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# Paper 5.2

# Flow Data for Natural Gas with Water and Hydrates


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## 1. INTRODUCTION

Natural gas hydrates are common when water is present in production, gathering, transmission, and processing flow lines, and can cause severe capital and labor intensive challenges to operators. The problems include measurement errors, equipment malfunctions and damage, flow shut-ins, and, in extreme cases, catastrophic failure to flow line equipment. Safety is a paramount consideration when hydrates are present. As fluids and operating environments become more severe, hydrate control becomes an increasingly important component in assessing capital and operating risks.

At the 23rd NSFMW, an update to a report on the Canyon Express project was provided [1, 2]. The authors indicated that the project design stage recognized the potential for hydrates and hydrate blockages, however, it was felt that the jumper and flow meter did not require methanol injection because it was expected the heat from the produced fluid would keep the system above the hydrate formation phase boundary. Results showed this was not true for the meter which experienced significant problems with the capillary lines to the differential pressure transmitters during shut-ins periods due to weather. Sub-sea temperatures were 35 deg F , (2 deg C). Erratic performance was observed with several meters during start-up, with one considered as non-performing due to a possible hydrate blockage. It was further noted that a similar situation occurred in Statoil's Mikkel field [3] where insulation was applied to both the instrument lines and around the flow lines. Insulation helped, but did not entirely eliminate the problem. Lastly, it noted that as wells mature, and liquid production increases, there is an increased probability of hydrate formation in the flowmeter. Management of hydrate risks mandates the need for advances in hydrate detection and control. Although much is known about the equilibrium behavior of hydrates little is known about their dynamic behavior in full-scale systems under a range of realistic flow conditions and practical operating scenarios. Full-scale natural gas hydrate flow data with water and hydrates provides a critical piece of information for hydrate risk assessment and for advancing hydrate management technologies.

Hydrate formation and blockages are frequent occurrences in natural gas storage fields. They often occur following extended shut-in periods, and during start-up conditions during injection and withdrawals that produce transients in the flow line. A research consortium is sponsoring a multi-year hydrate flow measurement program to improve the understanding of hydrate flow behavior for hydrate monitoring, control, and flow assurance in gas storage field flow lines. The program is sponsored by the U.S. Dept of Energy, Pipeline Research Council, and the Gas Technology Institute.

Field work has been carried out at two consortium member sites, the Greenlick storage field which provides late season and peaking gas to New York, and the Latigo storage field which supplies natural gas to Denver. Hydrate formation and flow data are being obtained at Colorado Engineering Experiment Station, Inc.'s, (CEESI) Hydrate Flow Test Facility (HFTF) located in Nunn, Colorado. The principal goal of the program is to obtain field and laboratory flow data to help identify the controlling mechanism(s) of hydrate constriction and blockage development, and to identify low cost options for monitoring and controlling hydrates in flow lines. Other objectives include identifying pre-emptive methods for hydrate constriction/blockage prevention and to improve blockage remediation practices in the field. The field sites were selected based on their operating characteristics. The Greenlick storage field is a high pressure field. Gas is typically drawn down from the Greenlick field at the end of the high demand winter heating season. Latigo is a moderately pressured field. Gas is continually cycled during the heating season at the Latigo field. Both fields experience low surface temperatures that are below freezing for significant time periods. The hydrate flow test program at CEESI was designed to complement the field data program. The data sets help demonstrate the behavior of hydrates in natural gas fluid flow lines at storage field flow conditions.

The flow tests that have been made by the consortium at the CEESI HFTF include hydrate flow tests include water saturated natural gas, natural gas with free liquid water, natural gas/liquid water/solid hydrate, and natural gas/liquid water/liquid condensate /solid hydrate flow. The test data include steady, unsteady, and transient flow data for isothermal and non-isothermal conditions. Test temperature conditions range from near wellhead fluid injection temperatures to flow line wall temperatures that are well below the ice point. The tests include full-scale horizontal, inclined, and vertical (simulated riser) flow line configurations. Work has been initiated to extend the effort to include hydrate flow behavior in the wellbore and subsurface safety valves.

The paper provides an overview of the hydrate flow testing program for storage field operators. It discusses: (1) the problems and issues storage field operators face with hydrates and presents field data from Greenlick and Latigo; (2) hydrate and inhibitor phase behavior as it pertains to the Greenlick and Latigo storage fields and identifies issues for wet gas and multiphase flow measurement; (3) a description of the CEESI hydrate flow testing facility. Lastly some concluding remarks on findings and suggestions made for future hydrate flow study needs.

## 2. NATURAL GAS STORAGE FIELD HYDRATES

In order to meet natural gas demands during peak winter months, gas storage field facilities operate at conditions that cause hydrates to form in their flow lines. Hydrates cause economic, maintenance, safety, and operating problems in storage field wells, flow lines and nearly all related equipment. These problems manifest themselves in gas deliverability and efficiency constraints which are most evident when the demand for gas is the greatest and of most value to the storage field operator. Depending upon the location of the blockage significant revenue may be lost during high demand periods. Demand charge refunds may be imposed on storage field operators if gas deliverability is constrained. Residential, commercial and industrial end-users cannot afford peak delivery interruptions due to weather and process condition requirements. As gas demand pressures increase and field automation efforts extend to more gas storage fields, there is a growing need for the ability to provide low cost technologies to detect and control hydrate accumulations in the gas storage field. Hydrate problems in storage facilities are not restricted to high demand cold weather periods, they occur throughout the year.

Table 1. provides gas composition data on the Greenlick and Latigo storage field gases. Figure 1. provides an example temperature, pressure trace over a twenty-four hour period for Well 37 at the Latigo storage field. The measurements were obtained at multiple locations including the orifice, pipe wall surface temperature located downstream of the orifice, the casing, and tubing. The data show the range of operating conditions the gas and fluids in the flow line experienced during that time period. Figure 2 combines operating data obtained from the Latigo site and Greenlick storage field site to show the temperature, pressure, operating region for both the Greenlick and Latigo gas storage fields. It also provides estimates of the operating conditions at which hydrates will form for the storage field gas mixtures. Based on the phase diagram, Well 37 spends most of its time in the hydrate forming region. The Latigo gas mixture forms hydrates at slightly higher operating temperatures than the Greenlick gas mixture. Figure 2 includes the identification of hydrate risk zones. The zones are a convenient means to help storage field personnel identify the approximate conditions where hydrates are present and blockage problems may develop. The conditions include sub-surface and surface (exposed) operating conditions which have been nominally characterized as isothermal and non-isothermal. The low temperature side of figure 2 represents surface facility conditions that include the tree, metering, and portions of the gas flow lines that are exposed to external weather conditions during shut-in periods. The isothermal range covers subsurface flow line temperatures and drip conditions. The high temperature region shows surface and subsurface gas conditions that exist during withdrawal and injection periods.
A substantial portion of the gas withdrawal and injection seasons for the two gas storage facilities is inside of the hydrate forming boundary.

Flow measurement data at some storage facilities is minimal at the locations where hydrates form. The Greenlick storage field eliminated orifice meters from their well flow lines due to hydrate blockage problems. There is very little instrumentation in-line at the Greenlick site because of the remoteness of the site and the problems that installed instrumentation causes for the facility personnel. Instrumentation is less of a problem at the Latigo, although maintenance can be a problem. Some well sites at Latigo have orifice meters installed. Meter locations vary depending on the well.

Hydrate blockage removal is a time consuming process for field personnel, consequently wells and flow lines are shut-in when a blockage occurs. A flow line with a blockage will typically remain shut-in until sufficient time is available for the field personnel to go through the steps necessary to locate and remove a blockage(s). Removal of a hydrate plug in the field has risks. Field personnel have described various means they apply to remove hydrate plugs. The descriptions include blowing down from both sides of the hydrate plug, heating the section where the hydrate plug may be located to loosen the plug, creating a large differential across the plug section to free the hydrate plug, e.g. 10:1 pressure differential, and/or injecting a slug of methanol.

Hydrate blockages occur in the production tubing following a subsurface safety valve, at the well head, at the inlet to a separator, upstream of the orifice, downstream of the orifice, instrument lines, in the liquid drips and in the gathering and trunk lines where fluids accumulate. Blockages in gas storage fields can lead to the shut-in of a well, multiple wells, or, in severe cases, a trunk line. The consequences of the shut-in depend on the operating characteristics of the facility. In all cases shut-ins create an undesirable condition for the operator because it constrains the facility’s ability to respond request from gas control. The development of a flow blockage is difficult to predict, monitor, control, locate and alleviate. The problem is exacerbated due to inadequate field instrumentation, fluid measurement, separation equipment, chemical injection monitoring and flow control. Anecdotal evidence from operators indicates that many storage field flow line blockages do not occur under gas withdrawal and injection conditions, i.e. gradual choking of the lines through growth on the pipe walls. Rather, flow line blockages are promoted during gas injection, after sustained shut-in periods, and on start-up during withdrawal periods. This experience is consistent with the experience reported by the authors of the Canyon express paper [2].

A variety of operational concerns arise when hydrate conditions are present. The concerns include safety to personnel, equipment malfunctions and equipment failures. A number of field examples are provided in figure 3 to figure 8. Figure 3 shows an example of hydrates that were obtained during a blow down of one of the flow lines from the Greenlick field. Figures 4 shows a three different 6” orifice plates that encountered hydrate blockage masses. Figure 5. shows a C-clamp that snapped due to vibrations on the flow line while a hydrate plug was being removed and a corrosion sensor that is often found snapped off due to hydrates. Figure 6 shows some historic chart recorder data dp readings with hydrates in the flow line, figure 7 shows differential pressure readings taken on Well# 37 with hydrates during this study. Figure 8 provides a dramatic example of a frozen hydrate mass extracted by Petrobras, similar hydrate masses have been reported by storage companies in subsurface flow lines below streams. Figure 9 provides an example trace of the estimate water that is condensing from the gas stream due to the temperature differential between the stream and the pipe wall.

The flow lines in gas storage fields are often oversized leading to low liquid velocities and liquid water hold-up problems. Storage field operating conditions create accumulations of hydrate solids and semi-solid masses in the flow line as gas is withdrawn and injected. The accumulations depend on the ambient conditions (for exposed pipe), subsurface pipe conditions and the operating conditions, e.g. shut-in, start-up, injection or withdrawal. The hydrate flow data from CEESI HFTF show that the formation of a hydrate blockage in storage field flow lines is highly dynamic. The blockage may not be a single blockage but consist of multiple hydrate mass accumulations and blockages. Decomposition of one blockage can create problems with other hydrate mass accumulations.

Wet gas measurements are not made in the gas storage field. Liquid production is not measured on a continual basis. The amount of inhibitor is not controlled based on the amount of produced water or the prevailing operating conditions. Inhibitor injection is based on field experience with a particular well. In the gas storage field the amount of methanol is often set to the lowest injection setting to reduce methanol costs. The presence of hydrate in a storage field flow line does not mean a hydrate blockage will form, it means that the ingredients to develop a hydrate blockage are in the flow line.

The Latigo storage field has a horizontal separator located downstream of the well-head. This separator has an automatic dump and a heater. The heater drives water from the liquid phase to the vapor phase. The water vapor re-condenses downstream of the separator. This occurs upstream of the orifice meter and approximately 200 yards from a drip which is located about 8 ft under the surface of the ground. The drip has a down-comer which is less than an inch in diameter. The drip plugs with hydrate if inadequate hydrate inhibitor is in the flow line.

## 3. HYDRATE AND INHIBITOR PHASE BEHAVIOR

Hydrate phase determination is the thermodynamic basis for hydrate control. Natural gas hydrates are solid, ice-like (but not ice) crystalline compounds that form when the lighter constituents of natural gas, gas condensate liquids, and oils come in contact with water at the appropriate temperature and pressure condition. The common hydrate formers for natural gas and gas condensates include methane, ethane, propane, carbon dioxide, nitrogen, hydrogen sulfide, and iso-butane. Hydrate formation is not restricted to these compounds. Hydrate chemistry establishes hydrate phase behavior. Hydrate phase behavior determines the operating conditions where hydrates will form and decompose. Sir Humprey Davy is credited with discovering hydrates in 1810. Hammerschmidt in 1934 began the work for the gas industry that showed the relation between natural gas, water and hydrates [4] noting their tendency to block flow lines in processing and pipeline facilities.

The industry has obtained a large amount of experimental hydrate phase data on the constituents of natural gas and related mixtures over many years. Thermodynamic information is missing for hydrate formation in the presence of various types of inhibitors and inhibitor mixtures. Modeling of hydrate phase behavior began with Katz around 1940 who provided a simple method utilizing gas gravity to estimate hydrate formation/decomposition conditions[5,6]. Van der Waals and Platteeuw [7] provided the basis for the development of our theoretical understanding of gas hydrates. Their work utilized an adsorption based model that treated the hydrate quest molecule (e.g. methane) as adsorbing onto a surface. The van der Waals and Platteeuw model is the basis for all modern hydrate prediction models/programs and has been refined by many investigators. Parrish and Prausnitz [8] extended the original work by van der Waals and Platteeuw to multi-component mixtures and devised an algorithm to predict the hydrate phase boundary. Their model worked well for pure gases but was less successful for mixtures. Subsequent research by Ng and Robinson [9], and many others, made both empirical and theoretical modifications to the original models, extended the capabilities to liquid phase predictions, and resolved differences between computed and measured values for hydrate formation, decomposition, and structure. A discussion of the phase equilibrium aspects of hydrates is provided in Sloan [10] and Carroll [11]. The ability to predict hydrate formation is available from most commercial simulators including Hysys, Prosim, Aspen and Infochem.

Fundamental phase equilibrium considerations are the basis for hydrate calculations. These considerations require: (1) the T,P for each phase present be equal, (2) the chemical potential, $u_{\Phi i}$, of each chemical component in each phase is equal, and (3) the Gibbs free energy for the system is minimum. If hydrates are forming in or near the meter, this implies that the composition of the gas stream has changed, i.e. components from the gas stream have been selectively adsorbed into the water/hydrate phase during the formation of the hydrate phase.

Hydrates in flow lines exist at conditions above and below the ice point. Although hydrates have an ice-like appearance they have a different physical structure then ice. Water molecules form a dynamic crystalline cage-like framework around dissolved natural gas molecules. Different size gas molecules fit into different size water cages that form the building blocks for hydrate crystals. Natural gas forms two different hydrate crystal structures, structure I and structure II. Pure methane forms structure I hydrate. Typically it is the concentration of the largest hydrate former molecule in the gas that determines which crystal structure will form. As a practical matter a relatively small amount of propane in the gas stream will cause structure II to form. The cage structure determines the stability of the hydrate crystal, i.e. the operating temperature, pressure and compositions conditions at which a given hydrate crystal will form or melt. Phase calculations are made to estimate the conditions for hydrate formation, decomposition, hydrate type (I or II) and to determine the amount of inhibitor required to shift the hydrate phase diagram away from the operating region. The hydrate phase can support a high concentration of natural gas components. It is this concentration of gas in the solid hydrate phase that is the basis for the high pressure gas release that is caused by a rapid decomposition of natural gas hydrates.

Flow data from the CEESI facility show that hydrate crystals form at the gas and liquid interface. The data also show that hydrates form very rapidly at liquid-liquid interfaces, i.e. between the water and condensate phase. Once hydrate formation is initiated, gas molecules are drawn from the gas phase into the hydrate phase. In other words, gas hydrates act as molecular-level sponge that draws natural gas components from the gas phase into the hydrate crystalline (solid) phase. In theory hydrate crystal formation will consume all of the free water. In practice this requires the renewal of the gas-liquid surface area through mixing. Under the right operating conditions the hydrate crystals will grow and agglomerate into hydrate masses. If gas is shut-in in the flow lines, with little or no mixing, the hydrate mass will grow and form a hydrate crystalline film or skin over the surface of any free water in the flow line. CEESI's data show that in the flow line stagnant hydrate films reduce the conversion rate of water to hydrate in the flow line by restricting the mass transfer of the gas components through the hydrate film to form new hydrate crystals. The data also show that start-up conditions rapidly disrupt hydrate films and accelerate the amount of hydrate growth. Hydrate deposition and accumulation can occur anywhere in the flow system where free water or condensed water is present. This includes all throughout the flow lines, in the instrument lines, meters, and in valves. The amount of hydrates formed at a particular location depends on the amount of water at that location, the operating and flow conditions, and the pipe geometry. Hydrate crystals and hydrate masses are transported by the flow in the gas and liquid phase.

Various hydrate control strategies are applied in the field. These include thermodynamic inhibitors such as methanol and ethylene glycol, kinetic inhibitors (KI's) such as vinylcaprolactam(VCL), vinylpyrrolidone(VP), and polyvinylpyrrolidone (PVP) and related derivatives and cocktails, and hydrate crystal anti-agglomerants (AI's). Thermodynamic inhibitors shift the phase boundary for hydrate formation, kinetic inhibitors slow the growth of the hydrate crystal by adsorption onto the crystal, and anti-agglomerants reduce the aggregation of hydrate crystals into larger hydrate masses so the fluid with hydrates can be transported. In general, KI's and AI's are attractive because they can be used in substantially lower dosages than methanol, e.g. < 1 wt% vs. 30 wt% for methanol. KI's and AI's do not prevent hydrate formation, they limit hydrate growth or limit hydrate aggregation to maintain the ability to flow respectively. It is common in gas storage field applications to use methanol to shift the hydrate phase boundary. KI's and AI's have not received extensive use in gas storage fields. Little data is available on the effect these types of additives may have on measurement. This is an important area to obtain hydrate flow data to support the need to identify the operating envelopes for hydrate control chemicals which can act as replacements or supplements to thermodynamic inhibitors like methanol.

Figure 10 provides the hydrate formation phase diagrams for different hydrate formers and storage field natural gas mixtures. The chart shows the difference between pure methane, two binary mixtures of methane with propane, and four natural gas mixtures. Pure methane provides the lower temperature limit for a natural gas structure I hydrate former. It illustrates that sI hydrates form at lower temperatures and require a higher driving force for formation than structure II hydrate formers. The two binary mixtures illustrate the influence a structure II former has on the phase diagram relative to pure methane. Propane helps stabilize the sII hydrate. A significant shift of the hydrate phase boundary to higher operating temperatures and lower pressure occurs with sII hydrates. A relatively small change in the propane concentration shows a large change on the hydrate phase boundary condition. Most gas mixtures form structure II hydrates. The multi-component natural gas mixtures are from the Greenlick and Latigo storage field mixtures and two similar reference gas mixtures from AGA Report No.8 [12], Table 1 provides the component compositions for the natural gas mixtures in the figure 10. In addition to the T,P conditions for hydrate formation, the diagram indicates what will occur to the hydrate formation curve when fluids are commingled in flow lines, i.e. increasing the propane amount will cause a shift in the hydrate phase diagram to the right. It also provides a relative reference point to identify the effect different concentrations of inhibitors have on the operating envelope. Lastly, it shows the influence of the uncertainty in the calculations on the phase diagram, i.e. a large uncertainty in the temperature will lead to a large uncertainty in the pressure condition at which hydrates will form or melt.

Figure 11 provides estimates for the inhibitor concentration (methanol) that is required to thermodynamically shift the phase boundary to achieve a given level of sub-cooling in the flow line. It predicts the effect of methanol on the hydrate phase boundary for both the Latigo and Greenlick gas compositions. The results show that in order to achieve hydrate formation control at the low temperature conditions experienced in the storage field methanol concentrations in excess of thirty weight percent relative to the amount of produced water are required. For the two storage field natural gas mixtures presented here there are 7 to 10 degrees sub-cooling achieved per 10 wt% addition of methanol at 1000 psia. The amount of sub-cooling varies as the operating temperature and pressure changes in the flow lines.

Figure 12. illustrates the difference between two thermodynamically based inhibitors for hydrates. This figure compares the relative hydrate inhibition performance between various concentrations of methanol and ethanol. Ethanol was selected because of a request from an operator regarding replacement options due to a disruption to their supply of methanol. They were considering ethanol as an alternative for methanol. The data show that there is a significant difference in performance between alcohols for controlling hydrates[13 ].

The hydrate formation phase diagram determines the equilibrium operating conditions for hydrate formation, hydrate decomposition, and hydrate inhibition for a range of inhibitors. Uncertainties in the basic experimental data and the methods used to compute hydrate phase behavior lead to errors in determining the exact hydrate formation conditions in the flow lines. These errors can be significant. Comparison to experimental data is the best way to validate the actual hydrate formation condition and performance that can be expected under field flowing conditions.

## 4. CEESI HYDRATE FLOW TEST FACILITY

The concept for the development of a Hydrate Flow Test Facility began with the Gas Research Institute (GRI) in 1995. GRI's initial focus was to obtain laboratory data on the physical chemistry and thermophysical fluid properties of hydrates and hydrate inhibitors[12]. It also investigated novel synthesis methods and performance evaluation methods to accelerate development of hydrate chemical control options for thermodynamic, kinetic, and anti-agglomerates. At that time GRI recognized the growing need for a full scale hydrate test facility capable of performing a range of hydrate flow tests to support overall hydrate control technology development and to validate hydrate control under a range of full-scale operating conditions. GRI commissioned Paragon Engineering to carry out the initial hydrate flow loop design. The early design provided by Paragon combined a wet gas measurement and hydrate flow test facility. The proposed project for HFTF received broad support from the gas industry and was approved by the U.S. Federal Energy Regulatory Commission. Budget reductions at GRI in the late 1990's caused GRI to redirect its program and curtail new projects. Following the basic research hydrate effort the need arose for improved hydrate control for gas storage facilities in the U.S. A scaled back project was initiated to obtain field and flow test facility data to support that need. In 2002 a program was initiated between Argonne National Labs and CEESI to investigate hydrate control issues for gas storage fields. The CEESI HFTF evolved from that effort.

The CEESI HFTF was developed to obtain data that mimicked the behavior of natural gas hydrate flows and blockage development in gas storage field flow lines. Gas storage field data was obtained and multiple test sections at CEESI were designed and developed to model storage field conditions. Each test section permits investigating different aspects of the hydrate flow and blockage problem, e.g. isothermal, non-isothermal, high pressure, sloping flow conditions, drip conditions, hydrates in sagging sections, hydrates up and downstream of the orifice and others that are common in gas storage fields. The typical fluids that are used in the test loop to study natural gas hydrates include natural gas, water, condensate, and methanol.

### 4.1 Hydrate Flow Test Facility Overview

Figures 13 and 14 provide an equipment block diagram and the T,P operating region for the CEESI HFTF respectively. The HFTF loop is made of multiple test sections consisting of 4 inch schedule 80 pipe. The test sections range in length from approximately 80 to 150 ft. Two of the test sections are in a horizontal orientation. One test section is predominately horizontal but includes subsections that include a sagging pipe section followed by a steep nearly vertical drop, followed by a drip and upslope section and another horizontal test section that mimics storage field flow line orientations. A recently added test section consists of a leading horizontal flow section for liquid accumulation followed by a long positive slope of approximately 15° for hydrate formation, transport and blockage on inclines. Lastly, a new vertical test section is in development. The new section is to provide natural gas/liquid/hydrate flow at well-bore and subsurface shut-off/flow control valve conditions for storage field operators. Pipe configuration is critical because it helps to establish the large scale structure and transport of accumulating hydrate masses. This affects fluid distribution(hold-up) and hydrate mass deposition, inhibitor distribution and performance, blockage development, and gas permeability through hydrate masses and hydrate decomposition. A discussion of the facility and different test sections is provided below.

Natural gas is supplied by the local distribution company to the CEESI Wet Gas Test Facility (WGTF) and HFTF at low pressure near .3MPa (50psi). A four-stage Ariel boosting compressor pressurizes the natural gas in the test loop to the desired operating test pressure for the specific test. For hydrate flow and blockage studies, the test pressures range is between approximately 2 MPa and 10 MPa (300-1450 psi). For high pressure tests, which are needed for some gas storage fields, another four stage Ariel boosting compressor is utilized to bring the pressure to above 20 MPa (2900 psi) in a special high pressure test section of the HFTF.

Once the hydrate test loop is pressurized, a Gardner-Denver 120HP single staged air-cooled positive displacement compressor circulates natural gas through multiple test sections that comprise the test loop. The circulating compressor can provide gas flow velocities up to approximately 20 ft/sec. These conditions meet the flow rate requirements for gas storage field operators. Higher gas velocities can be obtained by utilizing up to three compressors from the adjacent wet gas test facility. Specific flow velocities within a given test section of the loop are achieved by utilizing bypass values that redirect a portion of the flow other sections of the loop that are not being used during a given test.

Multiple liquid water and hydrocarbons injection points are utilized throughout all test sections of the hydrate loop. Water is typically supplied to a test section through an insulated holding tank that is pressurized by a blanket of nitrogen. Typically the injected state conditions are at or near the desired operating temperature and pressure conditions. This insures that equilibrium conditions will exist between the gas and liquid phases prior to the fluid entering the test section. Water is also provided by pre-saturating the gas phase with water prior to entering a test section to obtain data on condensing flow with hydrate formation on the pipe wall.

Fluid collection occurs at multiple points along the test loop. The hydrate test loop includes fluid drips, slug catchers, knock-out pots, intermediate separators, a vertical separator and a horizontal separator. In general, hydrate formation is occurs very rapidly once inside of the hydrate phase boundary at the test loop, i.e. there are sufficient nucleation sites in the fluid to promote nucleation and subsequent growth of the hydrate crystals. For gas storage field hydrate flow testing, the injected and condensed fluids have typically been tested in a single pass manner, i.e. newly formed hydrates are used to build up hydrates in the flow test section. After an initial pass through a given test section, excess fluid is collected at various drip, drain, and separator points in the loop. Depending upon the type of test fluid (e.g. water/hydrate/KI/AI inhibitor) can be re-circulated to the injection point or to the test location to evaluate time/kinetic dependent performance under realistic conditions with hydrates in the flow line. The hydrate test facility also includes a glycol dehydration unit.

Temperature control depends on the type of test, i.e. non-isothermal or isothermal. For non-isothermal testing, the ambient conditions at the facility, the compressor, exit conditions at shell and tube heat exchange, and the flow lines conditions determines the operating temperature conditions for the test fluids. It has not been necessary to provide any additional temperature control for non-isothermal tests since these are conducted during the cold season. For isothermal tests, a shell and tube heat exchanger located downstream of the re-circulating compressor is used to cool the exit gas from the compressor. The gas phase can be over-saturated with water using high pressure steam injection. The heat exchanger permits producing a gas stream that is at its dew point prior to entering the isothermal test section. In addition free water and/or hydrocarbon can be injected into this section. It is used for a range of testing including saturated gas flows, inhibitor testing and new separation technology testing. Five jacketed pipe test sections in series provide pipe wall temperature control. The temperature is maintained by a glycol chiller.

The instrumentation on the HFTF includes multiple temperature measurements locations including the inlet and exit gas and liquid flow streams, at the orifice meter, pipe wall temperature. Pressures are measured at the meter and near the beginning of the test section. Differential pressures are obtained across various sections under test. Video imaging is obtained through imaging spools for cross-sectional views, bulls-eye windows and an in-situ visual device that provides axial images of hydrate flow in the flow line. Ancillary test equipment that has been utilized includes a laser particle imaging that distinguishes the formation of multiple solid phases (ice and hydrate) from Oxford Instruments, an IR gas phase water content monitoring from Spectrasensor, clamp-on ultrasonic flow measurement from Controlotron, and a capacitance based meter from Sentech AS. The instrumentation data is transmitted from the HFTF to the data acquisition unit located in the flow loop control room.

In general, a hydrate test consists of establishing a flowrate condition that approximates the flow and operating conditions at the Latigo and Greenlick field sites, typically the gas phase flow velocities are less than five ft/sec. A by-pass valve establishes the pressure drop across the test section to achieve the target flow rate. All conditions are continually monitored and recorded in the flow line. Both free liquid and water saturated gas phase are preconditioned upstream of a given test section. Video monitoring is placed at different locations on the test loop depending on the type of test. Flow is controlled in the test sections to simulate steady, unsteady, and shut-in flow conditions that are typical in the storage field during gas injection, withdrawal and blockage development periods.

The experience gained in designing, building and operating the HFTF indicates that hydrate flow testing is complex due to their dynamics and the time scales required for the experiments. Multiple monitoring sites are required. In-situ visual data of hydrates in the flow line essential data. The data show that hydrates distribute themselves throughout the flow line, both on the wall, in the liquid phase, and in a relatively dry hydrate phase. The distribution depends on the fluid and flow characteristics and the interaction between them. Reproducing actual shut-in periods, start-up characteristics, gas cycling periods, and hydrate build-ups on the wall requires long time periods (days and weeks) in the field and in the flow lab. This requires coordination between the weather conditions and flow lab scheduling. Depending on the type of test, various sections of the test loops can operate independent of each other. In practice this is difficult to achieve due to the complexity and time required for hydrate flow tests.

### 4.2 Non-isothermal Flow Test Section

The non-isothermal test section is the south-leg of the hydrate loop. It was the first section of the loop constructed and is the longest test section. It was developed to mimic the conditions of hydrate flow with exposed surface facilities and drips. Figure 15 provides a picture of it. Gas flow is towards the viewer. The upstream non-isothermal section includes a riser section, water/hydrocarbon/inhibitor injection, sagging pipe before the senior orifice fitting with associated instrumentation, a steep elevation drop off of approximately 15 ft. to a viewing spool followed by a drip and then a shot 45° incline to a horizontal section which includes multiple bulls eye windows for viewing, another senior orifice fitting used to facilitate blockage development, and a slug/hydrate catcher section at the end of the test section. The drip section is insulated and permits fluid injection, i.e. water, condensate and methanol which then enters the view port section. The liquid drip permits simulating the impact of liquid and hydrate build up in the drip location. It is also used to fill the view port with water, condensate and inhibitors. Ambient conditions determine the type and duration of hydrate testing, e.g. long duration shut-in and restart tests. Fluids may be injected at multiple points along the test section. The tests that have been performed in the non-isothermal test section include: (1) hydrate formation and flow mixing tests in the viewing spool, (2) hydrate blockage development upstream of the orifice plate, (3) shut-in tests, (5) hydrates with condensates, (6) methanol injection testing, (7) blockage development during cycling, (8) clamp-on ultrasonic testing, (9) capacitance measurement testing, (10) IR imaging tests for the formation of ice and hydrate crystals, (11) pre-emptive blockage remediation tests. This test section permits evaluating hydrate monitoring and hydrate remediation methods by controlling the transport of the hydrate mass through the test section. It accomplishes this by restricting the flow through the downstream orifice plate and/or by hardening of the hydrates, i.e. shutting in, the hydrate mass that accumulates in the test section. The testing has been at low gas velocities that simulate storage field conditions. Figures 15 through 19 provide images of the non-isothermal test section and examples of hydrate flow data obtained from this section of the HFTF.

When water is injected near the entry riser to the non-isothermal test section, the water accumulates in the elongated u-shape section of pipe upstream of the first orifice fitting. The injected water creates pools of water and hydrates upstream of the orifice fittings. The degree of pooling depends on the gas flow rate. Liquid water pooling promotes the formation of a hydrate film. Once hydrates have formed on the surface of the pool they can be carried through the orifice plate to downstream locations. As hydrates accumulate in this section of the test loop pressure builds behind the accumulated hydrate mass. Periodically the hydrate mass is flushed through by pressure into the view port and drip section where its movement is visually recorded. Similar behavior is observed in other test sections of the loop.

Flow rate disturbances, e.g. start-ups conditions, induce the hydrate slurries to flow through the orifice, viewport and downstream piping sections where they are videotaped. Pressure, temperature, composition and slurry appearance are monitored. Hydrate blockages are induced to form downstream of the drip location in the blockage test section by using artificial obstructions in the flow line helping to accelerate test times. These obstructions are used to obtain data on the flow and pressure behavior as hydrates are transported down stream and accumulate in a particular location in the flow line.

### 4.3 Isothermal Flow Test Section

The isothermal section is the middle section of the HFTF and is located next to the heat exchanger. The total length of this test section is approximately 80 ft'. Figure 20 shows the downstream portion of the isothermal test section. It is utilized to obtain condensing flow and hydrate formation data on the pipe walls, hydrate growth on the walls during shut-in conditions, the effect of transient and start-up conditions on hydrate deposition and transport, and inhibitor transport at conditions that simulate subsurface flow lines. The isothermal test section includes steam injection, mixing, cooling and condensing, liquid knock-out drums, flow by pass valves, fluid injection points for water and hydrate inhibitor. Temperature, pressure, and differential pressures are monitored at different locations in the test sections. The tests that have been performed in the isothermal test section include: (1) hydrate formation with free liquid, (2) hydrate formation from condensing flows, (3) hydrate blockage development, (4) hydrate shut-in and growth tests from condensation, (5) inhibitor transport and distribution tests, (6) hydrate build-up during cycling, (8) transient tests, (9) inhibitor sweeping tests, and (10) hydrate sensing tests. This section of the loop is also being used to evaluate the performance of novel fluid separation technologies. Condensation studies are difficult because of the time required to obtain a significant build-up of hydrate on the pipe wall. Hydrate build-up due to condensation varies at different locations in the flow line. Visualization probes are inserted into the flow line to observe the tests in real time under varying flow conditions and fluid states. Figures 21 through 27provide hydrate flow data obtained from this section of the test loop. Each data set and sequence of data images provides insight into hydrate and inhibitor flow behavior in the flow lines. The images have captions which describe what is happening in the flow line for the particular test.

A glycol chiller is used to control the temperature in the jacketed pipe sections. This permits pipe wall temperatures approaching 40 °F . The heat transfer across the test section on the pipe wall is controlled by controlling the temperature in the jacketed pipe section. Methanol and water are injected downstream of the condenser.

Before beginning an isothermal test gas is usually saturated with steam before it enters into the condenser. This is accomplished through steam injection into the flow lines. The gas then flows through a mixer followed by a condenser where the temperature is significantly lowered. Excess water is removed at the exit of the condenser prior to entering the test section. The water saturated test gas then enters into the first jacketed pipe section which is maintained a constant temperature, typically between 40 – 55 degrees F.

The isothermal section of the test loop has a number of flow visualization options. A high pressure view port is located approximately mid-way through the test section, along with an orifice fitting. Axial visualization is also provided in this section of the loop. The axial viewing location is flexible. Temperature and pressure measurements are made at different locations along the isothermal test section. The flow rate can be obtained from an orifice meter in the test section and from a turbine meter that is located on the return to the compressor.

The isothermal section uses multiple viewing options. These include a cross-section view port spool similar to the one in the non-isothermal test section, bulls-eye windows, and an axial viewing capability. The axial view is provided by a small probe that is inserted in different locations along the test line. Many of the hydrate video images provided are axial views of the flow from the isothermal section of the hydrate flow test loop.

### 4.4 High Pressure Test Section

The high pressure test section is approximately 30 ft in length. High pressure is achieved by routing the flow from the isothermal/non-isothermal loop to a boosting compressor. The compressor raises the pressure of this test section up to approximately 3500 psia. Heat exchangers reduce the temperature prior to the flow entering the test section. Water and methanol are injected at the inlet to the test section. Hydrates form immediately in the test section at these operating conditions. Flow velocities in the section are constrained to less than 2 ft./sec. Visualization is a challenge in this section of the test loop due to the high pressure conditions. The section does not include a viewing spool. A number of bulls-eye windows are installed at different locations and angles to monitor hydrate formation and flow at extreme pressures. The tests that have been performed in the high pressure test section include: (1) hydrate morphology, (2) hydrate formation rate with free liquid, (3) hydrate formation from condensing flows, and (4) hydrate blockage development, (5) hydrate shut-in and growth tests from condensation. Figure 28 provides an image of the HFTF high pressure test section. Figure 29 provides an image of a hydrate mass recovered after blowing down the high pressure test section.

### 4.5 Sloping Flow Test Section

In the winter of 2006 a new sloping flow test section was added to the HFTF on the return from the non-isothermal test section to the vertical separator. Its purpose is to simulate hydrate mass flow that would occur in similar flow line sections on hilly inclines in a gas storage field. It consists of a 30 ft' horizontal entry section followed by a 15° incline pipe test section which is also approximately 40ft in length. The horizontal section can be filled to different liquid levels. Viewing ports are located at the entry to the slope and exit points. Bulls eye windows and an axial flow viewing device is installed halfway up the incline. Temperature, pressure, and differential pressures are monitored under different gas velocity and liquid loading conditions. Shakedown and scoping data were obtained from this test section over the past season. The data show the effect of gas velocity on water and hydrate transport through the test section. This test section has unique flow characteristics that are important for hydrate formation, inhibitor distribution and kinetic performance and fluid/hydrate transport and deposition testing. Figure 30 provides a view of the section of the HFTF where the sloping flow test section has been installed. Flow tests were conducted to scope out the effects of an incline on hydrate formation and transport. A large amount of data has been obtained on hydrate flow for this test section. The data are preliminary. Together all of the data show the influence of liquid hold-up coupled with hydrate transport up an incline section of pipe. Figure 31 provides some example differential data from the orifice meter and across the test section. The tests were evaluating the transport characteristics of hydrate masses on inclines. Video imaging of this type of flow has been made through two spools located at the top and bottom of the test section.

### 4.6 Bench Scale Simulated Riser Tests

A bench scale riser section was developed. The riser test section that was constructed is independent of the main hydrate flow test sections. The riser was approximately 8 ft tall. An exploratory test was run to investigate hydrate formation in risers. This condition exists in gas storage fields when a section of flow line has an elbow that is filled with water. The tests focused on evaluating how hydrate formation occurs when gas is percolated through the liquid water phase in the riser. In order to do this, a view-port spool was positioned vertically and attached to two sections of 4" pipe. The vertical pipe was filled partially with water and then gas bubbled up from the bottom of the pipe through the liquid section which viewed and video taped through the viewing port. Figure 32 provides an image of the development of a hydrate cap over a vertical section that is filled with water. The cap eventually chokes the flow. The new test section will obtain vertical flow data under a range of liquid water loadings and gas velocities to investigate how hydrate blockages develop in the well bore after subsurface valves and identify procedures to control the hydrates.

## 5. CONCLUSIONS

Considerable experience has been acquired working with gas hydrates in the field and in the flow laboratory. The hydrate flow test facility is unique. The hydrate flow data that have been acquired are unique and represent a step towards building a comprehensive understanding of complex hydrate flow behavior in flow lines. An extensive video library has been constructed of the measured hydrate flow data. The CEESI hydrate flow data are phenomenological data that have been obtained under specific flow conditions that have helped elucidate hydrate blockage development problems in gas storage fields. The data show the dynamic nature of hydrate transport, deposition and blockage development in flow lines. Hydrate flow data need to be expanded in a systematic manner beyond those conditions that occur in gas storage fields. As wells mature, and water production increases, there will be an increasing need to identify the best, reliable low cost options for monitoring, controlling and operating with hydrates in flow lines and meters.

The following summarizes the experience and some needs for future hydrate flow studies:

1) Hydrate flow is complex and very dynamic. Hydrate behavior in the flow lines depends on the specific fluids present, i.e. water, condensate, and oils and the range of flow velocities encountered in the flow line.
2) Inhibitor amounts must be tailored to the amount of fluid in the flow line.
3) Hydrate blockages create high risks for equipment and field personnel.

4) The less equipment on the flow line, the less likelihood hydrates will impede flow and instrumentation.
5) Simple, non-intrusive, inexpensive hydrate monitoring equipment is needed for gas storage fields.
6) Compact separators need to provide deep separation that can withstand hydrates.
7) Hydrate formation and transport studies in wet gas and multiphase flow meters is a needed.
8) Operating practices need to investigate how to reduce the likelihood of hydrate blockages during transient flow conditions.
9) Gas storage field data acquisition and communication for hydrate control needs to be improved for gas storage field operators.
10) The performance of advanced hydrate inhibitors and inhibitor cocktails under full-scale flow test conditions should be investigated.
11) Hydrate flow data are needed for a range of liquid loading and gas velocities. The fluids should include water and condensates, and include studies with different types of hydrate control chemicals.

## 6. ACKNOWLEDGEMENTS

The author expresses his appreciation to a number of individuals and organizations who contributed and supported this work. Gratitude is first expressed to the sponsors and advisors of the project including the U.S. Dept. of Energy, Gas Technology Institute, Pipeline Research Council, and CEESI. Special appreciation is expressed to J.Kinney for his work and skill, in running and juggling the challenges of the HFTF test facility. Special thanks are expressed to all of the field engineers, well tenders and operators at the Latigo and Greenlick storage fields who took their time to share their experiences with the author during this project. Their daily field experience with hydrates has provided unique data and insight that cannot be measured and could not have been obtained otherwise. This work is dedicated to them. We also wish to thank C.Britton for his contribution in helping with the development and shakedown testing at the CEESI HFTF.

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Table 1. Gas compositions for natural gas mixtures

| Component | Greenlick | Latigo | Amarillo | Gulf Coast |
|---|---|---|---|---|
| C1 | 94.91 | 90.84 | 90.67 | 96.52 |
| C2 | 2.76 | 5.23 | 4.53 | 1.82 |
| C3 | 0.47 | 0.82 | 0.83 | 0.46 |
| i-C4 | 0.08 | 0.09 | 0.10 | 0.10 |
| n-C4 | 0.09 | 0.10 | 0.16 | 0.10 |
| i-C5 | 0.03 | 0.03 | 0.03 | 0.05 |
| n-C5 | 0.03 | 0.02 | 0.04 | 0.03 |
| n-C6 | 0.06 | 0.01 | 0.04 | 0.07 |
| CO2 | 0.88 | 2.08 | 0.47 | 0.60 |
| N2 | 0.69 | 0.70 | 3.13 | 0.26 |

Figure 1. Pressure-temperature trace for Well #37 at Latigo for the gas, skin, casing and tubing.

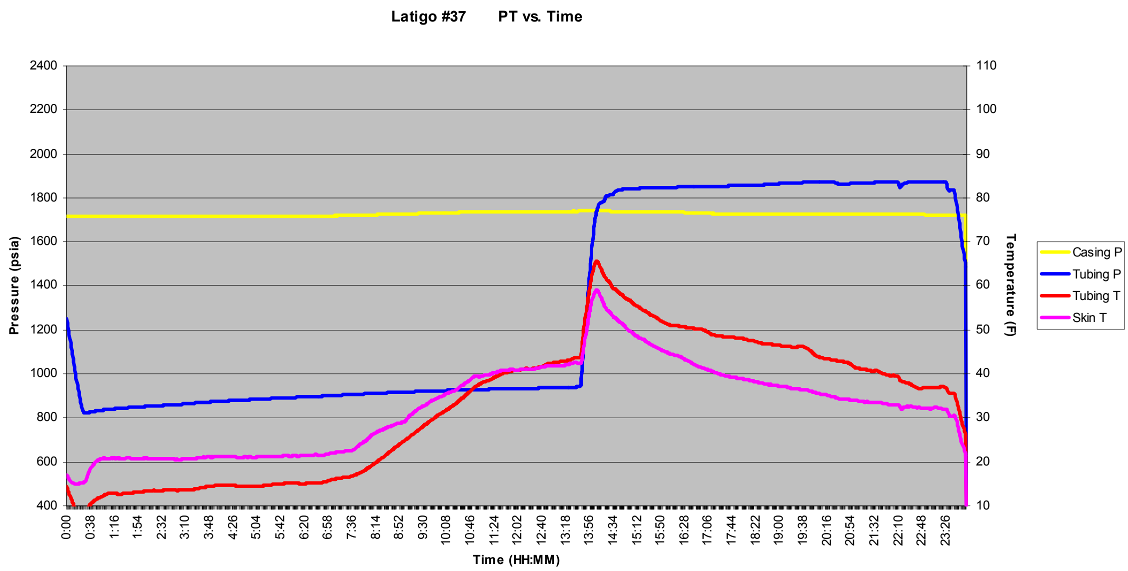

Figure 2. Latigo and Greenlick storage fields temperature and pressure operating range.

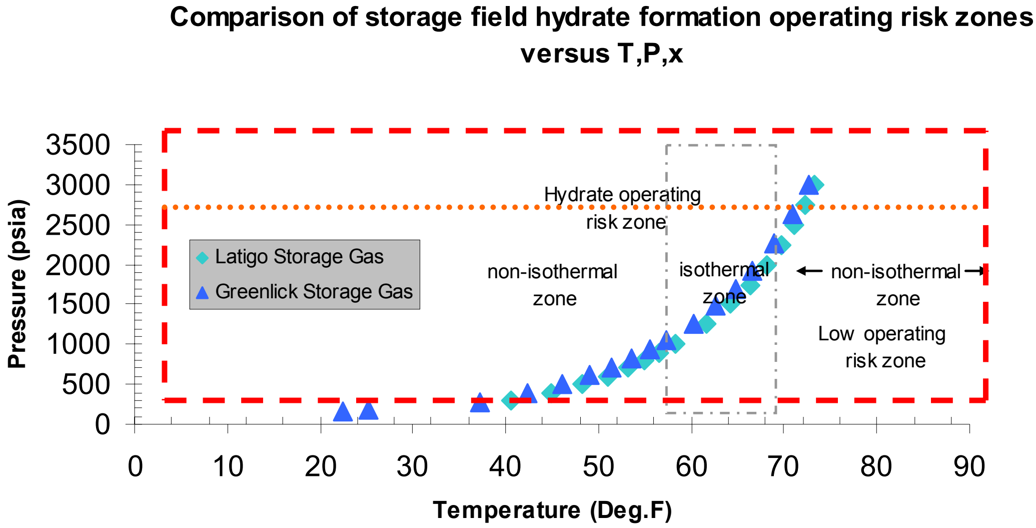


Figure 3. Storage field hydrates obtained during blow down at Greenlick storage field.
Image courtesy of the Greenlick Storage field.


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Figure 4. 6" Orifice plate(.3,.6 beta) damage caused by hydrates.
Image courtesy of the Latigo Storage field.


©

Figure 5. C-clamp snapped due to 6" flow line vibrations caused during hydrate removal. Corrosion sensor snapped due to hydrates in line. Image courtesy of the Latigo Storage field.


©

Figure 6. Example of chart recorder readings with hydrates present in the flow line. Image courtesy of the Latigo Storage field.

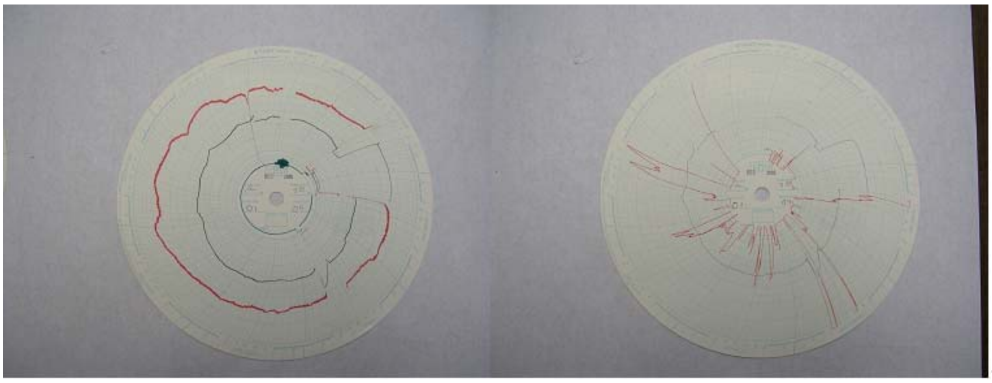

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Figure 7. Example orifice dp data and flow with hydrates present in the flow line.

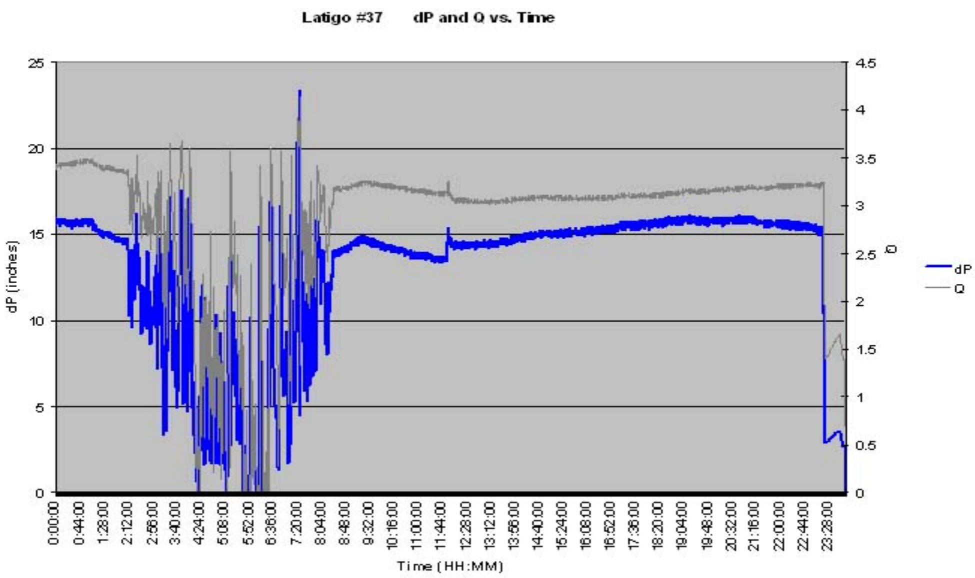


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Figure 8. Severe blockage example image. Similar hydrate masses have been found by storage field operating companies under road and stream crossings. Image courtesy of Petrobras.

Figure 9. Well #37, Temperatures and estimated condensed water vs. time

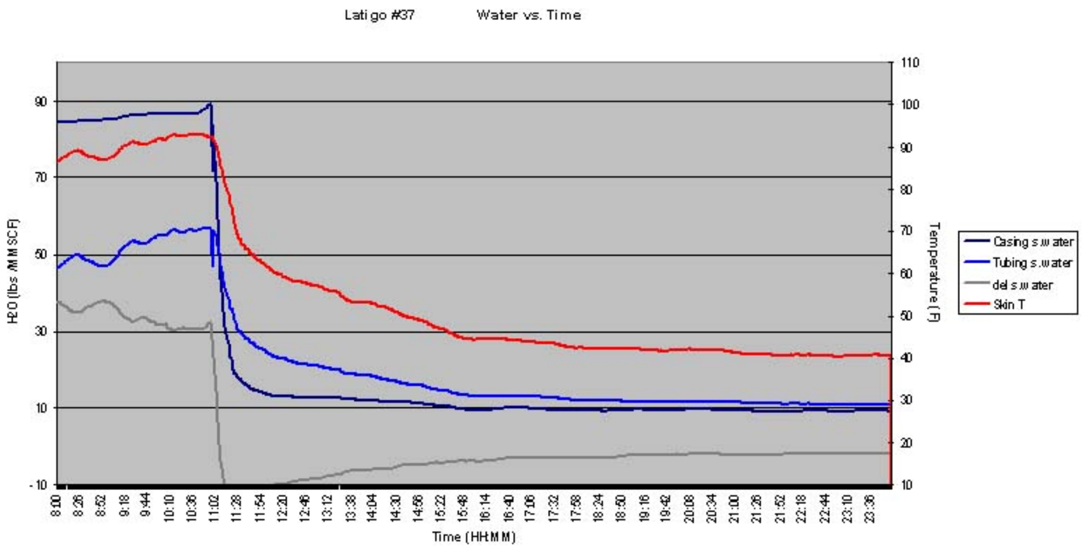

Figure 10. The influence of gas composition on hydrate formation conditions.

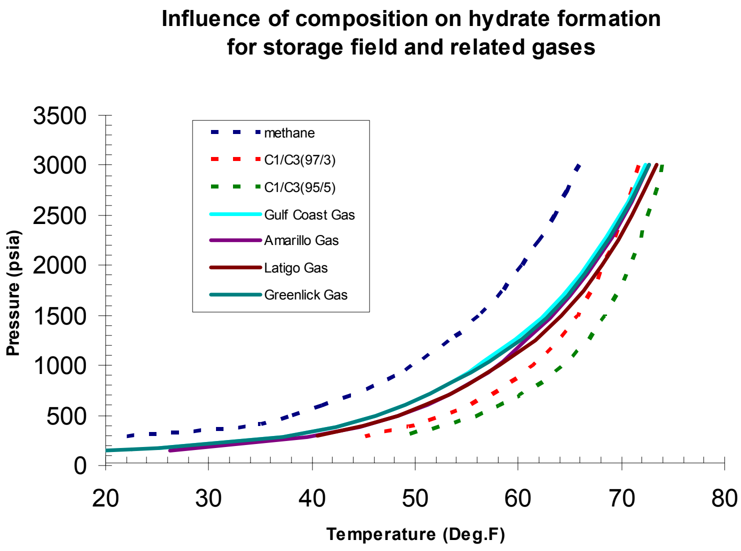


Figure 11. Effect of methanol on hydrate formation condition for Latigo (L) and Greenlick(G) storage field gas mixtures.

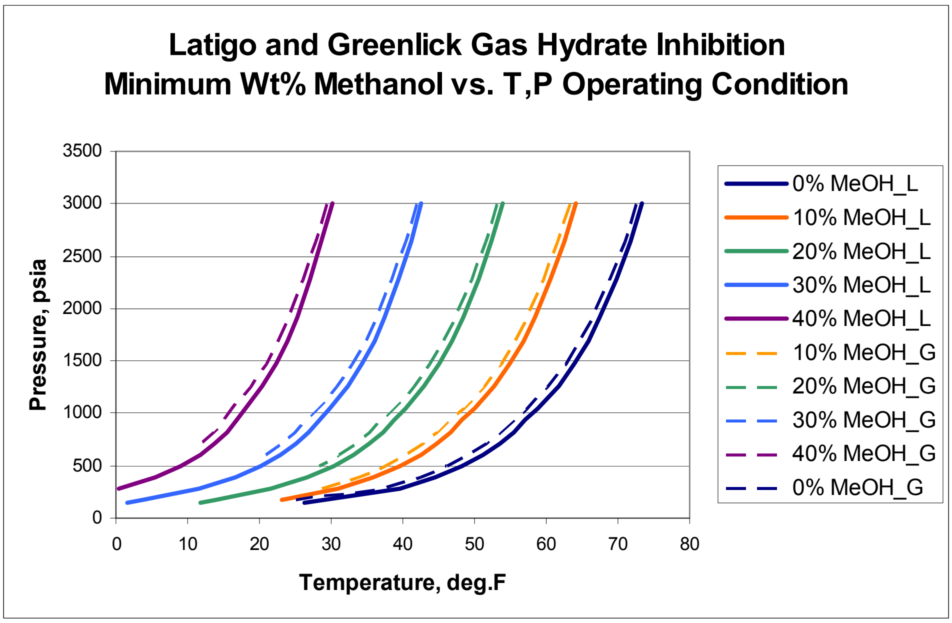

Figure 12. Relative effect on hydrate inhibition using methanol vs. ethanol.

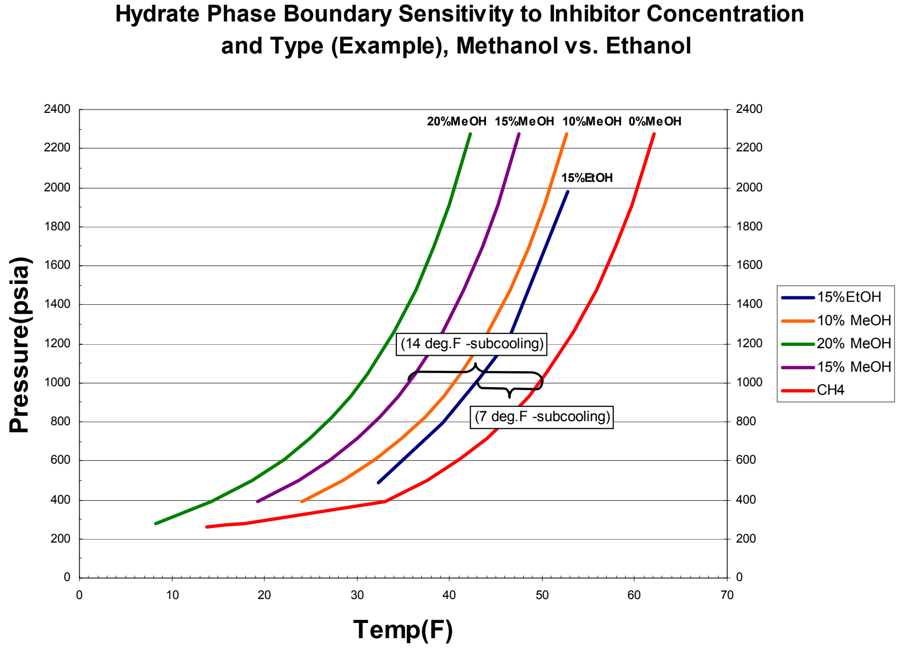


Figure 13. Simplified schematic of the CEESI hydrate flow test facility

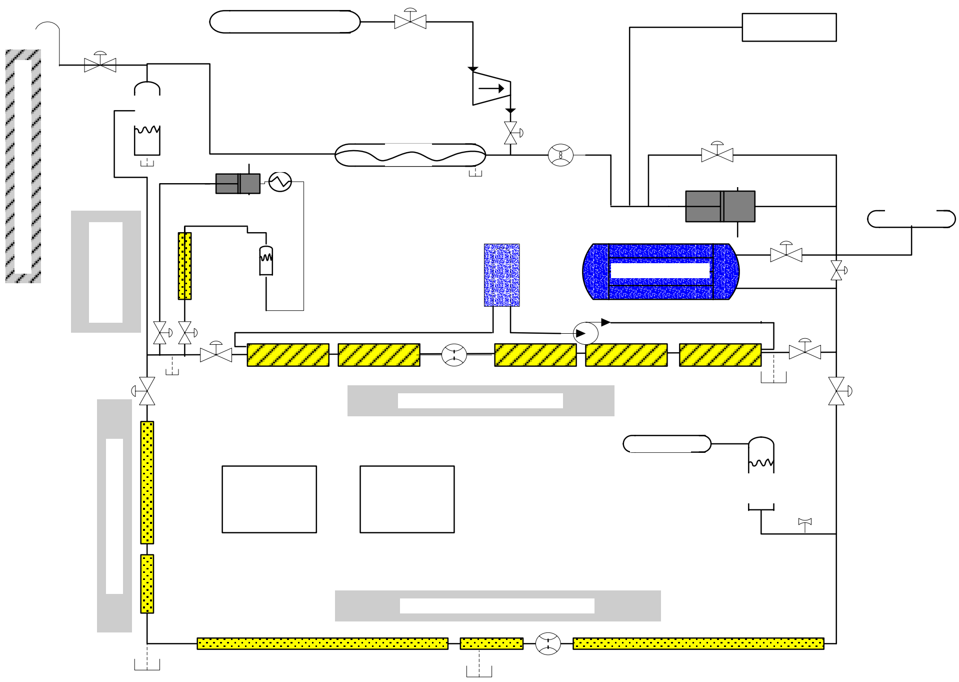

Figure 14. CEESI Hydrate Flow Test Facility Operating Region

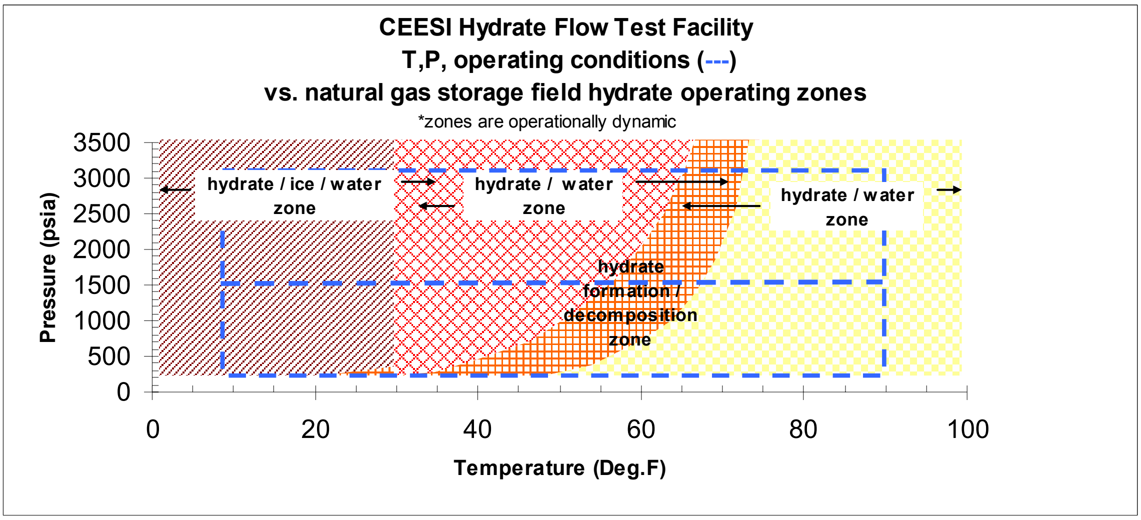


Figure 15. HFTF: Non-isothermal test section, flow is towards the viewer.

Figure 16: HFTF Non-isothermal test section:  Cross-section image through the viewing spool of gas, hydrate and water interface.  Hydrates splashed on the viewing port window. Gas flow is left to right.

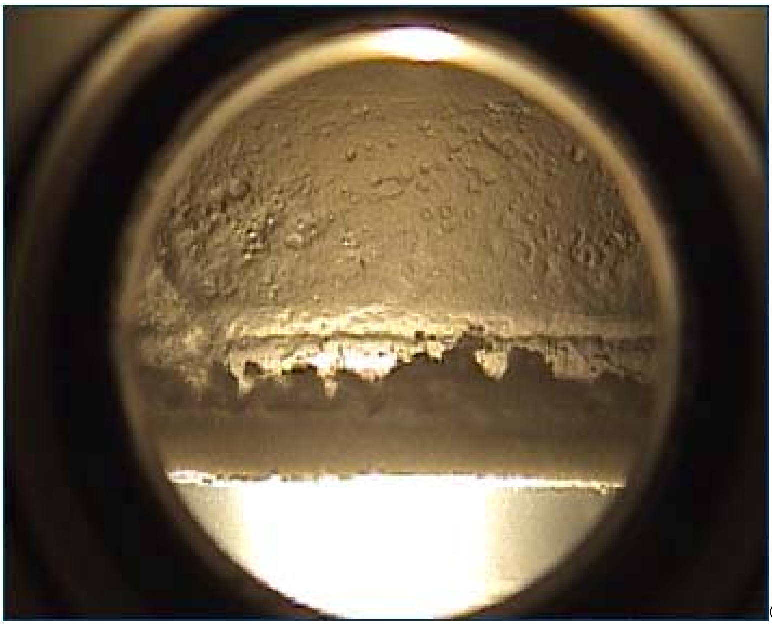

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Figure 17. Non-isothermal test section: Change in dp across orifice vs. dp across test section as hydrate plug is developed in non-isothermal test section.

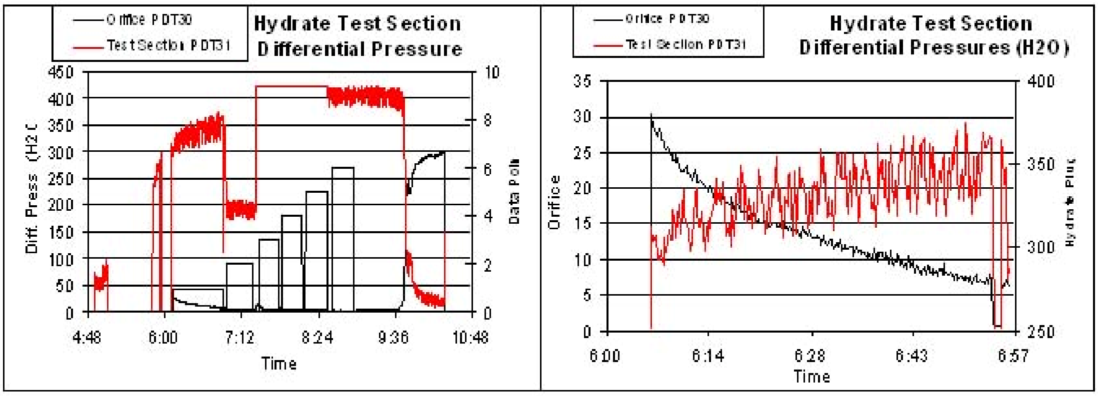


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Figure 18 HFTF Non-isothermal test section: Cross-section view through bulls-eye window of hydrate mass moving in test loop from left to right. 1. Leading edge, 2. near center of mass, 3. trailing center of mass, 4. trailing edge.

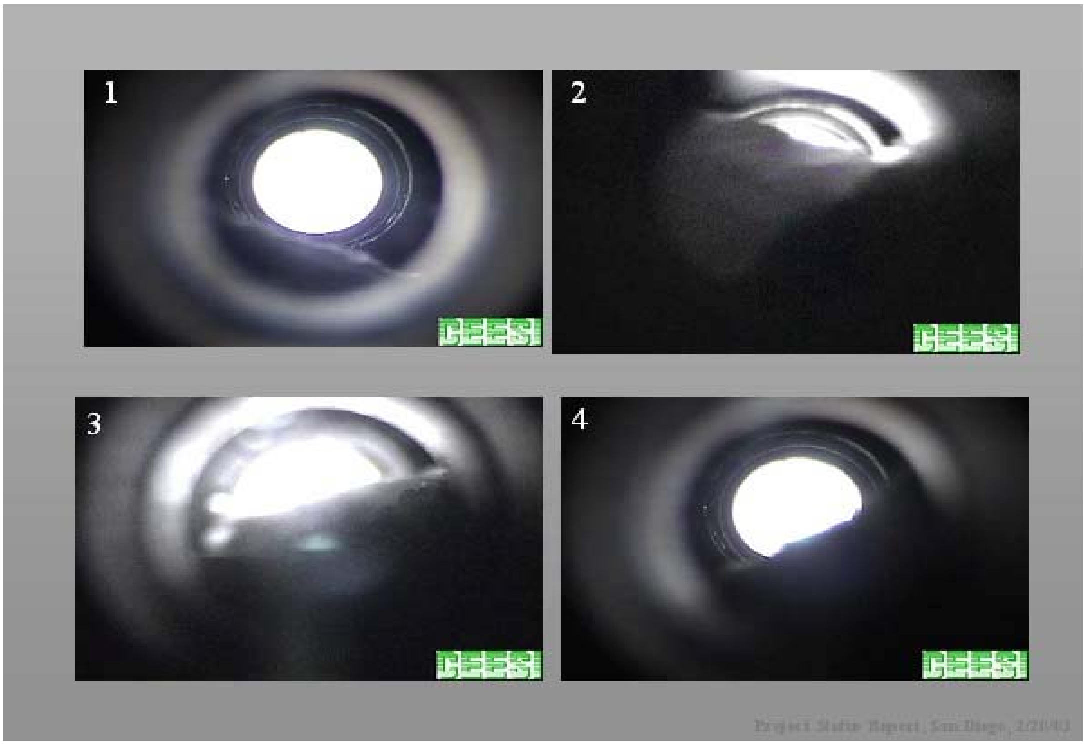


Figure 19 HFTF Non-isothermal test section: Viewing spool sequence of hydrate dissolution sequence as methanol is injected into flow line. Hydrate dissolution sequence is from top, left to right and bottom left to right. Hydrate mass in the center of the flow has dissolved, hydrates remain on wall.

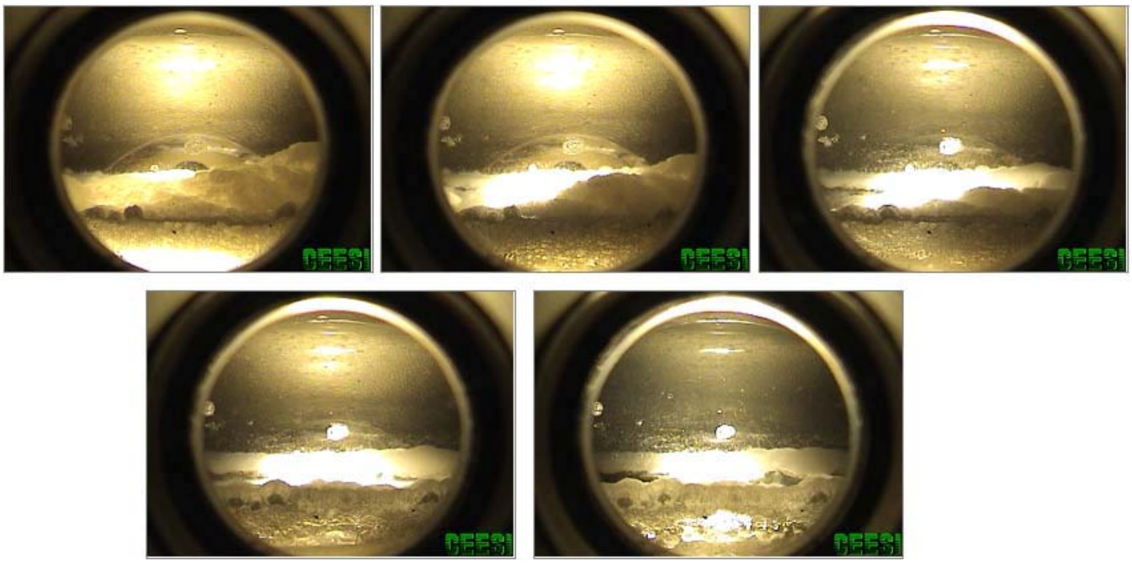

Figure 20: HFTF Isothermal test section. Flow is towards viewer. The test section heat exchanger and chiller are in the background.

Figure 21: HFTF: Isothermal test section results - hydrates flowing – no blockage.

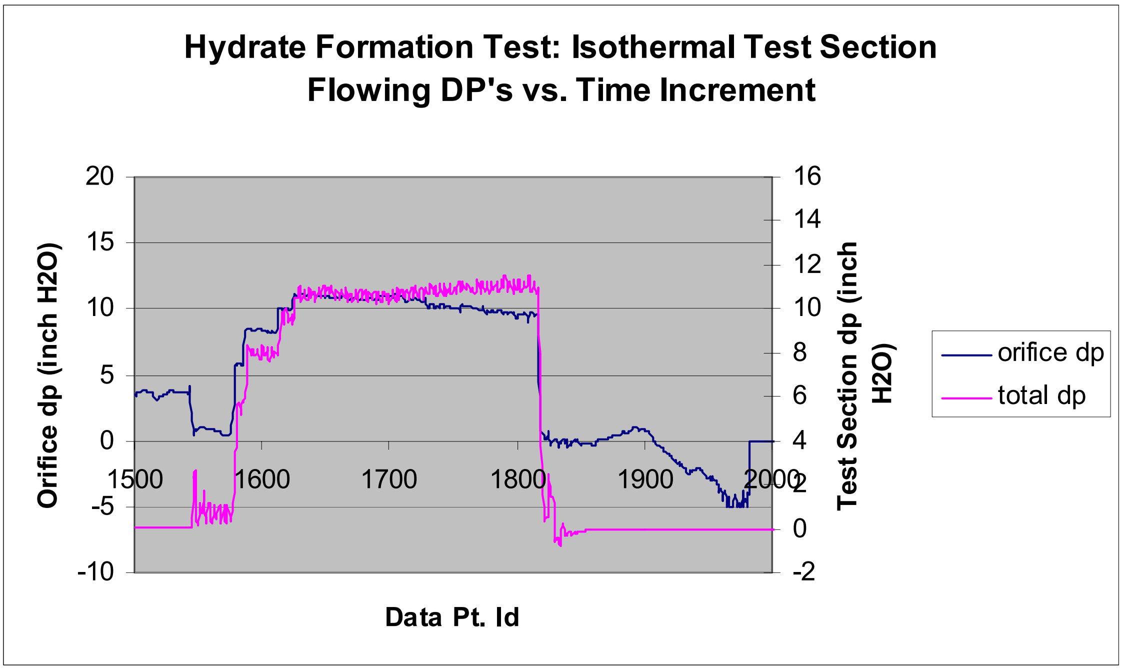

Figure 22: HFTF: Isothermal test section results – Saturated gas flow and hydrate growth after extended time period (1 week).

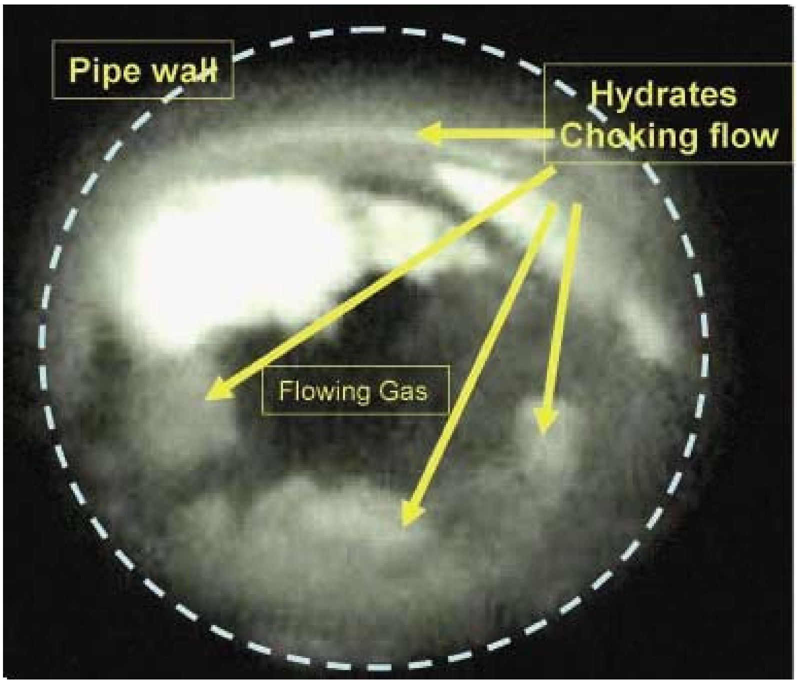


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Figure 23: HFTF: Isothermal test section results – Methanol wash of hydrates on the wall using a pressure transient.

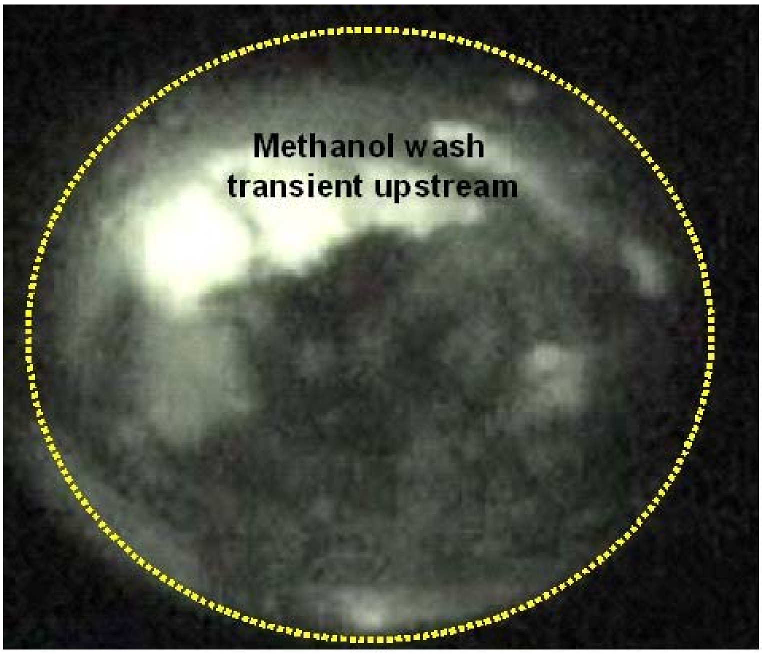


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Figure 24: HFTF: Isothermal test section results – Hydrate flowing on top of free water stream. Hydrate mass is developing in the flow stream.

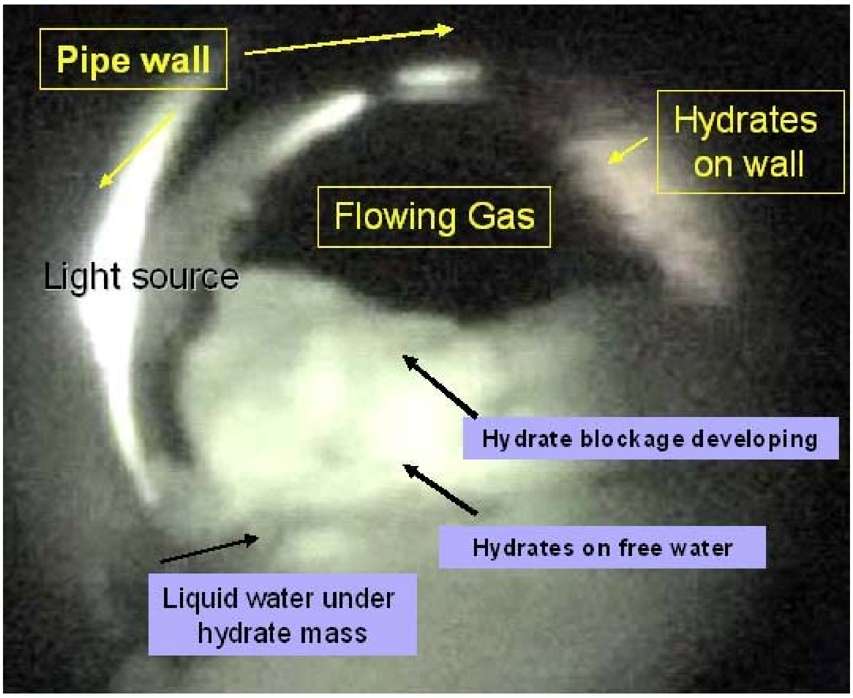


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Figure 25: HFTF: Isothermal test section results – Hydrate flowing on top of free water stream. Hydrate mass is developing in the flow stream.


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Figure 26: HFTF: Isothermal test section results – Sequence of steps caused by a pressure transient induced upstream of hydrate mass to simulate start-up conditions with hydrates in the flow line. Hydrate mass pushed from left to right in the sequence.


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Figure 27: HFTF: Isothermal test section results – Sequence of steps showing condensed hydrates on wall and then a stream of methanol which is moving through the pipe in the direction towards the viewer. The methanol simulates the behavior of a typical methanol drip at the Latigo gas storage field. Hydrates remain on wall with methanol stream in bottom of pipe.

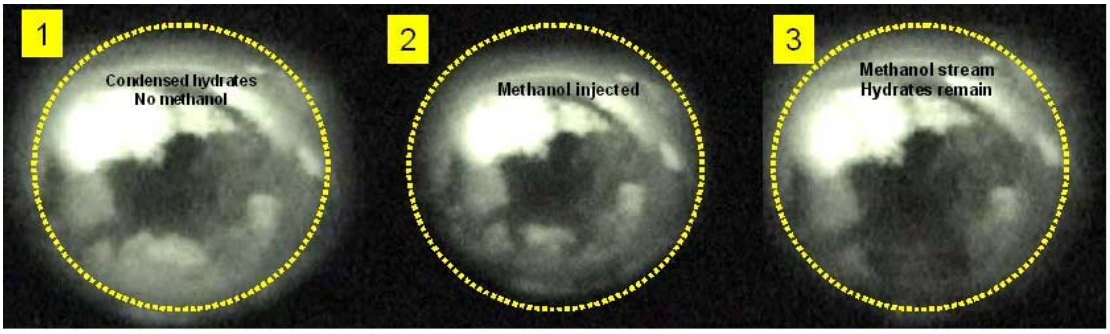


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Figure 28: HFTF: High pressure test section– showing inlet section and water saturation unit. Vertical separator is in the background on the right. Boosting compressor is located to the right of the image.

Figure 29: HFTF: High pressure test section– hydrate mass recovered after blow down of test section. The smoothness of the surface indicates melting due to low pressure atmospheric conditions. The individual grains appear in images from field studies.

Figure 30: HFTF: Slope flow test section prior to installation – bottom of slope is horizontal to a 15° pitch.

Figure 31: HFTF: Example slope flow test section data showing hydrate and fluid transport characteristics at constant (relatively) velocity.

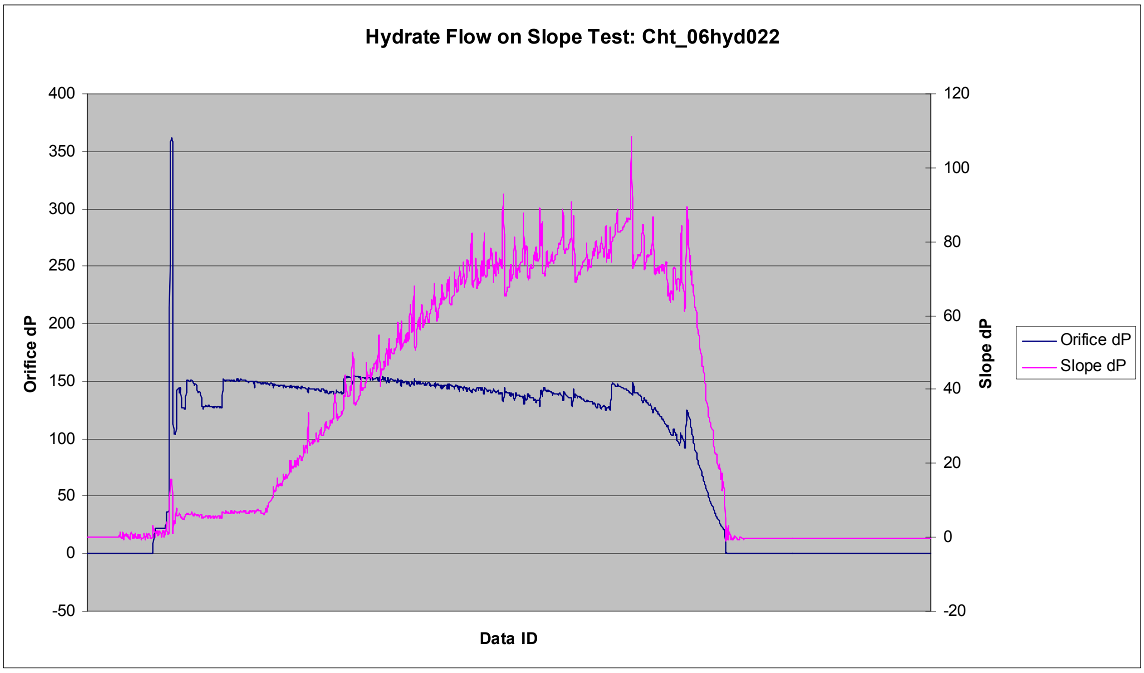
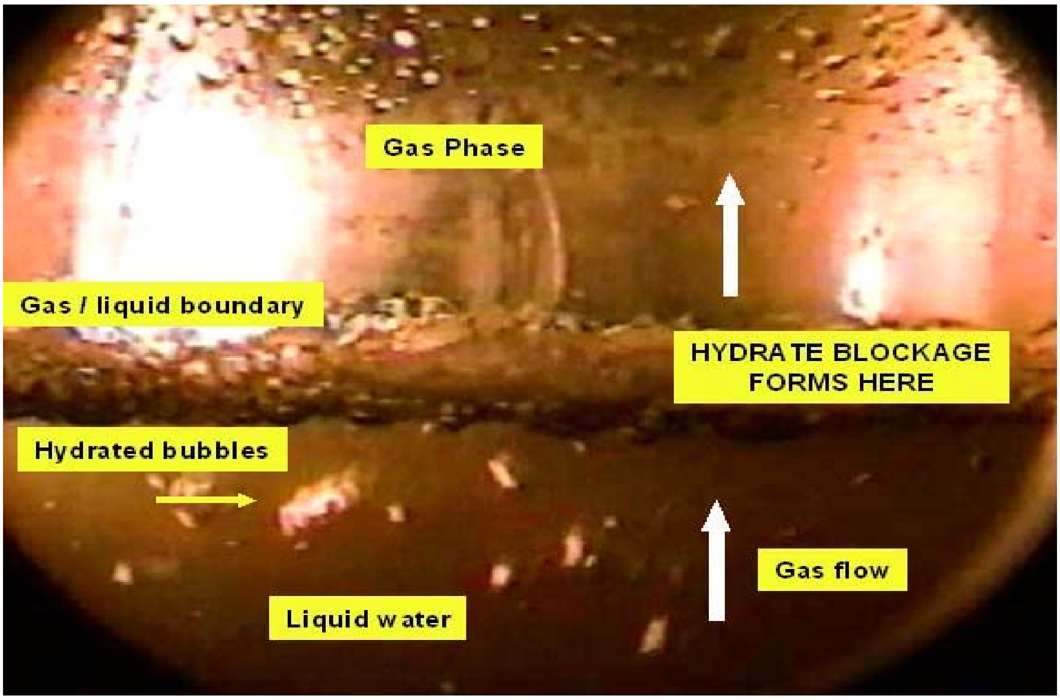



Figure 32: HFTF: Bench scale hydrate formation through a vertical section filled with water. New well bore section will extend this to a approximately a 40 ft test section with valves for hydrate flow tests for well bores.

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