservoir Drive System



Normal pump cycle (liquid)



$P_L < P_P < P_H$

$\mathbf{P_P < P_L} < P_H$

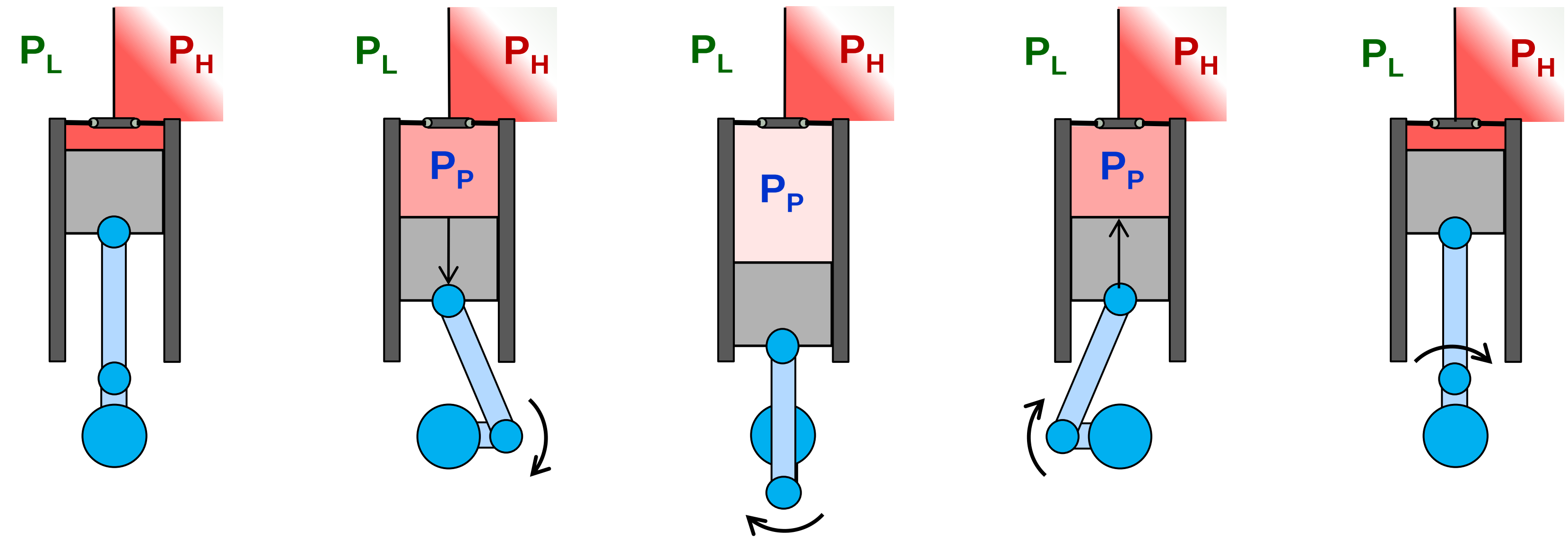
$P_L = P_P < P_H$

$P_L < \mathbf{P_H < P_P}$

$P_L < P_P = P_H$

Gas Lock

Fill? **Discharge?**



$P_L < P_P \le P_H$ $P_L < P_P < P_H$ $P_L \le P_P < P_H$ $P_L < P_P < P_H$ $P_L < P_P \le P_H$

Gas in pump expands, but

$\mathbf{P_L < P_P}$

so no flow.

Gas in pump compresses, but

$\mathbf{P_P < P_H}$

so no flow.

Gas Locking in Rod Pumps

The swept volume in the pump is occupied by gas. No fluid is pumped as the pump strokes:

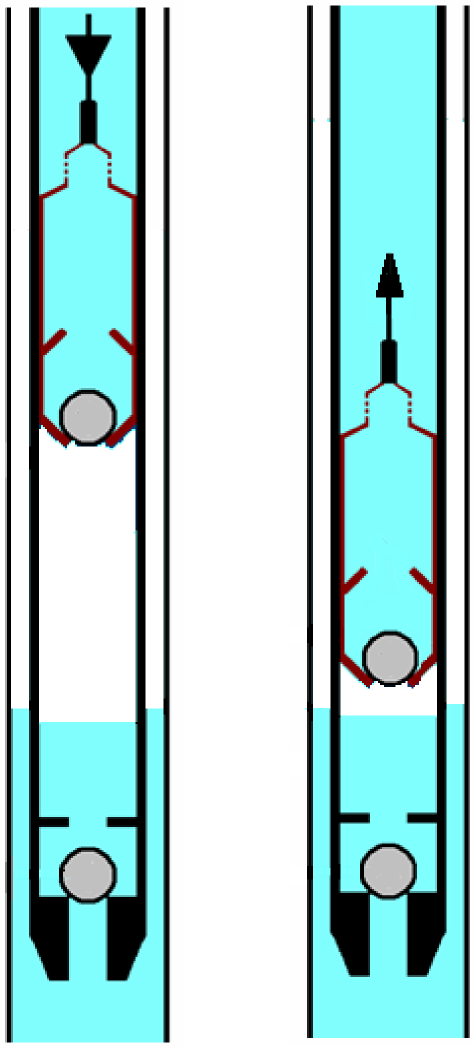
- Downstroke

  The gas compresses but does not have enough pressure to open the traveling valve.

- Upstroke

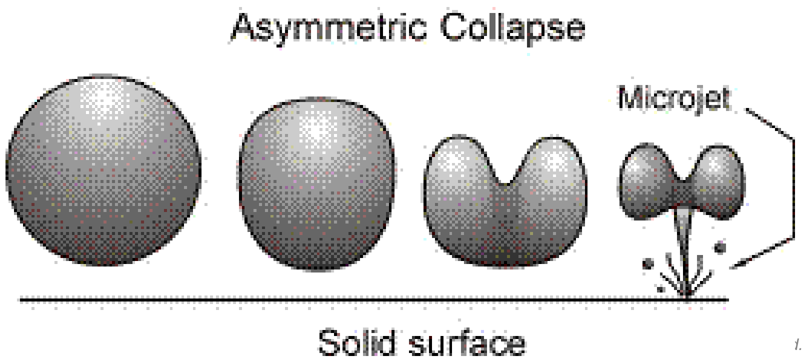
  The gas decompresses, but it has higher pressure than the reservoir so the standing valve remains closed.

RESULT: No fluid enters or leaves the pump.

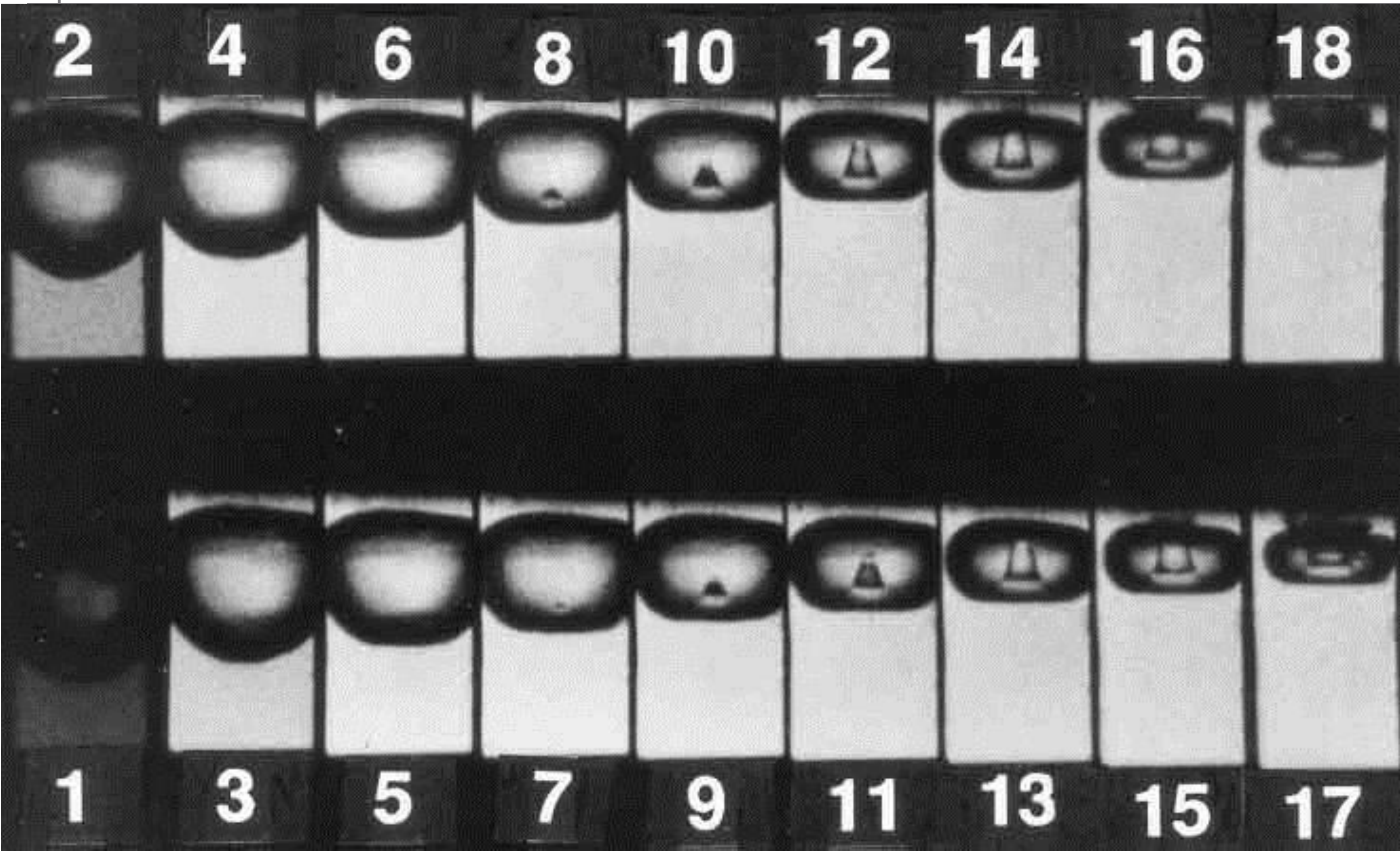


Cavitation in Pumps

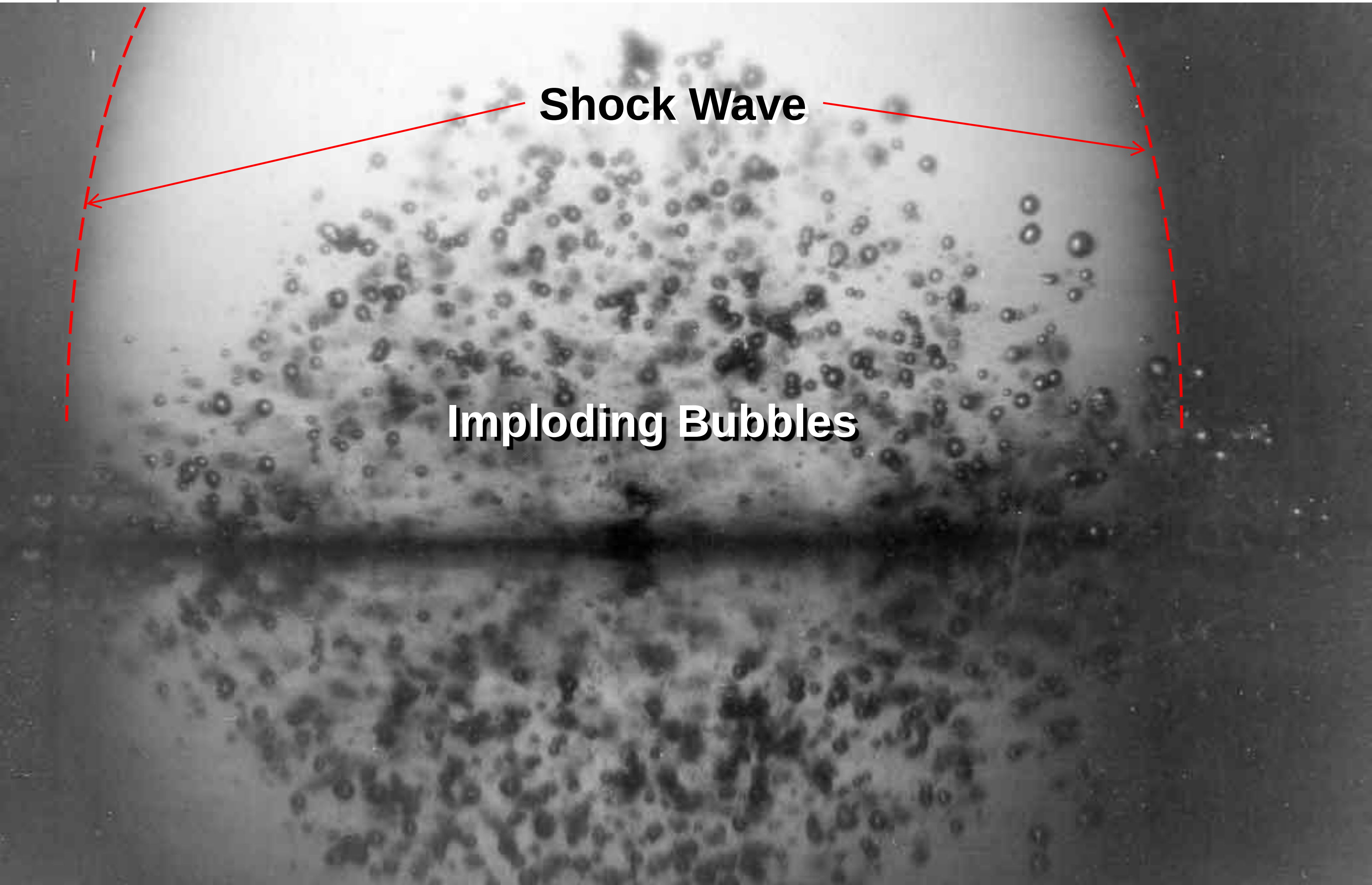
1. Low pressure gas bubbles form in liquids:
   - When a pump intake is starved for liquid
   - When localized fluid pressure drops below the vapor pressure of gas in solution
   - When existing gas bubbles are ingested into pumps
2. Higher pressure in the surrounding fluids causes the gas bubble to implode violently.
   - Shock waves
   - Micro-jets impact surrounding fluids and surfaces



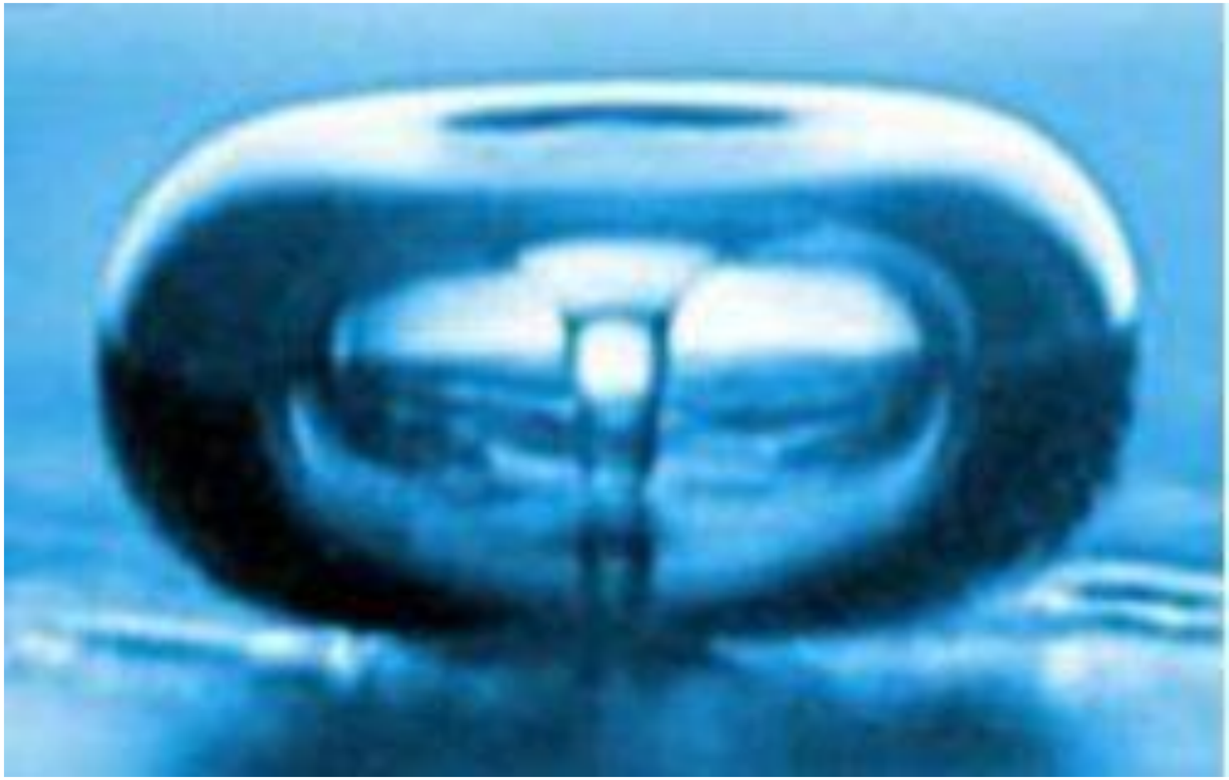
Cavitation Sequence



Cavitation Shock Wave



Cavitation Micro-Jet



Cavitation Damage
Centrifugal Pump Impeller Stage

Pump "Turndown Ratio"

Turndown ratio is a measure of a pump's capacity to change production volume:

$$\text{Turndown Ratio} = \frac{\text{Maximum Volume}}{\text{Minimum Volume}}$$

For example, a pump capable of 10 to 50 BPD would have a turndown ratio of ***5***:

$$\text{Turndown Ratio} = \frac{\text{50 BPD}}{\text{10 BPD}} = 5$$

Pumps with high turndown ratios are helpful when production volumes are expected to vary:

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Questions?