

ANALYSIS OF MODULAR DYNAMIC FORMATION TEST RESULTS FROM THE MOUNT ELBERT-01 STRATIGRAPHIC TEST WELL, MILNE POINT UNIT, NORTH SLOPE ALASKA

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ABSTRACT

In February 2007, the U.S. Department of Energy, BP Exploration (Alaska), and the U.S. Geological Survey, collected the first open-hole formation pressure response data in a gas hydrate reservoir (the "Mount Elbert" stratigraphic test well) using Schlumberger's Modular Dynamics Formation Tester (MDT) wireline tool. As part of an ongoing effort to compare the world's leading gas hydrate reservoir simulators, an international group conducted history matches of one 12-hour test that included an initial stage of pressure drawdown and response in which pressures were maintained above the level where gas hydrate dissociation would occur; a second stage with 15 min of flow and 97 min buildup that included gas hydrate dissociation and gas production; and

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a third stage of 116 min of flow and 266 min of buildup. The test also included temperature measurements taken by a device attached to the MDT's intake screen.

History matches of these test data were accomplished using five different reservoir simulators: CMG STARS, HydrateResSim, MH-21 HYDRES, STOMP-HYD, and TOUGH+HYDRATE. Simulations utilized detailed information collected across the reservoir either obtained or determined from geophysical well logs, including thickness (37 ft.), porosity (35%), hydrate saturation (65%), intrinsic permeability (1000 mD), pore water salinity (5 ppt), and formation temperature (3.3 – 3.9 degrees C). This paper will present the approach and preliminary results of the history matching efforts, including estimates of initial formation permeability and analyses of the various unique features exhibited by the MDT results.

Keywords: gas hydrates; reservoir simulations; production modeling; porous media

NOMENCLATURE

P	pressure [MPa]
r	radial dimension [meters]
t	time [seconds]
T	temperature [K or °C]
k_{rG}	gas-phase relative permeability
k_{rA}	aqueous-phase relative permeability
S_A	aqueous saturation
S_G	gas saturation
S_H	hydrate saturation

INTRODUCTION

The National Energy Technology Laboratory (NETL) and the U.S. Geological Survey (USGS) are guiding a collaborative, international effort to compare methane hydrate reservoir simulators. The intentions of the effort are: (1) to exchange information regarding gas hydrate dissociation and physical properties enabling improvements in methane hydrate reservoir modeling, (2) to build confidence in all the leading simulators through exchange of ideas and cross-validation of simulator results on common datasets of escalating complexity, and (3) to establish a depository of gas hydrate related experiment/production scenarios with the associated predictions of these established simulators that can be used for ongoing and future comparison purposes. To achieve these goals, a team of researchers was brought together to construct a series of problems designed to test/compare the performance of the leading gas hydrate simulators. Participating in this effort are researchers utilizing five distinct simulators. These simulators are: CMG-STARS, MH21-HYDRATE, STOMP-HYDRATE, TOUGH+HYDRATE, HydrateResSim, and. To date this team has constructed a series of seven problem sets. The

first five of these problem sets examined various facets of the multiphase flow/equilibrium behavior necessary to model this complex system accurately, and are reported on elsewhere [2]. In this work we will present results of Problem 6, and describe preliminary results related to the seventh problem set.

The objective of the sixth problem considered by the Methane Hydrate Reservoir Simulator Code Comparison Study was to analyze the data obtained from an actual hydrate well test. The data utilized were obtained from the Mt Elbert-01 stratigraphic test well which was drilled as part of the cooperative DOE-BPXA research project. The prospect was based on detailed geologic interpretation and mapping of sandstone reservoirs, including data from the Milne 3D seismic survey (Figure 1). The Mt Elbert-01 well included the acquisition of 432 feet of core, an extensive suite of wireline log data (Figure 2), and the acquisition of short-duration formation pressure transient data with the Modular Dynamics Tester (MDT) [3].

Four MDT tests, each containing a series of flow and shut-in periods of varying length, were conducted at four stations zones in two different gas-hydrate bearing sand reservoirs. For modeling purposes, the first through the third flow and recovery periods of the second MDT experiment (the "C-2" test) conducted on the Mount Elbert well were selected. The C2 MDT experiments involved alternating flow periods (of various durations), using a positive displacement pump, and build-up phases, during which there was no pumping (see Figure 3).

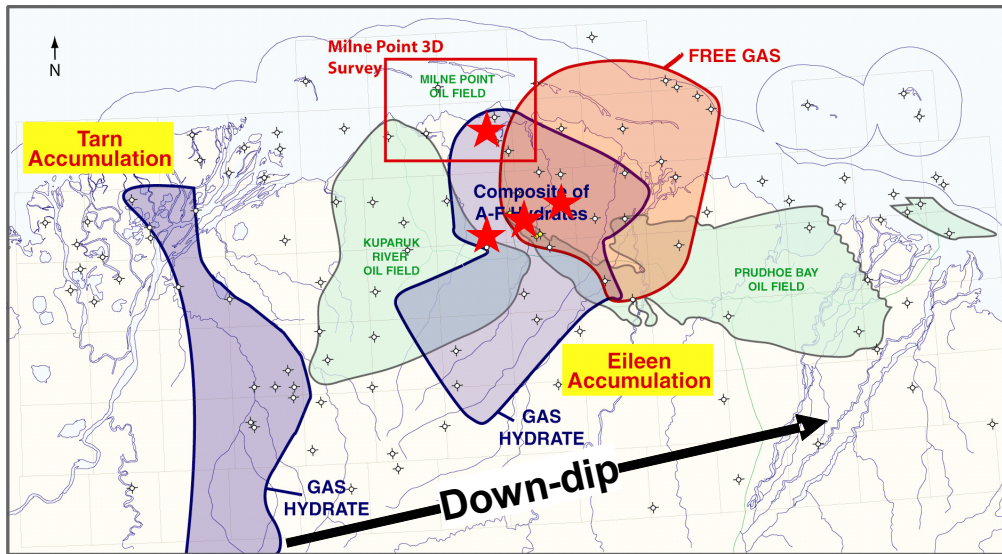


Figure 1: Location of delineated gas hydrate prospects and the Alaskan North Slope (after [1]).

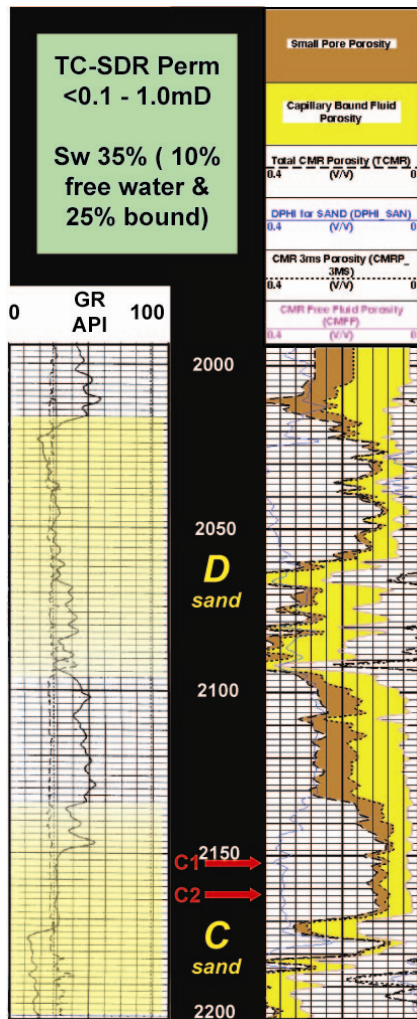


Figure 2: Well log from the Mt. Elbert Stratigraphic test well showing the C and D sand units.

In an effort to conduct this phase of the Methane Hydrate Reservoir Simulator Code Comparison Study in a manner that would reflect how actual history matches would be conducted using the codes separately, each modeler was given the freedom to determine the approach to conducting these history matches with respect to determination of the numerical grid, approach to finding fitting parameters, etc. The only constraints placed on the efforts were based on the experimental setup (ie., the location of the tool in the formation, the size of the wellbore, etc), experimentally observed properties of the formation (porosity, initial saturations, temperatures, etc), and the MDT test data.

THE MDT DATA

During the flow (pumping) periods, fluids (potentially containing a mixture of formation water and free methane gas) were extracted by the tool, thereby reducing the pressure in the formation in the vicinity of the well (as can be seen in the above figure which shows the pressure at the tool inlet throughout the test). Short-term MDT testing does not provide reliable information on reservoir deliverability or potential production rate. However, by examining the recovery of the pressure within the formation after cessation of the withdrawal of fluids resulting from each flow period, it was hoped that key reservoir parameters associated with the formation could be extracted.

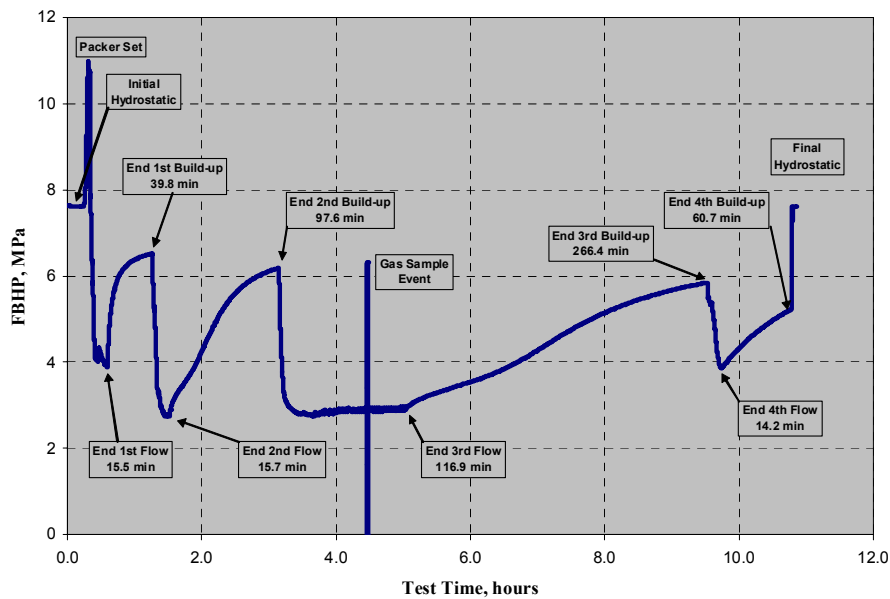


Figure 3: Downhole measured flowing bottom hole pressure (FBHP) for the C2 MDT experiment

The pressure and temperature were measured directly during the various flow and buildup periods of the MDT test. These experimentally measured temperatures and pressures are shown in Figure 4. Produced fluid volumes (aqueous, gas, and oil-based drilling fluid) were not measured directly, but were later estimated by Schlumberger from the stroke data for the positive displacement pump in the MDT and the optical analyzer data, which provides an approximate measure of fluid volume ratios for each component. Without more detailed produced fluid volume data, the numerical simulation history matching was less constrained by the produced fluid volumes than the pressure and temperature measurements. The best estimate of the produced water and gas volumes are shown in Figure 5.

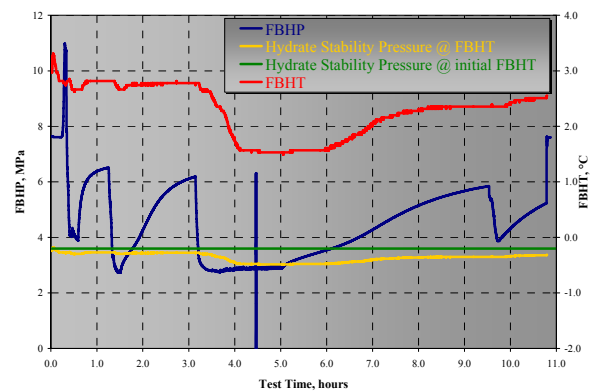


Figure 4: Downhole measured pressure and temperature for the C2 MDT experiment. Yellow trace indicates predicted [4] gas hydrate stability pressure at measured temperature

The MDT Flow Test

As shown in Figure 4, during the first flow period the well pressure was kept above the in-situ hydrate dissociation pressure (i.e., the well pressure [blue trace] remains above the gas hydrate equilibrium pressure [yellow trace] based on the in-situ temperature). As a result, the only methane extracted from the reservoir during this period was the very small amount that was dissolved in the extracted formation water (ie., no free gas was detected at the MDT intake port during this first drawdown period).

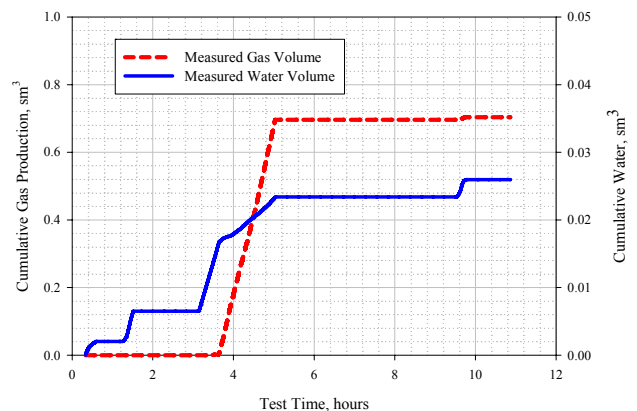


Figure 5: Estimated volumes of gas and water pumped from the test zone during the C2 MDT flow test

By analyzing the pressure response of the reservoir after this first flow period, an estimate of the effective permeability of the formation in the presence of hydrate can therefore be obtained. The importance of this parameter cannot be overstated as it is one of the key parameters controlling the potential productivity of any reservoir.

During the second and third flow periods the pressure was reduced below the expected gas hydrate equilibrium pressure, thereby resulting in dissociation of gas hydrate and the release of free gas into the formation (see Figure 3). The optical analyzer indicated that during the second pressure drawdown period no to little gaseous methane was pumped through the MDT tool, which initially was in contrast to the expectation of gas production with hydrate dissociation. Evidence of produced gas, however, was indicated during the pressure buildup response to the second pressure drawdown. The pressure buildup response after the first pressure drawdown was characteristic of the recovery in a confined aquifer. The prolonged pressure recovery after the second pressure drawdown indicated compressible gas in the annular space of the MDT above the screened inlet.

During the third (and longer) flow period, the pressure was once again reduced to a point below the hydrate equilibrium pressure, this time over a sufficiently longer period that resulted in the measurable production of both formation water and methane gas. The pressure recovery after this flow period was even more prolonged than that after the second. Both the second and third pressure-recovery curves display an inflection point in the experimentally observed pressure (see Figure 2 or 4), potentially indicating some type of flow regime transition or other significant change in the physical processes influencing the pressure buildups.

HISTORY MATCHING SETUP AND RESULTS

The experimental data discussed above was utilized in this study by incorporating it into the numerical models used to construct the desired history matches. First, a schematic of the well and the placement of the MDT tool in the well bore was constructed (Figure 6) based on the model setup. A two-dimensional cylindrical grid was used to model the annular space in the well and the hydrate-bearing formation that extended radially outward from the wellbore.

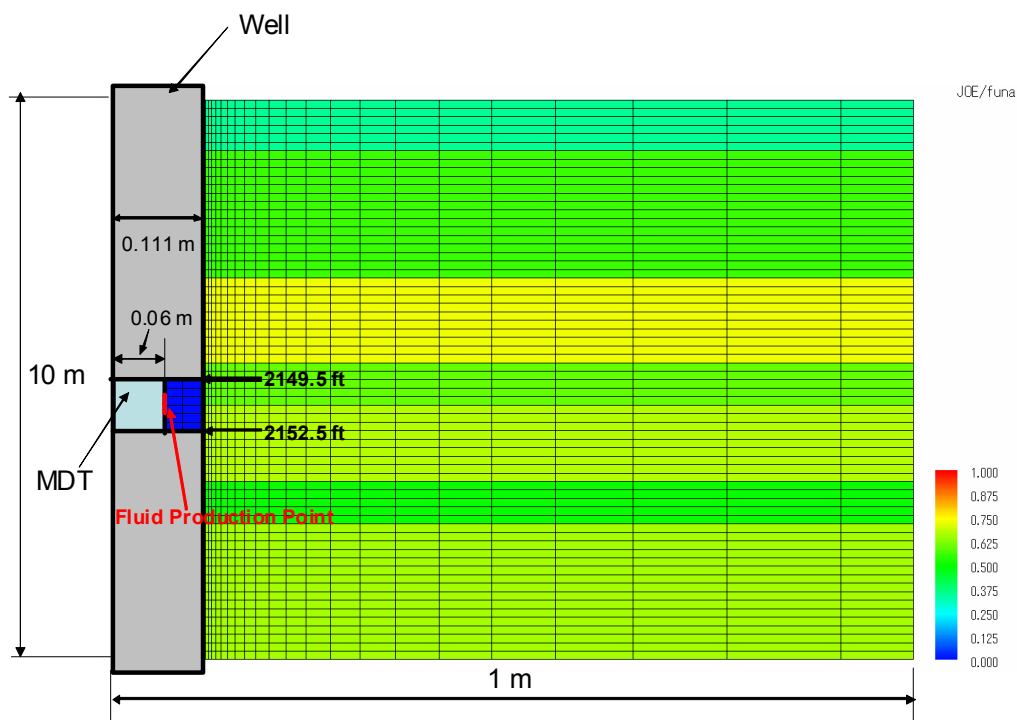


Figure 6: Schematic showing the relation of the MDT tool during the C-2 test to the 10-m thick C-sand. Also shown is an example of the reservoir (an annular space) gridding used in the simulations.

Simulations

Five simulators (CMG-STARS, STOMP-HYDRATE, TOUGH+HYDRATE, MH21-HYDRATE, and HydrateResSim) were independently used to conduct history matches based on the experimental data collected during the three flow periods. During the simulations being reported on here, the models used the observed pumping (flow) periods as specified boundary conditions (ie., the simulated pressure at the location of the MDT inlet was set to the experimentally observed pressure during the flow periods). Model parameters were then adjusted to obtain the best possible fits to the observed temperature and produced fluid volumes, as well as the pressure during the pressure build-up periods (ie., after the cessation of each pumping event).

Based on the nature of the data obtained from the MDT experiments, it was decided that the most accurate data were the pressures reported by the tool, followed by the temperature and produced fluid volumes. The latter two were of a lower quality for the following reasons: the temperature was felt to be of reduced accuracy due to the location of the sensor and the possibility that it was at various times in thermal equilibrium with formation water and/or free gas, and that the temperature might not necessarily accurately reflect the instantaneous (average) temperature of the formation at the physical location of the tool inlet, rather it was measuring the temperature of the fluid in contact with the tool.

With respect to the produced fluid volumes, the uncertainties were related to the necessity of having to interpret the volume of each fluid produced as a result of each pump stroke based on the pressure response of the pump chamber to the compressibility of the fluid(s) in the chamber during any particular stroke. It was therefore felt that the produced volumes contained the greatest error, and the pressure the least. As a result, in constructing the history matches, the observed pressure during the buildup periods was used as the primary fitting criteria, with temperature and produced fluid volumes given secondary importance.

The final history matches obtained by the various groups running the simulators are summarized in Figure 7 and shown individually in Appendix I. General conclusions concerning these results are discussed in the next section. The investigators used a wide range of approaches in constructing their individual history matches. For example, the number of total grid cells used to represent the modeled portion of the formation ranged from 360 to over 10,000. Some investigations included the solubility of methane in water as well as the formation water's observed salinity, while others ignored both. As can be seen by examining the figures in Appendix I, in all of the cases reasonable fits were obtained with respect to the observed pressure during the various buildup phases, however in none of them was a reasonable match to the estimated volume of produced gas obtained. General comments concerning these results are discussed in the next section.

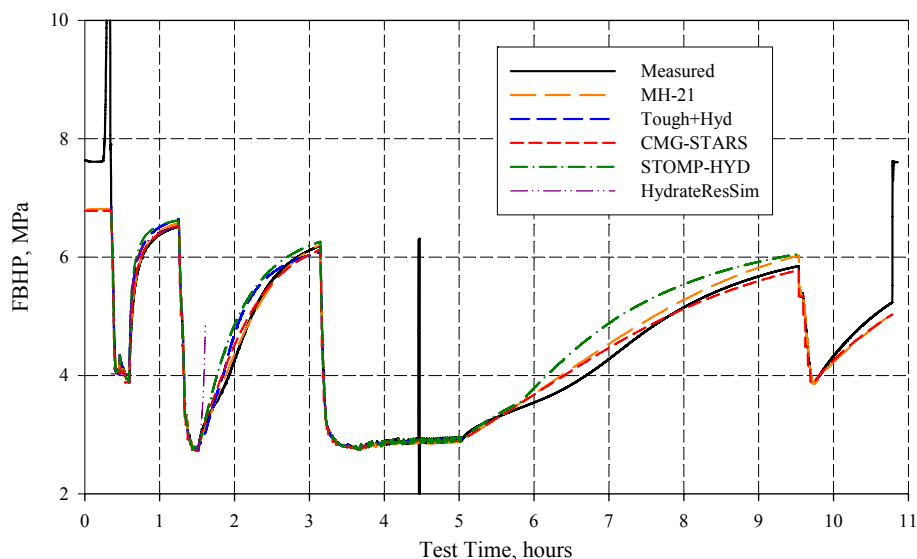


Figure 7: Summary plot of the history match to the C2 MDT test

LONG-TERM SIMULATIONS

Upon completion of the history-matching effort, the authors applied the information gained to producing first-order estimates of the potential long-term (50-yr) productivity of the gas-hydrate bearing sands in the Prudhoe Bay region. Three separate cases were conducted: Problem 7a examines a deposit similar to the Mt Elbert site. Problem 7b is based on a slightly warmer and thicker accumulation such as those that exist at the Prudhoe Bay Unit (PBU) L-Pad site. Problem 7c is a down-dip, and warmer, version of the L-Pad case. In all three cases, a standard set of parameters were used based on those found in Problem 6 (the history matches to the MDT data). The parameters chosen were consensus values based on the experiences of the various groups in attempting to match the MDT data for the C2 formation at Mount Elbert. Also, for all three cases, a vertical well using depressurization to 2.7 MPa was used for gas hydrate production.

Problem 7a: Mt Elbert-like formation

Problem 7a utilized the known data for the Mt Elbert C-Unit such as porosity, temperature, depth, and hydrate saturation, in addition to the relative permeability parameters found in the history-matching performed in Problem 6. The model domain was a 2-D (Figure 8), radial system, which was 450 m in the radial direction and 152.5 m in the vertical direction. In the vertical direction, 70 m (10 gridblocks) of an impermeable “shale” layer was placed on the top and bottom of a 12.5 m (50 gridblocks) gas hydrate-bearing sand layer. In the radial direction, 80 logarithmically-distributed gridblocks with an innermost block radius of 0.131 m were used.

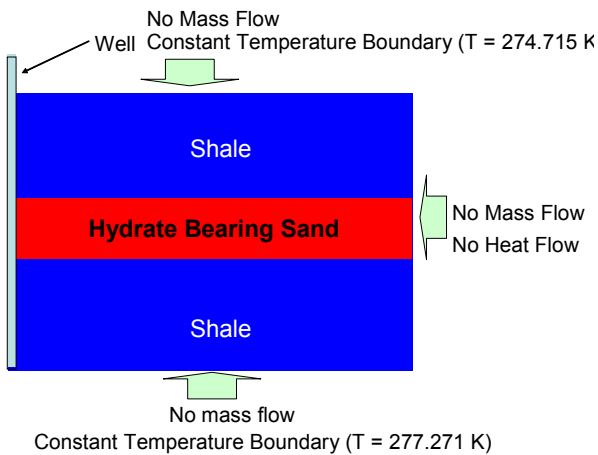


Figure 8: Schematic of Problem 7a

As one might expect, given the low initial temperature of the reservoir modeled in Problem 7a, the modeled gas production rates over the 50-yr life of the reservoir were uniformly low. This system has very limited *in situ* heat to provide for the endothermic hydrate dissociation reaction. The bottom-hole pressure used in the simulations was 2.7 MPa, slightly above the quadruple point in order to keep from forming ice in the reservoir.

Table 1: Problem 7a reservoir properties

Permeability (mD)	Shale Zone: 0.0 Hydrate Zone: 1000 rings in radial direction 100 layers in vertical
Porosity (%)	Shale Zone: 10 Hydrate Zone: 35
Pore Compressibility (Pa ⁻¹)	10 ⁻⁹
Rock Density (kg/m ³)	2650
Rock Specific Heat (J/kg/K)	1000

One notable result that was found using all of the participating simulators was the existence of a lag time before meaningful gas rates were realized. This lag time can be seen in Figure 9 for the simulation of Problem 7a using TOUGH+Hydrate. Figure 10 shows a summary of the lag times found using different simulators. An average lag time of 13.5 years was found among the simulators.

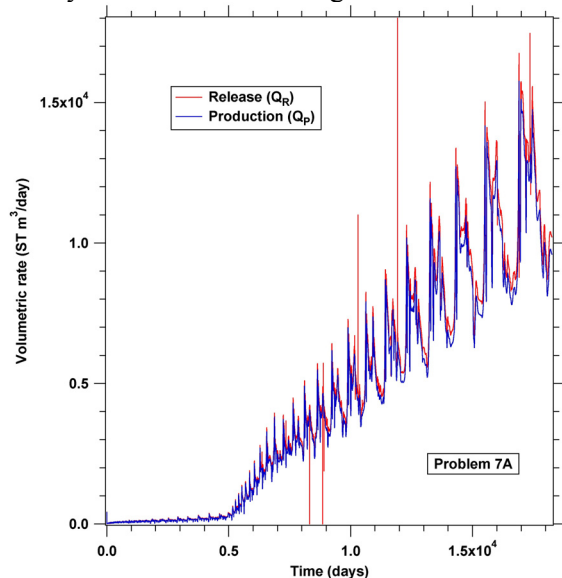


Figure 9: Gas release and production rates for Problem 7a simulated using TOUGH+Hydrate.

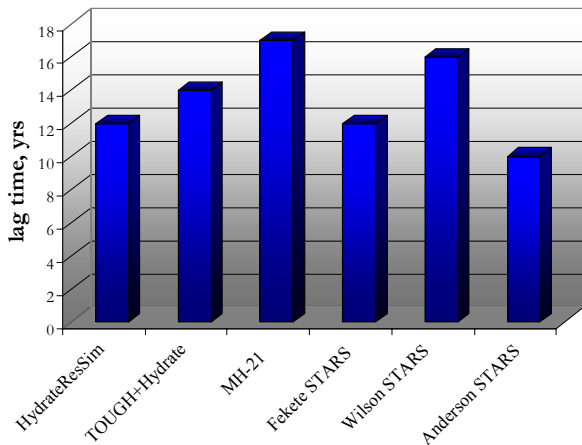


Figure 10: Lag times found in Problem 7a for six simulators.

The gas production rate for all the participating simulators continued to increase over the 50-year modeled timeframe; however, the max rate that was simulated was approximately 10,000 m^3/day or about 350,000 scf/day.

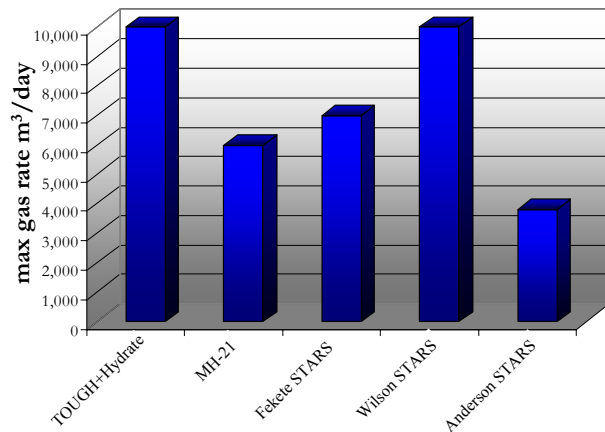


Figure 11: Max gas rates found in Problem 7a for five simulators.

Problem 7b: PBU L-pad formation

In Problem 7b, we simulated a reservoir with two shale-bounded hydrate layers (Figure 12) with constant hydrate saturation of 75%. Like in Problem 7a, the radial extent of the reservoir modeled in Problem 7b is 450 m; however, the two hydrate layers are each 18 m thick with 9 m of shale between. The top and bottom shales are each 100 m thick. The medium properties are the same as in Problem 7a as listed in Table 1, except that the porosity in the hydrate zone is 40% while the initial temperature and pressure are changed. As shown in Figure 12, the temperature at the top of

the reservoir is about 3°C (or Kelvin) warmer than the reservoir in Problem 7a.

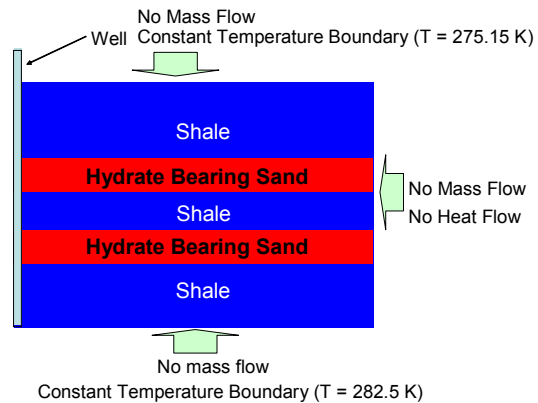


Figure 12: Schematic of Problem 7b

As one might expect, the predictions of the participating simulators for the warmer Problem 7b are quite a bit more optimistic than for Problem 7a. Gas production occurs from the beginning of depressurization, increasing to a maximum in all cases before decreasing near the end of the 50-yr simulation run. Figure 13 shows an example of the simulated gas rates and cumulative production for Problem 7b. The average maximum gas rate was approximately 25,000 m^3/day or about 825,000 scf/day while this maximum rate occurred at an average of 25 years.

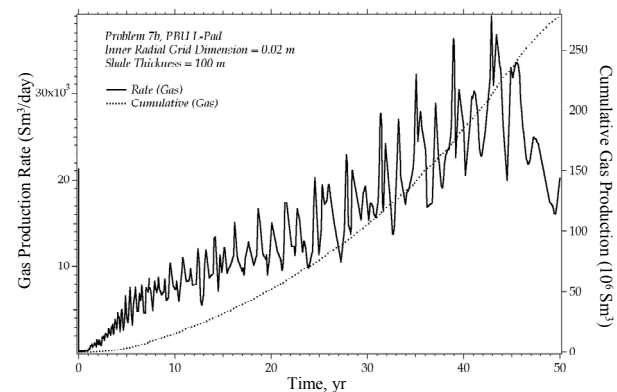


Figure 13: Gas rate and cumulative production for Problem 7b simulated using STOMP-HYD.

Problem 7c: Down-dip formation

The system modeled in Problem 7c is identical to the reservoir modeled in Problem 7b, except that the reservoir is located at the base of the hydrate stability zone at about 2,700 ft and warmer at 12°C. The pressure was set at 8.98 MPa consistent with expected temperature at this depth (Figure 14).

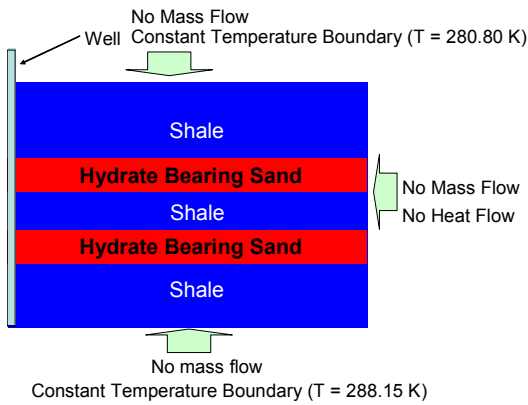


Figure 14: Schematic of Problem 7c

Problem 7c provided the most favorable gas production rates of the three long-term simulations. The average maximum gas rate among the simulators was 122,000 sm^3/day or about 4,300,000 scf/day while this maximum rate occurred at an average of 9 years. Figure 15 shows an example plot of gas rate and cumulative production simulated in Problem 7c and Figure 16 shows the maximum flowrates for six simulations.

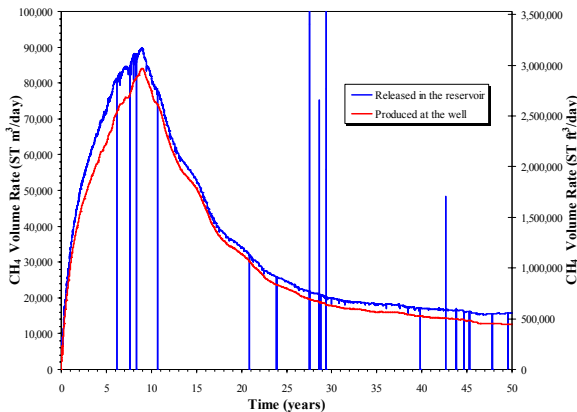


Figure 15: Gas rate and cumulative production for Problem 7c simulated using HydrateResSim (HRS).

DISCUSSION

History Match – First Pressure Buildup

As discussed above, during the first flow period the reservoir pressure never went below the hydrate equilibrium pressure. As a result, no hydrate dissociated, and the recorded data can therefore be used to reconstruct an initial estimate of the formation permeability (in the presence of hydrate) in the vicinity of the MDT tool. Based on the history match results of the various simulators, the effective permeability of the formation is

estimated to be in the range of 0.12 to 0.17 mD (with an intrinsic (no gas hydrate present) or absolute permeability of approximately 1 D).

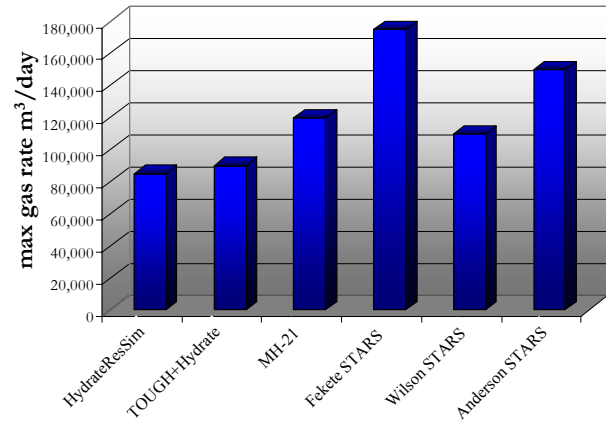


Figure 16: Max gas rates found in Problem 7c for six simulators.

It is noteworthy that even given all of the differences between the approaches utilized with the four different simulators, all of the history matches from the various models to this portion of the pressure data resulted in an estimate of the effective permeability in the same range (0.12-0.17 mD). Though this estimate may only be reflective of the reservoir in the very near vicinity of the borehole, it represents perhaps the best information to date on this key parameter.

History Match – Second and Third Pressure Buildups

As can be seen from Figure 17, initial attempts to construct history matches using the second and third flow/buildup periods were not very successful. This difficulty was overcome when an annular space was explicitly included around the MDT tool which accounted for well bore storage of reservoir fluids. After the inclusion of this annular space, very good pressure matches were readily obtained (as can be seen in the figures in the previous section). Based on the results from the various simulations, it seems that fluid segregation in this annular space plays a key role in the general shape of the recovery curves. Without this space, the simulated recovery curves have the more traditional shape seen during the first build-up phase (prior to the release of any gas from hydrate in the formation).

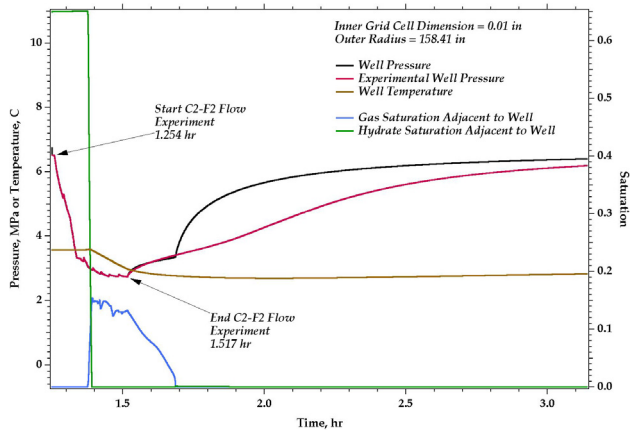


Figure 17: Modeled pressure response of the C2 MDT test using STOMP-HYD without explicit annular space. Black curve shows sudden pressure increase at ~1.7 hours.

As was also mentioned above, an appreciable amount of gas was not produced during the second flow period, yet all of the simulators indicate that an appreciable amount of hydrate did dissociate, and a corresponding amount of free gas was released into the formation during this time. With the annular space included in the numerical simulations, it was observed that as gas migrated into the region near the MDT tool inlet, fluid segregation resulted in the accumulation of free gas in the region above the inlet, resulting in the production of only formation water during the second flow period. Only after sufficient gas had migrated to this region (some time during the third flow period) and the water level had decreased below the tool inlet did appreciable amounts of free gas begin to be produced.

While inclusion of an annular space did allow the good history matches to be achieved (with respect to the pressure), there is one drawback to including this effect. Due to the small amount of fluid produced during the experiment, segregated fluid flow in the annular space had a significant impact on the observed pressure buildups. Unfortunately, none of the codes under consideration include the physical/mathematical models necessary to rigorously model instantaneous fluid segregation, in a fluid-filled annular space. As a result, there is a possibility that the model parameters determined during the history matches may have been skewed by the inclusion conditions where a phenomenon the models were not specifically designed to simulate was important to the results. Since

parameters would be useful as a starting point of a detailed sensitivity analysis directed at assessing potential production from such a formation, they should not be interpreted as “the” parameters from which a single prediction of the potential productivity of the formation should be made. A simple physical experiment is in progress at the Colorado School of Mines (CSM) that will quantify the pressure build-up response of a changing gas “headspace” in a liquid-filled annular void. Isolating these effects from hydrate or reservoir responses will help determine best practices for future testing.

Another interesting characteristic of the pressure buildups is that the latter two evidenced an inflection point (for example, examine the blue trace in Figure 3 shortly after a time of 6 hours). The change in curvature of the buildup at this point may be indicative of a change in the character of the fluid flow in the formation. Such a change may be due to, flow regime transition (perhaps involving the segregated fluid flow in the annular space), effects of hydrate reformation (or lack thereof) on the migration of fluids towards the MDT tool, or disappearance of free gas in the formation. Because the simulators do not explicitly include models for segregated flow in an annular space, we are unable to attribute this transition to a particular phenomena.

It is interesting to note, however, that while none of the simulations that utilized an equilibrium model for hydrate reformation showed this inflection point as seen in the data, a run done with STARS that kinetically inhibited hydrate reformation did in fact reproduce this characteristic (see Figure A3). Such an inhibition would correspond to a theory that due to the timescales of the processes being considered relative to the time scale of the MDT test, hydrate dissociation cannot be assumed to be dictated by equilibrium thermodynamics, because hydrate reformation (being on a much longer time scale than dissociation) is kinetically controlled and the rate of reformation plays a significant role over the 9-hour MDT test.

While this result is interesting, it should be noted that it is far from conclusive because the quality of the matches was much more dependent on the inclusion of the annular space than the nuances in the hydrate reactions as discussed above. Since

there is currently no direct experimental evidence of a flow regime transition causing the inflection in the pressure recovery curve, we cannot at this time determine what specific property of the formation led to its observation in the data. Experimental data from the experiment at CSM discussed above should help resolve this issue.

CONCLUSIONS

Independent analysis of the MDT data utilizing five simulators (CMG-STARS, STOMP-HYDRATE, TOUGH+HYDRATE, MH21-HYDRATE, and HydrateResSim) has led to very important insights into the potential behavior of hydrate bearing formations such as the one at Mt. Elbert.

One key observation is that three of the most important parameters impacting production predictions are (in order of importance): initial temperature of the reservoir (the warmer the better in terms of production), intrinsic permeability of the reservoir, and the relative permeabilities in the presence of hydrate. In addition, MDT data may be useful in estimating local permeabilities; “global” (or “average”) permeability estimates would require flow tests that sampled a much larger portion of the reservoir than is possible with the MDT tool. To understand why such long tests are so important in the case of hydrates, one should consider that during hydrate dissociation/formation the pore space available for fluid flow changes (due to hydrate dissociation and/or reformation), thereby impacting the apparent permeability of the formation. Thus, a short-term test is not indicative of the fully developed flow/behavior of the formation after significant hydrate has dissociated/reformed. Exactly how long such a test would need to be in order to provide optimum data is an open (and very interesting) question.

For this and other reasons discussed above, the parameters determined as part of the history match being reported on here (see Appendix I) should be viewed as informative, but not definitive. Because of the limited extent to which the formation as a whole was sampled by this test, and because there is an as yet unknown impact of having to include the annular space (due to the small volume of fluids produced during the test), there is insufficient evidence on which to base an assertion that the parameters being reported here would be

representative of the formation in general. However, these parameters (representing the best “local” estimates available to-date) would be extremely useful as a starting point for a detailed sensitivity analysis directed at assessing potential production from such a formation.

The simulations were highly sensitive to the amount of free water available for flow in the reservoirs. Data from the Mt Elbert site show that the free water accounts for about 10% of the open pore space, limiting the ability to flow water to the well. This is likely the cause for the lag time seen by the simulations.

All of the participating simulators showed a remarkable agreement in the characteristics of the long-term production simulations. The predicted gas rates, the cumulative produced gas, and the characteristic reservoir times were all in good agreement. As expected, the warmer and deeper model hydrate reservoir systems resulted in higher gas production rates and produced more cumulative gas.

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APPENDIX I

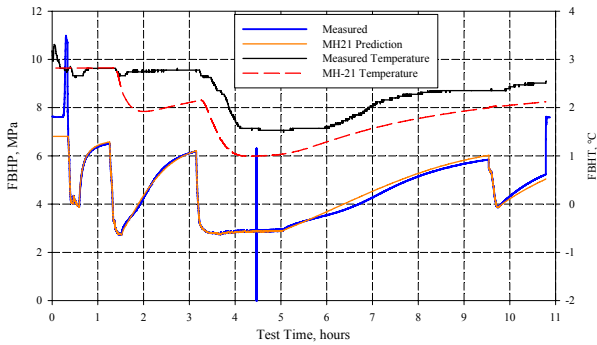


Figure A1: MH-21 History Match

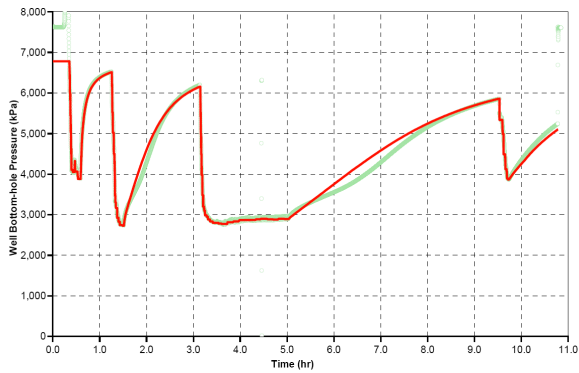


Figure A2: Pooladi-Darvish CMG-STARs History Match – No Hydrate Reformation

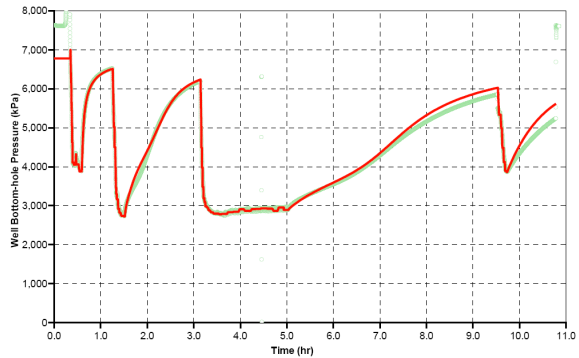


Figure A3: Pooladi-Darvish CMG-STARs History Match – Hydrate Reformation with decreased formation kinetics

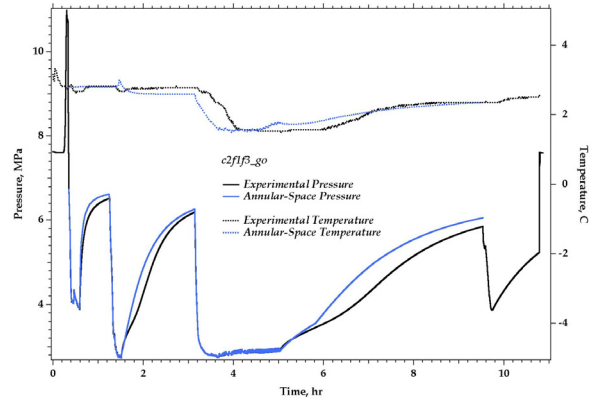


Figure A4: STOMP-HYDRATE History Match

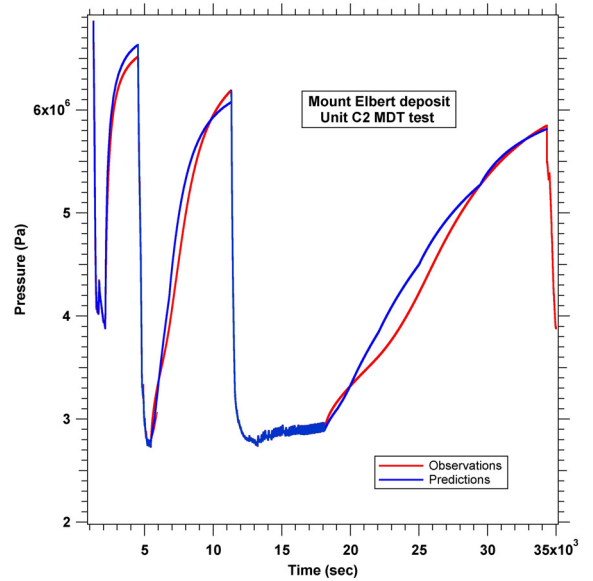


Figure A5: TOUGH+HYD History Match

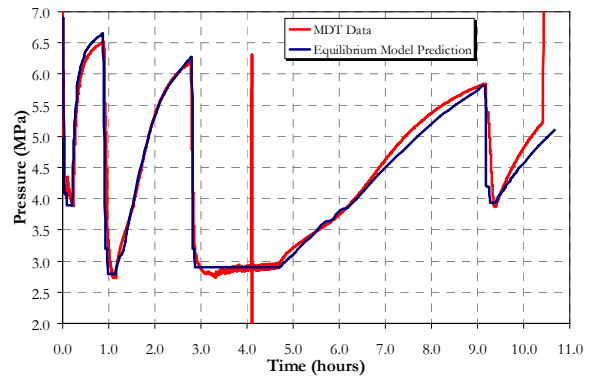


Figure A6: Wilson CMG-STARs History Match