Creating a New Well Control Paradigm
MPD Dynamic Influx Control

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Outline

- Introduction
- Managed Pressure Drilling
  - Benefits of Managed Pressure Drilling
- Current Well Control Options
  - Limitations and Constraints
  - Secondary Well Control problems
- Dynamic Influx Control vs. Conventional Well Control
- Alternatives for Enhancing Well Control
- MPD Operations Matrix
- Issues/Limitations of MPD Influx Control
- Conclusions

Introduction

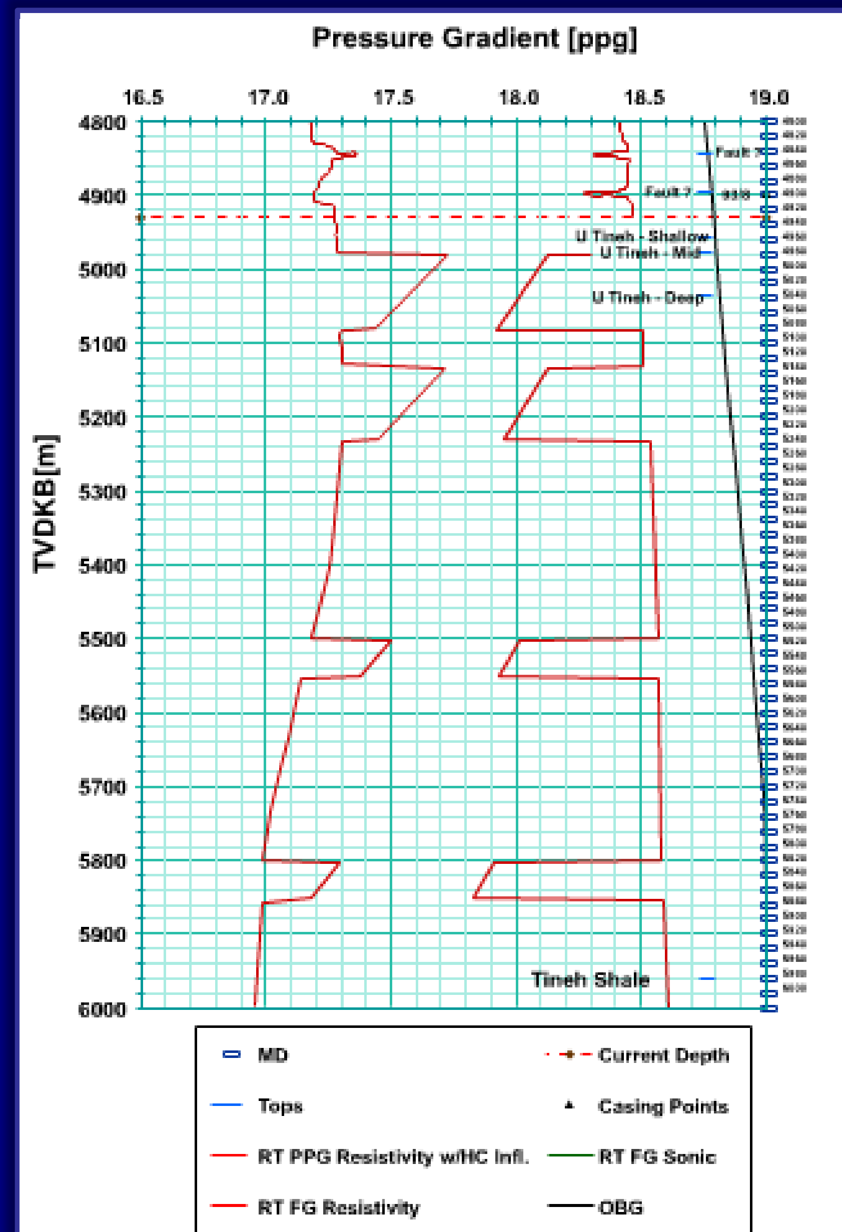
- MPD Definition as per IADC:

  'Managed Pressure Drilling (MPD): an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. It is the intention of MPD to avoid continuous influx of formation fluids to the surface. ***Any influx incidental to the operation will be safely contained using an appropriate process****.'*

- Benefits from MPD on influx control are significant, but perhaps not fully understood by operators and drilling companies
- MPD opens new possibilities on influx control

Why MPD?

- Enables Drilling where not possible Conventionally
  - Drill through narrow windows, otherwise impossible to drill conventionally
    - Natural fractures/Pressure Regressions/HPHT
    - Constant Bottom Hole Pressure through drilling, connections and other operations
    - Reduced probability of lost returns / influxes / cross flow



Why MPD?

- Improves Efficiency and reduces NPT
  - Reduction in NPT
    - Wellbore Instability, Ballooning, Losses
  - Increases length of hole that can be drilled
  - Improves Hole Cleaning
  - Improved ROP
  - Decreased formation damage
- Adds New Degrees of Freedom
  - Dynamic Pressure mapping
  - Dynamic LCM treating
    - Allows PWD During Operation

Improved Safety through MPD

- Enhanced Early Kick Detection
- Dynamic Influx Control
  - Ability to manipulate pressures instantaneously
  - Higher circulation rate
- Ability to keep pipe moving throughout the kill
- Elimination of ballooning and formation cycling
  - Constant pressure on open hole formations

So the question is, given we are catching an influx (kick) at gallons resolution, what do we do when we do detect a kick during MPD?

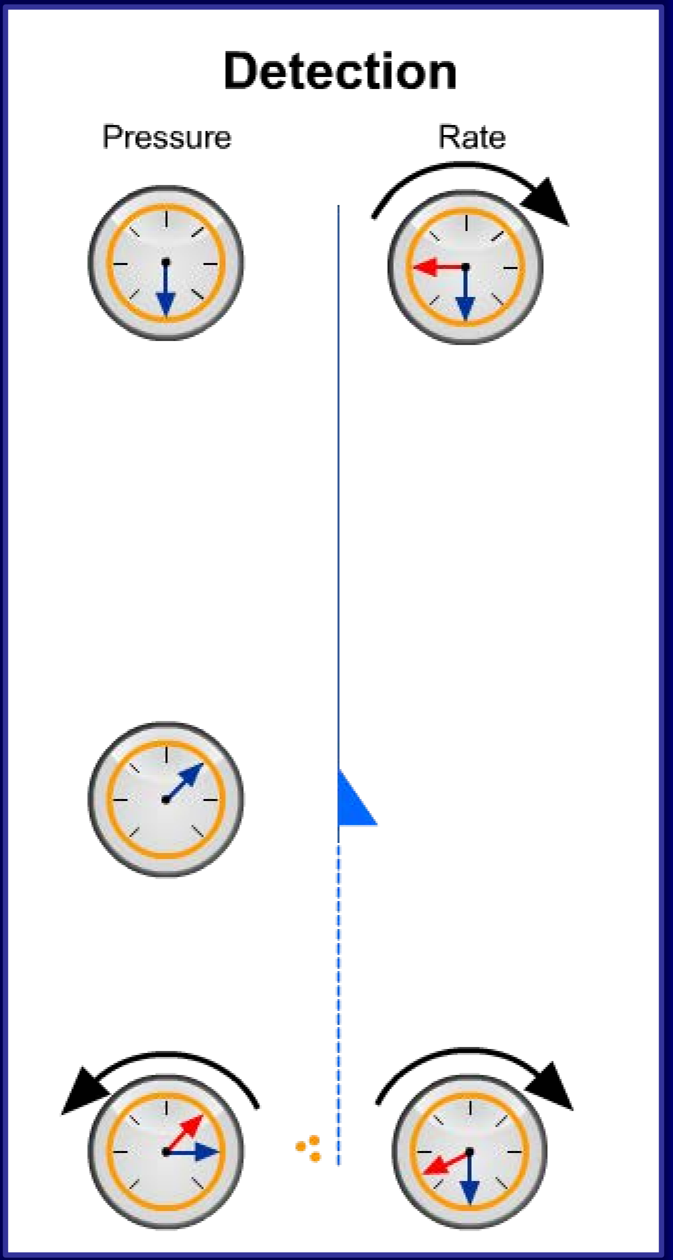
Conventional Well Control

- Constant Bottom Hole Pressure
  - Driller's method
  - "Wait and Weight"
  - Concurrent
- Alternative Well Control methods
  - Bullheading
  - Volumetric

Common current practice when influx detected, even with MPD, is to revert to conventional well control!!

Conventional Well Control

	Time Sec.	BHP	Qinf	Kick Volume
Detection	?	Pr>Pa	↑	↑



Kick Detection hampered by:

- Vessel movement
- Flow back on connections

Pr is reservoir pressure,
Pa is the bottom hole annulus pressure.

Conventional Well Control

	Time Sec.	BHP	Qinf	Kick Volume
Detection	?	Pr>Pa	↑	↑
PU/SO/ Pumps off	15 – 60	Pr>>Pa ↓	↑	↑↑

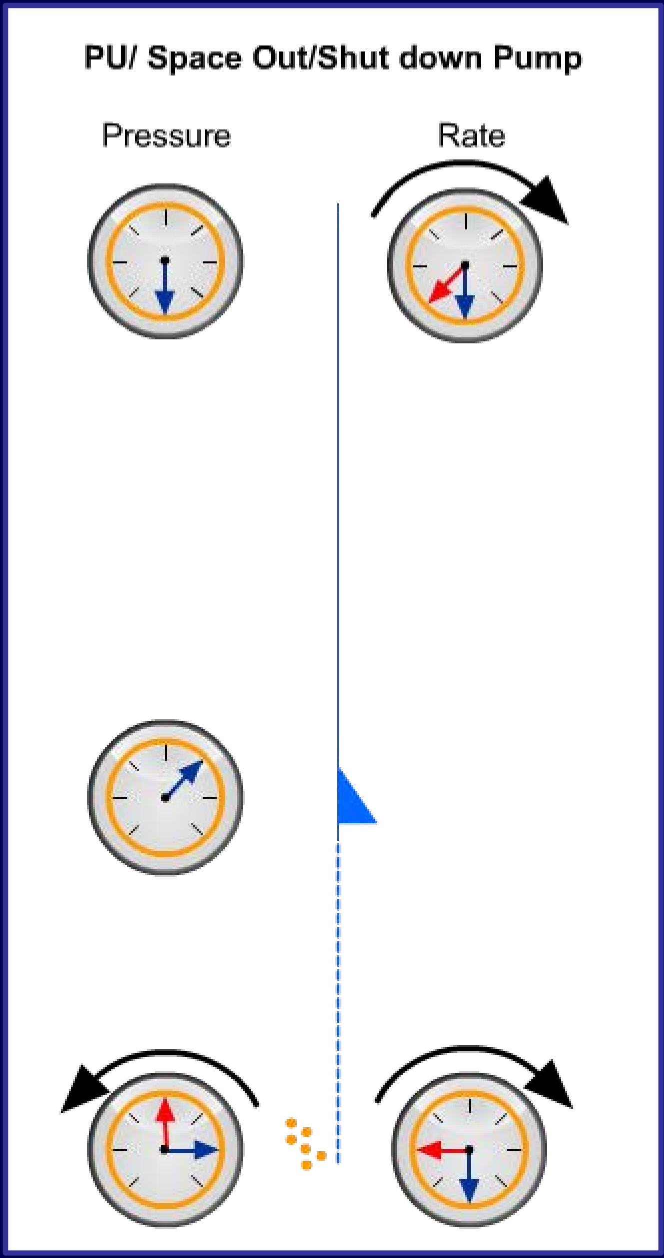
PU and shutting down Pumps Reduces BHP:

- Increases Influx Rate

Influx lowers BHP

- Increases Influx Rate

Loss of PWD when pumps are brought down

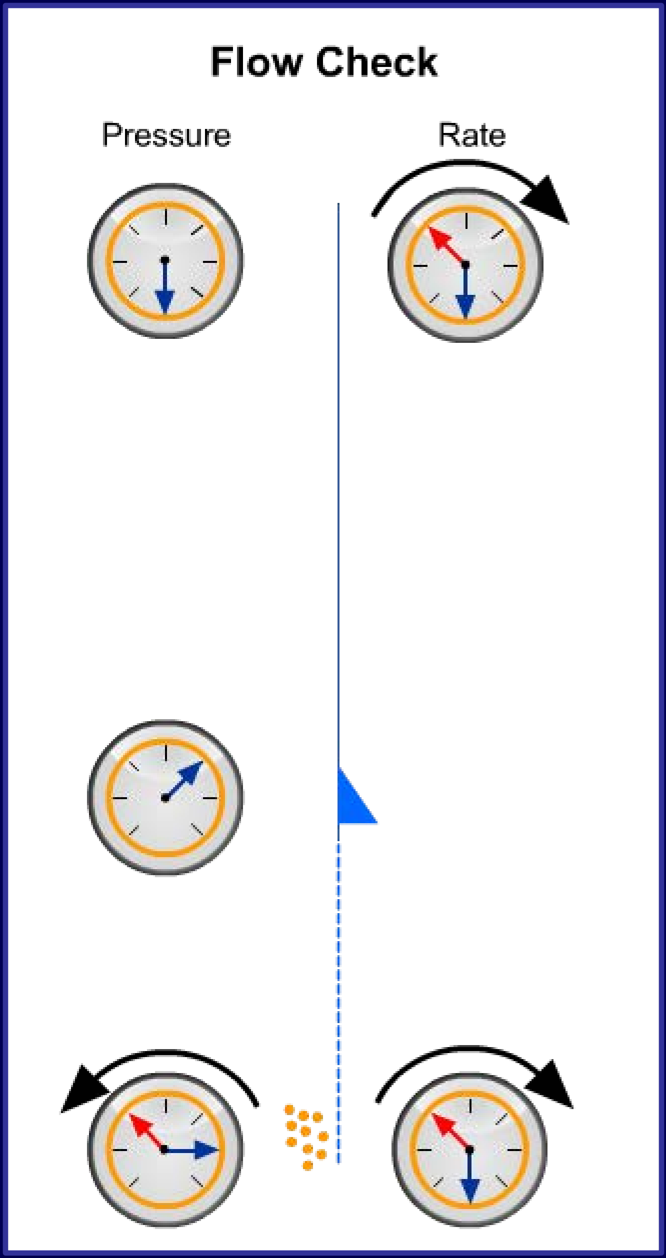


Conventional Well Control

	Time Sec.	BHP	Qinf	Kick Volume
Detection	?	Pr>Pa	↑	↑
PU/SO/ Pumps off	15 – 60	Pr>>Pa ↓	↑	↑↑
Flow Check	30 – 120	Pr>>Pa ↓	↑	↑↑↑

BHP continues to drop with Influx

- Increasing Influx Rate



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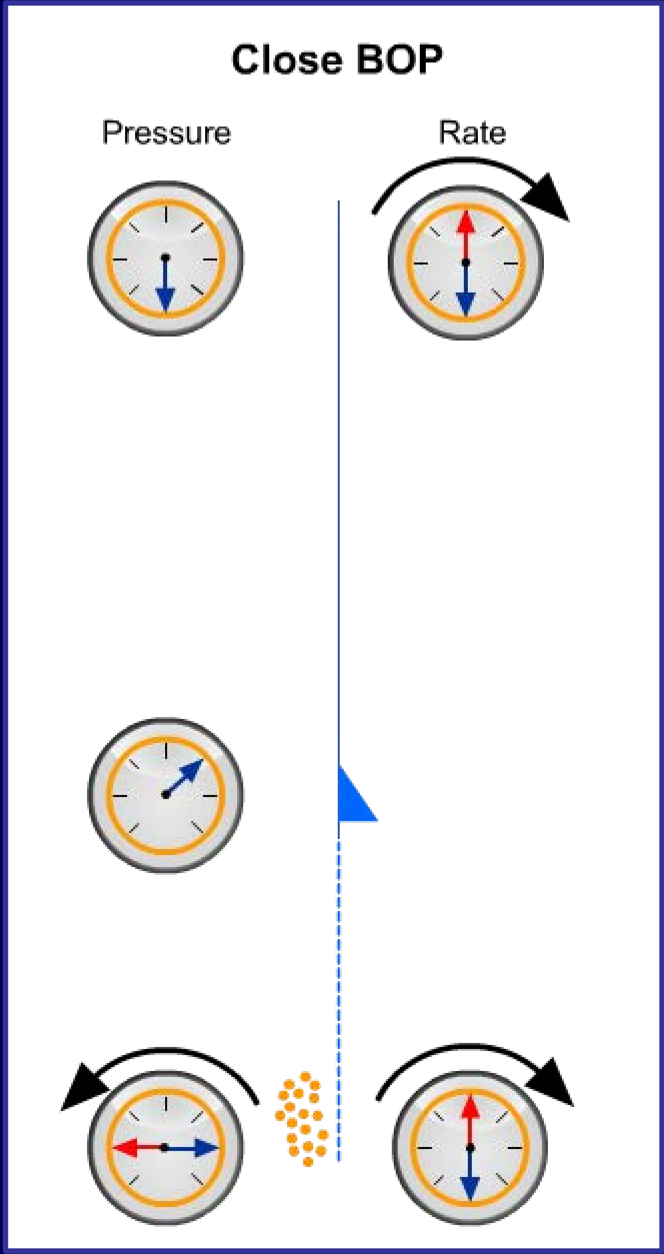
Flow Check	30 – 120	Pr>>Pa ↓	↑	↑↑↑
Close BOP	30– 45	Pr>>Pa ↓	↑	↑↑↑↑



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Conventional Well Control

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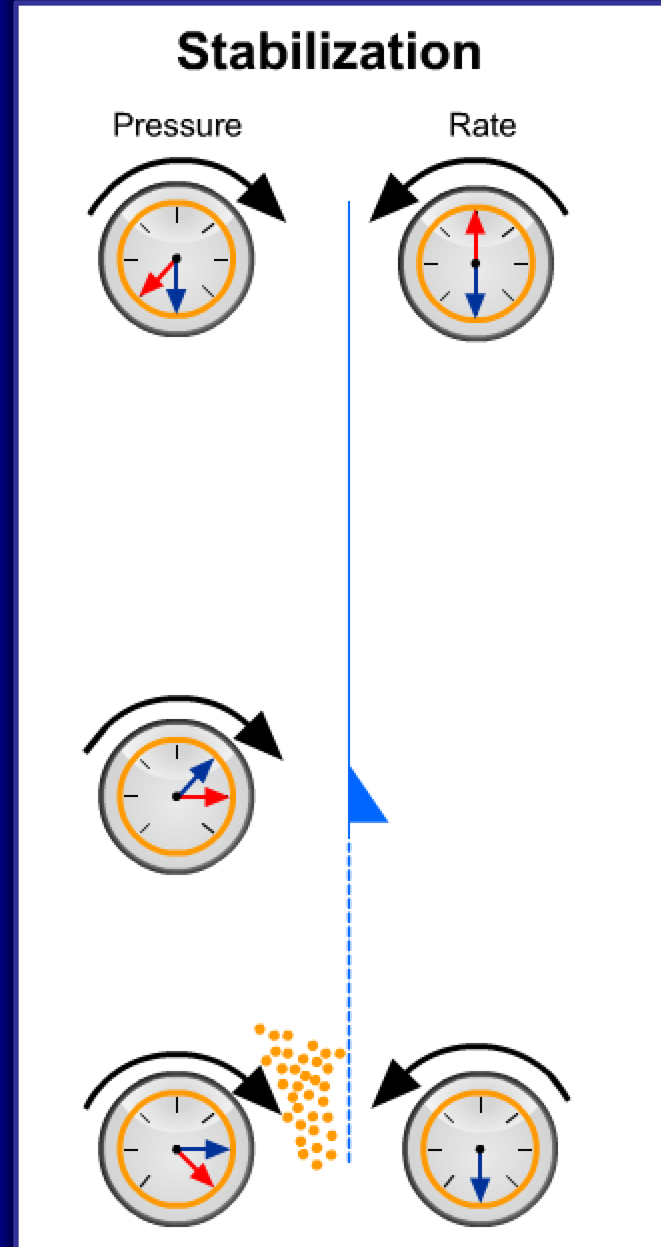
Flow Check	**30 - 120**	**Pr>>Pa** ↓	↑	↑↑↑
Close BOP	**30- 45**	**Pr>>Pa** ↓	↑	↑↑↑↑
Stabilization	**1200 - 3600**	Pr=Pa ↑	0 ↘	↑↑↑↑↑



So you have shut the well in. Have you stopped the kick?

Influx Continues until BHP reaches Reservoir Pressure

- Decreasing Influx Rate
- Concentration of Influx

Issues With Current WC Practices

- Influx continues *until reservoir balances itself*
  - Passive Well Control
- Slow Circulation Rate (SCR) Required
- Ballooning and Losses
- Lost Pressure While Drilling (PWD)
- Choke Control when Liquid to Gas/Gas entering Choke/Choke Lines.
- Pump Start up and Shut Down
- Second Circulation is normally required

Additional Complications with Deepwater Well Control

- High Choke Line Friction Pressure (CLFP)
  - Extended time for well control event
- Vessel Movement
  - Average kick size over 50 bbls
- Rig policies
  - No pipe movement
    - Possibility of stuck pipe
- Pressure Fluctuations
  - Pump Start ups and shut downs (CLFP)
- Low Shoe Strength

Kick Statistics in Deep Water

- Average Time for Control 2.16 Days
- Increases with Secondary Problems[1].
  - Ballooning/Losses (26%)
    - Increases time, risks and complexity
  - Stuck Pipe (14%) – 4.39 days
    - 45 % result in sidetrack
    - Additional 9 days per well
  - Hydrates (4%)

[1]*ES201252, Reliability of Deepwater Subsea BOP Systems and Well Kicks*

Well Control vs Influx Control

- Conventional definition of Kick
  - '*Unplanned, unexpected influx of liquid or gas from the formation into the wellbore, where the pressure of fluid in the wellbore is insufficient to control the inflow. If not corrected can result in a blowout.*'[2]
  - As generally understood, it requires use of secondary barrier envelope to control
- MPD approach
  - An influx that can be safely circulated using the MPD equipment (Primary Barrier) would **not** constitute a kick
    - Influx must be within certain limits (volume, intensity, etc.)
    - Staying within primary barrier
    - Only if secondary barrier envelope is required, would it be considered a kick
  - This opens the possibility of safely controlling influx dynamically!
    - Question is: When is this possible? And how is it done?

Point to ponder: Do we shut well in for connection gas?

[2] *IADC UBO & MPD Glossary*

MPD Dynamic Influx Control

- MPD circulation of an influx out of the well
  - Conceptually the same as first circulation of Driller's method
    - Maintain constant BHP while circulating out influx
  - Circulate at drilling pump rate
    - Adjusted for MGS capabilities
    - Maintains PWD during circulation
  - Eliminates or reduces Start up/ Shut down pressure fluctuations
  - May Eliminate Need for Second Circulation

Benefits of MPD on Influx Control

- Eliminates of the impact of floater rig movement on influx detection
  - Fixed volume container
- Smaller influx in the wellbore
  - Allows safer and earlier return to planned operations
- Lower Peak Pressures at exposed Shoe
  - Reduces probability of losses
- Lower peak pressures and % Free Gas
- Saves significant time
  - Higher Circulation rates
  - Significant cost saving from reduced NPT

- Overall, reduced probability of loss of well control
- 1 in 2,870,000 vs 1 in 6,100[3]

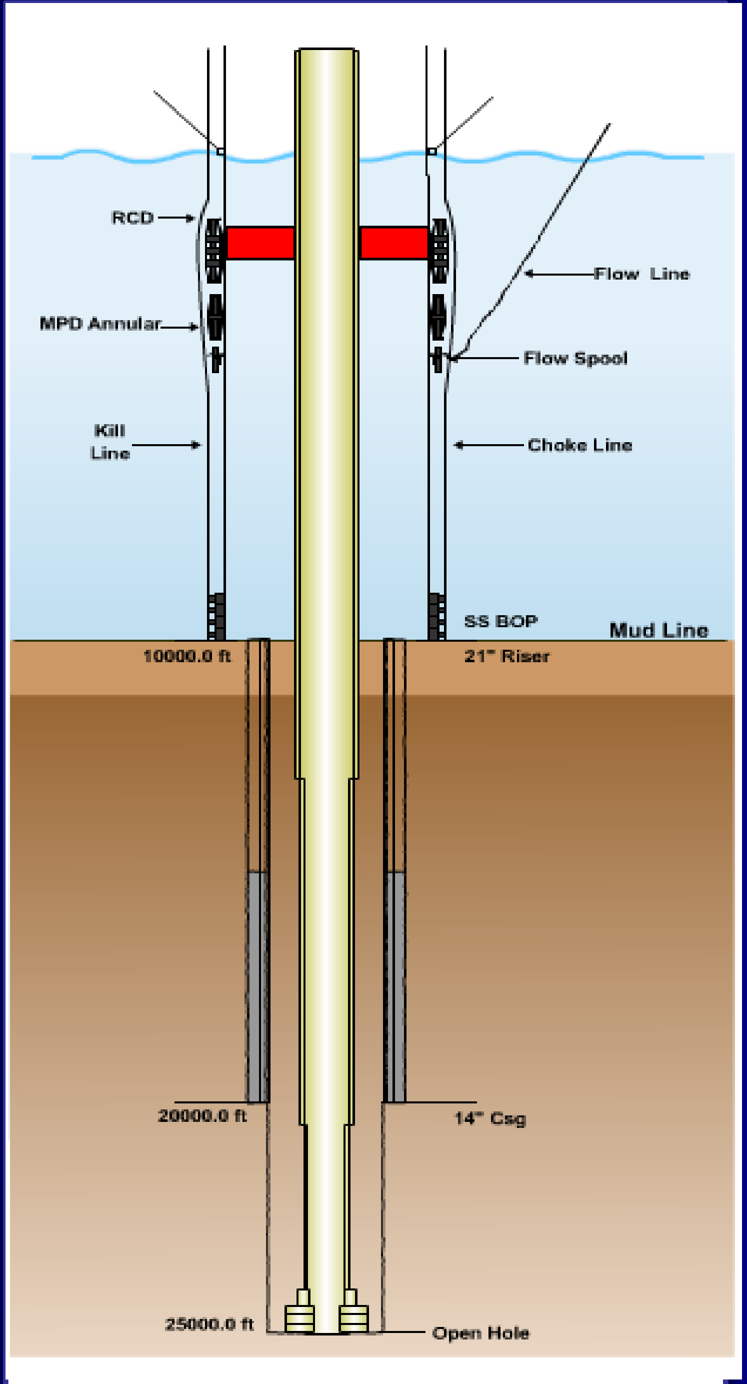
[3]Grayson and Gans, SPE 156893

MPD Dynamic Influx Control

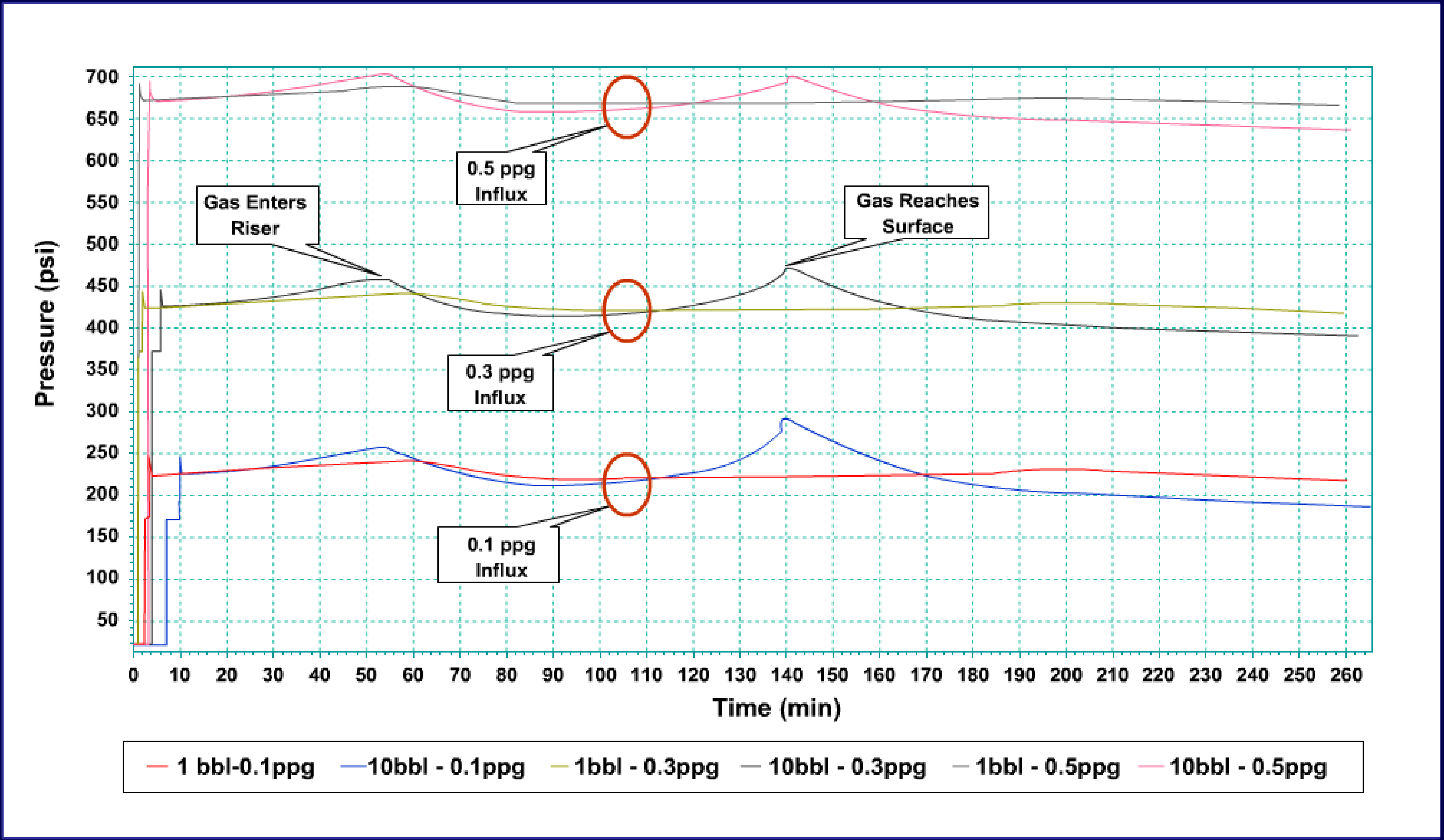
- Summary of well control options when using MPD
  - Fully dynamic influx control
    - Results is smallest influx, fewest pressure fluctuations, and shortest time for entire well control process
  - ASBP with conventional shut-in, followed by dynamic circulation
  - ASBP with conventional shut-in, followed by conventional circulation
  - Fully conventional well control
    - Results in largest influx, the largest pressure fluctuations, and the longest time for the entire well control process

How Does it Look?

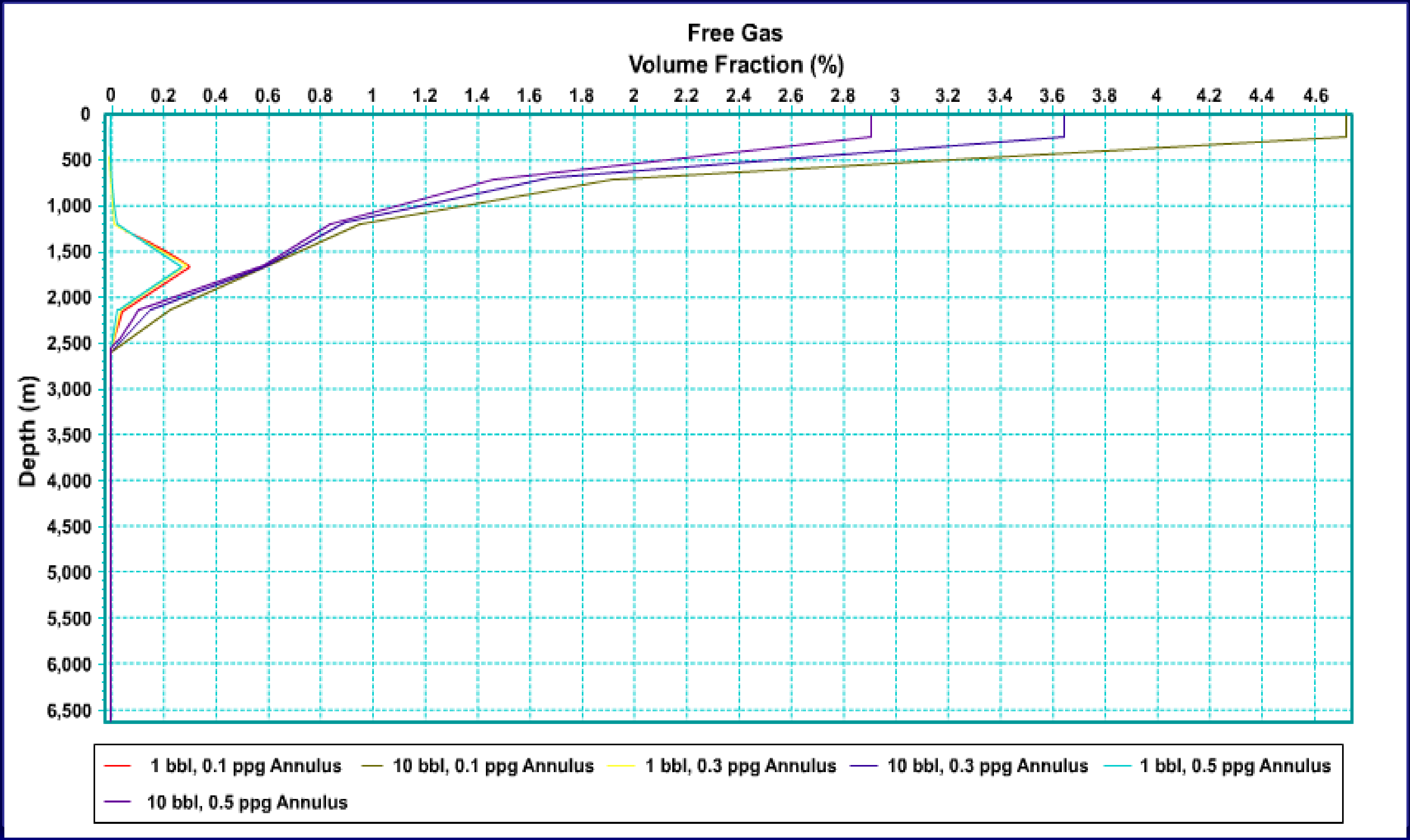
- **Assumptions**
  - Influx Detection – 10 bbl
  - Influx Intensity – 0.5 ppg
  - Dry Gas
  - Permeability - 100 md
  - Water Depth – 10,000 ft
  - Shoe Depth - 20,000 ft
  - Influx Depth – 25,000 ft



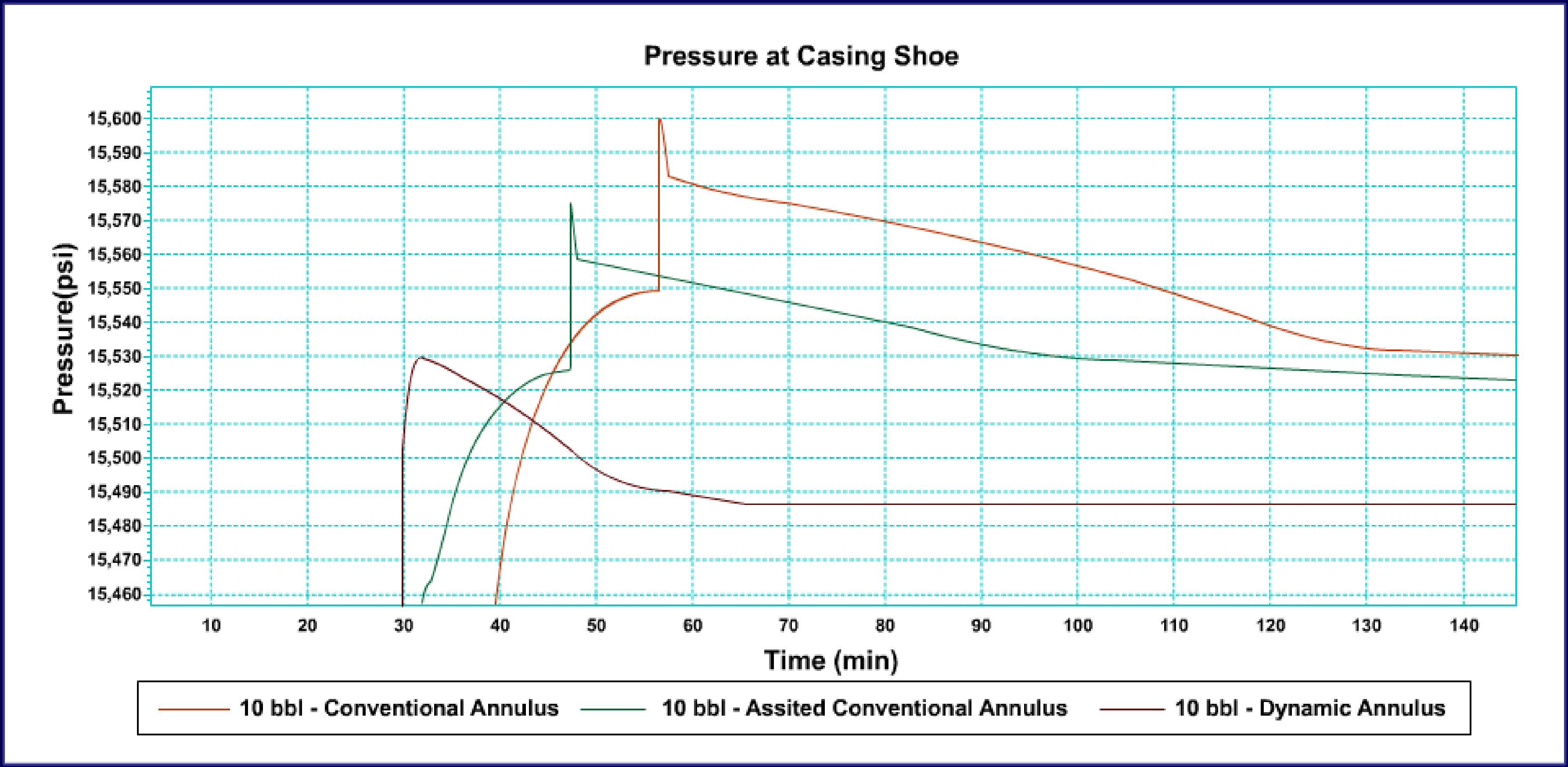
MPD WHP during Influx Circulation



MPD Free Gas during Influx Circulation

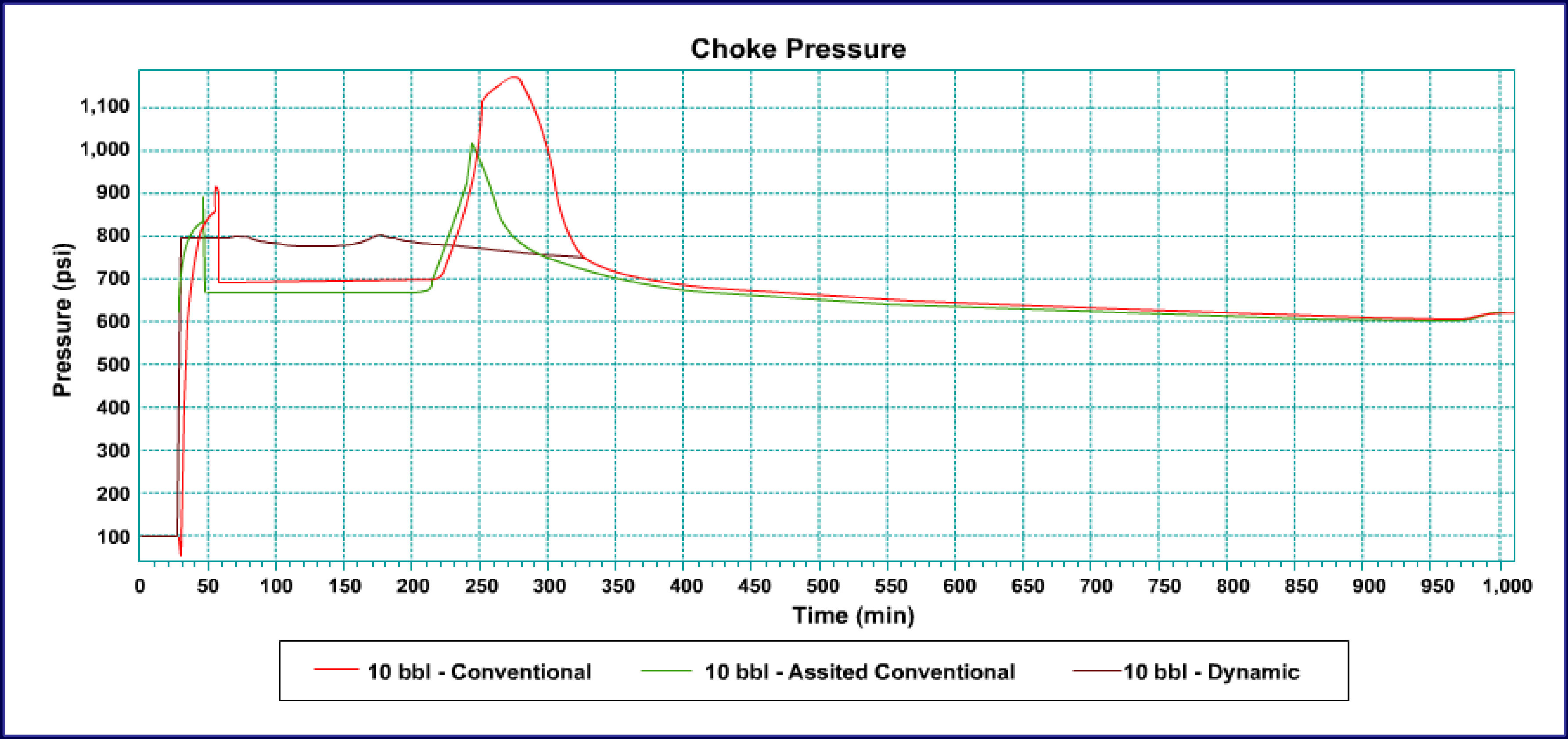


Impact on Pressure at Shoe



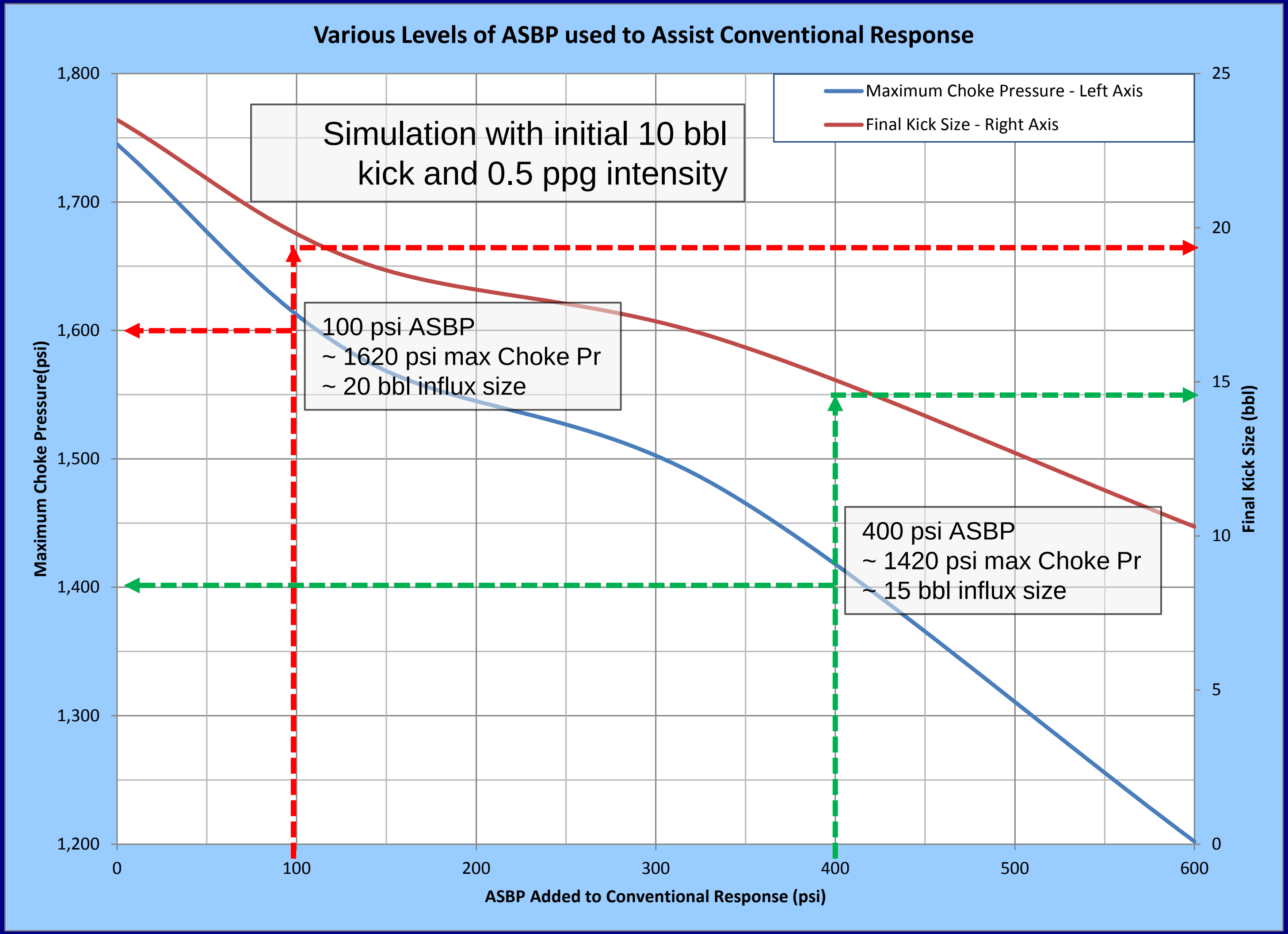
- Significant reduction in Maximum Pressure at Shoe
  - Smaller influx
  - Greater dispersion of influx (higher circulation rate)

Impact on Choke Pressures and Time



- Significant Reduction on Maximum Surface Pressures
  - Smaller Influx
  - No Lengthening in Choke Line
- Significant Reduction in Time

Assisted Conventional Shut-In



- Addition of ECD for Pump Shut Down
- Addition of Pressure to Stop Influx
- Addition of Pressure to Equipment Limits

Influx Control Options

Detection (10 bbl Pit Gain, 9.5 bbl Downhole)

Conventional

PU/SO/PO
T = 0.5 min
Qin = 3.8 ft^3/min
V = 9.8 bbl Downhole

Close BOP
T = 1.7 min
Qin = 3.9 ft3/min
V = 10.7 bbl Downhole

Stabilize
T = 24 min
V = 13.7 bbl Downhole

Gas to Surface
T= 222 min
Peak Pressure = 1,174 psi
Qout = 333 scfm

Gas from Well
T = 983 min

Assisted

ASBP/PU/SO/PO
T = 2.4 min
Qin = 0.1
V = 9.9 bbl Downhole

Close BOP
T = 3.1 min
Qin = 0.3 ft3/min
V = 9.9 bbl Downhole

Stabilize
T = 17.5 min
V = 10.2 bbl

Gas to Surface
T = 215 min
Peak Pressure = 1,019 psi
Qout = 258 scfm

Gas from Well
T = 973 min

Dynamic

ASBP/PU/SO
T = 1.9 min
Qin = 0
V = 9.9 bbl Downhole

Gas to Surface
T = 176 min
Peak Pressure = 805 psi
Qout = 547 scfm

Gas from Well
T = 298 min

MPD Operations Matrix

- Defines the acceptable limits for Dynamic Influx Control
  - Equipment Limitations
    - Surface Equipment
    - MGS
    - Riser
- Mandated by BSEE for surface BOP stack MPD applications
- Also used generally by operators for MPD projects outside BSEE regulated area

<table>
<tr><th colspan="2" rowspan="2">MPD Operating Matrix</th><th colspan="4">Surface Pressure Indicators</th></tr>
<tr><th>Max Planned Drilling Operating Pressure</th><th>Max Planned Connection Back Pressure</th><th>>Planned Back Pressure<Back Pressure Limit</th><th>>Back Pressure Limit</th></tr>
<tr><td rowspan="4">Influx Indicator</td><td>No Influx</td><td colspan="2">Normal Operating Window</td><td>Dynamic Influx Control</td><td rowspan="3">Conventional Well Control</td></tr>
<tr><td>Operating Limit</td><td colspan="3">Dynamic Influx Control</td></tr>
<tr><td><Planned Limit</td><td colspan="3">Dynamic Influx Control</td></tr>
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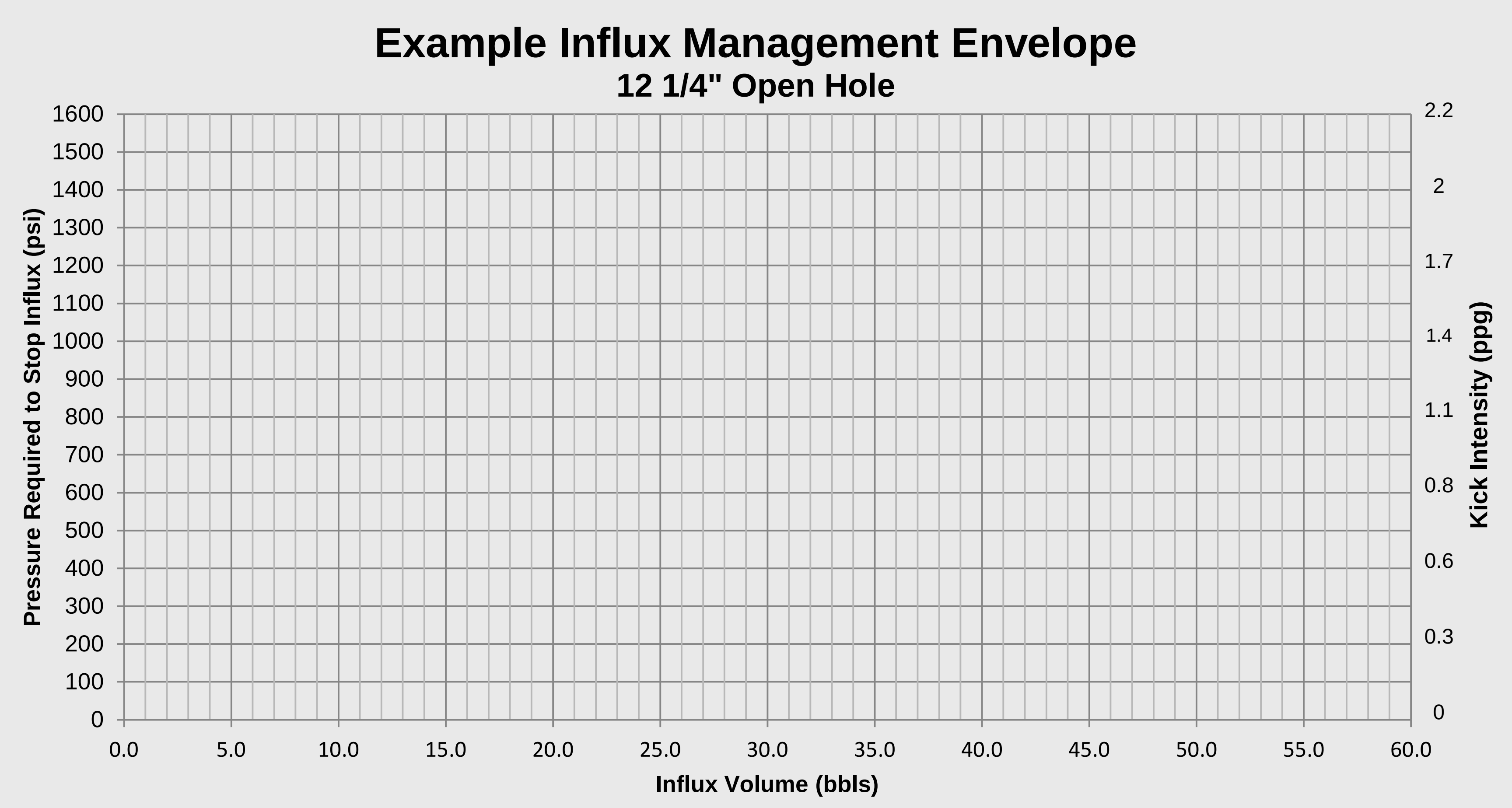
Influx Management Envelope



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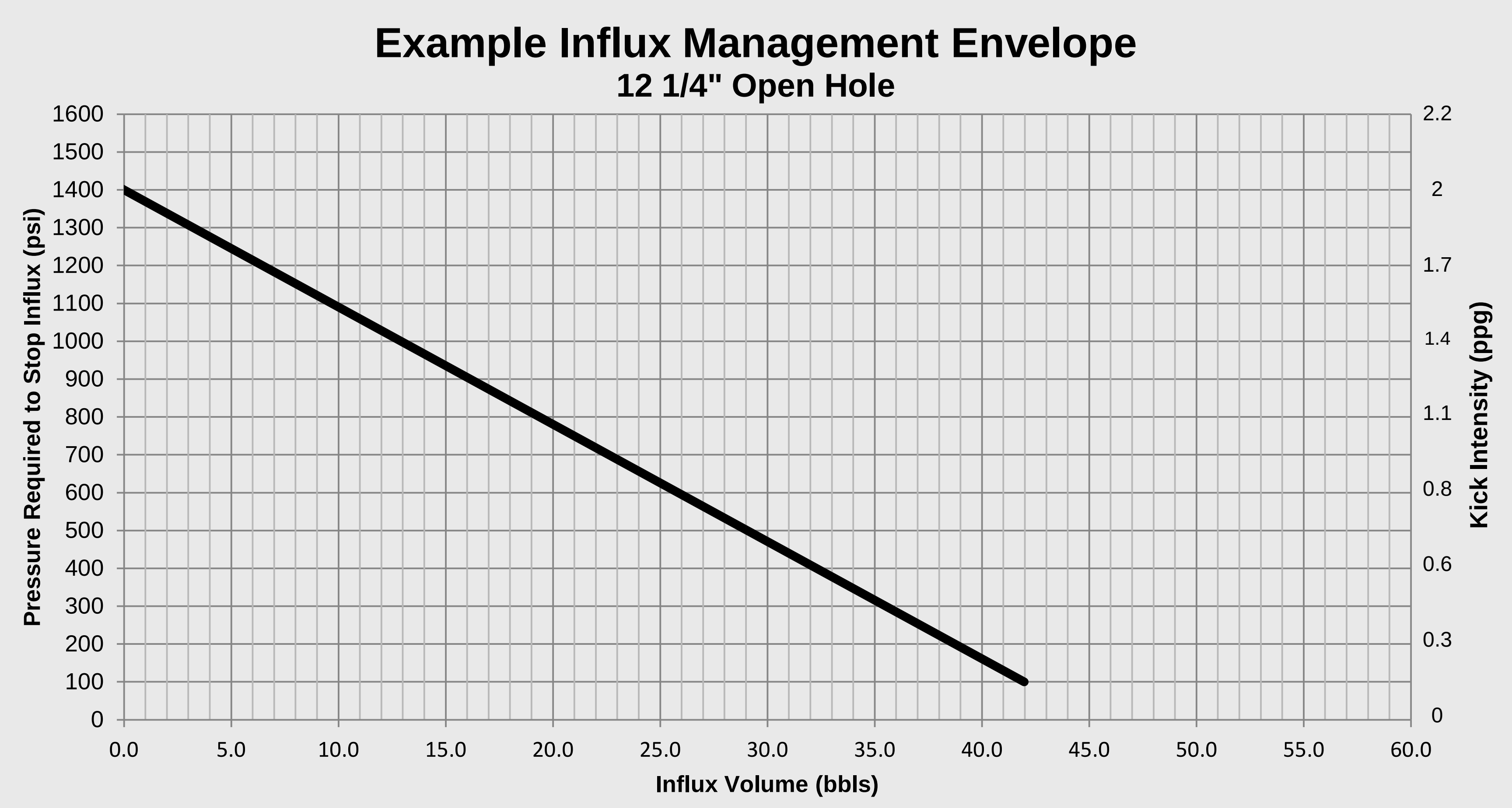

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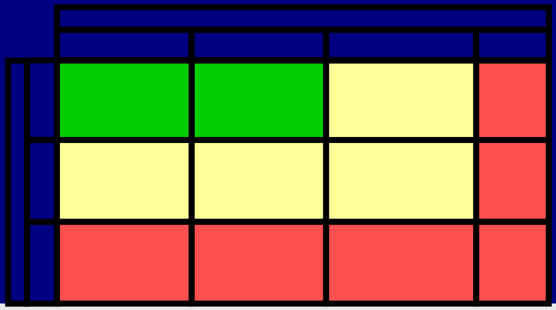

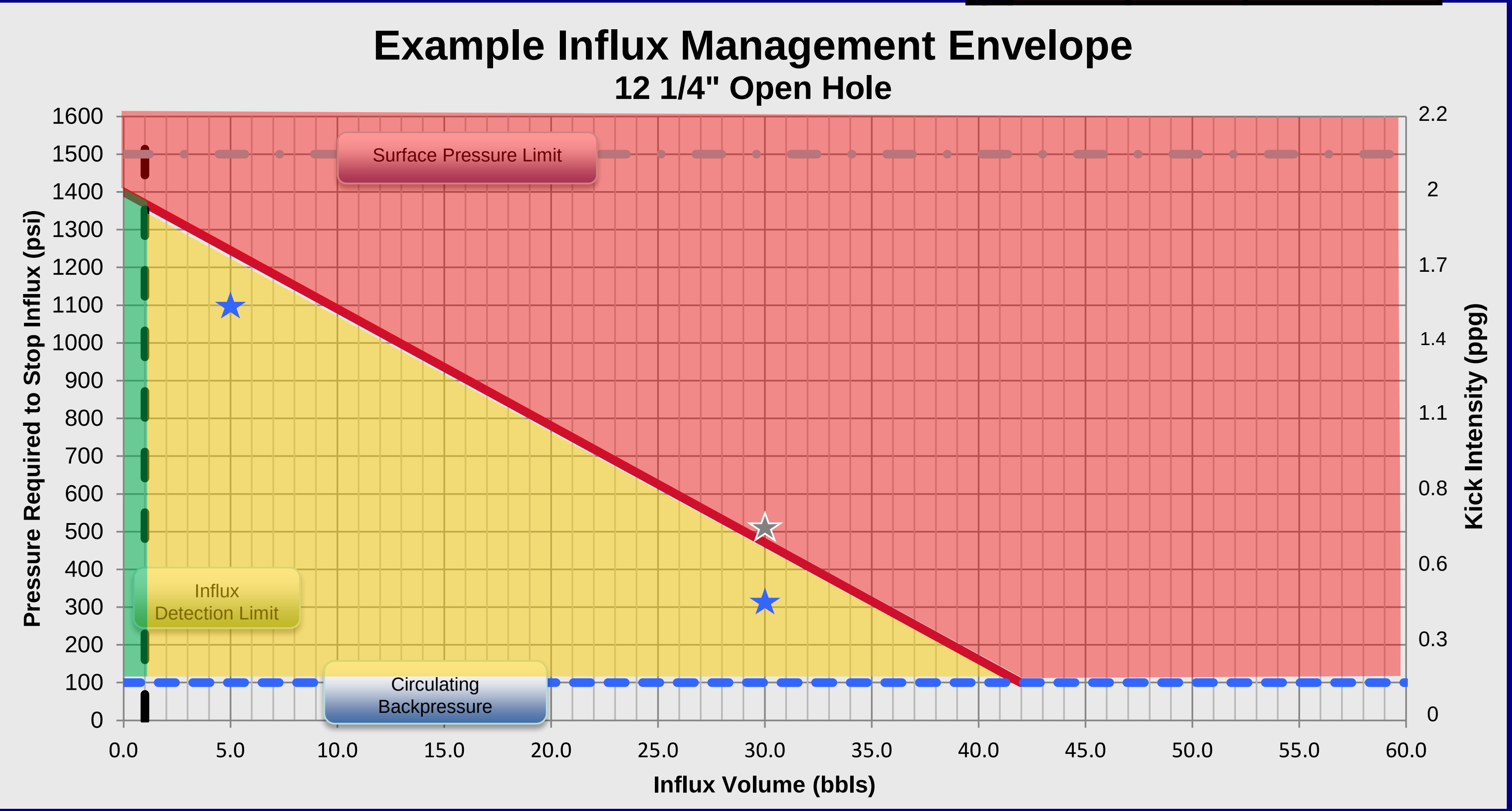

Limits and Challenges

- Breaking the current WC Paradigm
  - Industry Acceptance
  - Acceptance with Regulatory bodies
  - Company Policies
    - Bridging Documents
- Liability / Accountability
- Operating Matrix
- Verification that BHP is balanced
- Determining rate to increase pressure
- Confidence and Competencies (Training)

Broadening the Future

- Riser Gas Handling Capabilities
  - Currently only diversion
  - RGH systems allow controlled handling
  - Protection of crew due to near surface gas breakout
- Trapping Kick in Riser
  - Dynamically circulate influx into Riser
  - Close SSBOP
    - Isolates Influx from OH as influx reaches Surface
    - Isolates OH from pressure fluctuations

Conclusions

- Kicks defined the same for MPD and Conventional – an unplanned, unexpected influx of formation fluids
- Dynamic Influx Control Mitigates many of the current problems with Conventional Well Control.
  - Utilizes Primary Barrier
  - Improves Safety
  - Reduces Secondary Problems
  - Reduces Time and Cost
- An influx which exceeds the capacity of the MPD system is characterized as a kick **and must be controlled conventionally**
  - Use of the secondary barrier envelope.
- MPD equipment increases flexibility in bringing wells back under control.

Taking advantage of MPD capabilities creates a new paradigm for well control