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Review

Scientific Results of the Hydrate-01 Stratigraphic Test Well Program, Western Prudhoe Bay Unit, Alaska North Slope

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ABSTRACT: The United States Department of Energy, the MH21-S Research Consortium of Japan, and the United States Geological Survey are collaborating to enable gas hydrate scientific drilling and extended-duration reservoir response testing on the Alaska North Slope. To feasibly execute such a test, a location is required that is accessible from existing roads and gravel pads and that can be occupied without disrupting ongoing industry operations. A review of potential locations meeting these criteria determined the likely occurrence of gas hydrate in two fine-grained marginal-marine sands of Tertiary age in the vicinity of the inactive "Kuparuk State 7-11-12" exploration pad in the western Prudhoe Bay Unit (PBU). Existing well and seismic data for that site were insufficient to preclude the potential for free gas occurrence within the deeper (and most prospective) target sand. Therefore, with support from the PBU Working Interest Owners, Alaska Department of Natural Resources, and Petrotechnical Resources Alaska, the Hydrate-01 Stratigraphic Test Well (STW) was drilled in December 2018 to confirm the suitability of the site for future gas hydrate scientific testing. The Hydrate-01 well was successfully drilled to −3290 ft (1003 m) subsea vertical depth at a bottom hole location of approximately 900 ft (∼275 m) east of the surface location. The drilling program featured acquisition of a full suite of logging while drilling data, the collection of side-wall pressure cores, and the installation of distributed temperature and distributed acoustic sensor fiber-optic cables. The log data acquired confirmed the occurrence of gas hydrate at high saturation in two target sands. Integrated evaluation of log and sidewall core data provide petrophysical and geomechanical property information that allow for potential reservoir response to depressurization to be simulated. The deeper "B1 sand" is deemed to be most favorable for reservoir response testing as a result of confirmed gas hydrate occurrence in sediments of high intrinsic permeability, location within 100 ft (30 m) of the base of gas hydrate stability, and minimal risk for direct communication with permeable water-bearing (hydrate-free) zones. The shallower "D1 sand" provides a secondary target that is differentiated by colder *in situ* temperatures and the interpreted direct hydraulic communication to a lower section of non-hydrate-bearing, water-saturated sand. The Hydrate-01 log data also confirm the occurrence of at least one sub-seismic fault in close proximity to the B1 sand reservoir. To better image the distribution of the gas-hydrate-bearing reservoir sections and associated faults, a three-dimensional (3D) vertical seismic profile was conducted in early 2019 using the distributed acoustic sensors installed as part of the Hydrate-01 STW completion. Detailed two-dimensional (2D) and 3D geologic models have been constructed to enable numerical simulations to inform the planning for potential future scientific tests of reservoir response to depressurization at the site.

■ INTRODUCTION

The evaluation of gas hydrate as a future energy resource relies on the ability to assess and simulate reservoir response under production conditions over extended production periods.[1,2] This effort has been supported by wide-ranging laboratory and numerical simulation activities[3,4] that are currently benefiting greatly from substantial investments to collect and analyze reservoir petrophysical and geomechanical properties from natural samples captured under *in situ* pressure conditions.[5,6] However, most critical to assessing potential reservoir deliverability are complex scientific field experiments that allow for the direct observation of the nature of the migrating depressurization front, the manner of heat transfer, the dynamic evolution of reservoir petrophysical and geomechanical properties, and the interactions between the reservoir and

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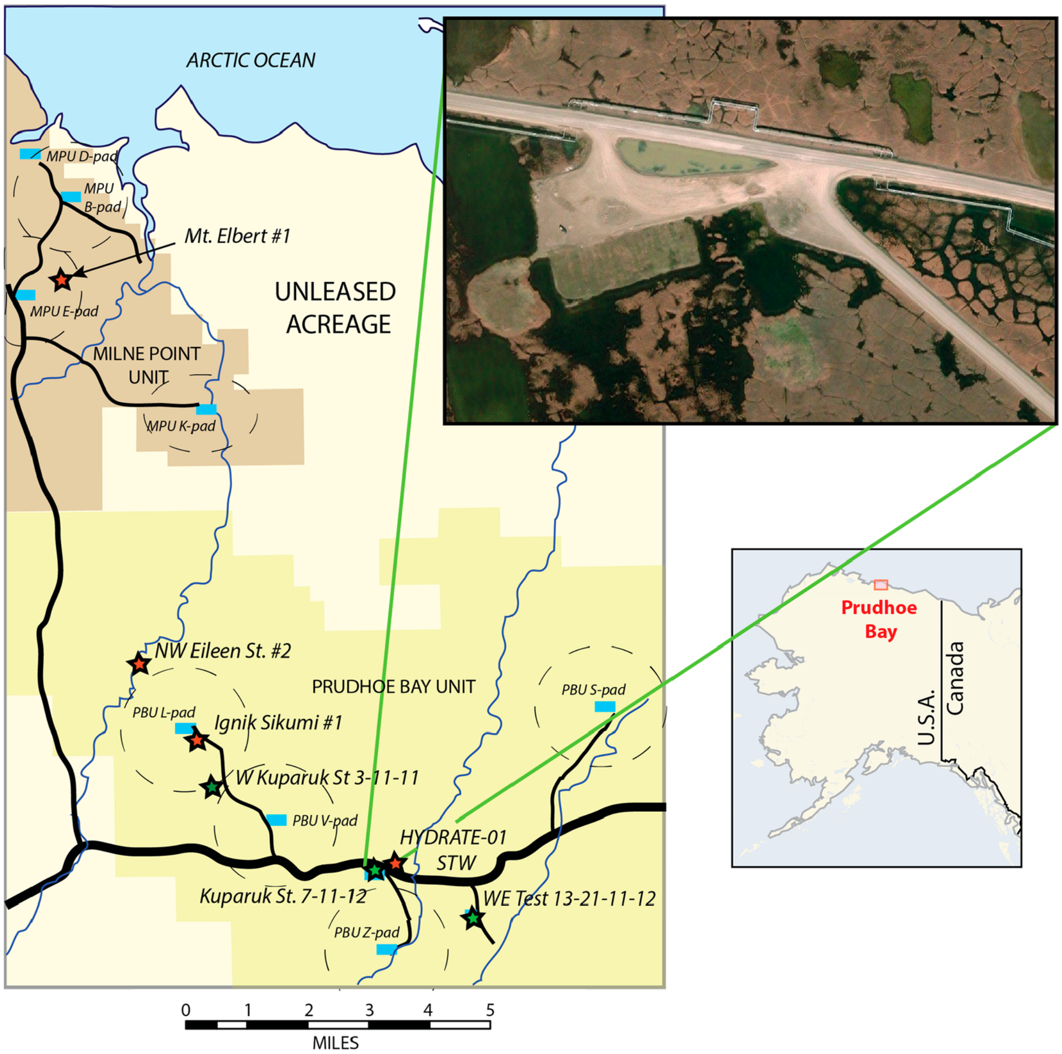

Figure 1. Location of gas hydrate research locations (red stars), unleased lands evaluated from 2014 to 2015 ("unleased acreage"), and primary production areas (blue boxes) within the greater Prudhoe Bay region on the Alaska North Slope. Locations of known gas hydrate occurrence outside the existing production pads are indicated by green stars. The upper right inset shows the existing gravel pad from which two exploratory wells were drilled, including the Kuparuk State 7-11-12. This pad was selected as the surface location for the Hydrate-01 well drilled in December 2018. This figure was modified with permission from ref 10. Copyright 2017 American Chemical Society.

the bounding formations within a gas hydrate reservoir undergoing induced dissociation. Reliable appraisal of potential productivity from gas hydrates will likely only be obtained through a series of fully monitored field experiments of increasing duration and complexity integrated with continuous calibration and validation of numerical simulations. Once the processes acting within producing hydrate reservoirs are more fully understood, production systems designed to optimize safe and sustained gas recovery for specific geologic conditions can be designed and demonstrated.

Field programs conducted onshore Canada,[7,8] onshore Alaska,[9,10] offshore Japan,[11,12] and offshore China[13,14] have confirmed that reservoir depressurization is the most promising foundation upon which to build viable production approaches. However, as a result of insufficient test duration, an inability to isolate long-term production response from potential transient phenomena, and various operational challenges, no tests to date have generated data to sufficiently constrain fundamental reservoir processes or to validate long-term production predictions.[15,16] At present, the most advanced long-term numerical simulations commonly show gradually increasing productivity over the first few years of production, whereas the available short-duration field tests typically show either stable or slowly declining well production rates that fall well short of expected commercial viability.[1] Therefore, a clear priority for gas hydrate resource evaluation is to conduct field experiments that allow for reservoir response to be monitored over a sufficient period of time to better understand the fundamental physical processes (including evolution of permeability, geomechanical response, and heat transfer) acting within a hydrate reservoir undergoing induced depressurization.

A closely related research priority is the identification and refinement of the most viable well designs that can achieve sustained production from gas hydrate reservoirs and be compatible with the required data acquisition needs. Such designs must address the issues of robust artificial lift across a range of flow rates, flow assurance, effective sand control, hydraulic isolation, and effective water and solids handling.[1,17]

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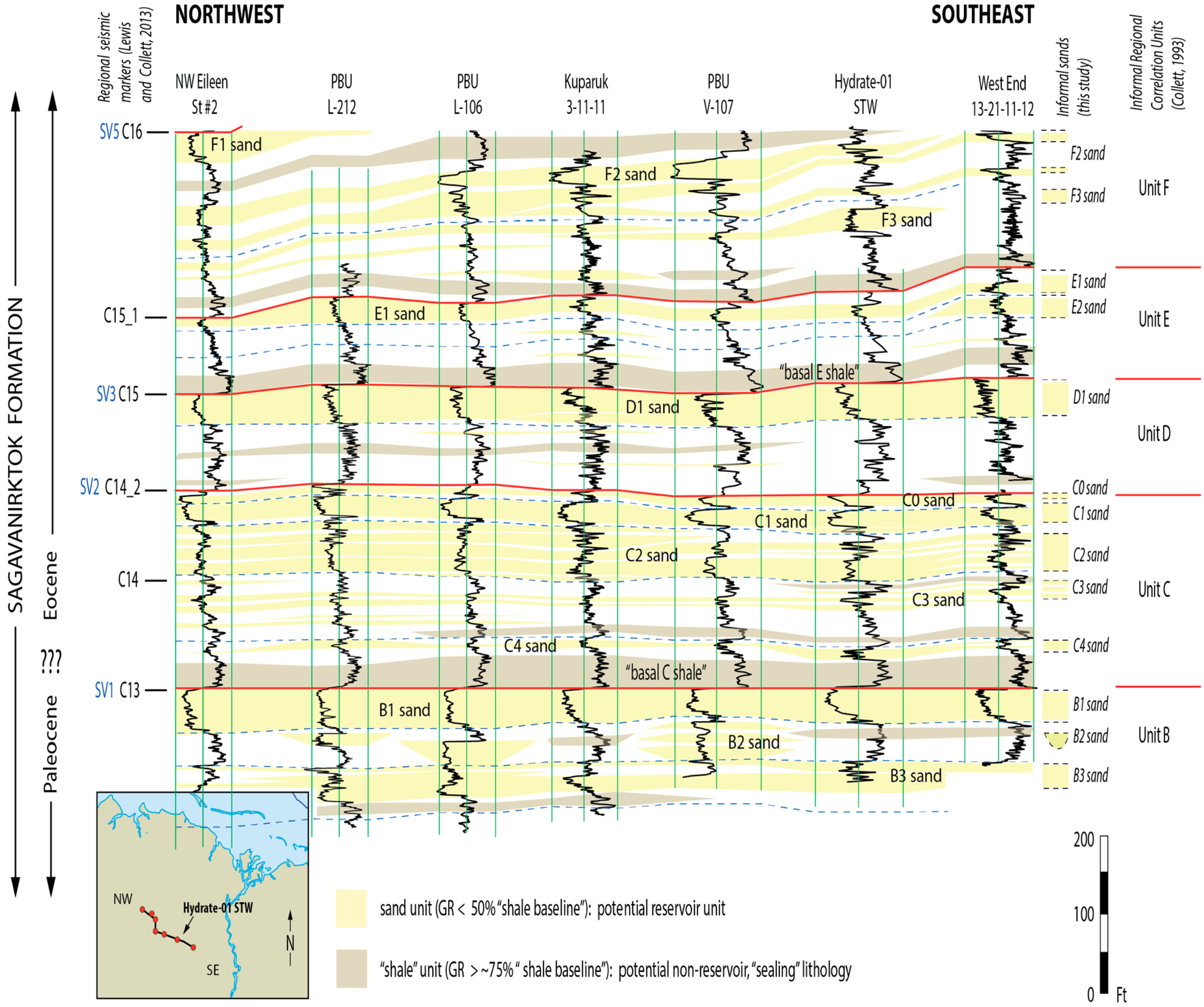

Figure 2. γ-ray well log cross section showing the correlation of geologic units (units B, C, D, E, and F) that are commonly gas-hydrate bearing in the western Prudhoe Bay Unit, Alaska North Slope, and were the primary targets for evaluation at the Hydrate-01 Stratigraphic Test Well. Informal terminology for sands and shales as used in the text are noted.

Critical to achieving these goals is access to a location where long-term testing can be feasibly conducted.[18] Key criteria for such a location include (1) confirmed gas hydrate accumulations of high reservoir quality (i.e., high gas hydrate saturation in a reservoir with high intrinsic porosity and permeability), (2) favorable reservoir containment[19] (i.e., competent bounding units that can inhibit vertical hydraulic communication to high-permeability water-bearing zones and sufficient lateral extent or occurrence of sealing faults or stratigraphic features that inhibit lateral hydraulic communication), and (3) a location onshore in an area of established industry field operations and support infrastructure that can support continuous operations over a period of a year or more. At present, the most favorable area to conduct such a test is within the known gas hydrate accumulations that reside within the established oil and gas production infrastructure of the Greater Prudhoe Bay infrastructure area region on the Alaska North Slope (ANS).

This report summarizes the effort to select and test via drilling, logging, and coring a site selected adjacent to a little-used exploration pad in the western portion of the Prudhoe Bay Unit (PBU). The reader is referred to the various papers in this Virtual Special Issue for further detail on the scientific findings obtained from data collected at the Hydrate-01 well.

■ GAS HYDRATES IN THE GREATER PRUDHOE BAY REGION

Many years of research on the ANS, leveraging data derived primarily from oil and gas exploration, have delineated two primary trends of gas hydrate occurrence within sand reservoirs: one is located in the western Prudhoe Bay and eastern Kuparuk River and Milne Point units called the "Eileen" trend, and a second located further to the west is known as the "Tarn" trend.[20] Beginning in 2000, the U.S. Department of Energy (DOE) has conducted a program designed to use the ANS as a natural laboratory for the evaluation of the resource potential of a gas hydrate. Because gas hydrate accumulations within the Eileen trend are very commonly observed below the base of ice-bearing permafrost and are coincident with the area of most extensive oil development and related log and seismic data collection, that area has been the primary focus of recent gas hydrate research. Eileen trend gas hydrates have previously been the subject of logging, coring, and testing by ARCO and Exxon in 1972 at the

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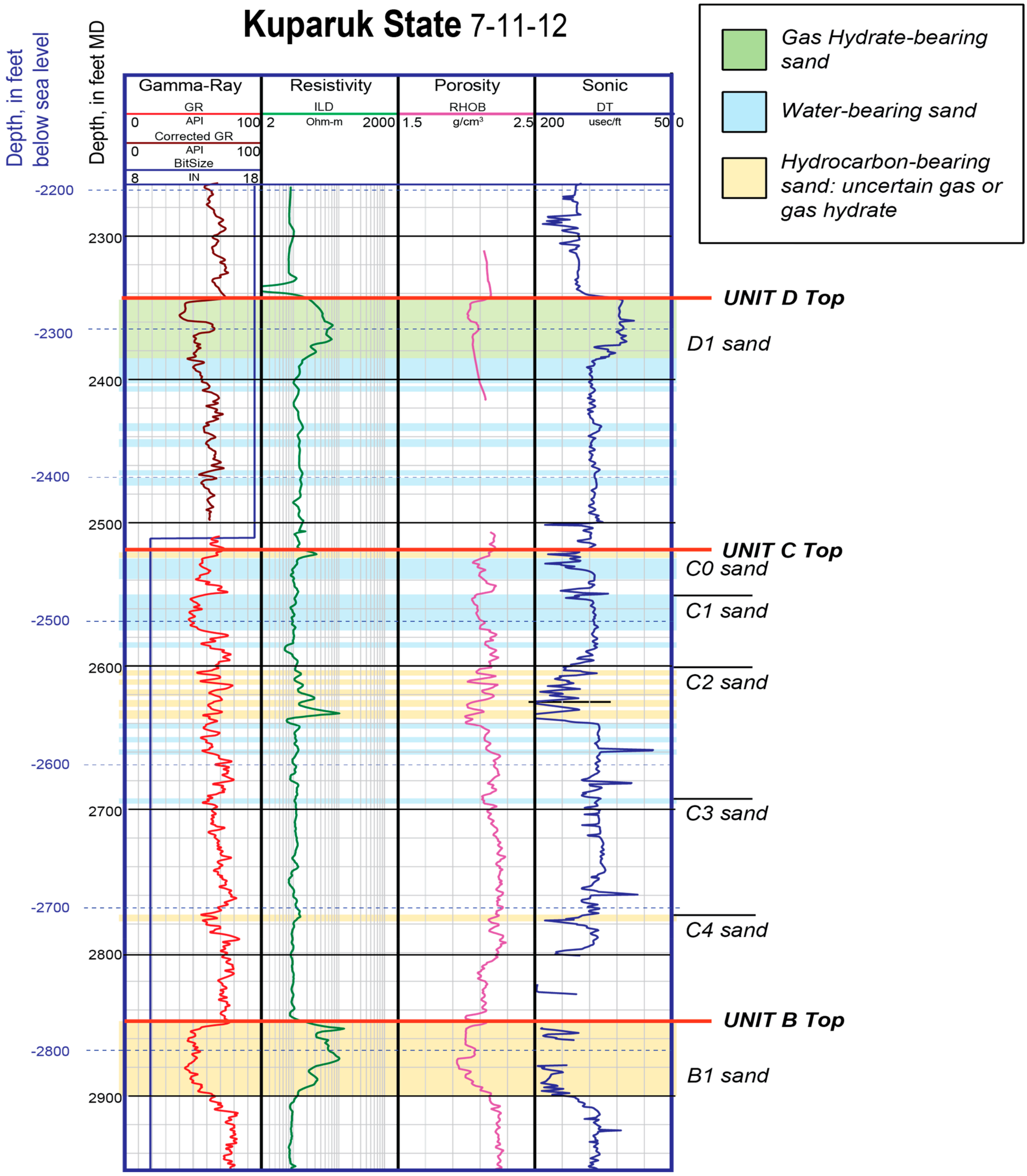

Figure 3. Log data from the 1978 Kuparuk State 7-11-12 well. The log data indicate gas hydrate in the D1 sand as indicated by high resistivity and high acoustic velocity. The C2 and B1 sands show elevated resistivity indicating hydrocarbon charge; however, low acoustic velocity indicates the presence of free gas. Subsequent drilling at the Hydrate-01 STW confirms prior interpretation that both units are hydrate-bearing and that observed gas is most likely related to drilling disturbance.[20]

Northwest Eileen State 2 well,[20] scientific programs at the Mt. Elbert 1 well in the Milne Point Unit (MPU) in 2007,[9,21] and drilling and testing at the Iġnik Sikumi 1 well in the western PBU in 2011/2012[10] (Figure 1).

With the increasing emergence of unconventional gas in the U.S. (circa 2013), industry views regarding collaboration on scientific investigations within the PBU have evolved. With the support of the Alaska Department of Natural Resource (DNR), the U.S. DOE, Japan's MH21-S R&D Consortium and the U.S. Geological Survey conducted a geological/ geophysical review of unleased and undeveloped lands north of the PBU and to the east of the MPU (Figure 1) to determine their suitability for the desired field investigations.[22] While several potential drilling locations were identified, log data were not available to evaluate the occurrence of potential reservoirs or gas hydrates, resulting in high geologic risk. More importantly, the lack of roads and other infrastructure within the unleased area imposed untenable logistical and operational costs and risks. On the basis of these findings, in 2015, the DNR engaged the PBU Working Interest Owners (WIOs) and reached an agreement that locations within the Prudhoe Bay and adjacent units could once again be considered for scientific field programs assuming a location was selected where scientific activities would not interfere with ongoing industry operations. This criterion necessitated a location featuring a gravel pad in good condition and access to roads but with no ongoing oil and gas operations.

In collaboration with DNR and PBU WIOs, the project team reviewed existing well log and seismic data to identify potential test site locations within the Eileen trend. The primary hydrate-bearing intervals of the Eileen trend occur within the largely non-marine and sand-rich Sagavanirktok Formation (Eocene to Paleocene age; Figure 2). This interval marks a period of increased marine influence within the Sagavanirktok Formation that is represented by the Mikkelson Tongue of the Canning Formation to the east.[23,24] In contrast to the thick and laterally discontinuous sands with blocky γ-ray signatures that characterize the bulk of the Sagavanirktok Formation, this section is noted by the occurrence of repetitive cycles of "cleaning-upward" trends on γ-ray logs. Each primary cycle is designated as an informal unit (units A−F);[20] individual sand units are herein designated with reference to the informal unit in which they occur ("D1 sand", etc.; Figure 2). Units C−F are characterized at the base by a transgressive marine flooding surface, overlain by a regressive section, including increasing occurrence and thickness of sand-rich units, and capped by a relatively massive progradational marginal-marine sand.[25] The architecture is similar in the older units A and B; however, increased non-marine influence in these intervals is indicated by the occurrence of massive sands with localized channel morphology and increased lateral heterogeneity.[18,26] The highest quality reservoir units are characteristically very well-sorted fine-grained sands to coarse silts.[27] Detailed petrophysical work conducted on samples acquired in the Milne Point Unit indicates that the reservoir quality of these sand units is highly sensitive to even modest local reductions in grain size or to increase in the shale content.[28]

The Eileen trend occurs along a monocline of approximately 2−3° eastward dip. The area is dominated by a series of normal faults with overall north−south trend.[20] Faults vary between down-to-the-east and down-to-the-west geometries, creating local horst and graben structures. The largest faults are likely migration pathways for deeper thermogenic and microbially altered thermogenic hydrocarbons leaking from the underlying Prudhoe Bay field into the shallow section.[29,30] Four-way structural closures are not common and small in scale. The occurrence of laterally extensive, fine-grained, and laterally variable sand reservoirs coupled with overlying potential seals and abundant normal faulting provides conditions that allowed for complex stratigraphic structural entrapment of hydrocarbons within units B, C, D, and E within the Milne Point Field[31] and is a likely condition throughout the greater PBU region.

■ SITE SELECTION

Examination of well and seismic data throughout the Milne Point, Kuparuk River, and western Prudhoe Bay units has identified numerous wells with evidence for one or more gas-hydrate-bearing sands.[20] However, only three exploration well locations, the West Kuparuk State 3-11-11, the Kuparuk State 7-11-12, and West End Test 13-21-11-12 (Figure 1), occur in association with existing gravel pad and road infrastructure that lack ongoing production operations. The 3-11-11 site was dismissed from consideration because the gravel has since been removed and the site revegetated. The condition of the existing gravel at the 13-21-11-12 site was more favorable; however, gas hydrate was indicated in log data (porosity and resistivity only) for one zone only (the B1 sand) and lacked confirmation from high-quality sonic data. The 7-11-12 site included an existing gravel pad in good condition with two exploration wells (drilled in the 1970s and abandoned since the 1980s). In the 7-11-12 well, both the D1, C2, and B1 sands exhibit low γ-ray, high porosity, and high resistivity (Figure 3). High sonic velocity in the D1 sand provides compelling evidence for gas hydrate as a primary pore fill; however, as with the 13-21-11-12 well data, poor sonic log quality (including cycle skipping) and generally low velocities indicate the likely presence of free gas in the C2 and B1 sands during logging operations. A review of the drilling history of the well indicated that a probable cause for that gas was destabilization of gas hydrate as a result of drilling disturbance compounded by an extended interval of 19 days between drilling and logging below unit D.[22] A second well from the pad (Chevron 18-11-12) contains log data only from the lower part of the C3 sand and below and shows the B1 sand in similar condition to the 7-11-12 well. While the C2 sand is clearly within the gas hydrate stability zone at the 7-11-12 location, regional analysis of temperature well logs indicated that the B1 sand is likely within ~100 ft (30 m) of the base of gas hydrate stability,[25] and hence, some risk remained that the B1 sand may be free-gas-bearing and not hydrate-bearing at the site.

A review of proprietary seismic data enabled by the PBU WIOs and DNR indicated that the occurrence of prospective gas hydrate in the D1 and B1 sands extended from the 7-11-12 well throughout a larger region bounded by arcuate, north−south trending, normal faults with large displacement (~100 ft; 30 m).[26] While the data suggested potential for smaller faults within this structure, none were clearly imaged with the available seismic data. Overall, the data indicated minimal structural elevation change over a broad area extending approximately 2000 feet (~610 m) to the east−northeast of the 7-11-12 well. Geophysical response (seismic phase and amplitude) at the interpreted top of the D1 sand remained relatively consistent throughout much of the fault-bounded structure, suggesting consistent and widespread gas hydrate occurrence and saturation.[26] Geophysical interpretations related to the deeper B1 sand were less certain with respect to both the potential for additional faulting as well as any evidence for potential pore fill change (transition from hydrate to free gas) within the area. Consequently, the 7-11-12 location was selected as the site for potential extended duration reservoir testing, with the deeper and warmer B1 sand as the primary target and the shallower D1 sand providing additional testing flexibility. Primarily as a result of the uncertainty regarding free gas or gas hydrate occurrence in the B1 sand (and also to uncertainty in geologic structures), the project

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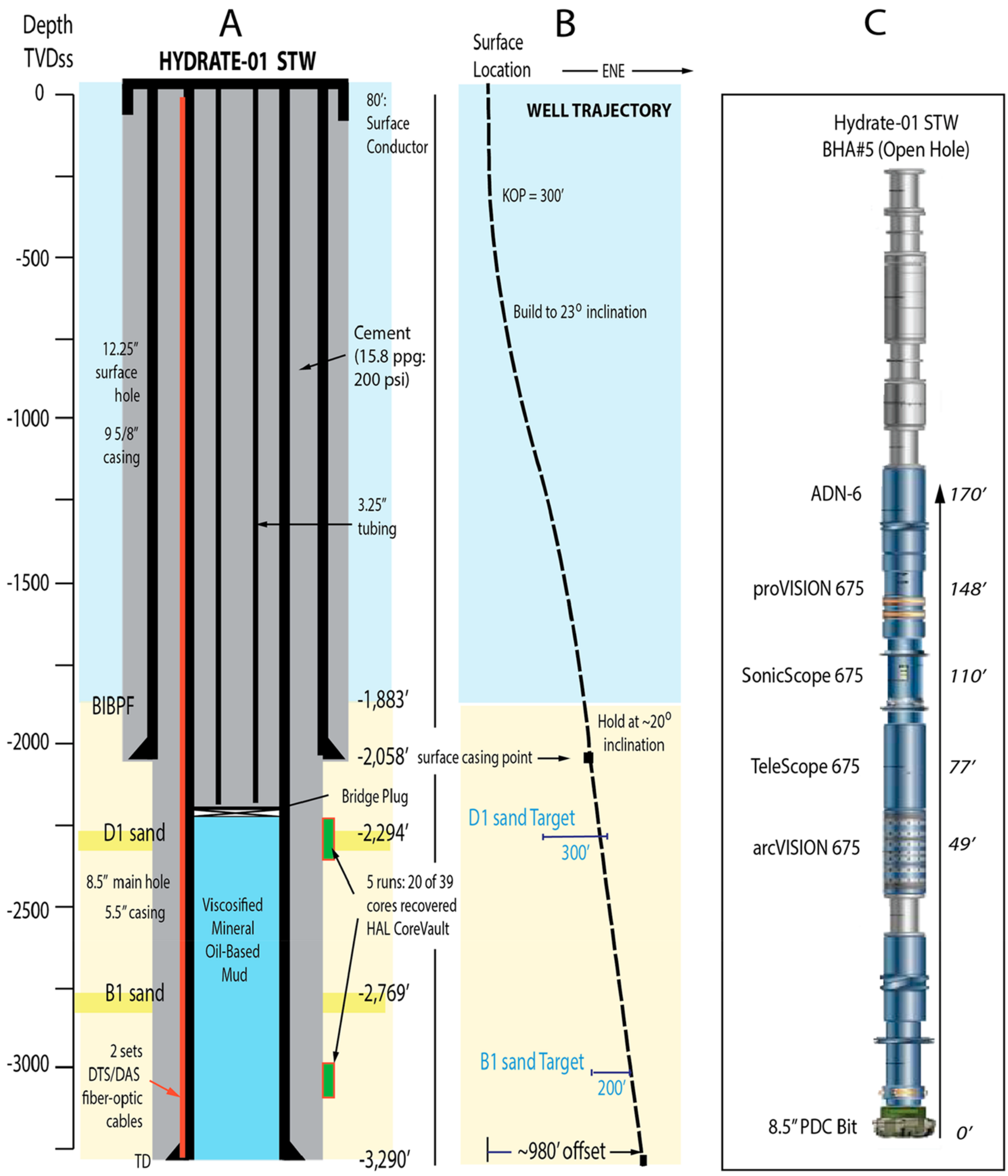

Figure 4. (A) Schematic of Hydrate-01 Stratigraphic Test Well. (B) Well trajectory showing the kick-off point (KOP), base of 9 $^{5}/_{8}$ in. surface casing, bottom hole location, and reservoir target tolerances. The permafrost section is denoted by a blue color. (C) Logging-while-drilling bottom-hole assembly used to gather primary well data through the main (reservoir) section. Depths are feet in subsea Total Vertical Depth (TVDss).

partners elected to drill an initial Stratigraphic Test Well (STW) to confirm the occurrence of gas hydrate and to provide necessary data to enable the planning for testing operations. The target location for the B1 sand at the Hydrate-01 STW was set as a circle of radius 200′ (61 m) centered approximately 720 ft (219 m) east of the B1 sand penetration in the 7-11-12 well (Figure 4). At that location, the geophysical interpretation anticipated B1 at −2786 ft (−849 m) true vertical depth subsea (TVDss) or roughly 6 ft (2 m) structurally lower than encountered in the 7-11-12 well. In addition to optimal positioning from a geologic standpoint, offset from the existing exploratory wells also served to minimize the risk that the presence of those wells within the dissociation radius of a future test would complicate operations or data interpretation.

■ HYDRATE-01 STRATIGRAPHIC TEST WELL RESULTS

Project Objectives. The primary goals of the Hydrate-01 STW drilling program were to (1) gather logging-while-drilling data (Figure 4 shows the bottom-hole assembly deployed in the well) sufficient to confirm the occurrence, thickness, saturation, and temperature of gas hydrate within the primary target (B1 sand) and secondary target (D1 sand) as well as other stratigraphic sections of interest (such as various sands within unit C), (2) acquire physical samples of all reservoir targets and bounding units to obtain, at a minimum, grain size

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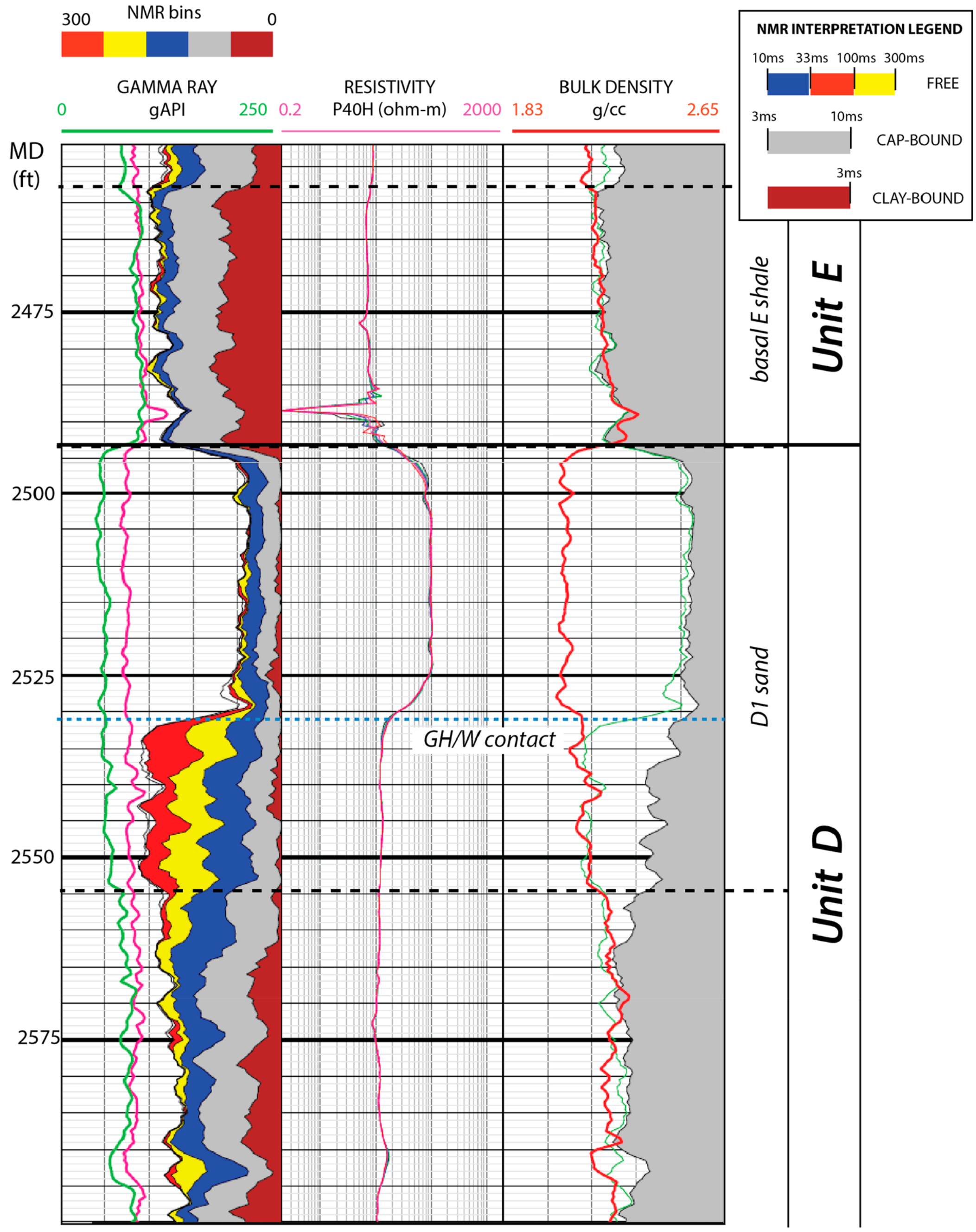

Figure 5. Nuclear resonance (proVISION) log data across the D sand of the Hydrate-01 Stratigraphic Test Well. The section is divided into four intervals, for which average petrophysical data are shown. Depths are in feet Measured Depth (MD).

data needed to support the design of sand control and other systems for the potential production test well, and (3) gain further experience and insight into the most effective gas hydrate well drilling and data acquisition systems. Upon successful demonstration of reservoir occurrence, the Hydrate-01 STW would be completed and temporarily abandoned with two sets of installed fiber-optic distributed temperature sensor (DTS) and distributed acoustic sensor (DAS), so that it could serve as a monitoring well for future reservoir response experiments.

Operations. The Hydrate-01 STW was spud on December 10, 2018 by BP Exploration (Alaska), Inc. from the Parker Drilling 272 rig. Careful attention to borehole mud temperatures within the large and fully enclosed rig were ultimately successful in limiting gas hydrate dissociation during drilling, resulting in a nearly in-gauge borehole and the acquisition of high-quality logging-while-drilling (LWD) data through the primary reservoir section.[32] Operations also included acquisition of sidewall pressure cores[27] and the installation of fiber-optic DTS and DAS.[32] After the drilling, the DAS cables were used for the acquisition of a large-scale DAS three-dimensional (3D) vertical seismic profile (VSP) survey[26,33] and to collect ongoing time-series temperature profiles along the length of the Hydrate-01 STW.[32]

Occurrence of Gas Hydrate. Logging-while-drilling data confirm the top of unit D, also marking the top of the D1 sand, at 2494 ft (760 m) measured depth (MD) [−2294 ft (−699 m) TVDss], 19 ft (6 m) lower than pre-drill projections

Table 1. Summary of Well-Log-Derived Depths and Estimated Petrophysical Properties of the Major Sands and Shales within the Hydrate-01 Stratigraphic Test Well

interval	top (ft) (MD)	thickness (ft) (MD)	thickness (ft) (TVDss)	average porosity (%)	average S_{gh} (%)	water clay bound (%)	water capillary bound (%)	water free (%)
"basal E shale"	2466	28	27	28.6	0.0	46	44	10
D1 sand (hydrate)	2494	37	35	39.5	74.3	9	41	50
lower D1 sand	2531	24	22	33.4	0.0	3	20	77
C0 sand (hydrate)	2680	5	4	40.0	54.9	11	14	75
lower C0 sand	2685	14	13	35.3	0.0	1	13	86
C1 sand	2705	41	39	35.9	0.0	4	14	82
C2 sand	2759	66	61	33.8	0.0	8	21	71
C3 sand	2853	25	23	32.3	0.0	14	18	68
C4 sand	2945	2	2	29.2	0.0	17	23	60
"basal C shale"	2957	46	43	25.3	0.0	47	37	16
upper B1 sand	3002	29	27	42.3	82.3	14	39	47
lower B1 sand	3064	33	31	34.2	47.7	13	35	52

(Figure 5). The upper 37 ft MD (11.2 m) of the sand is relatively homogeneous, with density porosity averaging ~39.5% (Figure 5 and Table 1). Resistivity is consistent at about 100 Ω m and shows no significant separation between the various resistivity log readings at different depths of investigations. A comparison of density porosity and nuclear magnetic resonance (NMR) porosity indicates that gas hydrate saturation throughout the upper part of the D1 sand is ~74%. NMR data also indicate that the remaining 26% water content is roughly distributed as 49% bound water and 51% free water based on free to bound water transverse relaxation time (T2) cutoff at 10 ms.[26] The NMR interpretation method continues to be refined as additional opportunities are realized to validate and calibrate the T2 cutoffs in the specific conditions posed by hydrate-bearing sands.

The lower 24 ft (7.3 m) MD of the D1 sand exhibits a gradual decrease in porosity and increase in γ-ray with increasing depth. However, despite the generally gradual apparent change in reservoir quality, NMR and resistivity data show a sharp transition (at ~2531 ft; 771 m MD) in pore fill from high gas hydrate saturation to 100% water saturation. Reservoir quality within the lower D1 sand remains high, as evidenced by the high percentage (~75%) of mobile water. Prior studies have shown similar gas hydrate/water contacts within a given reservoir,[19] and it remains uncertain whether such interfaces are due to partial reservoir charge (insufficient gas supply), some potential manifestation of the conversion of free gas accumulations to gas hydrate,[34] or a result of subtle petrophysical controls on hydrate occurrence within fine-grained reservoirs.[28] Regardless of cause, the lower portion of the D1 sand represents a large source of mobile water, which is assumed to be in full hydraulic communication with the upper, gas-hydrate-bearing zone. The basal E shale directly overlying the D1 sand exhibits an average porosity of 30%, with 18% of the water thought to be mobile based on NMR log analysis.

The top of unit C was encountered at 2680 ft (817 m) MD [−2469 ft (−753 m) TVDss] in the Hydrate-01 STW. Gas hydrate in unit C is limited to a single thin zone 5 ft (1.5 m) thick with 55% calculated saturation in the C0 sand (consistent with a likely occurrence in the 7-11-12 well). The C1 sand, which is the most porous and permeable sand in unit C, is hydrate-bearing widely across the Eileen trend and was the target of reservoir testing in the Iġnik Sikumi well.[10] However, the C1 sand was found to contain no hydrate in either the 7-11-12 well or the Hydrate-01 STW. The more thinly bedded C2 sands contain a partial gas hydrate occurrence in the 7-11-12 well (the C2 sand is partially filled with gas hydrate in the Iġnik Sikumi well[10]) but are fully water-saturated at the Hydate-01 STW. The C3 and C4 sands are of low comparative reservoir quality (Table 1) and contain no hydrate in either the 7-11-12 well or the Hydrate-01 STW (Figure 6). Explanation for the difference in pore fill within the C3 sand between the 7-11-12 and Hydrate-01 STW is uncertain and may include stratigraphic variation as well as potential trapping against a small fault that is discussed in the following section.

The B1 sand (top of unit B) was encountered at 3002 ft (915 m) MD [−2770 ft (−844 m) TVDss], 16 ft (5 m) above pre-drill projections. The sand appears massive and homogeneous to a depth of 3031 ft (924 m) MD (Figure 6). Similar to the D1 sand, the B1 sand appears slightly cleaner and more massive than indicated in the lower quality 7-11-12 log data. The upper 29 ft (8.8 m) of the B1 sand has an average porosity of 42% and an average resistivity of ~100 Ω m. On the basis of a comparison of NMR and density porosity, the average gas hydrate saturation is 82.3%. There is a thin layer within the upper 7 ft (2 m) of the unit of elevated resistivity (up to 250 Ω m) in those tools with greater depths of investigation. NMR analyses indicates 47% of the water within the upper portion of the B sand as free water.[26] Bound water is inferred to be primarily capillary-bound.

The lower 33 ft (10 m) of the B1 sand [to a depth of 3064 ft (934 m) MD] shows a gradual decrease in reservoir quality (reduced porosity and increased γ-ray indicating higher shale content) that is matched by a similar decrease in well-log-inferred gas hydrate saturation. The average gas hydrate saturation is 47.7%. The lack of significant increasing free water with greatly decreasing hydrate saturation toward the base of the unit indicates that the reservoir is likely fully charged with gas hydrate throughout, with the degree of gas hydrate saturation being primarily controlled by the decreasing petrophysical capacity of the reservoir with depth.[35] The basal C shale unit above the B1 sand has consistent porosity of 25% (4% less than the porosities observed above the D sand), with 72% of the water bound and 28% of the water free based on interpretation of NMR data.

The DTS cables indicate that the reservoir temperature at the top of unit D is ~40.6 °F (~4.8 °C) and at the top of unit B is ~50 °F (10 °C). Assuming methane-rich gas and low-

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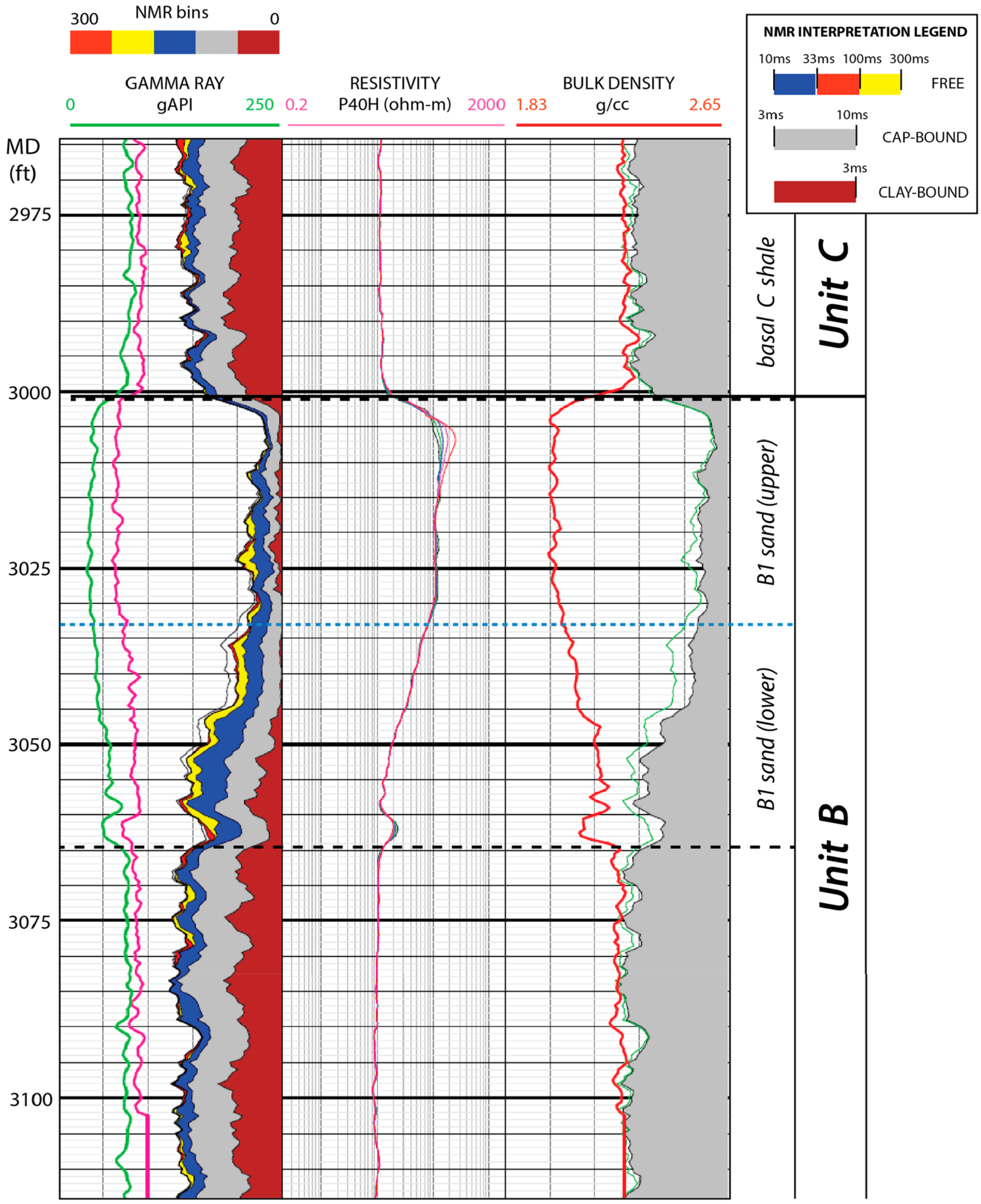

Figure 6. Nuclear resonance (proVISION) log data across B sand in the Hydrate-01 Stratigraphic Test Well. The section is divided into four intervals, for which average petrophysical data are provided.

salinity water chemistries that are typical of the shallow ANS stratigraphic section,[18] the base of gas hydrate stability is likely to occur from 50 to 100 ft below the base of the B1 sand. An additional package of thin sands (B3 sand) was encountered at 3130 ft (954 m) MD, with resistivity response indicating potential hydrocarbon fill. Only partial sonic data were acquired through this interval, and it is not conclusively known if these sands host hydrate, free gas, oil, or some combination.[32]

Faulting. As noted above, the top of unit D was encountered 19 ft (6 m) below pre-drill projections. The various unit C sands were similarly found ~15 ft (5 m) below projections. However, the top of the B1 sand (top of unit B) was encountered 16 ft (5 m) above projection. A comparison of well data in true vertical depth (Figure 7) between the 7-11-12 well and the Hydrate-01 STW indicates the loss of ~25 ft (7.6 m) of section at a level just above the B1 sand. There is no evidence of stratigraphic heterogeneity in the section that could explain this observation. The simplest interpretation is that the Hydrate-01 STW was drilled on the downthrown side of a normal fault through the entirety of the D and C units. This fault was not noted in the pre-drill interpretation. The well likely crossed this fault, passing from hanging wall into footwall, at ~3000 ft (914.4 m) MD just above unit B (Figure 8). It is possible that multiple faults within the basal C shale account for this missing section. It is also possible that some small portion of the uppermost B1 sand is removed at the STW location by this fault, but if so, this is inferred to be

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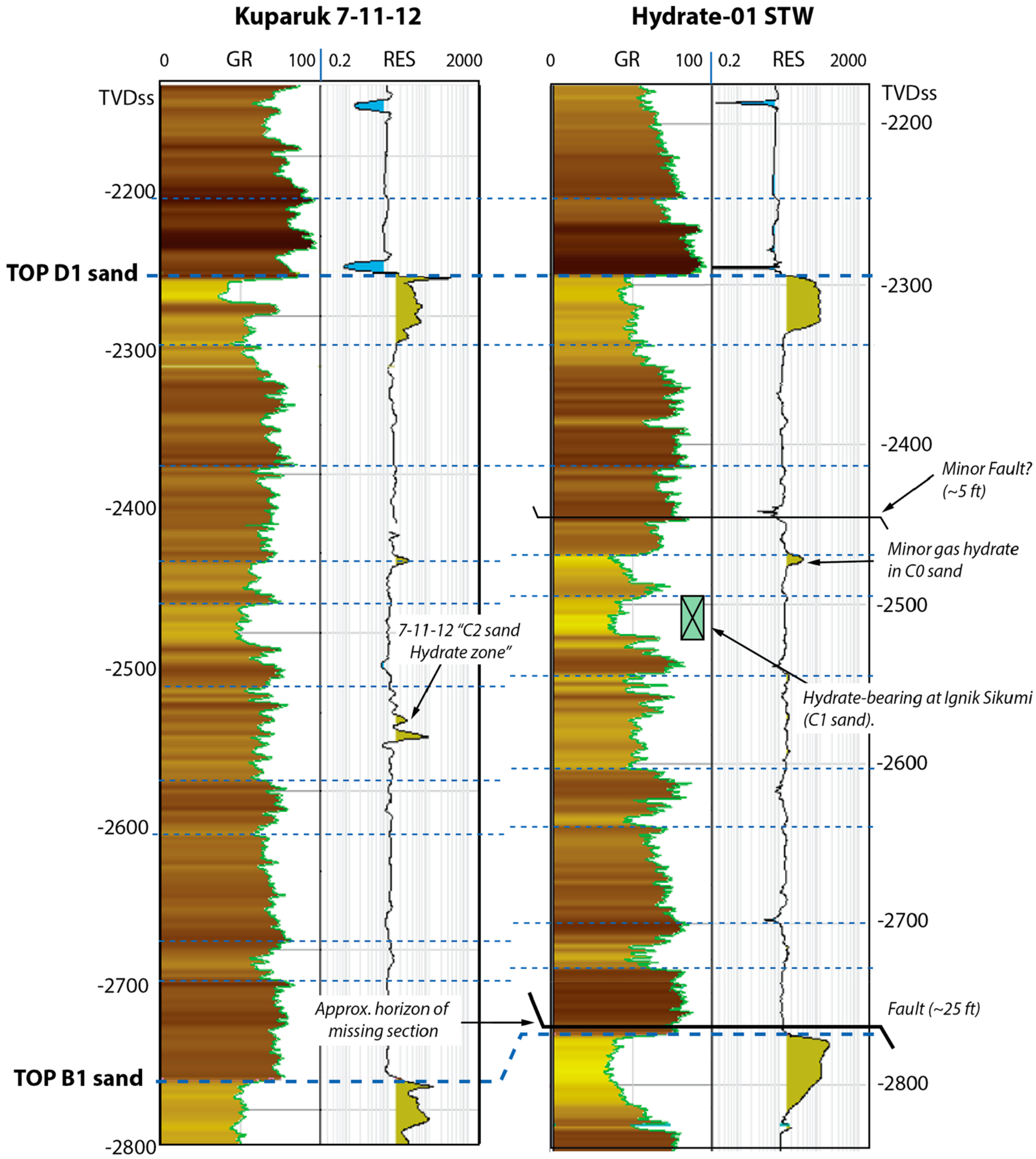

Figure 7. Comparison of γ-ray and resistivity log data for the 7-11-12 well and Hydrate-01 Stratigraphic Test Well. Both displays are converted to total vertical depth (in feet) relative to sea level. An estimated 25 ft (7.6 m) of section present in the 7-11-12 well is missing directly above the B1 sand in the Hydrate-01 Stratigraphic Test Well, indicating the presence of a fault. A smaller fault may also be present near the top of unit C.

minimal. Detailed correlation also suggests that a second minor fault (perhaps 5 ft of displacement) may occur within unit C. It is not clear where this minor fault may occur but could be coincident with a resistivity spike at 2651 ft (808 m) MD.

There is little evidence in the log data to determine fault orientation, and the faults observed in the Hydrate-01 well are not readily apparent in the surface seismic data.[26] It is likely that the larger faults conform with the general north−south orientation of major faults in the area; however, a wide range of orientations are likely for potential networks of small offset faults within the larger structure.[26] High-resolution 3D VSP data acquired after drilling and using DAS cables included in the Hydrate-01 STW completion confirm the continuity of the B1 sand between the 7-11-12 well and Hydrate-01 STW and provide good evidence for orientation of the larger fault encountered in the well just above the B1 sand as a down-to-the-east normal fault (Figure 9).[26,33,36] Given this interpretation, the fault (if it extends sufficiently far upward) offsets both the C unit sands and the D1 sand between the 7-11-12 well and Hydrate-01 STW locations. The similarity in pore fill between these two penetrations provides no evidence that the fault forms a lateral barrier to hydraulic communication within the D1 sand. However, the fault [in addition to the ∼15 ft (5 m) elevation difference] is a potential explanation for the different pore fill within the C2 sand in the 7-11-12 well and Hydrate-01 STW. Because the fault offset is less than the thickness of the B1 sand, it is interpreted that the fault is not likely to be a lateral flow barrier within the B1 sand. Figure 10 provides a post-drill interpretation of the structure present in the area.

Petrophysical Data. The collection of grain size data within the D1 and B1 sands in the Hydrate-01 STW was needed to support planning for subsequent test wells (particularly the design of sand control systems). Given the

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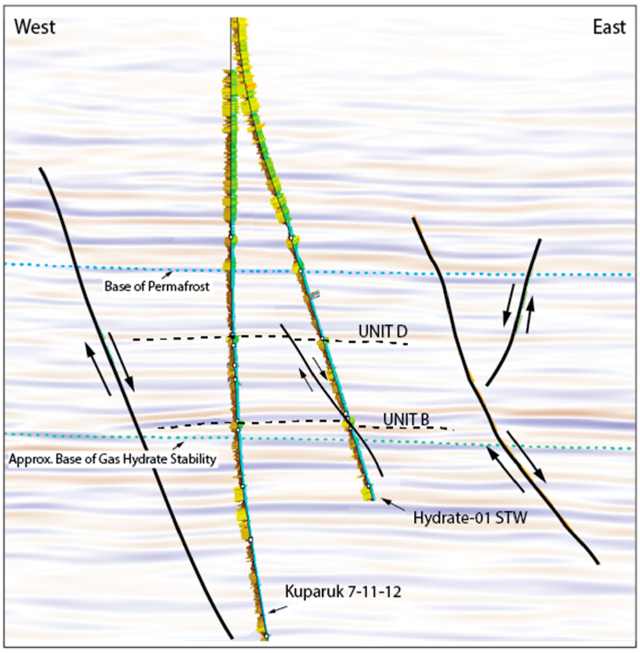

Figure 8. West to east surface reflection seismic line in the vicinity of the 7-11-12 well and the Hydrate-01 Stratigraphic Test Well in the western Prudhoe Bay Unit, with interpreted fault geometries and overlay of γ-ray log data for both wells. The base of ice-bearing permafrost and interpreted base of gas hydrate stability are also noted.

unconsolidated nature of the units and the possible loss of conventional side-wall core samples with hydrate dissociation upon retrieval, the acquisition of sidewall pressure cores was required. Halliburton's CoreVault system was deployed to collect samples from both the reservoir and the bounding sections.[27,32] The mean particle size within the D1 sand ranged from 40 to 60 μm (sandy silt). The B1 sand is coarser grained, with particle sizes commonly ranging from 70 to 100 μm (silty sand to very fine sand). The primary reservoir portions of both units are generally well-sorted, with clay size fractions commonly 10% or less.[27]

Intrinsic permeabilities (with hydrate removed) in the D1 sand average ~400 mD, while the intrinsic permeabilities in the B1 sand average ~1000 mD.[27] No devices exist that would enable the direct transfer of side-wall pressure core samples into storage/transportation vessels for later detailed analysis while being maintained under pressure. However, the development of rapid depressurization and liquid nitrogen supported core sample freezing processing techniques[27] resulted in outstanding sample preservation, allowing for a range of petrophysical measurements in the presence of gas hydrate. Notably, *in situ* effective permeabilities measured were ~10 mD in the D1 sand and ~30 mD in the B1 sand,[37] which are consistent with measurements obtained from gas-hydrate-bearing sand samples acquired both offshore Japan[38] and India.[39] However, application of standard methods of NMR analyses alternatively suggests low values (on the order of 0.1 mD) associated with the reservoir sections,[26] consistent with prior analyses conducted using NMR data on the Alaska North Slope.[40] Alternative NMR log interpretation (adjustment of the T2 cutoffs that bin formation waters into various mobility categories) was found to be compatible with the core analyses.[26] Further laboratory-based NMR studies provide support for the alternative NMR log evaluation approach that matches the core-based higher permeabilities.[37,41] In recognition of the complexity in effective permeability determination, alternative low (initial NMR-log-based) and higher (core-based) effective permeability cases are used to support production modeling studies (Figure 11).[42−44]

Reservoir Temperature. Re-equilibration of the formation temperature from the perturbation related to drilling and completion was essentially complete within 100 days of the end of well operations.[32] After calibration of DTS data to regional trends, the temperature at the top of unit D is ~4.8 °C (40.6 °F) and the temperature at the top of the B1 sand is 10.0 °C (50 °F). The temperature gradient below the permafrost section is 1.09 °C/100 ft (3.2 °F/100 ft). On the basis of stability of methane hydrate and formation fluid salinity of 5 ppt, the projected base of gas hydrate stability is ~100 ft (30.5 m) below the base of the B1 sand at 3227 ft (984 m) MD (−2979 ft; 908 m TVDss; Figure 12).

Ongoing monitoring shows that temperatures have remained stable within both hydrate-bearing sands post-drilling. However, several non-hydrate-bearing sand units within unit C have shown periodic warming events of up to +2 °C, suggesting the migration of gas from underlying drilling disturbed hydrate-bearing reservoirs into high-permeability water-bearing horizons, resulting in the exothermic formation of hydrate in the near-wellbore region. This phenomenon may have occurred first in the lower part of unit D and in the C1 sand and, subsequently, progressed through the C2, C3, and other sands with time (Figure 12).

Numerical Simulation. The Hydrate-01 STW data enable the numerical simulation of reservoir response to depressurization to support planning for well designs and surface facilities for future production testing.[42−44] These models incorporate two-dimensional (2D) geologic characterizations and various depressurization scenarios through a nominal 1 year production test. Alternative cases reflect uncertainties in the initial effective permeability, the potential proximity of lateral flow boundaries associated with faulting, and different approaches (aggressive or cautious) in the application of the pressure drawdown. Higher effective permeability generates accordingly higher production volumes for both gas and water. In those models where closer lateral confinement was assumed, the models predict generally increasing gas and water flow rates reaching ~1.5 million standard cubic feet per day (mmscf/day) and water rates ranging from 2000 to 6000 bbl/water per day. In contrast, where confinement is lacking, predicted production rates are lower and stable or slowing increasing. Gas and water production rates are also higher in the more aggressive depressurization scenarios;[42,43] however, it must be noted that these simulations do not address a range of engineering complications that may be more likely to occur under aggressive depressurization.[15,16] The reservoir simulations also focused on the implications of likely temporary well shut-ins (as a result of operational issues) on overall reservoir response during a long-term production test. These events (assuming no impacts to well or facility equipment) appear to pose no significant consequences for reservoir response or ultimate well productivity.[42,43] Detailed sensitivity analyses explore the potential uncertainties related to a wide range of input parameters and assumptions.[44]

Notably, significant water production is obtained through water sourced from the bounding non-hydrate-bearing sections.[43,44] These are phenomena that may not be evident in the production histories from prior, short-duration field tests

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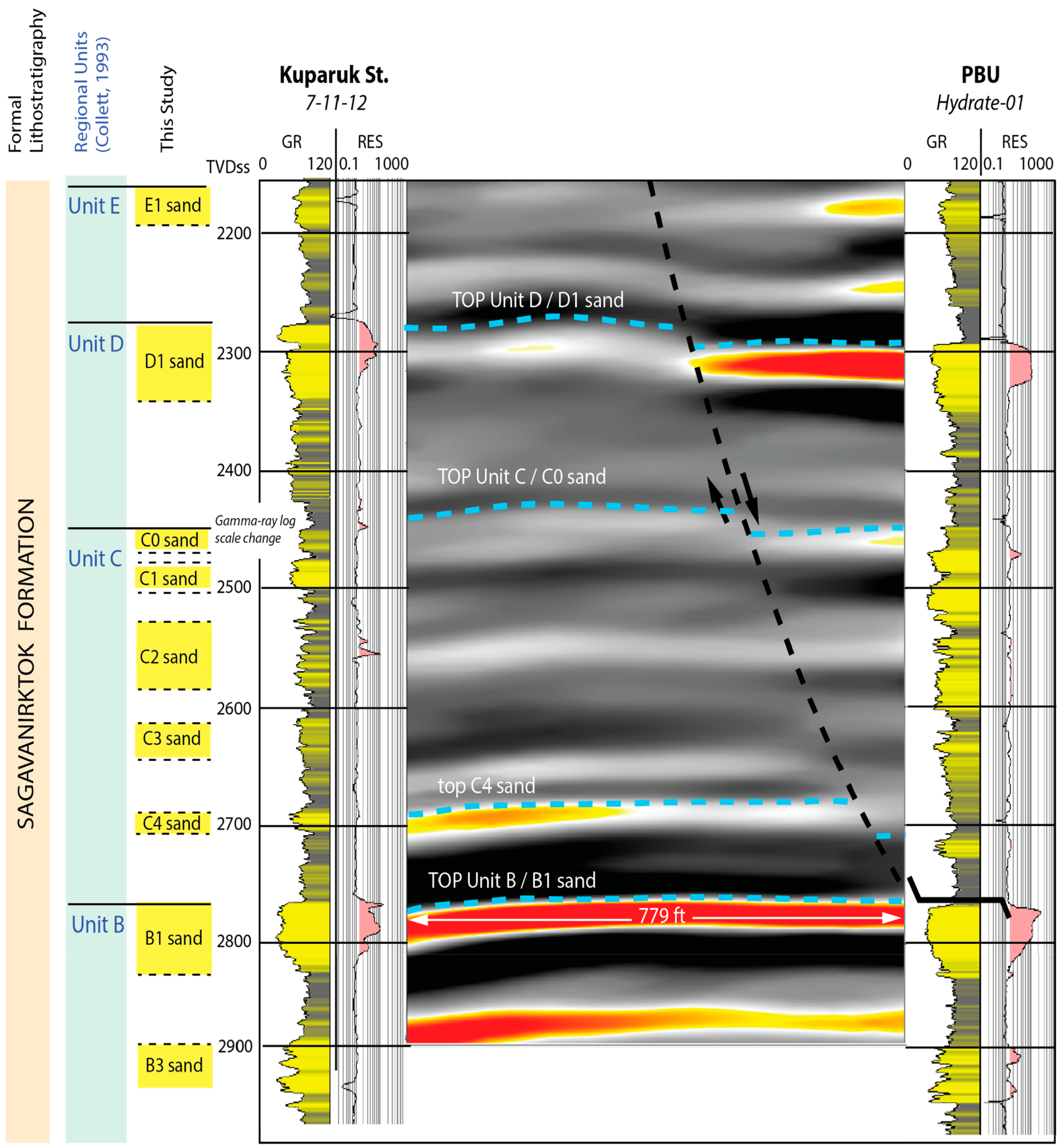

Figure 9. Seismic section extracted from the 3D DAS VSP data,[26] showing the correlation of major seismic reflectors between the Kuparuk State 7-11-12 well and Hydrate-01 Stratigraphic Test Well. The top of both units B and D in both wells (marking contact between hydrate-bearing sands below and transgressive marine shales above) corresponds to the zero crossing above high-amplitude trough reflectors. Discontinuities are apparent that correspond to a down-to-the-east normal fault with ∼25 ft (∼7.5 m) throw that intersects the Hydrate-01 well just above the B1 sand. Depths are in TVDss (feet).

but are anticipated from a range of potential water sources.[19] Initial geomechanical studies[45] explore phenomena related to initiation and localization of sand mobilization within the reservoir during depressurization, which can be expected to hinder effective wellbore pressure drawdown.[15] Further numerical simulations designed to address likely depressurization schedules, including either planned or unintended operational upsets (shut-ins), reveal that such interruptions may drive complex reservoir responses, including the potential for overall increases in well productivity.[43]

Because the 2D modeling predictions do not incorporate well completion issues or details of reservoir heterogeneity that may substantially alter production response from that idealized in the models, these results can be considered optimistic. In contrast, the use of 2D models in lieu of the more complex and computationally intensive 3D model is likely pessimistic, as revealed by prior studies conducted for Alaska North Slope reservoirs, which indicate that 3D depictions provide valuable alternative flow paths toward the producing well.[46]

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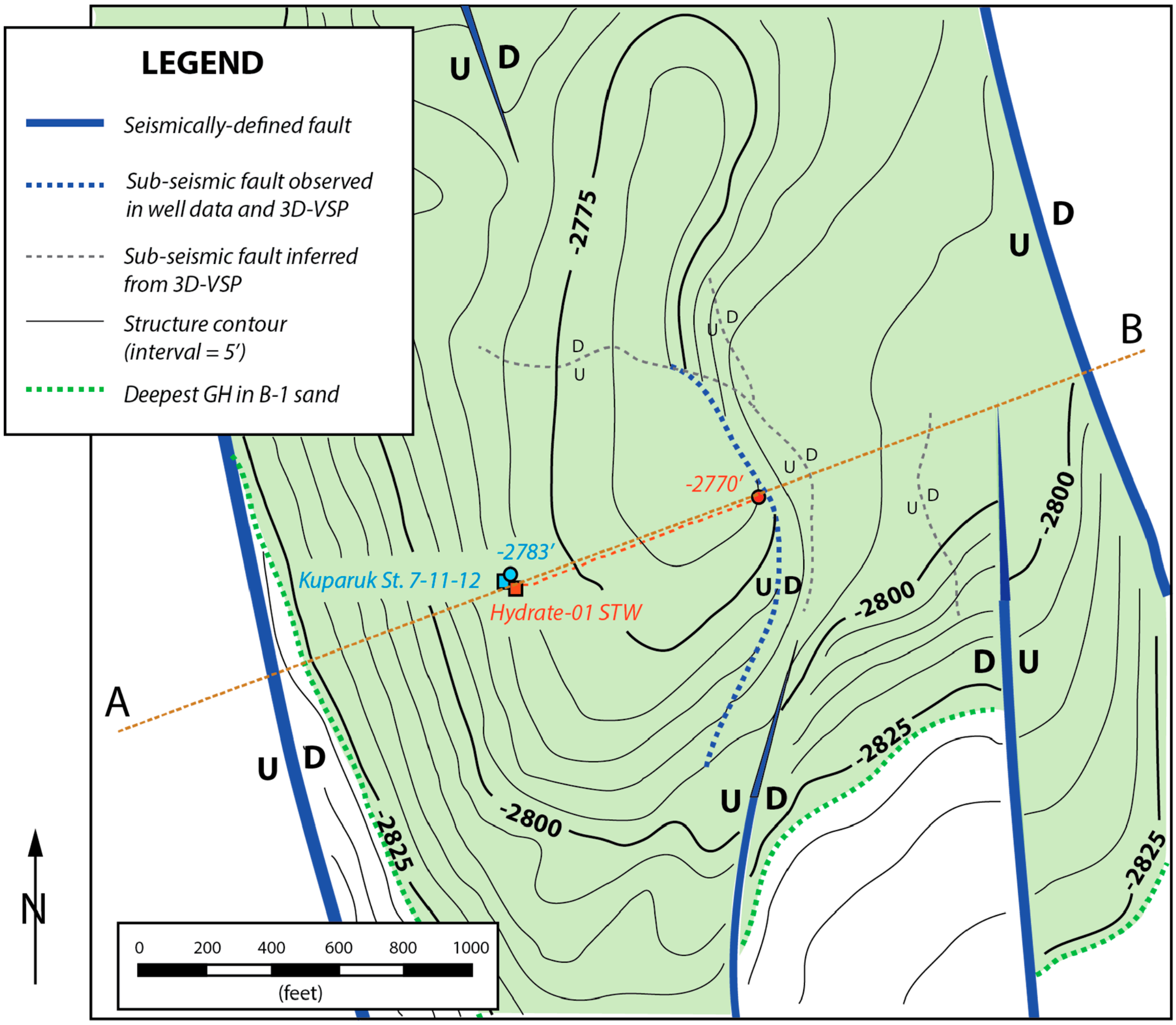

Figure 10. Interpreted geologic structure (in feet TVDss) on the top of the B1 sand within the fault-bounded structure drilled at the Hydrate-01 STW. The structure is based on integration of surface seismic, DAS VSP, and well logging data.

■ SUMMARY

The Hydrate-01 Stratigraphic Test Well was drilled as part of collaboration between the U.S. DOE, Japan's MH21-S Research Consortium, and the U.S. Geological Survey. The well was drilled by BP Exploration (Alaska), Inc. in December 2018 and 2019 as enabled by the Prudhoe Bay Working Interest Owners. Drilling was accomplished from the existing 7-11-12 gravel pad in the western portion of the Prudhoe Bay Unit via agreement with Petrotechnical Resources Alaska under contract with the U.S. DOE's National Energy Technology Laboratory. A full suite of logging-while-drilling data and pressurized side-wall cores was successfully acquired throughout the primary hydrate-bearing section. Upon review of the log data, the well was completed with DAS/DTS fiber-optic cables and temporarily abandoned.

The Hydrate-01 STW was designed to confirm the occurrence of gas hydrate in two sand units as suggested by log data from the Kuparuk State 7-11-12 well drilled in 1970. The two sands are marginal-marine progradational sands of the Sagavanirktok Formation (most likely early Eocene age) that are directly overlain by transgressive marine shales. The reservoirs occur below approximately 2000 ft (610 m) of permafrost within a fault-bounded block on a gently eastward dipping monocline. The bottomhole location for the well was designed to penetrate both target zones to the east−northeast of the 7-11-12 well penetration in an area of favorable geophysical indicators[26] and in a position more central within the fault block. The initial geophysical interpretation indicated that the STW would penetrate a generally flat-lying and undeformed structure. However, log data revealed ~25 ft (7.5 m) of missing section within the basal C shale in the STW, indicating the occurrence of a normal fault. The fault is not apparent in surface reflection seismic data but is indicated with down-to-the-east geometry based on features observed on the subsequently acquired DAS VSP data.[26] Therefore, the STW was interpreted to have drilled on the downthrown side of this fault and crossed the fault immediately above the primary target B1 sand.

The Hydrate-01 STW log data confirmed the occurrence of gas hydrate within both the D1 and B1 sands. The upper portion of the B1 reservoir is massively bedded and highly saturated (average of 82%) with gas hydrate, with nearly half of the remaining porosity occupied by mobile water. Further, the B1 sand reservoir is well-isolated from permeable water-

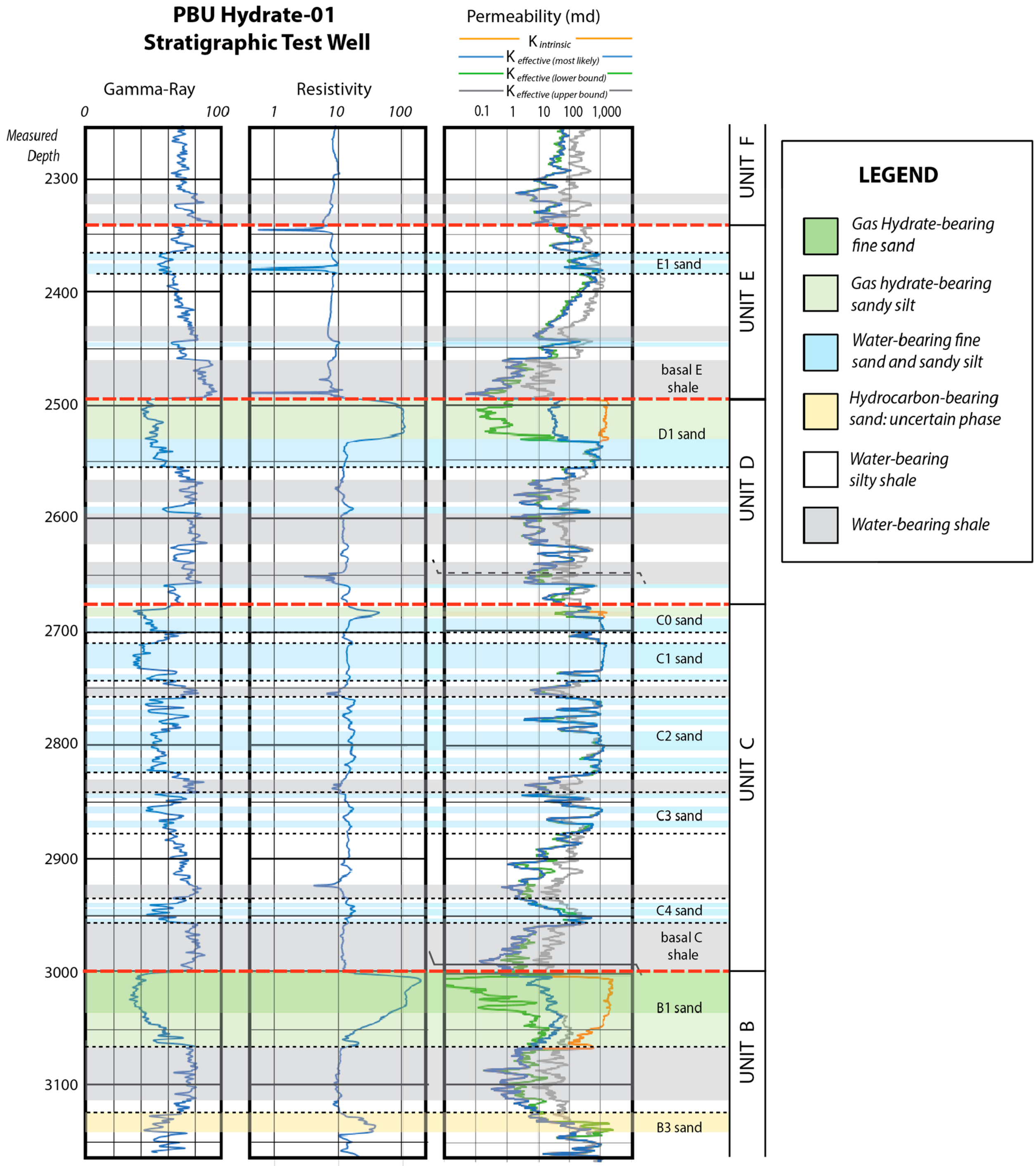

Figure 11. γ-ray and resistivity log data as well as calculated permeability throughout the target section of the Hydrate-01 STW. Depths are in feet MD. Permeability is based on nuclear magnetic well log data analysis[26,37] as calibrated with data obtained from sidewall pressure cores.[27,37] Shown are one estimate for intrinsic permeability and three alternative estimates for effective (*in situ*) permeability.

bearing units and is bound above and below by low-porosity shale-rich units, a setting conducive to effective depressurization. Finally, the B1 sand is interpreted to have the formation temperature of 10 °C (50 °F) and to occur roughly 100 ft (30 m) above the base of the gas hydrate stability zone. Therefore, the B1 sand is well-poised to respond effectively to depressurization and provide adequate heat flow to mitigate the risks for ice formation or hydrate reformation in the near-wellbore region during future testing.

The secondary reservoir target, the D1 sand, similarly provides good reservoir quality within the upper 35 ft (10.7 m) of the unit. However, depressurization experiments within the D1 sand would be challenged by lower formation temperatures (4.8 °C; 40.6 °F), a slightly more permeable overlying "seal", and most critically the occurrence of a basal bounding unit with high mobile water content. Therefore, the D1 sand provides a valuable option that can serve to expand the insights of scientific testing and optimal well design to a broader range

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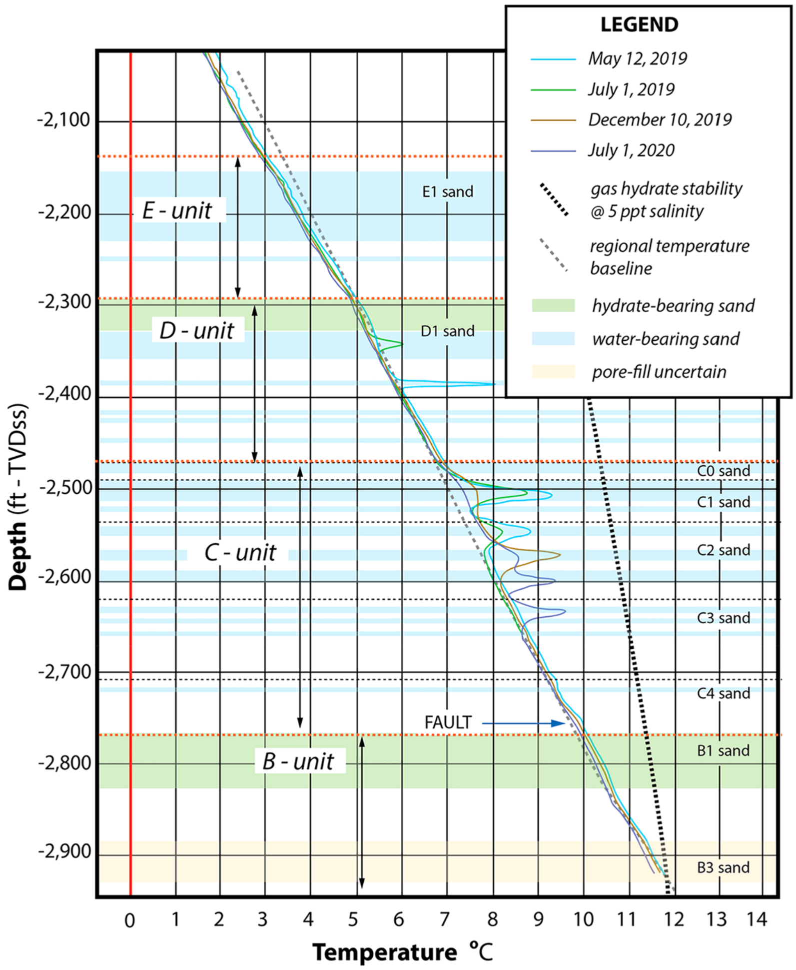

Figure 12. Hydrate-01 Stratigraphic Test Well DTS data (corrected to match regional trends[32]) collected from May 2019 to July 2020. Periodic temperature increases are interpreted to reflect gas hydrate formation within water-bearing sands progressing to lower stratigraphic horizons with time.

of conditions; however, the unit is not an ideal location for an initial scientific production test.

Given the uncertainty regarding effective permeability in gas-hydrate-bearing reservoirs, geologic models constructed for reservoir simulations represent an integration of measurements and a recognition of data uncertainty. To support numerical simulations, a conservative (low-permeability) case is built using standard NMR methods, a core-calibrated (higher permeability) case calibrated to the side-wall core derived permeability data (available only from the reservoir sections), and a third "most likely" case uses the initial NMR-based values in the non-hydrate-bearing sections and the relevant core-calibrated values within the reservoirs.[26,42]

The information obtained from the Hydrate-01 STW is now being used in the design of optimal well placement, well and facility design, and test design for anticipated extended term production testing at this site.

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