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SAMPLING GEOPRESSURED FLUIDS: DESIGN CONSIDERATIONS BASED ON PROPERTIES OF THE H_2O-CH_4 SYSTEM

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November 1980

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I. INTRODUCTION

The geopressured formations of the United States Gulf Coast contain hot brines with dissolved methane. These brines must be sampled for methane before an accurate economic assessment of the resource can be made. This has stimulated interest in use of conventional downhole fluid samplers and, recently, in development of samplers especially designed for the geopressured environments.

The purpose of these tools is to obtain fluid samples at reservoir conditions and to bring them to the surface, preserving their integrity, for subsequent chemical analysis. Although the samplers may be sophisticated devices, the process consists of the following simplified sequence. First, the sampler is lowered in the wellbore to the desired depth where a valve arrangement, either clock-controlled or triggered at the surface, is activated, trapping the fluid in a sealed chamber. The sampler is hoisted back to the surface, and into the wellhead lubricator. A valve isolating the lubricator from the wellbore is closed, and the hot, high-pressure fluid contained in the lubricator is bled off before the sampler can be safely recovered. Finally, the fluid in the sampler is transferred via a suitable valve assembly into containers for chemical analyses.

Formation fluids in geopressured reservoirs are at pressures of up to 1,400 atm (approximately 20,000 psi), and temperatures rarely exceed 200°C (400°F) (Dorfman and Fisher, 1979). After the sample is caught and the sampler starts its return to the surface, a pressure differential will occur between the fluid sample and the fluid in the wellbore. While the pressure changes within the sampler are controlled by temperature changes, the downhole pressure at any given depth is a function of the fluid densities within the well and, in the special case of a geopressured system, the formation overpressure. This overpressure results in wellhead pressures in excess of 360 atm (5,000 psi). The thermodynamic properties of the fluid, especially gas solubility, complicate any calculation of pressure in the well and in the sampler. The sample bulk composition will be constant, but in the wellbore there may be vertical compositional changes due to slippage between the gas and liquid phases as well as density changes caused by the thermal gradient in the well.

Prediction of these relative pressures is very useful to the design and operation of a sampler in geopressured wells. For example, if bottomhole conditions are known, the measured pressure and temperature of the sample at the surface will give an indication if seals have leaked, resulting in a loss of sample. Similarly, under certain temperature conditions, spring-loaded sampler valves may be forced open if the internal pressure of the sampler drops below the adjacent wellbore pressure. Also, the maximum differential pressure across the sampler wall will occur when the hot sampler is in the lubricator, the wellhead valve is shut, and the brine has just been vented from the lubricator. This is where the sampler seals may leak or the vessel burst from the high internal pressure.

Prediction of such effects and estimates of their magnitudes should have other uses. For example, this knowledge may help interpret field results, be used in assessment of sampling conditions to avoid those that favor leakage of the sampler, and suggest safer procedures for handling the sampler in surface operations, as will be shown in this paper.

This paper discusses how we can quantitatively estimate, in both the sampler and the wellbore, the geopressured fluid properties that occur during the sampling process. A simple model (an "equation of state") is presented that allows us to estimate thermophysical properties of geopressured fluids. This model is briefly described in Section II; full details are given elsewhere (Iglesias, 1980).

In Section III the "equation of state" is applied to compute and discuss fluid properties associated with the different stages of the sampling process. We consider (1) the probable range of CH_4 content, pressure, phase transitions, fraction of total volume corresponding to each phase, and composition of each phase present in the sample, over the expected range of temperatures; (2) whether and under what conditions the fluid collected at wellhead in a flowing well provides a representative sample of the bottomhole fluid composition; (3) the expected range of fluid pressures in the lubricator; and (4) the expected range of differential stresses on the sampler. Temperatures and pressures generally increase with depth in the geopressured formations of the Gulf Coast (e.g., Dorfman and Fisher, 1979). Thus, two well depths, representing approximately the top and the bottom of the geopressured zone, were considered in detail to assess effects associated with depth.

Finally, results and recommendations are summarized in Section IV.

II. A SIMPLE MODEL FOR GEOPRESSURED FLUIDS

Except for a correction factor for methane solubility in NaCl solutions, I neglected the complications posed by the presence of dissolved solids and considered a system composed only of water and methane. This approach is appropriate for the estimative purposes of the present work.

In this model, the thermophysical properties of the water-methane mixture are formulated in terms of five main variables; namely, pressure P, absolute temperature T, molar volume v, mole fraction of methane in the system λ, and volumetric gas saturation S. The contributions of methane to the liquid- and gas-phase molar volumes are estimated from a reported correlation (Brelvi and O'Connell, 1972), and from the ideal gas law, respectively. The corresponding quantities for liquid water and steam are estimated from the IFC Formulation (1967).

Methane solubility is computed from an empirical correlation (Haas, 1978), which assumes that steam exists in the gas phase at its saturated pressure and defines the methane partial pressure as the difference between P and the saturation pressure of pure steam.

III. RESULTS AND DISCUSSION

1. Bottomhole Compositions

The geopressured brines of the Gulf Coast are believed to be saturated with dissolved methane, whose solubility in water depends on temperature, pressure, and NaCl content. Thus, given the ranges of pressures and temperatures found in the geopressured formations, the probable range of methane content in bottomhole fluid samples can be estimated from known solubilities, as follows.

Bubble-point curves for the water-methane system were computed from Haas's correlation. These results are shown in Figure 1. The shaded area represents, roughly, the P, T ranges spanned by the fluids of the Gulf Coast (e.g., Dorfman and Fisher, 1979, and references therein). Assuming that in the unperturbed reservoir the pore water is saturated with methane, CH_4-H_2O ratios can be estimated from Figure 1 for given pressures and temperatures. Multiplying these results by the factor f_{NaCl}, plotted in Figure 2 as a function of the NaCl content, corrects these solubilities for salinity (Haas, 1978).

From Figure 1, the maximum methane solubility in the shaded area (for zero NaCl) is about 14,400 ppm at 1,400 atm (this pressure corresponds approximately to the bottom of the geopressured zone). This solubility may decrease to about 5,000 ppm, corresponding to $f_{NaCl} \approx 0.35$ for 250,000 ppm of NaCl (Figure 2). Taking 700 atm (which corresponds to a depth of about 3,000 m) as the top of the geopressured zone, the minimum methane solubility is about 4,000 ppm for zero NaCl (Figure 1) and decreases to about 1,400 ppm for 250,000 ppm of NaCl.

Two cases were considered in detail: a deep well (Z_B = 6,000 m) representing an approximate upper limit to the pressures expected, and a "shallow" well (Z_B = 3,600 m) sunk to near to the top of the geopressured formations. The corresponding bottomhole pressures were estimated from the lithostatic gradient. Bottomhole temperatures were then picked from Figure 1, and methane solubilities in pure water were computed from inversion of $P(\lambda,T)$ as defined by Haas. These results are presented in Table 1.

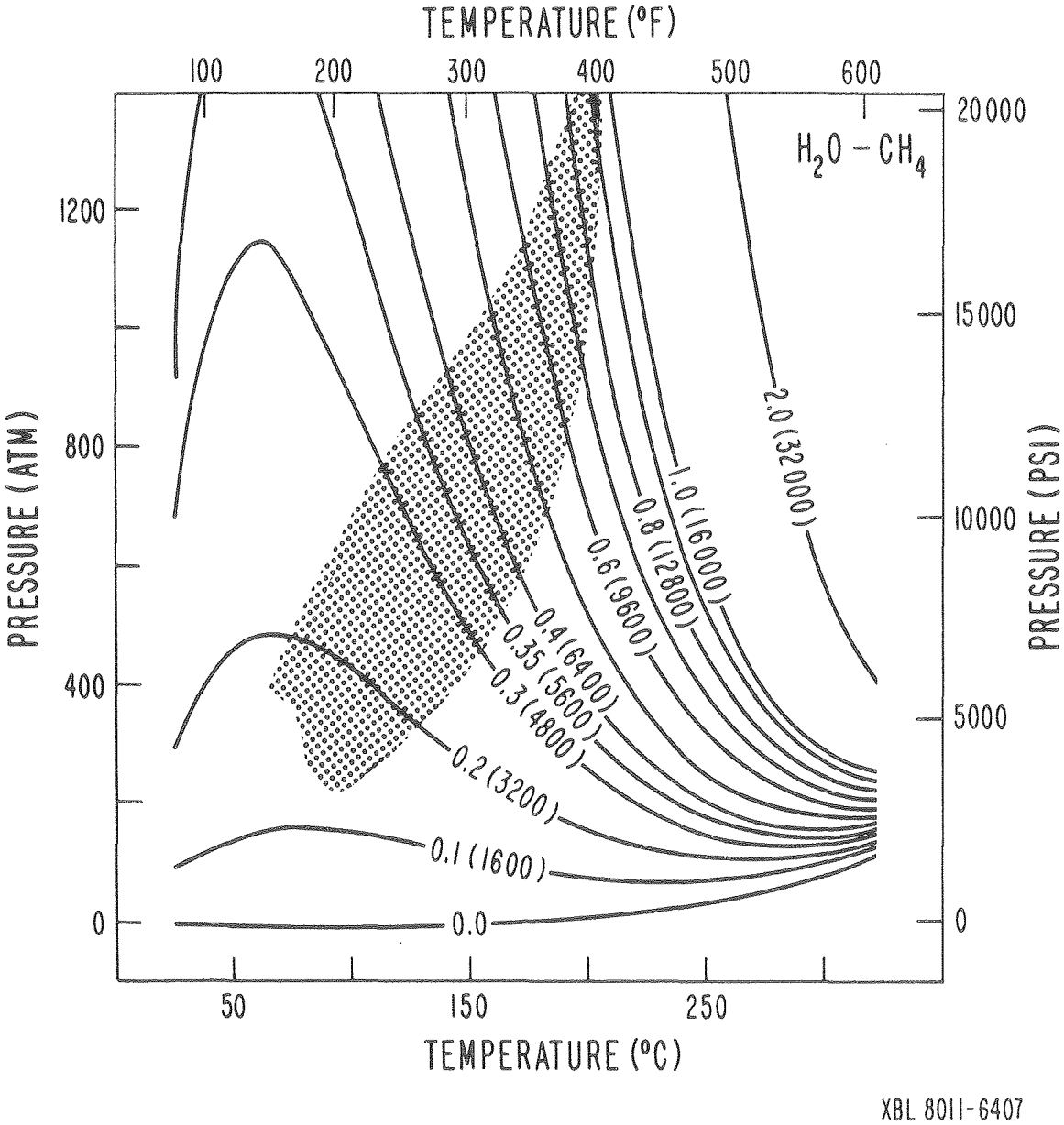

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Figure 1. Solubility curves for the H_2O-CH_4 system. Methane concentrations (in ppm) are indicated. The shaded area represents, approximately, the range of pressures and temperatures covered by formation fluids of the U.S. Gulf Coast.

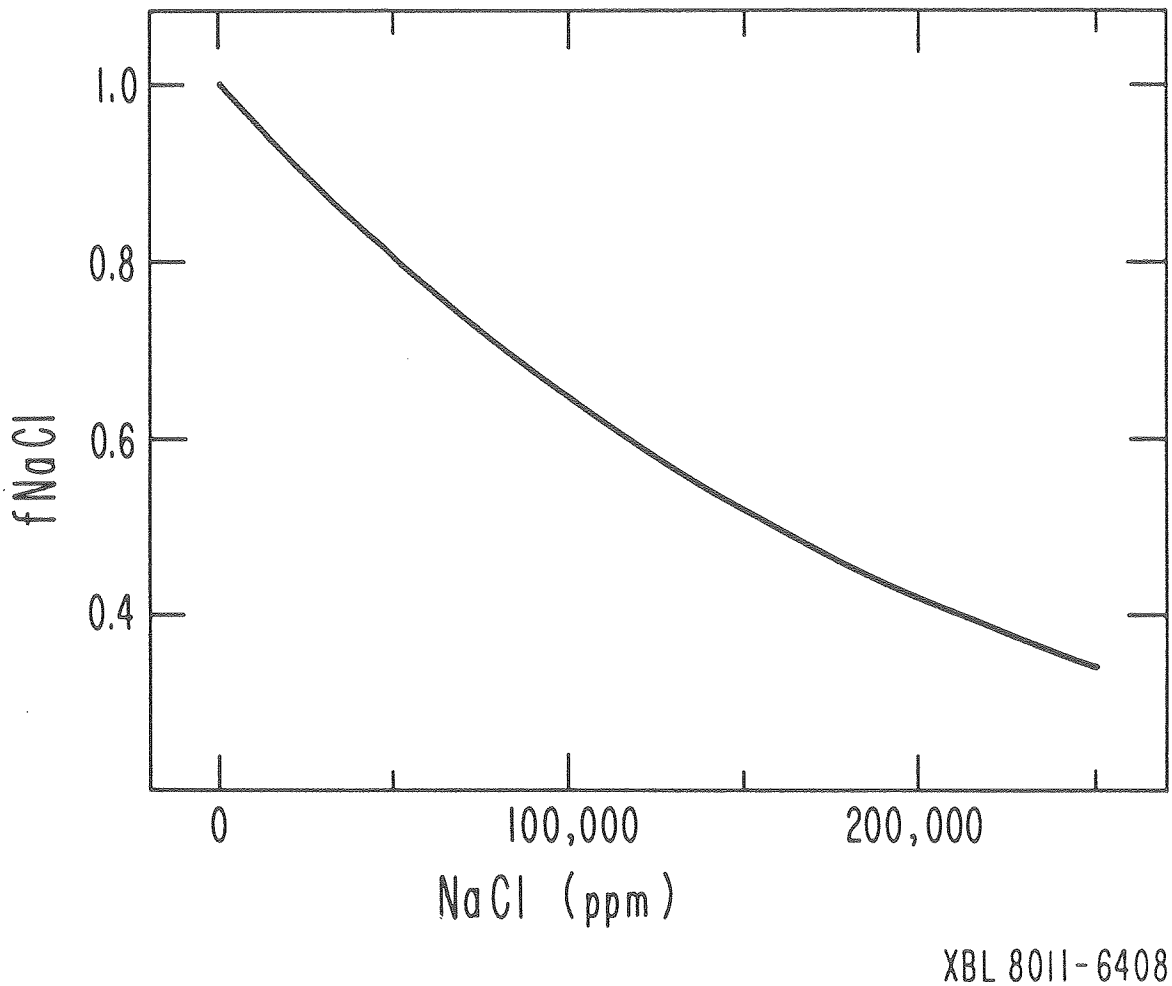

Figure 2. Salinity correction factor. The solubilities of CH_4 in NaCl brines may be estimated by the product of f_{NaCl} times the solubility of methane in pure water at the same pressure and temperature.

Table 1. Bottomhole-wellhead relations.

Z(m)	P_B(atm)	T_B(^oC)	T_W(^oC)	λ_W(mole%)	λ_W(ppm)	P_W(atm)	S_W(%)	x_W(mole%)	y_W(mole%)	r_W(%)
6000	1400	200	200	1.555	14,029	846	1.64	1.19	98.19	76.0
6000	1400	200	150	1.555	14,029	834	3.53	0.72	99.44	45.9
3600	800	150	150	0.704	6,297	460	1.51	0.51	98.98	72.9
3600	800	150	100	0.704	6,297	454	2.40	0.37	99.78	52.0

2. Wellhead

It is appropriate to consider here whether and under what conditions the fluid collected from the wellhead of a flowing well represents bottomhole fluid composition.

Since at present no geopressured reservoir is under significant production, the scope of this paper is limited to unperturbed reservoirs. In such reservoirs, the pore fluids are believed to consist of a single liquid phase saturated with methane. Wellbores penetrating geopressured reservoirs are filled with formation fluid because of the high pore pressures. Along the wellbore, pressure decreases with decreasing depth, causing gas (mostly methane but also some steam) exsolution. Buoyancy then tends to separate the gas bubbles from the parent liquid. This effect may cause the fluid composition at wellhead to differ significantly from the bottomhole composition.

To estimate the overall wellhead composition, slippage between the gas and the liquid phase must be considered. The extremely high bottomhole pressures imply high flow velocities even when friction losses are considered. For low gas saturation, only bubbly flow is encountered, and a typical value for the slip between the gas and liquid phases is only 0.5 m/s (e.g., Haberman and Morton, 1953). However, the fluid at the exit, when there is a two-phase region, is likely to be sonic (~ 100 m/s). Therefore one can neglect slippage and take $\lambda_W = \lambda_B$. The assumption of bubbly flow is reasonable because of the relatively small temperature gradients and high pressures involved and is supported by the small gas saturations calculated later in this paper.

To investigate the differential stresses exerted on the sampler at surface level, estimates of wellhead pressures and temperatures are needed.

For simplicity I considered steady-state, fast-flowing wells, one deep and one shallow, as described in the preceding subsection.

Neglecting drawdown and friction effects associated with finite flow velocity, the wellhead pressure P_W was approximated as the bottomhole pressure minus the hydrostatic head. The assumed steady-state flow conditions imply wellhead temperatures T_W not far from T_B. Thus, for convenience I assumed a linear temperature profile for the wellbore, with T_W ranging from T_B to (T_B - 50°C). These temperatures result in small gas saturations in the well, which are negligible in terms of mass. Neglecting the contributions of the gas phase and of the small amounts of dissolved methane to the total density, I approximated $\rho_1 \cong \rho_1^L(P,T)$. Results computed for the two well depths considered are shown in Table 1. Note the small differences in P_W arising from the temperature dependence of the density.

From P_W, T_W, and λ_W, which completely specify the thermodynamic state of the system, other wellhead variables of interest such as S, x, y and r were computed using the "equation of state." The corresponding results are summarized in Table 1.

In addition to yielding the wellhead conditions sought, these results provide semiquantitative information of interest for planning actual production. This information can be summarized as follows: If at bottomhole conditions the brine is saturated with methane, gas will evolve within the wellbore early in the production history, but the concomitant drawdown will eventually result in phase separation within the formation. The volume fraction corresponding to the gas phase anywhere along the wellbore is small, most likely less than about 4%. Therefore, the flow is expected to be in the small-bubble

regime. A substantial fraction of the total methane remains in solution at wellhead: about 50% if thermal losses along the wellbore are significant, and substantially more otherwise in the cases considered (Table 1). However, the computed values of r_W are upper limits because the actual wellhead pressures will be smaller than shown in Table 1 due to neglected friction losses and drawdown, and consequently there will be greater methane exsolution. Note that these results apply to the early stages of production; i.e., before a gas phase develops in the reservoir. After separation of the fluid in the reservoir slippage may become non-negligible.

3. Sampler

This subsection focuses on thermodynamic changes (pressures, phase transitions, etc.) taking place in the fluid sample over the expected range of temperatures.

If leaks and thermal expansion effects are neglected, the sampler can be regarded as a closed, isochoric system. On this basis, fluid variables of interest were computed as functions of temperature as the fluid is cooled from T_B to 25°C. The necessary initial conditions (P_B, T_B, λ_B) were taken from Table 1.

Gaseous methane and steam evolve in the process. The corresponding gas saturation values range from zero at bottomhole temperatures to less than 10% at 25°C, and increase (i.e., correlate, via the multiple correlation linking depths, temperatures and pressures of geopressured fluids) on well depth decrease (Figure 3). Methane is computed (Figure 4) to constitute in excess of 98 mole % of the gas phase over the range of temperatures considered; however, our model probably underestimates the gas-phase/steam mole-fraction. The

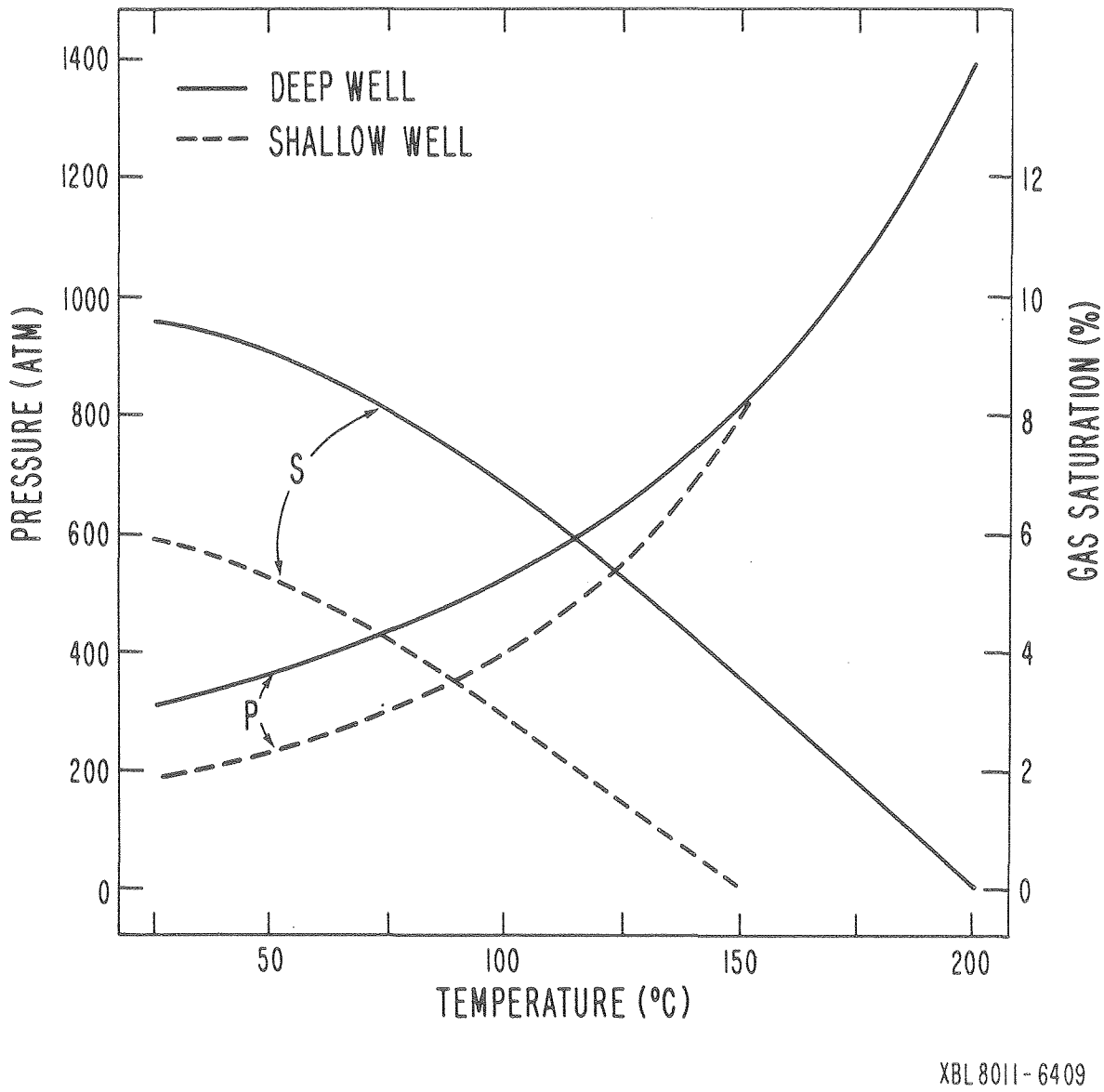

Figure 3. Pressure and (volumetric) gas saturation responses of sampler fluid to cooling for two well depths: 6,000 m (——) and 3,600 m (---).

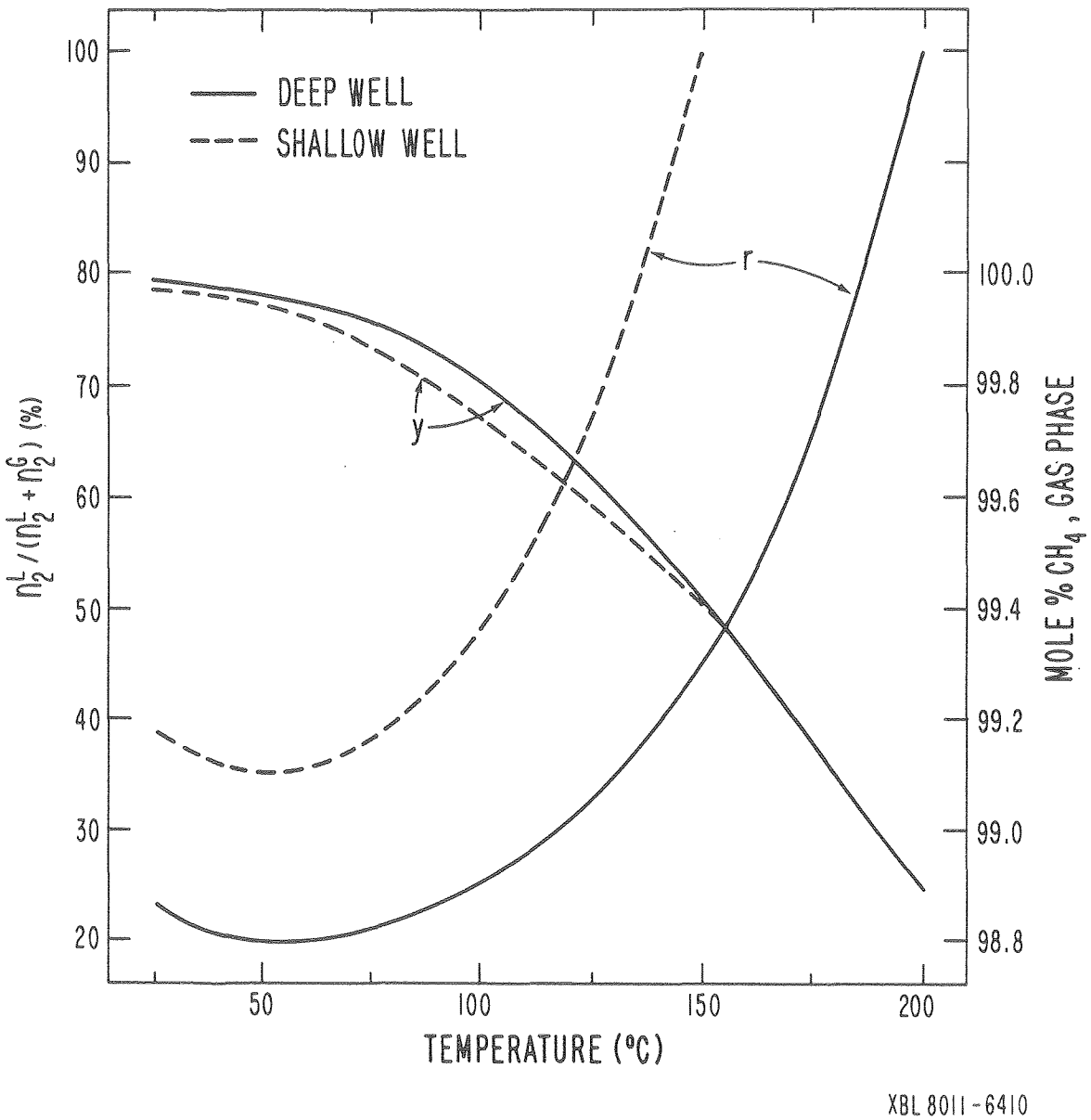

Figure 4. Fraction of total methane in solution and gas-phase methane mole fraction responses to sampler cooling for two well depths.

fraction of total methane remaining in solution correlates negatively with well depth; r decreases as cooling proceeds, until a minimum, which is insensitive to well depth, is reached near T = 50°C (Figure 4). The minimum value of r ranges upward of 20% indicating that considerable methane exsolution will take place upon depressurization for sample transfer, even at near-ambient temperatures.

As expected, the sampler's fluid pressure correlates with well depth. Cooling effectively decreases the sampler's fluid pressures from bottomhole values of up to about 1,400 atm at 200°C to a value not higher than about 300 atm at 25°C, where calculations were terminated (Figure 3). These results imply that formation of a methane hydrate, which occurs at pressures in excess of 463 atm at 25°C (Kobayashi and Katz, 1949), will not constitute a problem if the sampler is cooled to that temperature. However, if transfer is attempted at near-ambient temperatures, methane hydrate formation could occur in and near transfer valves because of possible local overcooling due to depressurization. This problem should be easily controllable by use of local heating (e.g., electric wires) of the affected zone.

4. Differential Pressure

In this section we consider the differential pressure on the sampler, which is defined as:

ΔP = P (sampler fluid) - P (surrounding fluid).

As shown above, the internal pressure of the sampler is controlled only by temperature, sample volume and composition being constant. On the other hand, the wellbore fluid pressure is mainly controlled by the hydrostatic head. The typical time taken to bring the sampler back to the surface

(one to two hours) considerably exceeds the thermal equilibration time between the fluid contained in the metallic sampler and the surrounding fluid. Thus, in the journey to the surface the fluid sample temperature follows the temperature profile of the well. Therefore, the internal and external pressures along the wellbore must be compared at the wellbore temperature.

Assume, for the sake of the argument, approximately linear profiles for P and T; then the wellbore pressure at a given depth is proportional to the corresponding temperature. This linear relationship, if superimposed on the P-T diagrams of Figures 3 and 7, would appear as straight lines (one for each well depth) running between (P_B, T_B) and (P_W, T_W), the points corresponding to bottomhole and wellhead conditions respectively. For given bottomhole conditions these straight lines would pivot around (P_B, T_B) if P_W or T_W are varied. As discussed, P_W is determined mainly by the hydrostatic head. Therefore T_W is the main variable controlling the slope of the straight lines representing the wellbore fluid pressure in the P-T diagram. The slope decreases with decreasing values of T_W. At a given temperature the difference between the curve representing the fluid sample pressure and the straight line representing the wellbore fluid pressure for each well depth is ΔP, the differential pressure. For T_W sufficiently large, the straight line lies below the fluid sample pressure, and ΔP is positive. But decreasing T_W causes the straight line to pivot around (P_B, T_B) towards high pressures, and eventually ΔP becomes negative in the wellbore. In actual wells the relationship between wellbore fluid and temperature generally shows some curvature. But the argument made above still applies qualitatively. Thus, ΔP tends to be positive in "hot" wells and negative in "cold" wells.

At wellhead, the sampler is brought into the lubricator. The fluid in the lubricator is isolated from the wellbore fluid by means of valves. In this condition the fluid in the lubricator is at constant volume and composition, neglecting leaks and thermal expansion. Thus, the lubricator fluid pressure is controlled by the temperature, given the initial values of the composition λ_W, pressure P_W, and temperature T_W.

Using λ_W, P_W, and T_W from Table 1 as initial conditions, I computed temperature dependent lubricator fluid quantities from the "equation of state" at constant molar volume v and composition λ, for both well depths considered. Two curves resulted for each quantity (Figures 5 through 7) because for each well, two different wellhead conditions (i.e., λ_W, P_W, T_W) were considered. Results closely resemble those obtained for the sampler.

In Figure 7 the fluid sample pressures are compared to the pressures of the surrounding fluid in the lubricator at the common equilibrium temperatures. This figure indicates that ΔP in the lubricator may be positive or negative. This comparison is valid for cases in which the wellhead parameters during sampling are comparable to the wellhead parameters of fast-flowing wells, as defined above. Negative values of ΔP are favored when $(T_B - T_W) \sim$ several tens of degrees C.

These results are useful to assess the performance of certain samplers in which the valves are kept closed by the combined pressures of a spring and of the internal (or external) fluid. Since the pressure exerted by the springs is negligible with respect to the fluid pressures involved, these samplers will leak when ΔP is negative (positive).

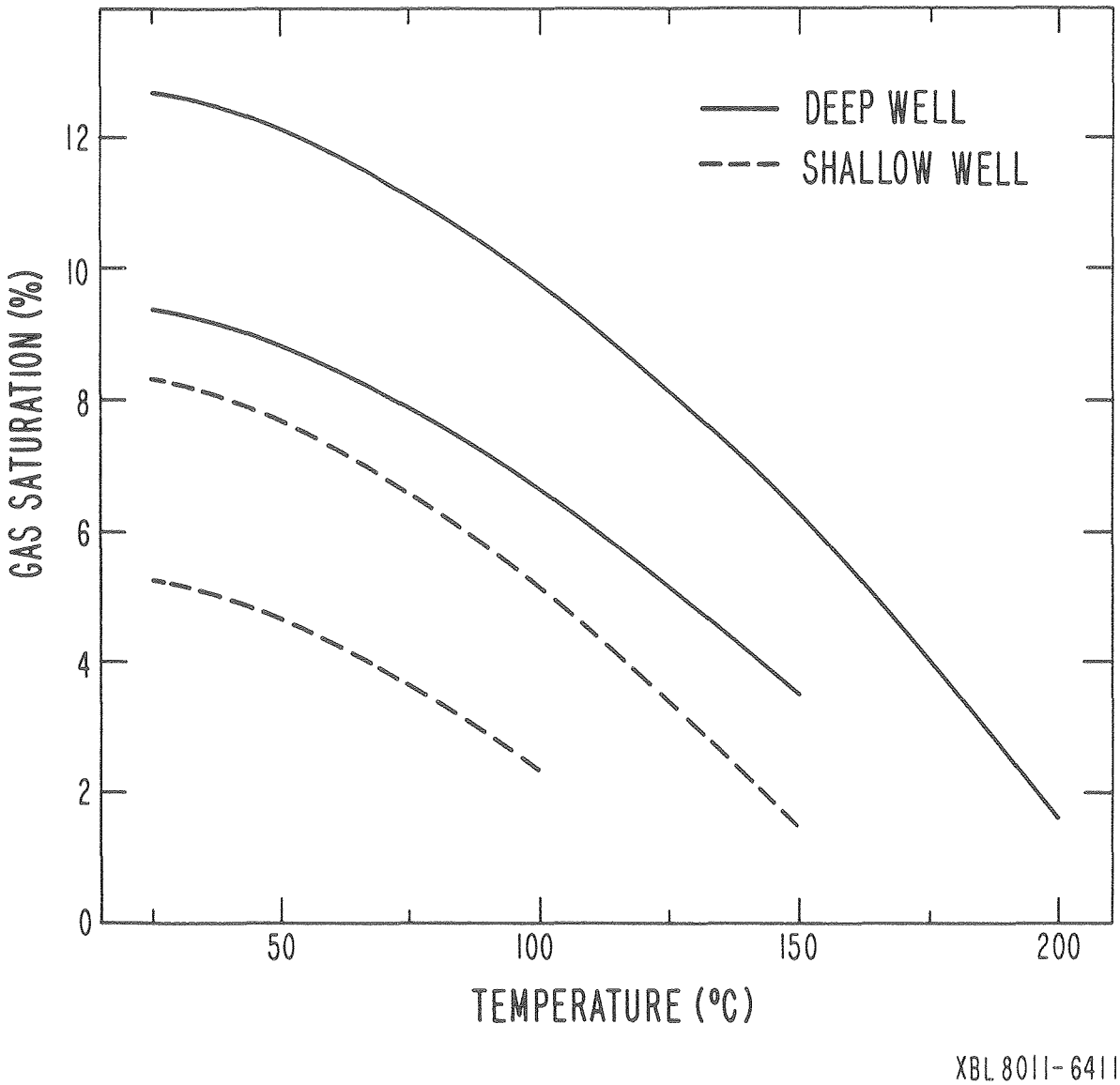

Figure 5. Gas saturations vs. temperature for the closed lubricator. Two curves, corresponding to two different assumed values for the steady-state wellhead temperature, are shown for each well depth.

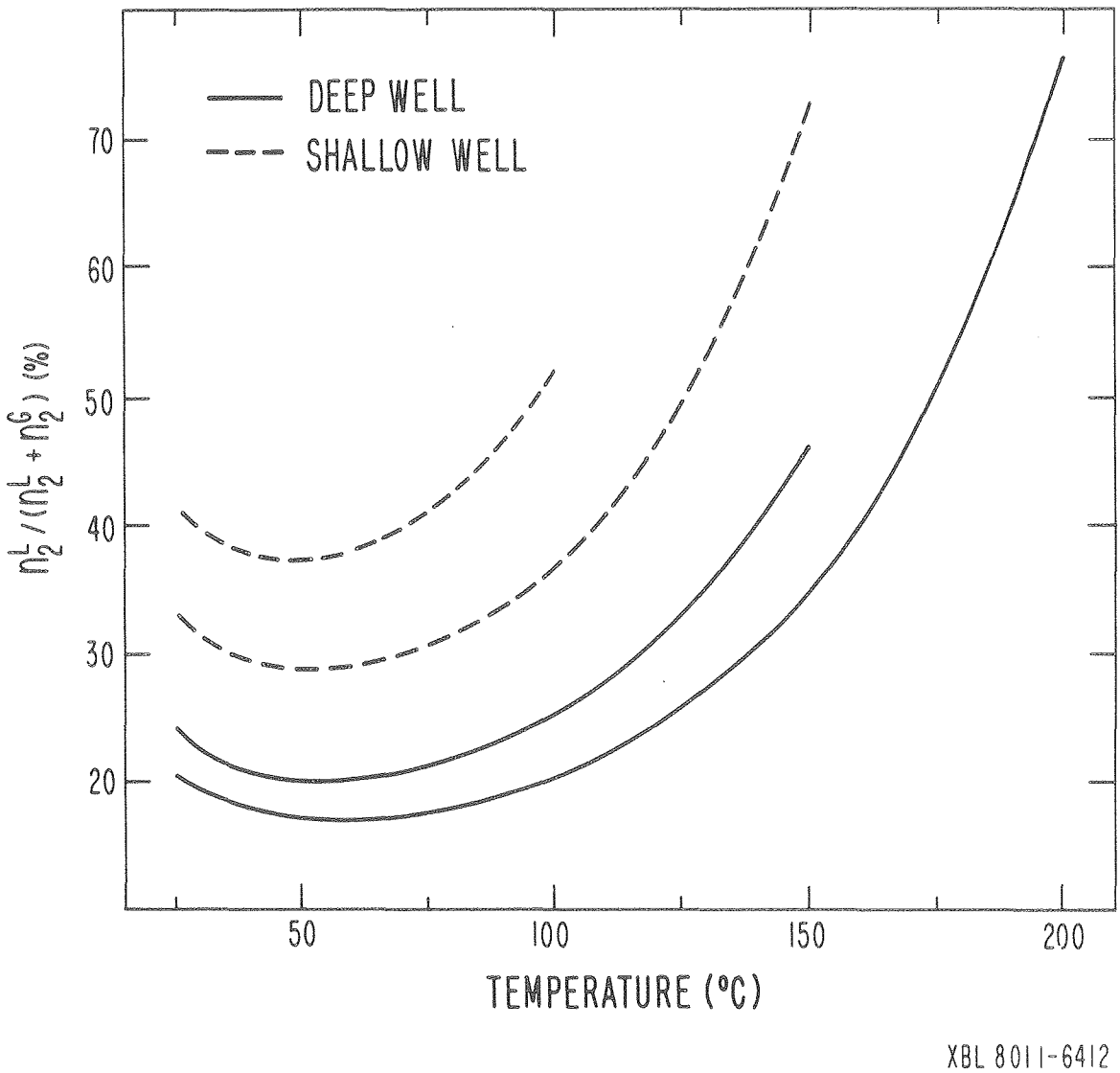

Figure 6. Fraction of total methane in solution vs. temperature for the closed lubricator. Two curves, corresponding to two different assumed values for the steady-state wellhead temperature, are shown for each well depth.

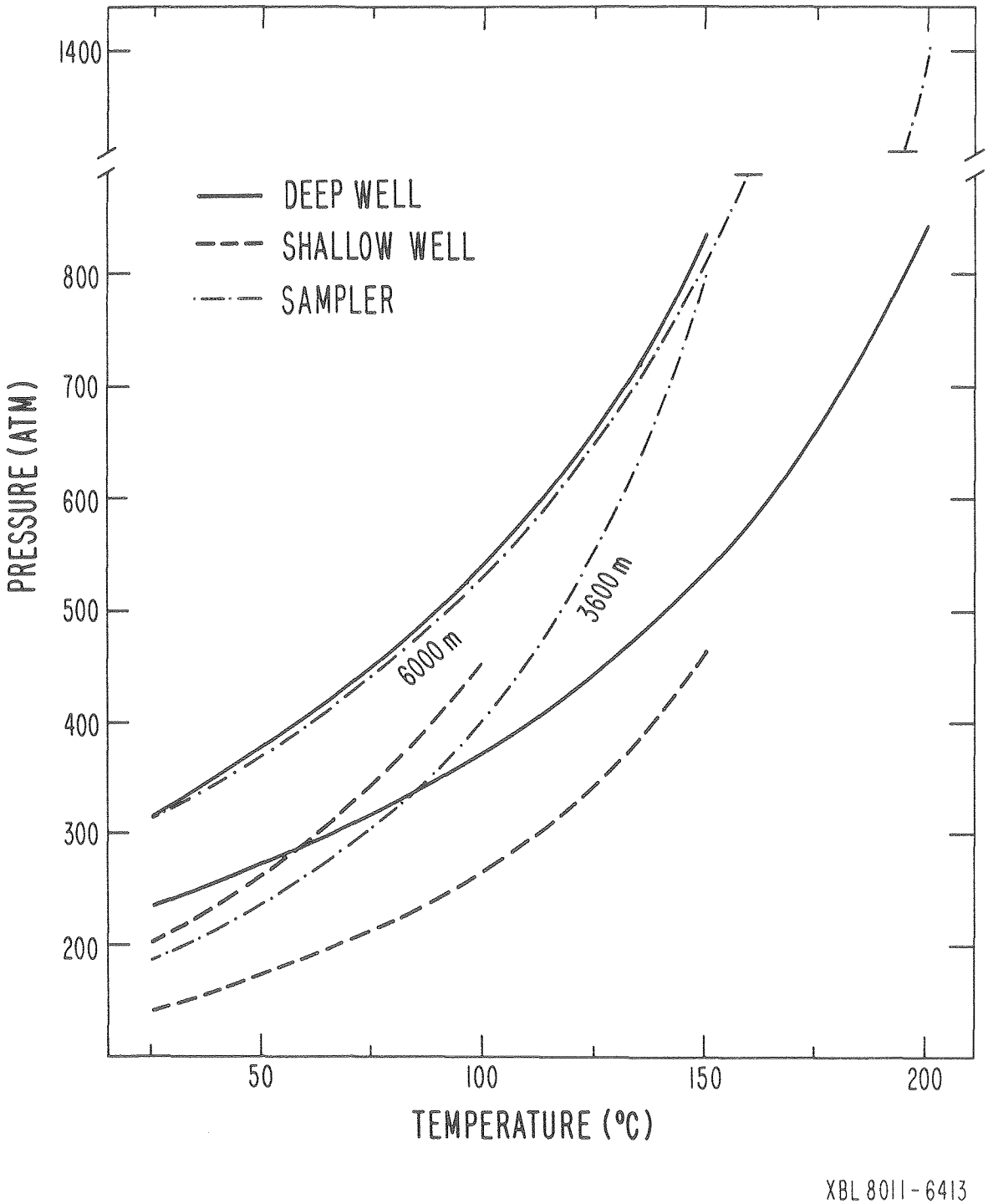

Figure 7. Fluid pressure vs. temperature conditions in the closed lubricator as the lubricator is cooled. Two curves, corresponding to two different assumed values for the steady-state wellhead temperature, are shown for each well depth. For comparison, the P-T curves corresponding to the sampler fluid for each well depth are also shown.

5. Sampler Recovery

High (up to about 840 atm) internal pressures are expected for the lubricator at steady-state wellhead temperatures. Even higher internal pressures, up to essentially P_B, are also indicated for the sampler. These high pressures are accompanied by high temperatures in a saline ambient which may include sulfur (and other) compounds, resulting in especially favorable conditions for micro-crack development that may result in catastrophic material failures. Hot, high-pressure leaks through joints and valves constitute another unpleasant possibility. These circumstances bear not only on the material aspects of sampling geopressured fluids, but also on the hazards faced by the persons recovering the sampler.

A simple procedure that would significantly lessen these material and personal risks is suggested by the results of this section. The procedure consists of two steps. First, the lubricator is isolated from the fluid flow by closing appropriate valves, to minimize thermal contact. Then the lubricator is externally cooled to near-ambient temperatures. This second step would substantially decrease the internal pressures of both the lubricator and the sampler (Figure 7), and thermal shocks on the sampler would be minimized. This procedure has the added advantage of minimizing the differential pressure exerted on the sampler walls. For example, in the extreme conditions corresponding to the deep well case, ΔP may reach (Figure 7) a maximum value of 554 atm, as compared to 1,400 atm if no cooling were performed; the value of ΔP would be reduced to essentially the internal sampler pressure of 310 atm, at recovery, if the lubricator were brought to 25°C before pressure release.

IV. SUMMARY

A simple model for the "equation of state" of the H_2O-CH_4 system has been used to predict fluid behavior during sampling operations of unexploited geopressured reservoirs of the United States Gulf Coast. The main results are as follows.

The methane content of the fluid samples may vary widely, from about 1,400 ppm to about 14,400 ppm. The lower figure corresponds to a hypothetical, highly saline (250,000 ppm NaCl) fluid from near the top of the geopressured zone; the larger figure corresponds to a hypothetical, very low salinity fluid from near the bottom of the geopressured zone. Methane content of the brine tends to increase rapidly with increasing temperature and pressure, and to decrease with increasing salinity.

When a geopressured well is initially tested, the overall concentration of methane (including liquid and gas phases) differs negligibly from that of the reservoir fluid, if large flow rates (velocities $\gtrsim$ 100 m s^{-1}) occur. This provides an approximate check on results obtained with samplers.

At surface temperatures (assumed to range approximately from 25 to nearly 200°C) and before depressurization, the fluid samples consist of a two-phase mixture (liquid and gas), but gas saturations are small ($\lesssim$ 10% by volume) and significant fractions ($\gtrsim$ 20%) of CH_4 remain in solution, indicating considerable methane exsolution upon depressurization for sample transfer. This information is useful in planning hardware and procedures for fluid sample transfer.

The differential pressures exerted on the sampler may be positive or negative, depending on the wellbore temperature profile. Substantial tem-

perature gradients along the wellbore ($T_B - T_W \approx$ several tens ^oC) could cause the external fluid pressure to exceed the internal pressure. This indicates that samplers relying on a combination of spring and internal fluid pressure to keep the valve(s) closed could leak when used in "cold," non-preheated wells.

Finally, a simple procedure to reduce personal and material risks associated with sampler recovery has been suggested. It consists of externally cooling the closed lubricator containing the sampler to near-ambient temperatures. This would substantially decrease the internal pressures of both the lubricator and the sampler, and also the differential pressure exerted on the sampler.

ACKNOWLEDGMENTS

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NOMENCLATURE

Variables

f_{NaCl}: Correction factor for CH_4 solubility in NaCl solutions

n: Mole number

ΔP: Differential pressure between fluid in sampler and fluid in wellbore

P: Pressure

$r = n_2^L/(n_2^L + n_2^G)$: Fraction of total methane in the liquid phase

S: Volume fraction corresponding to the gas phase

T: Temperature

v: Molar volume

x: CH_4 mole fraction in the liquid phase

y: CH_4 mole fraction in the gas phase

Z: Well depth

$\lambda = (n_2{}^L + n_2{}^G)/[(n_2{}^L + n_2{}^G) + (n_1{}^L + n_1{}^G)]$:

Mole fraction of methane in the system

ρ: Fluid density

Superscripts and subscripts

B: bottomhole conditions

G: gas phase

L: liquid phase

W: wellhead conditions

1: H_2O

2: CH_4