Transcription of Brian Morel interview notes
commenced 1040 hrs 27-Apr 2010

panel: Rex Anderson, Matt Lucas, Jim Wetherbee, Warren Winters

Opening discussion:

prior experience Anadarko Basin (challenge), Mad Dog (challenge), planning Macondo
was on rig for cleanout run (Thu), stayed thru Tue AM
at start of prod hole had high FIT (formation integrity test) above OB (overburden)
once drlg prod hole encountered losses, so reduced MW (mud weight) from 14.5 to 14.3 ppg
while drlg a sand zone Geotap showed 14.12, 14.16 ppg formation pressure
while drlg a deeper producing sand Geotap showed 12.6 ppg, originally thought low hence a tool error but later confirmed correct
while drlg a subsequent sand, drlg progress stopped (suspected underreamer failure) while losing 300-400 bbl/hr mud
pumped emergency lost circulation material without improvement
pulled into marine drilling riser, reduced mud weight, pumped Formaset
losses stopped holding 14.0 ppg mud (surface) 14.2 ppg (bottomhole due to compressibility)
ran new bottomhole assembly and drld 100 ft of rathole to provide room for logging tools
downhole ESD 14.16-14.2 ppg
logging went smoothly but rotary sidewall coring experienced differential pressure problems
encountered bridges at 12,272' and 12,280'
recorded 1100 units gas on bottoms-up, eventually decreased to 20-30 units
pumped out of hole and flow-checked at liner top
ran ca. 5800 ft 7" casing crossed-over to 9-7/8" casing
bought 7" casing from Nexen due to short lead-time
the XO came from R&M Machine
circulated, converted float equipment, diverter closed without issue
difficulty converting Weatherford float equipment but Weatherford rep. was not on rig so Allamon rep. recommended procedures to convert
called Houston (J. Guide) thinking reamer shoe was plugged so staged up pumping to clear shoe
1 bpm showed 125 psi, 4 bpm showed 400 psi which seemed low vs. modeled pressures

closed annular, pumped down C&K lines, pumped down DP and things looked okay
decided rig standpipe pressure gauge was incorrect
7bbls, 20bbls of 14.3 spacer, 5bbls cement job, 39 foam, 7 shoe track, 20 bbls spacer, 2bbls 4/m
modeled cement job in advance w/EPT assistance
did not see bottom dart release, attributed to calculation error by Allamon
saw top plug release
standpipe pressure and cementing unit pressure agreed but both were several hundred psi below model
saw 7" plug pass thru XO

4502
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saw bottom plug land 9 bbl ahead of plan
saw top plug land per plan
bled back and observed normal "no flow" which was actually a trickle attributed to "lines cleaning up"
next released from Drill Quip hanger/seal assembly
6 turns to right to release
pressure to 4 ksi, then 10 ksi for 10 sec to set seal assembly then held 6.7 ksi
tested for 1 hr vs. 5 min. as planned because pressure was observed decreasing ca. 5 psi/min throughout test
sheared out running tool, pulled 10 ft above wellhead and circulated
stabbed running tool in wellhead, applied 10 ksi for 10 sec, then hel 6.5 ksi losing 5 psi/min eventually reducing to 4 psi/min for 10 min.
went to bed, awoke next AM
wrote operations notes on negative test procedure, spoke to WSL & mud engineer about it for input & understanding
next contact learned rig on fire

Upon later review:
there are questions around the negative test
cementing unit was lined up to drill pipe to observe pressure
flowed back to either choke or kill line
saw 1400 psi on drill pipe so expected pressure or flow to cementing unit (seawater in line)
did not observe flow so concluded something must be plugged
displaced from 8300' to mudline to set cement plug
to run lockdown sleeve on same run to have at least 100 klb weight below lockdown sleeve
there was worrying on rig about the next operation (PxA on Nile)
were attempting concurrent activities
were planning riser cleanout run

Inquiry about rig communications culture:

rig is performance driven with strong history & record of safety & drilling performance
some operations are unfamiliar to the rig such as PxA on Nile
TxA is standard having run production casing before
no BP safety rep. on rig anymore
TO safety onboard, did observe that they do tape off before every pressure test, lift lines operated properly, safety meetings conducted
nothing sensed out of ordinary that day
were pumping and cleaning out mud pits
zero TIR and proud of that
emphasis on staying focused at all times
stop the job mentality, free to ask for clarity
John Guide and David Sims have been instrumental in ensuring uptake of BP safety culture by 3rd party personnel

Inquiry about nitrified cement job:
normal cement slurry is up to 16.9 ppg but working with fracture gradient of 16.1 ppg originally thought to be 15.1 ppg
formation was only tested to 14.5 ppg
thought loss zone was at bottom of sands

15% N2 foam reduces density of 16.7 ppg cement to 14.5 ppg
14.5 ppg cement plus base oil provided needed 14.2 ppg hydrostatic pressure in annulus
MOC in place for N2 cement job
Halliburton predicted 15.0 ppg EMW without base oil in annulus

Noticed cement job originally planned incorrectly relative to subsequent MDT data
EPT cementing expert advice led to 14.2 ppg design basis
purposely designed top of cement to be below 9-7/8" casing
used caliper data to compute hole volumes
top of cement designed to be 500 ft above17,800' sand per MMS requirement
circulating cement inside narrow 9-7/8" liner annulus would have caused pressure spikes above 15.0 ppg
floats were checked after pressure was released, allowing 5 bbl for compressibility set 6 bbl flowback as threshhold for acceptance
leave 40-50' in case they are off by one joint in the count
5.5 bbl flowed back reducing to a "finger tip trickle" hence deemed okay
other BP rigs have pumped N2 jobs including Marianas which started the well
N2 on production casing was new for Deepwater Horizon but they have used N2 on shallower strings

was on the rig 3 days before cement job, held large meeting to discuss cementing plan
issued step-by-step addendum to preliminary procedure

followed with another cementing meeting including toolpushers for both tours and OIM
did safety risk assessment
three (3) 7" casing joints were laid out due to galled connections

Inquiry about negative test procedure:

seal assembly tests are Dril-Quip procedures per instructions of onsite Drill-Quip rep.
Drill-Quip issued updated recommendation raising 3 ksi to 4 ksi
TO accepted 10ksi on pipe rams for 10 sec.
6.5 ksi test based on prior BOP test pressures
per Dril-Quip book only 1 test recommended but onsite rep. advised 2nd test due to prior issues where seal assembly pulled out

if negative test unsuccessful the decision tree says contact John Guide
on that night Mark Hafle was called but was unaware of drillpipe pressure
was told they had an issue that was resolved
he got the impression there was a good negative test
each rig does negative tests their own way
displaced from cement plug depth to annular preventers with seawater in order to set cement plug

displaced choke & kill lines to wellhead with seawater, tested lines, opened one line and drill pipe back to cementing unit to check for flow for cementing unit or pits
annular was closed
target was a hydrostatic pressure reduction of 2350 psi
this simulates final TxA condition
the procedure is a bulleted ops. note copied to WSLs
MMS must approve cement plug depth but not negative test

MMS rules require leaving kill weight mud in casing, therefore this was less and required dispensation
procedure said open kill line, with drill pipe open to monitor pressure
they (on rig) knew about pressure on the drill pipe but observed no flow from kill line; not reported to town
toolpusher & driller said it was due to annular BOP affect
gas in kill line would freeze in presence of low-temp seawater
no protocol to witness or verify negative test
ops. note directs results of positive test should be sent to Houston but no similar requirement for negative test
the 3 required tests are: seal assembly, positive casing test, negative test
Brian drew a U-tube diagram on whiteboard to elaborate setup of negative test

Discussion turned to:
make-up torque applied to 7" doubles in Smith yard
the HYD513 connections have been known to back-out, so were checked for proper torque on rig
casing make-up torque is checked on rig but not recorded using visual confirmation of tong pressure
Brian was present when 7" x 9-7/8" crossover was made-up

Inquiry about how MOCs and communications protocols are handled:
minor changes, i.e., drill bit is communicated verbally by engineer to team & rig
major changes use BP MOC process
all problems are discussed with ops. Leader, team leader and upward depending on severity

in relation to above, drilling procedure indicates negative test should last 30 min.
data does not indicate 2 full negative tests
had engineer been alerted to drill pipe pressure, John Guide would have been contacted

lead-time on production casing was shortened when 13-5/8" was set shallower than planned
it was a quick process within 2 weeks following sidetrack
re-checked casing design with EPT expert Steve Morey
re-checked APB with EPT expert Richard Miller
verified Nexen 7" casing certs. with Morey
casing was Q125 but XO was P110 as approved by Morey

adjourned 1220 hrs