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Development of Deepwater Natural Gas Hydrates

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Abstract

Deepwater natural gas hydrate resources potentially exceed all other conventional and non-conventional hydrocarbon resources on a world-wide basis. However, before these offshore gas hydrate resources can be classified as reserves, it must be demonstrated that gas hydrates can be produced under conditions that make economic sense. The purpose of this paper is to provide an overview of the technical issues that will challenge the development of deepwater natural gas hydrates.

Introduction

Extensive coring and logging programs have been carried out to characterize gas hydrate accumulations in deepwater basins around the world. Successful production tests have been carried out in onshore Arctic regions as well as in deepwater regions offshore Japan and China, with further testing planned in other offshore areas. The tests conducted in the Arctic provided a proof of concept that gas hydrates can be dissociated and produced by simple depressurization below the hydrate stability point [1]. This approach has subsequently been demonstrated and extended in the offshore of Japan [2] and China [3].

The results of these production tests as well as various geo-mechanical and field planning studies have also identified several technical issues which must be addressed before the development of the deepwater gas hydrates can be considered viable. In addition to normal deepwater operating risks, these issues include drilling and completing wells in shallow soft sediments; low operating temperatures and pressures; proximity to free gas and free water zones; early reservoir subsidence; formation solids control; artificial lift requirements; flow assurance with relatively high water to gas ratios; environmental issues; and potential requirements for subsea processing for water separation and inlet gas compression. Gas hydrate production wells must also be capable of surviving frequent planned and un-planned shut-ins, as well as being re-started with minimal risk to well productivity and well integrity. Certainty of gas and water production rates and forecasts must also be addressed prior to the development of deepwater gas hydrates.

Gas Production

The expected fluid production rates for a field development are a critical component of the basis of well design. Casing and tubing configurations can be adapted to any production forecast. Deepwater gas production fields are relatively few compared to conventional oil developments. While there are no standard production rates for these fields, completion designs to deliver in excess of 100 MMscf/d per well are not uncommon.

To date, onshore and deepwater gas hydrate production testing has been conducted at average rates <2 MMscf/d [3]. The objectives for these well tests have been largely science driven. Based on the results and analysis from these tests, the current state of knowledge is such that initial production rates can be reasonably predicted based on the log and core data collected during drilling operations. Future testing will need to incorporate objectives to test at higher rates for commercial considerations and longer durations to demonstrate well reliability and production trends.

Many factors contribute to the economic production rate for an oil or gas development, including capital and operating costs, reserve basis, and local economic factors including security of supply, thus there are no standard criteria to determine economic viability. Production rates and expected reserve recovery per well are also critical to determine well count for the field, which will be a major cost factor.

Water Production

Conventional gas production wells normally produce some water of condensation throughout the well life, typically in the order of say 2-4 bbls/MMscf. Free water production can also occur due to coning, cusping, or encroachment, typically occurring later in the life of a well. Water production can be minimized by limiting drawdown to a less than a critical value, or by working over a well to physically shut-off the water producing intervals. If the water production becomes excessive, the well may simply be shut-in to minimize impact on the remainder of the field.

Water production in gas hydrate developments is intrinsically part of the dissociation process. Significant water production during dissociation is expected for several reasons:

- A nominal relationship for gas hydrate yield is that 1 ft^3 of solid gas hydrate contains 164 standard cubic feet of natural gas, plus 0.9 ft^3 of fresh water. In more typical production terms, the water to gas ratio is in the order of 1000 bbls/MMscf. Initially, much of this water will be produced into the wellbore, however over time this may drop off depending upon well angle, reservoir geometry, gravity separation of water and gas, and relative permeability considerations, as well as the structural thickness and layering of the reservoir unit.
- Gas hydrate saturations may be highly variable throughout a gas hydrate accumulation, ranging from 0% in some layers (water being the only mobile phase), to over 70% in some layers (with roughly half of the water at or below the irreducible water saturation). Depending upon the productivity of any free water layers in the overall reservoir unit, achieving the required drawdown to dissociate the gas hydrate could be difficult without producing excessive water amounts.
- Free water layers above the gas hydrate unit, as well a free water layers at or below the base of gas hydrate stability may be difficult to isolate behind pipe, especially if the hydrate is acting as a seal isolating the water.

Under the right operating conditions, gas wells can lift significant quantities of water under steady state flowing conditions. Because of the expected high water production rates, gas hydrate wells will require artificial lift to initially start-up the well, restart the well after a shut-in, and possibly be required from time to time as water and gas rates vary. Excessive water in the subsea gathering system may be more problematic for stable flow and flow assurance issues due to the longer length (both horizontal and vertical) of the flowline system compared to the relative short length of the wellbore.

Temperature & Pressure

In deepwater environments, temperature at the mudline can be as low as 38 °F. Below the mudline, the geothermal temperature will increase typically in the range of say 1-2 °F/100 ft. This resulting temperature profile along with the corresponding pressure profile defines the area where gas hydrates can accumulate in the shallow sediments below the mudline as illustrated in Figure 1 (8000 ft water depth with hydrate stability temperature based on seawater hydrostatic and methane). The critical point to note from this figure is that while producing or shut-in, the wellbore temperatures will always remain at or below the hydrate stability temperature when the well is returned to initial pressure. Flowing temperatures may drop further depending on the reservoir configuration and heat flow during the gas dissociation process, and possible Joules-Thompson effects while flowing high rate gas volumes at low pressure. These wellbore temperatures will be a critical consideration for flow assurance.

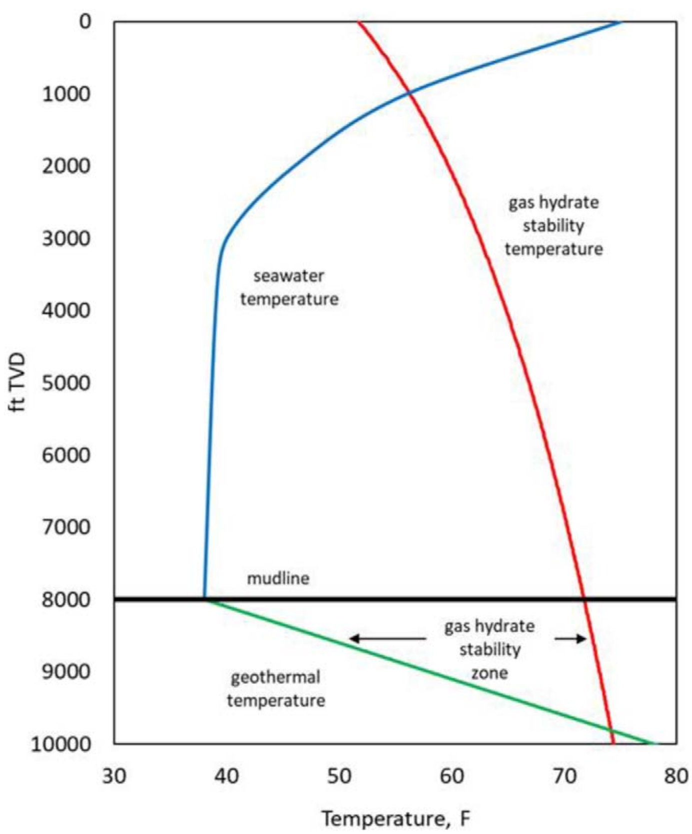

Figure 1—Hydrate Stability Temperature with Depth

Initially, deepwater gas hydrate pressures will be at seawater hydrostatic, and depending upon water depth, may be significantly higher than the required hydrate stability pressure at the corresponding reservoir depth and temperature. Assuming depressurization is the primary dissociation method, the required drawdown could be in the order of 1000 psi just to initiate dissociation (as illustrated in Figure 2 for an 8000 ft water depth and reservoirs near the base of the stability zone). Gas hydrate accumulations above the base of gas hydrate stability would require even higher pressure drawdowns to initiate dissociation. The required flowing bottomhole pressure would likely be even lower in order to maximize the dissociation and therefore gas production rate [4]. These low flowing bottomhole pressures and resulting differential pressures are well within the capacity of commonly used casing and tubing strings, as well as completion equipment (including gravel packs), and therefore do not present any design challenges. Low pressures however are a major factor in the design and operation of subsea and inlet facilities, including inlet compression which may required from day one of production

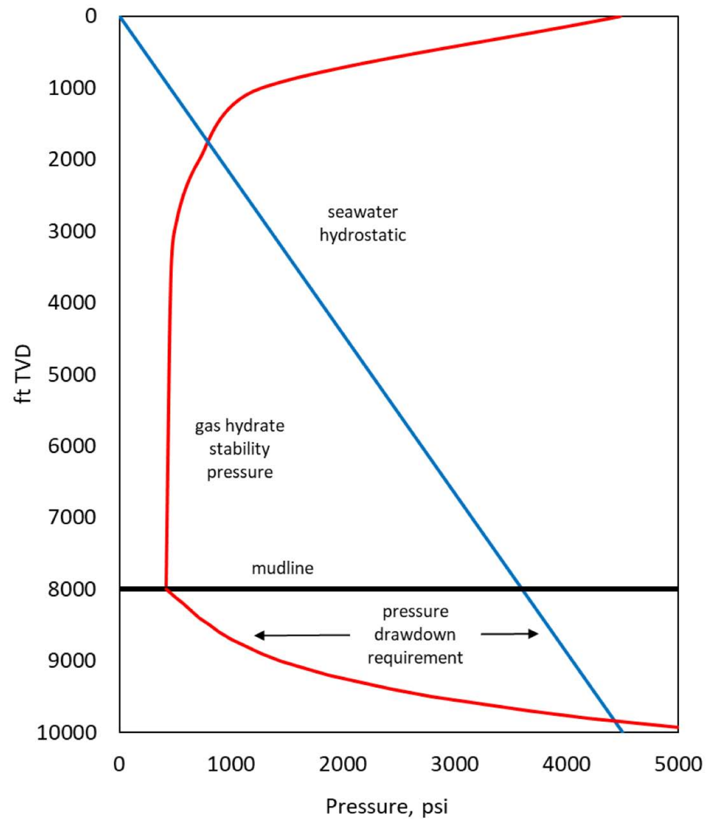

Figure 2—Hydrate Stability Pressure with Depth

Well Construction

Conventional deepwater wells have conductor casings jetted or drilled typically to say 350 ft below the mudline. An intermediate conductor casing may be run if required for shoe strength to drill the surface casing section.

The surface casing section is drilled riserless to a depth in the order of 3000 to 4000 ft or more below the mudline. The drilling fluid will usually start out as seawater however it is common to weight up to a water-based mud 12 ppg or more (referred to as pump and dump mud) for borehole stability concerns, or to control shallow gas or shallow flows if encountered. Given that the difference between pore pressure and frac pressure in this hole section is typically less than 0.7 ppg, foamed cement is used for the casing to avoid breaking down the formation and losing circulation.

In conventional drilling, gas hydrates are considered a shallow hazard along with shallow gas and shallow water zones [5]. The well location is typically selected to avoid these hazards, however if encountered they are controlled by weighting up as required. The thermal disturbance of shallow gas hydrate hazards is generally minimized as the drill fluids are cooled naturally by drilling without the riser in place. Seawater hydrostatic is sufficient to control further hydrate dissociation after the drilling thermal disturbance has diminished.

Based on this conventional experience, plus riserless drilling experience for gas hydrate coring and logging operations, it is conceivable that dedicated gas hydrate production wells can be drilled without a riser in place, possibly including the production liner if a cased hole completion is specified. Given the limited pore and frac pressure window, a riserless completion operation may also be beneficial to circulate gravel packs in place. Given that riserless drilling and completion operations in the hydrocarbon producing interval is not the norm, this approach will require operational risk assessments and probably regulatory review and approval.

Other than in scale, a gas hydrate production well will be similar in equipment and configuration to a conventional well as shown in Figure 3. As casing and equipment loads will be relatively light compared to a conventional well, the conductor for a gas hydrate well can probably be shortened to allow reasonable build rates for high angle or horizontal drilling.

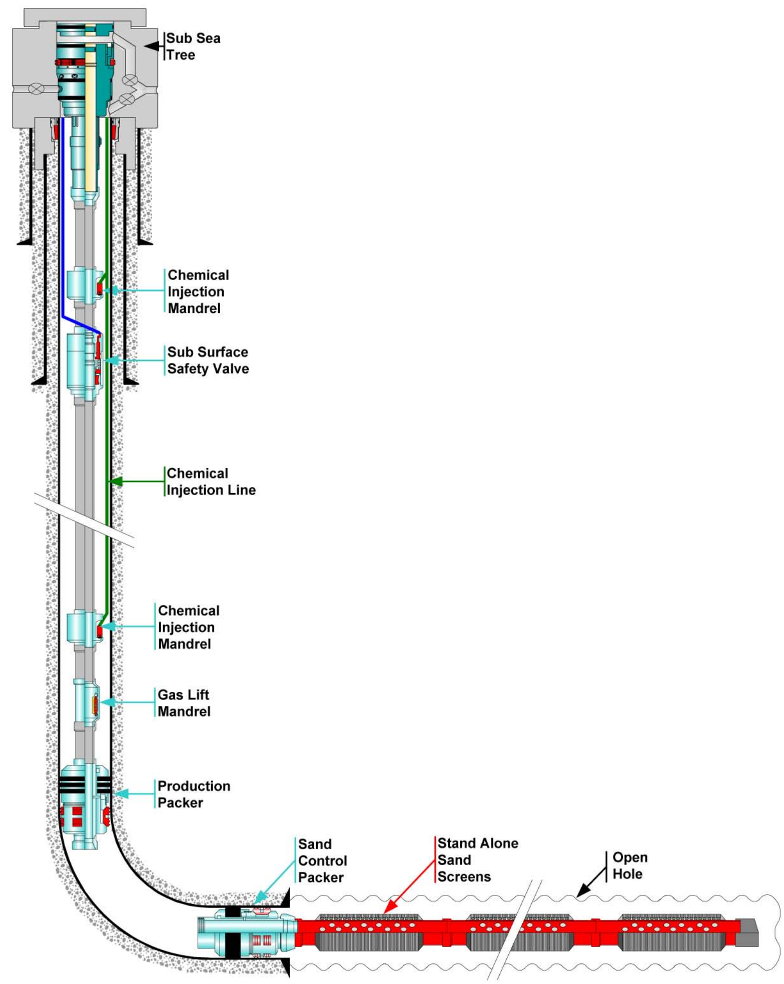

Figure 3—Deepwater Gas Hydrate Well

Advanced downhole instrumentation (pressure, distributed temperature fiber optics, permanent logging tools, etc.) and flow assurance equipment (chemical injection and heat trace) will probably be required in early deepwater gas hydrate developments. Some of this equipment could possibly be deleted as actual long-term operations experience is obtained. Every deepwater conventional well requires a surface controlled subsurface safety valve where there is the potential a release to the environment in a catastrophic well failure. Given that gas hydrate dissociation should stop if exposed to full seawater hydrostatic pressure, there should be a good case to eliminate this equipment (to be evaluated on field by field basis).

Perhaps one of the more difficult objectives to achieve in constructing a gas hydrate production is hydraulic isolation from free gas or free water zones above or below the gas hydrate production interval. Generally, there will not be thick competent shales above and below the production interval that can provide isolation with cement or external casing packers. In some settings the gas hydrate could be the only seal, especially at the base of hydrate stability, and once dissociated could provide a flow path for flow behind pipe or vertical flow through the reservoir (depending upon layering and vertical permeability).

Breakthrough of free gas may eliminate or delay gas hydrate dissociation. Breakthrough of free water, especially prolific zones, will further complicate water handling in the gathering system, inhibit or prevent gas hydrate dissociation, and possibly cause loss of the well [6].

The equipment and techniques required to drill and complete gas hydrate production wells are currently available. Complications in well construction are more related to the gas hydrate well depth and geological setting as opposed to mechanical equipment limitations. Some optimization of existing equipment may be warranted (for example gas hydrate wells will not require the standard 15000 psi rated wellheads, or 10000 psi rated trees that are used for conventional wells). Given that gas hydrate developments will require a large number of wellbores, it is probably appropriate to develop a line of lower pressure rated equipment to reduce capital costs.

Subsea & Inlet Facilities

The subsea and platform inlet facilities for a deepwater gas hydrate development will differ from a conventional gas development in several ways:

- For a similar development (reserves and plateau production rate), a gas hydrate field will probably incorporate more wellbores
- Given the relatively shallow depth of deepwater gas hydrate reservoirs below the mudline, the development wells will be vertical or high angle and widely spaced, as opposed to cluster or template drilled directional or horizontal wells for a conventional development
- Assuming depressurization as the primary gas hydrate dissociation process, inlet compression may be required from day one and at peak plateau production rates for platform processing and export pipeline requirements – conventional developments typically require booster compression later in the life of the field after the production rate has dropped well off plateau
- In order to maintain the target flowing wellhead pressure for gas hydrate dissociation, high back pressure in the gathering system due to high gas and high water production rates, mudline boosters may also be required as part of the overall compression plan
- Flow assurance for the flowline system becomes more problematic with high water rates

Critical elements to resolve while planning deepwater gas hydrate subsea facilities includes well count and spacing, how water will be handled (separated or comingled flow of gas and water), flowline operation pressures (considering pipeline size and flow assurance), and the hydrate mitigation plan during production or shut-in operations.

Assuming a 250 MMscf/d production facility, water production rates could be in the order of 250,000 bbls of water per day initially (possibly higher) before dropping off over time. The produced water will be primarily fresh water from dissociation with some salinity due to mixing with pore water in the reservoir. Disposing of the produced water into the ocean (either at the mudline with subsea separation or at sea level), may be problematic depending upon local regulatory or environmental requirements. If the produced water cannot be released, water disposal would require additional pumping and power generation facilities (plus additional deck space), a separate riser and subsea flowline system, and one or more disposal wells.

Subsea water separation will remove most (but not all) of the produced free water from the gas flow. Multiple separation points may be required depending upon the well count and layout of the subsea flowline system. Water can then be released (if appropriate) or pumped to surface in a separate flowline system. While the subsea separator skid(s) would add to the complexity of the subsea gathering system, reduced water production to surface in the gas flowlines would benefit design of the pipelines and platform inlet facilities and reduce inhibition requirements.

Conventional deepwater gas reservoirs are typically normal or over-pressured, and can flow to the platform using initial reservoir pressure only well past the plateau production rate. Inlet booster compression may be incorporated later in the life of the field if warranted by additional reserve recovery. Again, assuming depressurization as the primary dissociation method, gas hydrate developments will probably require compression throughout the life of the field. This equipment will add significantly to the capital and operating cost of a gas hydrate development compared to an equivalent deepwater conventional gas development. Operating costs will also be higher than for a conventional development.

Flow Assurance

Flow assurance covers all topics associated with well performance and well reliability. Production wells in deepwater operations can be shut-in several times or more per month for a variety of reasons. The shut-ins may be planned, allowing the well to be prepared for restart (pumping methanol or other treatments), or unplanned such as in an emergency shut-down where no preventative action can be taken. Durations can range from hours to days, or sometimes significantly longer periods during emergency or storm events. The well design must be able to survive multiple shut-in events and resume production without significant delay.

In the case of gas hydrate production wells, the unique aspects of flow assurance include:

- Gas production with extremely high watercuts
- Relatively low operating pressures and temperatures
- Hydrate reformation
- Erosion with solids production and high gas velocities

Figure 4 illustrates system performance curves (flowing bottomhole pressure versus gas production rate at various water to gas ratios) for a typical deepwater gas hydrate well and operating conditions (platform inlet pressure 1000 psi, well 800 ft deep, 8000 ft of water, single well and flowline). As indicated, the well and flowline could flow under stable conditions with water to gas ratios in excess of 1000 bbls/MMscf at rates of greater than say 5 MMscf/d (or any combination of rate and pressure that provides the required gas velocity). The flowing bottomhole pressure will increase with increasing water production due to the overall mixture density, which can be accommodated by varying the flowing wellhead pressure as required. On this basis, gas hydrate wells may be able to flow freely under the right operating conditions with what would generally be considered excessive water production. At high water rates however, booster compression and/or inlet compression will probably be required to achieve the required flowing bottomhole pressure

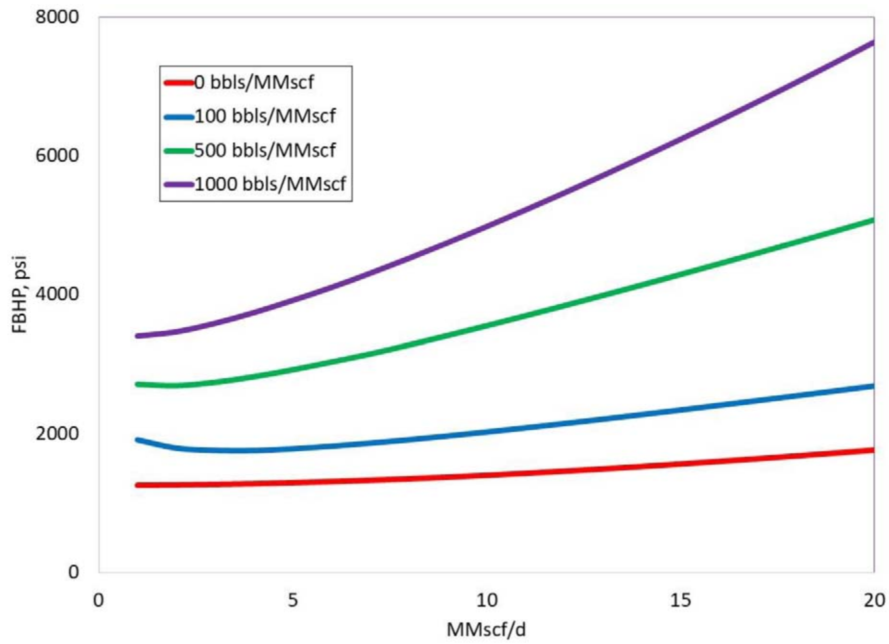

Figure 4—Flow System Performance Curve

Initial start-up of a gas hydrate well will require artificial lift to remove the hydrostatic head of the seawater to initiate dissociation. It is expected that water will accumulate in the wellbore during shut-in, therefore artificial lift will also probably be required to re-start a well. Electric submersible pumps have been used for production testing operations, but conventional gas lift or subsea multi-phase pumps may be alternatives for a permanent production operation.

Pressure loss through pipelines on the seafloor should be minimal when operating at design conditions. However, variation in gas or water rates could lead to water accumulation in the low spots along the pipeline, which could lead to slugging. Liquid slugs in the pipeline system can impact both the flowing wellbore pressures (adversely impacting gas hydrate dissociation), or impact process facilities when the slug of water arrives at surface. The impact of lifting these slugs in the flowline risers can be minimized with a riser gas lift system. Liquid accumulation in the flowlines can be managed with a pipeline pigging program. Oversize inlet separators (slug catchers) on the platform should minimize the impact of water slugs on the gas processing plant. However even with a fully optimized system, subsea booster pumps may be required to maintain the target flowing wellhead pressures as previously discussed.

The flowing temperature profile in a gas hydrate well will depend on gas and water rates, and reservoir effects caused by dissociation and gas expansion. When the well is shut-in, both pressure and temperature should return to the stable gas hydrate conditions reasonable quickly throughout the entire wellbore. Any free water in the wellbore therefore presents a risk of hydrate plugging during a shut-in of probably more than a few hours. A hydrate blockage in the tubing will be significantly more difficult to remove than simply restarting the dissociation process in the reservoir and could lead to significant delays in resuming production. During a planned shut-down, methanol can be displaced to prevent this from occurring. During an emergency shut-down displacing methanol may not be possible, therefore a supplemental method such as heat tracing may be required to remove a hydrate blockage.

The operating pressure of the subsea flowline system will depend upon several factors such as flowing wellhead pressure, water handling, hydrate inhibition systems, use of subsea booster pumps or compression, and flowline operating temperature, and will be a major engineering investigation as part of the overall subsea design and operating plan. The design of the flowline system will probably incorporate conventional insulation with advanced heat tracing systems. However, even with these measures in place, the flowline could quickly return to the mudline temperature in the event of an emergency shut-down or operating problem, thus hydrate formation in the pipeline during normal operation or a shut-down remains a risk.

Formation Solids Control

Fines production from unconsolidated reservoirs is not uncommon, but properly designed solids control systems will limit this to trace amounts in the flow stream. This is more critical in low pressure high rate gas systems than liquid systems due to the higher velocities and the potential for erosion. Solids accumulation in the wellbore and the flowline system may also be problematic.

The requirement for sand control for gas hydrate reservoirs has been evident since the first production tests at Mallik in 2002 [7]. Both onshore and offshore gas hydrates have been discovered in sediments ranging from coarse-silts to fine to coarse sands and gravels. Offshore systems have also tended to include reservoirs in finer-grained units as well. Further, onshore gas hydrates are also found below permafrost and are therefore relatively deeper (and therefore slightly more consolidated) compared to deepwater accumulations.

Deepwater gas hydrates are also typically found in thinly layered sediments. While some blocky medium to fine grained sand reservoirs have been discovered, the bulk of what may be considered potentially commercial deepwater gas hydrate accumulations are likely contained in fine sand, silt, and shale layers of variable thickness and variable gas hydrate saturation. Relatively high clay content and/or the presence of interbedded muds may also be expected.

The left curve on Figure 5 demonstrates a particle size distribution for a medium to fine grained sand reservoir. This sand would be considered clean (trace silt/clay content), uniform and well sorted. For this reservoir type, standard sand control design techniques and technology including gravel packs and premium pre-packed or filter type screens can be used. These technologies have an extensive track record in conventional completions and should also be successful for gas hydrate completions in this type of reservoir. The only issue for gas hydrate completions would be conventional gravel pack installation (circulation) with the expected low operating window between pore pressure and frac gradient.

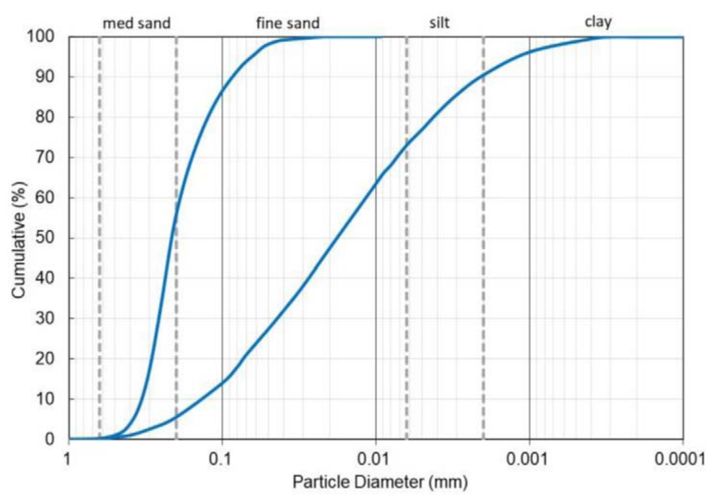

Figure 5—Typical Particle Size Distributions for Gas Hydrate Reservoirs

A particle size distribution of combined sand, silt, and shale layers would generally be considered as non-uniform and poorly sorted, as indicated by the example curve on the right in Figure 5. For gas hydrates in this type of reservoir, which could have silt and clay contents as high as 45%, a gravel pack completion would be the preferred sand control method. However, the conventional design approach for gravel size selection may not be appropriate. The optimal completion needs to balance fines migration through the gravel pack and fines retention behind the sand control completion. Excessive fines production can result in solids accumulation in the wellbore, flowline, or surface facilities, or possible erosion risks at high gas velocities. Fines retention can result in partial plugging of the sand control completion, which can result in increased pressure loss at the sandface and reduced productivity. An alternative approach to gravel pack selection for gas hydrate reservoirs with high fines content is discussed in reference [8].

As discussed previously, the small window between pore pressure and frac pressure in the shallow sediments below the mudline makes containment of the gravel pack difficult when circulating into place. Pre-packed screens or filter type screens may be an acceptable alternative, however plain screens would probably not work. Ultimately some trial and error, along with extended production time, will assist in optimizing sand control completions for deepwater gas hydrate wells.

Subsidence

Reservoir subsidence occurs when overburden loads exceed the structural capacity of the reservoir unit. This typically occurs in shallower unconsolidated normal or over-pressured sands when reservoir pressure drops below a critical value. The failure mechanisms include compression type failures within the producing interval (with sand control), or more commonly a tensile/shear failure of the production casing or liner some distance above the reservoir unit. Given the complexity of the factors involved, predicting well failures is probabilistic.

Strategies to minimize subsidence-induced failures include maintaining reservoir pressure above a critical limit, the use of damage tolerant completion equipment (sand control), strategically located slips joints in completion equipment, tubing, or casings/liners, or cementing technologies. Subsidence failures, while relatively rare, typically occur late in the life of the well when drawdown has occurred on a reservoir scale. The only remedy is to abandon the lower completion and sidetrack the well, assuming there is an economic basis for proceeding.

Deepwater gas hydrate accumulations occur in the shallow unconsolidated sediments at depths up to 3000 ft below the mudline, and generally at normal pressure conditions (seawater hydrostatic). Assuming depressurization is the primary dissociation method, the gas hydrate reservoir could immediately experience pressure drawdowns of say 1000 to 2000 psi. Initially this depressurization will be in the near wellbore area acting on the active hydrate dissociation face, and probably some distance beyond depending upon the relative permeability of the free water phase.

The solid gas hydrate in the pore space may support some of the overburden stress acting on the reservoir unit depending upon saturation. As production continues, the active hydrate dissociation face will move radially away from the wellbore (but not necessarily uniformly depending upon reservoir heterogeneities and layering) and more and more of the reservoir rock will be exposed to low operating pressures. Numerous simulation studies have shown that reservoir subsidence will begin very early in the life of a gas hydrate well, generally in days or weeks [9]. Given the nature of the shallow sediments in a deepwater environment, and because of the shallow well depth, subsidence may also be observed at the mudline. The magnitude of the subsidence may be sufficient to yield wellbore tubulars or equipment in tension or compression.

If a gas hydrate well fails due to subsidence, it may be possible to drill a replacement well in the radius of subsidence around the original wellbore as shown in Figure 6. This would allow the new well to continue producing the remaining gas hydrate reserves. As discussed above, predicting how the actual failure will be manifested (if at all) and how it may impact well integrity or future well operations are probabilistic in nature. Actual long-term production experience from the first deepwater gas hydrate developments will help reduce the uncertainty associated with this phenomenon.

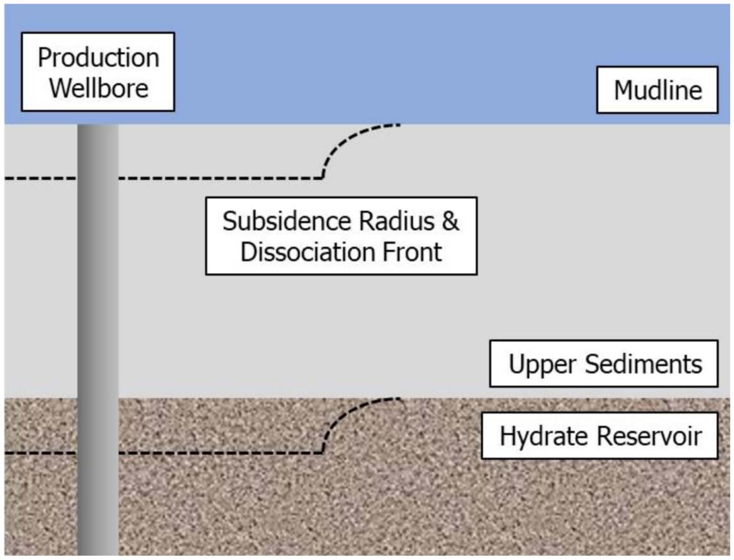

Figure 6—Radial Subsidence Profile

Conclusions

Gas hydrate well designs can incorporate many of the elements currently used in deepwater development. The reduced drilling depths and reservoir pressures will require modification or simplification of some systems. Gas hydrate production well issues include solids control, reservoir subsidence, high water to gas ratios, and flow assurance issues. The subsea system for a deepwater gas hydrate development will be more complicated than a conventional development, due to issues such as well count, control and inhibition facilities, water handling and disposal, and flow assurance. Subsea gas and water separation equipment may be required, as well as subsea compression to maintain the required low flowing bottom hole pressures for gas hydrate dissociation. Requirements for inlet compression and water disposal could add significantly to the capital and operating cost for a deepwater gas hydrate development. The technologies to address many of the production challenges issues are for the most part currently available, but some new equipment and techniques may be required. In addition, a few paradigm shifts with respect to drilling and completion operations may also be required as the industry moves from conventional to un-conventional deepwater development, in order to reduce installation and operating costs and maximize production rates and recoveries.

To date, the objectives for onshore and offshore gas hydrate production tests have largely been science based. In the future, one of the more critical technical issues will be to demonstrate that gas hydrates can be produced at rates significantly higher than currently achieved test rates, and that a production well can survive multiple start-up and shut-down sequences without an impact on well integrity and productivity. Production rate is a primary factor in well count, which will have a major impact on capital and operating costs. Certainty of gas and water production forecasts will be a critical element for field development planning for gas hydrates.

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