IV Gas Production Techniques from MH Reservoir

IV.1 Basic ideas behind gas production and advances in verification

(1) Introduction

In order to obtain combustible natural gas from solid-state MH underground, one possible method is to excavate it using a similar method as that used to excavate coal or minerals. Another method is to dissociate it into movable fluids (water in the liquid state, and methane vapor) and collect it through well-like conventional oil and natural gas (the in-situ dissociation method). The mining method, however, seems to be impractical for deep-water MH from the viewpoints of safety, environmental impact, and cost. On the other hand, the in-situ dissociation method is advantageous if the host sediment of MH has some degree of hydraulic permeability. This is because we can collect gas and water through permeable formations at the well, and so petroleum exploration technologies can be applied. Furthermore, the activities footprint on the seafloor is limited to regions in close proximity to the borehole.

MH21 regarded the in-situ dissociation method as a realistic technique to use, and has attempted to verify that the depressurization technique is the most efficient way to achieve in-situ dissociation. In this section, the theoretical basis of the method and its verification processes are outlined.

(2) Mechanism and condition for application of the depressurization method

In order to dissociate MH that is stable under low temperature and high pressure conditions, raising the temperature (thermal stimulation), reducing the pressure (depressurization), and also alternating the phase equilibrium conditions (inhibitor injection) can be used for in-situ dissociation.

When the first phase of the MH21 was started in 2001, the effectiveness of each of the above methods was not apparent. However, it was known that MH dissociation is an endothermic process, and that approximately 436.8kJ of heat is necessary in order to dissociate 1kg of MH, the equivalent to 160 liters of methane gas. This value is higher than the heat necessary to raise the temperature of the same mass of water from freezing point to just below boiling point. Furthermore, given that some of this energy will be consumed in warming the sediment and pore fluid around MH, not all of this injected heat will be used for MH dissociation. It can therefore be understood that simple thermal stimulation is not entirely efficient in terms of energy balance.

Meanwhile, if the pore pressure of formation can be reduced, the difference in heat between the original formation temperature and phase equilibrium temperature- multiplied heat capacity of the formation can be used for MH dissociation, and gas can be generated without any artificial thermal energy input (Fig. 1). In this case, the gas generated by depressurization can be regarded as the equivalent to “primary recovery” of conventional oil (oil that erupts by its own motive force). However, when the formation temperature reaches the phase equilibrium temperature, the dissociation is terminated. In this case, the recovery rate of MH is limited. If some heat supply by conduction or convection from surrounding formations continues, it will affect the gas production rate. In the case of depressurization, the direction of the expected heat supply is the same as the fluid motion (inward to wellbore). In this case, convection can contribute to the supply. In the case of thermal stimulation from a single wellbore, expected heat and fluid flow are in the opposing direction. This is because the heat should be transported from the wellbore to the dissociating area (in the outward direction). After the dissociation of MH in the pore space, enhancement of permeability is expected and the pressure reduced region may extend from near the well bore to regions further away (Fig. 2). The inhibitor injection technique has a similar disadvantage to thermal stimulation. This is due to the fact that the inhibitor is required to be brought from the center (well) to the outside.

For the above reasons, the depressurization method is judged as being the most efficient method for the dissociation of MH. Even given this case, the method is applicable under the following conditions (Fig. 3):

- That the original formation temperature is high enough (that there is sufficient heat available)
- That the initial formation permeability has reached a certain value (that the reaction area is sufficiently large)
- That the formation permeability after dissociation is sufficiently high (that the pressure drop between the MH dissociating area and the wellbore is low).
- That the dissociated zone is protected from the surrounding water sources (that there is limited water production).

In the case of offshore resources, research has shown that it is necessary to ensure depressurized conditions exist at the bottom of the deep-water well, and also that the operation should be conducted safely under the metocean conditions of the target area. The MH21 study has attempted to verify the applicability of the depressurization method through appropriate technical development and data acquisitions.

On the other hand, thermal stimulation and inhibitor injection may be necessary measures as well as stimulation or enhanced recovery techniques necessary for the improvement of recovery rates and productivity.

(3) Field verification of depressurization method

In the Messoyakha gas field in western Siberia in Russia, it is argued that depletion of the gas field caused unintended dissociation of MH in the overburden formation, and accelerated pressure recovery. (Makogon, 1984).

In 2002, the world’s first intentional gas production from MH-bearing sediment was achieved in the Mallik field in the Northwest Territories of Canada. This was a collaborative project involving Japan, Canada, India, Germany and the United States. While it utilized thermal stimulation (warm fluid circulation (Hancock *et al*., 2005a), the volume produced was small, (468 m^3 during five days of operation) and not stable. Meanwhile, the small scale depressurization test carried out using Modular Dynamics Tester (MDT, Mark of Schlumberger) proved that MH-bearing sediment has finite permeability (Hancock *et al*., 2005b, Kurihara *et al*., 2005a). This result suggested the applicability of the depressurization technique. (Dallimore and Collett, 2005a).

This result promoted further studies in Japan. Large numbers of laboratory experiments on MH dissociation using natural or artificial core sample were carried out (Okui *et al*., 2005; Kawasaki *et al*., 2005), and numerical simulations (Kurihara *et al*., 2004; Masuda *et al*., 2005) were conducted in order to prove the applicability of this method to the natural MH system.

Meanwhile, the drilling of the “MITI Nankai Trough” (1999-2000), 2D and 3D seismic surveys in the eastern Nankai Trough (2001-2002), and the drilling campaign of “METI Tokai-oki to Kumano-nada” (2003-2004) revealed the existence of MH-concentrated zones (MHCZs) – that is accumulation of pore filling type MH together with substantial thickness of sandy turbidite sediments in the Japanese EEZ (Saeki et al., 2008; Fujii et al., 2008). The obtained data suggested that the permeability and formation temperature of some MHCZ satisfy the applicability criteria of the depressurization method.

To prove applicability of the concept to a real field, a second offshore trial was conducted at the Mallik site during the winter seasons of both 2007 and 2008. The depressurized condition was realized by using an electric submersible pump (ESP) to displace water in the borehole. During the first winter, due to a sand production problem, operation was terminated after a short period. However, the produced gas volume was 830 m^3 during a half day of operation, a figure that was larger than the result of the entire five-day operation in 2002. Subsequent to the installation of a sand control device, the second year’s test was conducted and 13,000m^3 of gas was produced continuously and in stable conditions (Dallimore et al., 2012) (Fig. 4).

Based on these data and experiences, the Phase 2 and 3 studies carried out by MH21 have aimed to apply the depressurization method to offshore MH-concentrated zones and also to prove the concept of this method and its technologies.

During Phase 2 (2009-2015 JFY), the first offshore production test (2013) resulted in 119,000 m^3 of gas production during six days of depressurization. As was the case previously, this test was terminated by sudden production of sand. In order to obtain the necessary data to understand long-term behaviors, the second test was carried out during Phase 3 (2016-2018 JFY) while applying improved sand control and other techniques. The operation lasted a total of 36 days in two boreholes. Large amounts of information crucial to the estimation of long-term behavior was obtained.

Some unseen technical issues surfaced, however, such as the difference between results predicted by the model and actual gas production behavior. Accrual of further knowledge about long-term behavior should be critical to resolving those issues going forward. Due to the fact that long-term (for example, more than one year in duration) operations in offshore conditions are costly and technically difficult, a next step is an onshore production test in Alaska to be carried out with the cooperation of the United States.

(4) Conclusion

The applicability of the energy-efficient depressurization method is a key to gauging economies in gas production from MH. Integration of surveys, laboratory studies, numerical simulation, and field tests were performed in the first to third phases of the MH21 project. The current status of the project is that technologies carried out over several weeks of offshore operation were proved, and that while it was shown that gas was able to be produced by the depressurization method, its long-term behavior is considered uncertain. One of the more important issues is the difference between what the models actually predict and the behavior of actual gas production. While a large number of uncertainties remain regarding gas production such as those revolving around well productivity and recovery factors, it is expected that many hurdles can and will be cleared in order to achieve commercial gas production in future.

In the following subsections, the technical achievements of the offshore tests, the current status of the planned onshore test, and the individual study status of the production technologies during Phase 2 and 3 will be introduced.

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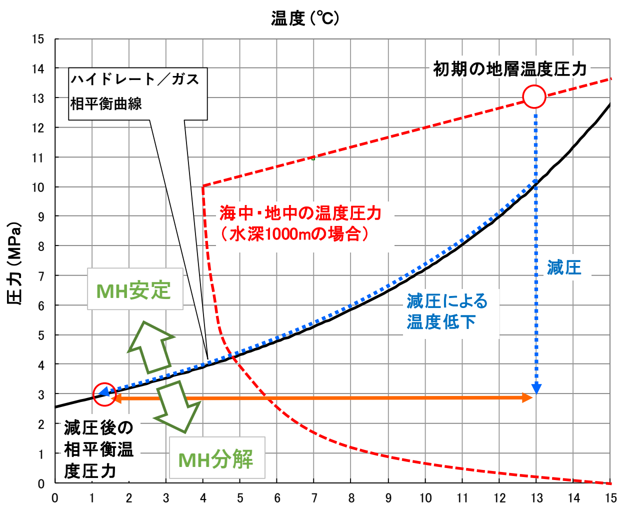

Fig.1 Heat supply mechanism of depressurization method. Difference between initial temperature and phase equilibrium temperature after pressure drop produces heat.

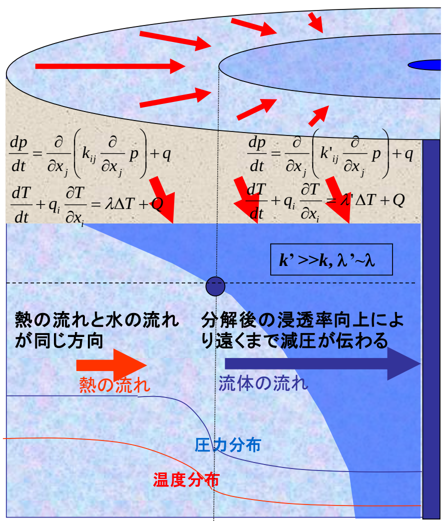

Fig.2 Heat and mass transport during depressurization operation. Heat and fluid mass (water and gas) move to wellbore.

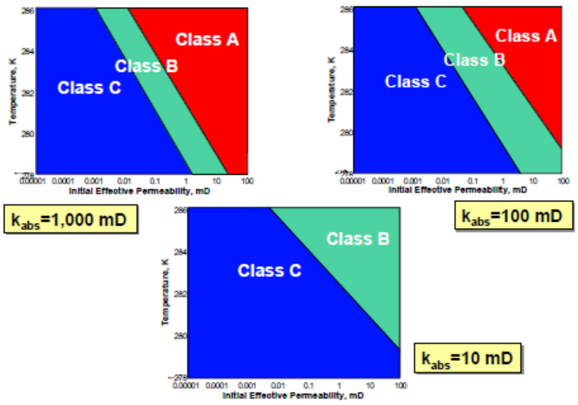

Fig.3 Applicability criteria of depressurization method based on modelling study. High initial and absolute permeability (k_{init},k_{abs}) and high temperature are preferable conditions (Class A).

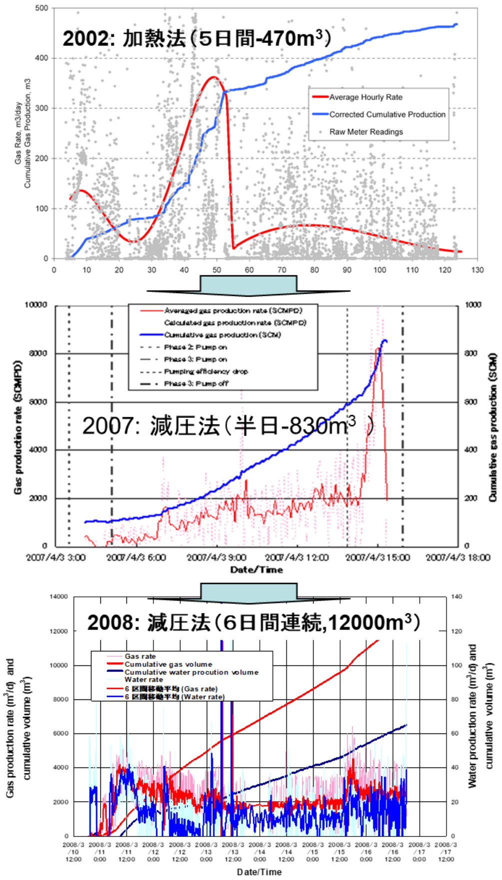

Fig.4 First and second onshore production test result. Stable gas production was realized by the depressurization method.

Fig.5 Views of Mallik site during operations in 2008.

IV.2 Process of the First and Second Offshore Production Tests

2.1 Location of the First and Second Offshore Production Tests and Related Geological Conditions

1) The location of the first production test and related geological conditions.

The location of the first offshore production test was chosen from two proposed sites that are methane hydrate concentrated zones (MHCZ) in the Eastern Nankai Trough. The two sites are called α MHCZ and βMHCZ.

We chose a "βMHCZ" the site for the test. The site is located on the north slope of the Second Atsumi Knoll, off the coast of Atsumi Peninsula and Shima Peninsula. From seismic data analysis and well data analysis, we interpreted the concentrated zone of Methane Hydrate as "β MHCZ" located at a water depth of approximately 1000m and located between 270m and 330m below the sea floor. We used data acquired from 16 wells from "Kiso Shisui Tokai Oki – Kumano Nada (2004)", a domestic exploration program in Japan.

The hydrate layer of the β MHCZ is located relatively deeper than in α MHCZ. In addition, in β MHCZ, there is the relatively thick clay layer approximately 100m from the sea bottom to above the hydrate layer. Therefore, β MHCZ is a relatively easy-to-isolate production section from the bottom of the sea. The β MHCZ location is suitable as a place to set well-head equipment of the well, and there is the advantage that it is easy to secure space to store pit underground equipment. In addition, stratum temperature was higher than αMHCZ, so we judged the β MHCZ was a more advantageous site in terms of gas production.

We selected the location of the production test in βMHCZ due to the high possibility of the existence of MH based on results of the reservoir property evaluation: (1) existence of sand as observed by channel facies analysis, (2) distribution of high P wave velocity, and (3) amplitude anomaly distribution. In addition to this MH reservoir property evaluation, we examined the next item in order to choose the location of the production test. The location had to be a sufficient distance away from existing wells on an area of sea floor that was not sloping excessively. We ultimately decided to drill the first offshore production test well in the AT1 area (Fig. 1(c)) approximately 150m southwest of the beta 1 well location that we drilled in 2004.

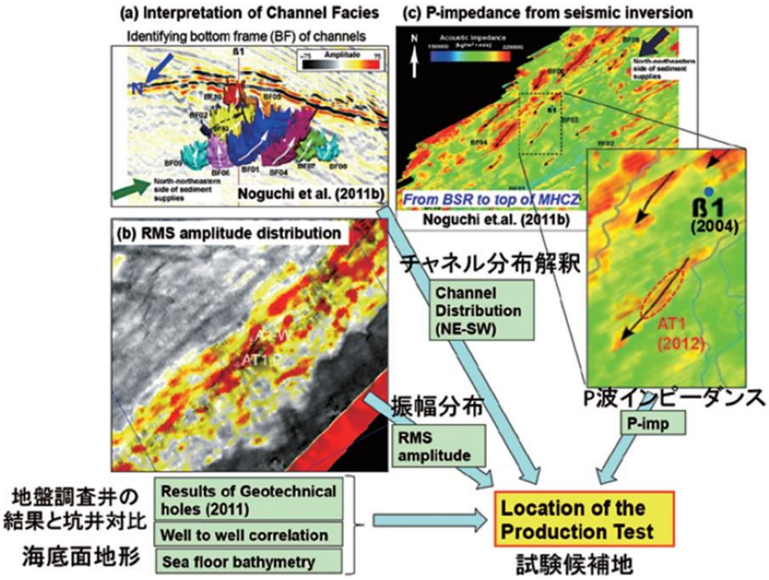

Fig.1 Approach of proposed site choice in first offshore production test（Fujii et al., 2016）

2) The location of the second production test and related geological conditions.

Basic conditions for choosing the candidate sea area site of the second production test for methane were as follows:

(1) New well locations are around 100-200m from existing wells in order to minimize risk of new wells and maximize prior drilling experience.

(2) A target zone where we can expect stable production at sufficient production rates.

- We considered that an important area for the production test would be at the upper part of the MHCZ. The alternate layers of sand and mud support efficient MH dissolution as is evidenced by the temperature change noted at the observation well during the first production test.
- The product section as long as possible in order to minimize the risk that water will be drawn from the top and bottom of the adjacent formation.

(3) There are few risks of interference with the existing well.

(4) There are few risks of drawing water from the fracturing zone.

(5) There are few risk of drawing water from the middle interval section (the low saturation of the MH layer).

(6) The slope of the seabed above the MHCZ is not steep.

We took the above-mentioned conditions into consideration and chose two locations (location 1 and 2 ') to show in Fig. 2. We recognized risks associated with location 1 and location 2. In the case of location 1, the upper MHCZ involves risks of water being drawn from under the BSR (the down dip side) although we could to a degree expect the distribution of "sand mud alternated layers". In the case of location 2, we can have a long production zone for a test, however, the upper MHCZ involves risks of water being drawn from the upper dip side, and we recognized risks associated with the distribution of "sand mud alternated layers" (Fig. 3). Therefore, we will decide the location of the second offshore production test after obtaining geological information from the additional well (AT1-UD) in the up dip side (Figs. 2 and 3).

In the UD well, we obtained data about important properties of the reservoir formation including resistivity images, neutron / density, sonic and nuclear magnetic resonance by logging while drilling tool (LWD). In Fig. 4, we show well logging data, natural gamma-rays and resistivity of the UD, MT2, MT3, MT1 and MC wells. As a result of our integrated evaluation coupled with a reservoir property evaluation, and after having examined it after drilling the UD well, we chose location 2 for the second offshore production test site.

(7) We can expect a total production section length at location 2 of 50m, over double the length of the production section at location 1, even if stop a above is 15m above BSR.

(8) We expected a layer thickness of approximately 20m at the AT1-P3 well as alternate thin layers of sand and mud supported efficient production in the section of the upper MHCZ during the first offshore production test. We estimated the thickness using the interpolation method and AT1-MC well data and AT1-UD well data.

(9) We considered that there was no increased risk that water would be drawn from the up dip at the location.

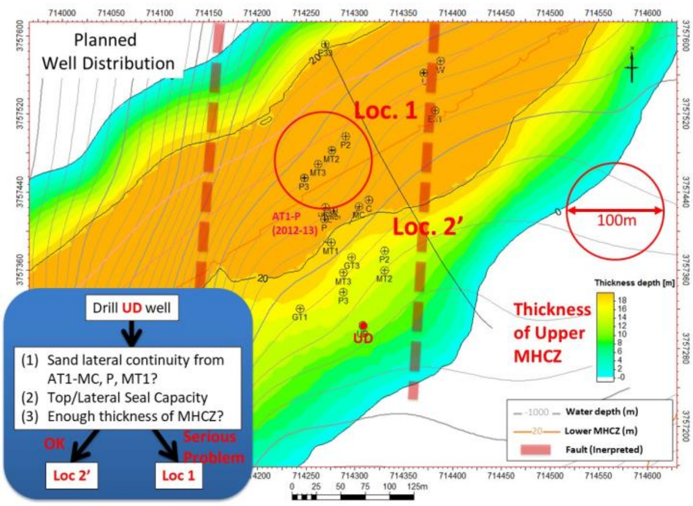

Fig. 2　Location of second offshore production test from methane hydrate（Layer thickness of the upper part of MHCZ, sand mud alternated layers）

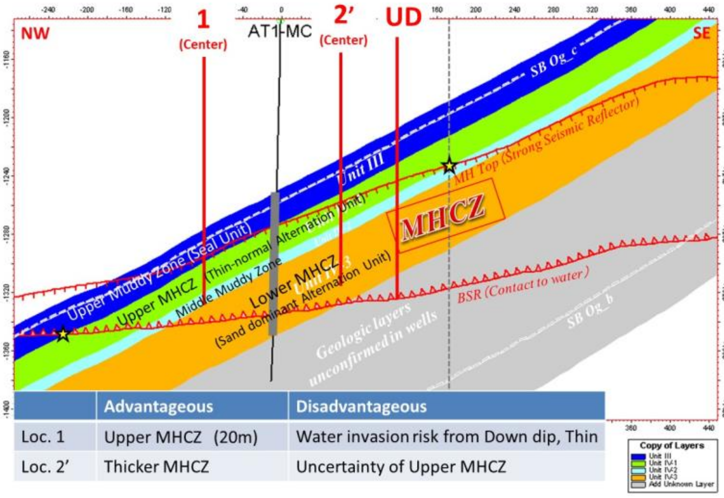

Fig. 3　Cross section of second offshore production test

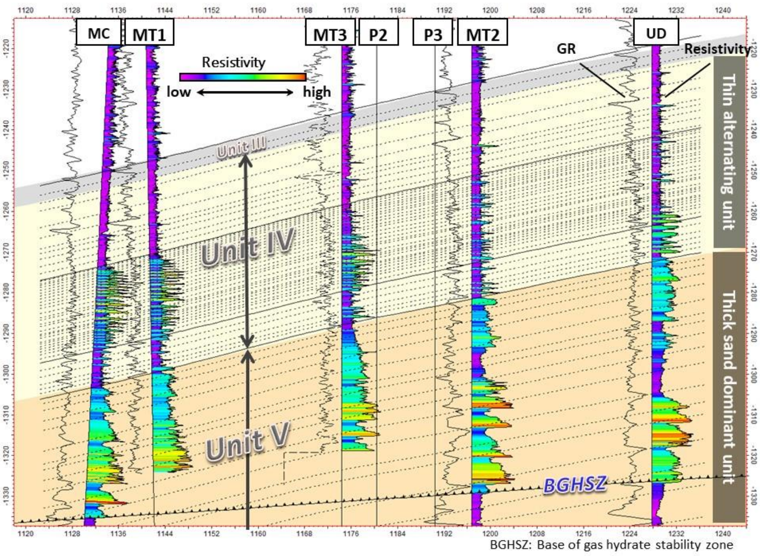

Fig. 4　Well correlation　(UD-MT2-MT3-MT1-MC wells)

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IV.2.2 Overview of Offshore Production Tests and Design Concepts of Used Boreholes

IV.2.2 Overview of Offshore Production Tests and Design Concepts of Used Boreholes

(1) Introduction

The two offshore gas production tests carried out at a gas hydrate reservoir in the Eastern Nankai Trough were planned to obtain data about MH dissociation and gas production behavior under depressurization conditions. Test terms were planned to be relatively short, e.g. approximately one month. Both projects were multi-year operations that included preliminary site surveys, well construction and data acquisition, flow tests, and plug and abandonment (P&A). An important objective of the second test was to verify countermeasures for technical problems that arose in the first test.

(2) Schedules and Drilled Boreholes

The major objectives of the operation along with the production tests themselves were to evaluate the effectiveness of the depressurization method, estimate long-term gas production behavior, and to obtain information about geological and petro-physical (hydraulic, thermal, and mechanical) properties. To accomplish this, geophysical logging, sampling (coring), and downhole monitoring (pressure and temperature - PT measurements) were important elements of the operations.

Another important aspect was HSE, and it was crucial that all boreholes, devices and operations met the relevant safety and environmental standards of the oil industry for drilling, production and P&A.

A. First Production Test (2012-2013)

The test utilized one producer well and two monitoring boreholes (Fig. 1).

- February 2011: Preliminary site survey

  Geotechnical hole (shallow borehole in overburden) drillings at two sites in the Daini Atsumi area and geotechnical and micro-bathymetry surveys using AUV were conducted for site selection, well design, and geo-hazard study purposes (see V-7).

- February to March 2012: Drilling and data acquisition operations

  Two monitoring boreholes (AT1-MC: the inside of the casing was kept open for cased-hole logging after the test, and AT1-MT1: the inside of the casing was filled with cement for high resolution temperature measurement) and the shallow part of the producer well (AT1-P) were drilled, and geo-physical logging data were taken by logging-while-drilling (LWD) and wireline tools. Temperature sensors were installed outside the casing of the monitoring holes, and long-term measuring began (see IV-2-5).

- July 2012 (AT1-C, see V-1)

  AT1-C well was drilled.

- January to March 2013: AT1-P production test (March 12-18)

  After drilling the reservoir section of the AT1-P well, a sand control device (gravel packing) was installed, and the test string (sensor, downhole separator, ESP, production packer etc.) was run into the hole. A flow test was conducted by applying the maximum 9 MPa drawdown (bottom hole flowing pressure (BHFP) down from 13.5 MPa to 4.5MPa), and 119,000m^3 of gas was produced in the six-day operation. On the seventh day, sudden and severe sand production occurred. ESP was still running but sand and water volumes were outside the range of shipboard treatment capacity, so the crew terminated the depressurization operation.

P&A operation on AT1-P was carried out.

- July to August 2013: P&A and additional data acquisition

  P&A on AT1-MC and MT1 and recovery of data storage after the cased hole logging in the AT1-MC well. To obtain information about reservoir character alternation, two holes (AT1-LWD1/LWD2) were drilled in the vicinity of AT1-P.

B. Second Production Test (2016-2018)

Some improvement of the sand control devices, downhole production devices, and subsea and riser tools were made as solutions to mitigate the problems that were encountered during the first test (see IV-2-3 and IV-2-4). Two different types of the shape memory material (activated and un-activated GeoFORM™) were installed in two producer wells for comparison purposes.

- May to June, 2016:

  Drilling of exploration well AT1-UD to aid in the decision of where to locate the well, and subsequent drilling of two monitoring holes (AT1-MT2/MT3) and the shallow part of the two monitoring holes (AT1-P2/P3) utilizing geophysical logging (Fig. 2). Improved PT sensors were installed in the monitoring holes and long-term monitoring commenced.
- April to June, 2017:
  - Drilling of the reservoir sections of the two producer holes and installation of the sand control devices.
  - Production test on AT1-P3

    Eight MPa drawdown (13MPa to 5MPa in BHFP) was achieved, however, intermittent sand production events were observed from an early stage. Sanding ceased once but then occurred again on a larger scale. After 12 days of gas production, we decided that enough data had been acquired from well operations, and we made the decision to terminate the flow to protect subsea and shipboard devices.
  - Production test on AT1-P2

    Some additional countermeasures were carried out to prevent sand production and manage the sand on the deck, and BHFP was gradually reduced from 13MPa to 10MPa. Due to the larger than expected amount of water produced and the plugging of one of the water producing lines, BHFP was kept at 10 MPa for a period of several days. After the closed line was re-opened, drawdown to 8 MPa was made.

    Due to expectedly rough sea conditions, a planned disconnect between the WCP (well control package) and the EDP (emergency disconnect package) was carried out on the 21st day, subsequent re-connection was successfully carried out, and flow was resumed. A total of 24 days of flow was achieved.
  - After the flow tests, two producer wells were suspended.

- April to May 2018:
  - Drilling of two new holes (AT1-CW1/CW2) for additional data acquisition

    A pressure coring was made and wireline logging tools were subsequently run into each hole. AT1-CW1 was drilled at a location between AT1-P2 and AT1-MT2 to represent data affected by the production test. On the other hand, AT1-CW2 was drilled at a location 20 m west of AT1-MT3 to represent a test case that was not affected by the flow test.
  - Plug and abandonment of all boreholes

    The memory gauge with one year's worth of PT data in the AT1-P2 was successfully recovered. An attempt was made utilizing a wash-over operation to recover the sensors and troublesome sand control device in the AT1-P3 well that had been buried under sand, however, the attempt failed. The data storage containing two year's worth of PT data was recovered.

To mitigate the well deviation problem that occurred during the first test drilling (2012 and 2013), a rotary steerable tool (Power V system produced by Schlumberger) was used to accurately drill vertical wells. The well location was selected to minimize interference between two producers and to distinguish the effects of initial fluid motion from the effects of MH dissociation.

Detailed time charts of the flow tests are shown in Table 1. Along with the well operation stated here, four component seismic and environmental impact surveys were carried out in the vicinity of the holes.

(3) Operation Platform

Due to the uncertainty of the economic value of MH and appropriate technologies to produce gas, the test operations were designed to minimize the capital cost of the test system by using or improving existing and field-proven infrastructure instead of developing newly designed or constructed equipment. As the operation platform, D/V Chikyu, a DPS drilling vessel owned by the Japan Agency for Marine-Earth Science and Technology (JAMSTEC), was used for IODP projects because of her operation capacity and relatively low cost of mobilization and de-mobilization.

The dynamic positioning system (DPS) vessel could drill holes in the test area where many subsea communication cables ran, and mooring was quite difficult. The wide operation window for the met-ocean conditions of the Daini Atsumi area was expected. The vessel's liquid reserve tanks could hold produced water temporarily, her large accommodation capacity enabled many scientists and engineers to remain on board the vessel to carry out complicated operations, and her laboratory and other scientific research facilities and staff matched the objectives of the R&D project.

Borehole-related operations such as drilling and flow tests were carried out by the D/V Chikyu while other ships were utilized for supply, environmental surveys, and 4C seismic surveys.

(4) Organization for Operations

Both offshore production tests were regarded as mining operations for inflammable natural gas under the Japanese mining law and the mining safety act. Japan Exploration Co., Ltd. (JAPEX) worked as the operator of the first trial, and Japan Methane Hydrate Operation Co., Ltd. (JMH) cooperated with JAPEX for the second test. For both tests, development of test equipment was carried out by Japan Drilling Company (JDC), and Schlumberger K. K. designed and operated the long-term downhole monitoring systems. Many other companies worked to support each operation. Onshore and onboard data analysis was carried out by JOGMEC and AIST with cooperation from universities and companies. The organization chart of both projects is shown in Fig. 3.

(5) Major Results and Conclusions

The first offshore production test (2013) was the world's first gas production attempt from a MH deposit below the seafloor. Large depressurization and subsequent gas production was successfully implemented using a floating drilling vessel, and MH dissociation and continuous production of methane gas was achieved for a period of six days. However, sudden and severe sand production forced the crew to terminate the flow, and as a result, stability of gas production was not able to be successfully proven. The large amount of data acquired shed light on the relationship between MH dissociation and reservoir characteristics, however, the data was not sufficient to enable prediction of the long-term behavior of gas production. Furthermore, a number of technical challenges surfaced such as how to control sand, separate downhole gas-water, and manage the risks of carrying out an emergency disconnect.

To demonstrate the reliability of countermeasures to the technical challenges that arose, and to acquire data that would facilitate understanding of long-term behaviors, the second test was planned with the aim of achieving longer-term gas production. In the AT1-P3 well, 12 days of gas production was achieved with 8 MPa drawdown in spite of intermittent sand production. The gas production rate was as low as 3,000-4,000 m^3/d and the expected increase in the gas production rate was not observed. The water production rate was approximately 80m^3/d.

The following operation in the AT1-P2 well suffered from a higher water rate than expected (300-500m^3/d) as well as a limited drawdown (maximum 5 MPa during stable term), however, a higher gas production rate (10,000 m^3/d) was achieved. Several flow assurance problems due to re-association of MH in the flowline occurred as a result of insufficient drawdown that made the PT condition around the seafloor be within the MH stability condition. A planned disconnect was successfully carried out, and the operation was resumed after re-connection. A total of 24 days of flow was achieved from the well.

A total of 36 days of flow was achieved and a large amount of data was acquired as a result of operations carried out at the producer and monitoring holes. Technical and scientific results of the tests are shown in the following sections.

Reference

Yamamoto, K., Terao, Y., Fujii, T., Ikawa, T., Seki, M., Matsuzawa, M. and Kanno, T. (2014): Operational overview of the first offshore production test of methane hydrates in the eastern Nankai Trough.” Proc. 2014 Offshore Technology Conference, Houston, Texas,

USA, 5-8 May 2014.

Table 1 Conditions and Results of the first and second offshore production tests

	AT1-P	AT1-P3	AT1-P2
Production interval	39 m	60 m (drilling interval) 41 m (interval except for isolated zone by packers)	60 m (drilling interval) 45.4 m (interval except for isolated zone by packers)
Flow duration*	05:00 March 12, 2013 ~ 15:00 March 18, 2013 (6d10h00m)	16:00 May 2, 2017~ 11:00 May 15 #1: 16:00 May 2-7:30 May 3 (0d15h30m) (ESD malfunction) #2 21:10 May 3- 11:00 May 15 (11d13h50m) Total 12d5h20m	20:30 May 31~ 18:50 June 28 #1 20:30 May 31 - 23:00 June 20 (20d2h30m) (Planned disconnect) #2 20:30 June 22 - 8:10 June 24 (1d11h40m) (Removal of MH plug) #3 14:25 June 25- 15:20 June 25 (0d0h55m) (Removal of MH plug) #4 4:50 June 26-18:50 June 28 (2d14h0m) Total 24d4h5m
Max drawdown	9MPa (13.5MPa-4.5MPa)	7.85MPa (13.0MPa – 5.15MPa)	Instantaneous: 6.73MPa (13.0MPa – 6.27MPa) Stable term: 5MPa (13.0MPa – 8MPa)
Cumulative production volume	Gas：119,000Sm^3 Water：1245m^3	Gas：40,849.9Sm^3 Water：922.5m^3	Gas：222,587.1 Sm^3 Water：8246.9m^3
Major events	Sand production 3/18 4:05~15:00	Sand production #1 5/4 4:30~5/6 6:00 (intermittent) #2 5/11 5:00~5/15 5:00 (intermittent)	No sand production Planned disconnect 6:15 June 21-11:30 June 22

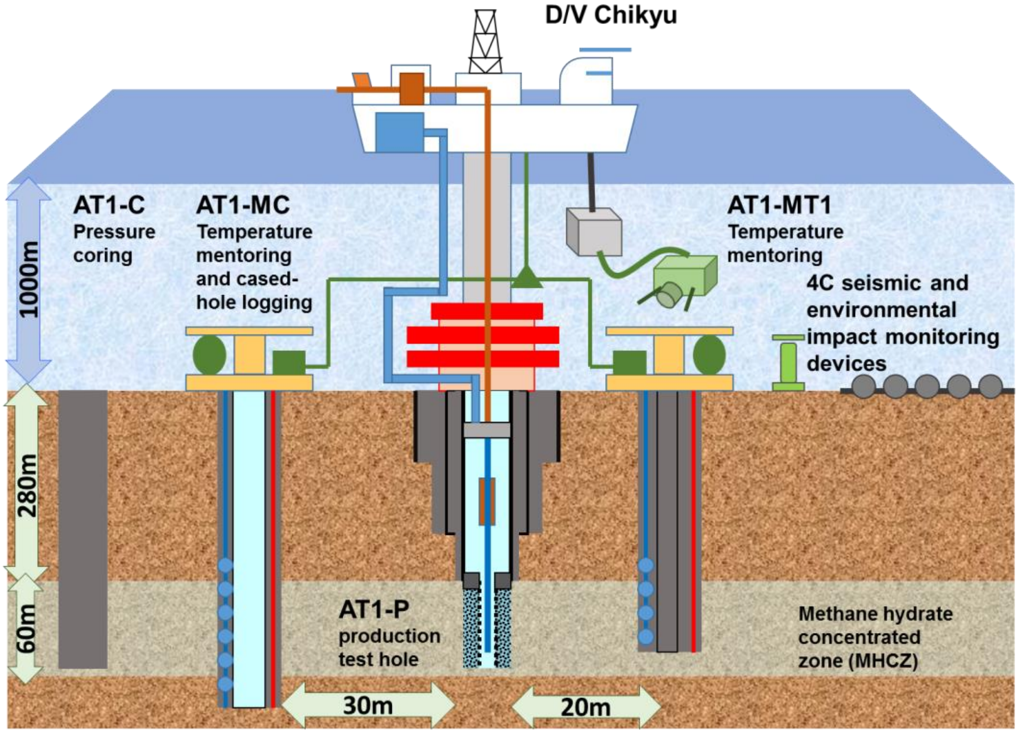

Fig. 1 Well configuration of the first test (2013)

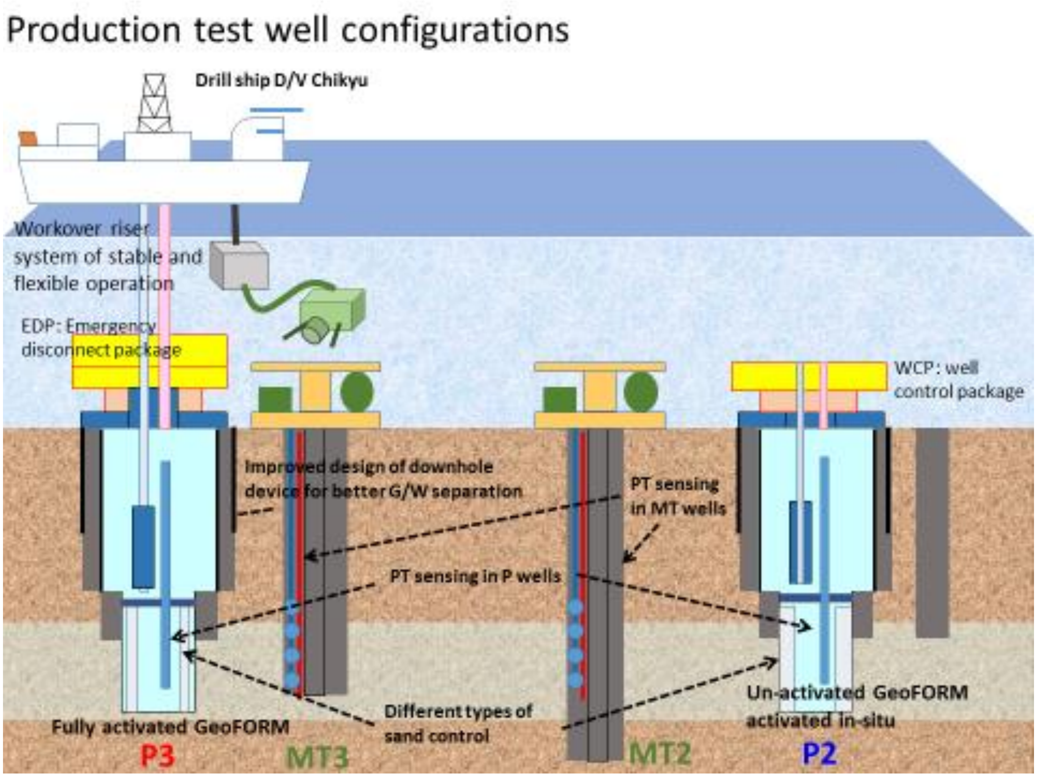

Fig. 2 Well configuration of the second test (2017)

IV.2.3 Production Test System

(1) Purpose

For the first and second offshore gas production tests, we developed dedicated production systems that enabled continuous gas and water production by reducing the bottomhole pressure.

(2) Background

The production systems consist of a downhole string, surface process facilities comprising gas and water trains, and riser pipes for connecting these. In both tests, the downhole pressure was reduced by pumping up water in the wellbore using an electric submersible pump (ESP), and thereby methane hydrate in the formation was dissociated into gas and water.

Since the test sites have a water depth of approximately 1,000 m, we conducted engineering studies and designed a system that can be operated in a safe and secure manner from the drilling vessel. A particular technical challenge involved riser disconnection in preparation for rough weather or at drift-off/drive-off events. Detailed flow assurance and pump design studies were also needed so that we could maintain the bottomhole pressure and prevent hydrate reformation in the flow path.

(3) Implementation and results

The production systems will be outlined below with a focus on bottomhole pressure control and riser disconnection.

① Gas-liquid separation and bottomhole pressure control

Figure 1 shows a schematic view of the downhole systems used in the first and second tests. In the first test, the ESP with an inverted shroud was installed in the 9-5/8" casing [1]. The fluid level in the drill pipe was reduced by controlling the ESP to start gas production. Production continued for five and a half days before sand production started. The main operational issue was poor phase separation and the slug flow that continuously reached the on-board gas train. As a result, the bottomhole pressure was not reduced to 3 MPa as planned, even when the pump was run at the maximum speed [2] (Fig. 2).

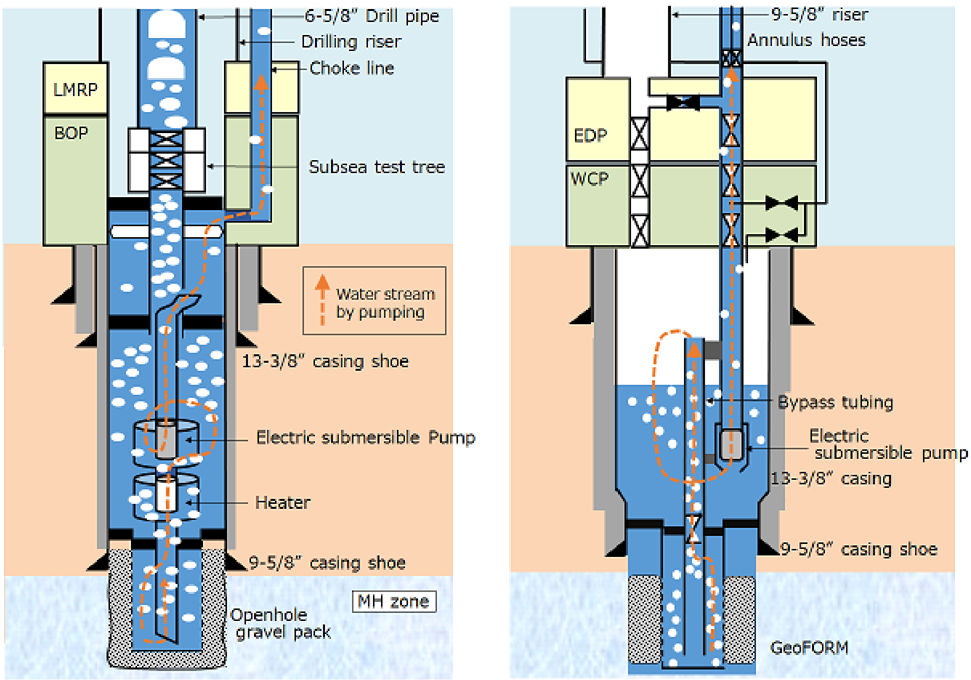

Fig.1 The downhole system for the first (left) and second tests

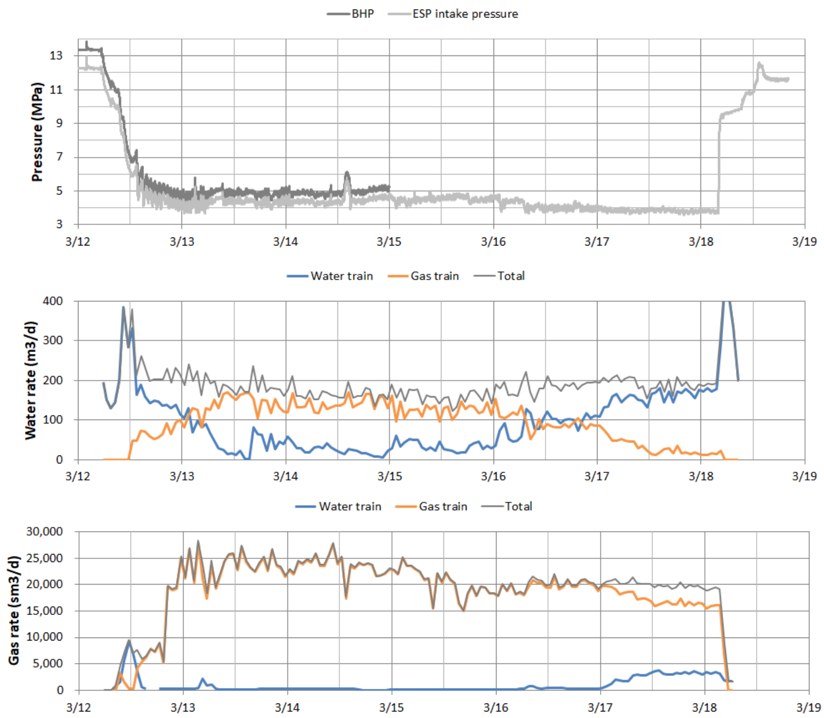

Fig.2 Changes in downhole pressure and production rate in the first test

During the second test, an ESP was installed inside the larger 13-3/8" casing to promote gravity separation. Furthermore, a choke valve was added to the on-board gas train to control the back pressure.

Consequently, gas was continuously produced for a total of 36 days from the two wells while the liquid level in the riser was reduced and the production of water accompanying the gas train was suppressed. The downhole pressure was controlled by either the ESP or the choke valve. However, it was not possible to depressurize the bottomhole to 3MPa as expected, due to the significant amount of sand produced in the P3 Well, and water production beyond the design flow rate in the P2 Well (Fig. 3). In addition, several signs of blockage caused by hydrate that had reformed in the flow path were confirmed in the P2 Well, and measures were subsequently taken, such as methanol injection.

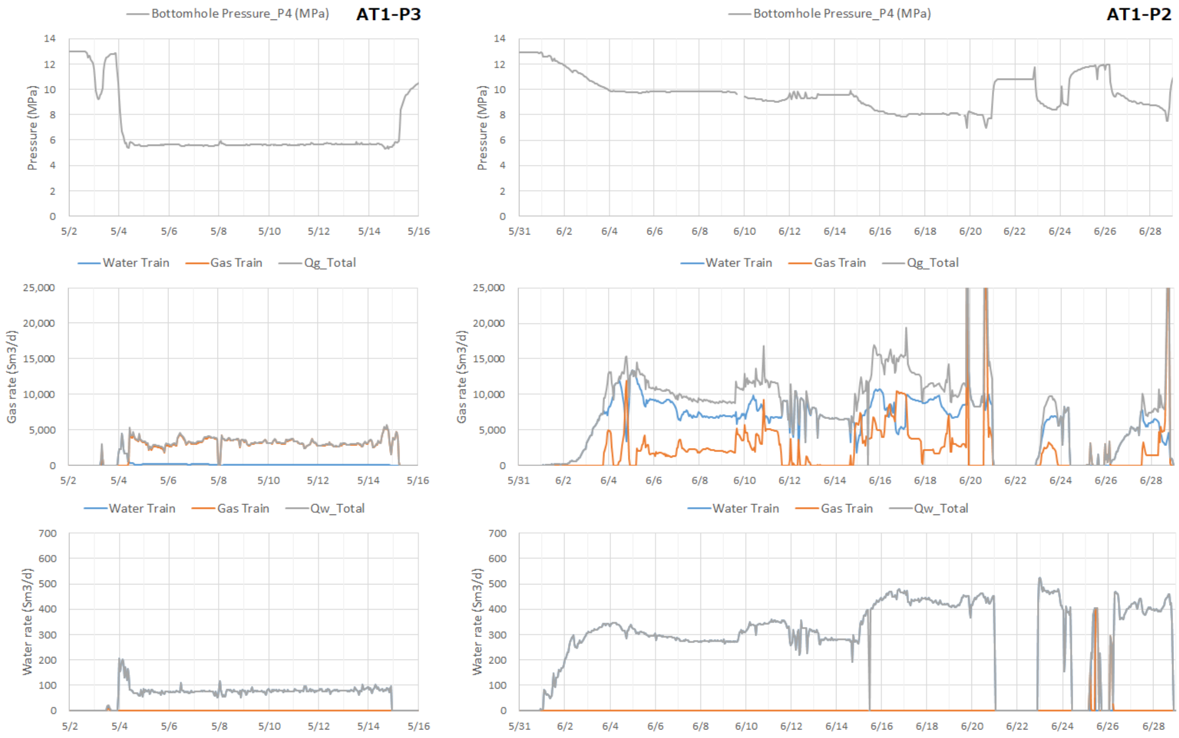

Fig.3 Changes in downhole pressure and production rate in the second test

② Riser disconnection

During the first test, the downhole test string and drill pipes were installed inside the drilling riser and the blowout preventer (BOP). When emergency disconnection took place, it was planned that the test string would be sheared with the BOP, and then the drilling riser would be disconnected. Due to the two-step disconnections, the allowable offset of the drilling vessel during gas production was limited to 14 m, therefore, concern remained regarding the risk of interrupting the experiment during rough weather conditions. In addition, in the case of a planned disconnection, the downhole string should be pulled up to the vessel for reconnection, and the test restarted because the downhole cables must be disconnected at the dry-mate connectors in the subsea test tree. Therefore, it was postulated that the experiments after disconnection should be abandoned, and riser disconnection during the production tests was fortunately avoided.

During the second test, by using the workover riser system, installation was carried out with the downhole string connected to the riser, which significantly reduced the installation time. It was possible to simultaneously disconnect the gas and water production lines at the seabed, between the well control package (WCP) and the emergency disconnect package (EDP) shown in Figure 4. As a result, the allowable offset of the vessel was expanded to 44m, and the test can be continued even in certain adverse weather conditions. In addition, since the downhole cables can be disconnected and reconnected in the sea at the wet-mate connectors, this enabled us to switch the two production wells within a short time frame.

Fig.4 Riser disconnection devices, WCP (bottom) and EDP (top)

(4) Conclusions

The results of the two offshore production tests demonstrated that continuous gas production using a drilling vessel is possible if sand inflow from the formation can be controlled. Significant design improvements were made for the second system with regard to the downhole pressure control as well as the riser disconnection and reconnection. On the other hand, design and operation issues such as hydrate blockage emerged throughout the second production test, which should be tackled and overcome to help ensure longer-term production in future.

References

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Conference Paper - 2014

[2] Issues and Challenges With Controlling Large Drawdown in the First Offshore Methane-Hydrate Production Test, Sakurai, Shunsuke, Nishioka, Itoyuki, Matsuzawa, Maki, Matzain, Bazlee, Goto, Ayae, Lee, Jay E., 182230-PA SPE Journal Paper -2017

IV.2.4 Sand Control Device

(1) History of Sand Control for Methane Hydrate Development

The pore filling type of hydrate, which exists in unconsolidated sand formations, can fluidize and disturb the formation when it dissociates. This fluidized formation material can easily fill up the well if sand control devices are not functioning correctly.

During the first winter of the second onshore production test (2007-2008), an unexpected volume of sand flowed into the well and led to the forced termination of the production test. The possibility of sand production was recognized in advance through the plugging of the MDT (Modular Formation Dynamics Tester: trademark of Schlumberger) tool used in the first onshore production test, therefore the well was drilled deeper than the production layer to accumulate the produced sand at the bottom of the hole. However, the volume of produced sand - which filled up the hole - was beyond our expectations. The alternative measure, taken to overcome this problem during the second winter of the second onshore production test, was to install a sand control device. This led to six days of continuous production.

During the second phase of the project, which started in 2009, sand control was regarded as one of a number of critical issues to be tackled based on the above-mentioned experience. Therefore, the study about sand control methods for the first offshore production test, which was planned for the second phase, was started from the beginning of this phase.

(2) Selection of Sand Control Device for First Offshore Production Test

Throughout the onshore production tests mentioned above, the effectiveness of sand control was a key issue. However, for the first offshore production test, it was necessary to select another optimal sand control method because the particle size distribution was considerably different between the onshore site and the offshore planned test site, where the existence of a large volume of fine contents was identified. (Fig.1)

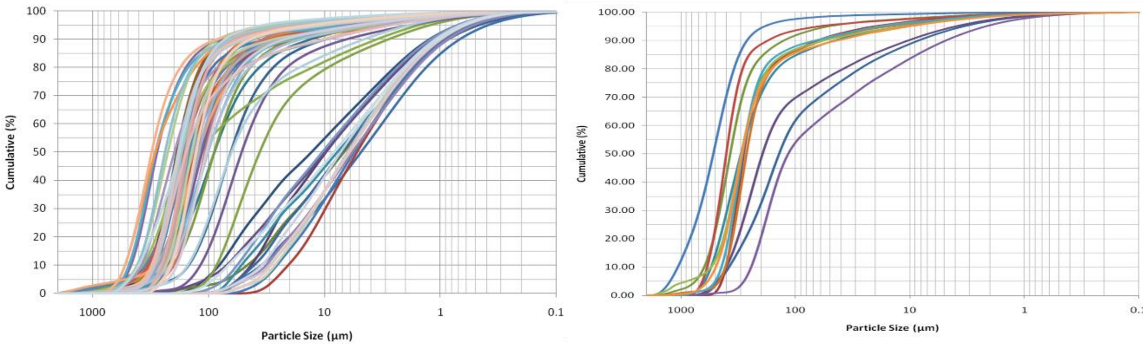


Fig.1 Particle size distribution of offshore (left) and onshore (right) site

For the first step of this study, a potential sand control device was identified based on particle size distribution data from Advanced Well Technologies PTY Ltd (AWT: Now, NauticAWT). The necessity of depth filtration and overall contact without gaps with the borehole wall was indicated as a possible requirement. As a result, Premium screen and Frac Pack were identified as candidates. The gravel pack was also thought to be one of the candidates and further testing was suggested to confirm its applicability although it was considered to be rather inappropriate for the layer with a high content of fine particles.

For the next step, laboratory testing for some of the candidate sand control devices was conducted by Oilfield Production Technology (A consignee of AWT: currently Oilfield Technologies). A sand pack test and a slurry test (Fig.2) [4] were performed to gain an understanding of the possibility of production failures due to plugging and the size of particles that pass through those devices, as well as to assess the applicability of the selected candidates. Similar testing was also conducted for the gravel pack to check the effect of fine particles. As a result, one of the premium screens exhibited good performance and indicated the applicability to the planned offshore production test. In addition, the gravel pack exhibited effectiveness for the offshore test site although concerns about the possibility of plugging caused by long-term production still remained.

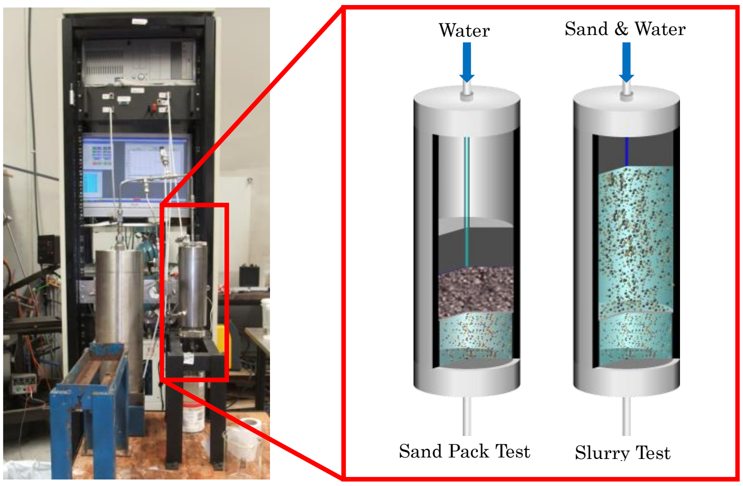


Fig.2 Outline of the experiment

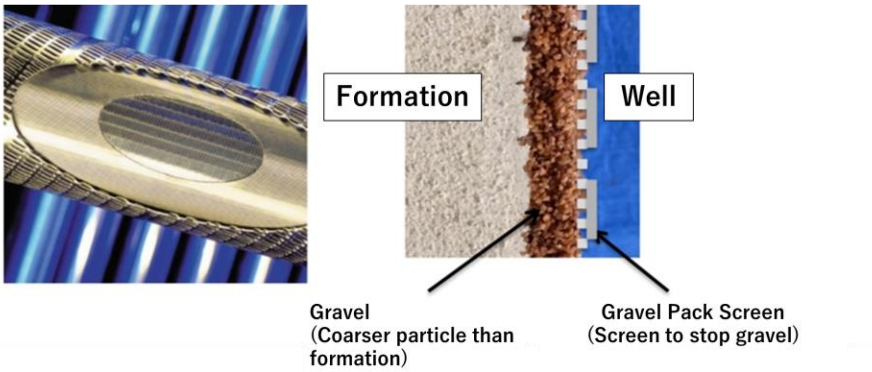


Fig.3 Gravel pack screen (left) and image of section of openhole gravel pack completion (right) (Extracted from Presentation of Methane Hydrate Forum 2014 (Japanese only))

From studies based on the above-mentioned results, the open-hole gravel pack was chosen for completion in the first offshore production test. [5][7] To achieve this, sand screens are installed into an open-hole well with annulus between sand screens and formations filled up with gravel. This secures a large flow area and reduces the risk of partial high velocity. In addition, the thickness of gravel in the annulus could work as depth filtration. On the other hand, some risks of fracturing and/or damage to the formation, which may lead to loss of gravel, could be recognized if the specific gravity of gravel exceeds the formation fracture pressure. As a countermeasure against these risks, a lightweight material called “LiteProp125” (product of Baker Hughes, a GE Company) was used.

(3) Sand Production in the First Offshore Production Test

Sand production occurred on the sixth day of the production test. There was no indication of the existence of sand at the onboard facility, however, real time monitoring data showed a sudden increase in current in the pump with a reduction in pump frequency due to activation of the safety device. Bottomhole pressure was expected to recover as the water volume increased. (Fig.4 (left))

Operation of the pump recovered within a short period of time, however, the amount of produced water was too great to facilitate continued production, and then 15 minutes later, sand was confirmed onboard. Around the same time, it was observed that the temperature in the wellbore increased to almost the same level as the initial value as pressure recovered. (Fig.4 (right))

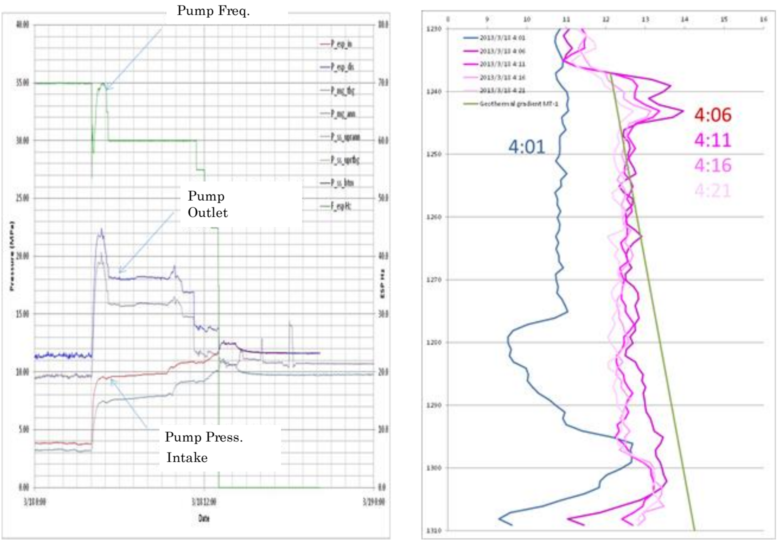


Fig.4 Pump behavior (left) and temperature change (right) during sand production
(Extracted from Presentation of Methane Hydrate Forum 2014 (Japanese only))

Fig.5 Sand Production
(Extracted from Presentation of Methane Hydrate Forum 2014 (Japanese only))

From the recognized events and measured data, the following three hypotheses were set up as a cause of sand production.

① Damage of screen due to pressure difference caused by depressurization and formation stress: This includes destruction of base pipe and screen due to overloading, buckling, and bending.

② Lowering of gravel top level caused by contraction of the formation: Gravel may flow out into gaps in the formation, which could arise due to contraction of the formation as a result of depressurization, resulting in sand inflow from the top void space.

③ Formation contacting the screen due to gravel being pushed out: Fluidized sand may push out the used lightweight gravel and then erode the screen.

After repeated analysis and discussions, we inferred that the most likely cause of sand production that occurred during the first offshore production test was the combination of case No.1 and No.3. [8]

(4) Selection of Sand Control Device for the Second Offshore Production Test

The sand control device for the second offshore production test was selected based on the following requirements, which were derived from the studies about the issues that occurred during the first offshore production test. [9]

① Device, procedure and/or materials that can eliminate the effects of pressure created during the operation
② The gravel or alternatives that must not move
③ Multiple barriers with material that is physically strong and resistant to erosion
④ Cost effective technology for future cost reduction

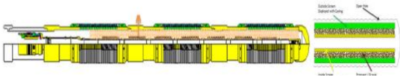
By considering the above four requirements, four types of sand control measures shown in Fig.6 were selected as candidates for the second offshore production test.

The first candidate shown in Fig.6 (a) is a prepack screen, which has two layers of screen with gravel between them. However, a number of technical issues such as limitation of the packer size for isolating the water layer and reliability were raised. Both of the second and third candidates shown in Fig.6 (b) and (c) are combinations of GeoFORM™ (Shape memory polymer: Trademark of Baker Hughes, a GE Company) and beads insert. The difference between the two is, for (b) GeoFORM™ will be activated (expanded) before installation, however, for (c), activation will be conducted in the well, or after installation. The advantage of option (b) is that waiting time for activation can be reduced, leading to a reduction in rig costs. On the other hand, the advantages for (c), activated in the well, can also fill up the gap between the formation and screen, which can prevent movement of formation material during production.

Fig.6 (d) is a combination of gravel pack and beads insert. The beads insert is understood to be physically stronger than sand screens. Also, heavy gravel was considered for use to prevent gravel migration. However, this option was considered to be difficult in terms of isolating the water layer, as well as being difficult to install.

All four candidates were considered to meet the technical requirements extracted from the first offshore production test, however, because of the fourth requirement, or the cost effective technology for future cost reductions, (b) and (c) were selected for the second offshore production test and we decided to apply (b) to one production well and (c) to another production well.

Fig.7 presents the structure of the selected sand control device. This device consists of three layers of barriers. The outer layer is GeoFORM™, which is the shape memory polymer with a certain degree of thickness and that works as depth filtration. The middle layer is the mesh screen, and the inner layer is the beads insert. With this system, sand production will not occur unless all three layers of barriers are damaged.



(d) Prepack Screen
Gravel will be packed between two screens

(c) GeoFORM™+Beads Insert
GeoFORM™ will be activated before installation

(b) GeoFORM™+Beads Insert
GeoFORM™ will be activated in the well

(a) Gravel Pack+Beads Insert

Fig.6 Selected sand control device candidates

Image of installed GeoFORM™

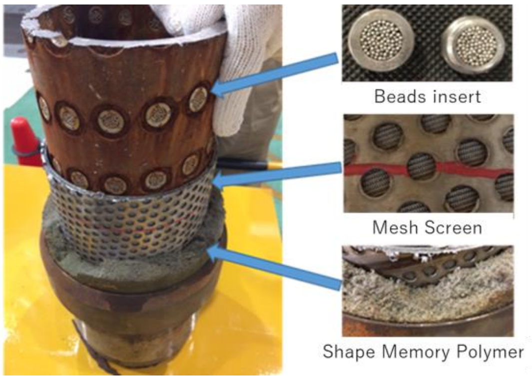


Fig.7 GeoFORM™
(Extracted from Presentation of Methane Hydrate Forum 2017 (Japanese only))

(5) Sand Production During Second Offshore Production Test

During the second offshore production test, production was conducted in two wells (AT1-P3 & AT1-P2). Sand production occurred in the first well (AT1-P3), which was completed by previously activated GeoFORM™. The first instance of sand production was recognized during the second depressurization after the malfunction of ESD (Emergency Shutdown). In this early stages of sand production, the amount of sand that collected on board was small, and contained particles that were smaller than the mesh size of the sand control devices, which means that the collected sand was able to pass through those devices. However, it was noted that over time, the particle size as well as the volume increased. When the frequency of the pump was reduced, sand production stopped for a few days, however, when the test reached the mid-term stage, sand production occurred again. For the latter instance of sand production, the flow of sand into the wellbore was predictable, due to significant temperature and pressure changes confirmed by the real-time in-situ measurement. (Fig.8)[11] In the end, in order to prevent the facility from being damaged and adverse effects from occurring during the next instance of production in the AT1-P2 well, a final decision was made to stop production after 12 days of continuous tests.

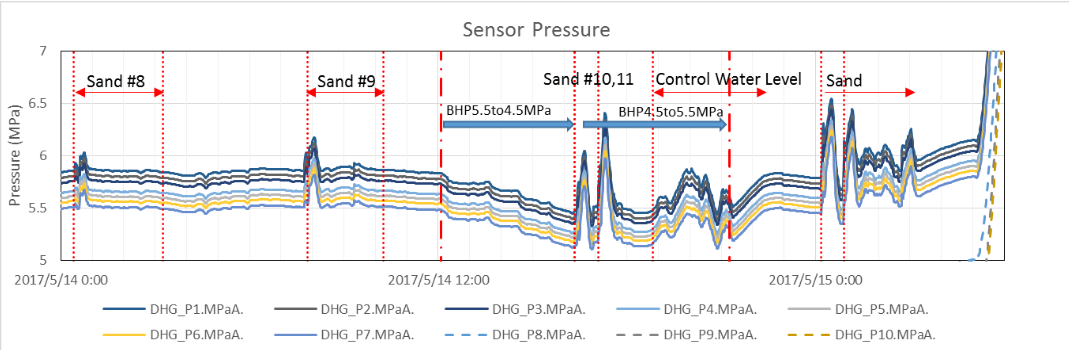


Fig.8 Example of pressure variation due to sand production

From the detailed study of the measured data, the sand produced in the AT1-P3 well was considered to come from the bottom side of the well. Erosion or destruction of the sand control device was one of the possible causes of this sand production, however, according to the experiment conducted in the laboratory, the shape memory polymer and the beads insert were strong enough for us to conclude that the possibility of erosion or destruction was very low. Instead, the most likely cause of sand production was considered to be the malfunction of a portion called a GPV shoe that has a check valve installed at the bottom of the assembly. Detailed analysis of the data showed clear evidence of warm flow coming from the bottom side of the well, and the pressure and temperature changes were also occurring from the bottom.

For the AT1-P2 well, to address the possible cause of sand production in the AT1-P3 well, a plug was set above the GPV shoe to prevent flow into the well from the bottom of the assembly. In addition, for the onboard facility, an additional sand management system was installed to handle sand. As a result, no sand was produced during 24 days of production, even with a longer production period and a larger volume of water produced than that of AT1-P3. These results suggest that the sand control device used in the test worked effectively although further verification in the test may be needed. [12]

(6) Future Tasks

We have selected the sand control device for each production test taking into account the previous results of laboratory testing and field production tests. The results obtained so far clearly show the effectiveness of depth filtration and the necessity of sand control.

On the other hand, we have not yet obtained a sufficient amount of information to understand the long-term effectiveness of sand control measures, considering the future long-term production. The high content of fine particles may cause clogging around the well or sand control device itself due to accumulation of fine particles, therefore the long-term production effect of sand control measures still needs to be clarified. Also, other sand control devices or new technologies need to be developed to create more suitable sand control against specific geological conditions.

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IV.2.5 Monitoring system device

During the gas production test using the depressurizing method, it is expected that the formation temperature, pressure, and other properties surrounding the production well will change due to the dissociation process of MH. To capture such reservoir responses and property changes in situ, the downhole monitoring system was installed to acquire formation temperature and pressure data, and geophones were also deployed in the vicinity of the production well to acquire 4C seismic data.

IV.2.5.1 Downhole monitoring

(1) Objective

When conducting a study on the MH development system with the aim of achieving long-term production, it is desirable to acquire as much data as possible about reservoir characteristics and responses. In fact, monitoring wells completed near the production well have the advantage of being able to passively observe reservoir responses during the production period. Therefore, the following objectives for downhole monitoring were determined for the first and second offshore production tests:

- Capturing the initial condition of formation and in-situ property information
- Acquiring information about formation response against the depressurization method
- Understanding the dissociation behavior of MH
- Acquiring knowledge about heat and fluid movement in the formation

To achieve these objectives, we aimed to acquire data about reservoir temperature in the first offshore production test, and about reservoir temperature and pressure in the second offshore production test. In the following, we will report on the techniques used to acquire temperature and pressure data performed in Phase 2 and 3, and the results of the data analysis.

(2) Background

In Phase 1, the downhole temperature sensor was introduced and installed in "Tokai-oki to Kumano-nada" in 2002 [1]. Subsequently, temperature measurements were performed in two on-shore production tests [2]. In Phase 2 and 3, the temperature measurement system was developed and enhanced to meet the requirements of the offshore environment for the production tests.

For the first offshore production test in 2013 during Phase 2, a monitoring system equipped with two kinds of temperature sensors using DTS (Distributed Temperature Sensing) and array-type RTD (Resistivity Temperature Detector) was installed into a borehole and at the seabed of two monitoring wells, and temperature measurements were carried out during the six-day production test.

Further upgrades and enhancements enabling in-situ pressure measurement were implemented on the downhole monitoring system developed for the second offshore production test in 2017 during Phase 3. This uniquely-developed subsea monitoring system equipped with both temperature and pressure sensors was deployed in two monitoring wells around the production well.

(3) Contents and results

① Monitoring system design

a. Results of temperature measuring

To measure formation temperature, an integrated system of DTS (Distributed Temperature Sensing) and RTD (Resistance Temperature Device) was designed for monitoring. DTS is a fiber optic distributed sensor that can measure temperature distribution as a function of depth from seabed to well bottom, while RTD is a resistor sensor in an array that mainly covers the MH-concentrated zone with higher temperature resolution.

The subsea monitoring system with a pressure vessel containing the measurement unit, battery, and other critical components was installed at seabed level so that it can control acquisition and store data obtained from downhole sensors. (Fig.1, 2) Both DTS and RTD sensors acquired reservoir temperature for more than a year, and real-time data acquisition was achieved during the production period.

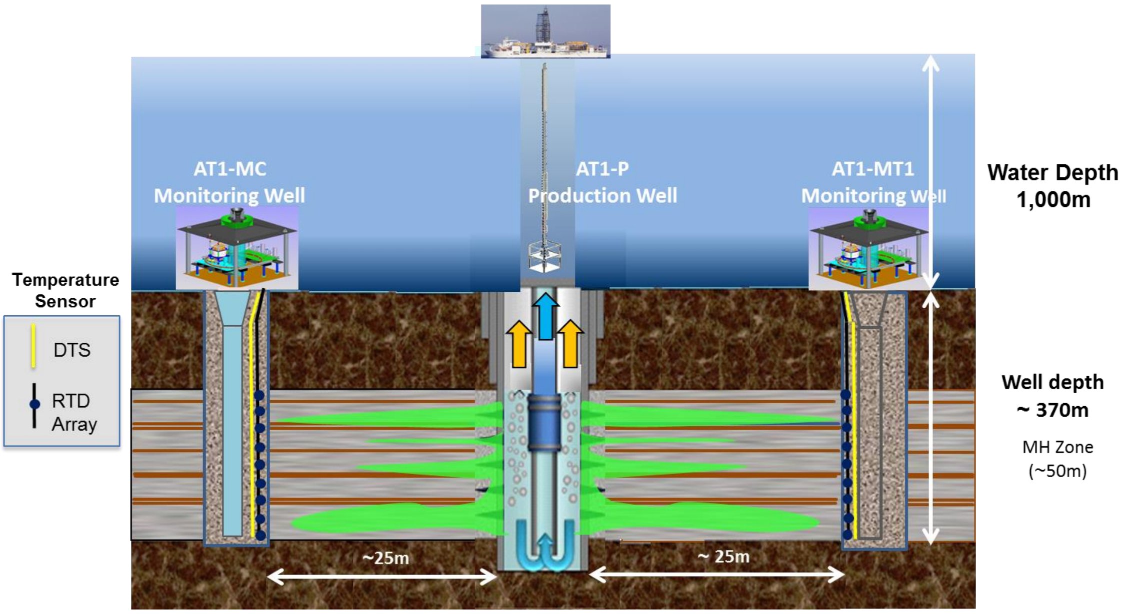

Fig.1 Overview of formation temperature monitoring system for first offshore production test

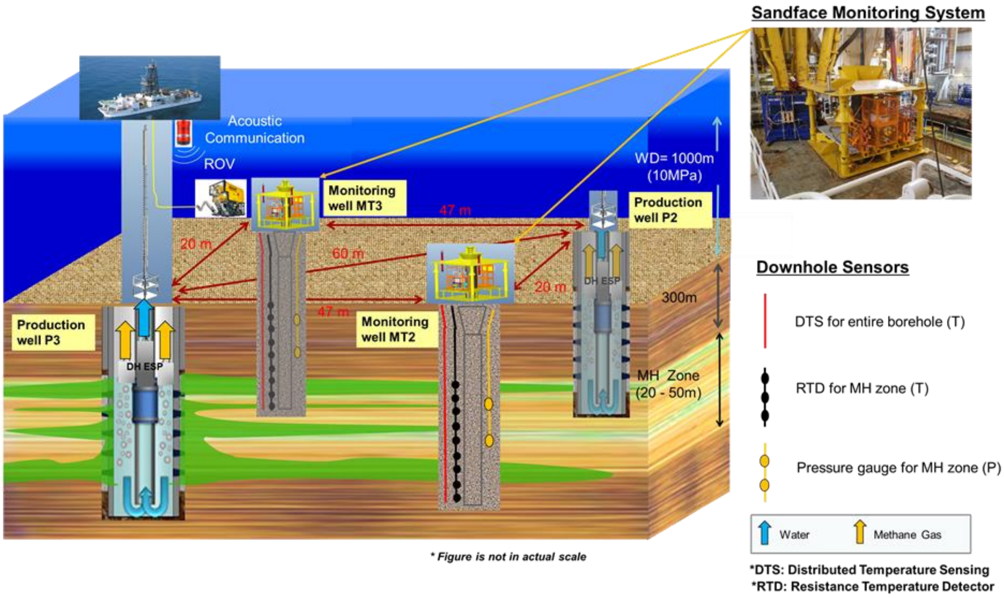

Fig.2 Overview of formation temperature and pressure monitoring system
for second offshore production test

b. Results of pressure measuring

Although reservoir pressure measuring in the monitoring well was waived during the first offshore production due to its technical complexity, realization of in-situ pressure measuring incorporated into the monitoring system was considered in order to provide such vital reservoir parameters along with temperature data.

At each monitoring well, the pressure sensors were respectively installed in upper and lower

MH-concentrated zones. To measure formation pressure, several pressure ports on the sensor protector were especially designed and developed to realize conduction of pressure propagation. Similar to temperature monitoring, pressure was recorded for more than a year while real-time data acquisition was confirmed during the production period.

② Demonstration of acoustic communication system

During the second offshore production test, acoustic communication system was used to retrieve the data at monitoring wells during and after the production period in order to efficiently data transfer from the seabed to the surface without requiring a physical connection comprised of subsea cables. (Fig.3)

With this system, the data was acquired as per the retrieval schedule, and establishment of reliable wireless data communication was confirmed during the offshore production test. As a result, operation efficiency and safety were significantly improved.

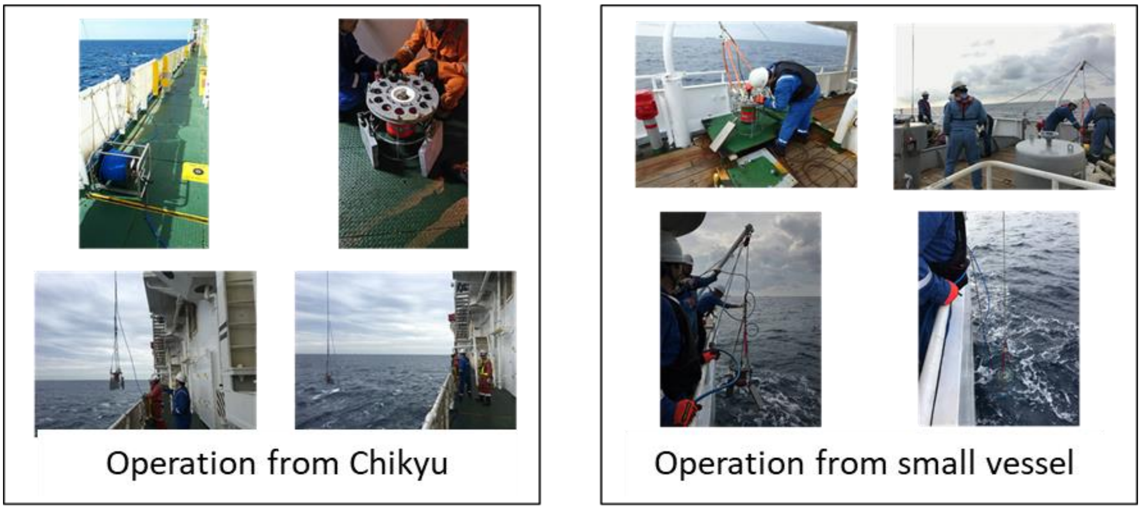

Fig.3 Data retrieval operation with acoustic communication system

③ Key findings and knowledge obtained from acquired data

a. Evaluation of impact from cement heat release on MH in the surroundings

One of the concerns in terms of completing a MH well is the integrity of cement used to maintain the separation between the production layer and another formation or the seabed. In this context, there is a concern that heat generation and temperature increases at the time of cement hydration could cause MH dissociation to affect the stability of the MH layer.

DTS started recording the temperature data before cementing (Fig. 4), and these temperature data are used to estimate the spatial impact by heat generation from cement at each depth level near the monitoring well. Since the amount of heat generation is relative to that of cement in place, a high temperature increase was observed in the interval where the borehole diameter became washed out and enlarged.

Based on the heat generation model of cement constructed in Phase 2, the stability of the MH layer in the vicinity of the monitoring well during cementing was evaluated. As a result, MH dissociation around the monitoring well arising from the cement hydration heat was in the order of several centimeters, and subsequently it was not considered to pose a particular hazard [4].

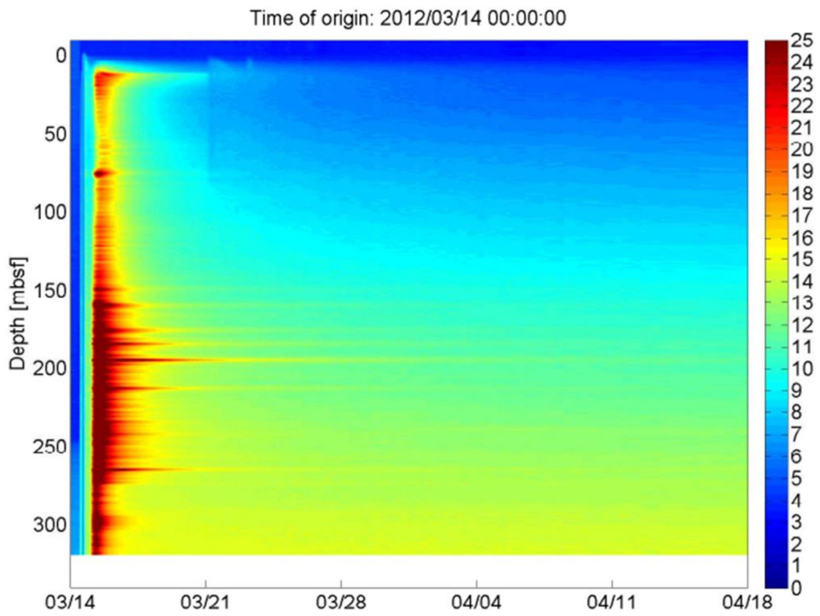

Fig.4 Temperature profiles in MT1 including period prior to cementing

b. Initial formation temperature determination

The installation of thermometers was attempted in the 2004 campaign at “Tokai-oki to Kumano-nada", however, the data could not be acquired in the Daini-Atsumi Knoll wells.

For the first offshore production test, stable temperature measurement in the formation was attained after almost reaching an equilibrium state, because there was one-year period for the temperature to relax between the drilling/cementing stage and the start of the production test [5].

c. Determination of sand produced interval

During the first offshore production test, sudden sand production occurred six days after the start of depressurization, and rapid temperature changes were observed in some formation layers in the monitoring well at almost exactly the same time that sand was seen inside the production well. Since a large amount of water was also noted to accompany sand production simultaneously, it was inferred that high permeable layers existed in the formation between the production and monitoring wells, and that the temperature measurement in the monitoring well supported the determination of the sand produced interval.

d. Validity of in-situ pressure measurement

The figure at left in Fig. 5 shows the pressure transients in the production and monitoring wells. By comparing these two curves, a strong pressure reduction correlation was identified in the monitoring well following the production well. The figure at right shows the phase diagram of the pressure and temperature observed in each monitoring well, and the general trend and change of pressure/temperature tracing the curve of MH dissociation during the test period that supported the valid and effective measurement of in-situ pressure.

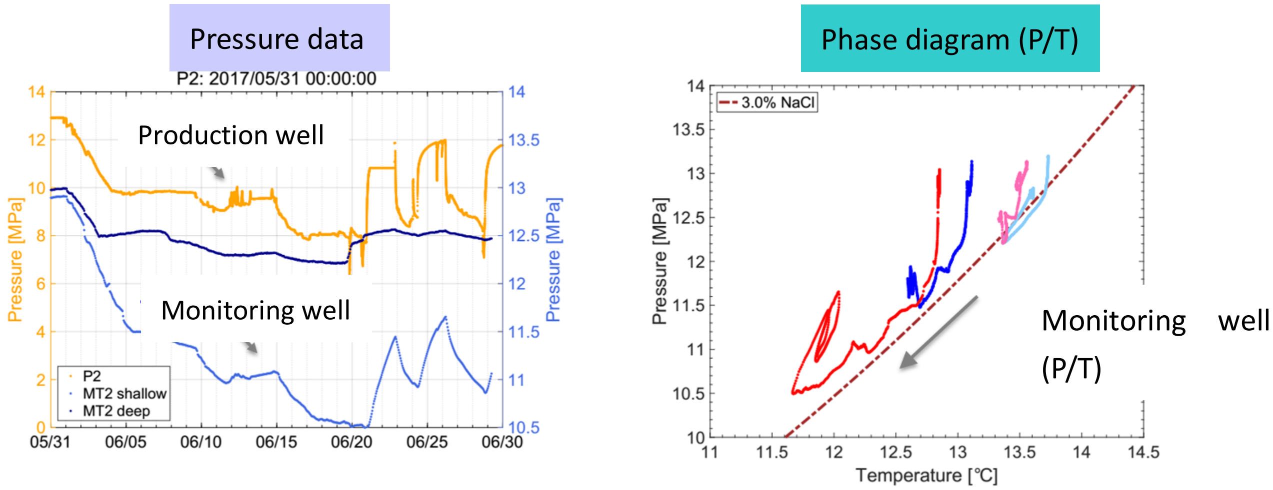

Fig.5 Pressure transients in production and monitoring wells (left), Pressure/temperature transients on phase diagram in each monitoring well

e. Understanding of MH dissociation behavior

During the second offshore production test, reductions in temperature were observed in the monitoring wells at the corresponding depths where the temperature in the production wells fell due to the dissociated water and gas inflow (Fig.6). From the temperature transients in the monitoring wells, layer permeability was estimated in the gas production interval from the numerical simulation assuming adiabatic conditions [6], (Fig.7).

It was also found that there was a difference in the dissociated interval among two production wells during each depressurization and flow test period by integrating the temperature data in the production and monitoring wells (Fig.8). The analysis of the MH saturation changes from the observed temperature and pressure data indicated that the estimated change in saturation would be within the range of a few percentage points, and that it is in line with the results of the first offshore production test.

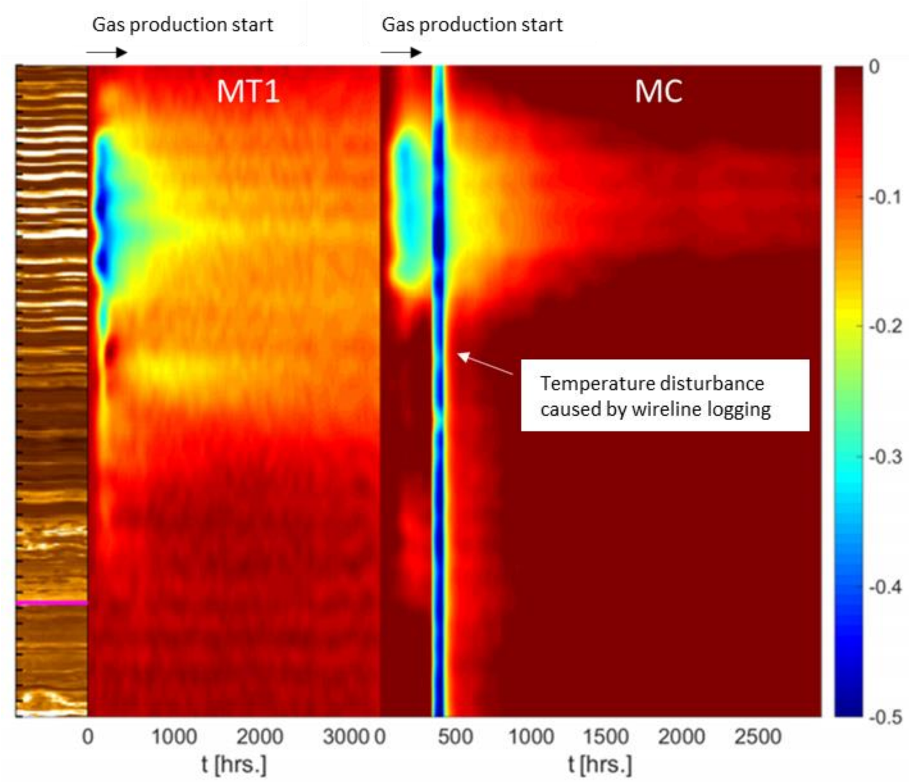

Fig.6 Resistivity image in MH reservoir (left track) and temperature change in monitoring wells (middle and right track)

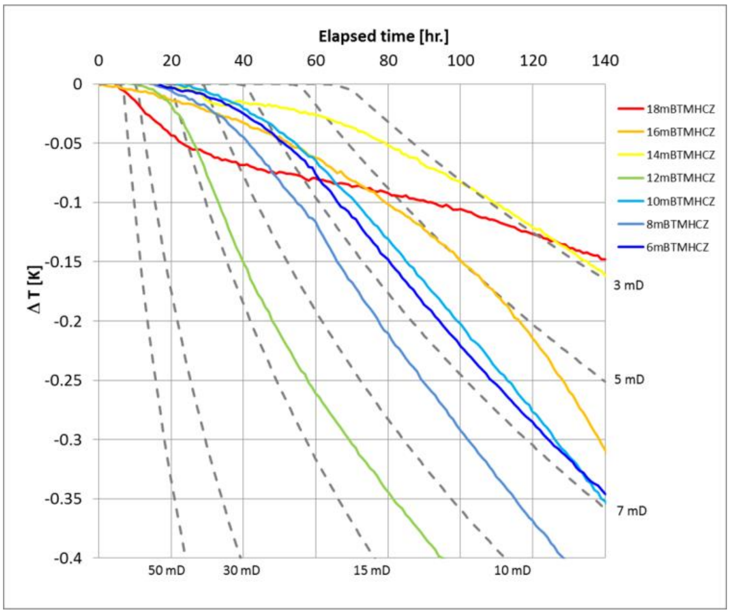

Fig.7 Simulated (dashed) and actual temperature changes for various layer permeability in AT1-MT1

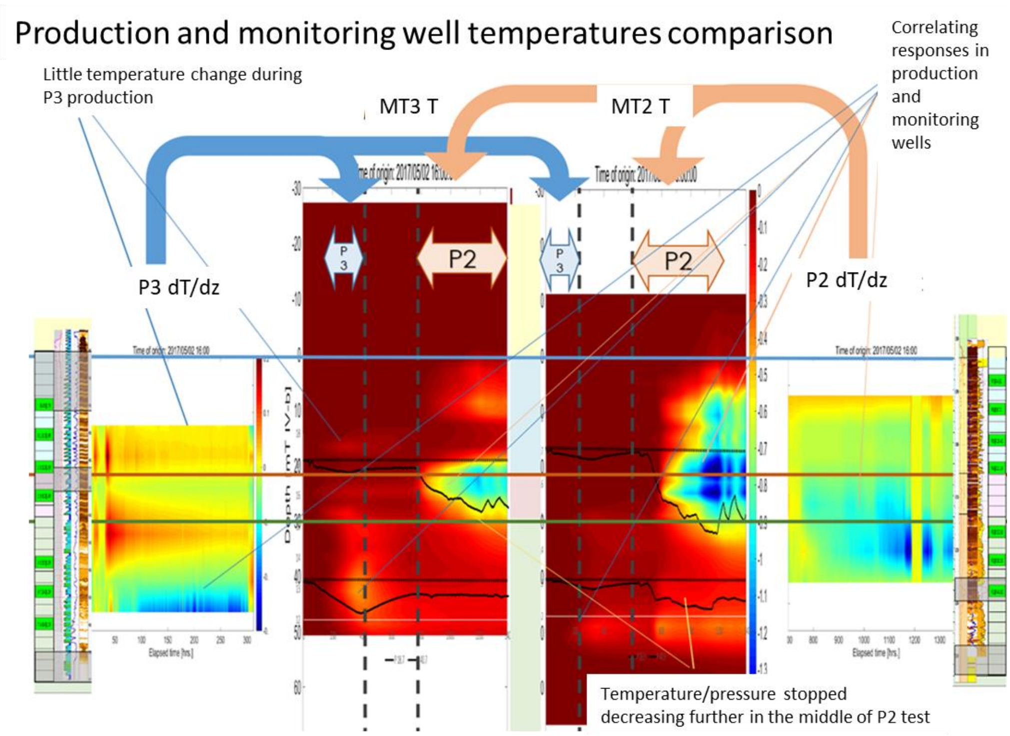

Fig.8 Temperature change in two production wells and two monitoring wells

(4) Summary

During the first and second offshore production tests conducted during Phase 2 and 3, the downhole monitoring system was developed and installed to measure reservoir temperature and pressure.

Data transfer from the seabed to the drilling vessel was carried out through using the acoustic communication system, which eliminated the need to have a physical connection using a cable. As a result, the necessary rigging time was shortened for the data retrieval operation, and the safety margin in case of emergency disconnection was increased.

The MH dissociation range as well as the characteristics of thermal transport in the reservoir were analyzed from the monitoring data obtained during the production periods. In future, it will be necessary to further improve and enhance the monitoring system according to the feedback and inputs from the data analysis and study results for future production tests with a focus on the commercial phase.

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IV.2.5.2 Four component seismic survey

(1) Background and Results

During the first offshore production test carried out in Phase 2 aimed at gaining an understanding of the changes in physical properties that accompany MH dissociation as a result of gas production tests, geophysical monitoring was carried out using four component seismic surveys. An OBC with 4 built-in components (two horizontal accelerometer components, vertical component, hydrophone) was installed near the production well, and seismic data was acquired (**Fig.1**). Data was acquired on three occasions, once before the gas production test (August 2012), and twice after the gas production test (April 2013 and August 2013). The purpose of acquiring data twice after the gas production test was to understand what kind of changes occurred by comparing the data after the gas production test approximately four months prior.

The obtained result shows that the changes in physical properties could be understood by comparing data before and after the gas production test.

During the analysis process, it was initially thought that the changes in physical properties were due to MH dissociation or the generation and regeneration of MH. A subsequent study has revealed that there are various factors involved such as changes in the gas saturation of pore water after MH dissociation, and changes in density due to consolidation of sediments.

In order to determine whether the difference due to the comparison the data before and after the gas production test is significant, it is necessary to improve the quality of acquired data and review data processing of acquired data. Subsequently when carrying out geophysical monitoring during the second offshore production test, a technological study involving items such as the receiver point and source point layout for enhancing imaging effects near the gas production test well, the method to improve source point accuracy, and data acquisition time, was conducted.

In order to significantly enhance the reservoir image near the gas production test by carrying out a simulation in advance (**Fig.2**), the two receiver cables were arranged in east and west directions with the gas production test well in between, and the source point was placed within the range of 4km north by 3km east to west centering on the gas production test well (**Fig.3**). In addition, in order to improve the accuracy of the source point, a GPS antenna was installed at the center of the float beneath the air gun (**Fig.4**).

Data was acquired before the gas production test (M0) was conducted from late July to early August 2016. Fig.5 shows a comparison of the source point, receiver point, well location, and data acquisition specifications, and Table.1 shows the comparison of data acquisition specifications between the first and the second offshore production tests.

The first data acquisition (M1) after the gas production test was conducted from the end of October 2017 to the beginning of November 2017.

In addition, data processing of acquired data was carried out, and M0 data and M1 data were compared.

Time-lapse data processing for the purpose of comparing data before and after the gas production test was carried out. In addition, the reproducibility index was calculated to evaluate the appropriateness of the time-lapse data processing result. As a result, the NRMS value became 10% in the region where the influence of the pressure reduction is small and the changes in physical properties due to the reduction is also small. It is judged that appropriate time-lapse data processing is applied because the NRMS value that is considered to be good for reproducibility is 30% or less (Johnston, 2013). An interpretation example of M0 and M1 is shown in Fig.6, and an amplitude image in the MH reservoir is shown in Fig.7.

The second data acquisition (M2) after the gas production test was acquired in late July 2018, and data processing of M2 data and time-lapse data processing of M0, M1 and M2 data were carried out to evaluate physical properties before and after the gas production test.

(2) Conclusion

In Phase 2 from 2012 to 2013, four component seismic surveys were conducted before and after the gas production test during the first offshore production test, and changes in physical properties could be understood from data comparisons before and after the gas production test. On the other hand, the causal relationship between MH dissociation and changes in physical properties remained a problem.

Based on the technical examination of issues at the time of the first offshore production test, four component seismic surveys were carried out a total of three times each involving M0, M1, and M2 from 2016 to 2018 during Phase 3 of the second offshore production test. Data processing has been completed and the analysis of those data is currently ongoing. Finally, based on the comparison of M0 and M1, and M0 and M2, the changes in physical properties due to the influence of MH decomposition is evaluated based on the examination of the significance of the difference. Furthermore, the comparison between M1 and M2 also confirms what changes have occurred after the gas production test. These results are expected to be useful for MH reservoir assessment.

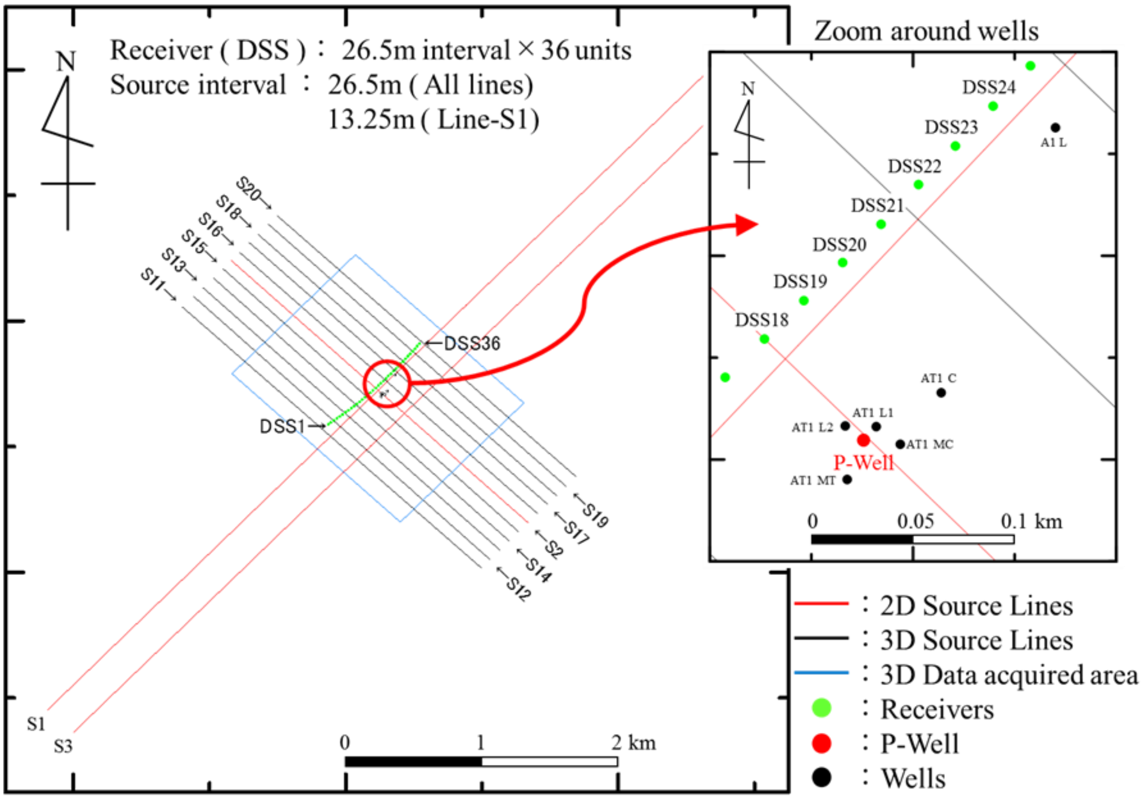

Fig.1: Receiver points/ shot points/ well location/ specifications of data acquisition in the first offshore production test

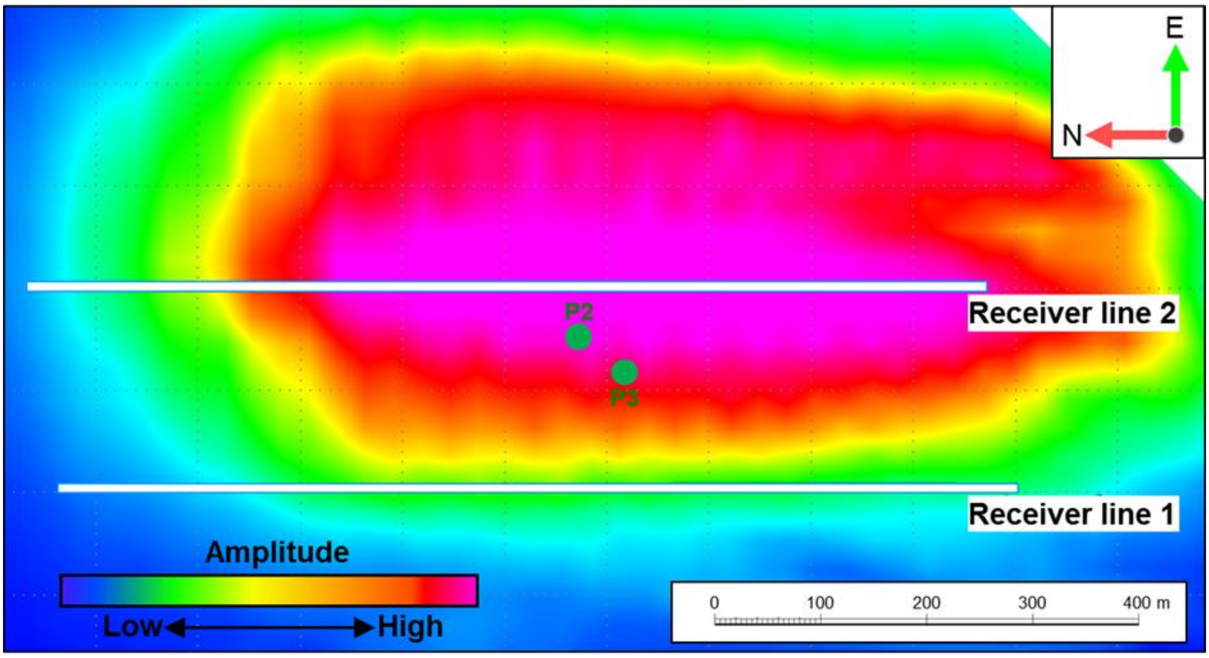

Fig.2: Result of simulation

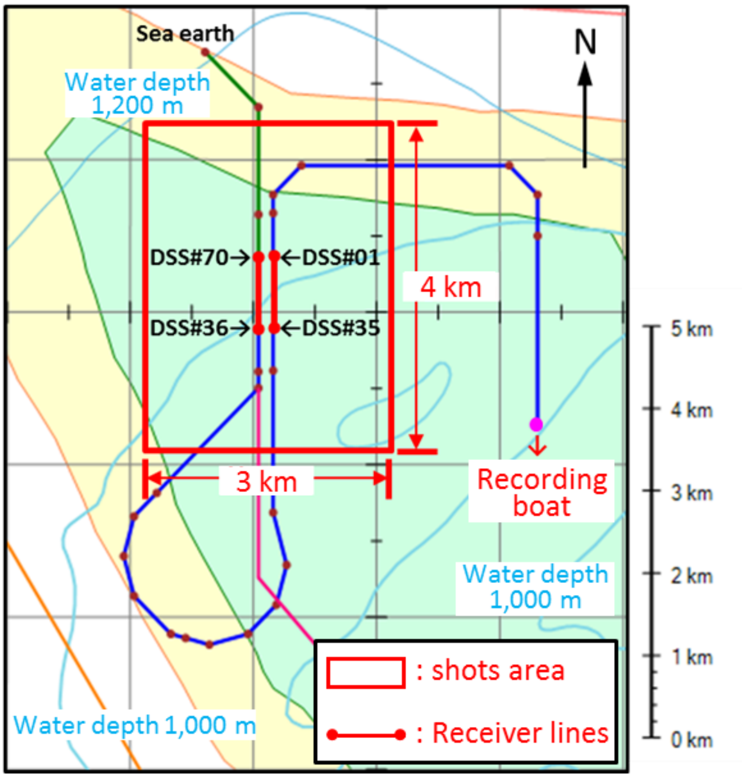

Fig.3: Layout of OBC and shots area

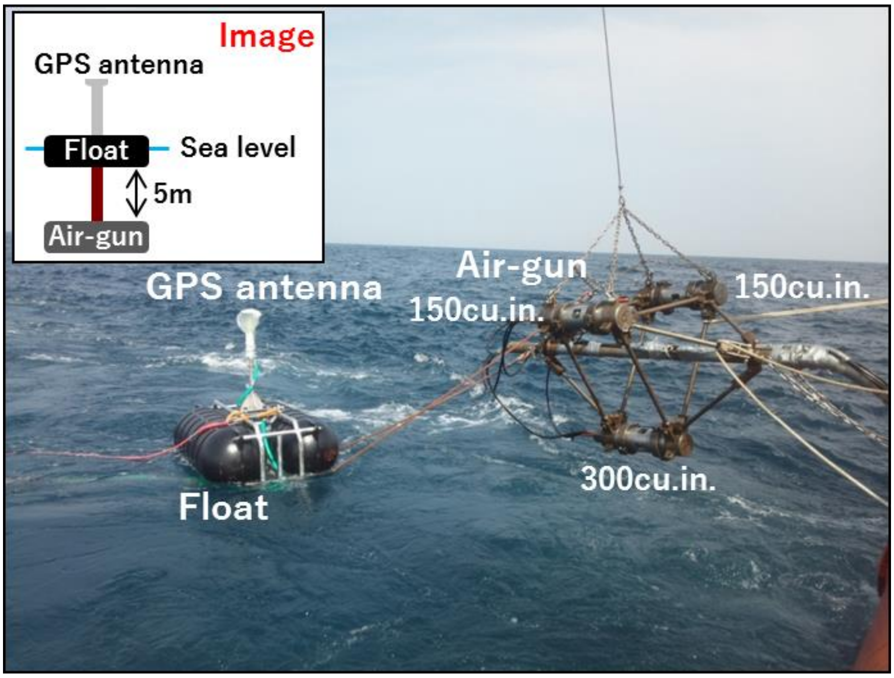

Fig.4: Arrangement for improving the accuracy of source point

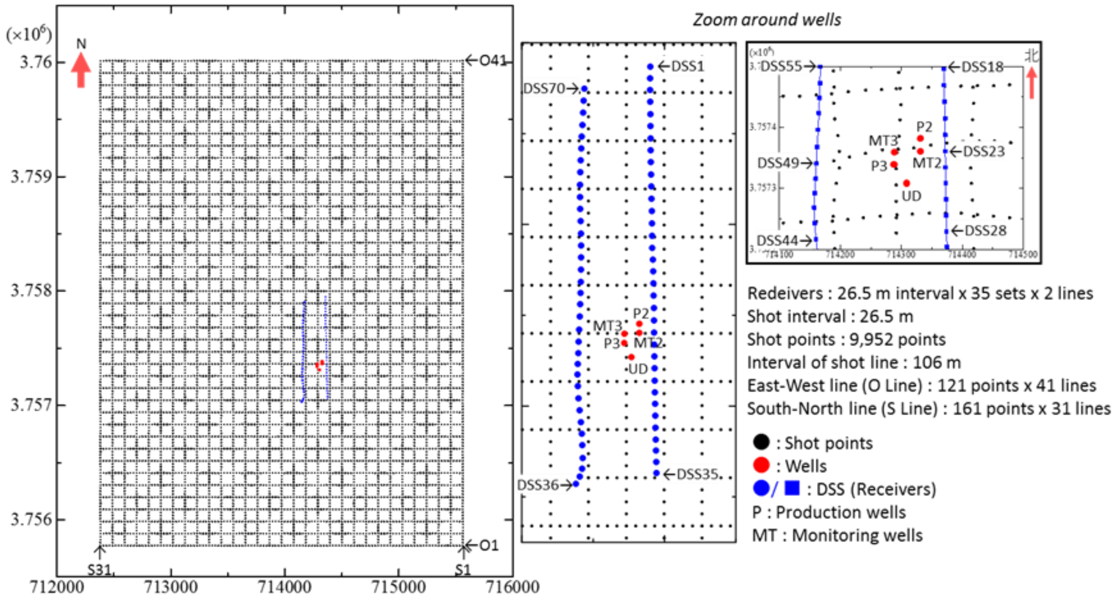

Fig.5: Receiver points/ shot points/ well location/ specifications of data acquisition in the second offshore production test

Table.1: Comparison specifications

	First offshore production test	Second offshore production test
Receiver line	36 units in one line	35 units in two lines each
Interval of receiver line		Approx. 200 m
Interval receive	26.5 m	26.5 m
Source line	Northwest – Southeast: eleven lines 11 lines	East - west: Forty one lines
	Northeast – Southwest: two lines	South – north: thirty one lines
Interval of source line	Northwest – Southeast: 100 m	East - west: 106 m
	Northeast – Southwest: 267.5 m	South – north: 106 m
Interval of source point	26.5 m	26.5 m
Number of source point	1,797	9,952

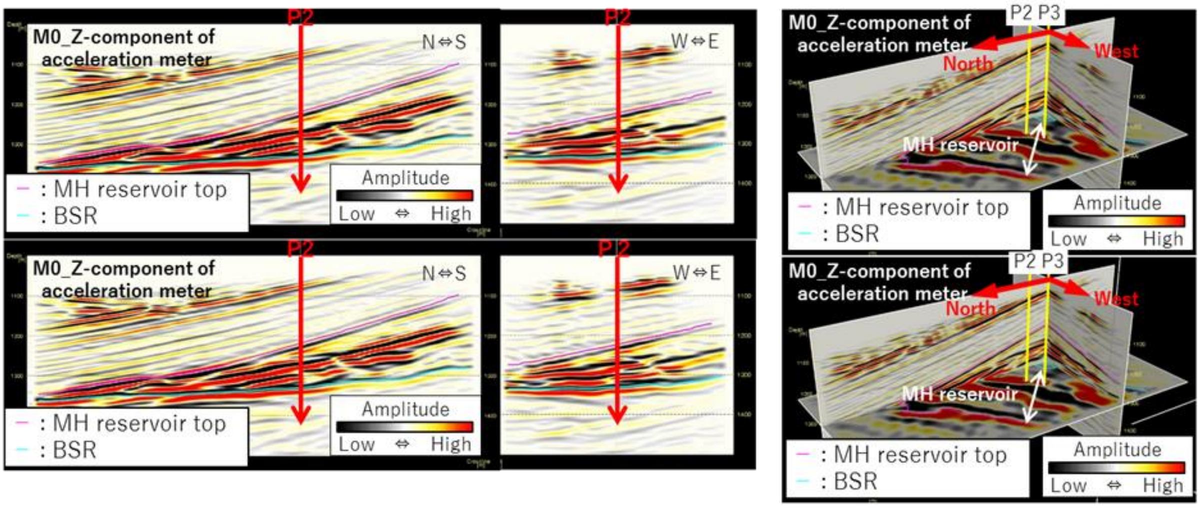

Fig.6: Examples of interpretation of M0 and M1

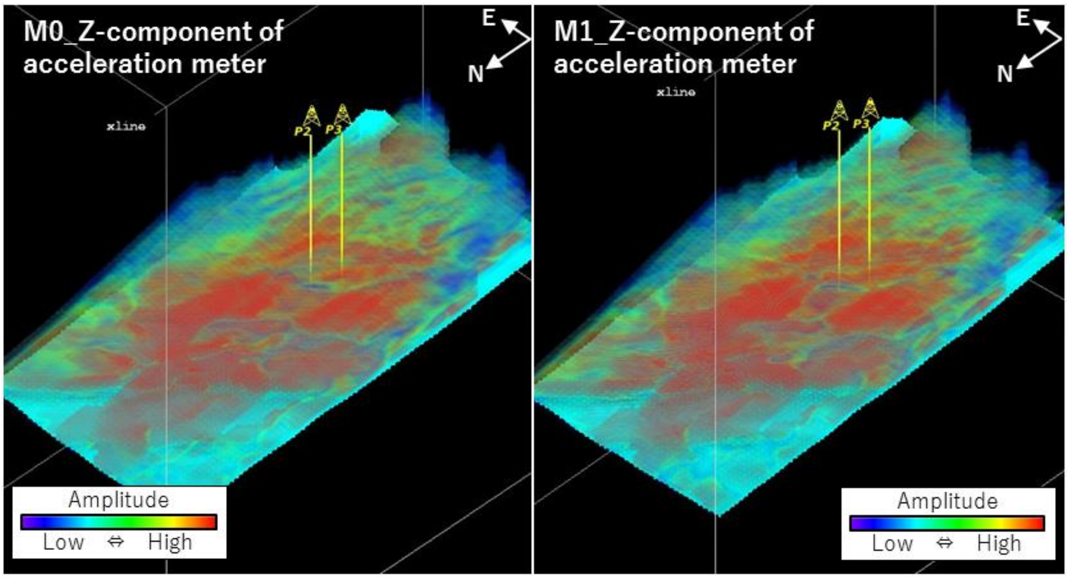

Fig.7: Amplitude image of M0 and M1 in the MH reservoir

Reference

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