

Warm water flooding of confined gas hydrate reservoirs

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ABSTRACT

Large quantities of natural gas hydrate are present in marine sediments along the coastlines of many countries as well as in arctic regions. This research is aimed at assessing techniques to produce natural gas from marine hydrate deposits. A multiphase, multicomponent, thermal, 3D simulator is used, which can simulate production of hydrates both in equilibrium and kinetic modes. Three components (hydrate, methane, and water) and four phases (hydrate, gas, aqueous-phase, and ice) are considered in the simulator. In this work, we simulate warm water flooding and depressurization for hydrate production from a confined reservoir with a hydrate layer underlain by a water layer. Water flooding has been studied as a function of injection temperature, injection pressure and production pressure. For high injection temperature and high production pressure, warm water injection is preferred over depressurization; an increase in injection pressure increases the heat influx to the reservoir making the gas production faster. If a low pressure can be maintained at the production well or the injection temperature is not high, then just depressurization is the best method of production. As reservoir porosity and permeability increase and the heat transfer coefficient to the over- and under-burden decreases, the warm water injection process becomes more favorable.

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1. Introduction

Gas hydrates are ice-like compounds formed by trapping of gas molecules in clathrates of water molecules under high pressure and low temperature (Sloan, 1998). The large amount of gas trapped in gas hydrates can be a potential source of energy. Their disappearance is accompanied by emission of methane, a green house gas which affects global climate (Matsumoto, 2002). Three types of crystalline structure of gas hydrates have been found so far, structure I (SI), structure II (SII), structure H (SH), in the order of increasing clathrate size. The properties associated with the crystalline structures have been studied in the past (Sloan, 1998). The conversion of methane and water into hydrates can be stated as



where, n is the hydration number. Many gas components (e.g. methane, ethane, and carbon dioxide etc.) can be trapped by water clathrates through hydrogen bonding under suitable condition. SI methane hydrate is common in natural deposits and is the focus of the present study.

Hydrates can exist either in onshore permafrost regions or in offshore sediments satisfying the hydrate stability temperature and

pressure condition (Bhatnagar et al., 2006). The hydrate reservoirs can be classified into three types (Moridis, 2005): class 1 reservoirs have a hydrate layer overlying a free gas layer, class 2 reservoirs have the hydrates overlying a water saturated layer and class 3 reservoirs have a single layer containing the hydrates bounded by two impermeable shale layers. Class 2 reservoirs are the focus of this study. The hydrate deposit at the Nankai trough is an example of such a deposit (Matsumoto, 2002).

Four methods and their combinations have been proposed to produce gas from hydrate reservoirs: depressurization, thermal stimulation, inhibitor injection, and CO₂ injection (Makogon, 1997; Ji et al., 2001; Graue et al., 2006). In depressurization, the pressure is lowered at the production well below the hydrate stability pressure and the dissociated gas flows into the production well (Ji et al., 2001; Moridis and Reagan, 2007). Pressure decline is sensed throughout the reservoir quickly, but ice forms if depressurization is done at very low pressures. If the pressure is kept higher than the quadruple point to stop ice formation, then the hydrate dissociation is slow. In thermal stimulation, either wells are heated or warm water (or steam) is injected into the reservoir raising the temperature above the hydrate stability temperature (Bayles et al., 1986). To minimize the cost of heating, aquifer water underneath the reservoir (dump flooding), sea water, or warm water from nearby oil wells can be injected. In the inhibitor process, chemicals that inhibit hydrate formation are injected along with water in injection wells (Makogon, 1997). The cost of inhibitors is usually high, formation of water

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dilutes it, and salt-based inhibitors can precipitate. In the CO₂ process, CO₂ is injected to replace methane in clathrate cages resulting in methane production and simultaneous CO₂ sequestration (Graue et al., 2006). The energy released during CO₂ clathrate formation is used for dissociation of methane hydrate. The mass transfer barriers within solid hydrate phases can slow this process.

Depressurization and warm water flooding appear to be relatively inexpensive processes for gas production from marine hydrates. The goal of this study is to determine the effect of injection and production conditions on gas and water production from a hydrate reservoir. In this study, we have considered only confined reservoirs (those bounded by impermeable layers at the top and bottom). In Section 2, we describe the methodology used. The results are described in Section 3, followed by the conclusions in Section 4.

2. Methodology

2.1. Reservoir description

A horizontal confined class 2 reservoir of 10 m thickness is considered. It is assumed that it would be developed in a 5-spot pattern and the area studied is a quarter of a 5-spot of size 120 m × 120 m. The hydrate saturation in the top 8 m of the reservoir is initially 0.6 with an aqueous saturation of 0.4. The bottom 2 m is an aqueous layer with aqueous saturation of 1, as in the case of class 2 reservoirs (Fig. 1). No gas is present in the reservoir initially. The reservoir porosity is 0.28 and absolute permeability is 100 md. The reservoir is considered to be 500 m below the sea floor with a water depth of 1000 m. Initial reservoir pressure depends on its depth according to the hydrostatic pressure; the pressure at the bottom is 9 MPa. The reservoir temperature also varies with depth with the geothermal gradient of 0.03 K/m; the bottom temperature is about 280.7 K.

The over- and under-burdens are considered impermeable shale (confined reservoir). No mass flow is allowed through these boundaries, but heat flow is allowed with a specified average heat transfer coefficient. Heat transfer coefficient for the base case is assumed to be 0.2 W/m²K. This value of heat transfer coefficient is an approximate average value for an infinite slab with the temperature rise typical of the problems considered and sand properties specified in Table 1. No heat or mass flow boundary condition is assumed for lateral boundaries due to symmetry of 5-spot pattern. Injection of warm water into these reservoirs and depressurization are simulated. Production well pressure, injection well pressure, and injection water temperature are varied (Table 2).

2.2. Thermal properties

Fig. 2 shows the hydrate equilibrium (P_e – T) curve, where P_e is the equilibrium pressure of three phase equilibria $H+G+A$ and $H+G+I$ at temperature T , represented with empirical correlations obtained by Moridis (2003). The region above the equilibrium curve is the hydrate stable zone and the region below is the gas stable zone. The region left of the solid line is the ice stable region and the region to the right is the water stable region. Solubility of methane in aqueous phase and water in gas phase, specific internal energy and specific enthalpy are taken from the literature and are listed by Sun et al. (2005).

2.3. Transport properties

For absolute permeability, a power law model based on effective porosity and proposed by Civan (2001) is used:

$$\frac{K^e}{K_0} = \frac{\phi}{\phi_0} \left(\frac{\phi^e(1-\phi_0)}{\phi_0(1-\phi^e)} \right)^{2\beta} \quad (2)$$

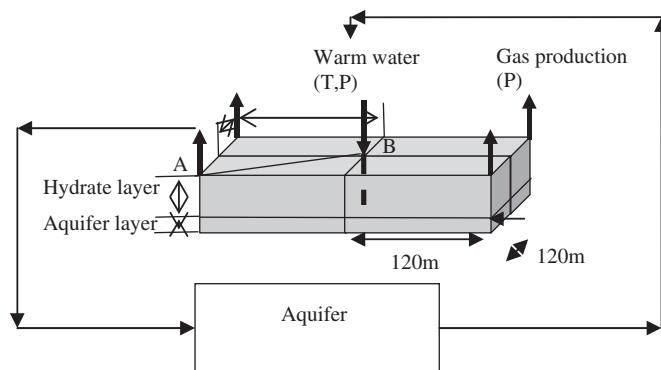


Fig. 1. Reservoir developed in 5-spot pattern considered for gas production from hydrates.

Table 1

Parameters for hydrate and sand.

Hydrate density	910 kg/m ³
Hydrate heat conductivity	0.49 W/m/K
Hydrate heat capacity	1.62 kJ/kg/K
Ice density	917.1 kg/m ³
Sand density	2670 kg/m ³
Sand heat conductivity	5.57 W/m/K
Sand heat capacity	0.83 kJ/kg/K

Table 2

Water injection parameters.

Figure	Injection water temperature (°C)	Production well pressure (MPa)	Injection well pressure cases
3	50	4	No injection, 5, 10, 30, 40 MPa
5	50	2	No injection, 5, 10, 30, 40 MPa
6	20	2	No injection, 5, 10, 20, 30, 40 MPa

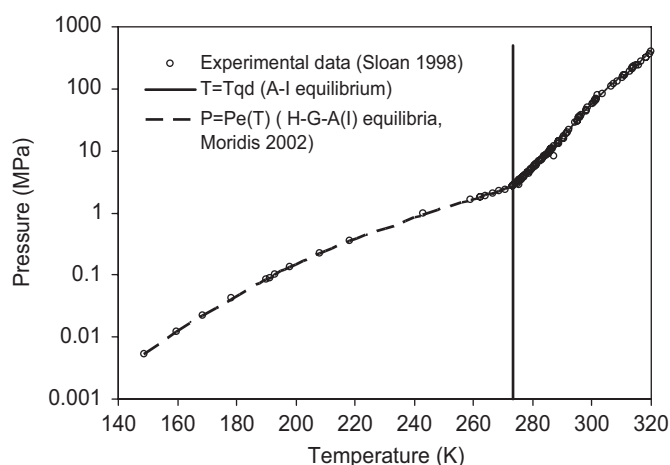


Fig. 2. Equilibrium curve for hydrate stability zone.

K^e is the effective permeability, K_0 is the reference permeability which is taken as 100 md for base case in the present study for reference porosity ϕ_0 0.28. The absolute permeability K , changes with ϕ according to Eq. (2) with ϕ^e equal to ϕ . ϕ^e is the effective porosity for the fluid phases which can be related to absolute porosity, ϕ as

$$\phi^e = \phi(S_G + S_A) \quad (3)$$

β is a parameter assumed to be 2.0. S_j is the saturation of the j th phase based on absolute porosity whereas S_j^e is the effective saturation based on the effective porosity. The two saturations are related by

$$S_j^e = S_j \phi / \phi^e \quad (4)$$

For relative permeability Brooks–Corey model is used, i.e.,

$$k_{rG} = k_{rG}^0 (S_G^{e*})^{n_G} \quad (5)$$

$$k_{rA} = k_{rA}^0 (S_A^{e*})^{n_A} \quad (6)$$

where k_{rj}^0 and n_j are the end point relative permeability and exponential parameter for phase j . S_j^{e*} is normalized saturation of gas or aqueous phase based on the effective pore volume occupied:

$$S_j^{e*} = \frac{S_j^e - S_{jr}^e}{1 - S_{Gr}^e - S_{Ar}^e} \quad (7)$$

The capillary pressure is described by Eq. (8):

$$P_c = P_{ce} (S_A^{e*})^{-n_c} \quad (8)$$

where n_c is a parameter for pore structure and P_{ce} is the entry capillary pressure which is related to effective porosity as

$$P_{ce} = P_{ce0} \sqrt{\frac{\phi^e K_0}{\phi_0 K^e}} \quad (9)$$

where p_{ce0} is the entry capillary pressure at the absolute porosity ϕ_0 . The residual saturation in Eq. (7) is also based on the effective porosity. For the present case, the residual saturation is assumed to be 0.2 for the aqueous phase and 0 for gas phase. Some of the hydrate and sand properties are listed in Table 1. Other details can be found in Sun et al. (2005).

2.4. Numerical model

The numerical model used is a 3D finite-volume simulator that takes into account heat transfer, multiphase fluid flow, and equilibrium thermodynamics of hydrates (Sun and Mohanty, 2006). The modeling scheme of the simulator is discussed in Appendix A. Energy and mass balance equations are solved in space and time domain. Three components (hydrate, methane, water) and four phases (hydrate, gas, aqueous-phase, and ice) are considered in the simulator; the salt concentration is not monitored in the present study. The 120 m × 120 m × 10 m domain is discretized typically into 15 × 15 × 10 grid blocks. Single-point upstream weighting is used in the space discretization. The simulator uses a fully implicit scheme to solve the discretized equations in time. Newton–Raphson method is used to solve the non-linear equations. All the phases in a grid block are assumed to be in equilibrium at a particular pressure and temperature as kinetics (Kim et al., 1987) are relatively fast for field-scale problems. Primary variable switch method (PVSM) is used to track the phase saturations. This method has been proven to be a robust technique in dealing with phase transitions (Forsyth and Simpson, 1991; Faltz et al., 1992). The simulator uses continuum-scale modeling, i.e., the coupling between thermodynamics, kinetics, and transport processes at the microscopic-scale is neglected. This simulator has been validated against several other simulators for the problems in the code comparison study conducted by US DOE (Wilder et al., 2008).

3. Results

3.1. Production schemes

Depressurization and thermal stimulation using warm water injection are simulated. The temperature and pressure of injection

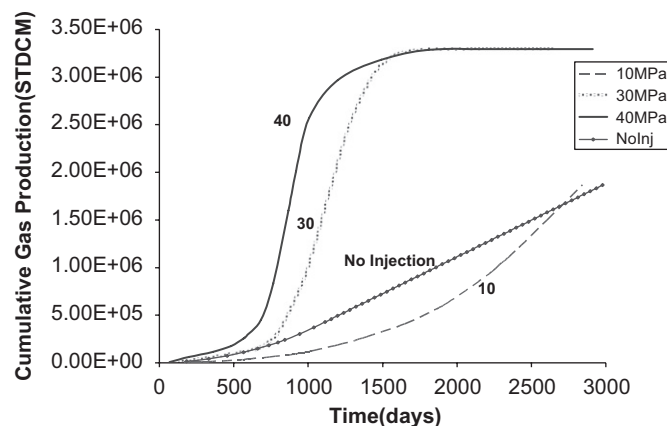


Fig. 3. Gas production at 4 MPa production pressure and 50 °C injection temperature.

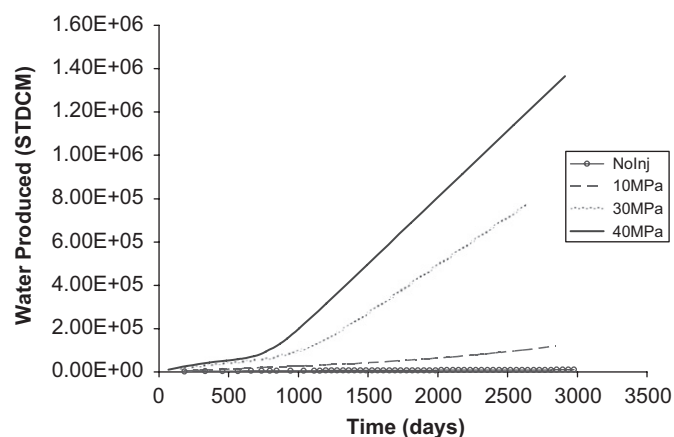


Fig. 4. Water production at 4 MPa production pressure and 50 °C injection temperature.

water are varied. Two production well pressures (4 and 2 MPa) are considered. Fig. 3 shows the cumulative gas production when production well pressure is 4 MPa and injection well pressure is varied with the injection water temperature of 50 °C. As the injection well pressure increases the rate of gas production increases. The rate of inflow of warm water (and heat) increases, which raises the reservoir temperature and thus increases the rate of dissociation. In the case of 10 MPa injection pressure, the gas production rate is less than that of just depressurization at 4 MPa. This is due to an increase in reservoir pressure without a significant increase in temperature. In the case of no injection, the pressure is reduced to 4 MPa in the reservoir. In the case of injection, the pressure around the injection well is higher than the initial pressure for the warm water to go into the reservoir. In the case of 10 MPa injection well pressure, the average pressure of the reservoir increases which hinders hydrate dissociation. The inflow of heat is not high enough to overcome the effect of pressure increase in the reservoir. In the case of 30 MPa (and 40 MPa) injection pressure, the average reservoir pressure is high, but so is the heat influx. The larger increase in temperature overcomes the increase in pressure and increases the rate of hydrate dissociation. For these warm water injections, the gas production rate is low for about the first 1.5 years and then increases sharply. The mechanism of this two-stage production rate would be discussed in the next section.

Fig. 4 shows the cumulative water production for the above case. The water production for about first 1.5 years is slow and then increases sharply. The total water produced until the time all the gas

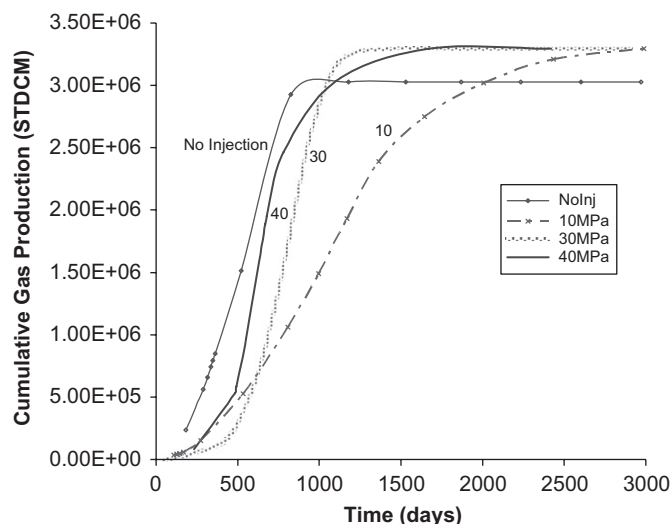


Fig. 5. Gas production at 2 MPa production pressure and 50 °C injection temperature.

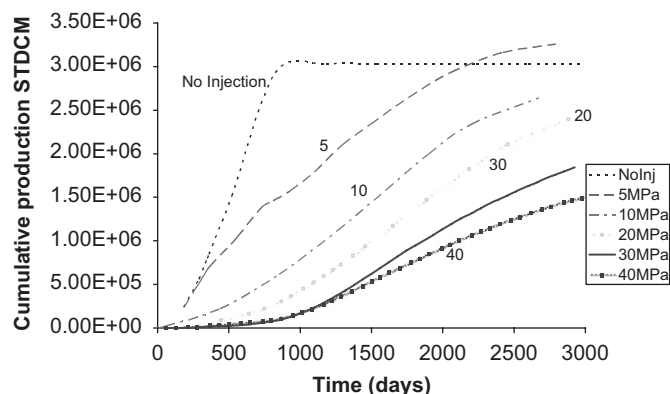


Fig. 6. Gas production at 2 MPa production pressure and 20 °C injection temperature.

is extracted is less than 5×10^5 STDCM which is less than total gas produced at that time which is about 32×10^5 STDCM.

Fig. 5 shows the cumulative gas production when the production well pressure is kept at 2 MPa with the injection water temperature of 50 °C. For the case of warm water injection, the rate of gas production increases with the increase in the injection pressure. However, the depressurization alone produces gas faster. When the injection well pressure is high, the reservoir pressure increases which leads to a lower dissociation rate in spite of the increase in temperature. The total production in the case of water injection is higher because the injected water displaces all the gas, whereas in the case of depressurization, gas is left in the reservoir at 2 MPa.

The sensitivity of this process to a lower injection temperature is illustrated in Fig. 6. The production well pressure is kept at 2 MPa, but the injection temperature is reduced to 20 °C. The gas production rate is again the highest for just depressurization. The gas recovery for warm water injection cases is lower because the heat influx is small and overshadowed by the pressure increase. In fact, the gas production rate decreases with the injection well pressure because the reservoir pressure increases with injection well pressure.

Thus at low production well pressure and low injection water temperature, depressurization is more favorable than water injection in confined reservoirs. However, if the production well pressure cannot be very low, for example, 4 MPa, then injection water at a temperature of 50 °C is more favorable than just depressuriza-

tion. This warm water can be found approximately 1400 m below the reservoir or can be obtained from a nearby operational oil well. Saturation, temperature and velocity profiles are described in the next section to understand the flow patterns in these processes.

3.2. Warm water flooding

The gas production during warm water injection is illustrated for an example case where 50 °C water is injected into the 5-spot pattern at a pressure of 30 MPa and the production well pressure is maintained at 4 MPa. Fig. 7(a) shows the temperature profile after 1010 days in the diagonal plane connecting injection and production wells. X-axis shows the grid number along the horizontal diagonal AB (Fig. 1) and Z-axis shows the grid number in the vertical direction. The production well is at grid number 15, and injection well is at grid number 1 along the X-axis. Grids 1 and 2 along the Z-axis belong to the initial water saturated layer. Temperature generally decreases from injection well to production well. As the warm water comes into the reservoir, it heats up the reservoir (rock, hydrates, and water) and loses some heat to over- and under-burden by conduction. As the hydrates warm up, they dissociate; the enthalpy of dissociation is provided by the warm water. The temperature gradient in Fig. 7(a) is the highest in the middle of the reservoir at the hydrate dissociation front, which is shown in Fig. 7(b). Warm water flows faster in the bottom two (hydrate-free) grid blocks initially and thus the temperature is higher at the bottom. As the production well is kept at 4 MPa, hydrate dissociates near the production well and the warm water from the bottom water layers arrives at the production well early raising the temperature in the production near-well bore region.

Fig. 7(b) shows the hydrate saturation profile at the same time (1010 days). Hydrate is completely dissociated within 40 m (~4 grid blocks) of the injection well. Hydrate is dissociated at the bottom part of the production well, but not at the top part. The main hydrate dissociation front is about five or six grid blocks away from the injection well. This front moves towards the production well with time. Hydrate saturation is the highest (~0.8) just downstream of this dissociation front. This hydrate saturation (0.8) is higher than the initial hydrate saturation (0.6). Gas formed at the dissociation front flows downstream, again combines with water (because of the high pressure and lower temperature than at the front) to form hydrates downstream of the dissociation front. There is also a dissociation front near the production well which is mostly due to depressurization at the production well and slightly due to the temperature increase because of the warm water flowing in the bottom water layer. This figure also shows that some hydrate forms in the original water layer due to flow of gas into this layer and subsequent pressurization.

Fig. 7(c) shows the gas saturation profile at 1010 days. Gas saturation is significant near the two hydrate dissociation fronts. The gas generated at the main dissociation front moves to the right and the lower right because of the higher flow rate of water at the bottom. The gas that moves directly to the right gets converted into hydrates because of high pressure and lower temperature; thus gas is absent at the locations with the highest hydrate saturation. The gas that moves to the lower right forms the highest gas saturation seen in Fig. 7(c). The gas that forms near the production well dissociation front moves downstream and is produced. Gas saturation is zero in the water-swept regions (e.g. near injection well) because the residual gas saturation is assumed to be zero in this simulation.

Water saturation can be computed knowing hydrate and gas saturations (not shown). It is 1 in the water-swept region near the injection well and close to 1 in the region near the production well. It is 0.4 in the undissociated hydrate region, but is lower than original in the region downstream of the main dissociation front, where

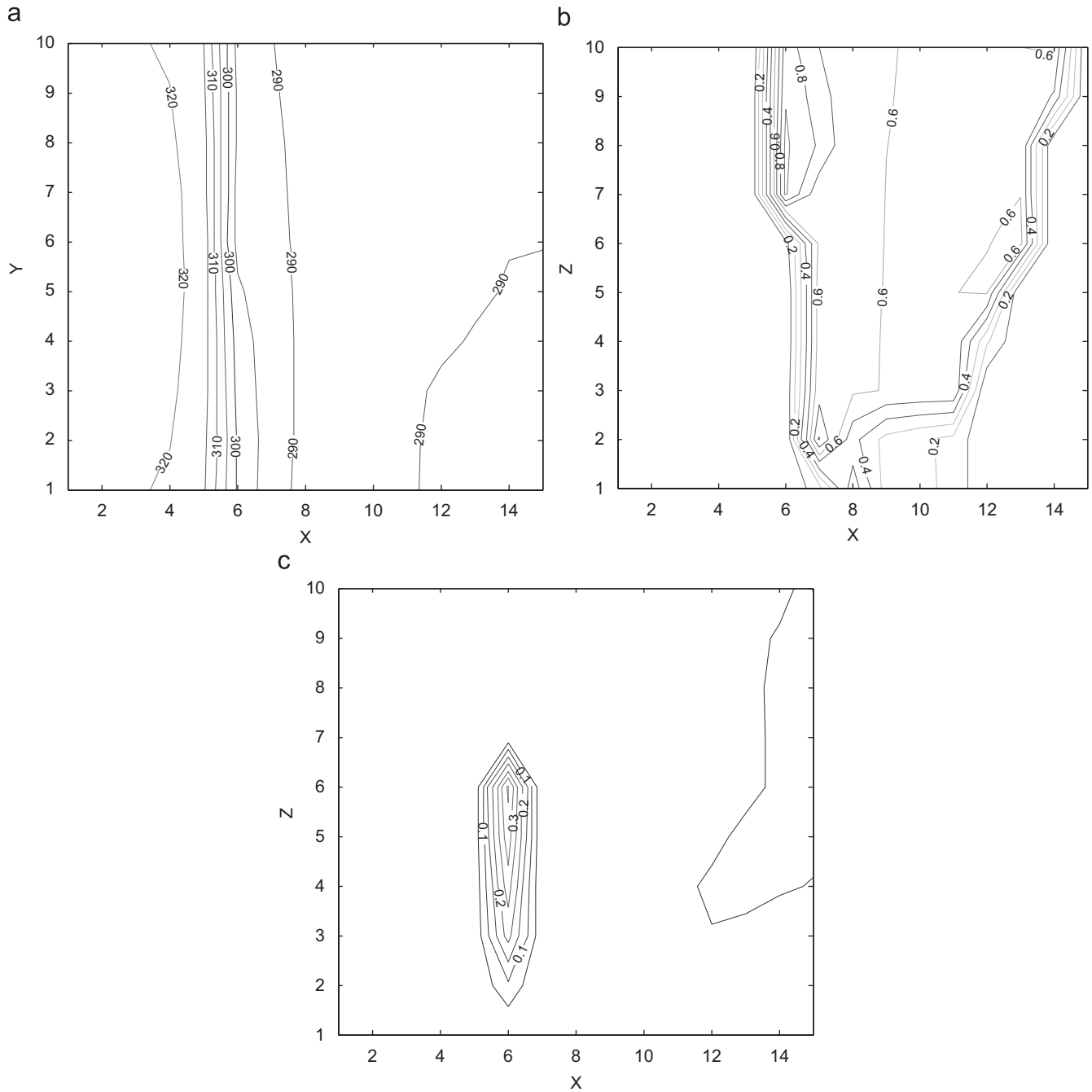


Fig. 7. (a) Temperature profile after 1010 days for production pressure 4 MPa, injection pressure 30 MPa, injection water temperature 50 °C, (b) hydrate saturation profiles after 1010 days for production pressure 4 MPa, injection pressure 30 MPa, injection water temperature 50 °C and (c) gas saturation profiles after 1010 days for production pressure 4 MPa, injection pressure 30 MPa, injection water temperature 50 °C.

hydrate reforms. Water saturation is also lower in the middle part of the original water layer where hydrate forms.

In the warm water injection case described above, initially temperature rises only near the injection well due to inflow of warm water where hydrate dissociation takes place. None of this gas reaches the producer initially and, hence, not produced in early days. The depressurization at the production well releases some gas but very slowly before about 600 days. Hydrate dissociation takes heat from the injection water as well as the surroundings, which lowers the temperature just downstream of the dissociation front. Dissociated gas moves downstream, comes in contact with colder water and reforms hydrates if the pressure is high enough. The hydrate satura-

tion increases downstream of the dissociation front as temperature and pressure condition are in hydrate stable zone. Hydrate formation decreases fluid porosity, and permeability. Initially the hydrate dissociation is faster near the aquifer region because warm water travels fast in the high permeable region and helps in hydrate dissociation. The water layer at the bottom has high initial water permeability; some of the released gas moves in that direction also. Hydrates form in the aquifer region downstream of the dissociation front. This reduces the permeability in the aquifer region. Due to reduction in permeability, the warm water does not flow easily and, hence, hydrate dissociation slows down near the aquifer region. Hydrate forms in the water layer after about 120 days. At about 600

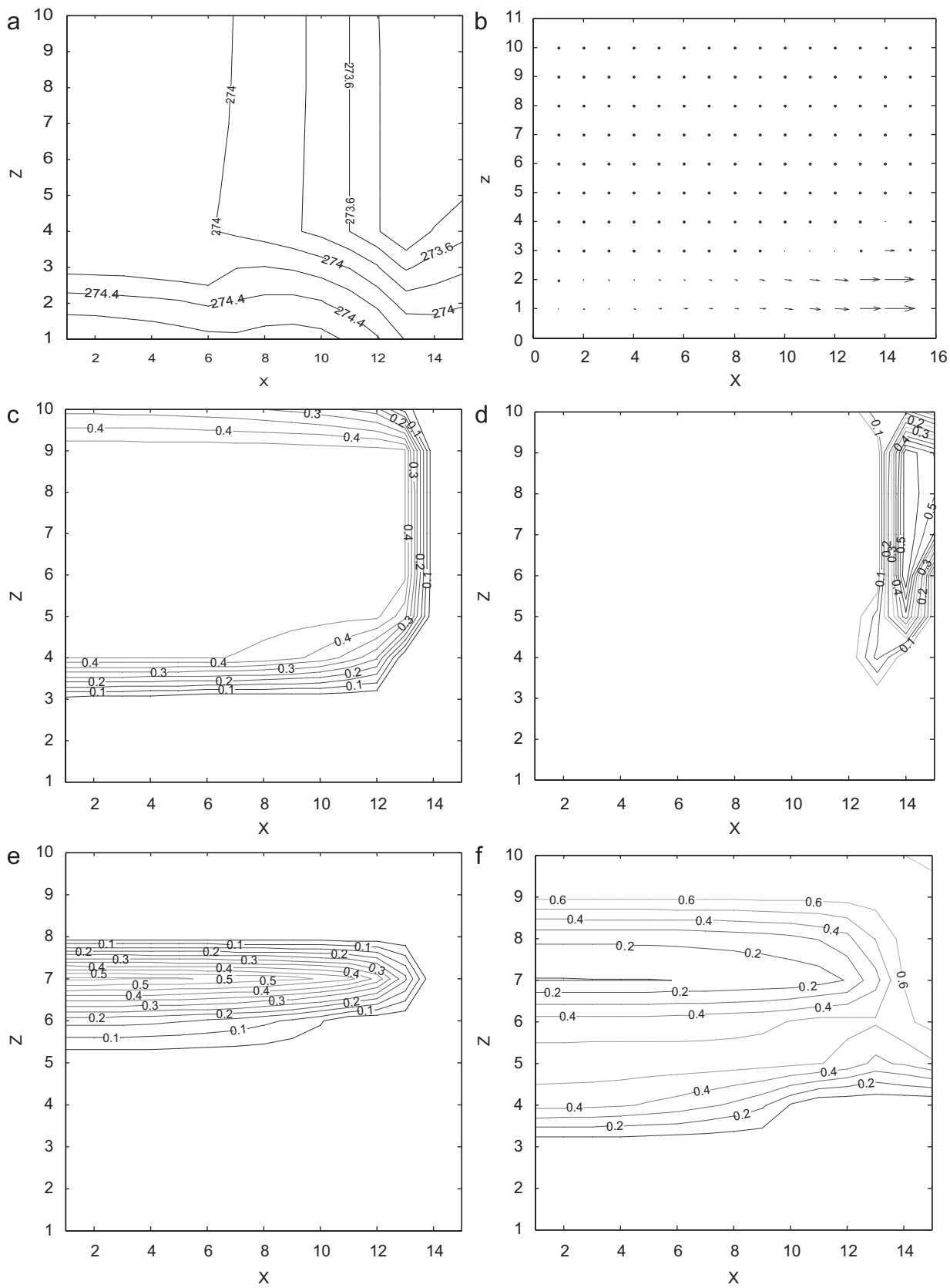


Fig. 8. (a) Temperature profile on vertical diagonal at 397 days for 2 MPa production pressure, (b) aqueous velocity profile after 397 days for 2 MPa production pressure, (c) hydrate saturation profile after 397 days for 2 MPa production pressure, (d) ice saturation profile at 397 days for 2 MPa production pressure, (e) ice saturation profile at 1622 days for 2 MPa production pressure and (f) gas saturation profile after 1622 days for 2 MPa production pressure.

days, warm temperature front and released gas reach the producer well and gas production goes up. The dissociation front moves up and towards the production well while most of the gas is produced by 1500 days. Thus the gas production is slow for the first 600 days (only depressurization) and quite fast in the next 900 days (mostly due to the temperature increase).

3.3. Depressurization

The gas production during depressurization (without any water injection) is illustrated for an example case where the production well pressure is maintained at 2 MPa. Fig. 8(a) shows the temperature profile along the diagonal AB (shown in Fig. 1). Hydrate dissociates because reservoir pressure falls below the hydrate-equilibrium pressure. The heat available for dissociation is, however, limited in this case. The temperature decreases initially as the hydrate dissociation (endothermic) uses the available heat in the reservoir. Fig. 8(a) shows the reservoir temperature profile at 397 days. The temperature is the lowest (~ 273.4 K) near the production well, where most of the hydrate is already dissociated. Initial temperature was about 280.7 K. The temperature increases away from the production well. The temperature gradient around the production well in the lower region is different due to the presence of the aquifer layer. No hydrates are present in the aquifer layer; temperature does not decrease as much as in the hydrate bearing layers.

Fig. 8(b) shows the aqueous velocity profile at 397 days. The velocity is the highest in the aquifer layer, because the water relative permeability is the highest due to the absence of hydrates. The vertical component of the aqueous velocity is non-zero in the aqueous layer. Water dissociated from the hydrate above the aqueous layer drains down and moves to the production well along the aqueous layer. Aqueous flow in the hydrate layer is small because the water relative permeability is low.

Fig. 8(c) shows hydrate saturation profile at 397 days. All the hydrates are dissociated near the production well and near the aqueous layer. Hydrate dissociation front is at the bottom, top and near the production well, where heat flows in and pressure falls. The bottom dissociation front moves faster than the top front. Dissociated hydrate produces water and gas, which flow downstream to the producer.

At the dissociation front, away from the top and bottom boundaries, the temperature falls because heat conduction to this area is lower than the heat needed for dissociation. If the temperature falls below the freezing temperature, then part of the water freezes and ice forms. This heat is used partly to dissociate hydrates. Fig. 8(d) shows the ice saturation at 397 days. It is mostly at the hydrate dissociation front near the production well. Ice starts forming at 122 days, and reaches maximum average saturation at about 857 days, which is the time when all the hydrates disappear. After 857 days, the thermal energy reservoir gets from the surroundings helps in melting the ice. Fig. 8(e) shows the ice saturation profiles at 1622 days. Ice is primarily in the middle of the reservoir. All the ice melts by 1897 days. The ice formation reduces the local permeability but Fig. 5 shows that the rate of gas production is not affected much. This is because the ice does not block all the pores in the path of the fluid flow. Also, the simulation model used is a continuum model, which may not account for trapping of fluids during ice formation at the pore-scale. Ice formation is not seen for low levels of depressurization (i.e., with production well pressure of 4 MPa).

Fig. 8(f) shows the gas saturation profiles at 1622 days, corresponding to ice saturation profile shown in Fig. 8(e). The gas saturation has a local minimum at the position with high ice saturation. Ice formation reduces the permeability and hinders the upward movement of gas due to gravity. All the ice disappears after 1897 days; gas phase moves up and aqueous phase moves down due to grav-

Table 3
Parameter values for sensitivity analysis.

	Base case value	Values used for sensitivity analysis
Porosity	0.28	0.2, 0.35, 0.4
Heat transfer coefficient	0.2 W/m ² K	0.02, 5, 10 W/m ² K

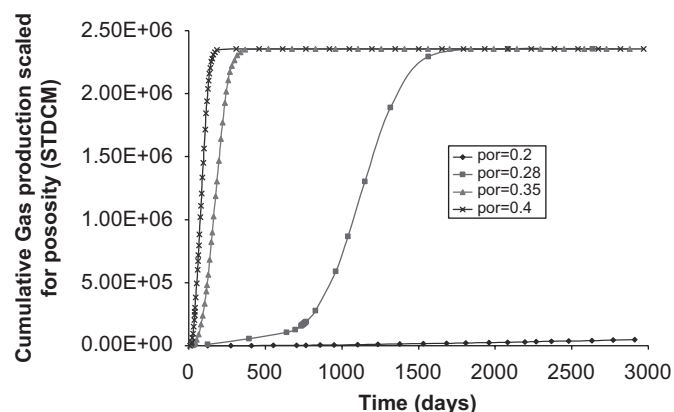


Fig. 9. Cumulative gas production with time for different porosities.

ity without any hinderance from ice. The gas saturation profile at 1960 days indicates (not shown) that water and gas saturations are vertically segregated.

3.4. Sensitivity analysis

The above results show that thermal stimulation using aquifer water is effective for the case of high depressurization pressure at the production well, i.e., slow dissociation rate by just depressurization. In this section, sensitivity of these results to assumed model parameters is discussed. The production well pressure is kept at 4 MPa, injection water temperature at 50°C and injection well pressure at 30 MPa for this study. Table 3 shows the parameters changed.

Fig. 9 shows the cumulative gas production for different porosities. For all the previous cases, the porosity was 0.28. Porosity is changed here from 0.2 to 0.4. As the porosity increases, so does the absolute permeability, from 12 to 1234 md according to Eq. (2). As the permeability increases, so does the penetration of heat for a given injection pressure. Also as the porosity increases, the heat capacity of the rock decreases, thus the temperature increases. Thus the gas production increases as the porosity and permeability increase, as shown in Fig. 9. The warm water injection is more effective in more permeable media. Fig. 10 shows the cumulative gas production for different reference permeability values for porosity of 0.28. The permeability is varied from 1 to 1000 md and the production rate increases with increasing permeability due to increase in penetration of heat from injection.

The heat transfer coefficient controls the heat loss to over-burden and under-burden. Fig. 10 shows the effect of heat transfer coefficient on cumulative gas production. As the heat transfer coefficient increases, the heat loss increases and thus heat input to the reservoir decreases. Thus the temperature rise in the reservoir would decrease and the production of gas would decrease with the heat transfer coefficient, which is shown in Fig. 11. An average, approximate value of heat transfer coefficient (0.2 W/m² K) is used in our base case calculations. If the heat transfer coefficient is 5 W/m² K or larger, then the gas production is too slow.

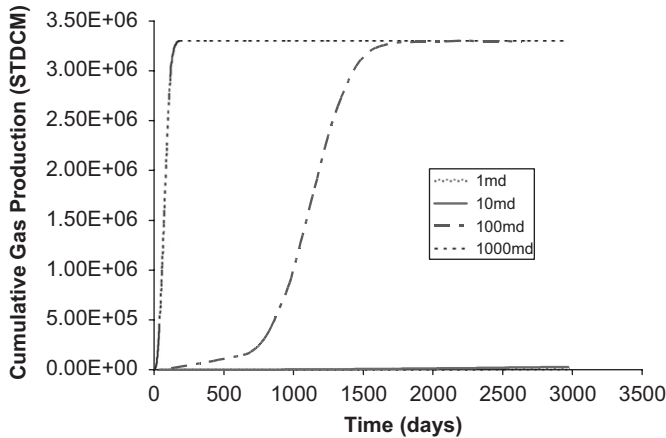


Fig. 10. Cumulative gas production with time for different permeabilities.

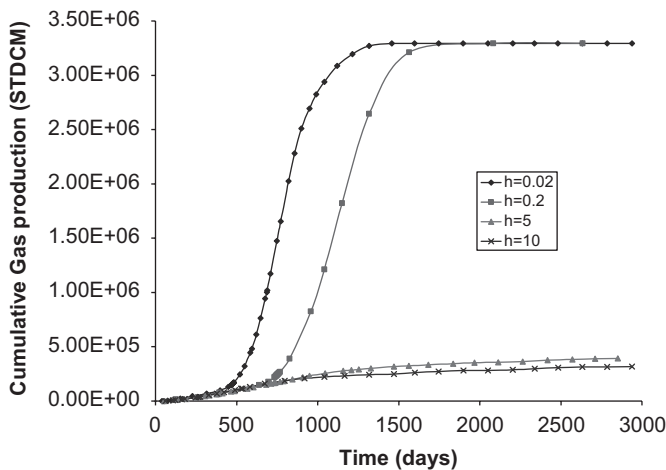


Fig. 11. Cumulative gas production for different heat transfer coefficients to over and under burden.

4. Conclusions

Injection temperature, injection pressure, and production pressure play an important role in gas production from confined class 2 hydrate reservoirs. If the production well pressure is high (~4 MPa) and the injection temperature is high enough (~50 °C), then warm water flooding is more favorable than just depressurization and gas production rate increases with injection well pressure. The production of gas comes in two phases: an initial slow production from just depressurization at the production well followed by fast production due to arrival of the thermal dissociation front. Such warm water can be found in aquifers approximately 1400 m below the reservoir or can be obtained from a nearby operational oil well. If a low pressure (~2 MPa) can be maintained at the production well or the injection temperature is not high (~20 °C), then just depressurization is the best method of production. Ice forms in the middle of the reservoir during low pressure depressurization, but does not obstruct the flow of gas. In fact, ice formation provides the heat of dissociation during hydrate dissociation and later ice melts as the over- and under-burden provide the heat by slow conduction. As reservoir porosity and permeability increase and the heat transfer coefficient to the over- and under-burden decreases, the warm water injection process becomes more favorable.

Notation

F^i	flux of component i
K^e	scalar of local effective permeability
K_0	scalar of local reference absolute permeability
k_{rj}^0	endpoint value of relative permeability for phase j
k_{rj}	relative permeability of phase j
n_j	exponent parameter in relative permeability model for phase j
P_c	capillary pressure
P_{ce}	entry capillary pressure
P_{ce0}	reference entry capillary pressure
q^i	source term of component i
S_j	saturation of phase j based on total pore volume
S_j^e	effective saturation of fluid phases based of effective pore volume
S_j^{e*}	normalized effective saturation of phase j
S_{jr}^{e*}	residual saturation of phase j
U	total energy per unit volume

Greek letters

β	exponent parameter in absolute permeability model
Φ	total porosity
Φ_0	reference porosity
Φ_e	effective porosity

Subscript

J A (aqueous phase), G (gas phase)

Superscript

i m (methane), w (water), e (energy)

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Appendix A.

The governing equations used for the simulator are methane, water and the energy balance equations:

$$\frac{\partial}{\partial t} \left(\phi \sum_{j=H,I,WA,G} \rho_j S_j w_j^m \right) + \nabla \cdot F^m = q^m \quad (\text{A.1})$$

$$\frac{\partial}{\partial t} \left(\phi \sum_{j=H,I,WA,G} \rho_j S_j w_j^w \right) + \nabla \cdot F^w = q^w \quad (\text{A.2})$$

$$\frac{\partial}{\partial t} \left(\phi \sum_{j=H,I,WA,G} \rho_j S_j U_j + (1 - \phi) \rho_R U_R \right) + \nabla \cdot F^e = q^e \quad (\text{A.3})$$

where superscripts m , w and e stand for methane, water, and energy, respectively. w_j is the weight fraction of the component in phase j , S_j is saturation and ρ_j is the density of phase j . U_j is the total internal energy per unit volume of the phase j and U_R is the internal energy of the sand phase. The mass transport flux F in Eqs. (A.1) and (A.2) account for convection and dispersion. The mass flux of the component i is defined as

$$F^i = \rho_G v_G w_G^i + \rho_A v_A w_A^i + J_G^i + J_A^i \quad (\text{A.4})$$

where v_G is the velocity of gas phase according to Darcy's law and v_A is the velocity of aqueous phase. J_G^i is the mass flux of the component i due to dispersion in gas phase and J_A^i is the mass flux of the component i due to dispersion in aqueous phase. F in Eq. (A.3) represents the energy flux through conduction and convection, i.e.,

$$F^e = \rho_G v_G H_G + \rho_A v_A H_A - \lambda \nabla T \quad (\text{A.5})$$

where H_j is the specific heat of phase j and λ is the effective thermal conductivity. The source terms q in Eqs. (A.1)–(A.3) are determined by the wells. No flow, constant pressure, and heat transfer conditions are applied at the boundaries (Sun, 2005).

Finite volume difference method is used to spatially discretize the governing equations. The time derivative is discretized with backward Euler method resulting in a fully implicit system of equations which ensures the stability of the numerical scheme. In the discretized system, each grid block is governed by three nonlinear equations, corresponding to three unknowns to be directly solved. Based on the assumption of local equilibrium, each grid block forms an open equilibrium system with mass/heat transport with its neighboring blocks. The evaluation of phase mobility, which is an inter-block property, is based on a single point upstream weighting.

Primary variable switch method (PVSM) is used in which primary variables are defined as the variables to be directly solved from discretized governing equations. For each grid-block, primary variables are chosen from “natural” variables such as pressure, temperature, phase saturations and concentrations according to the phase status. For example, for a grid block having hydrate and aqueous phases, the pressure and temperature are two independent variables and must be solved simultaneously to determine the thermodynamic state of this block. In addition, among the four phase saturations (S_H , S_G , S_A and S_I), $S_G = 0$, $S_I = 0$ and $S_H + S_A = 1$, so only one phase saturation (S_H or S_A) needs to be solved. Different phase statuses are defined and primary variables are identified for each phase status. For a certain grid block, the phase status may change with time because of local pressure, temperature, and composition and consequently, the primary variables for this grid block changes with time. The disappearance of a phase is identified by its saturation value. Identification of phase appearance is based on the pressure-temperature conditions along with the mass composition. Newton–Raphson method is used

in combination with PVSM to solve the nonlinear equations using Inside Scheme (Forsyth and Simpson, 1991).

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