STATEMENT OF
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THE PRODUCTION OF GAS HYDRATES

Mr. Chairman and Members of the Subcommittee, thank-you for the opportunity to appear before you today to discuss the production and economics of gas hydrate development.

INTRODUCTION

Unconventional oil and gas resources such as heavy oil, coal bed methane, and shale gas, required development of new technologies such as horizontal and multi-lateral drilling before they could be economically produced. Based on our current understanding of gas hydrate properties and reservoir performance, we theoretically have the technology to drill, complete, and produce gas hydrate wells at relatively high gas rates. So the question has been asked – when will gas hydrates be economic to produce?

There are no simple answers as to the commerciality of any particular gas hydrate accumulation. The economics of any hydrocarbon development can be highly variable due to uncertainties in geology, drilling and facility costs, reservoir properties, markets and commodity prices. Each development must stand on its own merit and unique set of circumstances. We can however examine a number of hypothetical developments to gauge the relative economics of gas hydrates compared to conventional gas. For gas hydrate developments, additional uncertainty must be assumed at this time because there has not been a well test at commercial gas production rates. All gas hydrate production forecasts are based on theoretical numerical simulation models calibrated to small scale controlled experiments conducted at the Mallik (Canada) and Milne Point (Alaska) test wells.

PRODUCTION STRATEGIES

Gas hydrates can be dissociated into natural gas and water by three main methods [1]:

- Depressurization, in which the pressure is reduced below the gas hydrate stability point at the prevailing reservoir temperature;
- Thermal stimulation, in which the temperature is raised above the hydrate stability point at the prevailing reservoir pressure; and
- Injection of inhibitors such as methanol which changes the gas hydrate stability conditions.

Production strategies can use one or a combination of these methods. Depressurization is thought to be the most technically efficient means of production from natural gas hydrate deposits [10], and is the basis for the economic studies reported in this statement.

Most research programs have targeted coarse-grained sand deposits as the most promising reservoirs for the production of gas hydrates. Natural gas hydrate accumulations within these types of reservoirs can exist in a number of ways, including [2, 3]:

- A gas hydrate layer in contact with a free gas layer – this situation has the obvious advantage that the free conventional gas can produced initially, with contribution from the gas hydrate layer starting as reservoir pressure declines below the stability point. The free gas is theoretically in contact with a large surface area of gas hydrate, which should increase gas hydrate response.
- A gas hydrate layer in contact with a free water layer - dissociation can be initiated by producing the free water layer and dropping reservoir pressure below the stability point. As above, the free water is theoretically in contact with a large surface area of gas hydrate, which should increase gas hydrate response.
- A gas hydrate layer only, with no free water or gas contacts - dissociation can be initiated in the wellbore contact area only.

The onshore gas hydrate developments evaluated in this study compared two gas hydrate reservoirs with single free gas and free water contacts. The offshore gas hydrate study considered a gas hydrate only reservoir

TECHNICAL CHALLENGES

Gas hydrate wells will be more complex than most conventional and unconventional gas wells due a number of technical challenges, including:

- Maintaining commercial gas flows with high water production rates;
- Operating with low temperatures and low pressures in the wellbore;
- Controlling formation sand production into the wellbore; and
- Ensuring well structural integrity with reservoir subsidence.

Technologies exist to address all of these issues, but will add to development costs. Gas hydrate development also has one distinct challenge compared to other unconventional resources, and that is the high cost of transportation to market.

Most gas fields require some compression to maximize reserve recovery, but this typically occurs later in the life of the field after production starts to fall below the plateau rate. For a gas hydrate development, the required pressure to cause dissociation will require the use of inlet compression throughout the life of the field including the plateau production time. This will require a larger capital investment for compression at the front end of the project, and will also result in higher operating costs over the life of the project.

Water production is not uncommon in gas wells, however water rates are typically less than say 10 bbls/MMscf (barrels of water per million standard cubic feet of gas) for water of condensation and/or free water production. Wells that produce excessive amounts of water are typically worked- over to eliminate water production or shut-in as non-economic. The water production from a gas hydrate reservoir could be highly variable, however water:gas ratios in excess of 1,000 bbls/MMscf are possible. This water must be removed from the reservoir and wellbore to continue the dissociation process. On this basis, a gas hydrate development will require artificial lift such as electric submersible pumps or gas lift, which will also increase capital and operating costs over the life of the field. But it is important to highlight that the water in gas hydrate contains no salts or impurities, it is fresh water and may be a valuable coproduced product of a gas hydrate development.

The combination of low operating pressures and high water rates will require larger tubing and flowlines for a gas hydrate development, in order to minimize friction losses and maximize production. Additional water handling facilities and water disposal will also be required. Larger inhibitor volume (such as glycol) will be required to prevent freezing and hydrate formation in tubing and flowlines. Other items such as sand control, reservoir subsidence, downhole chemical injection, possible requirements for near wellbore thermal stimulation, etc., will also require additional capital and operating costs for gas hydrate developments compared to conventional gas developments.

ONSHORE GAS HYDRATE ECONOMICS

Onshore gas hydrates in North America are located on the North Slope of Alaska and on the Mackenzie Delta in Canada. These resources, along with significant volumes of already discovered conventional gas, are stranded without a pipeline to market. In order to compete for pipeline capacity, the economics of onshore gas hydrate developments must be attractive at prevailing gas prices. This may have an impact on the timing of major onshore gas hydrate development, however, unique circumstances may allow production for local community or industrial use. For example, an oil lease on the North Slope in short supply of gas for heating and power generation could make use of gas hydrate production – the produced gas could be used for fuel, and the produced water could be used for waterflood operations to improve oil recovery.

The preliminary economics of two different hypothetical onshore gas hydrate developments are presented in this statement:

- The first case was based on a reservoir in which gas hydrate is underlain by free-gas. The gas hydrate layer in this case had an initial gas in place volume of 1.07 TCF (trillion cubic feet). The free gas layer added an initial gas in place volume of 0.23 TCF, for a total gas volume of 1.30 TCF.

- The second case was based on a reservoir in which gas hydrate is underlain by water . As above, the gas hydrate layer in this case had an initial gas in place volume of 1.07 TCF (with no free gas component).

Gas and water production rates were predicted using the commercial reservoir simulator CMG-STARS (Computer Modeling Group's Steam, Thermal and Advanced Processes Reservoir Simulator).

The field development plan consisted of 5 production wells and 2 water disposal wells. Production was initiated via depressurization in both cases. The capital and operating costs for the various field development plans considered in this evaluation were generated using IHS Energy's Que$tor™ planning software and costing database, plus information from a variety of sources.

Full discussion of these evaluations cannot be presented here. Additional information on reservoir properties, simulation results, capital and operating costs, and detailed economic discussions are presented in [4]. Key results from these investigations are summarized in the following discussion. Note that all prices in this document refer to 2009 United States dollars.

Figure 1 presents the predicted gas production rates for the two cases.

The first case starts out at a plateau or peak rate of 125 MMscf/d (million standard cubic feet per day), and declines thereafter. Note that conventional gas field developments are normally designed around a plateau or peak production rate lasting say two to five years. This is typically the most economic way to develop and produce a gas field considering capital costs and operating life. The high initial production rate is largely due to the free gas below the hydrate layer. After approximately five years, the total field production rate declines as the free gas is exhausted, and the gas production is due largely to gas hydrate dissociation.

The second case starts out at a low gas production rate, and builds slowly to a peak rate at approximately year five and declines slowly thereafter. In this type of reservoir setting, the free water must be produced to initiate gas hydrate dissociation, which itself produces significant water volumes. These water volumes must be produced prior to the start of significant gas production, which results in a slow build-up to peak gas production.

Typical project economic evaluations are based on risked net present value economics. In this procedure, annual capital and operating costs, along with revenues from gas production, are discounted annually from a starting point. Annual discount rates (or internally rates of return) typically range from 10% to 20% to account for cost of capital and risk. Compared to events which occur early in the life of the project, activities in future years are more heavily discounted and thus have less of an impact on the overall project economics.

A gas hydrate only development will characteristically have peak gas production rates occur later in the life of the field, as well as a lower peak production rate and a longer field operating life, compared to a typical conventional gas field. Thus gas hydrate only developments will be somewhat penalized for the expected production characteristics when using net present value economics.

Figure 2 illustrates the sensitivity of internal rate of return to gas price for the two cases considered. This evaluation includes revenues, capital and operating costs, typical frontier royalties, but with no incentives or taxes. In addition, a pipeline tariff to the southern US markets of $2.50/mscf (thousand standard cubic feet) has been assumed.

The first case is reasonably robust as the gas price increases over $ US 6.00/mscf. This is due primarily to the production of free gas early in the project. The rate of return for the second case is somewhat insensitive to increasing gas price, as the discounting on the delayed peak gas production reduces the impact of increasing price. To achieve a rate of return of 15%, the first case would require a gas price of approximately $ 6.50/mscf, and the second case would require a gas price of approximately $12.00/mscf.

Complexities and geologic heterogeneities encountered in any natural settings may either reduce or improve the well performance, which could significantly change project economics. However these preliminary analyses do indicate that the gas price required for a reasonable rate of return for an onshore gas hydrate development is only slightly beyond the peak historical gas prices that have been observed in North America. It is also obvious from these analyses that comparable conventional gas resources will always be more attractive in net present value terms than gas hydrates.

OFFSHORE GAS HYDRATE ECONOMICS

Gas hydrates have also been discovered in the deepwater areas of the Gulf of Mexico and along most of the deep coastal margins throughout the world. Deepwater drilling technology and experience continues to evolve, and the worldwide deepwater fleet continues to expand. However the deepwater environment is still a very high cost and very high risk area of operation. Offshore gas hydrate developments must have strong economic drivers in order to compete with other deepwater exploration and development opportunities.

By all estimates, the majority of gas hydrates considered for production are located in sandstone reservoirs in deepwater environments. In order to understand the economics of deepwater gas hydrates, stand alone field development plan were prepared for a gas hydrate accumulation not in contact with gas or water-bearing reservoirs. The gas hydrate production rates were based on a study conducted in [4] for a deepwater Gulf of Mexico reservoir condition, which used the TOUGH+HYDRATE (Transport of Unsaturated Groundwater and Heat) numerical simulation model. Capital and operating costs were again developed using IHS Energy's Que$tor™ development planning tool and costing database program. For comparison purposes, a similar sized deepwater conventional gas field was developed using the same tools in order to determine comparative economics.

The field development plans for both fields assumed a subsea development in 5000 feet of water. A new purpose built floating production facility plus a 75 mile pipeline are added to standard costs such as compression, dehydration, and separation. Extra costs associated with hydrate gas production, such as artificial lift, reduced platform pressure, and flow assurance are also considered, in addition to sand control. It was assumed that there would be sufficient wells in place to maintain a plateau production rate of 500 MMscf/day, and recover 2.0 TCF of produced gas over a 20 year life. Additional wells were added for both development types to account for structural and drainage issues typically encountered in large areal discoveries.

Figure 3 illustrate the typical gas production profile for the gas hydrate wells studies in [5]. This result follows the previous discussion regarding delayed onset of peak production followed by a decline as the gas hydrate is exhausted. Also as discussed, significant production of water is required to continue the gas dissociation process. Figure 4 illustrates the predicted water to gas ratio for the simulated well. For the first several years, the predicted water volumes are significantly higher than the well could naturally flow with, therefore artificial lift would be required to initiate and assist production through most of the life of the field.

Based on the predicted gas production profile, 48 wells would be required for the deepwater gas hydrate development. For the conventional gas case, it was assumed that 18 wells would be required, but it is noted that this will count could be significantly reduced in prolific offshore gas fields. Figure 5 presents the total gas production forecast for both cases.

Full discussion of these evaluations cannot be presented here. Additional information on reservoir properties, simulation results, capital and operating costs, and detailed economic discussions are presented in [6]. Key results from these investigations are summarized in the following discussion. Note that all prices in this document refer to 2009 United States dollars.

For the comparative analysis, risked cost and production profiles were developed in order to account for greater uncertainty in a gas hydrate development compared to a conventional gas development. Figure 6 illustrates a pre-tax, pre-royalty plot of rate of return versus gas price for the expected results for both the conventional gas and gas hydrate developments.

Given the risks associated with conventional deepwater hydrocarbon developments, the gas hydrate developments probability adds another level of risk which cannot be quantified at this level of investigation. The capital and operating costs developed for this evaluation considered the unique differences between conventional gas and gas hydrate developments and allowed significant contingency to account for these unknowns. While the absolute costs at this level of study have a wide range of uncertainty, the comparative analysis is considered a reasonable indication of the differences between the two types of developments: i.e. while the gas price required to make a gas hydrate discovery economic will be higher than that for conventional gas discovery, the difference in price is measured in terms of dollars, not orders of magnitude. This also again illustrates that on a comparable basis, a conventional gas development will be more attractive than a gas hydrate development in net present values terms.

CONCLUSIONS

The results of these investigations, while preliminary, have been very encouraging:

- For onshore gas hydrates, stand-alone developments could be economic with a gas price in the upper range of historical North American prices, and
- For deepwater gas hydrates, stand-alone developments could be economic with a gas price in the upper range of what India has paid for liquefied natural gas imports on the spot market.

As with all hydrocarbon developments, the economics of gas hydrates will be highly variable, depending upon such factors as well performance, sediment type, gas-in-place, thermodynamic conditions of a reservoir, and the access to existing infrastructure. It is also clear that comparable conventional gas reservoirs will generally be economically more attractive than gas hydrate only reservoirs, suggesting that the production of gas hydrates on a large commercial scale may be delayed.

Unique circumstances may allow production of onshore has hydrates for local community or industrial use, especially where there is some underlying gas. Offshore gas hydrate developments may proceed sooner on the basis that the premium price required may not be onerous when there is no conventional gas competition, and where security of supply may be a major consideration.

Significant scientific and exploration work must be completed before gas hydrates can be considered as a viable source of natural gas. Critical among these tasks remains the validation reservoir and well performance through extended field testing that demonstrates the ability to produce gas hydrates at commercial rates with current technology. The small scale production experiments conducted at Mallik and Milne Point provided valuable insight into gas hydrate reservoir performance. The short term production test recently conducted at Mallik also demonstrated that gas hydrates can be produced with current technology. The long term production test planned for the North Slope of Alaska is an important step in achieving this goal.

Thank you Mr. Chairman, for this opportunity to provide an overview of the production and economics of gas hydrate developments. I would be happy to answer any questions you may have.

References

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Figure 1: Field Gas Production Rate (MMscf/d) for Onshore Gas Hydrate Study

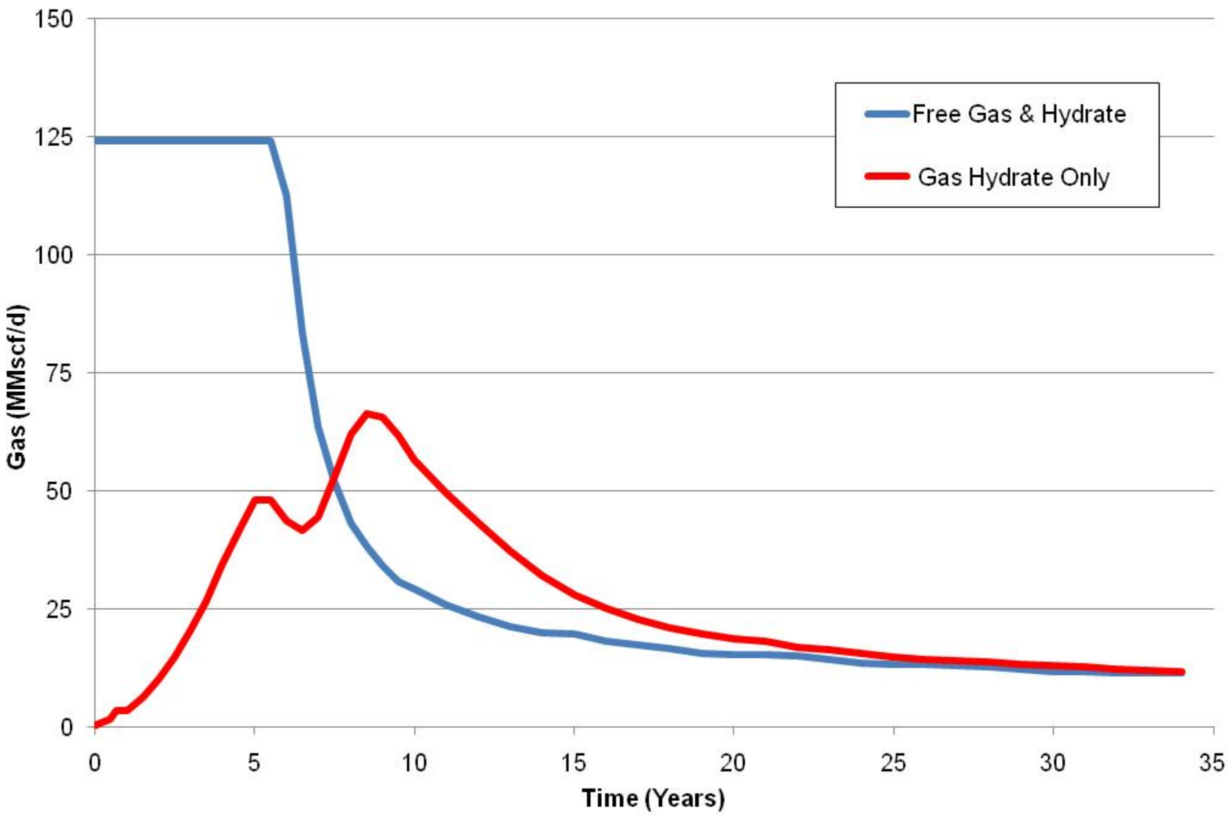

Figure 2: Internal Rate of Return as a Function of Gas Price ($/mscf) for Onshore Gas Hydrate Study

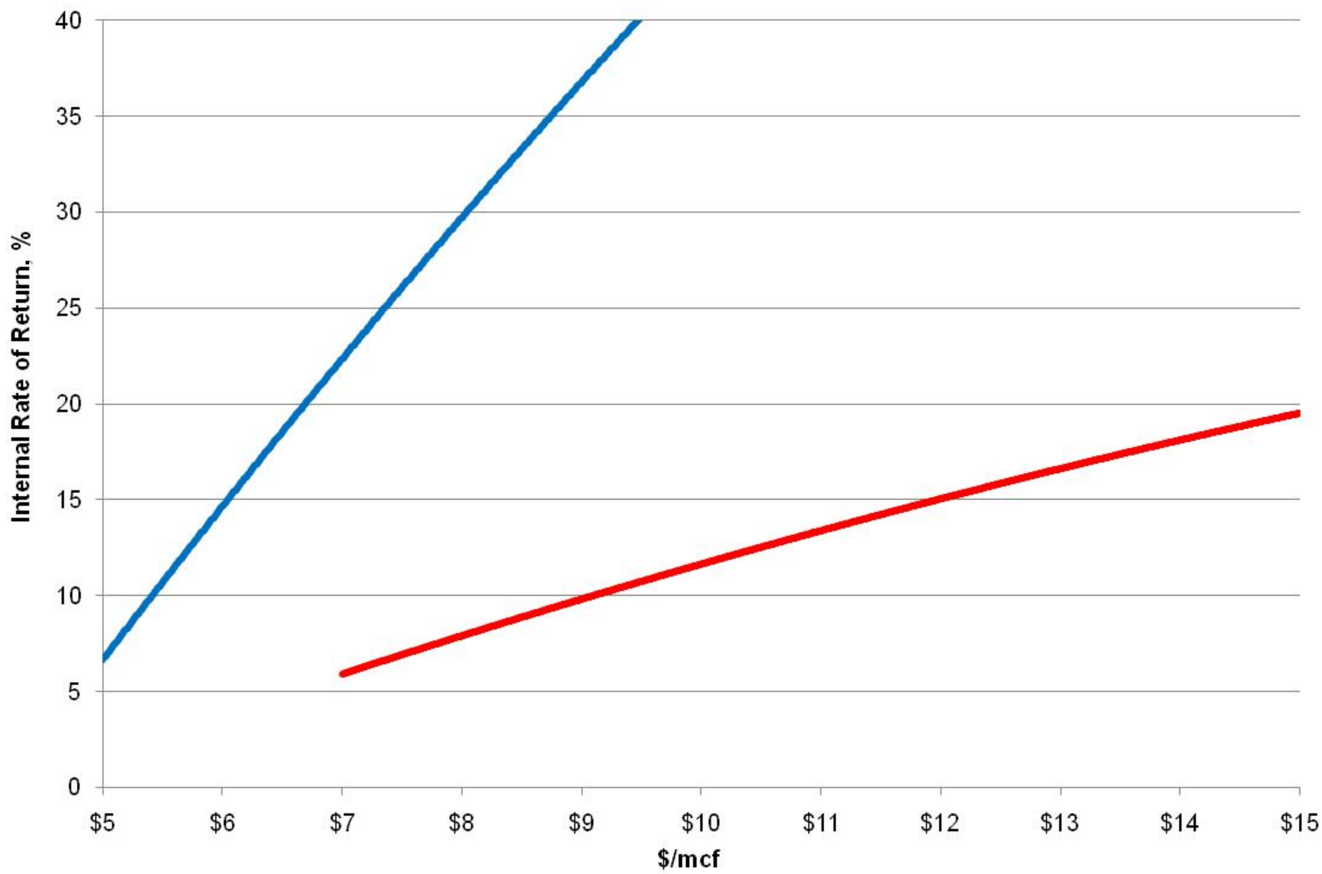

Figure 3: Single Well Gas Production rate (MMscf/d) for Offshore Gas Hydrate Study

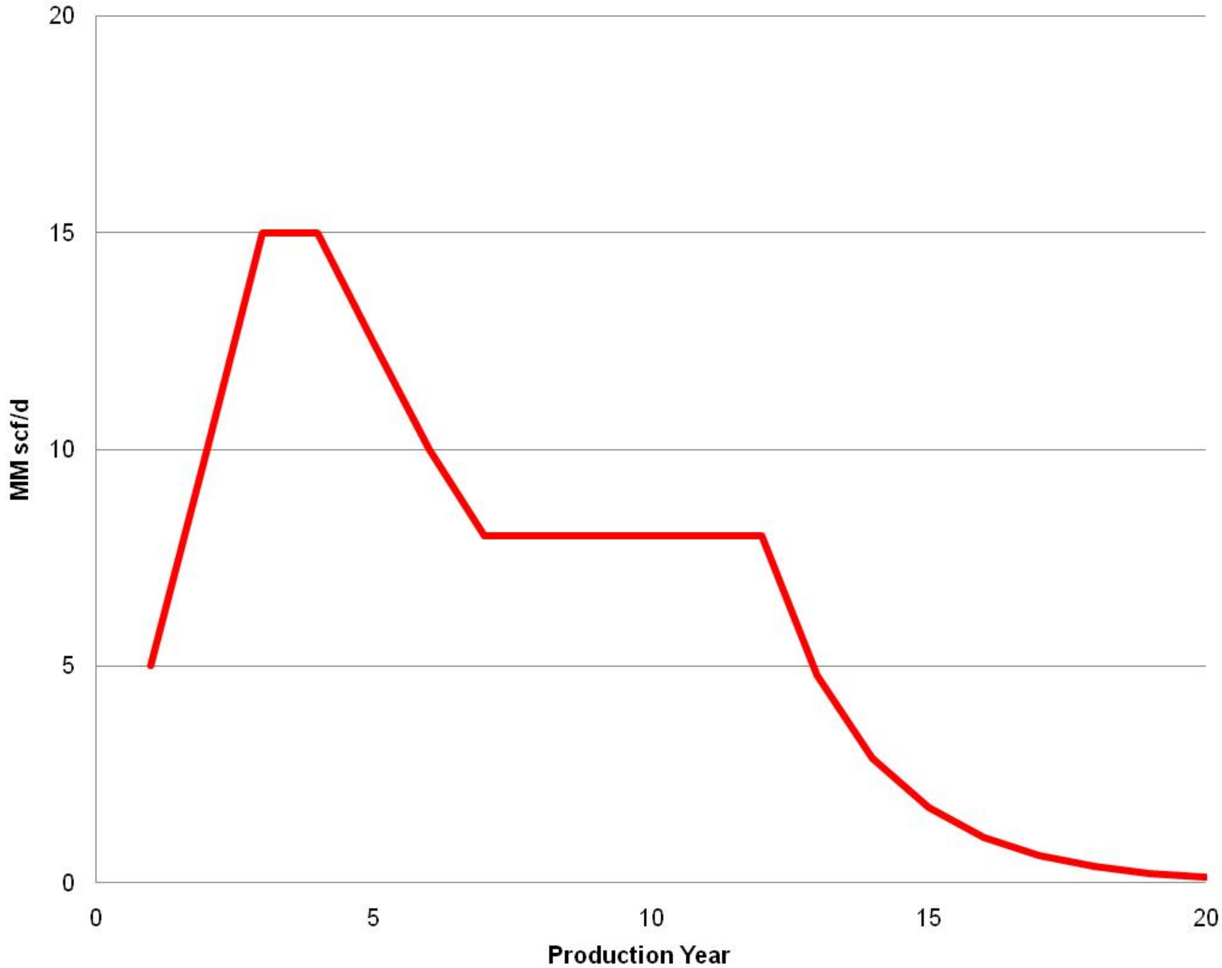

Figure 4: Field Gas Production rate (MMscf/d) for Offshore Gas Hydrate Study

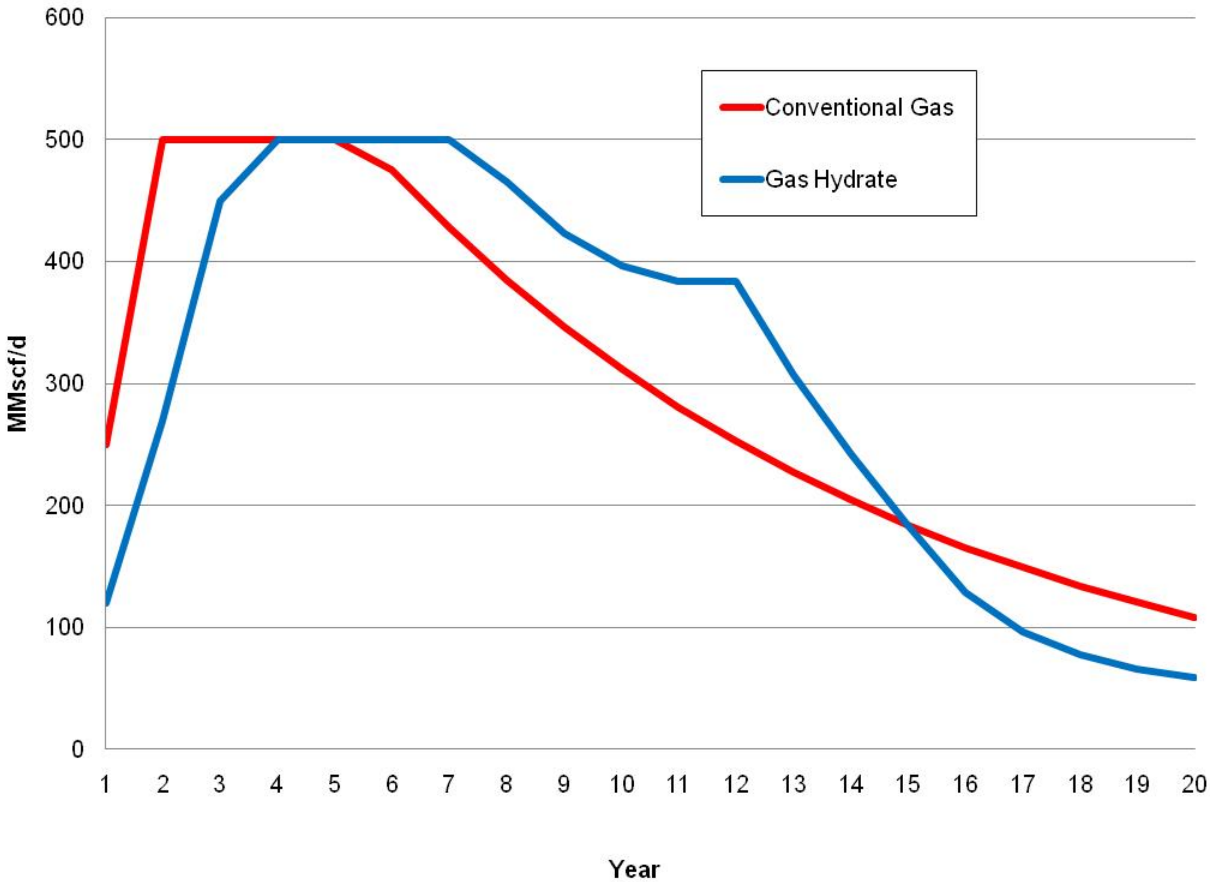

Figure 5: Gas Water Ratio (bbls/MMscf) for Offshore Gas Hydrate Study

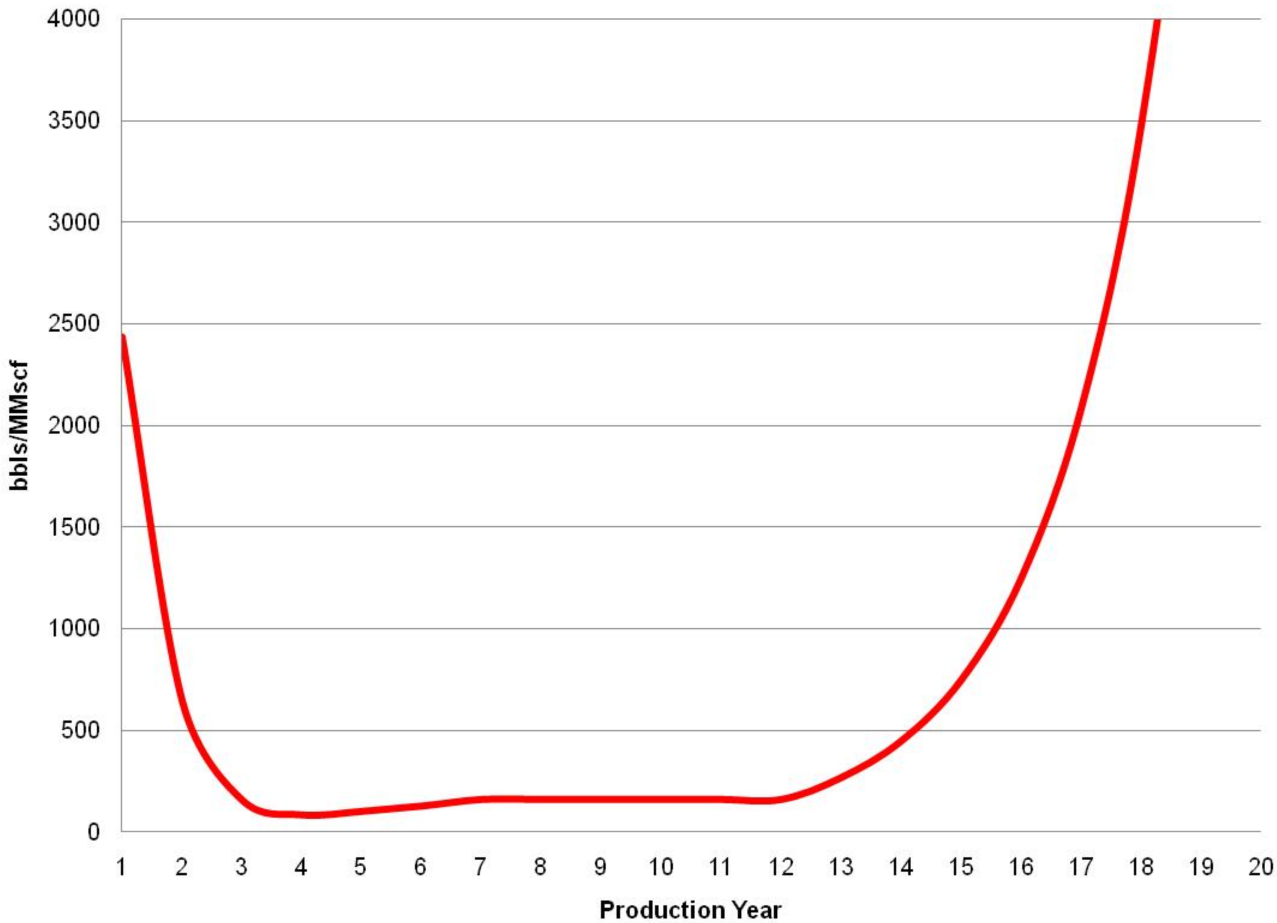

Figure 6: Internal Rate of Return as a Function of Gas Price ($/mscf) for Offshore Gas Hydrate Study