The Increasingly Complex Challenge of Gas Hydrate Reservoir Simulation

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Abstract

Gas hydrate reservoir simulation is a complex endeavor. Reliable simulation capability will allow the proper design of field tests and the interpretation of field test data that are necessary to advance the understanding of the response of gas hydrate reservoirs to production activities. Increasing appreciation of the complexity of gas hydrate reservoirs, as well as continued uncertainty in key petrophysical parameters, requires great care in the design of simulation studies. This report outlines select emerging issues that greatly impact the relevance of numerical simulation resulting, including reservoir heterogeneity, geomechanics, log and core data interpretation, grid size, and others.

Introduction

The numerical simulation of gas hydrate reservoir response to depressurization has evolved greatly in recent years. Scientific and industrial drilling programs have acquired detailed reservoir data from gas hydrate systems in Canada, Alaska, Japan, India, Korea, China, and the Gulf of Mexico that enable increasingly realistic reservoir characterizations. Information on the initial reservoir response to pressure perturbation are also emerging, including short duration, small volume wireline tests [1] as well as complex multi-day production tests [2,3,4]. In aggregate, these tests have confirmed the technical feasibility of gas hydrate production via depressurization and revealed a few salient features, such as the immediate production of gas and the clear and rapid response of the reservoir (both in terms of production rate and near-wellbore temperature) to even modest changes in wellbore pressure. Critical issues remain, including determining optimal approaches to enable sustainable production by matching production rate with reservoir heat influx, the isolation of production systems from water-bearing zone, optimal completions for well-bore stability, and controlling and dealing with the effects of temporary cessation of production activity.

In the initial phase of gas hydrate simulation, data sets were generally quite simple and reservoirs were typically depicted as homogeneous, highly-saturated, clean-sand reservoirs. The primary distinguishing feature in these reservoirs was the nature of the vertical reservoir boundaries, with the most promising reservoirs being those of Class 1" in which the hydrate reservoir is in hydraulic contact with underlying free gas [5,6,7]. As it became clear that Class 1 systems were likely rare in nature [8], and that "Class 2" systems (hydrate in communication with underlying free water) would be challenged by typical unconfined nature of the water zone [9,10], the focus of gas hydrate reservoir simulation shifted to "Class 3" systems (hydrate encased within low-permeability units), despite the recognition that production from such settings might feature large volumes, but at modest flow rates and over long durations (multiple decades) and with multi-year production "lag" times (initial periods of no or very limited gas production) [11]. A critical advance in numerical modeling approach was catalyzed by acquisition of detailed reservoir datasets in the Nankai trough [12], in the Gulf of Mexico [13], and in Alaska [14, which revealed significant lithologic and structural heterogeneity. Preliminary sensitivity analyses that incorporated vertical reservoir heterogeneity showed the complete removal of the lag period, with shorter production profiles highlighted by higher, and sooner, peak production rates [15]. Further simulation efforts have refined the issues associated with reservoir heterogeneity, both vertically and horizontally within increasingly realistic geologic models [16, 17]. The production rates that have been generated in these models suggest the potential for commercially viable production in select settings, dependent on site specific geologic conditions, costs, and many other factors (Figure 1).

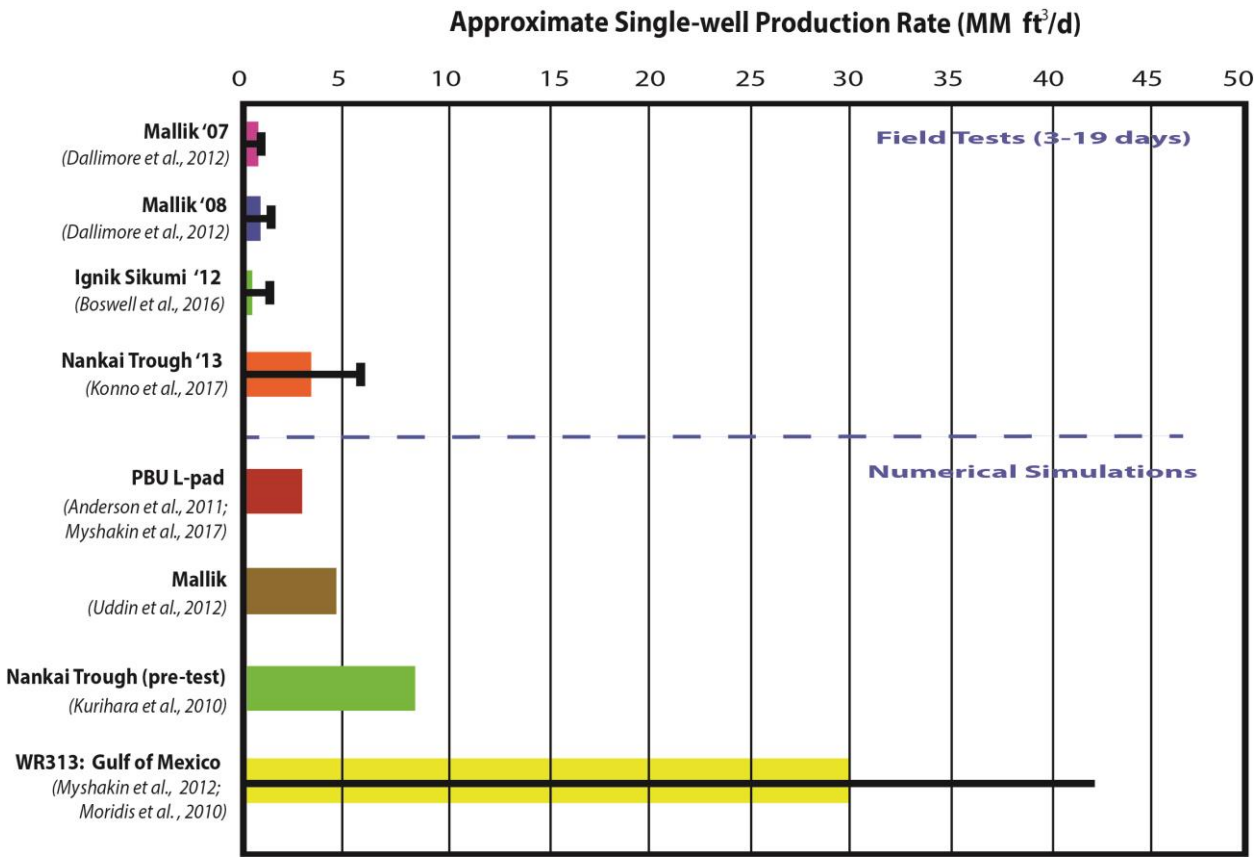

Figure 1: Top: Observed average and peak (black bar) production rates from gas hydrate field production experiments. Bottom: Peak production rates from numerical simulations of production potential over full potential well life. Black bar at bottom shows peak rates obtainable using deviated well designs. Data from [2,4,8,12,15-20]

Application of these complex geologic models raises several emerging issues that may have profound implications for the accurate prediction of production response of gas hydrates, including (1) capturing reservoir heterogeneity in a geologically informed manner; (2) proper handling of the interdependency of key petrophysical parameters, (3) the nature of reservoir boundaries, (4) uncertainty in effective permeability and the evolution of permeability during production; (5) integration of geomechanical phenomena; and (6) modeling process decisions such as 2D v 3D model and grid cell size selection.

Emerging Issues in Numerical Simulation

Reservoir Heterogeneity

Heterogeneity is a ubiquitous aspect of every natural reservoir, and proper representation of this heterogeneity is vital to the prediction of reservoir behavior. However, heterogeneity is not fully random, but is instead a function of natural variation in depositional environments in time (vertical variation) and space (lateral variation) [21,22]. In the vertical dimension, variation in reservoir character can be evaluated with core and well log data. In the case of cores, incomplete recovery and recovery that is biased to select lithologies, and difficulties in direct ties between cores and logs must be addressed. In the case of well logs, derivation of reservoir properties is complex [23], and significant issues can arise particularly where reservoirs are thinly-bedded (which is the norm in many deepwater system), as limited vertical resolution of various logging tools will result in log data that may not accurately reflect reservoir conditions (Figure 2). This inaccuracy of is particularly true with porosity data, but it can also be true of resistivity and lithologic (gamma-ray) data. These uncertainties then must be extended to those key petrophysical properties, such as gas hydrate saturation, that are calculated from log data. In most cases, the log will be influenced by both the reservoir and the bounding beds, resulting in underestimates of porosity or resistivity (and hence, saturation) in gas

hydrate-bearing beds and overestimates in associated non-gas hydrate-bearing beds. In such cases, geologic interpretation is required to convert log-derived data to values most likely to represent nature. Extrapolation of log data laterally is also complex. Geologic mapping of the reservoir system, where possible, is vital, as it is likely to provide insights about the areal geometry and structural complexity of individual reservoir units. An understanding of geologic environments can also support interpretations of reservoir compartmentalization. Such interpretations may suggest some units to be highly continuous laterally, whereas others are more prone to lateral heterogeneity.

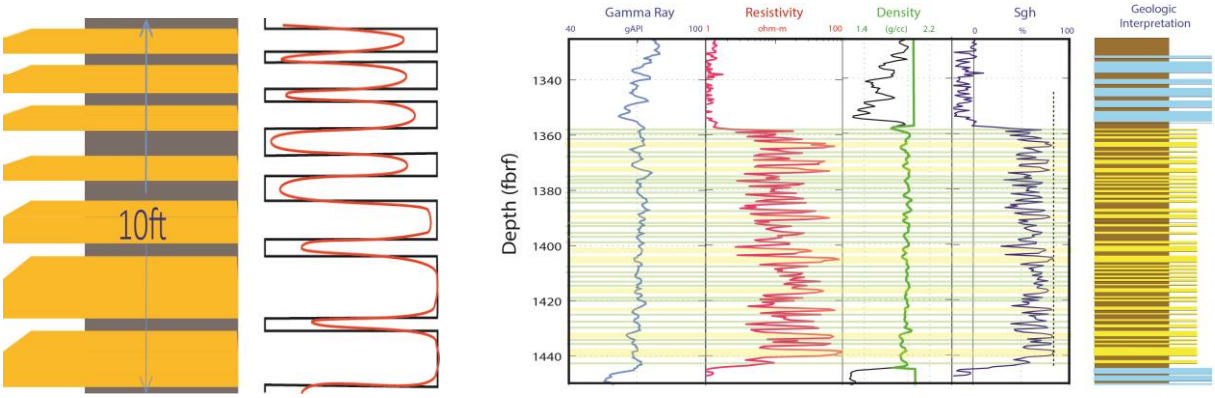

Figure 2. Left: Increased uncertainty in log derived parameters can result were bed thickness is less than vertical log resolution. Red curve is idealized log reading for some generic parameter; the black curve is potential true value of the parameter. The log only reads correct values in beds of sufficient thickness. Right: an example of log data in a thinly-bedded reservoir (Green Canyon block 955; Gulf of Mexico). Modified from [24].

Interdependency of Petrophysical Parameters

Many processes combine to determine the response of a gas hydrate reservoir to an induced change. Key among these are pressure and temperature, as well as petrophysical features such as porosity, permeability, water saturation, amount of bound- and free-water, and others. Field data collected to-date suggest that gas hydrate reservoirs (particularly those that are candidates for potential production) are most commonly saturated with gas hydrate to the extent that the reservoir quality allows. That is, the degree of hydrate saturation (S_{gh}) is strongly controlled by reservoir quality, such that a lower-quality reservoir may be maximally-saturated at 50%, whereas higher-quality reservoirs can achieve 80% saturation (Figure 3). High-quality reservoirs with low or moderate (10% to ~50%) saturations are likely rare. Whatever the saturation, the remaining pore space is typically occupied by water (gas is not commonly observed), with some portion of that water being free (S_{wf}) and some being bound (S_{wirr}). The ratio of free to bound water is also controlled by reservoir petrophysics, with a higher share of the available water being free in high-quality reservoirs. A common convention in modeling is that free water will range from 5 to 10% in any fully-saturated gas hydrate [1]; therefore, in an 80% gas hydrate reservoir; the liquid water might be apportioned 1:1 between S_{wirr} (=10%) and S_{wf} (=10%). In a lower quality reservoir (50% S_{gh}) the ratio might be 4:1 (S_{wirr} = 40%; S_{wf} = 10%). Given this insight, it is necessary to recognize that gas hydrate saturation is not independent of other parameters, such as porosity or permeability. Therefore, input characterizations that suggest high S_{wf}, for example, in a gas hydrate-bearing reservoir should be given extra scrutiny. While it is well known that high-quality, moderate-saturation reservoirs may provide a more favorable long-term response in production models (due to increase permeability associated with high free water content), such situations may be unlikely nature.

The Nature of Reservoir Boundaries

Significant progress has been made in recent years with regard to geologic characterization of reservoir boundaries. Initial numerical simulation of gas hydrate reservoirs commonly assumed vertical reservoir confinement enabled by no-flow vertical boundaries (zero permeability seals and underburden). Such conditions are clearly optimal for gas hydrate production, they are generally not present in the shallow, under-consolidated sediments where gas hydrate typically resides. In some situations, it is likely that bounding, vertical seals may have sufficient permeability to enable not only the transfer of heat from seals to reservoirs, but also the movement of fluids in either direction.

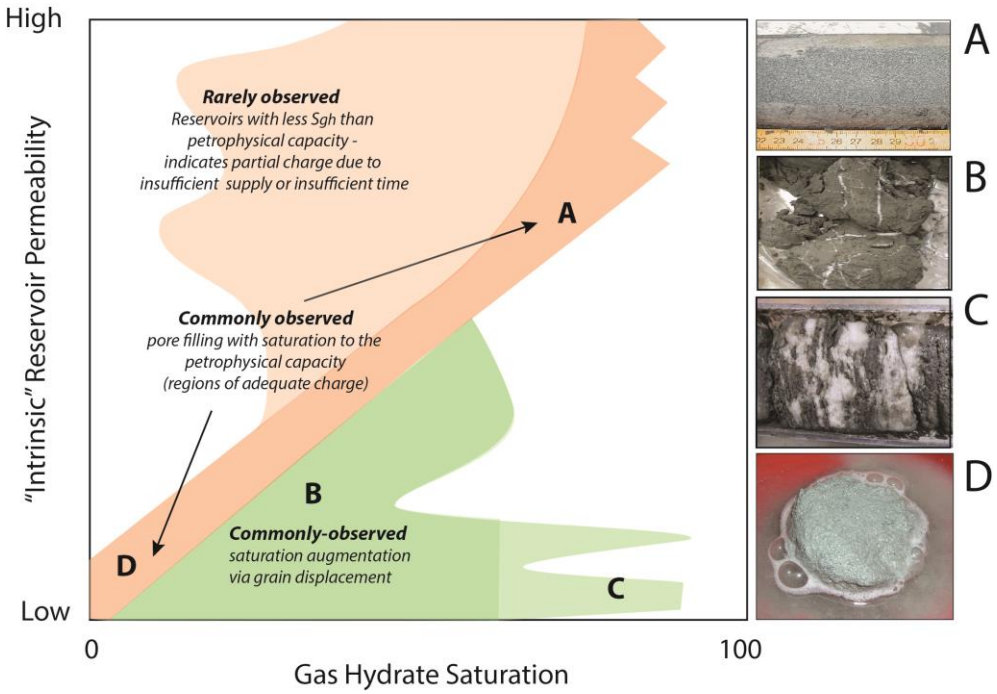

Figure 3. Schematic depiction of observed relationship between gas hydrate saturation (S_{gh}) and reservoir quality as represented by intrinsic reservoir permeability. Within pore filling gas hydrates (beige), there is a strong tendency for S_{gh} to be positively correlated with reservoir quality (modified from [25]).

Hydraulic Isolation

Gas hydrate in contact, either vertically or laterally, with extensive porous and permeable water-bearing sediments will greatly challenge gas hydrate production [10,11,15] by countering pressure reduction and augmenting water production [25]. Examples of interlayered gas hydrate and water-bearing reservoir sands are common, including Green Canyon 955 [13], Mt Elbert [14]; and Nankai Trough [2]. Great care should be taken in regional mapping efforts to assess the compartmentalization of the target reservoir and the potential for hydraulic communication with water-bearing zones. Lateral stratigraphic changes can provide lateral flow boundaries of similar nature to the vertical boundaries. Faults may act to laterally isolate the reservoir and provide lateral no-flow boundaries, particularly where fluid levels in adjacent fault blocks can be shown to be different.

In situ Permeability

A primary petrographic parameter with critical importance to gas hydrate reservoir simulation is permeability. The intrinsic permeability (K_{int}) refers to the permeability of the sediment in the absence of gas hydrate, while effective permeability (K_{eff};) is the permeability when the reservoir is in its natural, gas hydrate-bearing sate. With respect to K_{eff}, much prior work, based primarily on short-duration borehole pressure-transient testing and nuclear-magnetic resonance logging in Alaska [1], Japan [27], and Canada [28,29], had generally indicated a low value, such as 0.1 md. Such values successfully supported history matching studies. However, recent evaluation of pressure cores acquired in Japan [30,31] suggest in situ permeability of hydrate-bearing sands may range from 10 to 100 md (see [32] for further discussion). These higher values, if they are found to be typical of marine hydrate occurrences, will have profound implications on current concepts of gas hydrate production. With respect to K_{int}, values of 100s md to 1 Darcy are commonly expected for reservoir quality sands; however, the most appropriate estimation of K_{int} is likely not an idealized value that simply removes the hydrate, but one that compensates for the loss of hydrate with the likely geomechanical compaction of the reservoir that hydrate dissociation would entail, as discussed further below.

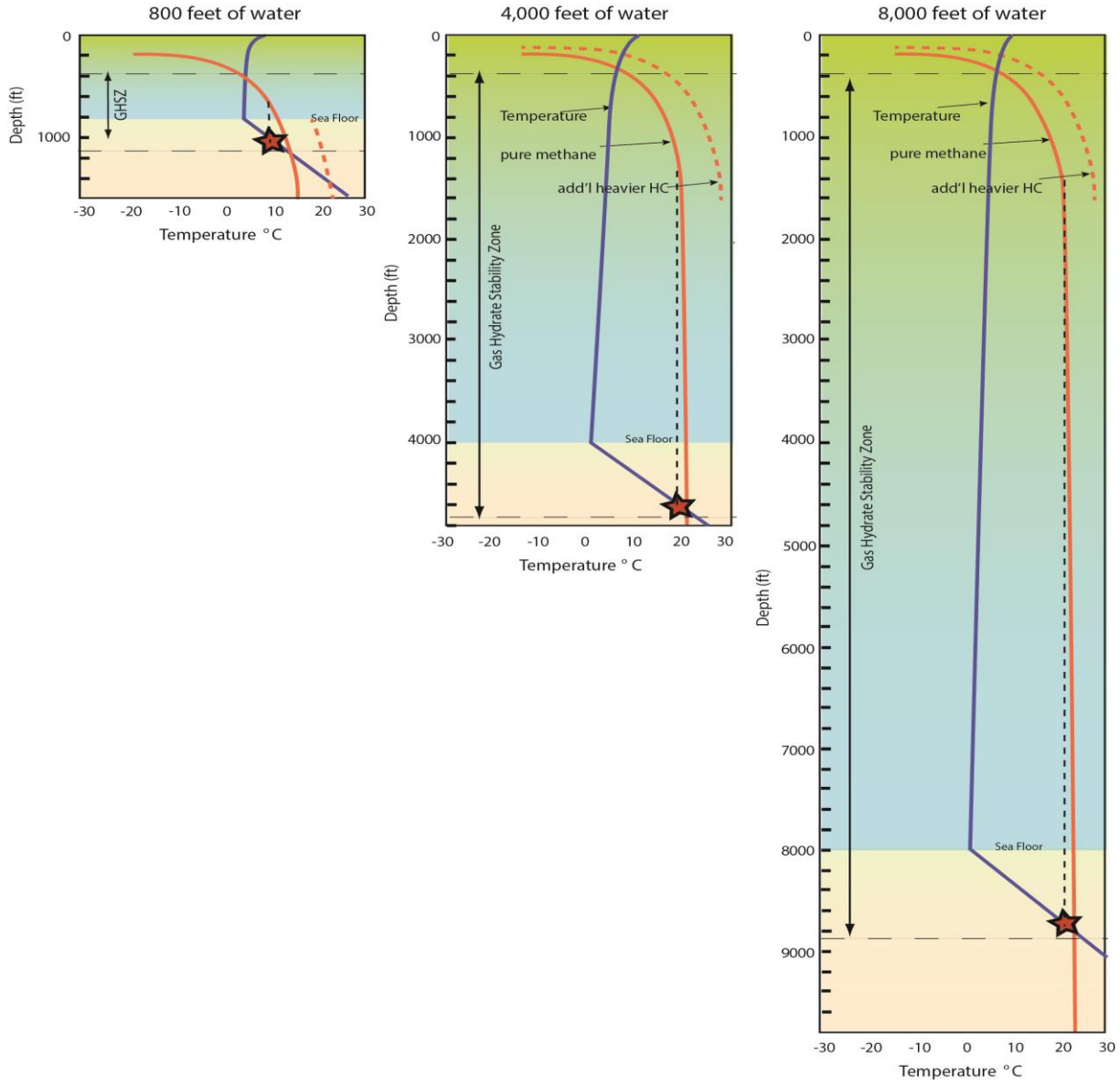

Figure 4: Schematic comparison of gas hydrate reservoir position (red star) relative to schematic stability boundaries (red curves) for various water depths. At great water depths, substantial pressure reduction (dashed black line) is required to initiate dissociation.

Geomechanics

For many years, gas hydrate simulation was focused on consideration of thermodynamic and hydraulic phenomena: the only things physically moving in the reservoir were heat, liquid, and gas. Efforts to extend modeling capability to allow movement of sediment grains (which will invariably exist in a range of sizes) remains in the early stages [33-37]. The effort introduces various complex mechanical and petrophysical feedbacks to the already challenging issue of capturing the dynamic changes in basic petrophysical properties that attends the removal of the solid hydrate phase. In addition to the critical wellbore stability and subsidence issues, geomechanical phenomena may have a profound impact on the dynamic evolution of reservoir petrophysics and hence, production. For example, early notions of gas hydrate reservoir potential had assumed that deeper and hence warmer reservoirs would perform best. Although prior workers had noted that higher pressures could lead to greater water influx (complicating depressurization, [12]), the notion of improved prospectivity with depth was supported by many factors, including

higher temperatures and assumed greater consolidation (and therefore geomechanical stability) of both reservoirs and seals. However, it was not as well appreciated that the increasing verticality of the hydrate stability boundary with depth (Figure 4) means that the deeper one goes, the greater the depressurization that is needed to shift the target reservoir out of hydrate stability. Consequently, at great depths (generally meaning in deep water depths) very high pressure gradients will be required, which may be highly positive for potential production rates, but may also have implications for reservoir and seal geomechanical stability standpoint.

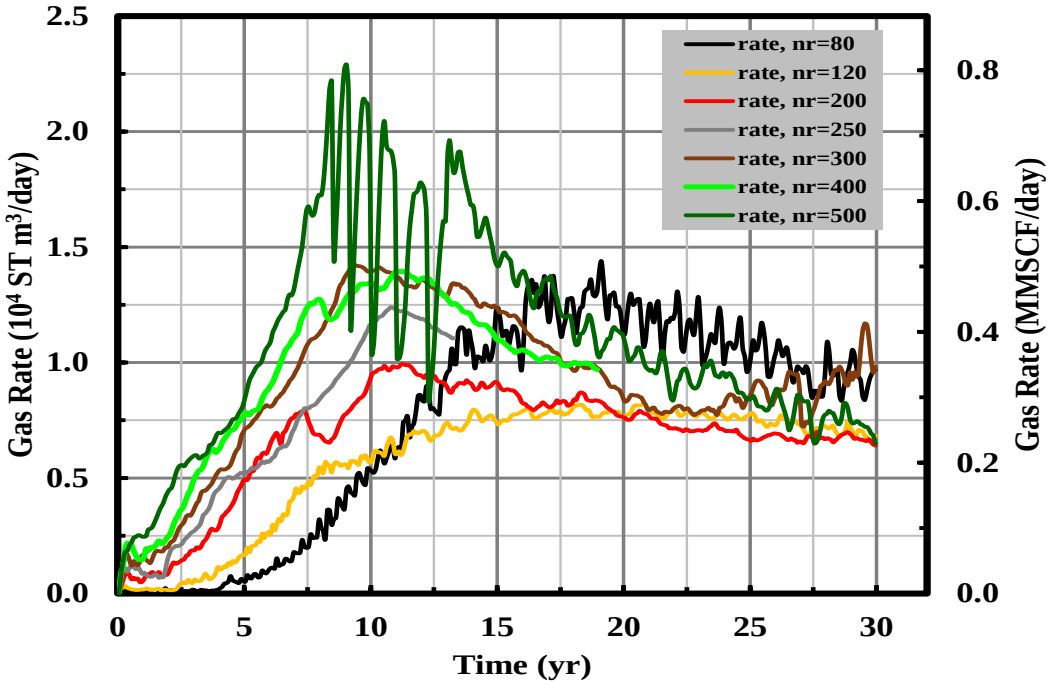

Figure 5. Gas rate profiles using different mesh resolutions. Finer scale grids (higher "nr" values) result in more rapid initiation of production and higher and sooner peak production rates as compared to coarse grids. In all cases, the input geologic/engineering descriptions are identical.

Gridding Convention

In addition to being highly dependent on the optimal depiction of reservoir properties and dynamic hydraulic, thermodynamic, and geomechanical phenomena, the results of reservoir simulations is highly, and surprisingly, dependent on certain non-geological decisions made in the execution of the model. Perhaps foremost among these is "mesh resolution", which relates to the spatial dimensions of the idealized reservoir grid. A reservoir is not modelled as a continuous media, but is instead an array of individual cells of select dimension. The coarser the grid, the greater the difference in conditions any cell "sees" between one edge and another. These variations can lead to results that are clearly erroneous when cells are too large. However, due to computational load of high mesh resolution (fine-scale grids), modelers on occasion face the issue of trading time and cost for increased simulation resolution and confidence. At present, it would appear that the finer the grid the better. Vertically, these gradients should be much more consistent, although they would tend to appear as a horizontal reservoir boundary was approached. A common convention is to set vertical grid size at 0.1 m. The question is how small to make the grid blocks in the lateral direction. One approach used to balance computational intensity with reliability of results is use logarithmic grids that are fine near the wellbore and coarser further out. This recognizes that the potential for large gradients (for example, in pressure) across individual cells is much higher in the near wellbore region. However, if the gas hydrate dissociation front were to advance from the wellbore as a discrete, "hard" surface, at some point the region of high gradients will ultimately impinge on the area of coarse grids, providing suspect results. However, as inferred by [2], it may be the case that the dissociation front is expressed as an envelope of transitional dissociation of increasing width and complexity as it advances from the wellbore, which could mitigate the risks of using larger grid cells in distal locations. To demonstrate effects of grid size selection, we have conducted simple sensitivity analyses utilizing

the Hydrate ResSim model (Figure 5). A 100 m extent of hydrate bearing sand reservoir is represented alternatively by 80, 120, 200, 250, 300, 400 and 500 cells. In each case, the specific grid cell size increases logarithmically with distance from the wellbore. The model with 80 cells features a production "lag" of about 4 years. As resolution increases, the lag diminishes until it disappears completely with 200 cells; the production peak occurs sooner, and the maximum production rate increases. These are very large difference in outcomes that profoundly impact production viability. It is not clear that these rate predictions converge, or whether increasingly small grids would continue to return higher production rates. The fluctuations in gas rates from the higher resolution simulation could be an indication of numerical instability and therefore results may be unreliable.

2D v 3D modeling

In numerical simulation, a 2D model is one in which a laterally homogeneous wedge extended out from the wellbore is assumed to be replicated around the wellbore). The primary benefit of the 2D model is simplicity in model creation and greatly reduced run times. However, while 2D modeling allows full incorporation of vertical reservoir heterogeneity, it assumes complete radial reservoir heterogeneity around the borehole. This assumption is only slightly problematic if short-term reservoir response estimates are desired; however, when applied to assessment of longer-term production, the use of 2D models can introduce significant errors. One source of error is the inability to deal with simple geometric asymmetry in the reservoir, which can be introduced by features such as faults, formation dip, and large changes in reservoir thickness [12]. 3D models also allow for the incorporation of inherent, and perhaps even subtle lithologic heterogeneity which have been shown to substantially impact simulation results (Figure 6) by mitigating the development of certain features, such as dynamic barriers related to hydrate reformation [16] that were a common feature in 2D models [11]. (Figure 6).

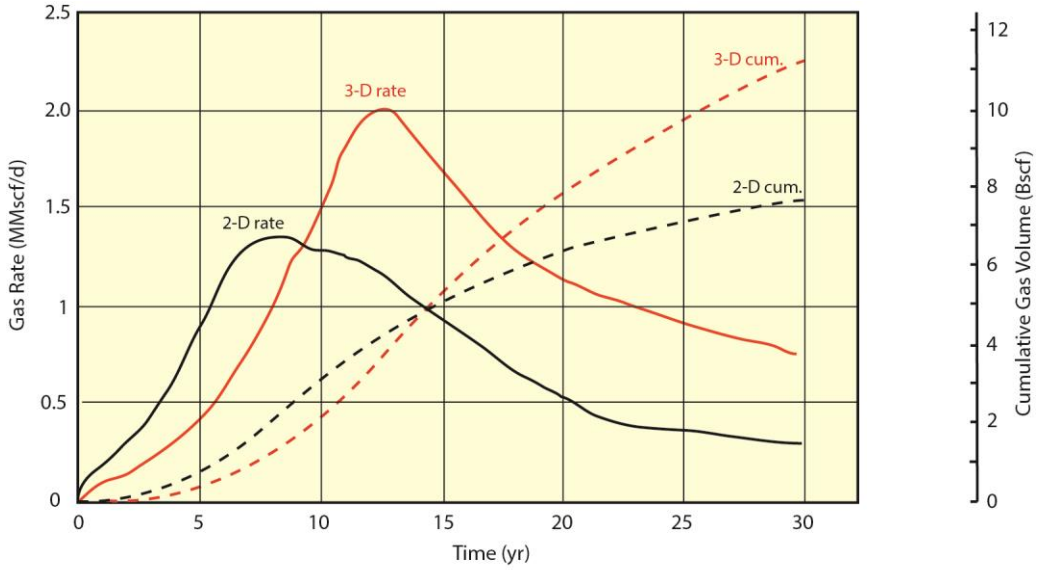

Figure 6. Comparison of 2D and 3D models for a given hydrate reservoir. The models are the same other than the incorporation of modest statistical heterogeneities in reservoir parameters in the 3D case. The results suggest that 3D models are needed even in cases where structural complexities are not expected (from []).

Conclusions

The numerical simulation of gas hydrate reservoirs has now transitioned from the evaluation of poorly-constrained hypothetical situations to the detailed evaluation of reservoir response with profound implications for the safe and successful operations of complex and costly field experiments. As simulation capability advances, increasing complex issues are being encountered and assessed, ranging from confronting uncertainty in primary reservoir parameters to the need to fully embrace the geologic complexity of potential field sites. To be successful, modeling activities must take great care to obtain and incorporate comprehensive geologic depictions that embrace structural

and lithologic complexity; must fully appreciate the limitations of field data, and carefully translate field data obtained from cores, logs, and test monitoring data into the most optimal modeling input sets incorporate all relevant phenomena, including geomechanical responses; and must be careful to not oversimplify modeling approaches in the effort to manage simulation run-times.

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