The Case History of an Underground Flow Offshore Texas

An Interactive Group Learning Exercise

Developed by
John Rogers Smith, P.E., Ph.D.
Louisiana State University

Funded by
Minerals Management Service
U.S. Department of the Interior
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Overview

- Begins during platform development drilling during 1980’s
- The real beginning a few months earlier
- Focus on “Turning Points”
Mudlog
6th Well
Unanticipated Pressure

- Kill wt. mud
  \[ = \text{mud wt.} + \frac{\text{SIDPP}}{(.052 \times \text{TVD})} \]
  \[ = 9.8 + \frac{600}{(.052 \times 8710')} \]
  \[ = \underline{\hspace{1cm}} \]

- Drill pipe stuck

- Required 13.6 ppg mud to stop flow

- Cemented drillstring in hole
Unanticipated Pressure

- Moved well location
- Took kick 30’ shallower in same drilling break; shut in immediately; 3 bbl. gain
- Kill wt. mud
  = $12.6 + \frac{800 \text{ psi} \times 0.052 \times 8680'}{0.052 \times 8680'}$
  = 14.4 ppg
  (Note: Pressure at shoe exceeds the fracture pressure)
- Pipe stuck while working it through the Hydril
- Killed well with 14.4 ppg
- Cemented drillstring in well to plug back
What's Wrong Here?

Geologic Possibilities

- Pressures higher in section due to being in different fault block
- Pressures shallower than offsets due to missing stratigraphic section

*Neither geologic possibility was supported by either geological or geophysical data*

Man Made Possibilities

- Pressure transfer in offset well
- 5th well was one of the following:
  - closest offset
  - had seen this section normally pressured
  - had a major well control problem deeper
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Reaction

- Establish ad hoc, multi-disciplinary team including division operations manager and assigned essentially full time to this problem
  - Drilling Engineers
  - Drilling Supervisors
  - Production Engineers
  - Log Analysts

- Re-enter 5th well

- Clean out to TD

- Run logs:
  - temperature
  - noise
  - cement bond
  - pulsed neutron

- Check annulus pressures
Temperature Log
Before
Noise Log
Before
Cement Bond Log

“Free Pipe” From 11900’

(170’ Below 9 5/8” Shoe) To 14100’
How Did We Get In This Shape?

Let’s review the “Well Control Problem” in the 5th well
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Well Plan

BOP's 10,000 psi WP
7,500 psi Test

Casing Burst = 8150 psi

Implications:
1. Similar to four previous successful wells
2. Maximum possible SICP = 9723 psi
3. Kick tolerance = Gas Kick of 670' ~ 22 bbls

11-3/4" 60# N-80 Casing
@ 10389' MD · 10066' TVD

9-5/8" 47# HC-95 & P-110 Casing
@ 11730' MD · 11407' TVD
Fr. Gr. = 18.7 ppg = 11092 psi

13230' MD · 12892' TVD
Pore Press. = 17.7 ppg = 11851 psi @ 12892' TVD
13630' MD · 13292' TVD
8-1/2" Hole

TD @ 14250' MD · 13911' TVD
Offshore Texas Case History

Well Plan

Assumption:
Under-reaming and slow running speeds would allow 7-5/8" liner to succeed as had prior 7" liners

Implications:
Tighter clearances in overlap and at liner hanger not critical during running or cementing

11-3/4" 60# N-80 Casing
@ 10389' MD · 10066' TVD

Squeeze Tool
(Not Set)

9-5/8" 47# HC-95 & P-110 Casing
@ 11730' MD · 11407' TVD
Fr. Gr. = 18.7 ppg = 11092 psi

8-1/2" Hole

7-5/8" 38# p-100 FL-4S Liner
13230' MD · 12892' TVD

Gas Sand

Pore Press. = 17.7 ppg = 11851 psi @ 12892' TVD
13630' MD · 13292' TVD
approx. 10" Hole

TD @ 14250' MD · 13911' TVD
Running Operation

Known:
1. Run very slowly
2. Run with "pump open shoe"

Unknown:
1. Whether shoe was opened to allow inside flowback while running
2. Whether displacement was measured or was correct during running
3. Actual by-pass area on inside or outside of liner equipment

Results:
1. Run and hung OK
2. Could not get any returns around liner
Assumption:
Under-reaming would avoid excessive ECD

Result:
Almost no returns during cementing, no other indication of fluid level in annulus (only had to fall 140' take kick)
After Cementing Operations:
1. Pick up 3 stands
2. Reverse out with "nearly full returns"
3. Open Hydril, well flowing
4. SIDPP = 150 psi
   SICP = 150 psi

Cause of Kick:
Flow after cementing
or
Loss of hydrostatic (If >140')

Implication:
Well probably static after shut-in
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**Attempt to "Control" – a turning point**

**Operations:**
Attempt to circulate gas out with constant DDP

**Implication:**
Constant pressure at end of drillpipe ≠ Constant pressure at gas sand

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9-5/8" 47# HC-95 & P-110 Casing
@ 11730' MD · 11407' TVD
Fr. Gr. = 18.7 ppg = 11092 psi

8-1/2" Hole
approx. 10" Hole

800' Gas

Wellbore Pressure = 11809 psi

Pore Press. = 17.7 ppg = 11851 psi @ 12892' TVD

13230' MD · 12892' TVD
13630' MD · 13292' TVD
7-5/8" 38# p-100 FL-4S Liner
approx. 10" Hole

TD @ 14250' MD · 13911' TVD
Loss of Control

**Operations:**
Circulated for 3-1/2 hours (700 bbls)

**Results:**
1. "Gained 75 bbls"
2. SICP increased 5000 psi

**Implications:**
1. Nearing design basis SICP = 6170 psi
2. Pressure at 9-5/8" shoe exceeding fracture pressure
3. Underground transfer in progress
Loss of Control

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Attempted Recovery

Operations:
1. Ineffective attempt to lubricate annulus (6 bbls pumped)
2. Ineffective attempt to "lubricate" down drillpipe (26 bbls pumped)
3. Attempt to "test shoe" by pumping 8 bbls in annulus; drillpipe and casing pressure increased as if in closed system
   Max. SIDPP = 2000 psi
   Max. SICP = 6200 psi
4. Bleed gas to "flow" well and then attempt to pump in annulus; pressure broke back on second try
5. Pump 588 bbls mud in annulus
**Offshore Texas Case History**

### Attempted Recovery

**Operations:**
1. Close Hydril, equalize below
2. Open pipe rams
3. Set squeeze tool
4. Inject at 3 bpm and 2500 psi
5. Squeeze Liner top with 40 bbls of fresh water followed by 385 SX class "H" cement and displace to liner top and hold pressure 13 hrs

### Implication:
SIDPP + hydrostatic after squeeze
≈ 11100 psi ≈ Fr. Gr. = 18.7 ppg EMW
Confirming Recovery

1. No flow from well

2. Cement tested to +3000 psi

3. Dressed off liner top cement and tested to +3200 psi for 30 min.

4. Test liner top with water cushion in stages to –2300 psi ~14.5 ppg EMW for one hour

5. Ran liner tieback

Turning point:

No attempt to confirm that probable (in hindsight) underground flow had been stopped or that pressure source on 11 ¾” x 9 5/8” annulus was shut off.
Recovery

Now we are back to where we started the review:

What are we going to do to stop the apparent on-going underground flow?

Kill it?

or

Bridge it?

Can we kill it?
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**Flowing Bottom Hole Pressures**

**For Dynamic Kill**

- **Flowing BHP (PSI)**
  - 13500
  - 13000
  - 12500
  - 12000
  - 11500
  - 11000

- **Gas Rate (MMCFD)**
  - 10
  - 1

Demonstrates 5 BPM kill for assumed conditions

Assumes:
- Back pressure = 11092 psi
- 11.7 ppg fracture gradient
- Length = 1500' to TOS
- 1900' to BOS

Reservoir Pressure = 11902 psi at BOS

Fracture Pressure at loss zone

5 BPM and gas at top of sand

Dry gas up 10" x 7-5/8" Ann - 1900' (at base of sand)

IPR at BOS
Recovery

Operations:
1. Pump 18 ppg mud thro drillstring to 5700 psi "breakdown" pressure; then pump 3 bbls at 300 psi thru 7-5/8" shoe -drillstring on vacuum- then "static" for rerunning logs
2. Retest 7-5/8" shoe, broke down at 800 psi and bled to 0 psi
3. Cement through shoe with 500 SX thixotropic +300 SX class "H"
4. Test 7-5/8" shoe to 3350 psi
5. Rerun temp and noise logs
6. Run CBL
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Recovery

Operations:
1. Perforate and squeeze 400 SX class H cement at top of sand
2. Cleanout and run CBL
3. Perforate at top of prior squeeze and squeeze 400 SX class H cement
4. Cleanout and run CBL
5. Reperforate and squeeze interval with 400 SX class H cement and over-displace
6. Resqueeze with 400 SX and over-displace
7. Resqueeze with 400 SX and leave cement in 7-5/8"
8. Cleanout
9. Run CBL, temp and noise logs
Temperature Log
Before vs. After
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Noise Log

Before

After
Cement Bond Log

Before

· “Free Pipe” from 11900’

· (170’ Below 9 5/8” Shoe) To 14100’

After

· Cement with some bonding to both pipe and formation from 13200’ to 14100’ (Throughout major gas sand)

· 20’ cement seal at top of gas sand (where multiple “Squeezes” were performed)

· Some additional cement up to 12950’ (Confirmed with tracer)
## Offshore Texas Case History

<table>
<thead>
<tr>
<th>Phase</th>
<th>Critical Issue</th>
</tr>
</thead>
<tbody>
<tr>
<td>Planning</td>
<td>Risk of lost circulation with tight clearances not mitigated</td>
</tr>
<tr>
<td>Avoidance</td>
<td>No record of displacements</td>
</tr>
<tr>
<td>Detection</td>
<td>Poor, hole not kept full</td>
</tr>
<tr>
<td>Reaction</td>
<td>Good, shut-in when flow seen</td>
</tr>
<tr>
<td>Control</td>
<td>Poor, squeeze plan not followed, Driller’s method improperly applied</td>
</tr>
</tbody>
</table>

### Original “Kill”:

- **Loss of Control**: Not identified
- **Recovery**: None – only isolated
- **Confirmation**: None

### Second Kill:

- **Loss of Control**: Inferred by kicks, logs confirmed
- **Second Recovery**: Planned, evaluated after each step
- **Confirmation**: With comparison to baseline logs