2

Meeting in Houston June 29 - July 1
Travel - Tuesday AM arrive noon
Meeting - Tuesday / Wed / Thurs
Return - Thursday night

This week June 24 Thursday to Houston
Friday - Breakfast at Omni

Walter attorney cell phone [redacted]
Steve Hickman cell phone [redacted]
Cathy
Phil Nelson [redacted]

We are in the "Well Integrity Team"

Mark Sogge [redacted]
Travel account [redacted]

SharePoint [redacted]
~~q0weTy4u~~

https: //collaborate.sandia.gov/sites/deepwater

Monday June 21

Wed June 23 2pm.

Telephone conversation with Phil

Lessons Learned

- Trevor - pressure data Monday meeting with BP
  in charge of top kill operation
- Marsha on 3rd floor - oil spill response
- Cindy on 2nd floor - exporation operations
- DOE workroom on 18th floor < Charlie, Marjorie, Mark

After lunch - meeting led by Mike Mason / Chris, Carl / Tom Hunter(?)
Software - Prosper calculations of flow in pipes

Have in writing - Well integrity team advises USGS Director - who advises Sect. of Interior - who advises the official interaction with BP.

We need 'rules of engagement' and mode of operation between our team + BP

Preparation

DOE - public web site

Document from May - 18" casing shoe
burst disk - 16"

Pressure reversal (pressure drop at producing horizon)

oil properties - bubble point 6610 psi

Conference Call June 23 4pm PDT
Well Integrity meeting.

Steve Wilson - will interact with USGS well integrity team on Friday.
Meeting 2pm central West Lake - 1
11th floor, Room 198

M110 sand - opposite 18" shoe or just above

Steve W is estimating how much flow the M110 sand can accept.

General consensus from BP is the they can draw a relatively tight curve relating flow rate and well head pressure.

Sheldon Tieszen will also meet us on Friday

Kate Baker (BP) cell phone [redacted]

Tom Hunter - Sandia chief liason with BP on data request

Schedule for Friday June 25

7:00 Meet Steve + Walter for breakfast
at Omni
8:00 meeting with Mark Sogge
review "rules of engagement"

PB office
200 Westlake Blvd
Houston TX 77079
Parking structure on west side of building

June 25 9 am
Meeting with ~~Mark~~ Marcia McNutt, Mark Sogge

- Well shutin may occur in situation other than hurricane
- Question - should relif well be used to divert flow and kill the main well.
- There is a strong suspection that a lot of mud has already be lost in the main well by loss through breaks in casing.
- Whether the main well can be adequately cemented is an issue.
- In the end, there will be a Federal position on what is the proper ~~cause~~ course of action.
- Need to keep pushing to consider ~~was~~ worst case scenario.

USGS Room MC 252 3rd floor (Marcia McNutt)

Wireless for BP building
- vanilla
- [redacted]

Room 094 2nd floor

6/25 Work Sessions

6/25 2-4 pm 11th floor WC1 - Shutin Procedure
- Pressure Response
- Operation.

4 pm Steve Willson

~~For~~ June 25 10:20 meeting in "the hive"
contact: Cindy Yielding, BP

Attendees

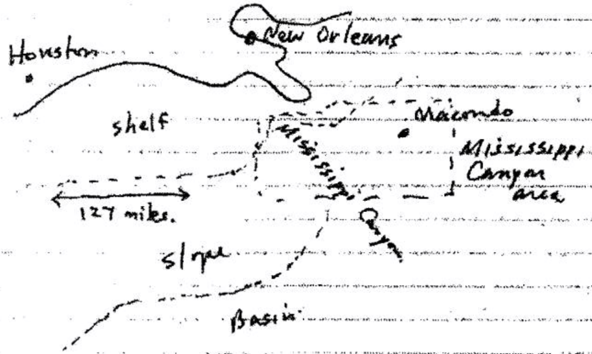
BP Marty Albertin ← has good knowledge of drilling history of Macondo well.
Jonathan Bellow
Bobby Bodek
Kelly Mc Aughan - Reservoir engineer
Geophysics - Craig Scherschel
Technology - steve Willson
Geological Surprises - Cindy Yielding ~~Geologist~~
Kate Baker (contractor)
Sandia - Sheldon Tieszen - Leak rate into formation. (National Lab Team)
Ross Benthein - exploration

USGS Steve Hickman
Paul Hsieh
Walter Mooney

Sharon Murchison - Hive Lead

① Remit of USGS team (well integrity)
- Hazard implications of ~~shott~~ shut in the wel
- Well integrity issues (leakage)
results
- Address additional requests as subject Matter experts advice to Marcia
- Request to to BP surface team
  PPFG
  reservoir modeling
  data quality
  in situ stress
  rock properties

Shallow Hazard Overview
Macondo MC 252 Area.



Presentation by Craig Schershel.

Whiting Dome

MC 208

Mitchell Dome

MC 251

MC 252-BP1 Macondo

MC 253

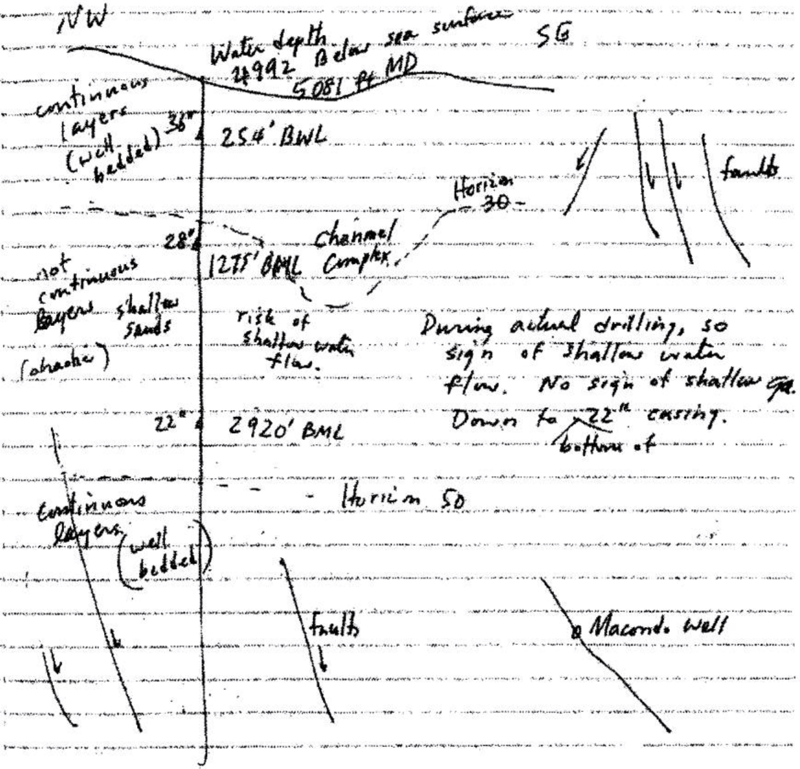
Rigel

relief wells

Gloria Dome

MC 296

Biloxi Dome



During actual drilling, so sign of shallow water flow. No sign of shallow gas. Down to bottom of 22" casing.

This is a normal faulting environment.
extensional

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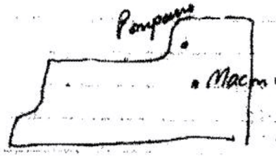
Ross Benthein   Macondo Geoscience Overview.

- ~~[illegible]~~



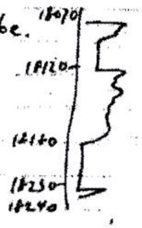
2007 Isabella
MC 252 acquired 2008

M56 structure map

4-Way trap
target - M56   Midde Miocene

above oligocene boundary

20-25 upper lobe.
70 main lobe
10 3rd lobe



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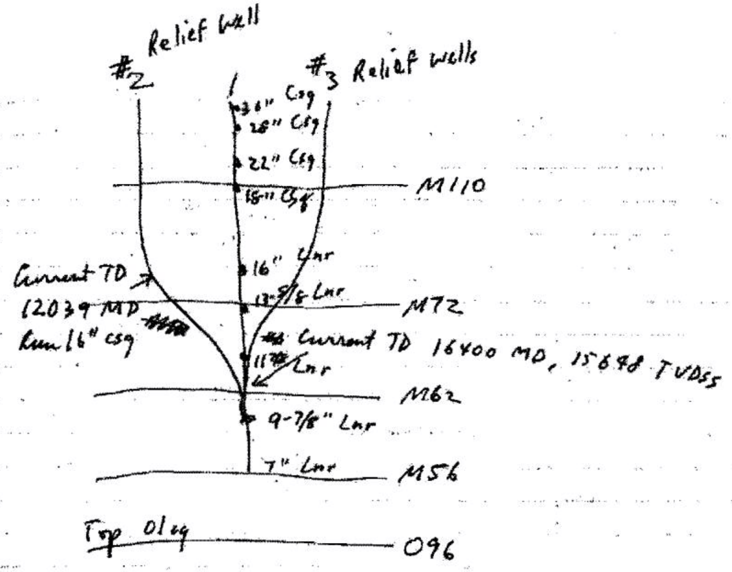
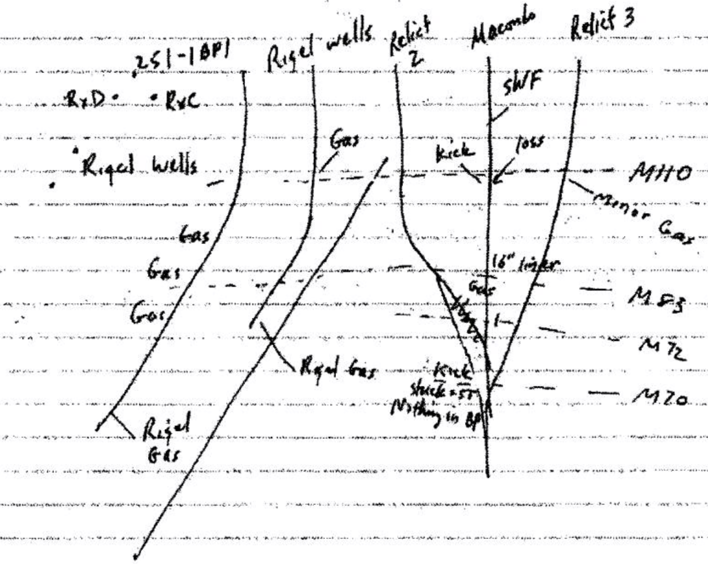
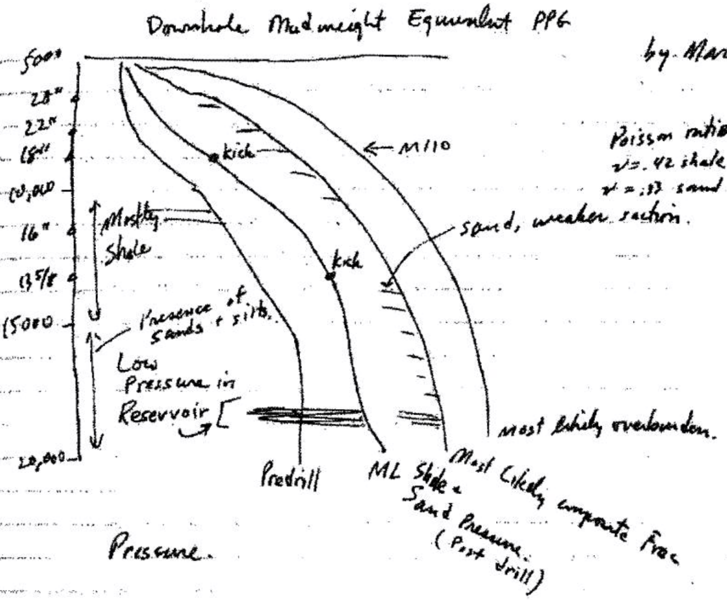


16 Macondo and Rigel wells.



Pressure in Macondo well 17

by Marty.



Poisson ratio
$\nu = .42$ shale
$\nu = .33$ sand

start at ~~9am~~ 8:30am

Items for Wednesday.
- History of Gulf Coast.
- 3D seismics
- reservoir modeling, reservoir properties ⟨ Kelly / mikes
- Geomechanics, fracture propagation.
  - case histories — Steve Willson, Mark Alberty
  - other incidents — Andy Hill, Craig Schershel)
- follow up on Mike/Mason/Mike Leaton Meeting
- follow up on pressure + fracture gradient.

June 25 2pm - Shut in Procedure + Pressure Respon

Shut-in Protocal

Objective - Determine integrity status of the well and whether it can remain shut-i

Benefit
- May not need containment system until dynamic kill
- reduce or no flow during hurricane
- removes degree of uncertainty for relief we and simplifies diagnostics during dynamic kill.

Questions.
- Range of BOP pressure expected for successful shutin
- how to know if we have small leak or integrity of wellbore.
- What is acceptable small lake range. How long to test?
- leak to rupture disk? Can be detected from pressure response?
- How to decide we should not shut in
- Will the planned rate reduction of taking vessels off line meet the requirements of a multi rate test. Will multi rate test provide new info for well integrity.
- What is pressure rating of system component? Where is the well least shut.
- What is the shut-in sequence for different rates

- What procedure do we have to determine whether we have a high choke?
-

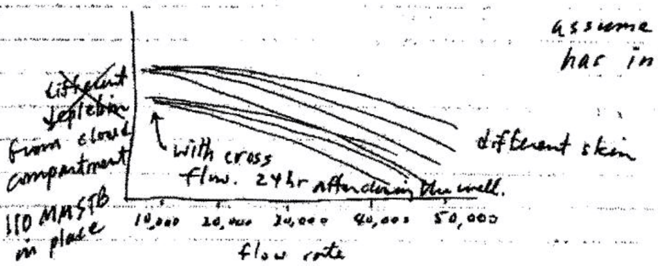
Steve ~~Hte~~ Willson - Vertical fracture growth
- Model of fracture propagation
- assume no leakoff in fracture propagating in sediments
- fracture would breach seafloor after 30,000 ~~tt~~ bbl of injection (1-6 days).

- More sophiscated model of fracture propagation gives completely opposite results - no breach at sea floor.
  · This assume sands extends to infinity.
  · There is no good diagnosis for vertical fracture growth.

Mike Levitan
- Well have been flowing for over 2 months
- Don't know flow rate.
- Know initial pressure - 8900 psi

Assume - Well was flowing 50,000 bbl/day
Simulate - well flow decrease by 10,000 bbl/d

assume well has integrity.



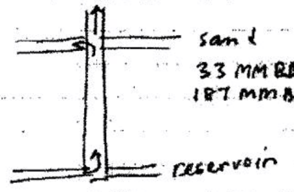
Comment
Need to verify if pressure is absolute.

Aquifer support ← get definition
(6500 psi)
- The lowest shut in pressure calculated is still higher than the ?

Range ~~for to~~ of shut in pressure
6500 psi - 8900 psi

- k = 300 md in reservoir

Simulation if flow goes out of ~~xxx~~ casing
to sand ~~xx~~ at 18" shoe. (1 darcy)
- increase k by factor of 6.7 to account
for 2 phase (oil-gas) flow.
- increase compressibility ~~x~~ for similar reason.



4750?
Δp = 4855 psi between
reservoir and sand.
— closed compartment.

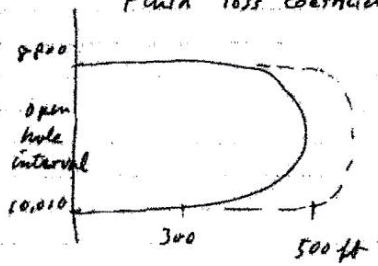
Phil Pattillo System Integrity
Technical Note available.
- casing integrity.
- Flow up inside, outside of casing + both.
· The only way to rupture ~~xx~~ an inward acting disk
is lack of internal pressure.

Next meeting Monday morning ~~10am~~ 9-11 CDT
7 am PDT.

June 25 5 pm.
Hydraulic Fracture Calculation Stephen Wilson
Stimplan model.

Data for model
Pore pressure
Young's modulus
Fluid loss coefficient

stress contrast between
sand + shale



The only way that fracture does not reach
seafloor is when there is stress contrast
between sand + shale.

June 28 Webex Conference 7am

Steve Willson
Breach & fracturing

Bob Merrill
32 mbd
MIIO sand - if 5ft thick, small volume
then will "fill" in 10 days.
Can we detect if there is cross flow at 18" shoe
~~Can we~~ Leak off cannot be detectable.

Kate:
Do we absolutely have to know the
flow rate before the well is shut in.

(tubing head)
Uncertainties of Shut in top hole pressure.
Aquifer Size ← makes a big difference
~~Depln Rate~~ Depletion Rate
Leak Size
smaller uncertainties.

What can you do with ΔQ vs ΔP data (stepping
rate test).

Shut in will not further damage the
well integrity ← if rupture disk is intact

4200 - 4700 psi ← current BOP pressure
4375 ← most recent value.

Flow team to agree on boundary conditions

Kelly - reservoir model. Sheldon cell: [redacted]

Sheldon Tiezen - report content
is USGS comfortable with direction
the meeting is going?

Next meeting Thursday morning 9 am.

~~1:30 - 2:~~ 12:30 - 2:30 Flow team meeting
Today

10:30 PDT

June 28 10:30 am PDT Conference Call
Macondo Shut-in & Well Test Protocol.
Chaired by Mike Mason BP.

Mike Mason

Sheldon Tiezen
Kelly
Bob Merrill
Hill
Lorenzo
+ Phone participants

Agenda
- Restate rupture/compression disk issue
- Review pressure + flow history
- Summarize flow path scenarios

There are credible reasons that during the explosion, the casing (hanger) was lifted causing failure of compression disks inward or by overpressure or rupture

- Questions + comments
- Agree baseline flow data

- flow could ~~be~~ be up casing and/or annulus
- flow could be up casing then into annulus.

Lots of discussions on Casing size, couplings, & areas open to flow, etc.

Since explosion, the pressure is nowhere close to triggering the rupture disks.
burst disk burst at 10,300 psi at well head

What is the shut-in pressure above which we a confident that there are no leaks?

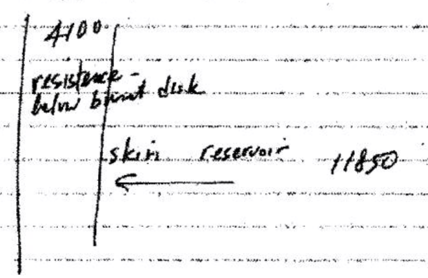
Depletion w or w/o aquifer support makes a difference of 800 psi.

If we shut in well without damage
(highest ~~11 8050~~ 11850 psi (maybe too high)
(lowest no aquifer support, small reservoir.
reservoir pressure outside of skin
highest flow rate 9,300 - 10,600 no ag
10,700 - 11,300 w. ag
extremely high skin.

6500 psi in well at downhole (well side of skin)

model - propper.

DOE calculations.
11850 driving through various resistences.
4100 pressure under BOP ← recalculate with 4300?
50,000 BBl/day.
~~6500 at~~
↑ 50,000 bbl/day. - flow through annulus.



Bounding calculation.

Scenarios
- Shut in
- measure pressure
- ~~what is the~~ are wee leaking? Don't know
- What is the maximum flow rate out of stem (into M110)

6400 bbl/day] if .41 diameter flow area. 1 burst disk.
7900 psi — ~~at BOP~~ above burst dist
7640 psi at BOP

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IGS700-000605

TREX 008659.0015

2 30

31

- Key question is how much flow the sand can absorb.

* Agreed
  - 11850 psi initial
  - hanger lifted if occurred, would be
  - disk failed, April 20 compression or rupture disk. not both

- Current flow 60,000 bbl/day.
- all hydrocarbon, no water
- opening 0.41

June 29
12:30 - 1:30
#: [redacted]
code: [redacted]

#0 assistance

Calling in from car while going from airport to BP building

Briefing for Steve Chu.

USGS Reviewing fracture propagation

Ron - presenter
- single equation model
Slide hydrostatic head
#5 - flowing loss
#6 - 11850 psi static
9100 psi highest top pressure with gas
6500@bottom deep choke 3300 at top
10K-50K bbl/day flowrate
#8 - 1180 - well drawdown → pressure at BOP
source pressure (known)
w/ leak
w/o leak
leak calculated from pressure difference
BOP 4300 (known)
calculate skin resistence at bottom.

#10 ~~DAM~~ Unknowns

lots of talk about calibration

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This doesn't sound like a high-level briefing.
Technical people at conveying information to each other.
Can't hear very well. Cell breaking up.

Slide #11 ↑ Everything above assumes deep choke.

#12 ~~#~~ Assume shallow choke – ~~at~~

#13

#14 ~~Do~~ Do we have a deep or shallow choke. Should see different pressure response at shut in

More complex model

Dr Halstad(?) include more complex well geometry (annulus, etc) presence of mud etc.
9000 psi shutin
4100 psi Top of BOP gage

Discussion on experiments and what to measure during shutin.

Disconnect at 15:15 arrival at BP building.

Meeting of U.S.G.S. Well Integrity working group
June 29 2:30 pm →

Wednesday – Presentations by BP

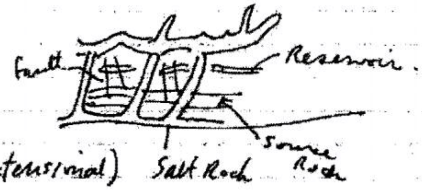
Today – Go through power point. ② shallow hazards ④ pressure summary ① Macondo Over
⑥ discuss ~~binder~~ data in binder.
③ well diagram
* ⑤ well logs in different scales.
⑦ decision process

Issues to follow up
- Seismic data for interpreting the scarp near well
- is fracture calculation appropriate for clay.
- Review pressure curve Rev 6.

www.adrive.com
[redacted] @gmail.com
[redacted]

June 30 Meeting with BP in Hive
Cindy Yielding - Chair

GoM Geology
Salt
Source Rock
Reservoir
faulting (extensional)



Middle Jurassic 157 million ago J86 ← BP internal

Late Jurassic deposition of source rock 144 My.

Middle Cretaceous 95 million yr.
depositional fan systems.
Paleogene (54 million yr) Lower Tertiary
continue deposition. Salt mobilization.

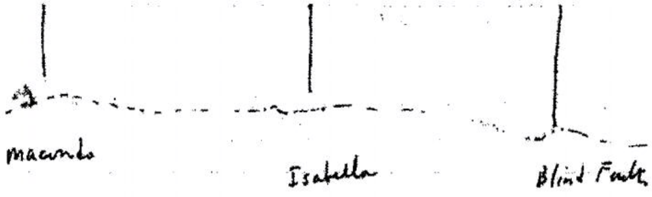
Middle Miocene 14 million year
Proto Mississippi, sandy deposit.
~~pa~~ "blocky" sand.

Pliocene 3 ~~mya~~ million years go
Continued sediment input.

Geology of Macondo

in Block 252 Mississippi Canyon.

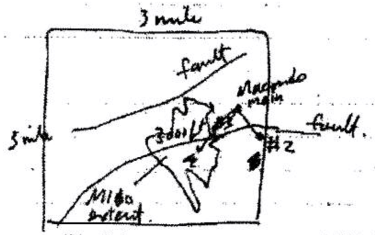
090 structure



M56 13 million years old.
Pre drill estimate
94 - 60 - 40 million barrels
Current estimate 40 million barrels.

~95 ft sand - oil reservoir.

unconformity
Pliocene
MPU ← M110 at top of Miocene system.
M100 Miocene ↓
M86 4 channel systems.
M83
M72
M70

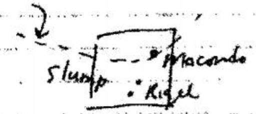


Seismic can see sands thicker about 20 ft (?)

M110 – about 100' package composed of sand + shale layers.

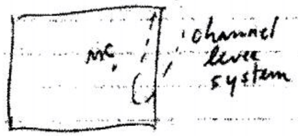
Did see much sand in cuttings when drilling through M110

Shallow hazard. 0 – 3000 ft below mud line.
by Craig (22" casing shoe in Macondo well.)
Scarp 4% seafloor angle.
No fault in 252



No geohazard ~~&~~ on seafloor.

Riserless drilling down to 3000' BBL 22" shoe.
no indication of shallow water flow.



Max Negative Amplitude Display – seafloor to horizon 30 (units 1, 2+3)
Above 28" shoe

Macondo – Above 18" casing shoe

Total sand ~ 518' Vshal cutoff • 65%
By interval A 137' ← suspicious ("very generous")
B 98'
silt ← 5 md. C 147' rule of thumb 30% = sand
sand – 1-5 d. D 121' 30 – 60 = silt
<60 – ~~c~~ clay

at 30% cutoff – there would be no sand.

Blow out data base

Global all water Depths blowout 573
Global - deep water 13
GoM all depths 324
GoM Deep water 8

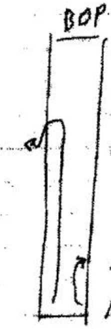
Deep Water means greater than 1500.

Of 324 blowout 25 broach to seafloor
of 25 - 18 shallow gas blowout

In the Macondo setting, broach to
seafloor could open a crater
~~of~~ that is several hundred feet deep.

No close analog in database.

Reservoir Modeling.
Bob Merrill



need : rate of cross flow
volume of M110
frac gradient

Can we detect if cross flow occurs
Would cross flow be liable to cause a
surface broach.

Scenarios
- Varying depletion
- w/wo disc failure.
- w/wo 5000 ft gas head.

At shut-in
- Limited cross flow
- well integrity
- Large aquifer
- Low production

High Wellhead Pressure

- Integrity failure
- Smaller aquifer
- Higher production

Low Wellhead pressure

After Shut-in

Rising THP (tubing head pressure)
- Fluid Segregation only if $P_{thp} < 6650$
- Reservoir Response
- Cessation of Cross flow

Falling THP — pressure below BOP
- Well bore temp equilibration
- Large Leak with limited flow

	Near-Well Pressure	Reservoir Pressure
M56E	10842,	11258
	9800,	10,600 ← with cross flow

k = 300 md

initial press M110, 4730

Uncertainty in SITHP
- Size & Presence of Aquifer
- Flow Rate
- Rate of Crossflow

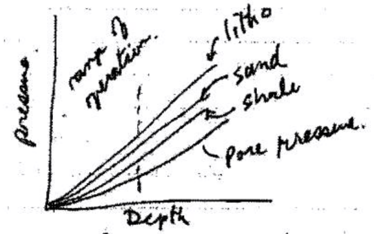
- 18 layers - 9 active

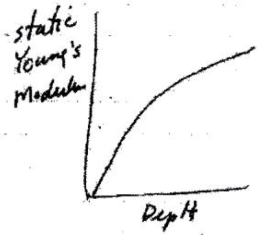
area equivalent
110 million stock tank bbl.

12 million stock tank bbl
.7 multiplier to 2.5

Geomechanics
Scenario
- propagation thru shale & ineffective sand (no leak off)
- progressive fracture / ~~tate~~ leak off / fracture sequence. (most probable)
- progressive fracture / sand-fill / fracture sequence. sand at lower fracture gradient.

Shut in scenario
- less than 1 week (pressure testing)
- 1-2 weeks (hurricane)
- 4-8 weeks (shut in until ~~relief~~ bottom kill)





fracture gradient

Sand with the overburden

StimPlan - model use for hydraulic fracture.

For more complicated model set up fracture ~~took~~ doesn't grow.

Kate - BP needs to start writing shut-in procedure.
- Do we need to know flow rate
- After capping, can only capture 35,000 bbl/day
- Do we need a step rate test

Do we need to test the well in order to know about well integrity.

U.S. GoS Team discussion
- Has rupture disk(s) failed.
  Trevor thinks mud loss during top kill can be explained by the ~~fact the~~ possibility that ruptured disk failed.

Flow Team Meeting July 1. West Lake 1
- Broach to seabed
  - Define the most conservative case
  - Define the consequence

- Reservoir Storage Capacity

- Sand ~~Mechanics~~ Modulus

- Shut in wellhead pressure.

- Fluid Flow

Trevor - Operational conditions.

High level sequence of event
- pressure measurement at base of BOP
- BOP stack ram differential pressure measurement prior to HP commissioning
- Total flow rate measurement up to 50 Mbd.
- Decision hold point Remove top Hat
- Make temperature measurement of flow leaving cut riser.

- Connect capping stack
- Decision on stepping or quick shut in
- stepped shut in with HP and Q4000 online.
  alternative Choke back flow to 35 Mbd
  Choke back to 25 Mbd
  Stay, shutin, or reopen
- Quick shut-in.

Consequence of Broach to Seabed.
all shale
currently under frac pressure] Most conservative case.

Leak off test indicate that frac pressure is about ~~4300 - 5100~~ ~~4700~~ Steve thinks there is ± several hundred psi uncertainty. This is 4300 - 5100 at bottom of BOP.

Sheldon: 5275 frac pressure] M110
4730 formation pressure.]

Increase difficulty in caping the breach - Yes.

Reservoir storage Capacity - kelly

for Vshale < 25% sum ~~32~~ 16 ft of sand from 18" shoe
(not counting A sand)

65% sum to >500 ft

Kelly thinks that using Vshale < 30% or 35% would not significant increase ~~as~~ the amount of sand in ~~the~~ above the 18" shoe

No sand in cutting below 22" shoes. Above 22" shoes drilling is riserless so that there is no cutting

Steve Willson

Review 3 fracture scenarios (shown yesterday)
1) ~~strata~~ fracture through shale and in effective sand
2) progressive shale fracture / sand leak off
3) progressive fracture / sand / fracture.

Bob Merrill
- Reservoir has been flowing for 70+ days
- Depletion is not detectable at wellhead.
Possible cause
- Broken gage
-

initial
11,850
11,288 psi
10,042 psi

Discussion on pressure measurement below BOP.

Sand Shale VSH < 0.25 < 0.30 < 0.40
sum 16 ft 74 ft ← Thickest sand
6747-6785.

Liao
Tony - Flow through rupture disk
6 rupture disks
6047 8304 9560 ft ← location
If they failed, they failed at April 20th
Only one set failed either (outward or inward)
Steve Wilson - Only ~~one~~ inward ~~dis~~ failure.

Flow

5000 bbl/day per disk   Discharge to M110 4730 psi
1/8" choke.   formation pressure.
reservoir RST pressure 11,150 psi

Discharge to M110 Annulus flow
3001 bbl/day.

1/8" ID   Discharge to 22"x16" annulus, casing flow.   no solution not found
" " " annulus flow
3391 bbl/day.
14" ID

U.S.G.S. discussion

Is there significant probability that the well has integrity. If yes, worth shutting in for a short period of time (~6hr) to see if well ~~is~~ truly has integrity. If p rises up to above some "safe" level then well has integrity and shut in can continue. If p doesn't rise above some "safe" level, then discontinue shut in.

If there is good reason to believe that the well doesn't have integrity, then it is not worth trying to shut in.

If shut in pressure levels out at 5000psi, then casing has no integrity. Flow out of casing is more than what can be accounted for by

above 8700 psi - safe
7000 - 8700 psi - safe or small leak
below 7000 - bigger leak.

50 July 2, 2010 5pm Houston.

Briefing for Energy Secretary Science Team.
Conference call

4-5 days → 1 week decision on installing new ceiling cap.

Steve Black - ~~[illegible]~~ various cap design.
latch cap

~~Relief well~~ -
Integrity Test.

Add to presentation depletion calculation.
Stratagraphic profile
Well casing

July 8, 2010 51

Meeting with Kelly McAughan [redacted]

Parameters used in reservoir model

$C_f = 12 \times 10^{-6}$ psia^{-1} (was 6×10^{-6} psia^{-1})

$C_w = 3 \times 10^{-6}$ psia

$C_o = 12.2 \times 10^{-6}$ psia^{-1}

$\nu_o = 0.21$ cp (oil viscosity)

$\rho_o = 0.589$ gm/cc

Bubble point 6430 psi

initial pressure 11856 psi

Formation Volume factor 2.538

Skin = 0

Bottom flowing pressure at 60,000 bpd ≈ 7,000 psi

CONFIDENTIAL

IGS700-000616

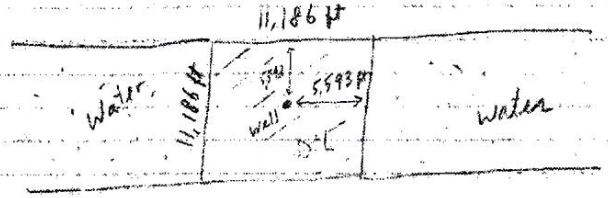
TREX 008659.0026

$$\begin{array}{r} 280 \\ 56 \\ \hline 336 \end{array}$$

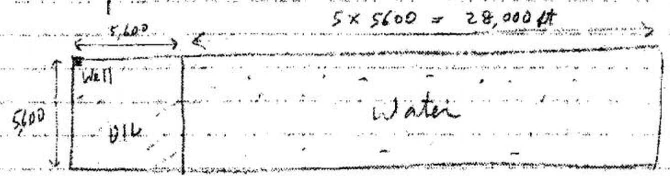
July 8 2010

sand thickness 66 ft.

Depth to top of reservoir 18,000 ft TVDSS



SE quadrant



$k = 300\ md = 2.96 \times 10^{-13}\ m^2$

For oil	For water
$\rho_o = 589\ kg/m^3$	$\rho_w = 1000\ kg/m^3$
$g = 9.8\ m/s^2$	$g = 9.8\ m/s^2$
$\mu_o = 0.21\ cp = 2.1 \times 10^{-4}\ kg/m/s$	$\mu_w = 0.27\ cp = 2.7 \times 10^{-4}\ kg/m/s$
$\frac{\rho_o g k}{\mu_o} = 8.138 \times 10^{-6}\ \frac{m}{s} = 2.31\ ft/day$	$\frac{\rho_w g k}{\mu_w} = 1.074 \times 10^{-5}\ m/s = 3.04\ ft/day$

Compressibility

$C_f = 12 \times 10^{-6}\ psi^{-1}$

For Oil

$C_o = 12.2 \times 10^{-6}\ psi^{-1}$
$S_o = (1 - S_w) = 0.9$
$S_w = 0.1$

$C_t = S_o C_o + S_w C_w + C_f$

$= 23.3 \times 10^{-6}\ psi^{-1}$
$= 3.38 \times 10^{-9}\ m^2/N$

For Water

$C_w = 3 \times 10^{-6}\ psi^{-1}$

$C_t = C_w + C_f$

$= 15 \times 10^{-6}\ psi^{-1}$
$= 2.18 \times 10^{-9}\ m^2/N$

$$S_s = \rho g \phi C_t$$

For Oil

$\rho_o = 589\ kg/m^3$
$g = 9.8\ m/s^2$
$\phi = 0.21$

$S_s = 4.10 \times 10^{-6}\ m^{-1}$
$= 1.25 \times 10^{-6}\ ft^{-1}$

For Water

$\rho_w = 1000\ kg/m^3$
$g = 9.8\ m/s^2$
$\phi = 0.21$

$S_s = 4.49 \times 10^{-6}\ m^{-1}$
$= 1.37 \times 10^{-6}\ ft^{-1}$

distance from M56 reservoir to bottom of BOP = 13,000 ft
= 3962 m.

Pressure of 3962 m of oil $= 3962\ m \times 9.8\ \frac{m}{s^2} \times 589\ \frac{kg}{m^3}$

$= 2.287 \times 10^7\ \frac{N}{m^2}$

$= 3317$ psia

If assume
Oil gradient = .25 psi/ft
13000 ft → 3250 psi

$\frac{1}{m} \times \frac{1\ m}{3.28\ ft}$

$\frac{N}{m^2} = \frac{kg}{m^2} \frac{m}{s^2}$

18" shoe at

4000

July 9 2010

Capping stack
- back pressure control
- shut in
- total capture

Well & formation integrity issues
- Can we distinguish between depletion + leakage from the well
- What is the consequence of leakage, and ultimately broaching to seabed
- Can we adequately monitor to detect significant leakage from the well

Operational Issues
- Gauge accuracy + dependability
- communication + decision making
- practicalities of opening well

Experimental Method
- Can we tell anything from transient behavior
- Do ~~we~~ we need to bracket flow rates prior to starting the test.

Sunday

July 11 2010 4pm PDT
Conference call.

time from start of shut in to complete
shut-in is about 2 hr.

Don't call this a shut-in test
call this a well integrity test

July 13, 2010 Conference call

Well integrity test.
Estimated shut in 9000 psi

5300 psi fracture pressure at 18" shoe
4200-4600 pressure at BOP

Experts from Shell and Exxon Mobil + Mark Zoback
added to give advice.

July 14 8am PDT conference call

Comments by Exxon-Mobil (?) experts.
- Leakage could be occurring at present at 18" shoe
- ~~Possible to~~ Shutin could cause leakage from 22" shoe

General discussion
- Barite plug can develop
- If shut in pressure exceeds 6800 psi, mechanical seal at (?) hanger could rupture/fail.

Assumptions
- 5.2 lb/gal - density of fluid in well
- 4300 psi - pressure at base of BOP
- 13 lb/gal - bottom hole pressure.
- 12.6 ← given ~~by Steve~~ in ~~charge~~ chart sent by Steve Hickman.

22" casing 6260 psi burst pressure
18" casing 6680 psi " " 117 lb ft 10 grade

Potential shut-in pressure BOP 8819

Form barite plug / cement channeling

Channel ~~forat~~ in formation
can propagate very quickly (broach in hours)

Maximize monitoring
Minimize Time.

Shell

4100 psi allowable shutin
→ 18" shoe may be breached and currently taking fluid.
→ Once ~~bee~~ fractured, hard to heal
→ Increase well pressure during shutin may cause addition fracture growth that can develop into channel.
→ OK to do a very short shut in test

– Seismic survey

800 psi 1422 4

25 30

8216
1425 8185
331

6660
6642 4:10 ~~6642~~
~~6609 3:30~~
6624 3:00
6633 3:10
6609 2:30

5600

30
26
50

10
26

11,850
– 3200
8,650

6,800

60,000 stb/day × 85 days.

July 28 - Aug 8
Marcia McNutt on vacation

July 19 11 am meeting BP

New today - observed flange leak in well cap.
Minor problem
- seismic - no discernable change
sonar ?
modeling data - no agreements on final assessment.

To do

- Talk to Tim about - Consensus comments
- Horner Plot controversy.

Margie Tatro DOE coordinator

2 pm Meeting

Quantative Evidence	Questions
- temperature	- Is there a leak
- pressure v. time	- What is the flow path
- acoustic data	- What is the flow
- seismic data	>27 mbpd, < 70 mbpd
- Q @ sfc	48-65 mpd via CV
- fluid properties	data (multiphase Bsco)

Decision to snake

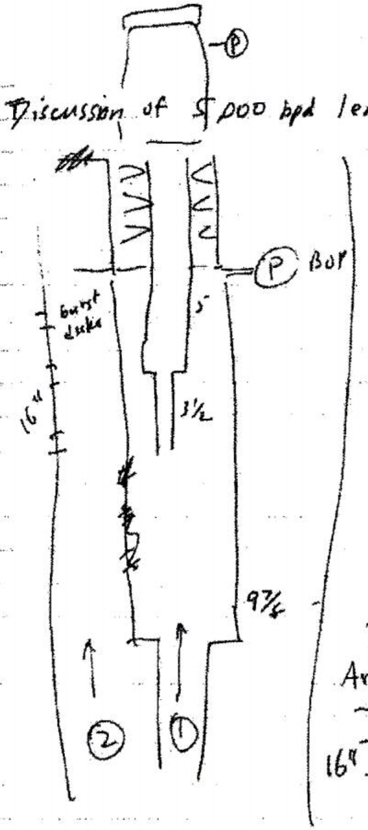
Stop shut in
Start "top-kill"

BP Issues

- Large Leak > 5 mbd
- P_{BOP} is not reliable but trents
- casing seal assembly lifted
  If so, would elevate T @ well head.

Norweigen Group has volunteered to do calculation of flow through valve.

Discussion of 5000 bpd leakage — is this likely



Flow Path
① casing
② annulus - lifted casing/seal assembly.

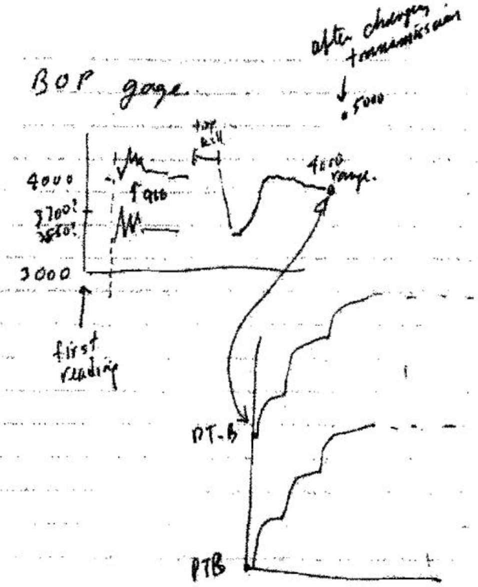
First # at P_{BOP} = 3700 psi

Initial reservoir pressure.
11,850

During top kill P_{BOP} = 4700 psi
Argument for leak < 5 mbp
- Top kill pressure
- temperature modeling
16" - erosion of burst disk hole

68

BOP gage



Bob Merrill [redacted] 281-366-2874 desk
[redacted] cell.

BOP pressure
many ~~cuts~~ changes to back pressure

look for period of
sealing sea pressure 2250
After June 4 – ~~S~~ cap.
to → before Q-4000 started taking flow
June 15 – Q-4000 start taking flow.
see folder in room.

Look for June 4 to last week. BOP gage.

Tim Lockett – modeling of shut in rate.
Farrah ← modeling.

Tina Behr - Andres LANL

Doyouknow
What is the approximate, average thickness of the reservoir? ?

Support
Depletion
Leaks.

Is the reservoir supported by an aquifer.

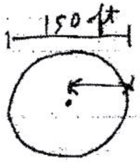
Is the reservoir depleted by ~ 1800 psi

Is there leaks, how big?

Omni [redacted]

[redacted] cancellation # Embessy Suites

detection dimension = 150 ft



~~Reser~~ M110 thickness = 20 ft
porosity = 0.2

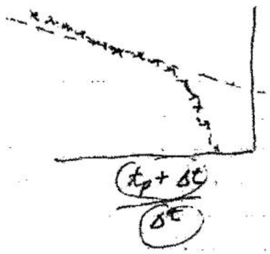
Volume of reservoir = $75ft^2 \times \pi \times 20ft$
= 353,429 ft^3

Volume of oil in reservoir = 353,429 × 0.2
= 70,685 ft^3

1 barrel ~~ft~~ = 5.615 ft^3
= 12,589 bbl

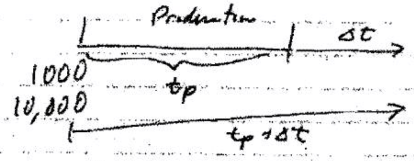
Formation factor = 2.2
Volume of oil in stock tank
= 12,589 stb/

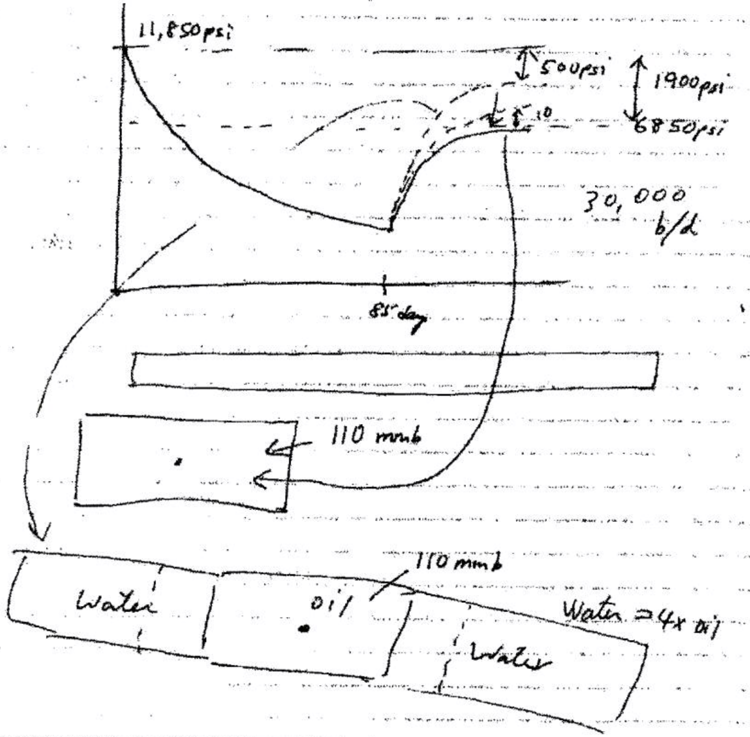
1



160 md = 1.19

1600 md ~~[illegible]~~ 11.9

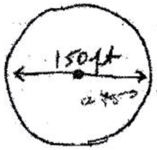




Detection dimension = 150 ft

M 110 thickness = 20 ft

porosity = 0.2



Volume of ~~[illegible]~~ reservoir = $\pi \times (75\,ft)^2 \times 20\,ft$
= $353,429\ ft^3$

Volume of oil in reservoir = 353,429 × 0.2
= $70,685\ ft^3$

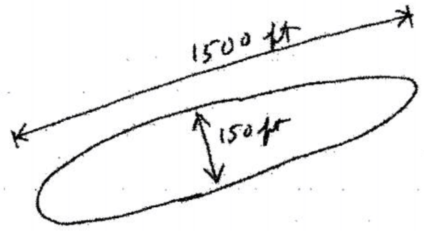
1 barrel = $5.615\ ft^3$

Volume of oil in reservoir = 12,589 stb

Formation factor = 2.2

Volume of oil in stb = $\frac{12,589}{2.2}$ = 5722 stb

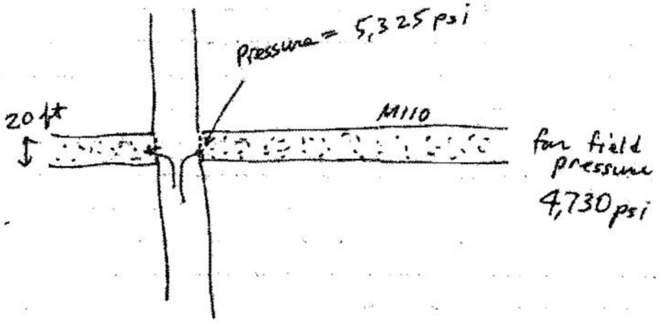
(2)



Volume of oil = 57,220 stb.

Days need to reach detectability

Shape ↓	1,000	5,000	10,000	20,000 ← Leak Rate stb/d
circle	5.7	1.1	0.6	0.3
ellipse 10:1	57	11	6	3



permeability = 500 md
total compressibility = 2.3×10^{-5} $psia^{-1}$

	Leak Rate	Days needed to reach detectability
Circle	10,000 stb/d	0.6 days
Ellipse	10,000 stb/d	6.5 days

k_{major} = 160 md
k_{minor} = 1600 md

TVD	Temp.
WH 5205	
ML 5218	
5471	41
6616	73
8576	105
10100	131
11900	157
13400	179
14900	200
17000	227
18360	244

$$K = \frac{\rho g k}{\mu}$$

$$K_{oil} = \frac{\rho_o g k}{\mu_o}$$

$$k = \frac{K_o \mu_o}{\rho_o g}$$

$$K_{water} = \frac{\rho_w g k}{\mu_w} = \frac{\rho_w \cancel{g}}{\mu_w} \frac{K_o \mu_o}{\rho_o \cancel{g}}$$

$$= K_o \frac{\rho_w}{\rho_o} \frac{\mu_o}{\mu_w}$$

1 MPa = 145.0377 psi

= 81,703 KN/m²

11850 psi = 81.70287 MPa = 817.0287 bars

244 °F = 390.9278 °K = 117.778 °C

$S_s = \rho g c_t$

~~S_{s0} for~~ $S_{s_0} = \rho_0 g n c_t$

www.engineeringtoolbox.com/water-properties-d-1258.html

At 10,000 psia
~~120 °C~~ 250 °F

Water density = ~~63.3~~ 60.6 lbm/ft³ = 971 Kg/m³

Specific heat = ~~1.017~~ .981 Btu/lbm degR =

Viscosity = ~~14~~ 5 ×10⁻⁷ lbf s/ft² = 0.244 cp.

July 21 11:00 am Meeting
see handouts

At T = 244 °F
P = 11,850 psia

density = 980.97 Kg/m³
viscosity = 0.25769 cp

thermal conductivity = 0.72924 W/m·K

C_v = 3.5834 J/g °K
C_p = 4.0772 J/g °K

Ron Dykhuizen
Sandia

July 23, 2010

- Tropical storm declared 6pm, July 22
- Transocean · delatch & evade. away from site 24 hr before storm arrives
- storm packer in well.
- Q4000 – delatched leave site afternoon.

Bubble count from capping stack approximately doubled.

July 28 8:30 am Well Flow meeting.

Provide guidance to leadership on status of where we are in regards to estimation of flow rate.

Current government estimate of Flow Rate 35 - 60 thousand barrels per day

Closure of ~~choke~~ choke may provide better flow rate (lower confidence interval).

55±5 ← DOE estimate of flow rate at present.

Question to consider when modeling
define the time periods (epics)
- initial period after production / later period
- change in well head configuration
- addition of capping stack

#1 focus on Friday - post riser cut flow number
95% confidence bound
summary of how model work

nodal team
reservoir modeling team

conclusion & recommendations

For Friday
- What you modeled
- Model attribute
- assumptions
- uncertainty / concerns
- results
- summary of results

Bill Lehr
- Are DOE previous estimates of 80 too high
Act - we are working ~~&~~ with 55.

George Guthrie
Time -
Release process for view graph - predecisional draft.

(1) Bill - PIV calculation Alberto Alseider 30-45 min
(2) George - 5 teams - nodal analysis, integrated summary. 30 - 45 min
(3) Don - Assumptions - reservoir modeling - 30 min
(4) Paul - 30 minutes.

George Cooper on Steve Chu's science team reservoir engineering - Berkeley

(5) Andy + Rich - late caller in. Woodshole.
May 31
After top kill / during top hat.

(6) DOE ~~&~~ valve closure.

Friday 12:30 central daylight time.

Presentation by 10:00 am to Annie.

July 28 11:00 am BP - Govt WIT meeting.
see viewgraphs.

202-
287- 12pm
6677 noon

IPR arrives
- Tom Buscheck LLNL Livermore
- Art Group
- {Rajesh Pawar - Los Alamos
  Grant Bromhal -

1600

1800

11850

8600
7000
1600

7000

$\frac{\rho}{1g} = \frac{7000}{9.8}$

11450
10250
1600

4.9 ±10%

[5.4]
[4.4]

6695 pressure at start of injection
6609 pressure at end of injection test
303 bbl injected = 1701 ft^3

density of oil in well ≈ 4.74 ppg. = 568 kg/m^3
~~relative~~ density of injected oil = 6.55 ppg = 785 $\frac{kg}{m^3}$

$$\begin{array}{r} 6695 \\ -6609 \\ \hline 86 \text{ psi} \end{array} = 5.9 \times 10^5 \ N/m^2$$

$$\begin{array}{r} 785 \\ -568 \\ \hline 217 \end{array}$$

$$\Delta\rho g h = \Delta p$$

$$h = \frac{\Delta p}{\Delta\rho g} = \frac{5.9 \times 10^5 \ N/m^2}{217 \frac{kg}{m^3} \cdot 9.8 \frac{m}{s^2}} \approx 277 \ m$$
$$\approx 910 \ ft$$

13,000

~~kg~~ $217 \frac{kg}{m^3} \times 9.8 \frac{m}{s^2} \times 13{,}000$

Aug 3 2010 7.5 10 12.5 15 BBL/min

Injectivity Test with Mud.

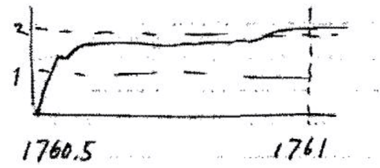
Time	PT-3K-2	BJ Rate ~~PT-3K-2~~	Density lbs/gal
9:13 pm	3903	5.1	
9:18 pm	3919	5.1	
9:22 pm	3924	5.1	
9:28 pm	3952	5.1	13.37
9:46	4195	10	13.25
9:48	4205	10	13.31
9:52	4209	11.7	13.31
9:53	4242	12.4	13.31
9:54	4266	12.5	13.37
9:56	4280	12.5	
9:58	4299	12.5	13.25
9:59	4388	15.0	13.25
10:00	4421	15.0	13.19
10:01	4416	15.0	13.31
10:02	4421	14.9	13.25
10:03	4425	14.9	13.25
10:05	4505	14.9	13.19
10:06	4533	15.0	13.02
10:08	4552	~~15.~~ 14.9	13.19
10:08	4552	10	13.19
10:10	4313	10	13.19
10:14	4294	10	13.19
10:17	4088	5	13.02
10:19	4074	5.1	13.25
10:26	4022	5.1	13.19
10:32	3975	5.1	13.13

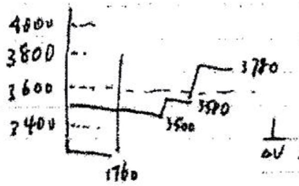
107
48
298
203
656

PT 3K 2 211

3900
frac pressure ~~3600~~

3500 – 3580





37

$\frac{1}{\Delta V}$ $\frac{\Delta V}{\Delta P}$

3780
3500
280

1760	
1760.5	2
1761	2
1761.5	5
1762	5

Aug 4 9 am Static Kill Assessment meeting with
Questions Industry Experts
① What happened - review data, alternative hypotheses, role of annulus
② How to proceed - cement kill
How to choose parameters for cementing job
Relief well.

1 ppg = 0.052 psi/ft

12:50 pm
New modeling results by BP suggest that drill pipe is in the upper part of the well.

10 barrels
800 psi

$\frac{1}{V}\frac{dv}{dp}$ $\frac{1}{656}\frac{10}{800}$ 19×10^{-6} psi^{-1}

$\frac{1}{1735}\frac{10}{800}$ 7×10^{-6} psi^{-1}

$\frac{1}{1000}\frac{10}{800}$

Problem in understanding pressure/volume data
- fracture too soon. (650 bbl)
- fall off after breakdown to gradual (700-1,100 bbl)

1760	3500 psi
1762	3950 psi
Δp	450 psi

.75
.5

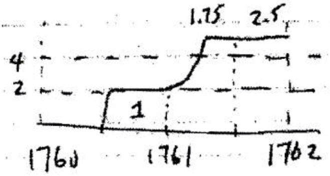
1760	0	
1760.5	2	1
1761	3.5	1.7
1761.5	5	2.5
1762.0		5.2 bbl

$C = \frac{1}{V}\frac{dv}{dp}$

$V = \frac{1}{c}\frac{dv}{dp}$

c = 10 μsips

V = 1155



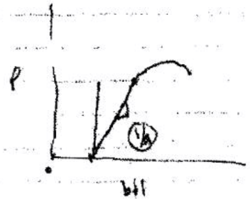
$dV = 5.25$ bbl

$\Delta p = 3950 - 3500 = 450$ psi

$C = \frac{1}{V}\frac{dV}{dp}$ $\qquad$ $c = 10 \times 10^{-6}\ psi^{-1}$

$V = \frac{1}{c}\frac{dV}{dp} = \frac{1}{10^{-5}\ psi^{-1}}\ \frac{5.2\ bbl}{450\ psi}$

$= 1170$ bbl



pahsieh

700 bbl mud $\qquad$ 3450 psi
2 bbl air

14.5 psi

air $\quad$ bulk Modulus 1.0×10^{5} Pa
Comp $= 10^{-5}\ Pa^{-1} = .069\ psi^{-1}$
1 psi $= 6894.757$ Pa

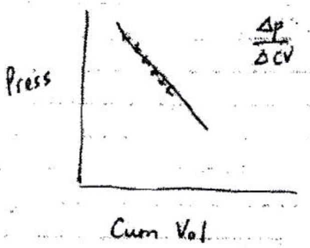
~~.069~~

$$C_{eff} = \frac{1}{V}\frac{dV}{dP}$$
$$= \frac{1}{(V_a + V_m)}\frac{dV_a + dV_m}{dP}$$
$$= \frac{1}{V_a + V_m}\left(\frac{dV_a}{dP} + \frac{dV_m}{dP}\right)$$
$$= \frac{V_a}{V_a + V_m}\left(\frac{1}{V_a}\frac{dV_a}{dP}\right) + \frac{V_m}{V_a + V_m}\left(\frac{1}{V_m}\frac{dV_m}{dP}\right)$$
$$= \frac{V_a}{V_a + V_m} C_a + \frac{V_m}{V_a + V_m} C_m$$

Aug 5 2010 Injectivity with base oil

~14:10 – 14:24 Pump rate ~ 7.2
Pressure drop 6844 to

	P (psi)	Q bpm	Total V (bbl)
~~14:10:12~~	~~6844~~	~~7.2~~	~~206.5~~
14:07:40	6876		
~~14:23:27~~			
14:22:58	6708		



$\frac{\Delta P}{\Delta CV} = -1.45819 \frac{psi}{bbl}$

Friction Loss .726 psi at 7.2 bbm

1 ppg = 0.05194 $\frac{psi}{ft}$

Casing exclud DP

$$\left.\begin{array}{r} 7567\ ft \\ -\ 5067\ ft \\ \hline 2500\ ft \end{array}\right] \to 107\ bbl$$

$\frac{\text{Casing Vol}}{ft} = \frac{107}{2500} = 0.0428 \frac{bbl}{ft}$

Injecting 1 bbl would displace - 23.36 ft → decrease of 2.184 psi

reservoir oil density 4.75 ppg
base oil density 6.55 ppg] difference = 1.8 ppg = .0935 $\frac{psi}{ft}$

Casing include DP

$$\begin{array}{r} 7567 \\ 5067 \\ \hline 2500\ ft \end{array} \to 163\ bbl$$

$\frac{\text{Casing Vol}}{ft} = \frac{163}{2500} = 0.0652 \frac{bbl}{ft}$

Injecting 1 bbl would displace 15.33 ft → decrease in pressure by 1.43 psi

1785
2097

1:30 pm Aug 6 2010

Monitoring Protocol from now until when DD3 enters the annulus of the Macondo

Propose standard monitoring plan to science team.

Bigalow - once a day over the well.
one ~~raw~~ run or average several runs?

tomorrow Nicola tomorrow - last seismic run.
conditional seismic run after DD3 entering Macondo.

wellhead geophone left on. pull data and remount. ~~to~~ Keep until DD3 enters Macondo

Discontinue wellhead temperature

~~E~~ Monitor for surface sheen by overflight.

stop temperature
stop big ears.

Pisces/Bigalow every 48 hours.

August 10 11:00 conference call

Relief Well -
Tropical storm forming in Gulf of Mexico.
Expected to track over site
Will ~~set~~ set packers but will not detach from riser pipes. Will "sit out" the storm.
Activities suspended 3 - 5 days.

Discussion - Relief Well intersect might have negative consequence on Macondo well. static test might help to manage risk.

Relief well is expected to intersect Macondo well just below the 9 7/8 in shoe. There should be mud in the annulus.

Pressure response in annulus will depend on whether or not the annulus is connected to the reservoir.

If annulus is connected to the reservoir, then intersection of the relief well will cause fracturing of reservoir and there is not pressure increase in the capping stack.

If annulus is not connected to reservoir, then there might be pressure building in capping stack.