Welcome!

The program will begin soon.
You will not hear audio until we begin.

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Artificial Lift Life Cycle & Optimization

Subash K Kannan
Occidental

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Agenda

Webinars

- Artificial lift technology
- Impact on Well performance
- Understanding Well Performance in Unconventional wells
- Digital Oil Field
- Takeaway

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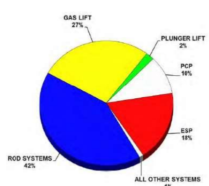
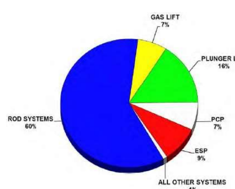
Artificial Lift Installations

Webinars

- Share of Artificial Lift Installed:



International



North America

SPE International

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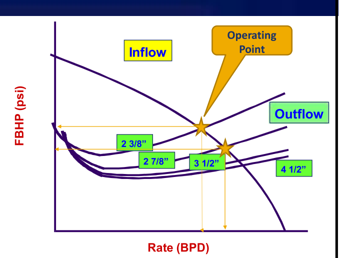
Well Performance

Webinars

- Quick 101



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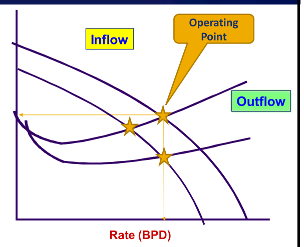
Well Performance

- What does Artificial lift do?



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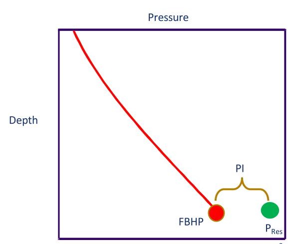
Well Performance

- Gradient Curve



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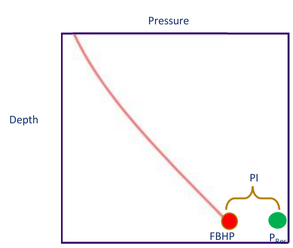
Well Performance

- Gradient Curve



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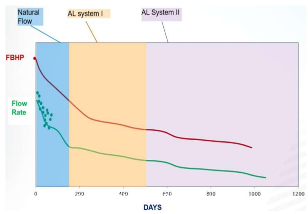
Artificial lift – Unconventional wells

- Artificial lift selection is a challenge for unconventional reservoirs.
- There is a short operating window before the final artificial lift is installed.
- In shale oil plays like Delaware Basin, the dynamic behavior of the wells results in slugging and instability as the pressure and rate decline.



About 85% of shale wells need some form of artificial lift system in the first 2-3 years of their life.*

* Welling Report -2017

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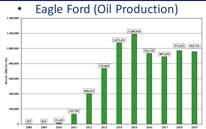
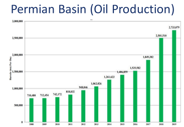
Unconventional Activities

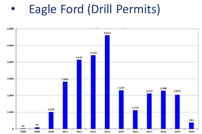
- Eagle Ford (Oil Production)



- Permian Basin (Oil Production)



- Eagle Ford (Drill Permits)



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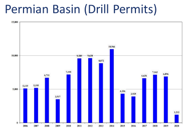

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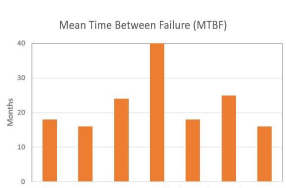
Artificial Lift Failures



- What could be done to extend the life?
  - Design – Fit for purpose
  - Reliability
  - Flow assurance challenges
    - Sand, Wax
  - Failure analysis
  - Monitoring

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Reality Check/ Opportunities

- Base production is very important
  - Well count increases
  - Well productivity drops
  - Uncertainty in oil prices
  - Well becomes older (more maintenance, more associated cost)
    - The only way to keep up the efficiency is to reduce the operating cost

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Reality Check/ Opportunities

- High cost elements
  - Well Servicing, Energy and Labor
    - Operating cost doesn't go down in proportion with the oil/gas prices
    - There is no flexibility in changing these prices overnight with reduced oil/gas prices
    - Chances for inefficiencies to creep up within the organization

Planning to be **proactive** and contain the cost is the key for **low cost operations.**

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Examples

- **Example 1 -** Shows a typical decline curve
- **Example 2** - Shows the instability at a very early stage
  - Onset of liquid loading?
  - Our theory
- **Examples 3&4** - Transient simulation for choke management
- **Example 5** - Knowing the behavior from Examples 1 and 2:
  - How do we assess the Inflow performance of a well to understand the well better?
  - Can this methodology be applied for proactive decision making at the field level?

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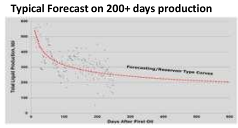
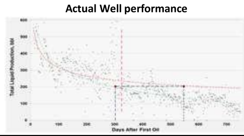
Example - Well 1

- Based on the forecast/ decline curve analysis @200 days, the well is expected to reach 200 BLPD in ~600 days.
- In reality (plot below) it reaches ~300 days
- If Artificial lift change is required at this point (~200 BLPD) , the planning time is less – resulting in increased downtime.

Typical Forecast on 200+ days production



Actual Well performance



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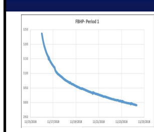
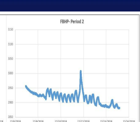
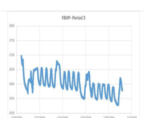
Example – Well 2 Observations/ Challenges







- High Frequency FBHP data at various intervals are displayed (~10 days each)
  - Period 1 – 214 days
  - Period 2 – 235 days
  - Period 3 – 310 days
- What causes these fluctuations?
- What's going on at the heel?
- How is it impacting the Artificial lift/ well performance?
  - Any mitigation strategies?

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Problem: Slugging – Theory & Approach

- Instability and intermittent slugging in horizontal wells are caused in three main regions:
  - lateral section of the well
  - heel of the well
  - tubing section
- Slugging at lateral / horizontal section of well
  - tends to cause fluctuations in the FBHP
  - Is minimal compared to the slugging at the heel
- Most of major slugging effect observed in FBHP fluctuations is attributed to the heel effect.

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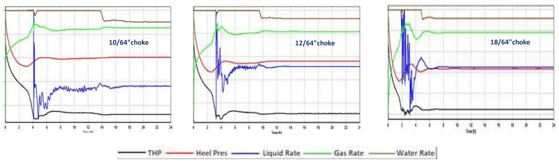
Example – Well 3 Transient Simulation



- 10/64", 12/64", 18/64" → stable production (sweet spot)
- Production becomes stable with 18/64" sooner (varies well by well)

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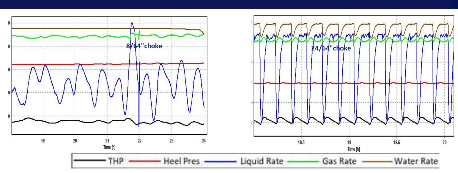
Example – Well 3 Transient Simulation



- 8/64", 24/64" show slugging behavior
  - Sweet spot is in between these choke ranges
- Injecting more gas didn't seem to help with 24/64" choke

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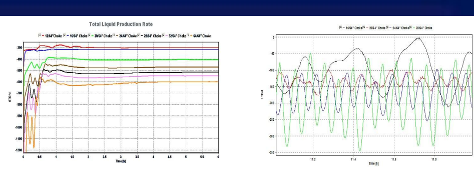
Example – Well 4 Transient Simulation



- Initial Stage (high P_{res} – about 3,200 psi)
  - Higher production could be achieved with larger chokes
- Later Stage (low P_{res} – about 1,700 psi)
  - No steady flow at any choke opening

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Methodology for Unconventional Well Performance
(Inflow Performance at Heel)

- Modeling a Transient IPR
  - How do we define Reservoir Pressure?
    - SRV
    - Matrix
  - Can we shift our node to the heel or end of tubing?
    - Will that be a good proxy?
    - How can that help with artificial lift selection / analysis?

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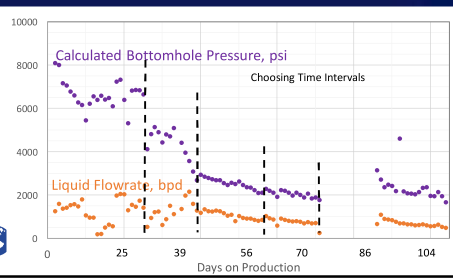
Example – Well 5



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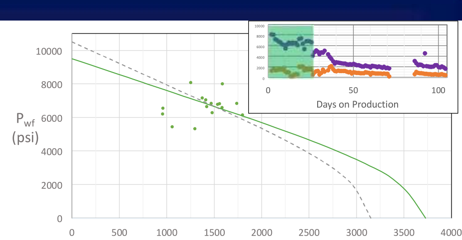
Initial Reservoir Pressure



Initial Reservoir Pressure 9,500 psi Next

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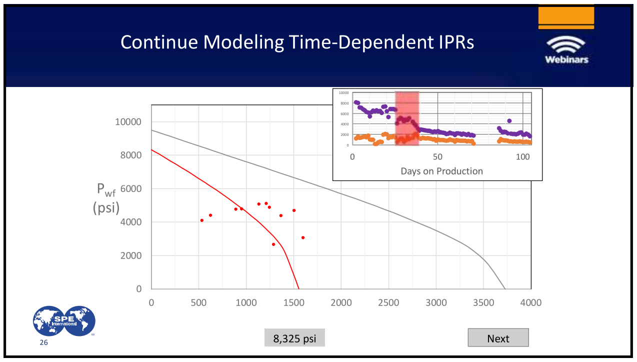
Continue Modeling Time-Dependent IPRs
Webinars
Pwf (psi)
10000
8000
6000
4000
2000
0
0
500
1000
1500
2000
2500
3000
3500
4000
0
50
100
Days on Production
8,325 psi
Next

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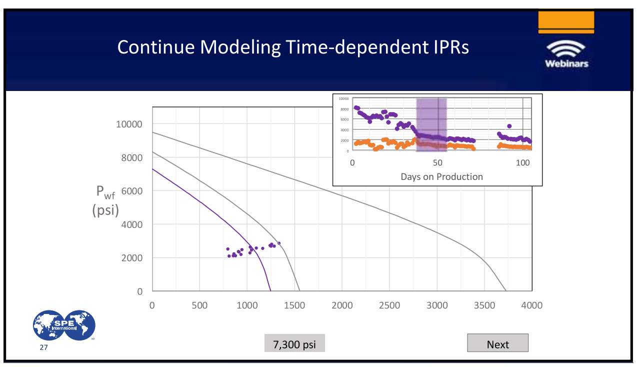
Continue Modeling Time-dependent IPRs
Webinars
Pwf (psi)
10000
8000
6000
4000
2000
0
0
500
1000
1500
2000
2500
3000
3500
4000
0
50
100
Days on Production
7,300 psi
Next

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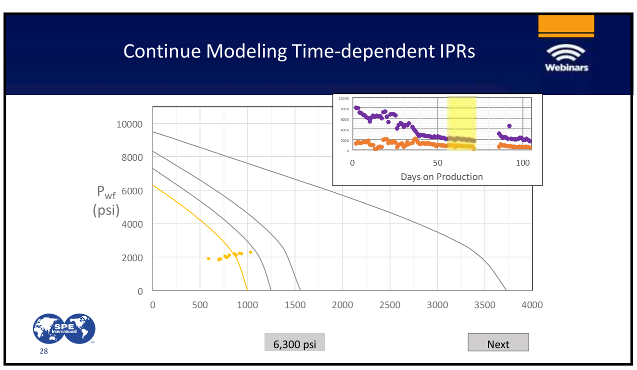
Continue Modeling Time-dependent IPRs
Webinars
Pwf (psi)
10000
8000
6000
4000
2000
0
0
500
1000
1500
2000
2500
3000
3500
4000
0
50
100
Days on Production
6,300 psi
Next

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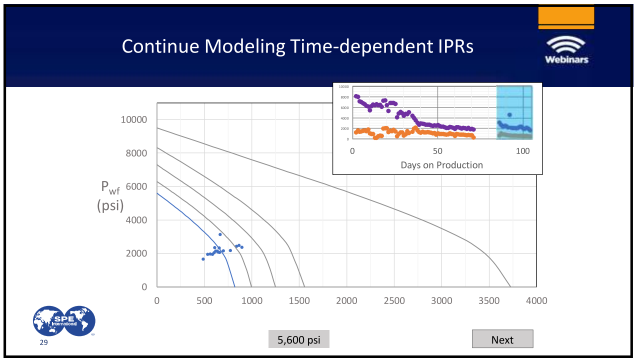
Continue Modeling Time-dependent IPRs
Webinars
10000
8000
P_{wf} 6000
(psi)
4000
2000
0
0 500 1000 1500 2000 2500 3000 3500 4000
0 50 100
Days on Production
5,600 psi
Next
29

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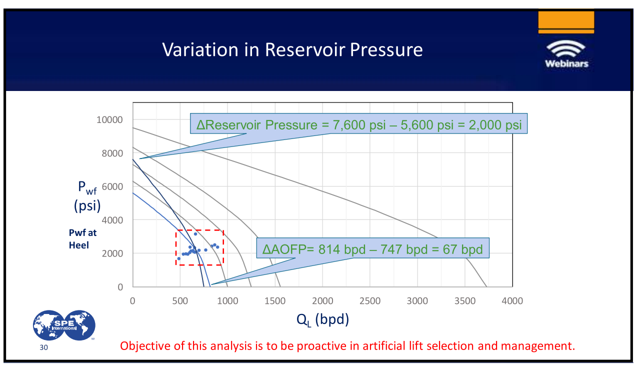
Variation in Reservoir Pressure
Webinars
ΔReservoir Pressure = 7,600 psi – 5,600 psi = 2,000 psi
10000
8000
P_{wf} 6000
(psi)
4000
Pwf at Heel
2000
0
ΔAOFP= 814 bpd – 747 bpd = 67 bpd
0 500 1000 1500 2000 2500 3000 3500 4000
Q_L (bpd)
Objective of this analysis is to be proactive in artificial lift selection and management.
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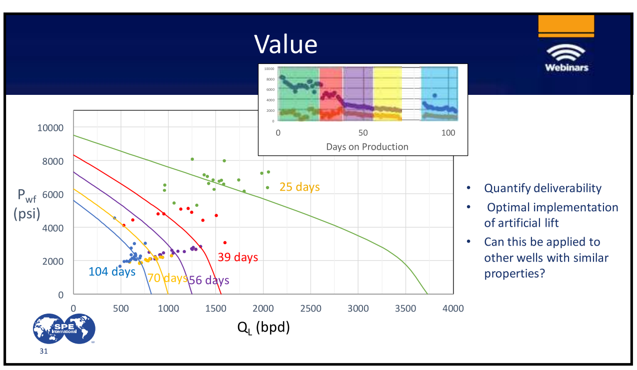
Value
Webinars
0 50 100
Days on Production
10000
8000
P_{wf} 6000
(psi)
4000
2000
0
25 days
39 days
104 days
70 days
56 days
0 500 1000 1500 2000 2500 3000 3500 4000
Q_L (bpd)
• Quantify deliverability
• Optimal implementation of artificial lift
• Can this be applied to other wells with similar properties?
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Well Performance Prediction

- Use historical data to predict a production trend
  - Group wells by peer parameters through clustering
- Determine the well parameters that significantly impact the production life = Peer Parameters
- Analyze which wells are close enough (in terms of peer parameters) to exhibit similar production trends
  - Example : PVT properties play a major role in plays like Eagle Ford

Example- Field 1	Example- Field 2	Example Field 3
Initial Production GOR	PVT Region	Initial Production Volume
Oil API	Fractured Lateral Length	Initial Production Trend
PVT Region	Initial Production GOR	Average Water Cut
Fractured Lateral Length	Total Stages	Fractured Lateral Length
Average Water Cut	Initial Production Volume	Total Stages
Initial Production Volume	Initial Production Trend	
Initial Production Trend	Average Water Cut	

Understanding and defining the primary drivers for every field or group is key.

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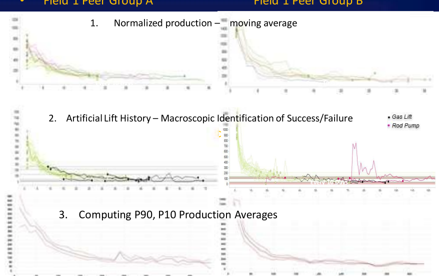
Predicting Rates – Peer Grouping Process

- Field 1 Peer Group A Field 1 Peer Group B



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Onshore - Unconventional

- No basic changes in artificial lift in decades
  - Technological improvements ongoing
- Unconventional field development is so fast-paced that not much time is taken for R&D
  - Most wells in the Delaware Basin would be rod pump candidates in the first 6 years of their life
  - Horizontal wells drilled in pads (deviated or S–shaped) have more challenges with the rods than vertical wells
  - This reduces the MTTF (mean time to failure)
  - With 1000's of wells drilled each year, at some point there will be a huge need for the same artificial lift method
    - Are we prepared for the supply?
    - Are the vendors ready?
  - Assuming rod pumps, even with the best failure rate, how will the MTTR be managed? How will that affect downtime?

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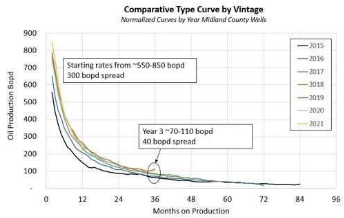
Type Curve



Comparative Type Curves in Midland County for Recent Vintage HZ Unconventional Wells[7]

Source: Enverus; Laura Freeman

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Opportunities - Onshore (Unconventional)

- Onshore (Unconventional) optimization is a strategic play
  - High well count
  - Low well productivity
- Industry studies show that workflow of proactive management has more opportunities:
  - Reduces the downtime by 5% - 10%
  - Increases production by 5% - 15%
  - Reduces lifting cost by 5% - 15%
  - Improves efficiency and fuel savings in engines
  - Reduces capital expenditure

15% – 40% Opportunity

3% downtime = $1.5 B production loss
(Permian Basin daily oil production rate of 2.73 MMBO at $50 oil price used)

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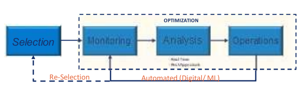
Holistic Artificial Lift Optimization (HALO) Cycle

- HALO cycle is a process that could help the artificial life cycle along with wells' performance.



- The key components of this integrated artificial lift solution include:
  - Process
    - Selection of artificial lift system
    - Well Performance (Optimization)
  - Knowledge, Expertise, and Training
  - Technology
    - Artificial lift systems
    - Automation

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Data Science / Digital oilfield

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- Millions of data points collected from a field on an annual basis
- How are the data leveraged / converted into information?
- Digital oilfield
  - Keep it simple

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Why Digital oilfields Fail?

Source: Luigi Saputelli

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- Common misconception is to believe that the project is finished when the system goes live. This is just the beginning.
- Considered upgrade and not a necessity
- Seen as additional work
- Little time dedicated to understand reservoir, wells and surface issues
  - Jumping straight in to implementing solutions to automate current process, and there is little time dedicated to understand the fundamental problem. For example, if production is declining, production will not increase just by adding monitoring or smart surveillance.
- Understanding and narrowing down the objective is key

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Conclusions/ Take away

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- Artificial lift challenges are around reducing downtime
- Understanding well performance is key
- An integrated strategy to implement artificial lift life cycle management should be considered from the development stage
- For an integrated Digital oilfield solution, keep it realistic

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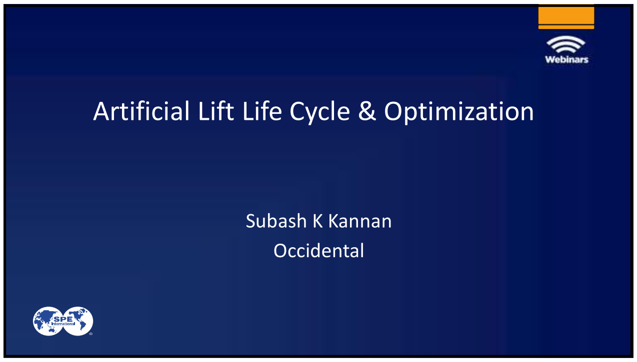
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