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Systematic Approach to Selecting Completion Fluids for Deepwater Subsea Wells Reduces Completion Problems

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Abstract

Completing deepwater subsea wells brings new challenges in the selection of completion fluids. Practices that work well on “shelf” wells do not always transfer directly to the deepwater environment. Problems associated with an inappropriate choice of completion fluid can have a significant impact on a project, not only during completion operations and start-up, but also throughout the well’s productive life.

A systematic approach to brine selection has been developed to identify an optimum fluid for specific formations and deepwater conditions. Since its initial application in early 2000, this approach has led to seven successful completions on both oil and gas wells in the Gulf of Mexico (GOM). Unlike previous subsea completions, these wells met cost and production goals and experienced no subsea control difficulties.

Introduction

The water depth for these completions ranged from 800 – 4200 feet, and the brines used varied from a simple 10.0 ppg $CaCl_2$ to a 14.8 ppg $ZnBr_2/CaBr_2$ brine. In every case, the completion brine was displaced to a compatible packer fluid (NaBr at densities of 10 ppg to 11.5 ppg with a corrosion inhibitor and ethylene glycol for hydrate suppression) after the interval was completed and before the production string and tubing hanger were run.

Unlike previous subsea completions, these wells have experienced no subsea control difficulties, no hydrates or blocked control lines, and no intermittent loss of IWOCS function. The well productivities demonstrated high completion efficiencies and low skin factors. The productivity level expectations were met or surpassed. After production start, annulus pressure was bled off without difficulty – in contrast to previous completions.

Selection Criteria

Most of the issues that drive the selection of completion brine for a deepwater subsea well are similar to most other completions, e.g., density and crystallization point and compatibility with reservoir rock, formation fluids and other completion chemicals. What makes deepwater completions more challenging is the combination of younger formations, the greater hydrostatic pressure and colder temperatures at the sea floor, and the interaction with subsea systems and control fluids. The following list identifies the most critical drivers:

Deepwater Completion Fluid Selection Drivers

1. Density required to control formation pressure and the ability to modify density without adverse effect on crystallization and hydrate inhibition.
2. Crystallization point at seafloor temperature at the maximum anticipated pressure.
3. Hydrate inhibition at seafloor temperature and the maximum anticipated pressure.
4. Compatibility with formation, both reservoir rock and shale laminations
5. Compatibility with reservoir fluids – formation water and hydrocarbons
6. Fluid compatibility between completion brine and the following:
    a. gravel pack or frac pack fluids, stimulation chemicals and acids
    b. corrosion inhibitors and packer fluid additives
    c. fluid loss control materials and LCM breakers
7. Compatibility with subsea control fluids and elastomeric seals

Deepwater Completion Fluid Selection Process

1. Cull the candidate brines by two requisites: density and crystallization temperature.
2. Use hydrate inhibition models to further narrow the field and identify the need for a hydrate inhibitor

(e.g., methanol or ethylene glycol).

3. Use petrophysical data to evaluate formation sensitivity issues, follow-up with tests on core samples to confirm compatibility of the candidate brines with the producing formation and interbedded or adjacent shales.
4. Conduct tests on the remaining candidate brines to evaluate compatibility with reservoir fluids (gas, water, condensate or oil); identify the potential need for scale, sludge, or emulsion inhibitors.
5. Check compatibilities with subsea control fluids.
6. Check compatibilities between reservoir fluids and all of the other completion fluids: frac gels, acids, packer fluid additives, corrosion inhibitors, etc.
7. Weigh the candidates in terms of cost, benefits, risks, logistics, and environmental issues.

Density

For most wells in the deepwater GOM, temperature-related change in density in the well is insignificant (typically less than 0.1 ppg overall) because reservoir temperature gradients are relatively low (1.2 to 1.5ºF per 100 feet). The gain in density with the colder seafloor temperatures typically offsets the loss with increasing formation temperature. The relative range of densities for several brines is shown in Figure 1.

Crystallization Point

A brine's true crystallization temperature (TCT) is the temperature at which salt crystals begin to fall out of solution given sufficient time and proper nucleating conditions (the presence of small angular particles that seed crystal formation). Once formed, masses of salt crystals are difficult to remove and can block access to the well, foul subsea systems and sea floor BOP equipment. A brine's TCT is the crystallization point at atmospheric pressure.

For single-salt brines, the TCT depends on the fluid density and cannot be adjusted. With multi-salt brines, the TCT for any density can be adjusted by varying the relative amounts of each salt. For example, a 12.0 ppg $CaCl_2/CaBr_2$ brine can be blended to achieve a range of TCT from 70ºF to below 0ºF. Generally, the lower the TCT, the more expensive the brine (a higher proportion of heavier salt is used) and the lower the hydrate inhibition (more 'free' water in the solution).

Pressure-Dependent Crystallization Temperature (PCT)

With divalent brines made from calcium and zinc salts, the crystallization temperature increases with increasing pressure. For deepwater operations, a brine's PCT is the definitive parameter because of the colder temperatures and higher pressures at the sea floor. Applying pressure of 10,000 psia to divalent brines raises their crystallization temperature by as much as 10ºF to 20ºF. Monovalent brines have less pressure dependency – generally only 1°F to 5ºF increases in PCT up to 10,000 psia. Recent tests of certain monovalent blends have shown an interesting ***decrease*** in PCT with increasing pressure.

In deeper water, crystallization is most likely to occur at the sea floor – typically the coldest point in the well – in the mud-line wellhead, subsea tree, BOP stack, and choke and kill lines. The choke and kill lines are most vulnerable because they reach seafloor temperature quickly – perhaps within 30 minutes of cessation of circulation. Modeling can be used to predict temperature response.

Figure 2 shows the effect of pressure on crystallization temperature for three blends of a 12 ppg $CaBr_2/CaCl_2$ brine over a range of pressures from atmospheric to 15,000 psi. The bottom (green) curve has a TCT of 5ºF, the middle (blue) curve 14ºF, and the top (red) curve has a TCT of 26ºF.

The accepted practice to avoid crystallization is to choose a salt blend with a PCT that is 10ºF below the lowest anticipated temperature at the highest anticipated pressure, which often comes during BOP testing. For a well in 5,000 feet of water, with 11.0 ppg fluid and a BOP test pressure of 7,500 psig (measured at surface), the pressure at the BOP stack is 10,400 psia (7,500 psig + 15 psia atmospheric + 2,860 psi hydrostatic). With a sea floor temperature of 38^{o}F, the 14-degree TCT brine would be the proper choice to have a 28-degree PCT at the BOP test pressure. The PCT of the selected brine should be confirmed in the lab.

Changes in Density and Salt Composition

Increasing or maintaining density by adding dry salt or by adding volumes of a saturated 'spike' brine can change the proportion of salts in a multi-salt blend, which can alter the brine's PCT and hydrate inhibition. The common practice of using spike fluid to 'slug' the work string before tripping to prevent U-tubing on trips should be done with caution. Adding water to reduce density will cause the hydrate equilibrium curve to shift, possibly increasing the risk of forming hydrates. Adding lighter salt brine or alternatively, adding drill water along with a hydrate inhibitor, might be a safer option. Density control contingencies should be worked out in advance.

Hydrates

Gas hydrates trap natural gas molecules within 'cages' of water molecules. Like ice, they adhere to metal surfaces and form quickly in large amounts, plugging or “cementing” tubing or work strings in place, interfering with valve operation and BOP equipment function, plugging choke and kill lines, and trapping pressure.

Deepwater environments often present the four required elements for hydrate formation: 1) low seafloor temperature; 2) hydrostatic pressure at the seafloor; 3) hydrocarbon gas; and 4) water from the water-based drilling mud, formation water, seawater, or completion brines.

Hydrate Equilibrium Conditions

Laboratory measurements can determine under what conditions (pressure and temperature) hydrates can exist for a given gas composition and water-based fluid. As shown in Figure 3, a risk of eventually forming a hydrate exists in the area to the left of the equilibrium curve. With this particular brine and gas composition at a seafloor temperature of 38ºF, the maximum hydrate-free pressure is approximately 5,000 psia at the sea floor.

Figure 4 represents a hydrate equilibrium curve for fresh water when mixed with a natural gas common to the GOM Green Canyon area. Hydrates would be stable at 2,000 psia at 70°F, under 200 psia at 38°F.

Pumping seawater to kill a deepwater well, a common practice on the ‘shelf’, can pose a hydrate risk in deepwater. Seawater at a seafloor temperature of 38ºF can form stable hydrates at less than 500 psia, which is less than the hydrostatic of seawater in water depths greater than 1,100 feet.

Several computer models, which compile hundreds of laboratory measurements, are available to predict hydrate equilibrium conditions (pressure and temperature) for a variety of completion brines. Some models include the effect of dosing the brine with thermodynamic hydrate inhibitors – such as glycol and methanol. One industry model also includes the thermal behavior of the wellbore to help predict ***when*** hydrate equilibrium conditions will be reached after shut-in.

Compatibility with Formation

Without attempting to duplicate the many references that address brine compatibility, formation damage, and fluid interaction, here is a list of considerations specific to the deepwater GOM.

1. Very young formations containing clays sensitive to divalent or monovalent brines;
2. Thick, clean sandstones with little or no cementation and less confining stress;
3. Thick, highly-laminated, low-resistivity pay zones that expose completion fluid to intervals with high-clay content. Finding completion fluids that won’t destabilize these sensitive formations is crucial. Core sensitivity studies should include reservoir rock, shale laminae, and the adjacent shales.
4. Acid- and pH-sensitive mineralogy (e.g., aluminum-rich zeolite, clinoptilolite);
5. Oil-wetting of the near-wellbore region caused by synthetic drilling fluids. Conventional approaches (e.g., a xylene wash) may result in tight emulsions and even greater impairment – lab testing is imperative.

Petrographic description and clay mineralogy are useful in ranking one brine system over another. Laboratory testing on core samples should be performed on a short list of brine candidates once all of the other considerations have been evaluated, including:

1. Core Flow Tests – reservoir flow
2. Return Permeability – reservoir flow & clean-up
3. Linear Swell Meter – shale
4. Capillary Suction Time – shale

Compatibility with Reservoir Fluids

The following investigative tools are helpful in evaluating completion fluid interaction with reservoir fluids.

1. Formation Water – scaling tendency
    a. Scale Prediction Software – If the composition of the formation water is known, software models can be used to estimate the scaling potential – look for barium sulfate and carbonate scale.
    b. Bench-top Tests – tests conducted on samples of formation water confirm the scaling tendency and the required dosing of inhibitor.
2. Gas, Condensate or Crude Oil – emulsion, sludge
    a. Emulsion blocks can seriously impair productivity and some inverted drilling mud systems add to the problem. Native crudes exhibit varying degrees of emulsion potential when exposed to water-based completion brines. Testing with the proposed completion brine(s) will determine the need for an emulsion preventative.
    b. Some native crudes and condensates form sludge when contacted with acid. Testing with all proposed acid treatments, including the pre-gravel pack acid used to break or remove post-perforating LCM pills and any post-gravel pack acid treatments held in contingency to clean-up frac pack gel or a post-gravel pack LCM pill.

Compatibility between Proposed Completion Fluids

It is essential to investigate potential incompatibilities between each of the many fluid systems and chemicals that will be used in the completion. For example, could the dense divalent brine compromise the normal iron sequestrate used with the acid treatment to prevent the formation of iron precipitates?

Below is a partial list of the different fluid and chemical systems typically used on a deepwater GOM well:

1. Drilling mud or drill-in fluid and filtrate – water-based or oil, diesel, or synthetic based,
2. Completion brine with hydrate inhibitors, non-emulsifiers and lubricity packages
3. Fluid loss control materials
4. Pre-frac pack (gravel pack) clean-up acid and additives
5. Frac or gravel pack gels, surfactants, and pH modifiers
6. Post-frac pack (gravel pack) fluid loss control materials
7. Packer fluid additives – corrosion inhibitor, oxygen scavenger, biocide, pH modifiers
8. Methanol
9. Contaminants – iron from tubulars, salts from previous jobs or other sources (e.g., zinc residue reacting with formate brines can form an insoluble zinc formate precipitate, sulfates in sea water mixing with barium salts in formation waters to form insoluble barium sulfate).

Compatibility with Subsea Control Fluid

Just prior to landing the tubing hanger in a subsea tree, subsea control fluid (used to operate subsea systems such as the subsurface safety valves) and methanol comes into direct contact with completion brine. Lab tests confirm that most heavy completion brines are incompatible with methanol and some brines within a specific density range are incompatible with certain control fluids. Precipitation of brine salts and separation of control fluid components occur immediately on contact. With some of the control fluids, contact with brine causes separation of the control fluid's dye, lubricity package, and corrosion inhibitor suggesting a loss in control fluid performance.

With divalent brines ($CaCl_2$, $CaBr_2$ and $ZnBr_2$) salt precipitation appears sufficient to plug SCSSV control lines, block a chemical injection line, or annulus bleed-off line. Precipitation was observed with only a few of the monovalent brines and there was much less precipitation with methanol with the monovalent brines. Taking advantage of these results, sodium bromide with ethylene glycol as a hydrate inhibitor was successfully employed as a packer fluid on seven deepwater wells.

The results of mixing various brines with one of the available control fluids at room temperature and at 40^{o}F are shown in Figure 5. Green bars signify no salt precipitation. Red bars indicate significant precipitation. Marginal results are indicated in gray. Some of the test results, found smaller crystals that did not stick to the glass jar, suggesting that the control fluid may have included a kinetic inhibitor (anti-agglomerate) to mitigate the impact of precipitation.

Many completion teams and subsea tree vendors have modified their installation procedures to minimize the mixing of brine with control fluid and have eliminated opportunities for brine to back-flow into control systems, however, intimate contact between brine and control fluid and methanol still occurs and cannot be avoided.

Confirmation Tests of the Selected Completion Fluid

Once the completion fluid has been selected, the following tests are recommended:

1. Measure the PCT of the specific brine composition with additives.
2. Confirm the hydrate equilibrium curve.
3. Devise density control procedures that won't compromise hydrate inhibition and PCT.
4. Confirm formation compatibility with brine and other completion fluids (frac fluid and acids) in the presence of iron.
5. Confirm brine compatibility with reservoir fluids in the presence of iron.
6. Measure corrosion rates on coupons of specific metals of the tubing and production equipment; determine the necessary dosage of corrosion inhibitors, pH modifiers, and oxygen scavengers. Corrosion rates should be measured for a minimum of 28 days.

Careful Brine Selection Avoids "Train Wrecks" and Cost Overruns

Generally, the costs related to completion fluids (including brine, displacement chemicals, filtration, fluid loss control materials, and scale and hydrate inhibitors) are greater for deepwater wells because of the larger volumes needed – often 2-3 times more than required for 'shelf' wells – and the different fluid chemistries needed. Altogether, the cost for completion fluids (including brine, displacement chemicals, filtration, fluid loss control materials, and scale and hydrate inhibitors) can account for $500,000 to $2,000,000 per well, representing 10% to 20% of well completion costs.

While cost reduction in this area is obviously helpful, project profitability may be better assured by avoiding formation damage so that well deliverability targets are met. With marginal prospects, profitability demands cost containment and the avoidance of the “train wrecks” (significant operational problems) that lead to significant cost overruns during the completion.

Project profitability can also depend on avoiding future intervention to address subsea problems after completion. Just the cost to mobilizing a semi-submersible rig back to the well site (rig tow, deploying and later pulling of the anchors, BOP stack, and marine riser) can easily reach $2 million dollars. Add to this the cost to troubleshoot, and perhaps to retrieve the production tubing or subsea tree to re-gain control of the subsurface safety valve, for example. Prudence calls for spending what is necessary to avoid problems associated with fluid compatibility, pressure-related crystallization, and hydrate formation.

The selection process described here, including proper testing and modeling, has proven itself repeatedly on challenging deepwater wells in preventing hydrate formation, crystallization and subsea control failures.

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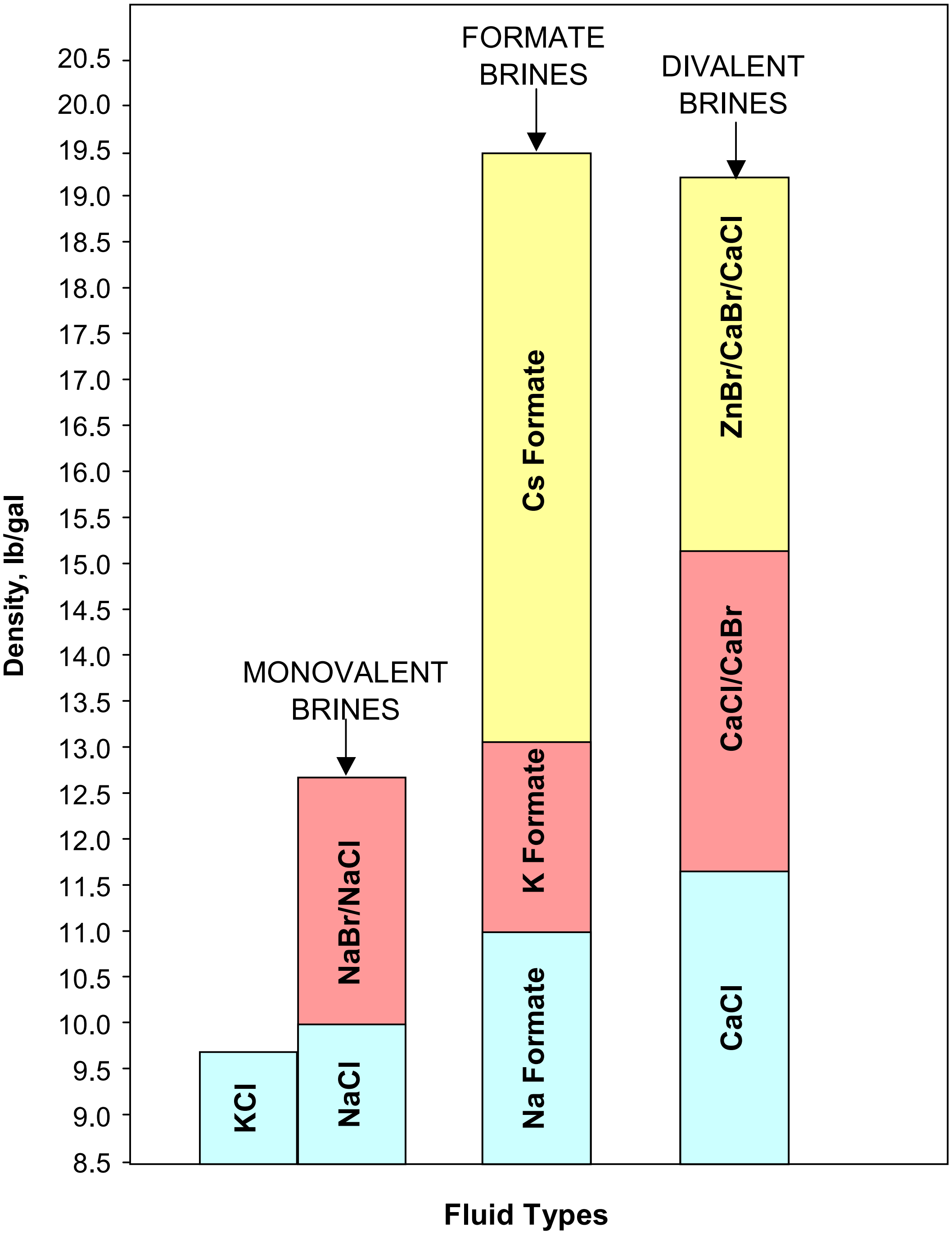

Figure 1 - Brine Densities

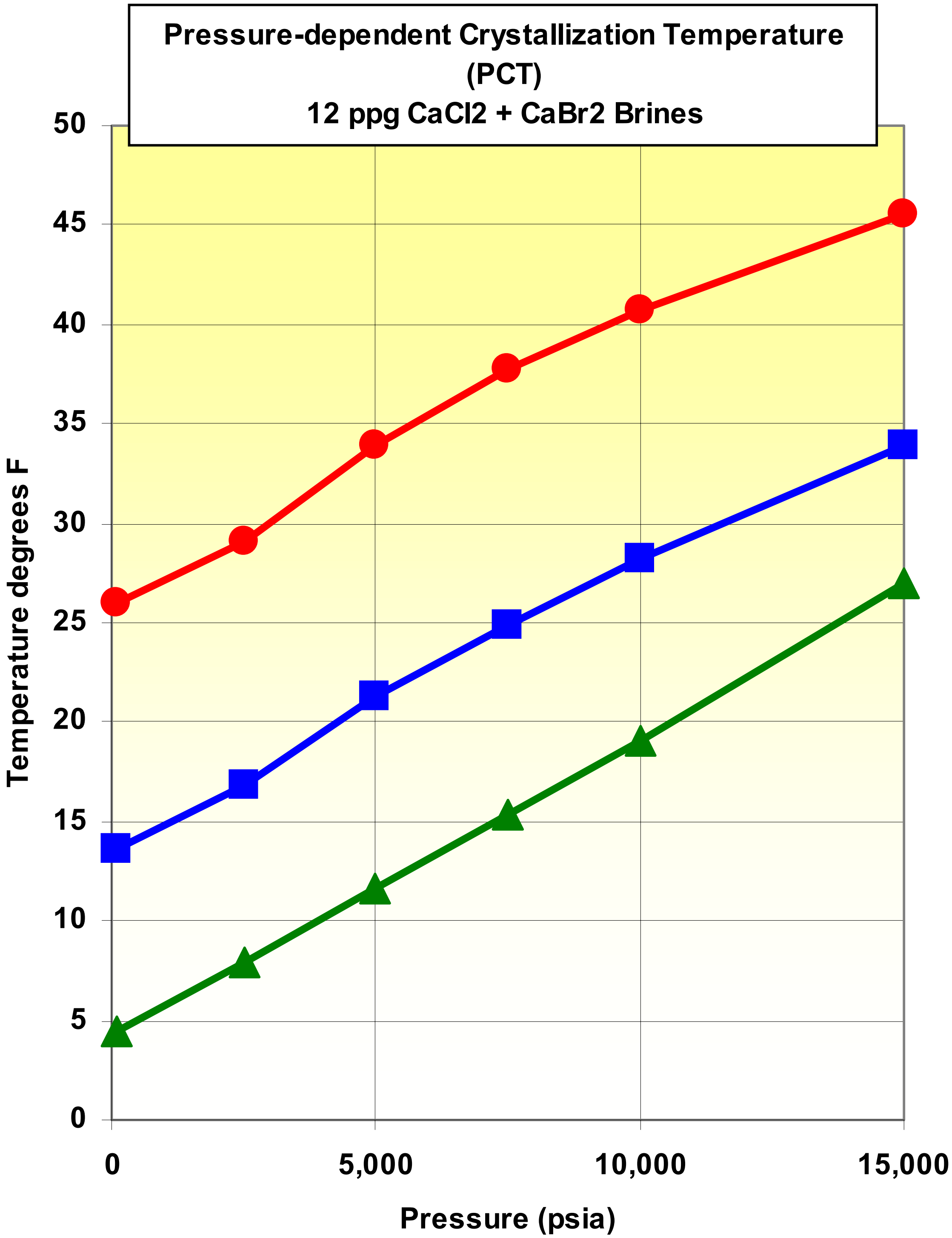

Figure 2 - Effect of Pressure on Crystallization Temperature for 3 Blends of 12 ppg $CaBr_2/CaCl_2$ Brine

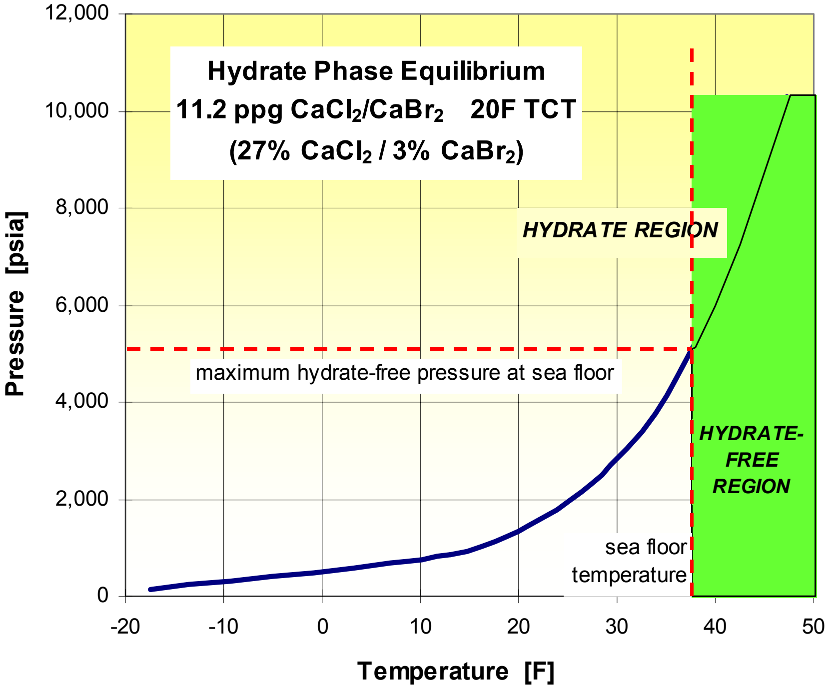

Figure 3 - Effects of Pressure and Temperature Combinations on Hydrate Formation

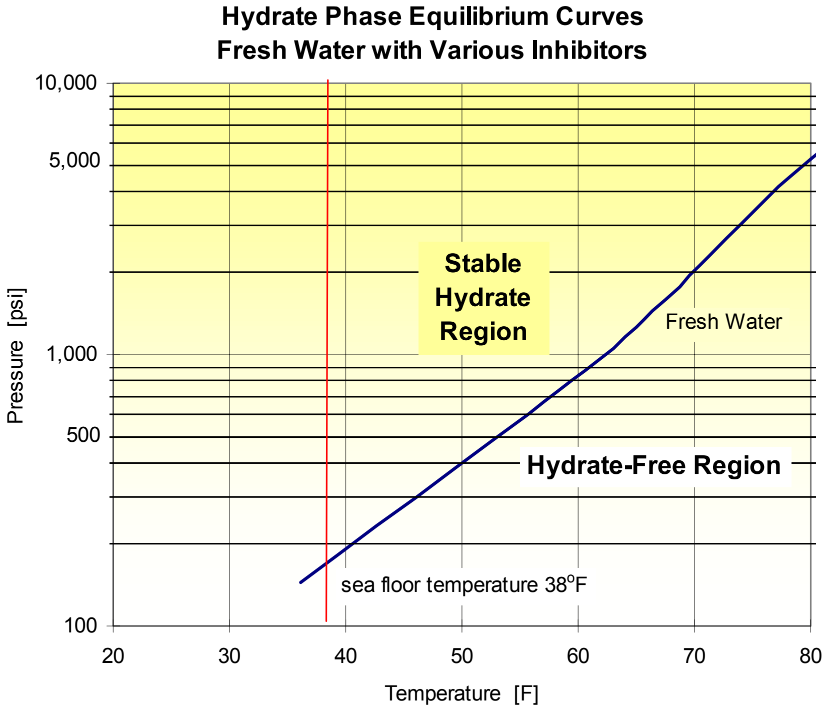

Figure 4 - Hydrate Equilibrium Curve for Fresh Water Mixed with Natural Gas (similar to that found in the GOM Green Canyon area)

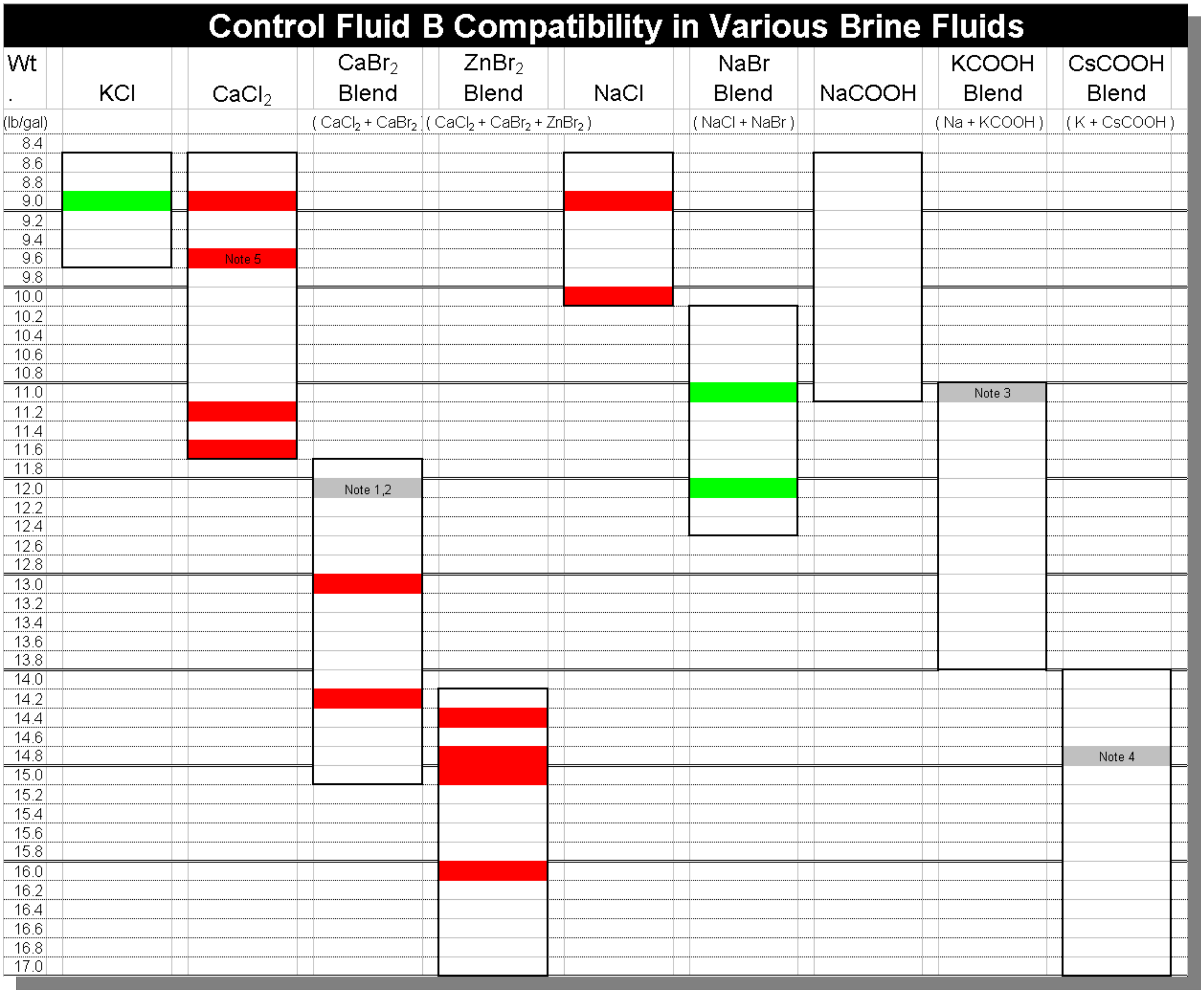

Figure 5 – Results of Mixing Various Brines with a Control Fluid (room temperature and 40ºF)