Methane hydrate gas production by thermal stimulation

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Two models have been developed to bracket the expected gas production from a methane hydrate reservoir. The frontal-sweep model represents the upper bound on the gas production, and the fracture-flow model represents the lower bound.

The *in situ* hydrate permeability is a major factor in estimating hydrate reservoir performance. A high-permeability reservoir may approach the high-efficiency performance of the frontal-sweep model. A low-permeability reservoir may have to be fracture-linked to establish injectivity, and will probably have low-efficiency performance that is similar to that of the fracture-flow model. Excess-gas reservoirs appear to be the most desirable; although excess-water hydrate reservoirs below the permafrost zone could also have reasonable permeabilities. In any case, drill stem testing and/or core analysis data should be used to evaluate the reservoir.

Parametric studies were made to determine the importance of a number of variables, including porosity, bed thickness, injection temperature, and fracture length. These studies indicate that the hydrate-filled porosity should be at least 15 per cent, reservoir thickness should be about 25 ft or more, and well spacing should be fairly large (maybe 40 acres per well), if possible. Injection temperatures should probably be between 150 and 250°F to achieve an acceptable balance between high heat losses and unrealistically high injection rates.

Deux modèles ont été mis au point pour encadrer la production prévue de gaz d'un réservoir d'hydrates de méthane. Le modèle à balayage frontal représente la limite supérieure de production, alors que le modèle à écoulement dans des fractures représente la limite inférieure.

La perméabilité *in situ* des hydrates est un problème important de la prévision de la performance d'un réservoir. Un réservoir à haute perméabilité peut avoir la performance très efficace illustrée par le modèle à balayage frontal. Un réservoir à faible perméabilité peut avoir à être fracturé pour permettre l'injection, et même alors il aura sans doute la performance peu efficace du modèle à écoulement dans des fractures. Les réservoirs ou le gaz est en excès semblent les plus souhaitables, bien que les réservoirs sous la zone de pergélisol ou l'eau est en excès puissent aussi avoir des perméabilités raisonnables. Dans tous les cas on devrait avoir recours à des essais aux tiges ou des analyses de carottes pour évaluer le réservoir.

On a effectué des études paramétriques pour déterminer l'importance d'un certain nombre de variables comme la porosité, l'épaisseur du lit, la température d'injection et la longueur des fractures. Ces études indiquent que les espaces remplis d'hydrates devraient représenter au moins 15 pour cent du volume, que l'épaisseur du réservoir devrait être de 25 pieds ou plus et que l'espacement des puits devrait être assez important (peut-être 40 acres par puits). Les températures d'injection devraient probablement se situer entre 150 et 250°F pour obtenir un équilibre convenable entre les trop fortes pertes de chaleur et les trop grands volumes d'injection.

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[Ed. Note: Data have not been converted to SI units.]

Introduction

Methane hydrates are thought to occur in large quantities in Siberia and in the North American Arctic. The estimated gas-hydrate reserves in these on-shore and off-shore Arctic areas are vast, although they are highly speculative at best. Of more importance though is the repeated occurrence of hydrates in sediments overlying conventional oil and gas fields in the MacKenzie Delta, Arctic Islands, and Beaufort Sea of Canada, and in Alaska's Kuparuk Field (Barraclough 1980). Billions of dollars and thousands of man-years have already been invested in exploring and developing these areas for conventional oil and gas production, and this is the realm in which hydrates may have significant resource potential. Hydrate deposits in these areas should be viewed as a long-term resource that could extend the life and productivity of these conventional oil and gas fields and their associated overhead and equipment. It is within this context that the hydrate production modelling effort at Los Alamos National Laboratory has been conducted.

Objectives in Production Modelling

Because little is known about naturally occurring hydrates, relatively straightforward models that yield good "ballpark" numbers are desirable. Only guesses can be made for basic reservoir parameters such as the hydrate-filled pore fraction, the occupancy ratio of gas in the hydrate, and the permeability distribution within a given hydrate zone. This uncertainty about major hydrate variables significantly limits the usefulness of sophisticated multidimensional, multicomponent reservoir models. Until such basic information can be reliably obtained, the use of such sophisticated models is not justified. For this reason, two fairly simple models, one to evaluate hydrate gas production from a hot water flood pattern and one to evaluate hydrate gas production from a fracture-linked injector/producer pair, have been developed.

Once the models were developed, it was planned to run parametric studies of major reservoir variables to rank their importance. A major objective of the parametric studies was to develop some preliminary screening criteria to identify promising hydrate reservoirs. Such a tool would be valuable in estimating the potential hydrate gas reserves in fields where hydrates have been encountered. Finally, a more realistic model could be used to analyze the economic feasibility of gas production from a given hydrate reservoir.

Frontal-sweep Model

In a plan view (Figure 1) of the frontal-sweep production system, hot water is injected into a central injection well and the dissociated hydrate gas flows to the surrounding production wells. This system is analagous to steam flooding a heavy oil reservoir, and the frontal-sweep model uses the Marx–Langenheim heavy oil recovery equations to calculate hydrate-gas production (Marx and Langenheim 1971). The frontal-sweep model is a heat-transfer model, not a porous flow model, and is essentially a time-dependent energy balance between heat injection, heat losses to the sediments above and below the hydrate zone, and the latent and sensible heat required to raise the hydrates from T_{hyd}, the hydrate dissociation temperature, to T_{inj}, the hot fluid injection temperature. This model assumes that:

(i) The hydrate is completely swept out by a moving vertical front of injection water;
(ii) All of the swept portion of the reservoir is at T_{inj}, the injection temperature;
(iii) The entire reservoir and surrounding sediments are initially at or are very near T_{hyd}, the hydrate dissociation temperature;
(iv) Injection rate, injection temperature, and reservoir thickness are constant;
(v) There is no significant heat conduction along the flow path of the injection fluid; and
(vi) All of the gas that is liberated at the dissociation front flows to a production well.

There are several additional assumptions that are implied by the use of the frontal-sweep model, but are not part of the model itself. These assumptions include:

(i) Sufficient *in situ* permeability exists within the hydrate zone to effectively flood the pattern;
(ii) The gas produced at the dissociation front does not reform into hydrates as it migrates toward the production wells; and
(iii) Technical considerations such as wellbore heat losses, melting of permafrost, and feedwater treatment do not pose serious problems.

Numerous technical problems do exist, especially with steam injection, but these are beyond the scope of this paper.

The major variables in the frontal-sweep model include reservoir thickness, porosity, and injection temperature. Other pertinent variables such as the thermal diffusivity of the sediments above and below the hydrate reservoir, the fraction of hydrate filling the pores, the occupancy ratio of methane to water in the hydrate, and the dissociation energy of the hydrate are either relatively constant from field to field or are virtually unknown (Appendix). In either case, these variables have been held constant for modelling purposes. The dissociation area (the area from which all hydrates have been produced) is given by

$$[1] \quad A(t) = \frac{IM^1 h\alpha}{4k^2 \Delta T} \left[e^{z^2} \operatorname{erfc} z + \frac{2z}{\pi} - 1 \right],$$

where

$$[2] \quad z = \frac{2K}{M^1 h} \left[\frac{t}{\alpha} \right]^{1/2}.$$

This is identical to the Marx–Langenheim equation except the weighted heat capacity, M, has been re-

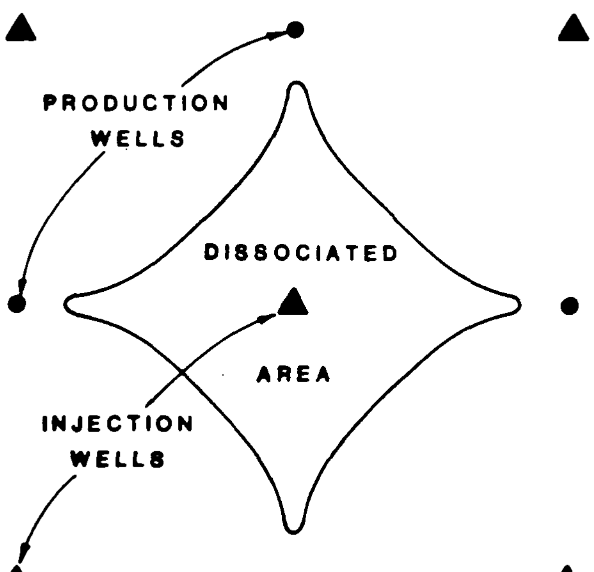

FIGURE 1. Plan view of the frontal-sweep production system.

placed by M^1, which also includes the heat of dissociation of the hydrate. This term is calculated from

$$[3] \quad M^1\Delta T = (1-\phi)\rho_r c_r \Delta T + F_{hyd}\phi H_{diss} + S_w\phi\rho_w c_w\Delta T + S_g\phi\rho_g c_g\Delta T.$$

Because the energy absorbed by the gas is negligible, this equation can be reduced to

$$[4] \quad M^1 = (1-\phi)\rho_r c_r + S_w\phi\rho_w c_w + F_{hyd}\phi H_{diss}/\Delta T.$$

The rate of gas production is given by

$$[5] \quad G_p = \frac{IB_{hyd}\phi F_{hyd}}{M^1\Delta T} e^{z^2} \operatorname{erfc} z,$$

where B_{hyd} is the volume of gas produced in standard cubic feet per cubic foot of hydrate dissociated. In all model cases, B_{hyd} was 140 scf/ft^3, F_{hyd} was 1.0, H_{diss} was 14,000 *Btu/ft*^{3}, $\rho_r c_r$ was 35 Btu/ft^3, $s_w\rho_w c_w$ was 56 Btu/ft^3, K was 1.5 Btu/h-ft-°F, and α was 0.0482 ft^2/h (Makogan 1974; Marx and Langenheim 1971). These values may vary somewhat with pressure and temperature and with location, but the changes are of little consequence in equations 1 and 5 compared to variations in bed thickness, porosity, and injection temperature.

For the results of the parametric studies, using the frontal-sweep model, see Figures 2 to 4. In Figure 2, a graph of the total gas produced in one year from one 50 MMBtu/h injection pattern in a 25 per cent porosity reservoir, note that the gas production is substantial at temperatures below 250°F. The gas production is less than the estimated fuel consumption (dashed line) for steam injection, where the injection temperatures will likely be in excess of 400°F. This same phenomenon is seen in Figure 3, in which the total gas produced in one year is from one 50 MMBtu/h injection pattern in a 50-ft-thick hydrate reservoir. The heat losses to surrounding sediments are too large to allow effective stimulation of hydrate reservoirs by steam injection, even if the steam can be injected at high rates (50 MMBtu/h) into thick hydrate reservoirs. At the other end of the scale, low injection temperatures require very large volumetric flow rates to carry worthwhile quantities of heat into the reservoir. Injection of roughly 30,000 bpd of 150°F water is required if a heat flux of 50 MMBtu/h is to be maintained. The constraints of excessive heat losses on the one hand and unrealistically high injection flow rates on the other hand will probably limit injection temperatures to between 150 and 250°F.

Inspection of the figures also indicates that, to be of interest as a potential resource, the reservoir should be 25 ft thick or more. Similarly, unless the porosity is at least 15 per cent, the heat wasted in raising the rock matrix temperature will render thermal stimulation ineffective in producing useful quantities of gas. The relative importance of porosity *versus* reservoir thickness in determining hydrate-gas production is illustrated (Figure 4).

It is important to recognize the limitations of the frontal-sweep model before using these results in evaluating a given hydrate reservoir. The model is based on a heat transfer solution and is in no way a porous flow model. Injectivity limitations, viscous fingering, out-of-pattern gas migration, and reformation of free gas and water into hydrates are among the problems that are not addressed by the frontal-sweep model. This model is quite useful in estimating hydrate-gas production, however, because it represents the upper bound of that production. Practical considerations such as those previously mentioned

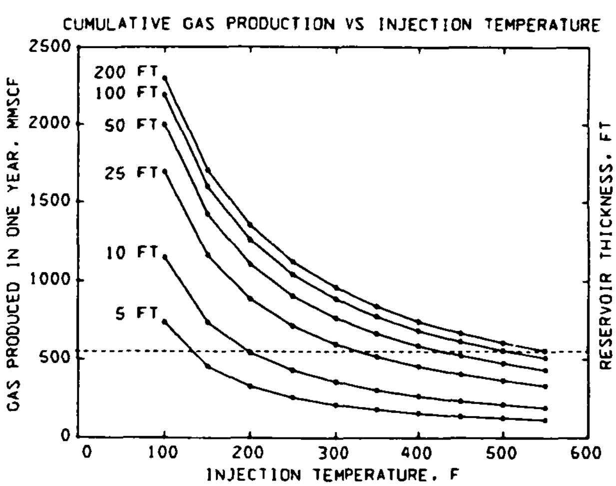

FIGURE 2. Hydrate-gas production as a function of injection temperature and reservoir thickness, ϕ = 25 per cent.

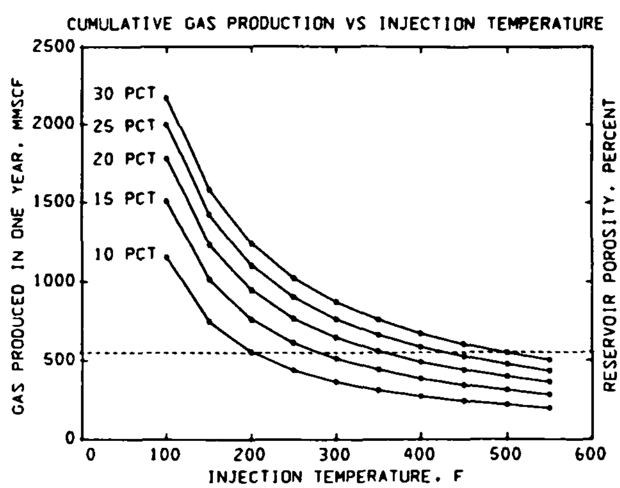

FIGURE 3. Hydrate-gas production as a function of injection temperature and porosity, h = 50 ft.

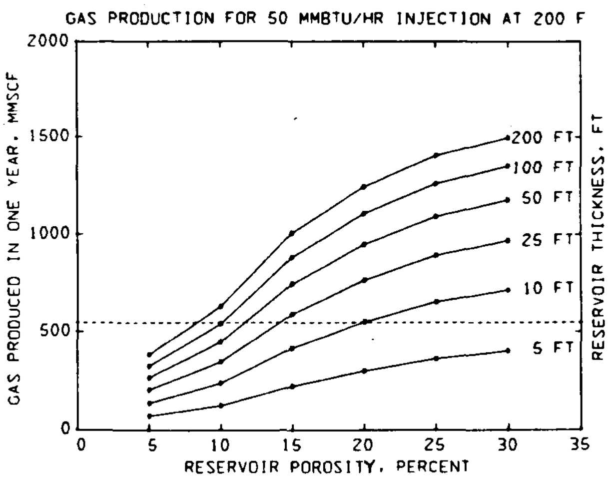

FIGURE 4. The relative importance of porosity *versus* reservoir thickness in frontal-sweep hydrate gas production.

will only serve to reduce the actual gas produced from a thermally stimulated hydrate reservoir.

Fracture-flow Model

A plan view (Figure 5) is of the fracture-flow production system in which hot water is pumped into an injection well that has been linked by hydraulic fracturing to a single producing well. This is the anticipated production technique in hydrate reservoirs where the *in situ* permeability is extremely low because of hydrate blockage of the pore channels. This fracture-flow case is much less effective than the frontal-sweep case because a large percentage of the injected energy is removed from the reservoir at the production well. The heat-transfer efficiency (HTE), which is equal to the energy expended in the reservoir divided by the total injected energy, decreases with time as the flow path between the wells becomes

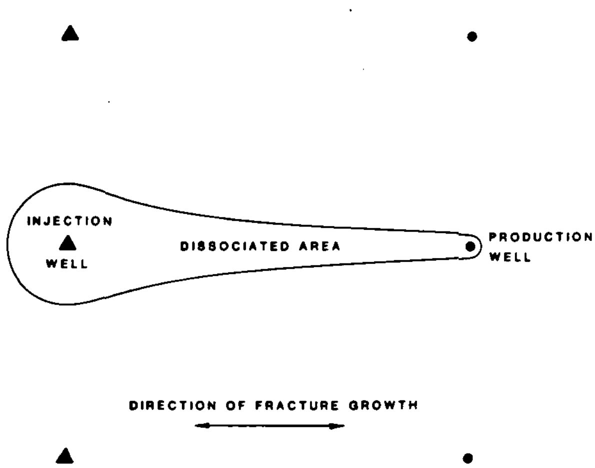

FIGURE 5. Plan view of fracture-flow production system.

wider. This results in higher produced water temperatures and lower gas production rates.

The fracture-flow heat transfer problem is extremely complicated because it is dominated by two-phase porous media flow, boundary layer considerations, gravity segregation of gas, hot water, and cold water, and the complication of phase changes and gas production distributed along the "fracture" (that is, the hydrate-free flow path) face. All of the above factors vary both vertically and horizontally along the fracture face and are time dependent. This system obviously has no closed-form solutions, nor are any existing finite-element programs equipped to model this behavior. A lower limit to the heat transfer can be established, however, by assuming laminar slug flow of the injection water through the porous media between the fracture faces. This case then becomes a variation of the widely known Graetz laminar-flow conduction problem, and it can be solved in closed form for a constant flow path width (Arpaci 1966). The laminar slug flow solution has been incorporated into a one-dimensional finite-element model to establish the worst-case fracture-flow performance.

The fracture-flow model uses the following simplifications:

(i) The flow path, whose width is a continuously varying function of both time and distance along the path, is represented by a series of constant-width elements, each one smaller than the last. The width of each element is changed after every time step.

(ii) The fluid flow is assumed to be laminar slug flow with a constant mass flux of water throughout the flow path. This implies that the *in situ* hydrate permeability is effectively zero, and that the mass transfer changes because of hydrate dissociation and gas production are small.

(iii) The effects of two-phase flow, gravity segregation of gas and water, and the diffusive mixing inherent in porous flow are all ignored. This should yield a conservative worst-case model for heat transfer into the hydrate reservoir.

(iv) Heat losses to the sediments above and below the reservoir are ignored, resulting in a two-dimensional problem.

(v) Thermal storage effects of the porous media are incorporated in the hydrate dissociation calculations, not in the basic temperature distribution equations.

The finite-element representation of the fracture-flow channel is shown in Figure 6 and a typical element is shown in Figure 7. Ten elements of equal

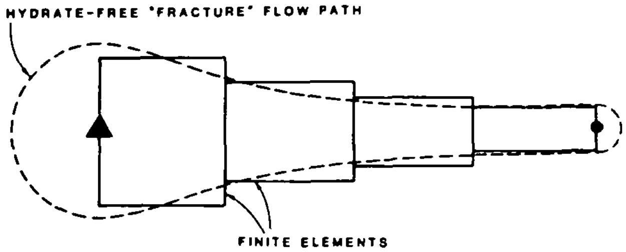

FIGURE 6. Representation of the fracture flow path by a series of constant-width elements.

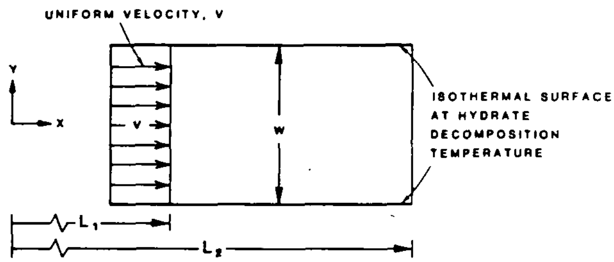

FIGURE 7. A typical finite element at distance L_1 from injection well.

length and initial width, W, were used in the model. The steady-state temperature distribution within a flow channel of constant width, W, is given by

$$[6] \quad T(x,y) = T_{hyd} + \sum_{n=0}^{\infty} \frac{4(T_{inj}-T_{hyd})(-1)^n}{\lambda_n} e^{-\left[\lambda_n^2 Khx/\rho_w c_w Q_w W\right]} \cos\left(\lambda_n \frac{y}{W}\right),$$

where $\lambda_n = (2n+1)\pi$. The heat flux through the isothermal surfaces of the finite element (*see* Figure 7) can be approximated by

$$[7] \quad q(L_1,L_2) = 8\,(T_{inj}-T_{hyd})\,Q_w \rho_w c \times \sum_{n=0}^{\infty} \frac{1}{\lambda_n^2}\left[e^{-[\lambda_n^2 KhL_1/\rho_w c_w Q_w W_{eff}]} - e^{-[\lambda_n^2 KhL_2/\rho_w c_w Q_w W_{eff}]} \right],$$

where W_{eff}, the "effective width," is the average flow path width over the interval $0 \leqslant x \leqslant L_2$. As this heat flux is applied to the isothermal dissociation surfaces over a time step of length τ, hydrate is dissociated and the flow path is widened by an amount $\Delta W(L_1,L_2)$. Hydrate-gas production from the element during the time step is given by

$$[8] \quad G_p(L_1,L_2) = B_{hyd}\, q(L_1,L_2)\tau\phi / M^1(T_{inj}-T_{hyd}).$$

During the next time step, the new values of W_{eff} for each element are used in equations 7 and 8 to calculate hydrate-gas production. The effective flow path width increases with every time step; therefore, gas production always decreases with time.

The major variables in the fracture-flow model are the same as those for the frontal-sweep model: reservoir thickness, porosity, and injection temperature. The only new variable is fracture length, which is the distance between the injector and the producer. Parametric studies were run using this model to evaluate the influence of each of these variables. Because the model does not account for heat losses to sediments above and below the hydrate zone, the results are fairly insensitive to injection temperature. Porosity appears only in the numerator of equation 8 and indirectly in the denominator as part of M^1, so the gas production is roughly proportional to porosity.

The gas produced after one year of injecting 30,000 BWPD of150°F water (roughly 50 MMBtu/h) into a fracture-linked well pair is shown as a function of fracture length and reservoir thickness (Figure 8). It is interesting that the gas production is a function of the product of these two variables. For example, a 50-ft-thick by 330-ft-long fracture, a 25-ft-thick by 660-ft-long fracture, and a 10-ft-thick by 1650-ft-long fracture all produced 140 MMscf. In all cases studied, the total gas production in one year was less than the estimated fuel consumption required to heat 30,000 BWPD from 32 to 150°F. Even in the most favourable case (a 2640-ft-long fracture in a 200-ft-thick reservoir), the produced water temperature was over 130°F after a year of injection, yielding an HTE of

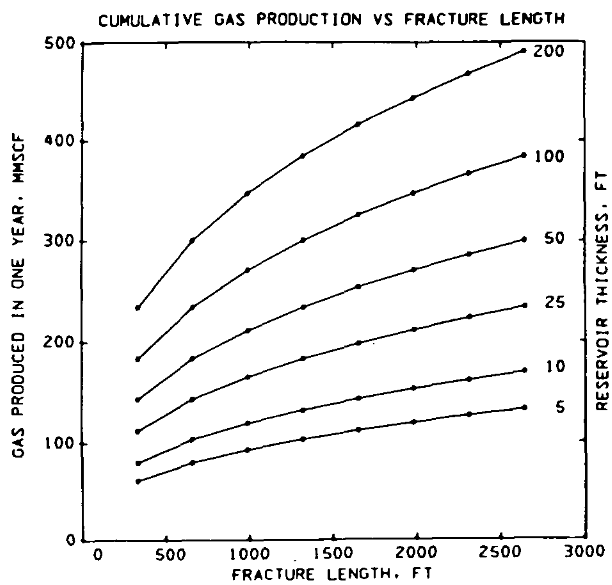

FIGURE 8. Hydrate-gas production as a function of fracture length and reservoir thickness.

only 16 per cent. A temperature profile of the fracture-flow system (Figure 9), illustrates the "thermal short circuit" that causes such low efficiencies and production rates.

As in the case of the frontal-sweep model, it is important to realize the limitations of the fracture-flow model before using these results to evaluate a given hydrate reservoir. The model is based on a heat transfer solution and is in no way a porous flow model. The assumption of laminar slug flow with no fluid mixing is highly conservative, as is the assumption that the hydrate permeability is zero, confining all of the injection fluid to the hydrate-free flow path. The fracture-flow model represents the lower bound on hydrate-gas production, and a real system should be much more effective.

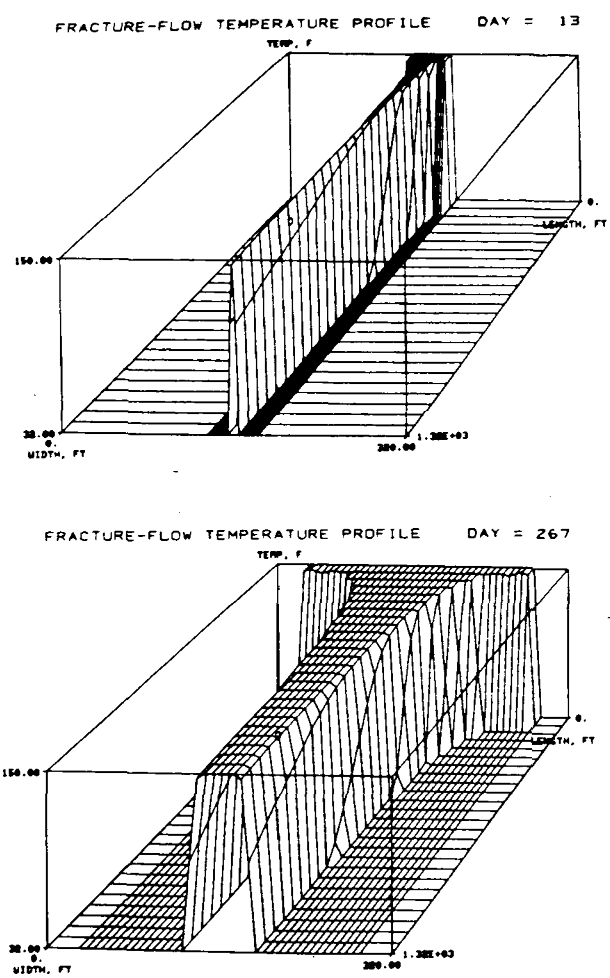

FIGURE 9. Temperature profile of fracture-flow system after nine months of injection at 150°F.

Comparisons Between the Models

Several conclusions can be drawn by comparing the frontal-sweep data with the fracture-flow data. First, the *in situ* permeability of the hydrate zone could play a major role in determining the effectiveness of hot-water injection in producing gas. The higher the permeability is in the hydrate zone, the more closely the high-efficiency frontal-sweep model will be approached. If the hydrate zone is virtually impermeable, the reservoir performance will approach that of the low-efficiency fracture-flow model. Thus, hydrate zones below the base of the permafrost, where either excess gas or excess water is likely to exist, would appear preferable to hydrate zones within the permafrost. Drill stem testing to establish *in situ* hydrate permeabilities would be desirable in evaluating the resource potential of a given hydrate reservoir (Bily and Dick 1974).

Secondly, if the frontal-sweep model represents the best performance (barring chemical effects from inhibitors, such as salts and alcohols) that can be obtained from the reservoir and the laminar fracture-flow model represents the worst performance, one can at least bracket the production rates and the economics of thermally stimulating a hydrate reservoir. Such a comparison is shown (Figure 10) for a 25-per-cent-porosity reservoir as thickness is varied from 10 to 200 ft. The gap between the two models is quite large, but it can be reduced by "correcting" the models for real-life conditions. For example, by accounting for the effects of fluid mixing and two-phase flow, one can increase the efficiency of the fracture-flow model, while accounting for free gas migration out of the pattern. This will decrease the

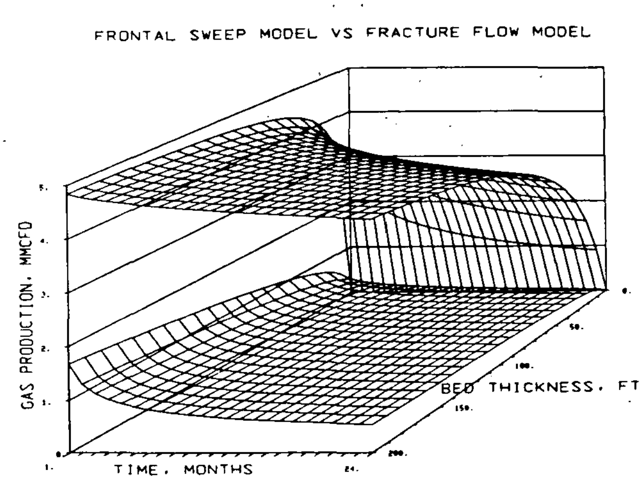

FIGURE 10. Parametric study of gas production *versus* reservoir thickness showing the upper and lower bounds of anticipated gas production.

efficiency of the frontal-sweep model. These corrections will, of necessity, be somewhat arbitrary, but should yield more accurate production estimates than the two existing models.

Conclusions

Numerous important questions about hydrate-gas production remain unanswered. For example, how serious is the problem of dissociated hydrates reforming as the gas and water migrate toward the producing well? Could brine injection, either of surface-heated sea water or direct injection of warm brines from deeper zones, be effective in dissociating hydrates and preventing them from reforming? What are the important properties (that is, fractional pore filling, excess gas content, occupancy ratio of methane in the hydrate lattice) of hydrate deposits as they occur in nature? These questions warrant additional investigation for several reasons. Not only is the potential hydrate resource base vast, but also a good deal of the resource overlies conventional oil and gas fields where huge amounts of equipment and organizational overhead are already in place. Finally, production modelling indicates that methane hydrates could perhaps be produced at sufficient rates to extend the life of these fields as conventional resource supplies dwindle.

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Appendix

Nomenclature

The numbers in parentheses were used in the models.

A	The area of the reservoir in which all hydrates have been dissociated, ft^2.
B_{hyd}	Hydrate formation volume factor, scf of produced gas per ft^3 hydrate (140 scf/ft^3).
c_g, c_w, c_r	The specific heats of gas, water, and rock, respectively, Btu/lbm (0, 1.0, 0.2).
F_{hyd}	The fraction of the pore space containing hydrates (1.0).
G_p	The gas production rate.
h	The height or bed thickness of a hydrate reservoir, ft.
H_{diss}	Heat required to dissociate hydrate into gas and water at 32°F, Btu/ft^3 (14,000).
I	Rate of heat injection into the reservoir, MMBtu/h (50).
K	Thermal conductivity of the reservoir and surrounding sediments, Btu/h-ft-°F (1.5).
L_1, L_2	The minimum and maximum distances, respectively, to the injection well from a given finite element, ft.
M	The weighted heat capacity of the reservoir and its fluids, Btu/ft^3.
M^1	Same as M, but includes the heat of dissociation of the hydrate, Btu/ft^3.
q	Heat flux into the hydrate-bearing portion of the reservoir, Btu/h-ft^2.
Q_w	Volumetric rate of water injection, ft^3/h.
S_g, S_w	Gas saturation and water saturation, respectively.
t	Time since start of injection, h.
T_{hyd}	Hydrate dissociation temperature, °F (32).
T_{inj}	Temperature of injection water, °F.
ΔT	$T_{inj} - T_{hyd}$, °F.
W	The width of the fracture-flow channel, ft.
W_{eff}	The effective width, in terms of estimating the heat transfer, of the fracture-flow channel at a given point, ft.
ΔW	The change in the fracture-flow path width because of dissociation, ft.
x	The distance along the path from the injection well to the production well, ft.
y	The "width dimension" of the fracture-flow channel, perpendicular to the x-axis, ft.
α	The thermal diffusivity of the reservoir and surrounding sediments, ft^2/h (0.0482).
ρ_g, ρ_w, ρ_r	The gas, water, and rock matrix density, respectively, lb/ft^3 (0, 62, 167).
ϕ	The reservoir porosity.
τ	Time step length, h (12).