Formate brines as non-damaging drill-in and completion fluids for HPHT wells

What have we learnt from the first 100 jobs?

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Cabot Specialty Fluids

IQPC Formation Damage Control, Kuala Lumpur, 10-13 September 2007
Presentation outline

• What is wrong with traditional HPHT well construction fluids?
• How did formate brines evolve to provide a new solution?
• What benefits do formates bring to HPHT well constructions?
• How has cesium formate brine performed so far?
• Laboratory formation damage testing with heavy brines
Some reference documents

- **SPE 73766**  Formate brines – A Comprehensive Evaluation of Their Formation Damage Control Properties Under Realistic Reservoir Conditions

- **SPE 97694**  Improving Hydrocarbon Production Rates Through The Use of Formate Fluids – A Review

- **SPE 99068**  Drilling and Completing Difficult HPHT Wells with the Aid of Cesium Formate Brines – A Performance Review
What is wrong with conventional HPHT drilling fluids?

- High levels of weighting solids create problems
  - High ECDs
  - Potential to sag
  - High swab and surge
  - Differential sticking risk
  - Formation damage (intractable)
  - Failure of hydraulically-activated tools and valves
What is wrong with conventional oil-based HPHT drilling fluids?

- Oil phase can create well control problems
  - Oil is a good solvent for natural gas
  - Can create a well control problem if left static in horizontal well
  - Gas/condensate influxes can destabilise oil-based muds
  - Well control problem created by barite sag after destabilisation
What is wrong with conventional HPHT completion fluids?

• Environmental contamination of halide brines can cause structural failure in Corrosion Resistant Alloys (CRA – 13Cr, 22Cr, 25Cr)

• Chloride and bromide* brines can cause pitting corrosion and Stress Corrosion Cracking of CRA if O₂ or CO₂ are present

* 1. Craig, B.D., SPE 93785 “Stress Corrosion Cracking of CRA in Brine Packer Fluids”
2. Downs, J.D., SPE 100438: "Effect of Environmental Contamination on the Susceptibility of Corrosion Resistant Alloys to Stress Corrosion Cracking in High-Density Completion Brines"
Stress cracking of CRA in CaBr$_2$ brine
160°C, 0.2 bar O$_2$ (CO$_2$ gives same problem)

Downs et al, Royal Society of Chemistry – Chemistry in the Oil Industry Conference
Manchester, UK, 1st November 2005
Making a better HPHT drilling/completion fluid

Remove **weighting solids, oil and halides** to correct the fluid performance deficiencies

- Reduce the flow resistance
- Improve well control
- Reduce local corrosion and SCC
- Reduce formation damage
Objective: Design an improved HPHT drilling-in and completion fluid that was free of the bad stuff

- Free of solids
- Free of oil
- Free of halides
Shell’s strategy – base the new fluid on a non-halide brine

Brine specifications

- Density to at least 19 ppg
- Safe
- Minimal environmental impact
- Non-corrosive
- Compatible with elastomers
- Minimal formation damage
- Shale stabilising
Formate brines – ideal non-halide brines

- Sodium, potassium or cesium formates dissolved in water
- Density up to 2.3 SG
- Non-toxic
- Safe to handle, pH 9-10
- PLONOR and biodegradable
- Non-corrosive, no SCC
- Protect against CO$_2$ corrosion
- Minimise formation damage
- Protection for polymers against thermal degradation
Formate brines – ideal non-halide brines

- Lubricating
- Hydrate inhibition
- Positive influence on shales*
  - reduce shale swelling
  - reduce filtrate invasion
  - reduce pore pressure penetration
  - induce osmotic back-flow

* Potassium formate has been used in over 300 wells as shale drilling fluid
No stress corrosion cracking of CRA with formate brines in presence of $O_2$ or $CO_2$

SG 1.7 K/Cs formate, 160$^\circ$C, 10,000 ppm Cl with 0.2 bar $O_2$

Ref: SPE 100438
# Typical low-solids drill-in fluid formulation based on formate brine

<table>
<thead>
<tr>
<th>Component</th>
<th>Function</th>
<th>Concentration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formate brine</td>
<td>Density</td>
<td>1 bbl</td>
</tr>
<tr>
<td></td>
<td>Lubricity</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Polymer protection</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Biocide</td>
<td></td>
</tr>
<tr>
<td>Xanthan</td>
<td>Viscosity</td>
<td>1 – 2 ppb</td>
</tr>
<tr>
<td></td>
<td>Fluid loss control</td>
<td></td>
</tr>
<tr>
<td>PAC and modified starch</td>
<td>Fluid loss control</td>
<td>4 – 8 ppb</td>
</tr>
<tr>
<td></td>
<td>Minimal viscosity contribution</td>
<td></td>
</tr>
<tr>
<td>Sized calcium carbonate*</td>
<td>Acid-soluble filter cake agent</td>
<td>15 – 20 ppb</td>
</tr>
<tr>
<td>$\text{K}_2\text{CO}_3/\text{KHCO}_3$</td>
<td>Buffer</td>
<td>2 – 8 ppb</td>
</tr>
<tr>
<td></td>
<td>Acid gas corrosion control</td>
<td></td>
</tr>
</tbody>
</table>

**Important note:** Use of >30 ppb solids cancels out some important benefits!!
Formate-based drilling fluids
Formate brines – benefits in HPHT well construction operations

Reduced risk of differential sticking

- Very thin lubrious filter cakes
- Reduced risk of differential sticking at high overbalance
Formate brines – benefits in HPHT well construction operations

Better hydraulics

- Lower surge and swab pressures
  - Faster tripping times
  - Reduced risk of hole instability or well control incidents
- Lower system pressure losses
  - More power to motor
- Lower ECD
  - Drill in narrower window between pore and fracture pressure gradients
  - Less chance of fracturing well and causing lost circulation
- Higher annular flow rates
  - Better hole cleaning
- No failure of hydraulically-activated tools and valves
Formate brines – benefits in HPHT well construction operations

Improved well control and reduced risk

- Barite sag eliminated (no barite!)
- Thermal equilibrium reached quickly
  - Reduces flow-check time
- Low methane solubility and diffusion rates (no oil!)
  - Easier kick detection
  - Low rate of static influx
- Mud properties not degraded by gas influx

Solubility of methane in drilling fluids: T = 300°F (149°C), P = 10,000 psi (690 bar)

<table>
<thead>
<tr>
<th>Fluid</th>
<th>Solubility (kg/m³)</th>
<th>Diffusion coefficient (m²/sec x 10⁸)</th>
<th>Diffusion flux (kg/m²s x 10⁶)</th>
</tr>
</thead>
<tbody>
<tr>
<td>OBM</td>
<td>164</td>
<td>1.15</td>
<td>53.30</td>
</tr>
<tr>
<td>WBM</td>
<td>5</td>
<td>2.92</td>
<td>3.98</td>
</tr>
<tr>
<td>Formate brine</td>
<td>1</td>
<td>0.80</td>
<td>0.25</td>
</tr>
</tbody>
</table>
Formate brines – benefits in HPHT well construction operations

Reduced formation damage

- Zero or very low level of solids (and no barite)
- Thin impermeable filter cake to minimise filtrate invasion
- Self cleaning – filter cake has low lift-off pressure
- Filter cake soluble in dilute organic acid (never needed)
- Brine filtrate is inherently non-damaging*
- Completion in same fluid, avoiding filtrate incompatibility
- Same fluid base used for kill pills, perforating, gelled LCM

* Any residual filtrate appears to produce over time in the field.
  In the lab it can be mobilised with formation water (SPE 105733)
Formation damage by formate brines

What do the laboratory core analysis experts say?

“In a large number of laboratory formation damage tests.. formate-based drilling and completion fluids have demonstrated no unusual or significant formation damage potential” *

“This finding is in keeping with evidence from numerous field applications of formate brines where many oilfield operators have reported well productivity improvements”*

* Byrne et al., in SPE paper 73766, reviewing more than 40 return perm test results with formates on cores from many different reservoir types worldwide
Formation damage caused by exposure to well construction fluids

Formation damage results from unintentional reduction in:

- Pore throat size
- Relative permeability
- Fluid mobility
Formation damage – the hydrocarbon habitat

- Clay particles and water
- Framework grains
- Cement

CONTINUOUS OIL
GRAIN
Causes of reservoir pore throat size reduction during exposure to well construction fluids

- Plugging by mineral particles, polymers or bacteria
- Salt precipitation (filtrate incompatibility)
- Migration of pore-lining clays
Results of laboratory core flooding tests with formate brine

Effect on reservoir pore throat size

- No permanent plugging
  - filter cake tends to lift off easily under drawdown
  - any residual filter cake is soluble in dilute organic acids
  - formate filtrates are sterile and biocidal
- No scaling salt precipitation
  - formate brines cannot create scaling precipitates
- No disturbance of pore lining clays (e.g. see SPE 38156)
  - formate brines stabilise clays
  - no mobilisation of clay fines
Causes of relative permeability reduction during exposure to well construction fluids

• Fluid saturation change
• Fluid entrapment – capillary and clay adsorption
• Alteration of surface-wetting properties
Results of laboratory core flooding tests with formate brine

Effect of formate filtrate on relative permeability

• Occasional instances of filtrate retention in lab tests
  - may reduce relative permeability to gas by 30-70% in core tests
  - wash with formation water or dilute acid restores 100% perm *
  - no effect in field* except sometimes an extended clean-up time**

• No alteration of surface wettability
  - formate brines contain no surface-active agents

* Huldra (SPE 74541) and Kvitebjørn (SPE 100573): No intervention needed – no skins
** Rhum (SPE paper in preparation): WHP and production increased over several weeks as perforations cleaned up
Example of the effect of formate filtrate retention in cores from HPHT Huldra field*

<table>
<thead>
<tr>
<th>Sample</th>
<th>Fluid</th>
<th>Filtrate loss (ml)</th>
<th>Base perm to gas (mD)</th>
<th>Perm after 13 days mud flow followed by drawdown (mD) (% change on base perm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1A</td>
<td>Formate field mud</td>
<td>15.4</td>
<td>1416</td>
<td>881 (-38%)</td>
</tr>
<tr>
<td>2B</td>
<td>Formate field mud</td>
<td>11.7</td>
<td>2.9</td>
<td>1.17 (-59%)</td>
</tr>
<tr>
<td>6A</td>
<td>Formate laboratory mud</td>
<td>10.5</td>
<td>1978</td>
<td>1272 (-36%)</td>
</tr>
<tr>
<td>4D</td>
<td>Formate laboratory mud</td>
<td>8.4</td>
<td>7.5</td>
<td>3.64 (-51%)</td>
</tr>
</tbody>
</table>

* SPE 73766
A mild acid wash releases retained formate filtrate in cores from HPHT Huldra field*

<table>
<thead>
<tr>
<th>Sample</th>
<th>Fluid</th>
<th>Filtrate loss (ml)</th>
<th>Base perm to gas (mD)</th>
<th>Perm after mud flow, 15% acetic acid wash and drawdown (mD) (% change on base perm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>7A</td>
<td>Formate field mud</td>
<td>18.5</td>
<td>2 198</td>
<td>2 341 (+6.5%)</td>
</tr>
<tr>
<td>6B</td>
<td>Formate field mud</td>
<td>12.3</td>
<td>3.5</td>
<td>3.56 (+2.6%)</td>
</tr>
<tr>
<td>8A</td>
<td>Formate laboratory mud</td>
<td>12.5</td>
<td>1 988</td>
<td>1 982 (-0.3%)</td>
</tr>
<tr>
<td>4B</td>
<td>Formate laboratory mud</td>
<td>10.0</td>
<td>10.9</td>
<td>10.7 (-1.8%)</td>
</tr>
</tbody>
</table>

* SPE 73766
Results of drilling and completing with cesium formate brine in Huldra field, Norway

• Excellent PIs on all six wells
• Average 1.9 million scf/day/psi
• Plateau production from first three wells
• No sign of filtrate retention effects
• No need for acid clean-up

See SPE 74541
Example of effect of formate filtrate retention in cores from HPHT Kvitebjoern field *

<table>
<thead>
<tr>
<th>Core sample</th>
<th>Fluid</th>
<th>Initial gas permeability (mD)</th>
<th>Final gas permeability (mD)</th>
<th>% reduction in permeability</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Formate mud</td>
<td>29</td>
<td>10.15</td>
<td>65</td>
</tr>
<tr>
<td>2</td>
<td>Formate mud</td>
<td>26.1</td>
<td>7.3</td>
<td>72</td>
</tr>
<tr>
<td>3</td>
<td>Formate mud</td>
<td>46.1</td>
<td>13.4</td>
<td>71</td>
</tr>
<tr>
<td>4</td>
<td>Formate mud</td>
<td>51.6</td>
<td>31.5</td>
<td>39</td>
</tr>
</tbody>
</table>

All cores regained 100% native permeability after flushing with 2 PV of formation water

* SPE 105733
Results of drilling and completing with cesium formate brine in Kvitebjørn field, Norway

- “High production rates with low skin”
- No signs of filtrate retention effects
- LWD passes show filtrate being replaced by gas *
- Operator states: “We selected cesium formate to minimise well control problems and maximise well productivity”

* See SPE 105733
Cause of fluid mobility reduction during exposure to well construction fluids

Filtrates create viscous emulsions with in-situ hydrocarbons
Results of laboratory core flooding tests with formate brine

Effect of formate filtrate on fluid mobility

- No emulsion formation
  - formate brines contain no surface-active compounds
  - no divalent cations to form soaps
  - no evidence of emulsions in lab return perm tests
Key applications for formate brines

Drill-in and completion fluids for challenging HPHT development wells, typically:

- Sub-sea
- High angle, extended reach
Cesium formate applications in HPHT wells 1999-2007

Over 100 HPHT well construction jobs in 24 fields – North Sea, Europe, USA and South America

- Drill-in (BHST up to 236°C)
- Completion/workover
  - as a brine and in LSOBM formulations (SG 1.62 max.)
  - excellent perforating record (Rhum, Visund, Braemar, Judy)
- Long-term well suspension
- Melting hydrate plugs

At least another 100 HT drill-in and completion jobs with potassium formate brine since 1996
Feedback from users of cesium formate –
Extracts from SPE papers

General

• “Major operational success”
• “Drilling benefits have given rig time savings”
• “New record for shortest time to complete HPHT well in N. Sea”
• “Transition from drill-in fluid to completion fluid was simple”
• “For our specific well conditions there was no other alternative”
• “Selected cesium formate to minimise well control problems and maximise well productivity”

Note: This is the only high-density brine that can be used as a combined HPHT drilling and completion fluid
Feedback from users of cesium formate –
Extracts from SPE papers

Well control

• “No well control or loss situation”
• “Extremely good well control environment”
• “No sag potential”
• “Elimination of gas diffusion into horizontal wells”
• “Well stabilises quickly during flow checks”
• “Unique track record: 15 HPHT wells drilled and completed with cesium formate brine without one well control incident”
Feedback from users of cesium formate – Extracts from SPE papers

Hydraulics

• “ECD is SG 0.04 – 0.06 (0.30 – 0.50 ppg) lower than OBM”
• “Reduced ECD improved ROP in hard formations”
• “Fast tripping speeds”
• “ECDs higher when drilling clay than when drilling sand”

Lubrication

• “Torque values indicate friction factors as low as 0.22”
• “No need to add lubricants”
• “Low torque and drag”
Feedback from users of cesium formate – extracts from SPE papers

Hole stability and cleaning

- “Good hole stability in interbedded sand and shales”
- “Good hole stability”
- “Caliper log of 8-1/2” hole shows 9” in shale sections..”
- “Good hole cleaning”
- “Wash-outs up to 20” in 8-1/2” hole at 45° inclination”
- “Even after a few weeks of open hole, hole sizes over 9.5” have been very rare”

Differential sticking

- “Low potential for differential sticking”
- “No incidence of stuck pipe”
Formate brines and formation damage – conclusions from literature review (SPE 97694)

Every * published field case history from the 1994-2004 period shows that production rates were equal to or higher than expectations after using formates

- No significant skins
- Recorded production increases of up to +600% compared with offsets or expectations
- No stimulation required

* Excluding the occasional cases where potassium formate brines have been weighted with solids (e.g. CaCO₃) to create traditional-type ‘muds’
Example of well productivity improvements from formate brine – Visund field, Norway

- Oil reservoir
- BHST: 120°C
- Fluid density: 13.8 ppg
- 13 long horizontal wells
- 300-3000mD sandstone
- PI only 60-90 Sm³/day/bar

Poor PI due to formation damage caused by CaBr₂ perforating kill pill:
- Incompatible with formation
- Reacting with charge debris
- Unstable, with high fluid loss
Example of well productivity improvements from formate brine – Visund field, Norway

- Good return perm test results with formates
- Next three wells perforated in formate brines
- New perforating guns used in dynamic underbalance
- Elimination of formation damage
  - PI of up to 900 m³/bar/day
  - PIs improved by 300-600%"
  - Best case: 53,000 bbl/day/well
Example of formate brine delivering good well productivity: tight gas reservoir – Devenick, UK

- Gas condensate reservoir
- BHST: 145°C
- Fluid density: SG 1.65
- Long horizontal well, 3,300ft
- V. low permeability (< 0.1 mD)
- Hard sandstone, TVD 15,130 ft

Drivers for using formate

- Better well control – no sag, low gas solubility
- Lower ECD - improved margins between pore and frac pressure
- Increased production – return perm 33% better than OBM
- Excellent well test: zero skin
- Increased ROP and bit life – fewer trips and reduced casing wear
- Increased power to turbine
Conclusions

Formate brines have clearly delivered some important benefits in more than 100 challenging HPHT well constructions

- Enhanced drilling performance
- Improved well control
- Good well productivity
  - PI’s always equal to, or higher than, expectations
  - Occasional indications of some filtrate retention
  - No significant filtrate retention effects in the field (lab results are artifacts?)
  - Multiple-pass logging shows that heavy formate filtrates are mobile over time: replaced by hydrocarbons