SAND2010-6403P

# Well Integrity During Shut – In Operations: DOE/DOI Analyses

August 31, 2010

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# Report Outline

- Issues to be Addressed
- Background
- Geologic Conditions
- Wellbore Flow Conditions
- Conclusions and Recommendations

# Issues to be Addressed

- Are geologic conditions conducive to an uncontrolled broach to the sea floor during shut in, assuming a lack of well integrity?
- Can well integrity be assessed by pressure measurements during a shut in?

# Risk Management Recommendation

## Recommended Shut-In Protocol

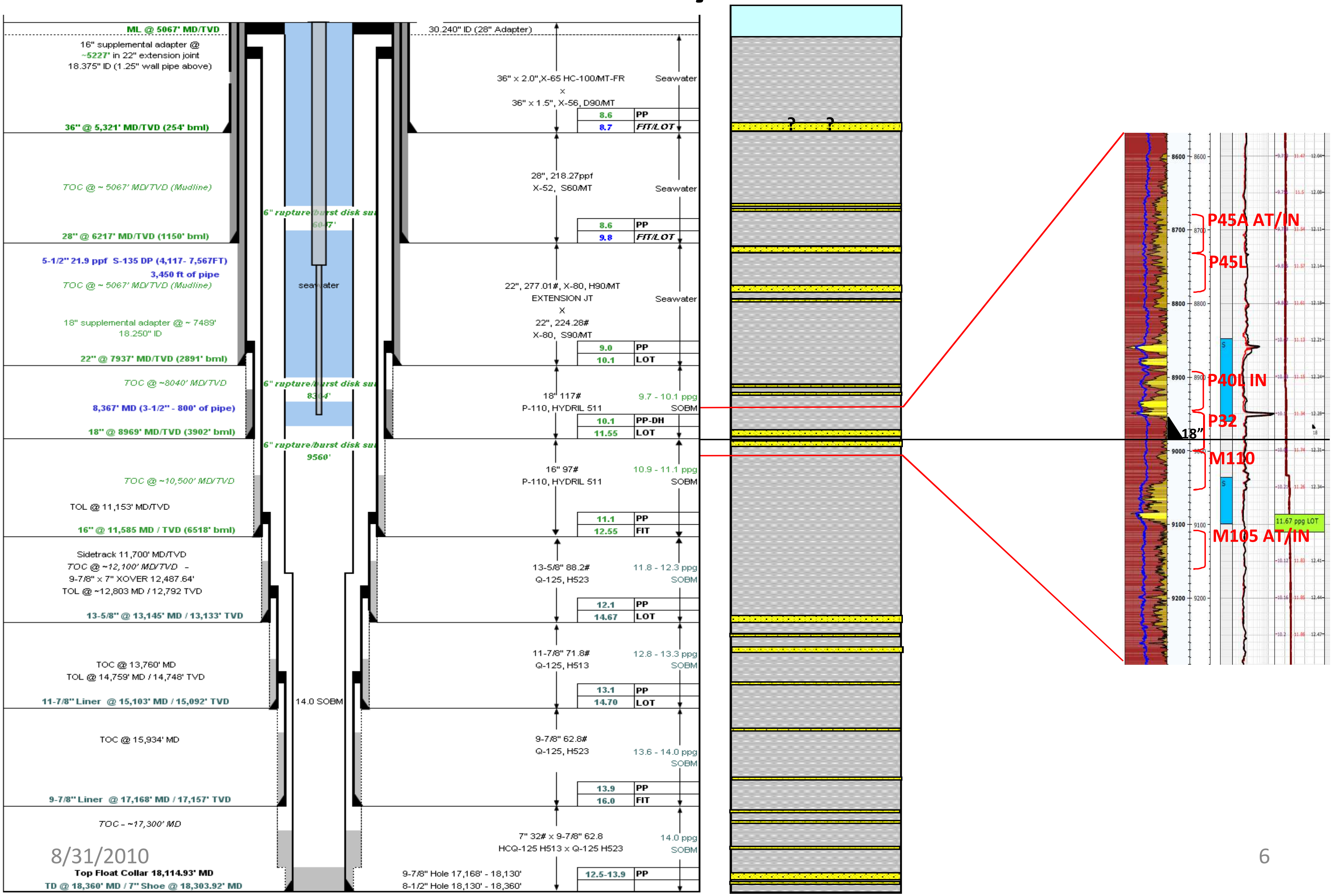
| | Short Duration | Mid-Duration | Long Duration |
|---|---|---|---|
| P > 8000 psi | | | |
| 8000 psi < P < 6000 psi | | | |
| P < 6000 psi | | | |

– Green: Risk is low.
– Yellow: Risk is moderate to high.
– Red: Risk is unacceptable.

If wellhead pressure during test stabilizes at < 6000 psi then test should be immediately terminated.

# Background

# Reference Geometry -Below Mudline



# Advantages of Installing Well Cap

- Well cap will allow full capture of hydrocarbons.
- Well cap has capability of shutting in well at seafloor.
- Well cap provides back pressure, which is beneficial to kill and cement operation.
- Well cap provides new capabilities for quick disconnect as hurricane approaches.

# Possible Shut In Durations

- Shut in test
  - Minimum duration
  - Necessary to manage risk appropriately
- Duration of Shut in Decisions
  - Short duration (<1 day)
    - Short shut in for operational reasons
  - Mid-duration (< 10 days)
    - Hurricane
    - Well kill control/back-pressure enhancement
  - Long-duration (<100 days)
    - Minimize flow to gulf
    - Minimize hazards to personnel
    - Focus resources on well kill

# Geologic Conditions

# Data Reviewed

The following were examined from the Macondo #1 and other wells in the vicinity, including relief wells:

- Logging-while-drilling data (primarily gamma ray and resistivity) and mud logs.
- Geomechanical models and borehole measurements pertaining to in-situ pore pressure, overburden stress (lithostat) and fracturing pressure.
- 3D-seismic, high-resolution 2D-seismic, and side-scan sonar collected pre-drill and post-incident.

# Consultation with BP

Detailed in-house discussions between BP and government scientists and engineers on topics that included:

- Lithologic and structural interpretations
- Seafloor morphology
- Drilling history and borehole completion
- Stress and fluid pressure conditions
- Geomechanical and fracture propagation modeling
- Reservoir modeling and borehole fluid flow
- Kill and cementing procedures
- Microseismic monitoring and multi-channel seismic

# Geologic Conditions

- Data indicate geological formations consist of fine-grained, low-permeability sediments such as shale, mud stones and silt stones, and few permeable sands at or above the 18 inch casing shoe (~4000 ft below seafloor).
- Data indicate extensional stress environment, which is conducive to vertical hydraulic fracture growth.
- Data indicate existence of numerous faults that are potential paths for hydrocarbon flow to sea floor.
- Significant oil and gas flowing from main reservoir 13,000 ft below seafloor to well-head.

# Implications of Geologic Conditions

- In the event of a casing leak, geologic formations and in-situ stress field are conducive to hydraulic fracture propagation from the 18” casing shoe to the seafloor.
- Pre-existing faults can also serve as conduits for hydrocarbon flow to seafloor.
- Limited thickness and areal extent of sand layers at and above  the 18” shoe suggest that vertical fracture growth will not be significantly inhibited and that storage for hydrocarbons from a casing leak will be limited.

# Possible Adverse Effects of Well Shut-In

In the event of a casing leak, geologic conditions are conducive to a broach of the seafloor by hydrocarbons during shut in, which would have serious consequences:

- There could be a significant release of hydrocarbons into the sea.
- This could result in an inability to control wellhead pressure, which could seriously jeopardize the bottom-kill and cementing operations.

# Wellbore Flow Conditions

# Flow in Well Issues

- Principal Questions to be Addressed
  - A: Can well integrity be determined during short-duration shut-in?
  - B: Can well integrity be determined during longer shut-in?
  - C: Can the flow rate through the disks be bounded?
- Following analysis assumes that all leakage to the formation is through rupture disks.
- Other fluid-flow pathways to the formation are also possible. In fact, one reason for doing the shut-in test is to determine if there is significant unknown damage to the wellbore.

# Flow in Well Issues
# No Leak Shut – In Pressure (SIWHP)

- Principal Uncertainties (1 observation dependent on 3 processes)
  - Extent of gas volumes
  - Reservoir depletion
  - Leakage and flow pathways
- Government Assessment
  - No depletion SIWHP range: 8250 – 8750 psi (no depletion, no leakage)
  - No independent means of verifying reservoir depletion
    - BP estimates an uncertainty interval of 800 psi
    - Note – The pore pressure reduction associated with reservoir depletions depends on the flow rate, reservoir properties, and the reservoir volume.
  - Combined intervals span 1300 psi range

# Flow in Well Issues
# Leakage Through Burst Disks


- Principal Uncertainties
  - Number of disks open
  - Diameter of disk opening
  - Flow rate through disks
- Government Assessment
  - BP asserts that a maximum of 6 disks could have burst
  - Government has not independently analyzed accident scenario. For the purpose of our analysis, we assume that 6 burst disks have ruptured.
  - Flow = 550 bopd/disk at a pressure differential of 4000psi into formation for 1/8” diameter disks
  - Disk diameter can increase through erosion. Recommend BP testing or analysis.
    - Limited data from other application suggests 6 hours of mud flow would result in < 20% increase flow rate.

# Flow in Well Issues
# Measuring Leakage at Shut In

- Principal Uncertainties
  - Sensitivity of shut-in pressure to leakage compared to shut-in pressure uncertainty
- Government Assessment
  - Simplified to complex models– Assumptions in next slide, details in Appendix A and B
    - Assumes no leakage into formation at current conditions
  - For every 1% of the flow from well head, shut in pressure will decrease by approximately 50 psi. Thus, for a 1300 psi uncertainty interval, this sensitivity corresponds to a flow of the scale of 25% of the flow from well head.

# Flow in Well Issues
# Basic Modeling Assumptions

- Modeling requires assumptions of the current well condition.
  - There is a significant resistance to flow in the well as illustrated by the 4300 psi BOP pressure measurement. This can be distributed to a deep and shallow choke. However, from steady flow observations, one cannot determine the distribution of these resistances.
  - All wells have some resistance to fluid entering (well drawdown and skin resistance). We cannot measure this, but we can determine this as a function of the total flow rate if we assume other blockages (shallow choke) are small. The total flow rate must include the cross-flow and we have no way to measure.
  - Any resistance assigned to a top choke makes the model predictions less sensitive to cross flow.
  - Simple scaling analysis shows that our inability in determining the current condition results in an inability to predict a shut-in pressure. Our major unknowns are:
    - Distributing resistance between a deep and shallow choke
    - Inability in measuring the current cross flow
    - Depletion of reservoir
    - Elevation head

# Flow in Well Issues
# Value of Discrete Steps During Shut-In

- Principal Uncertainties
  - Flow Measurement
  - Limited number of measurements during shut-in
  - Transient conditions during shut-in
- BP Technical Staff Estimates of Capability (as of 1 July)
  - 3 perhaps 4 discrete measurements
- Government Assessment
  - Very difficult to make quantitative determination from 3-4 measurements.
  - Recommend single step shut-in.

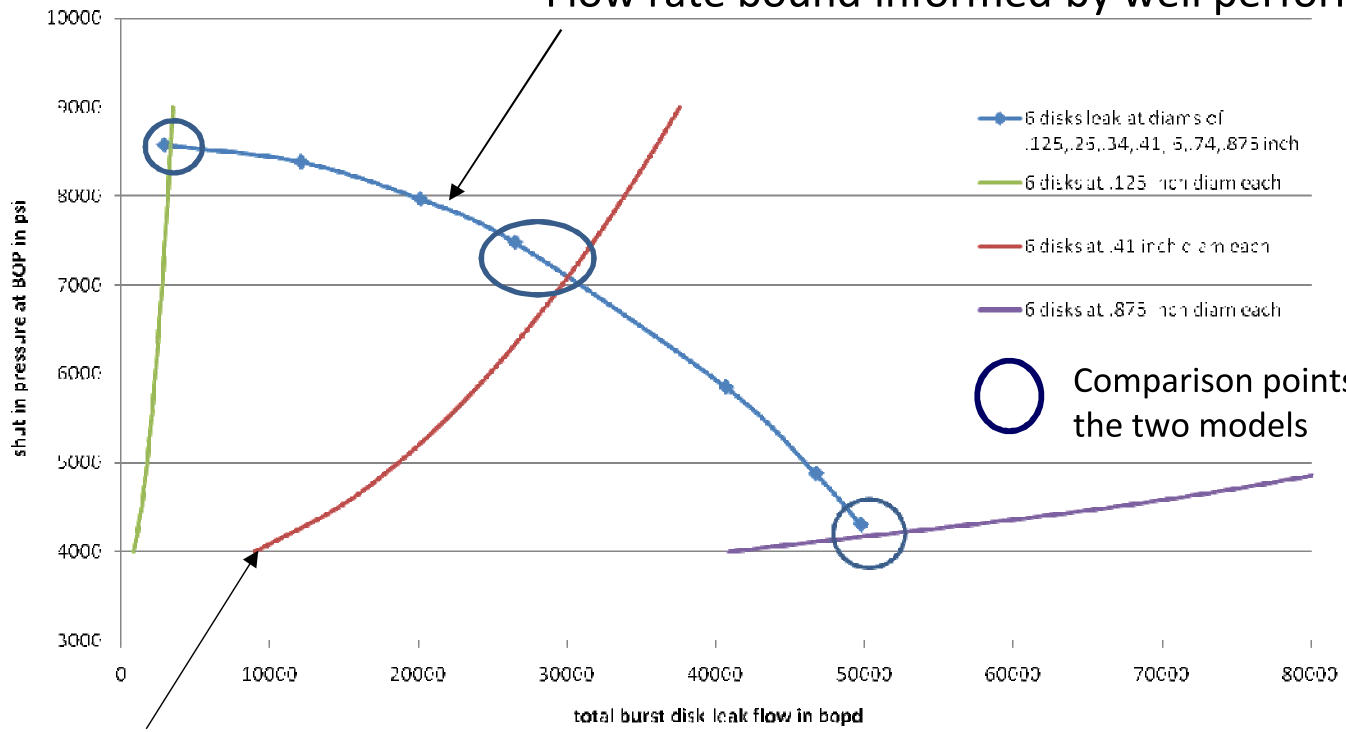
# Flow in Well Issues
# Flow Rate Bounds - 1

- Government Assessment
  - There is no pressure for which it can be conclusively asserted that the well has zero flow out the burst disks.
  - However, flow rate can be bounded (next slide)
    - Bound informed by well performance
    - Theoretical upper bound for given flow area
  - Flow into geologic media must be considered possible for all scenarios.

# Flow in Well Issues
# Flow Rate Bounds - 2

- Government Assessment

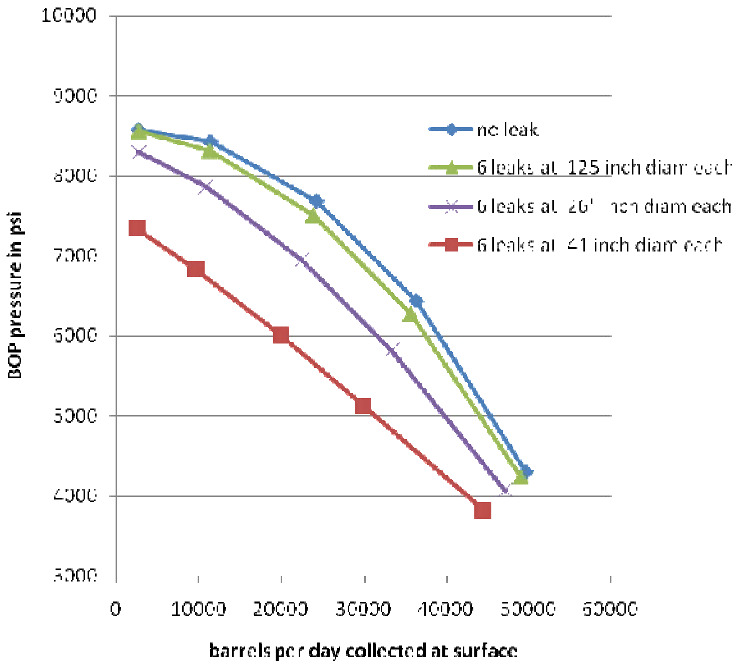
Flow rate bound informed by well performance.

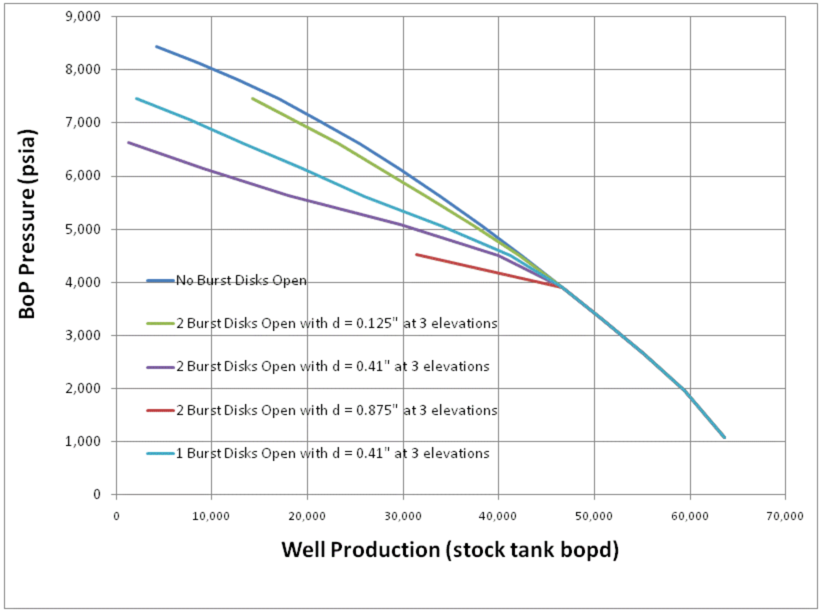



Comparison points between the two models

Flow rate theoretical bound for given flow area.

# Multi-Step Shut-In Pore Pressure vs. Fracture Pressure




Assumes leaking into sand
- Currently above sand pore pressure

Assumes no leak until rock fracture
- Currently at or above rock fracture

# Flow Sensitivity To Changes in Downstream Pressure

- Scenario
  - Assume leakage from well, if it occurs, is limited to the burst disks (ignores more extreme damage to the wellbore)
  - Model back pressure outside the burst disks as:
    - Pore pressure (conservatively no skin)
    - Fracture pressure
    - Hydrocarbon column to seabed
- Consequences For
  - Flow rate
  - Kill difficulty
  - Broach capping

# Decision Context/Recommendations Response Determination

- Shut in pressure can be used to discriminate three categories
  - Pressure > 8000 psi
    - Well may have integrity but this cannot be assured due to uncertainties. Leak rates from worst case scenarios are bounded. Broach is possible but there is a low risk to the well killing and cementing operation.
  - 8000 psi > Pressure > 6000 psi
    - Well does not have integrity unless there is significant reservoir depletion. Discharge into formation is no worse than current discharge rate from well head. However, there is a moderate risk to the well killing and cementing operation.
  - Pressure < 6000 psi
    - More is wrong in the well than just blown burst disks. Discharge into formation is greater than current discharge from well head, and broach to seafloor is likely. There is high risk to the well killing and cementing operation.

# Conclusions and Recommendations

# Risk Management Recommendation

- A successful well kill and cementing operation is the highest priority and should not be put at risk.
- The risk posed by a short-term shut-in test is acceptable if the test is required for operational reasons. However, to avoid possible broach to the surface, the shut-in period should not exceed 1 day without continuous evaluation of results and reevaluation of consequences.
- Intermediate and long-term shut-in could lead to a broach to the sea floor and could jeopardize well kill and cementing operations. Therefore:
  - These operations should only be undertaken after results of short term shut-in test are analyzed by BP and reviewed by the government.
  - Long-duration shut in should not be carried out unless BP can demonstrate the capability to continuously monitor fracture propagation to the sea floor (e.g., AUVs, seismic).

# Risk Management Recommendation

## Recommended Shut-In Protocol

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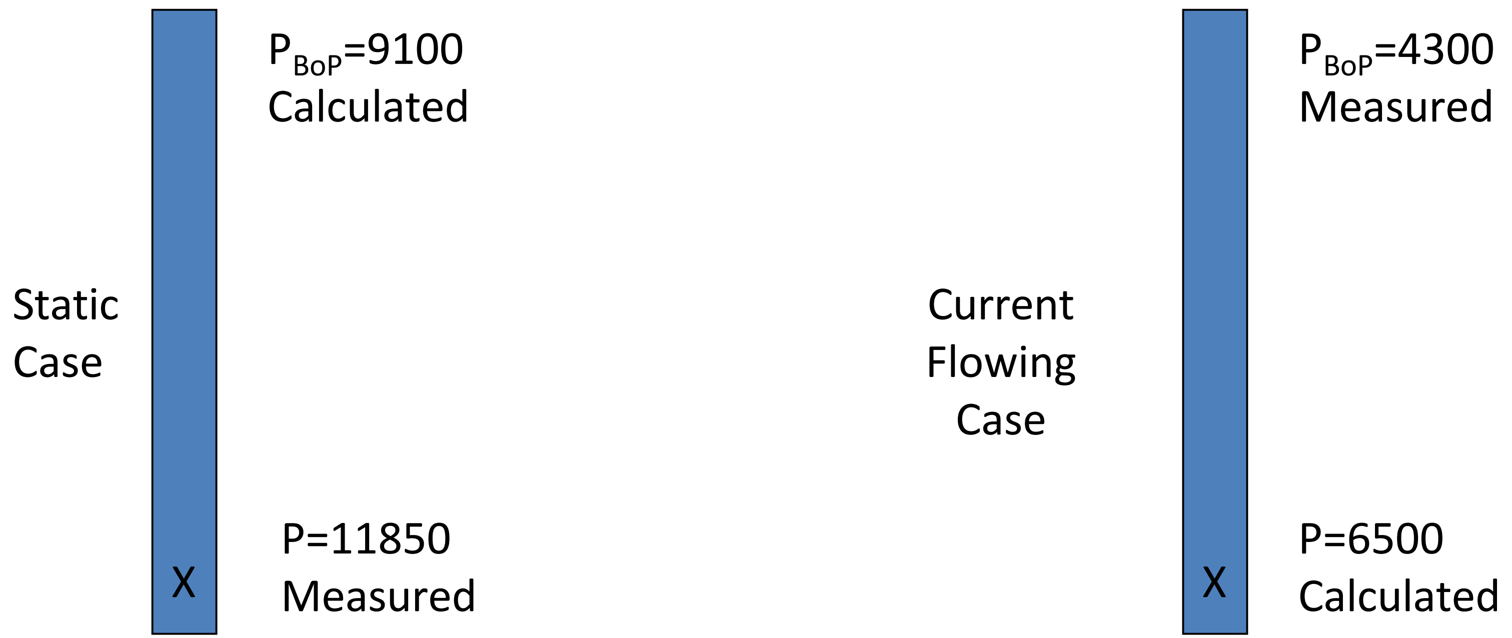
# Appendix A
# Simplified Flow Model

# Flow in Well Issues
# Simplified Analysis

- Address pressure/flow relationship
  - Sensitivity of pressure & flow rate measurements at capping stack can be compared with uncertainties.
- Two parameters dominate well flow
  - Hydrostatic head
  - Hydrodynamic loss across principal flow restriction
    - There are two cases
      - Restriction deep in well – most likely (will use for now)
      - Restriction near surface (hangers) – less likely (address later)
- Assumes all other parameters can be neglected
  - There are many secondary/second-order parameters

# Flow in Well Issues
# Description of Controlling Parameters



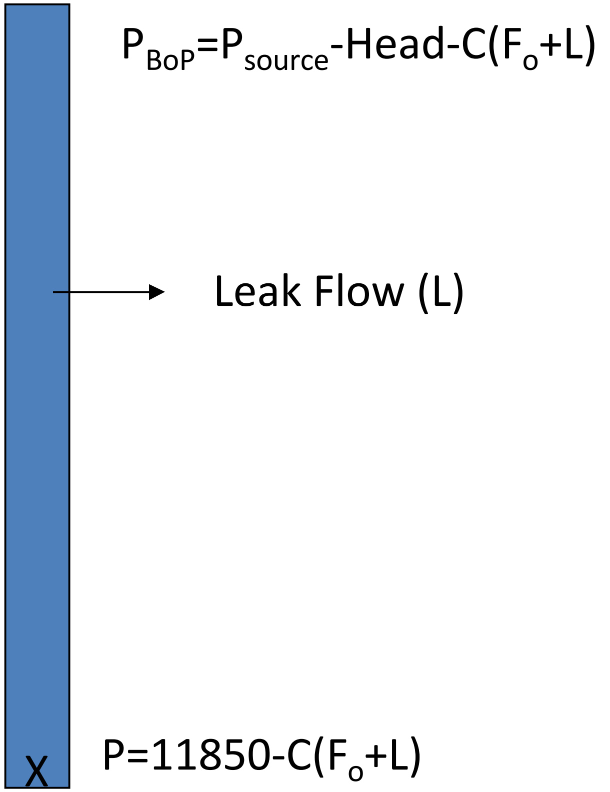
# Flow in Well Issues
# Simplifying Assumptions

- Resistance is concentrated near the bottom of the well and linear with flow rate (well draw down, skin)
- Elevation head is independent of flow rate
  - This simplifies the math, but may be relaxed with a more complex model
- Reservoir depletion is zero
  - Based on constant $P_{BoP}$
  - Can be relaxed by a more complex model
- Pressure at the bottom of the well is 6500 psi at current conditions
  - Hydrostatic + small flow resistance calculation from measured 4300 psi. BP/DOE labs get same result.

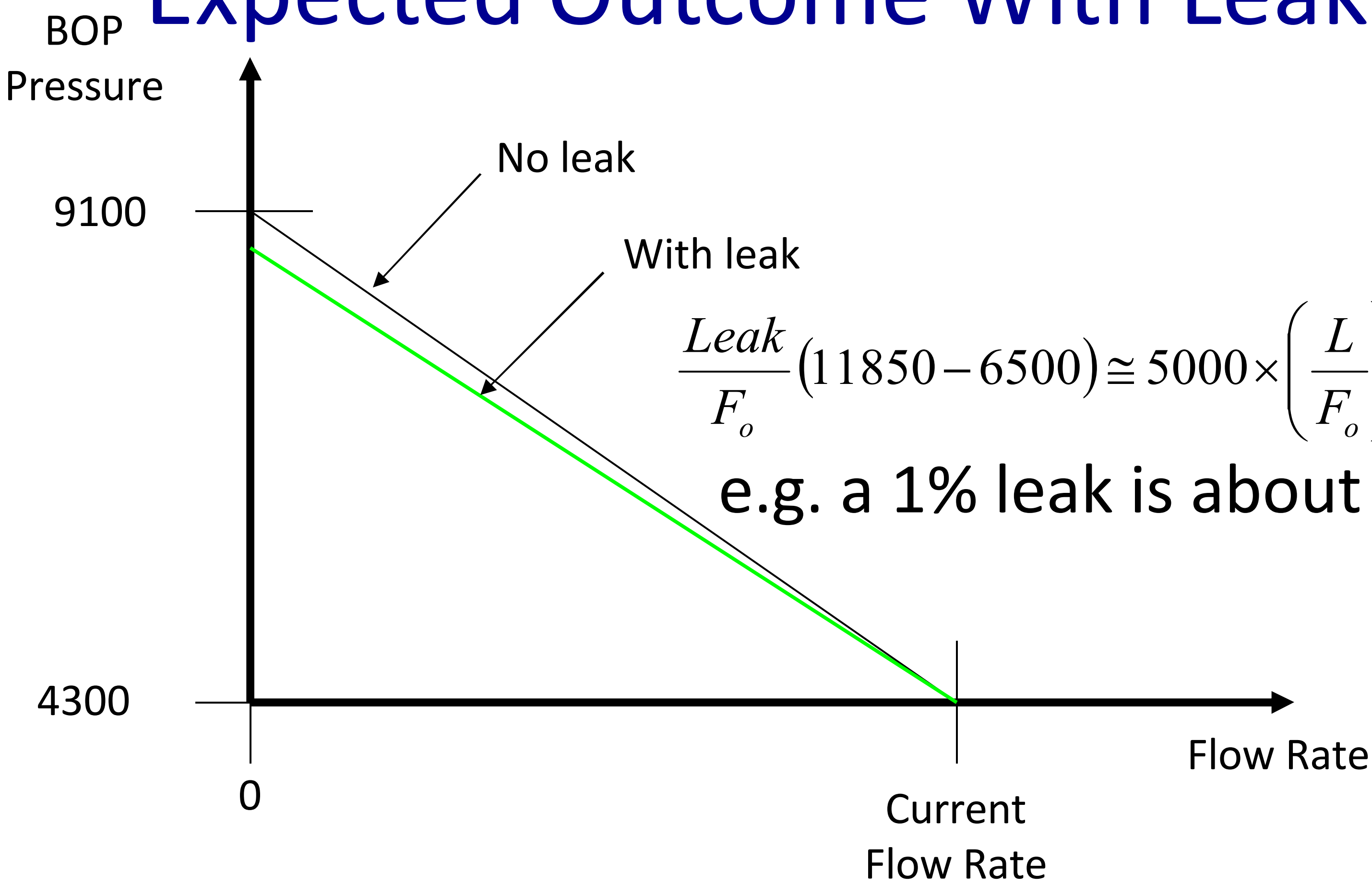
# Flow in Well Issues
# Simplified Model with Leak

- Pressure at bottom of well is equal to source pressure minus a linear term
- Linear coefficient is estimated from current conditions (assuming leak flow << $F_o$)     $C=(11850-6500)/F_o$
- The difference between the $P_{BoP}$ with and without a leak can be determined:

$$\frac{Leak}{F_o}(11850-6500)$$



# Flow in Well Issues
# Expected Outcome With Leak



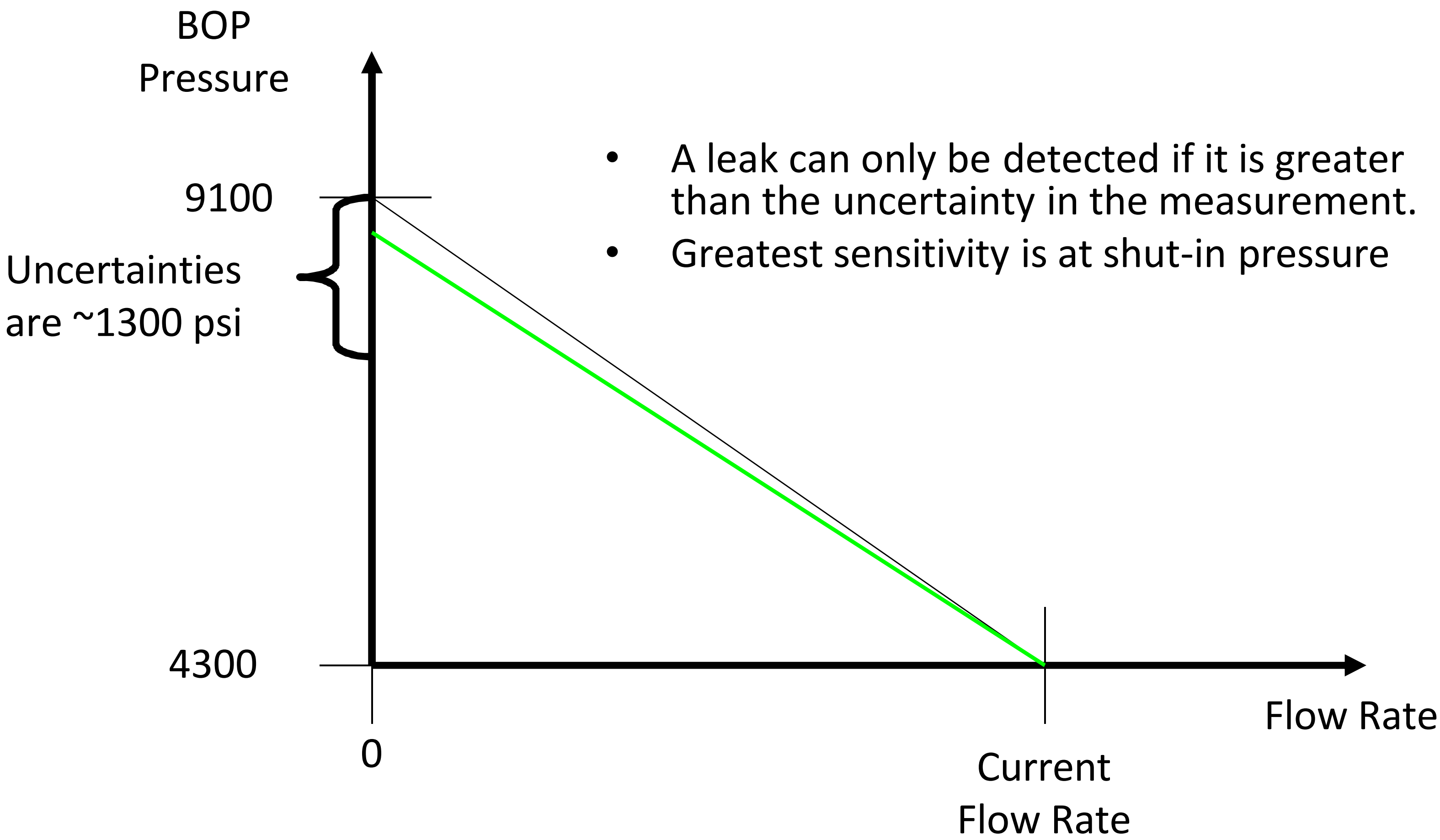

$$\frac{Leak}{F_o}(11850-6500) \cong 5000 \times \left(\frac{L}{F_o}\right)$$

e.g. a 1% leak is about 50 psi

# Flow in Well Issues
# Uncertainties in Shut-In Pressure

- Reservoir depletion
  - BP calculations suggest the range could be ~800 psi (from ~11,300 to ~10,500 psi)
  - May be zero psi as suggested by the constant $P_{BoP}$=4300 psi
- Elevation Head
  - Previous shut in pressure calculations have all assumed no depletion and they have ranged from 8300 psi to 9100 psi due to unknown density within the well (re-absorption of gas may be slow)
- Linearity of deep choke pressure drop
  - Due to 2 phase flow, this pressure drop may not be always linear as assumed
  - The deep choke resistance may change with time due to erosion, and the model assumes it is constant
- Pressure measurement accuracy
  - 0.25% of reading or about 25 psi at 10,000 psi.

# Flow in Well Issues
# Uncertainties & Leak Interpretation




- A leak can only be detected if it is greater than the uncertainty in the measurement.
- Greatest sensitivity is at shut-in pressure

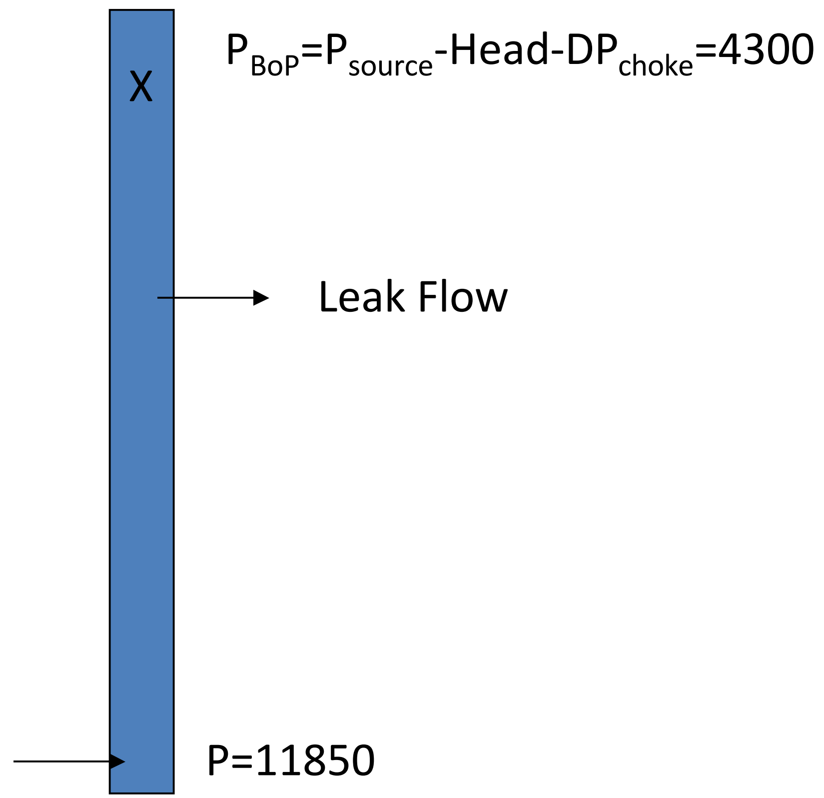
# Flow in Well Issues
# Shallow Choke vs. Deep Choke

- Previous viewgraphs assumed a deep choke (e.g., fractured concrete at reservoir interface).
  - Leak sensitivity is not good given uncertainties in pressure

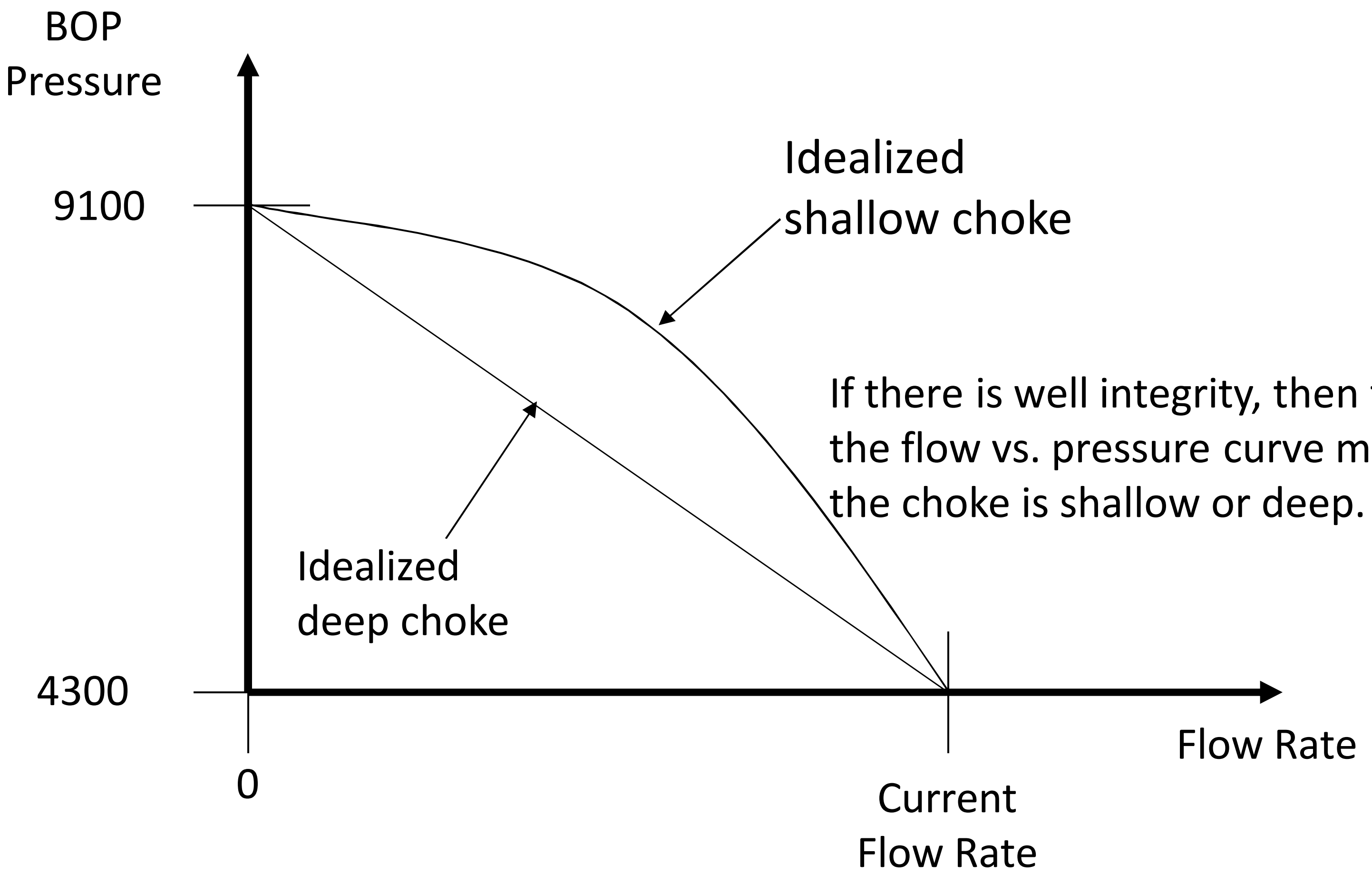
- Location of choke could be shallow (e.g., casing hangers)
  - This is possible but not likely
  - A leak cannot be detected at all if the choke is above the leak.
  - A shallow choke is more likely to be turbulent (non-Darcy) flow than a deep choke.

# Flow in Well Issues
# Shallow Choke Leak Sensitivity

- Major resistance is shallow in the well (X)
- Pressure at bottom of well is equal to the source reservoir pressure
- At no time in the step down does the Leak Flow does pass the choke, and thus does not impact $DP_{choke}$
- $P_{BoP}$ is unchanged if leak exists or not
- Shallow choke will not result in any indication of leak



# Flow in Well Issues
# Detecting a Shallow Choke




If there is well integrity, then the shape of the flow vs. pressure curve may tell us if the choke is shallow or deep.

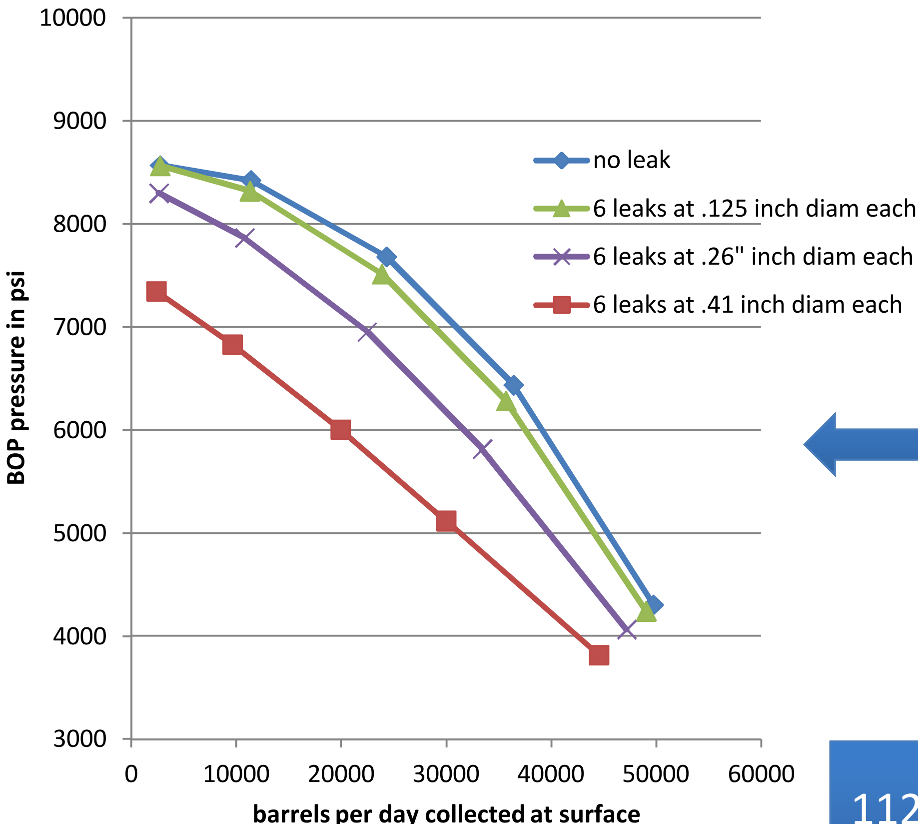
# Flow in Well Issues
# Moving Beyond Simplified Modeling

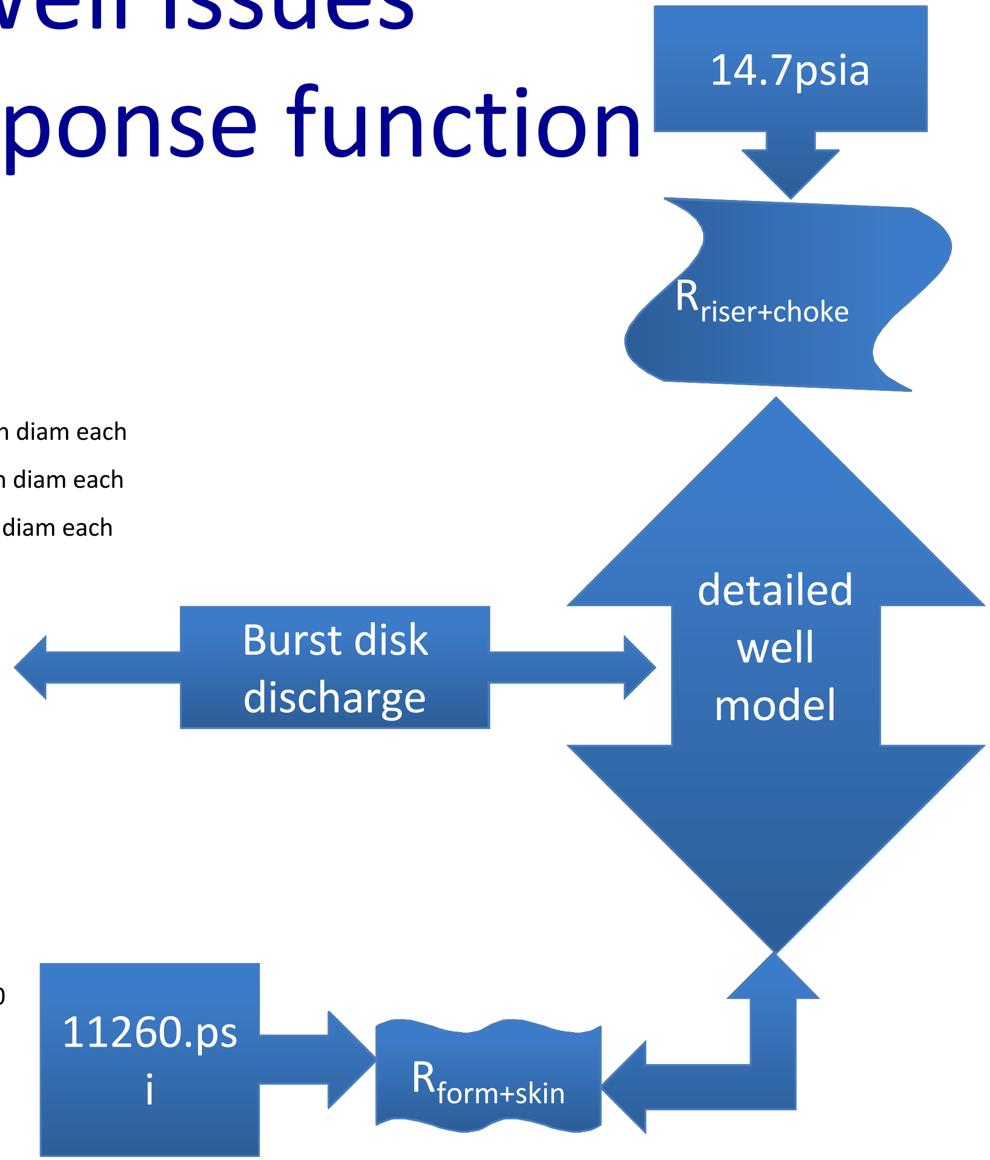
- Flow path description (annulus, well bore, or both)
- Fluid properties
- Leak geometry
  - Even a 1/8 inch diameter leak can flow 600 bopd
- Source reservoir pressure (including depletion)
- Sink reservoir parameters
  - Fracture pressure
  - Porosity
  - Permeability
  - Initial fluid pressure
  - Initial fluid properties

# Appendix B
# DOE Natl. Labs Flow Modeling

- Started from detailed well model for annular flow which had been checked amongst tri-labs
- Enhanced model with simple reservoir, surface collection and burst disk flow representations
- Set parameters for 50000 bopd with BOP gauge at 4300psi and no burst disk leaks
- Exercised model for a range of burst disk original and eroded diameters

# Flow in Well Issues
# BOP gauge response function



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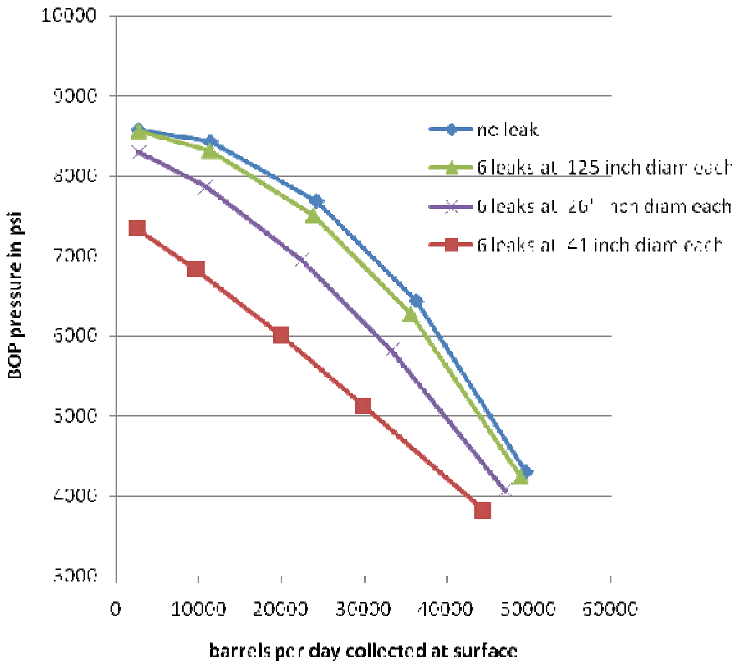


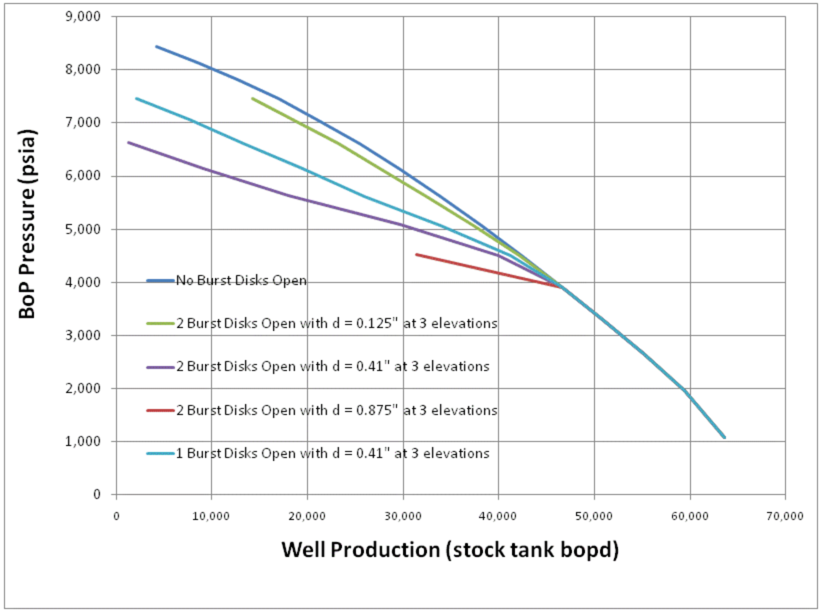


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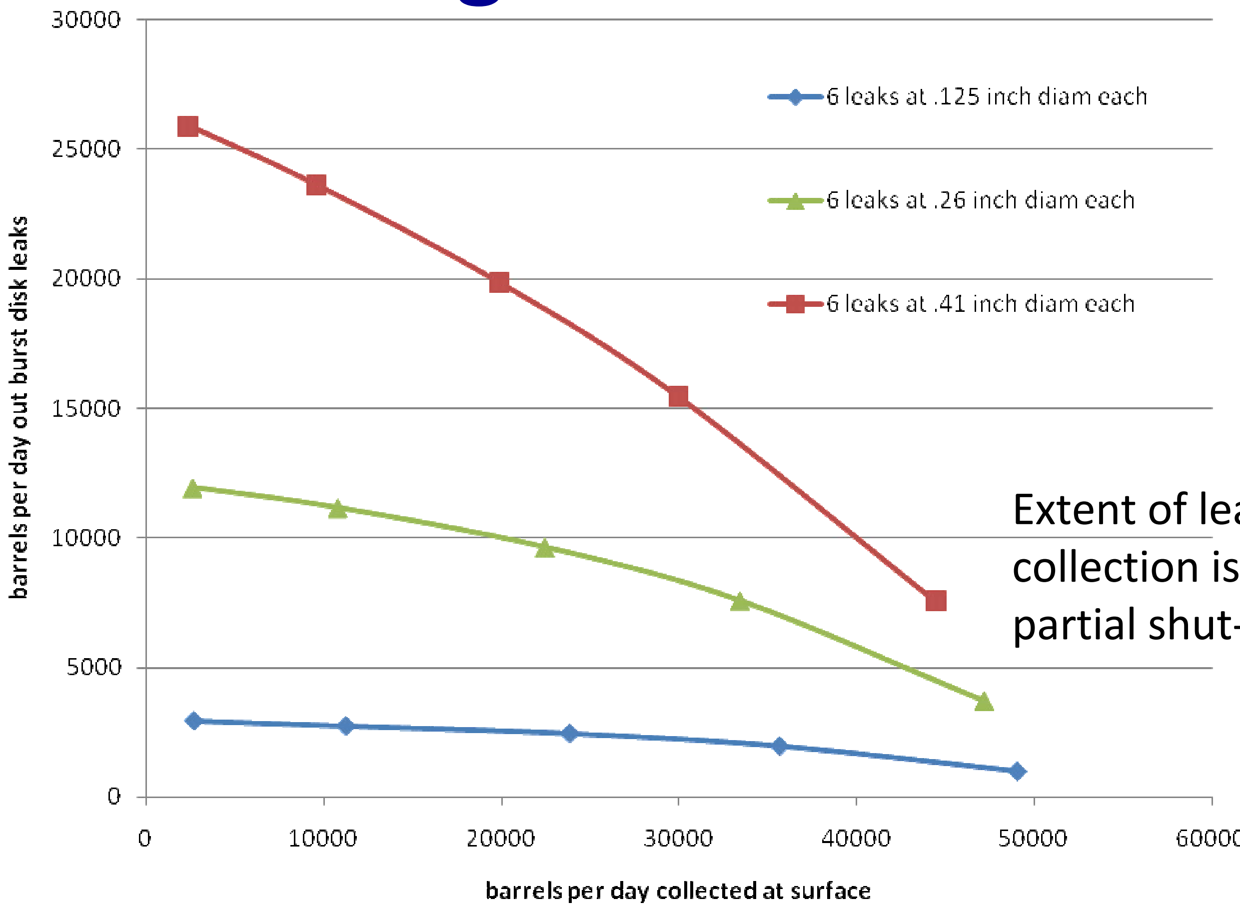
# Flow in Well Issues
# Magnitude of Leaks




Extent of leak as surface collection is curtailed by partial shut-in.