

Numerical Simulations of Gas Production from Gas Hydrate Reservoirs at the Prudhoe Bay Unit 7-11-12 Pad on Alaska North Slope

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ABSTRACT

In December 2018, a partnership between the U.S. Department of Energy National Energy Technology Laboratory (DOE NETL), the Japan Oil, Gas and Metals National Corporation (JOGMEC), and the U.S. Geological Survey (USGS) successfully drilled and logged the Hydrate-01 Stratigraphic Test Well (STW) in the greater Prudhoe Bay oil field on Alaska North Slope. The logging-while-drilling (LWD) data confirmed the presence of gas hydrate-bearing reservoirs within two sand reservoirs (Unit B and Unit D) that are suitable targets for future testing.

The interpreted log data and core sample measurements were used to create reservoir models for the Prudhoe Bay Unit (PBU) Kuparuk 7-11-12 Site. The models combine both gas hydrate-bearing sections in Unit B and Unit D together with the intermediate Unit C and over- and underburden sands and shales. The vertical heterogeneity in porosity, gas hydrate saturation, and permeability distributions for reservoir and non-reservoir units was implemented using fine mesh discretization. The depressurization method was applied to Unit B to induce gas hydrate destabilization at constant bottom hole pressure (BHP) values. The results of the numerical simulations support the development of production scenarios, well design, surface facilities, and field test procedures with the main goal to perform efficient and safe scientific production testing. Project results contribute to the knowledge base of permafrost-associated gas hydrate accumulations as a future energy source.

Keywords: *gas hydrate; numerical simulations; Prudhoe Bay Unit, Alaska North Slope*

1. INTRODUCTION

Gas hydrate represents crystalline ice-like compounds where the gas molecules are encapsulated within water cages of the hydrate lattice. Methane hydrate is widely spread in nature in permafrost areas and sub-oceanic sediments and considered to be a promising future source of energy.[1] Natural gas production from gas hydrate requires a shift of the pressure and/or temperature conditions outside of the gas hydrate stability zone to initiate gas hydrate decomposition. Production can be achieved by reducing formation pressure, increasing temperature, applying inhibitors, or a combination of thereof. Depressurization is regarded as the most effective method to induce gas hydrate dissociation.[2]

In recent years, a number of field-scale drilling and testing programs were conducted at the Mallik research site in Northwest Canada,[3] at the Mount Elbert site in Northern Alaska, [4] in the eastern Nankai Trough, offshore Japan,[5] in the Bay of Bengal, offshore India,[6,7], in the South China Sea, offshore China,[8] and in the Gulf of Mexico, offshore the United States.[9] These programs were successful in confirming the technical viability of gas production from gas hydrate reservoirs through depressurization, understanding site-specific reservoir petrophysical parameters, and details of the geological settings necessary to develop geological input models for reservoir simulations.

USGS has conducted geophysical studies of the Eileen Gas Hydrate Trend and determined that the PBU Kuparuk 7-11-12 site in northern Alaska contains gas hydrate occurrences and the existing infrastructure (gravel pad) required for a successful production test. DOE NETL, JOGMEC, and USGS led the effort that identified and characterized the PBU 7-11-12 prospect as the pilot site for a potential long-term gas hydrate

production test. In December 2018, data acquired in Hydrate-01 STW drilled from the 7-11-12 Pad confirmed the occurrence of two high-quality reservoirs (Unit B and Unit D) fully saturated with gas hydrate. The drilling of Hydrate-01 STW [10] was the initial phase of a science program designed to conduct an extended duration test of gas hydrate reservoir responses to depressurization. The deep and warm Unit B is very fine-grained sand to coarse silt of about a 59 ft (18 m) thickness with gas hydrate saturation ranging from 22 to 93%. Unit B occurs near the base of the gas hydrate stability zone (BGHSZ) and contains no free-water leg at the well location. Unit B is therefore very well suited for scientific production testing [11]. The shallow and cold Unit D represents a gas-hydrate reservoir with thickness and saturation similar to that of Unit B. Occurring at temperature 40.3 °F (4.6 °C) and with a water-bearing section at its base, Unit D sand could provide opportunities to investigate additional scientific and well design issues as a potential follow-on to testing in Unit B.

The LWD, wireline logging, and sidewall coring operations were conducted to obtain detailed characterization of reservoir and non-reservoir units, and provide geological and geophysical data to reservoir modeling.[10-12] DOE NETL and JOGMEC are conducting cooperative gas hydrate production modeling to determine gas and water flow rates required to understand the gas hydrate reservoir properties and production potential. These studies are also considering the test well design requirements (completion design, sand control, flow assurance systems, gauges, measurement and control systems, production monitoring systems, etc.) and depressurization scenarios to implement a successful production test.

This paper reports predicted gas/water production volumes/rates using depressurization up to one year. The results of this work contribute to finalizing the design of several additional wells, surface production facilities, and testing procedures to allow the implementation of efficient and safe scientific production execution and monitoring that will address a range of scientific questions regarding the response of gas hydrate-bearing reservoirs to depressurization.

2. INITIAL CONDITIONS AND RESERVOIR MODEL DESCRIPTION

The pressure was assumed to follow a hydrostatic pore pressure distribution, the assumption supported by measurements taken in natural hydrate deposits (cite). At the bottom of ice-bearing permafrost (BIBPF) (1883 ft TVDss; true vertical depth below sea surface / 1936 ft TDVgl; true vertical depth below ground level) the

temperature is tentatively assumed to be 0 °C and the thermal gradient is 2.04 °F/100 ft (0.037 °C/m). These pressure distribution and temperature profile provide 8.57 MPa and 50.1 °F (10.03 °C) at the top of Unit B at 2822 ft TVDgl (Figure 1). Unit B is located close to BGHSZ around 3,000 TVDgl, so that a drawdown only about 1.5 MPa is sufficient to induce gas hydrate decomposition. The pressure at the Unit B reservoir define moderate effective stress increase under fluid withdrawal during depressurization; that results in minimal geomechanical impact on production.[13] Easy destabilization, warm temperature (providing ample sensible heat to maintain the decomposition reaction), a high quality reservoir, and hydraulic isolation are the main factors making Unit B as an excellent target for a long-term test and the depressurization method with controllable BHP as a tool to devise production scenarios [11].

The PBU Kuparuk 7-11-12 reservoir model was approximated using a cylinder with a wellbore placed along its axis. Taking advantage of the cylinder symmetry, 2D models were created using two reservoir radii in the lateral direction, 500 and 3,000 m. These values were chosen as limiting numbers in advance of detailed analysis of the inferred sealing fault locations and the areal map of Unit B. In the vertical direction, the 2D models include all gas hydrate-bearing Units depicted in Figure 2 with the top set at BIBPF and the bottom of the underburden located at 3,785 ft TVDgl. Including all units allows studying sequential depressurization of the cold Unit D also featuring high *Sgh* (Figure 2) after shutting down production at Unit B. In the vertical direction, the fine mesh discretization (0.1 m) was created for the gas hydrate-bearing Units with coarse discretization provided for non-reservoir units. In the lateral direction, logarithmically increasing grid block lengths were used to ensure a very detailed meshing around a wellbore. For reservoir models with a 500-m radius, the mesh size was 200 (horizontal) x 440 (vertical) grid blocks; and for those with a 3,000-m radius, it was 254 x 440. The mesh size sensitivity analysis was carried out to confirm that mesh size does not significantly affect numerical results.[7]

The PBU Kuparuk 7-11-12 production test well is modeled as a vertical well with an open hole completion with assumed perfect sand control. The top of the perforated 10-m interval to induce depressurization was placed 3 m below the top of Unit B. Such a well design provides better hydraulic isolation from over- and underburden compared to perforation implemented throughout the entire thickness of the Unit.

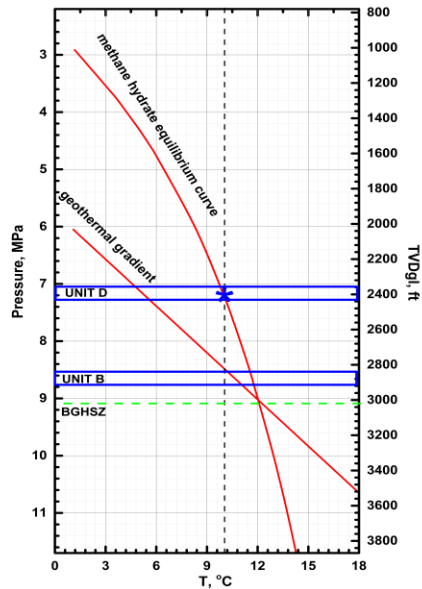


Figure 1. Methane hydrate equilibrium curve (corrected for 5 ppt salinity) plotted together with the geothermal gradient and subsurface depth. The blue rectangles, the star, and the dotted green line designate the location and conditions of Unit B and Unit D, the minimum wellbore pressure required to initiate gas hydrate decomposition for Unit B, and the approximate location of BGHSZ, respectively.

The suite of LWD, wireline logging, and sidewall core data sets provides a basis to implement vertical heterogeneity in petrophysical properties in the reservoir models. For details, the reader is referred to the companion reports summarizing the general scientific findings from the 2018 drilling and subsequent data evaluation.[10,11] Total porosity, gas hydrate saturation, irreducible water saturation, *in situ* and absolute permeabilities were varied with depth with a resolution following the mesh discretization in the vertical direction. In the lateral direction the properties were approximated using the homogeneous approach. The results of the unsteady relative permeability tests using the brine saturated core samples extracted in the upper section of Unit D were used to devise parameters for the relative permeability model.

Three production cases were designed based on interpretation of *in situ* permeability. For Case A, effective permeability is estimated using the Kozeny-Carman equation model. This high-end case utilizes *in situ* permeabilities on an order of 10 md within the hydrate bearing sections. For Case B, effective

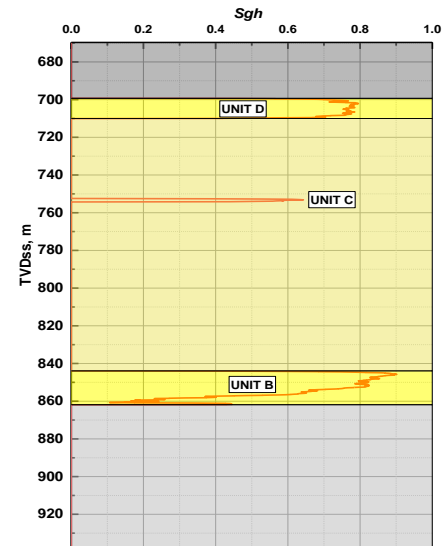


Figure 2. Vertical stratigraphic representation of the PBU Kuparuk 7-11-12 reservoir showing locations of gas hydrate-bearing Units. The orange curves display gas hydrate saturations (S_{gh}) within the Units.

permeability is estimated using Timur-Coates equation. This conservative case provides effective permeabilities for reservoir and non-reservoir units on orders of 0.1 and 1.0 md, respectively. The most likely Case C is created by combination with Cases A and B, applying a gradual shift from Case A to Case B to the lower section of Unit B. Figure 3 depicts geological input data to the reservoir model for each case.

3. SIMULATION RESULTS

Figure 4 displays gas and water production from Unit B in response to depressurization induced using BHP equal to 3.0 MPa predicted using the Tough+ and MH21 codes. The gas production demonstrates a close agreement between two codes, however, water rates are different. This difference is most likely attributed to the treatment of irreducible water saturation (S_{wir}) within the codes. In Tough+, S_{wir} stays fixed during gas hydrate decomposition, while in MH21 it increases to keep S_{wir}^* fixed relative to pore space not occupied by gas hydrate.

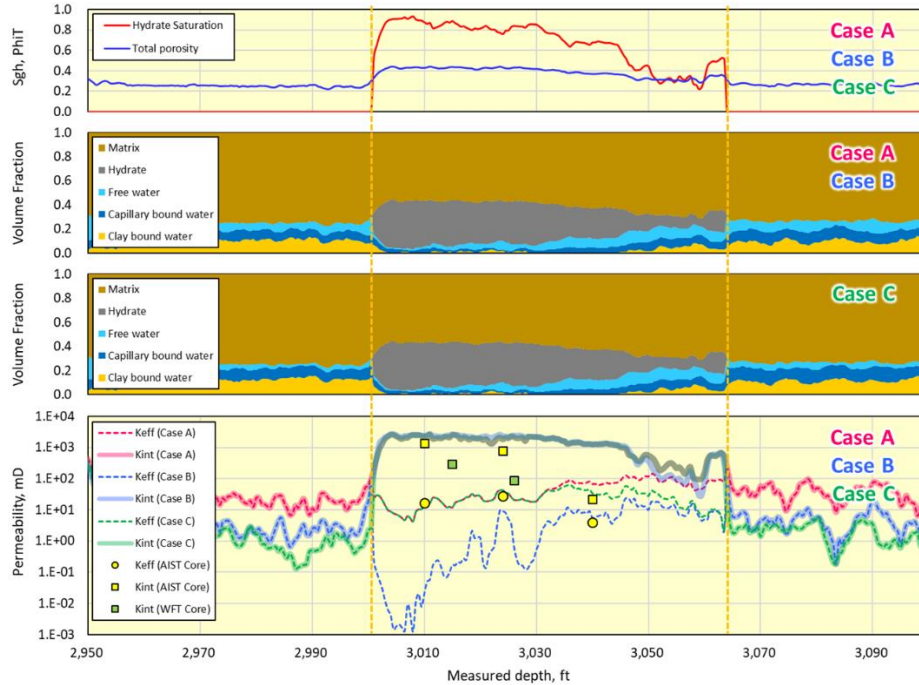


Figure 3. Geological input showing porosity, gas hydrate saturation, volume fractions, and permeabilities. Yellow dashed lines define the boundaries of Unit B.

Besides the products of the gas hydrate decomposition reaction, water originally present in the reservoir and influx from over- underburden competing with gas flow are also produced at the wellbore. In this regard, a reservoir model with a more distant (or no) lateral no-flow boundaries will allow more water influx from non-reservoir units under the same depressurization regime. Figure 4 shows that after around 30 days of depressurization, the models with a 3,000-m radius produce more water compared to the models with a 500-m one that adversely affects the gas rates. Notably, in Cases A2 and C2, gas production slowly declines over time, opposite to the corresponding Cases A1 and C1 showing steady increase. The cases utilizing two radii of 2D models demonstrate the continuous deviation in production values with time that suggests that for more precise estimates of long-term reservoir performance, a three-dimensional model accounting for actual positions of the lateral boundaries is needed. Figure 5 demonstrates gas hydrate saturation and pressure distributions within the first 150 m from a wellbore located along the Y axis after 1 year of production. The heterogeneous nature of S_{gh} is revealed showing that in the upper Unit B gas hydrate decomposes slower compared to the lower part due to high initial saturations and lower initial effective permeability. Gas hydrate has

also decomposed along the boundaries with non-reservoir units owing to conductive and convective heat supply from over- and underburden. Once created, these free-of-hydrate areas within Unit B create high-permeable channels facilitating hydraulic communication with surrounding strata. The pressure distribution confirms that communication resulting in strong pressure decrease in the formations just above and below Unit B.

4. SUMMARY

The PBU Kuparuk 7-11-12 (Unit B) gas hydrate 2D reservoir models have been used to predict reservoir performance using up to 1 years of depressurization at a vertical wellbore completion. The models utilize detailed geological input compiled after interpretations of LWD and wireline logs at Hydrate-01 STW, measurements of core samples, and provide vertical heterogeneity in porosity, saturations, and permeability descriptions. The Unit B reservoir responses were estimated using three cases, which are designed based on NMR log-derived and pressurized sidewall core measurements of effective permeabilities. The simulations revealed that a radius of the model / a drainage area strongly affects gas and water production. This indicates the importance of 3D modeling accounting for interred boundaries of the gas hydrate accumulation.

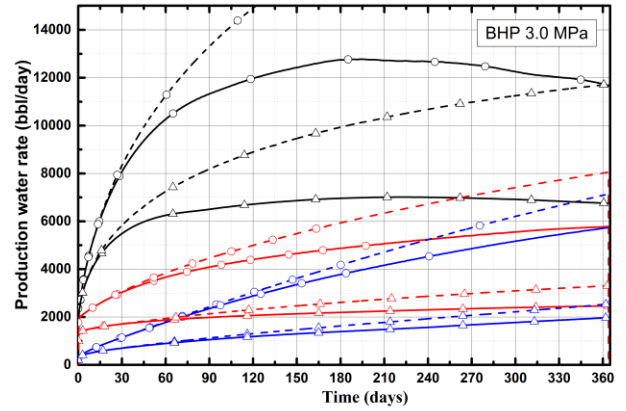
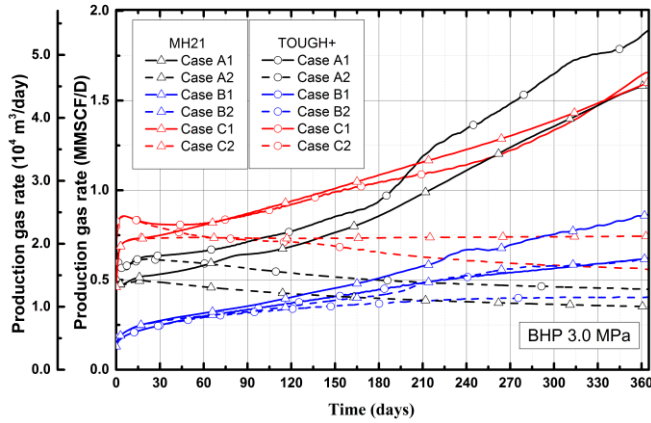


Figure 4. Gas (left) and water (right) production rates predicted from the PBU Kuparuk 7-11-12 reservoir (Unit B) using depressurization at BHP equal to 3.0 MPa during 1 year. For three production cases, the “1” (solid curves) and “2” (dashed curves) designate 500 and 3,000 m radii for the 2D reservoir models, respectively. The production data predicted using the MH21 code are given by the curves with open triangles, those made by the Tough+ code are depicted using open circles.

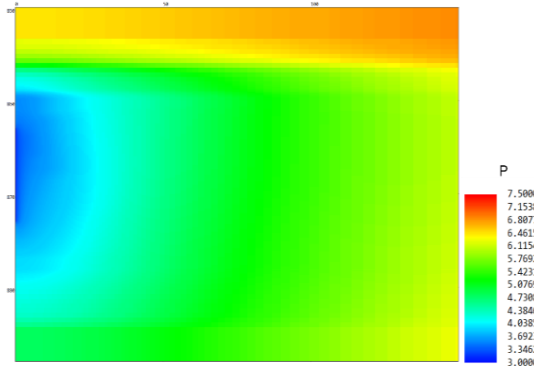
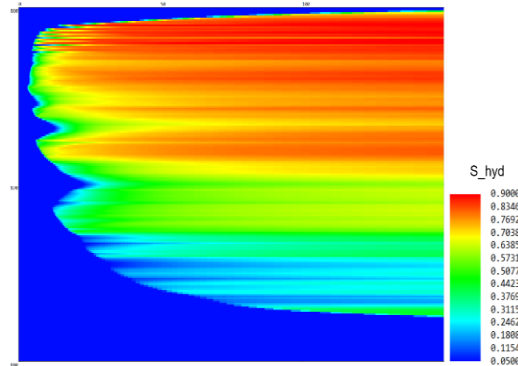
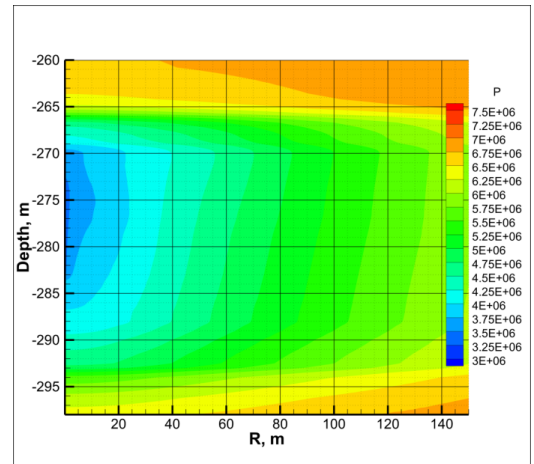
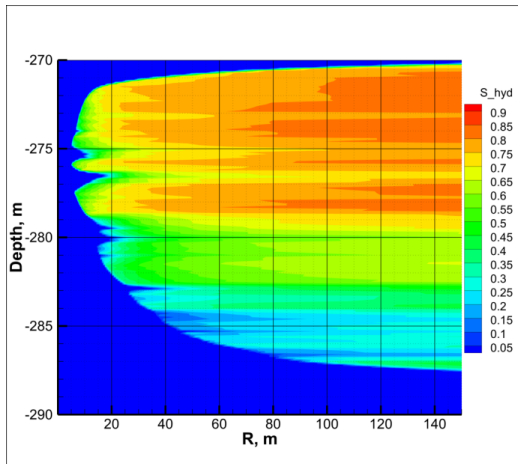


Figure 5. Gas hydrate saturation (left) and pressure (right) distributions within the reservoir model using Case C1 after 1 year of depressurization at BHP equal to 3.0 MPa. The top and bottom figures are the distributions predicted by Tough+ and MH21, respectively.

5. ACKNOWLEDGEMENTS

The authors wish to thank the Ministry of Economy, Trade and Industry of Japan, the Alaska Department of Natural Resources, the US DOE Office of Fossil Energy, BP Exploration (Alaska) Inc., and the Prudhoe Bay Working Interest Owners. Research conducted in the United States was performed in support of the US Department of Energy's Fossil Energy Crosscutting Technology Research Program. The Research was executed through the NETL Research and Innovation Center's Gas Hydrate Program and supported in part by an appointment to the National Energy Technology Laboratory Research Participation Program, sponsored by the U.S. Department of Energy and administered by the Oak Ridge Institute for Science and Education. Research performed by Leidos Research Support Team staff was conducted under the RSS contract 89243318CFE000003.

6. DISCLAIMER

Research conducted in the United States was funded by the Department of Energy, National Energy Technology Laboratory, an agency of the United States Government, through a support contract with Leidos Research Support Team (LRST). Neither the United States Government nor any agency thereof, nor any of their employees, nor LRST, nor any of their employees, makes any warranty, expressed or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

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