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INVESTIGATION OF GAS HYDRATE-BEARING SANDSTONE RESERVOIRS AT THE "MOUNT ELBERT" STRATIGRAPHIC TEST WELL, MILNE POINT, ALASKA

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ABSTRACT

In February 2007, the U.S. Department of Energy, BP Exploration (Alaska), Inc., and the U.S. Geological Survey conducted an extensive data collection effort at the "Mount Elbert #1" gas hydrates stratigraphic test well on the Alaska North Slope (ANS). The 22-day field program acquired significant gas hydrate-bearing reservoir data, including a full suite of open-hole well logs, over 500 feet of continuous core, and open-hole formation pressure response tests. Hole conditions, and therefore log data quality, were excellent due largely to the use of chilled oil-based drilling fluids. The logging program confirmed the existence of approximately 30 m of gas-hydrate saturated, fine-grained sand reservoir. Gas hydrate saturations were observed to range from 60% to 75% largely as a function of reservoir quality. Continuous wire-line coring

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operations (the first conducted on the ANS) achieved 85% recovery through 153 meters of section, providing more than 250 subsamples for analysis. The "Mount Elbert" data collection program culminated with open-hole tests of reservoir flow and pressure responses, as well as gas and water sample collection, using Schlumberger's Modular Formation Dynamics Tester (MDT) wireline tool. Four such tests, ranging from six to twelve hours duration, were conducted. This field program demonstrated the ability to safely and efficiently conduct a research-level open-hole data acquisition program in shallow, sub-permafrost sediments. The program also demonstrated the soundness of the program's pre-drill gas hydrate characterization methods and increased confidence in gas hydrate resource assessment methodologies for the ANS.

Keywords: gas hydrates, coring, Alaska North Slope, formation pressure testing

INTRODUCTION

Gas hydrates have been known to occur within shallow sand reservoirs on the Alaska North Slope (ANS) for nearly 40 years. Spurred by reports of gas hydrate resources and potential production in Arctic Russia [1], industry drilled, cored, and tested gas hydrate reservoirs at the Northwest Eileen State No. 2 well in 1972 [2]. That test indicated sub-commercial production rates and for the next 30 years, gas hydrates have been viewed primarily as a drilling hazard that must be managed during development of deeper oil resources.

In 1995, the U.S. Geological Survey (USGS) provided a mean estimate for gas hydrate in-place resources on the ANS of 16.7 trillion cubic meters (tcm: 590 trillion cubic feet (tcf)) [3]. Of this total, 1.0 to 1.2 tcm (33 tcf) were assessed to exist where nearshore marine sands of the Canning Tongue of the Mickelson Formation [4] traverse the gas hydrate stability zone (GHSZ) with the “Eileen” trend beneath existing ANS oil and gas production infrastructure including the Milne Point, Kuparuk River, and Prudhoe Bay Units [2].

In 2002, the U.S. Department of Energy and BP Exploration (Alaska), Inc. (BPXA), initiated a cooperative research program in association with the U.S. Geological Survey to assess ANS gas hydrate resources. The primary goal of the program was to plan and conduct a production test to help determine the potential for environmentally-sound and economically-viable production of methane from gas hydrates. Associated goals of the program include further refinement of ANS gas hydrate resource potential, improvement of the geologic and geophysical methods used to locate and assess gas hydrate resources, and further development of numerical modeling capabilities that are critical in both planning and evaluating gas hydrate field programs.

In addition to addressing issues of ANS gas hydrate potential, the project is also expected to provide critical information on the nature and behavior of gas hydrate-bearing reservoirs in general, providing new insights into an accelerating and increasingly collaborative international effort to understand the production potential of the much larger marine gas hydrate resource. More recently, the U.S. Minerals Management Service [5] has assessed Gulf of Mexico in-place gas hydrate resources at 607 tcm (21,444 tcf) with 190 tcm (6,710 tcf) being assessed as occurring at relatively high saturations within sand reservoirs.

MILNE POINT GEOLOGICAL REVIEW

BPXA, as project co-sponsor, contributed a 3-D seismic survey across the Milne Point Unit (MPU), which covers the extreme northern edge of the “Eileen” gas hydrate accumulation (Figure 1). Initial seismic interpretation indicated a mix of potential gas hydrate prospects including accumulations both at the base of GHSZ (in

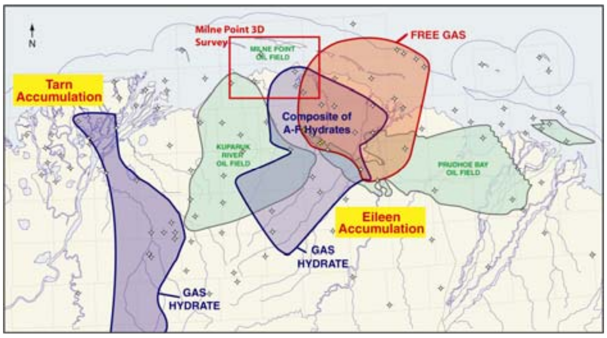

Figure 1. Location of major oil fields of the Prudhoe Bay region, Alaska North Slope (green) with “Eileen” gas hydrate trend and Milne Point 3-D survey (red box, after [2]).

contact with underlying free gas) and those higher in the stratigraphic section. However, new well log data collected by the project within "wells of opportunity" (wells being drilled to deeper horizons in which additional shallow log data were acquired) showed that the gas hydrate and free gas saturations of these deeper accumulation were prone to be low due to leaky seal or inadequate charge [6].

In 2005, the project team completed the delineated, described, and ranked (including probabilistic volumetrics) 14 gas hydrate prospects (Figure 2) via integrated geological and geophysical analyses within the Milne Point area [7]. The seismic aspect of the work was based on rock physics relationships conditioned by offset well data that enabled the prediction of gas hydrate "pay" thickness and saturation from analysis of seismic amplitudes and wavelengths 3-D seismic data [8]. Based on the geological, geophysical, and reservoir modeling studies conducted within MPU, total in-place resources within the Eileen trend were revised to approximately 0.93 tcm (33 tcf) of gas. In addition, initial reservoir modeling studies conducted in association with the project using the CMG-STARS model suggested that up to 0.34 tcm (12 tcf) of the gas could be technically-recoverable using tailored applications of already existing drilling and completion technologies [6].

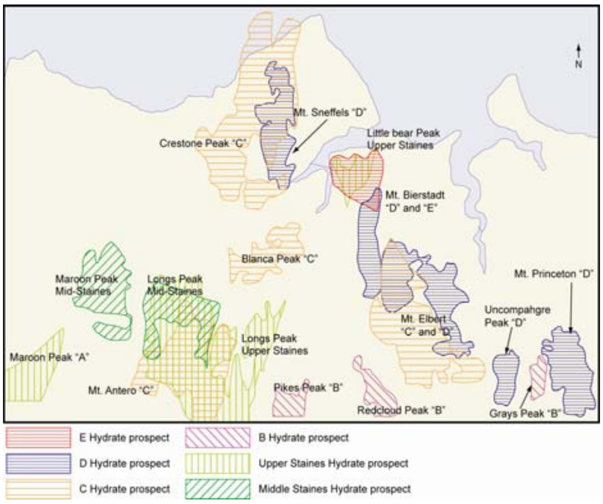

Figure 2. Location of delineated gas hydrate prospects at Milne Point (after [7]).

The Mount Elbert Prospect

The highest-ranked of the identified Milne Point prospects (named "Mount Elbert") was selected as the subject site for the planned field data acquisition program. The prospect was assigned a mean estimate of 60 billion cubic feet (bcf) of gas in-place in two reservoir sands [6]. Although other Milne Point prospects were assigned greater volumes of gas hydrate, the Mount Elbert location was selected due to lowest assessed geologic risk.

One advantage of the Mount Elbert location was that it provided two vertically-stacked drilling targets. In addition, the prospect contained a strong and well-organized seismic response. At both stratigraphic horizons, the amplitude anomalies were observed to be restricted within a well defined three-way fault closure, with high-amplitudes located in the structurally-high portion of the trap (Figure 3). This geometry suggests that the accumulation may have formed originally as a free-gas accumulation in a structural trap that was later converted to gas hydrate by imposition of depressed thermal gradients associated with the development of permafrost conditions across the ANS.

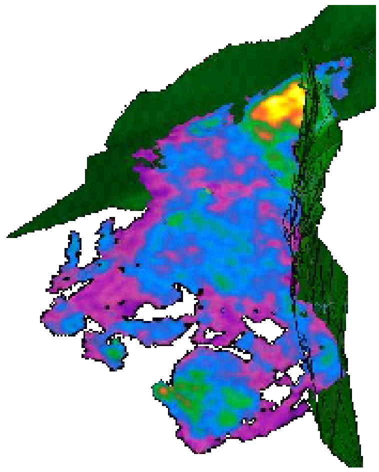

Figure 3. 3-D display of a seismic amplitude anomaly within the Mount Elbert prospect. Green planes are interpreted faults. Amplitudes are confined within the bounding faults, and highest amplitudes (yellow) occur in the structurally highest position (after [7]).

The prospective reservoir sands within the Mount Elbert target interval (base of permafrost to base of gas hydrate stability) within the Mount Elbert prospect include the "B", "C" and "D" sands of the Mikkelson Tongue of the Canning Formation. The pre-drill predictions for the D-sand were 14 m (46 ft) thick with 68% gas hydrate saturation. The pre-drill prediction for the C-sand was 21 m (70 ft) thick with 89% gas hydrate saturation. The B-sand was predicted to be water-bearing, with no gas hydrate expected to be present.

The Mount Elbert prospect, like all of the most promising MPU prospects, had not been penetrated by existing wells. In addition, existing reservoir data for MPU gas hydrate prospects was not well enough constrained to enable confident modeling of reservoir response to potential production testing options. Therefore, to further mitigate both the geologic and operational risks of a future long-term production test, it was decided to drill a stratigraphic test well to confirm reservoir occurrence, ground-truth the prospecting and assessment methodologies, and enable collection of additional reservoir data to support more robust and relevant modeling studies.

FIELD OPERATIONS

On February 3, 2007, the Mount Elbert Science Team and the crew of the Doyon 14 rig began a 22-day program of drilling, logging, coring, and transient pressure testing at the Mount Elbert site. Field operations were originally slated to occur in the winter of 2005/2006, but were delayed one year due to lack of rig availability.

To enable acquisition of high-quality core, log and MDT data in a vertical well, the well was drilled from a temporary ice pad constructed east of the existing "E-pad" and south of the existing "B-pad". An ice road was constructed southward from the B-pad to the well site (Figure 4). The well was drilled with water-based mud and with logging-while-drilling tools from surface and through the permafrost section with 12 ¼-inch bit. On February 8, 9 5/8-inch surface casing was set and successfully cemented just below the base of permafrost at a depth of 594 m (1,950 ft). This is an unusually shallow and cold casing depth for ANS operations. Just one of the unintended benefits of the Mount Elbert program was demonstration of the ability to set casing at this stratigraphic horizon, providing expanded drilling options for ANS operators.

The well was then drilled using a fit-for-purpose mineral oil-based drilling fluid (formulated by MI-SWACO). The primary purpose for this choice, which added both cost and additional operational complexities, was that the drilling fluid could be kept chilled at or below $0^{o}C$ to mitigate the potential for gas hydrate dissociation and hole destabilization and to promote core, log, and test data quality.

Coring Program

The well was continuously cored from the base of casing (594 m: 1,950 ft) to a depth of 760 m (2,494 ft) using Corion's wireline-retrievable coring system. In 23 total deployments, this system successfully recovered 131 m (430 ft) of high-quality 3-inch diameter core from 153 m (504 ft) of section (85% recovery efficiency).

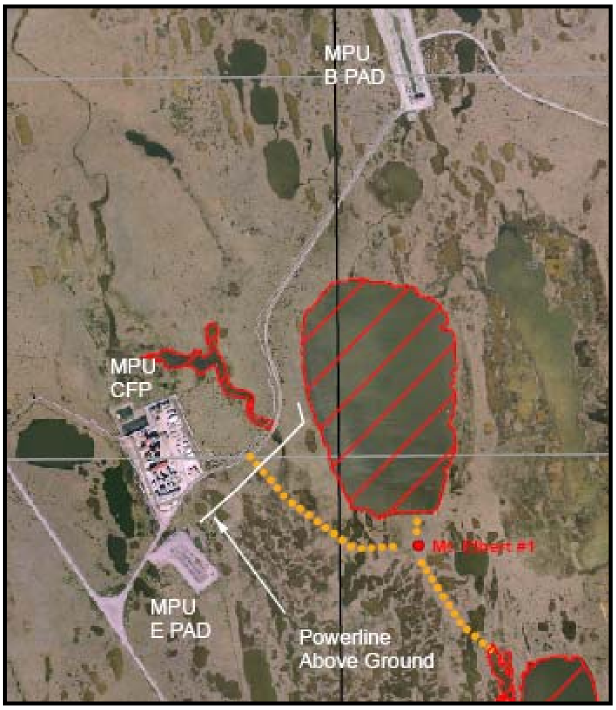

Figure 4. Location of Mount Elbert-01 stratigraphic test well relative to the MPU E- and B-pads and the Central Facilities Pad (CFP).

Initial core processing occurred in the Doyon 14's pipeshed, where the slotted aluminum core liner was retrieved and cut into a series of 3-foot lengths. The cores were then transported a short distance to an on-site, cold-temperature core processing trailer. During the coring operations, cores were likely outside pressure-temperature stability conditions for roughly 20 to 45 minutes.

In marine gas hydrate coring programs, gas hydrate-bearing intervals are identified through infra-red imaging of plastic core liners to identify cold spots related to gas hydrate dissociation. However, due to 1) the use of aluminum liners in ANS operations; 2) very poor core contact with the liners, and 3) very cold ambient temperatures in the core lab (typically from 4 – 15°F), IR imaging was employed. Instead, the core liners were removed, the cores scraped to remove the rind of drilling mud, and the cores visually described. Gas hydrate occurrence within the cores was readily indicated by several factors, including 1) substantial hydrate and ice cementation of the cored sediments such that sub-samples could only be taken with a mallet and heavy cleaver; 2) observation of gas release when small samples were immersed in water; and 3) evidence of progressive temperature decrease recorded on temperature probes inserted into the cores.

The science team collected a total of 261 whole round sub-samples during the field program (Figure 5). Of these, 204 samples from both hydrate-bearing and non-hydrate bearing zones were processed for post-field analysis of physical properties, microbiology, and gas geochemistry. Forty-six (46) samples were cleaned and squeezed at the well site to extract pore water samples for interstitial water geochemical analyses. The selection of oil-based drilling fluids provided good visual evidence of the extent of fluid invasion, and also ensured that all waters collected from the samples were formation waters.

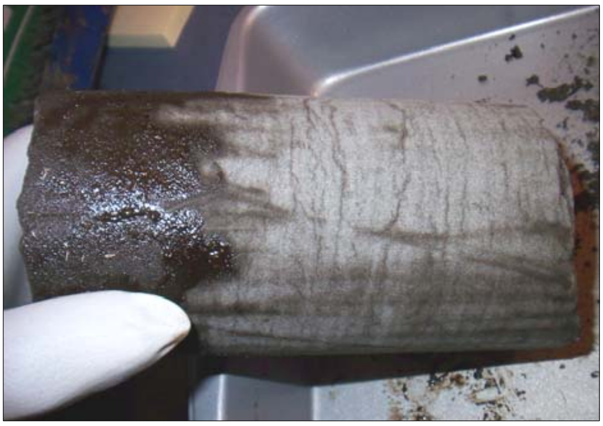

Figure 5. Whole round core sample of gas hydrate-bearing sand. Rind of oil-based mud coats the left end of the core.

Eleven hydrate-bearing samples were stored in liquid nitrogen or methane-charged pressure vessels to halt further gas hydrate dissociation. All of these cores were later converted to liquid nitrogen, and then shipped first to Lawrence Berkeley National Lab for CT imaging, then forwarded to a variety of laboratories in the USA and Canada for further advanced study.

The remainder of the core is half-slabbed and archived in Anchorage, Alaska. These cores have been scanned (high-resolution photography) and continue to be accessed for further study and sampling.

Wireline Logging Program

Upon the completion of the coring program, the hole was deepened to 914 m (3,000 ft), and reamed to a diameter of 8 ¾ inches. A full research-level wireline logging suite was collected with Schlumberger tools as follows:

Run 1: Platform Express (including gamma ray, resistivity, neutron porosity, lithodensity, electromagnetic propagation (EPT), and RT scanner logs)

Run 2: Dipole sonic imager (DSI) and oil-based micro imager (OBMI) logs

Run 3: Combinable magnetic resonance (CMR), elemental capture spectroscopy (ECS), and hostile environmental natural gamma ray (HNGS) logs.

Overall log quality was excellent. There were two failed attempts to collect the acoustic and microresistivity data (Run 2) that we have attributed primarily to the unusually cold borehole conditions. Caliper data indicate that the hole was almost entirely within one-inch of gauge throughout the section, and virtually fully in gauge within the primary gas hydrate bearing intervals. This outcome is due largely to the continued use of oil-based drilling fluid and successful chilling using DrillCool Inc.'s surface heat exchanger (Figure 6).

Wireline Pressure Transient Testing Program

The final phase of the Mount Elbert science program consisted of a series of tests with Schlumberger's Modular Formation Dynamics Test (MDT) tool. These tests were conducted in open-hole, and were designed to build upon the knowledge gained during cased-hole MDT tests conducted at the Mallik test site in 2002 [9].

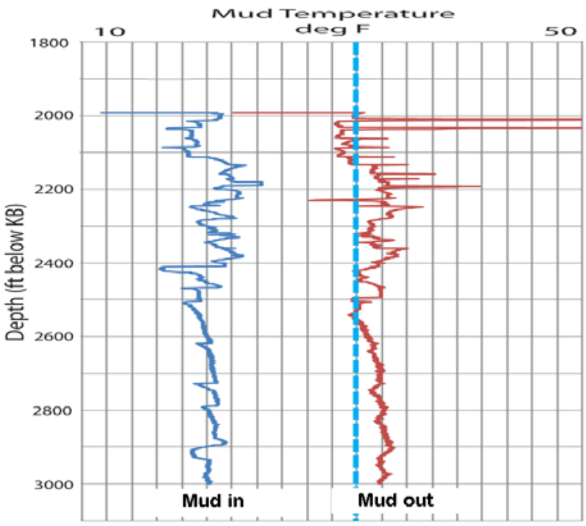

Figure 6. Recorded drilling mud temperature both entering the well (left) and exiting the well (right)

Analyses of the field log data, particularly the CMR data, resulted in the selection of four zones for testing (Figure 7); two in the C-sand (tests C1 and C2) and two in the D-sand (tests D1 and D2). Test zones were picked in an effort to isolate zones of high-gas hydrate saturation away from potential flow boundaries that could complicate the analysis of test results. Each test consisted of multiple stages of varying length, with each stage consisting of a period of fluid withdrawal (and accompanying depressurization) followed by pump-shut off and monitoring of subsequent pressure build-up (Figure 8).

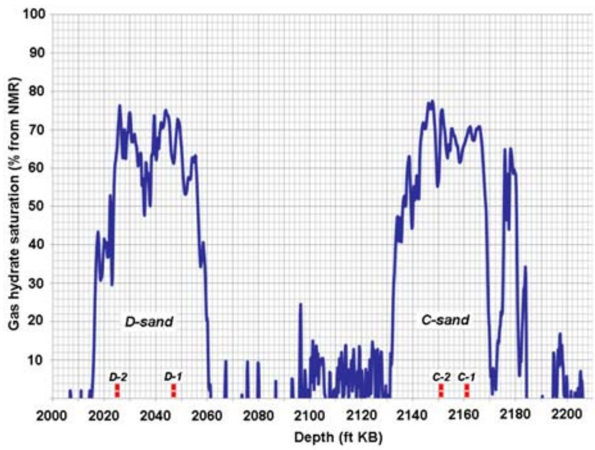

Figure 7. Gas hydrate saturation with depth based on magnetic resonance log data. Locations of MDT tests noted in red.

The MDT program included two types of tests. To investigate the petrophysical properties of the hydrate-saturated reservoirs, several stages were conducted in which pressure was reduced sufficiently to mobilize unbound formation water but not sufficiently to induce gas hydrate dissociation. To provide insight into reservoir behavior at a small scale in response to gas hydrate dissociation, numerous stages were conducted that produced pressure reduction sufficient for gas hydrate dissociation.

In addition to pressure data, both gas and water samples were also collected by the tool during the tests. Also, temperature data was collected by attaching a small pressure-temperature recorder within an iron pipe welded onto the outside of the MDT screen.

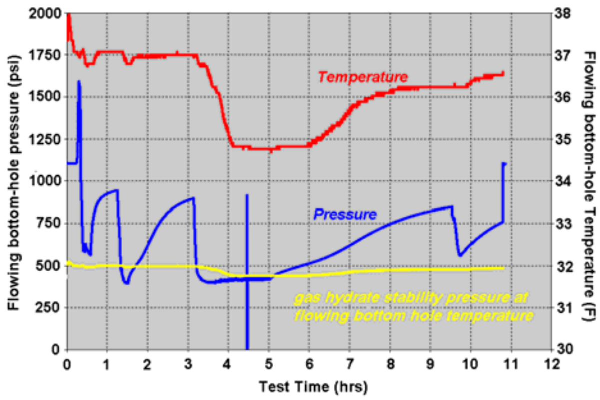

Figure 8. Plot of flowing bottom-hole pressure and temperature with time for the C-2 MDT test.

FINDINGS AND IMPLICATIONS

The Mount Elbert field program encountered roughly 100 ft of gas hydrate-bearing sands (Figure 9). The effort in the field and in ongoing study of recovered samples and datasets is producing one of the most comprehensive and integrated scientific datasets yet collected on a natural gas hydrate reservoir. In addition, the field operations at the Mount Elbert Site provided key insights into a number of operational and technological issues that are currently being integrated into planning for a potential long-term production test on the ANS.

Perhaps most fundamentally, the Mount Elbert field program demonstrated the ability to conduct safe, state-of-the-art research operations within shallow, poorly consolidated, and gas-hydrate-bearing sediments within the heart of an ANS producing field. This success is critical to enabling subsequent data collection including potential extended production testing. A critical component of this success was the choice to use an oil-based drilling fluid and the field engineer's success in maintaining the fluid temperature near or below 0^oC throughout the trip to the drill bit and back to the surface. The Mount Elbert program also included a number of technological milestones, including the first deployment of wireline-retrievable coring technology on the ANS; and the first open-hole pressure test within a gas hydrate reservoir.

Gas Hydrate Prospecting

The coring and logging program indicates that gas hydrates occurrence in the two target sands are in close conformance with pre-well predictions. Although total gas hydrate thicknesses and average reservoir saturations are still being analyzed and refined, initial data indicate that roughly 14 m (46 ft) of gas hydrate bearing sand at ~65% saturation (14 m and 69% predicted) in the D-sand. In the C-sand, the field values are 16 m (54 ft) and 65% saturation (21 m and 89% predicted). The B-sand was encountered with water saturation at 100%, as predicted (see Figure 9). This success is due in large part to accurate prediction of reservoir porosity and p-wave velocities enabled by access to well log data from offset wells [8]. The overestimation of both thickness and saturation in the C-sand is directly

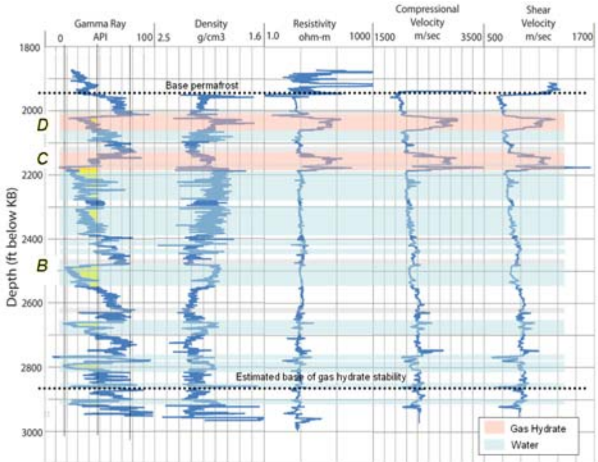

Figure 9. Log data showing occurrence of gas hydrate and water within reservoir quality sands in the Mount Elbert well

attributable to the occurrence of an anomalous thin, high-resistivity hard streak within the C-sand. The overall success of the pre-drill prediction confirms the soundness of the arctic gas hydrate exploration methodology that was used not only to select the Mount Elbert location and design the field program, but to also support more regional gas hydrate resource assessment.

Mount Elbert Gas Hydrate Reservoir Quality

Initial analysis of core samples indicates that the D and C-sands consist primarily of very fine grained, well sorted, and quartz-rich sandstones. Intrinsic permeabilities are likely very high, in the multiple Darcy range. Porosities are also high, averaging 38% in the D-sand and reaching 40% within the C-sand. In both zones, gas hydrate saturation is observed to vary between ~45% and ~75% in close association with changes in reservoir quality (porosity, and by extension, permeability).

The CMR log indicates the presence of mobile water, even in the most highly gas-hydrate saturated intervals, (as was also seen in data from the Mallik tests [9]). In the D-sand, mobile water may be 8 to 10% of total pore volume. In the C-sand, it appears to range upwards to 15%. The successful depressurization of the reservoir by fluid withdrawal during the MDT program confirms this observation. The presence of mobile water would appear to be a pre-requisite for initiation of the depressurization method for gas hydrate reservoirs that are not in direct contact with underlying free gas or water reservoirs.

The MDT test data from the stages that targeted fluid withdrawal without gas hydrate dissociation produced pressure responses that are typical of low-permeability porous media. Analysis of these test stages in a variety of advanced reservoir simulators [10] has enabled an estimate of 0.12 to 0.17 md for the in-situ effective permeability of the reservoir in the presence of the gas hydrate phase.

Gas hydrate dissociation and production was confirmed by gas monitoring and sampling during the MDT test stages that drew flowing bottom-hole pressures below the gas hydrate stability pressure. This was (at that time), only the second demonstration of production by depressurization. In these tests, three apparently linked phenomena were observed in the pressure transient data: 1) pressure build up was significantly dampened as compared to those in which gas hydrate was not dissociated; 2) that dampening increased in severity with progressive depressurization stages within a given test; and 3) the slope of the pressure build-up curve within any given stage steepened slightly, but consistently, as pressure increased beyond the original destabilization pressure. The physical cause of these features is not yet determined. Additional discussion and analysis of the Mount Elbert MDT testing program is provided elsewhere in these proceedings [10].

NEXT STEPS

Analyses of Mount Elbert core, log, and wireline pressure test data is ongoing. The data are being analyzed to provide further insight into a wide range of scientific and technical issues, including, 1) the controls on gas hydrate occurrence in nature, including relationships between Sgh and various physical properties of the enclosing porous media; 2) the development of gas hydrate accumulations as revealed by levels and nature of microbiological activity, gas geochemistry and inferred origin, and pore fluid geochemistry; and 3) the proper location and design of long-term production tests of gas hydrate reservoirs.

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