Hydrate Management With Real Time Data Visualization

Jianjiang Lv, **Jianbo Yuan**, **Minh Vo***, Chevron Unocal East China Sea Ltd, Chengdu, China; and **Junliang Zhang**, Southwest Oil & Gas Field Company, CNPC, Chengdu, China

Abstract

Hydrate is a common issue in the natural gas production, which can be accelerated by the presence of H_2S and CO_2. This paper is to present the current experience in a gas project in Sichuan, including application of several surveillance technologies for the benefit of hydrate prevention and management, to support production optimization.

This sour gas project has high H_2S and CO_2 content. With the high deliverability at the wells, the project has used a two-choke configuration in the surface system to manage the surface pressure to feed the gas into the production process. Given a design of the 2-choke system, the sour gas is choked, heated, and then choked again, and finally flows to the Tri-Ethylene Glycol (TEG) dehydration unit. Hydrate formation risk normally exists downstream of the first choke and the second choke if the heater is not efficient, and at the filtration process upstream of the dehydration.

Hydrate prevention had been considered during the design phase of the surface production facilities. Methyl-Ethylene Glycol (MEG) is therefore selected and injected to the upstream of the first choke to mix with the gas flow stream. Real time data surveillance (i.e., pressure and temperature) with digital gauges are installed in the areas with high probability of hydrate formation. The most important next step is the real-time data (i.e., gas rate, water rate, pressure, temperature and MEG injection rate), which are updated and the hydrate formation curves are plotted to display on the central control computer. Based on the displayed relation of the pressure and temperature, the integrated digital control system can be used to optimize production by controlling gas rate, heater temperature and MEG injection.

In brief, with this visualized monitoring system in place, hydrate prevention has been visually and effectively managed and MEG consumption has been optimized to minimize the operational cost.

Introduction

Methane hydrate, a crystalline solid that consists of a methane molecule surrounded by a cage of interlocking water molecules, is very common in the natural gas industry. Methane hydrate is an "ice" that only forms when temperature and pressure conditions are favourable for its formation, such as presence of “free” water, low temperature, high operating pressures, presence of H_2S and CO_2, high velocities, or agitation, or pressure pulsations (King 2017). **Figure 1** shows an example of pipeline hydrate blockage.

The components of hydrate is not limited to methane, but also, many other natural gas components, such as ethane, propane, isobutene, hydrogen sulphide, carbon dioxide and nitrogen.

Oil companies have known about methane hydrate since the 1930s, when they began using high pressure pipelines to transport natural gas in cold climates. Pipelines were noted to be obstructed by ice-like crystals, even though temperatures were higher than the freezing point of water. Before gas enters the pipeline, water must be carefully removed, since formation of methane hydrate will impede the flow of gas. Although scientists have been working to reduce formation of hydrates, the problem still exists and it affects the normal operations and increases cost (PSU 2017).

DOI: 10.14800/IOGR.441

Received October 3, 2019; revised November 12, 2019; accepted December 2, 2019.

*Corresponding author: minh.vo@chevron.com

The prevention of hydrate formation is preferable to remediation to ensure operational safety and efficiency. Some common hydrate prevention techniques are temperature control, water jacket heater and dehydration, inhibitors. There are several steps which may be employed to remove hydrates once formed, for instance, heating, pressure reduction and chemical injection.

Figure 1—Hydrate.

Sour Gas Project

This greenfield sour gas project is developed in Sichuan, China. The full field development schematic is shown in **Figure 2**. The project involves development of gas resources in Triassic carbonate reservoirs. The unique challenges for this project are sour gas, rugged terrain, large operating area, and high population.

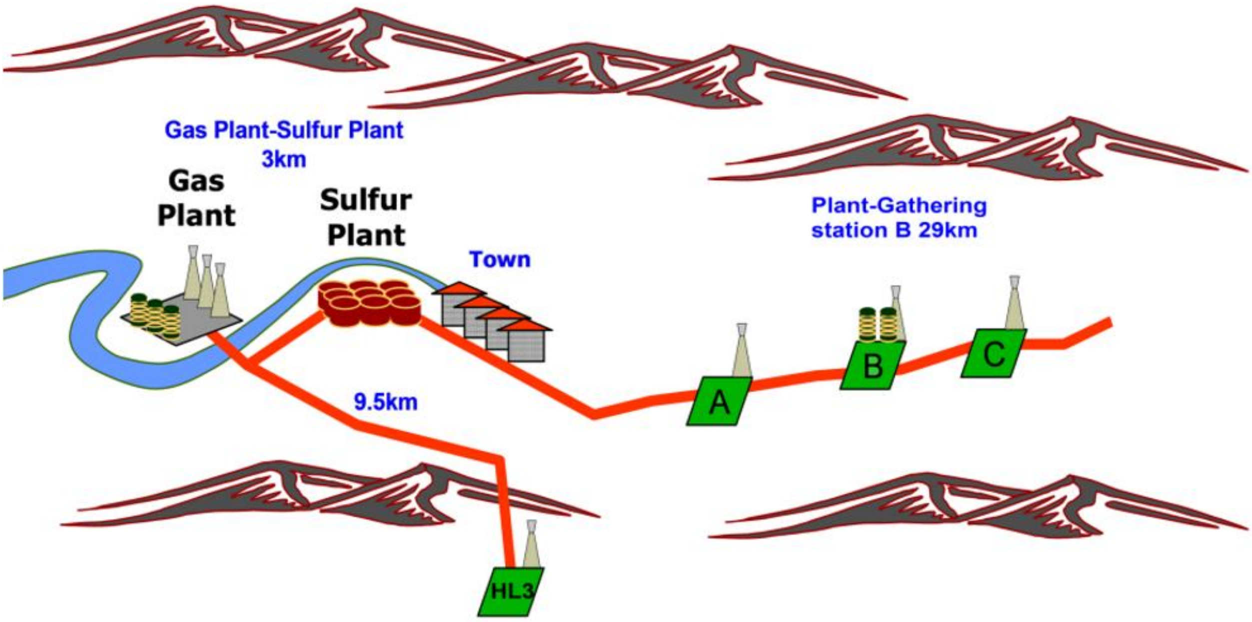

Figure 2—Sour gas development project.

Two-Choke Production System. Sour gas from the gas reservoir flows via the production tubing in the well to the wellhead, losing heat to the wellbore strings. The wellhead temperature, however, is still high enough to prevent hydrate formation. As illustrated in **Figure 3**, the first choke remotely controlled by operators in the central control room reduces the gas pressure to meet the pressure design of the surface flowline, resulting in a dramatic temperature drop due to the Joule Thompson J/T cooling effect. Meanwhile water vapor is condensed at such lower pressure and temperature conditions, and flows together with sour gas to the water jacket heater, where the sour gas is heated up to a temperature as per the designed heating capacity. Next, the gas is choked again to further reduce the gas pressure to meet the pressure design of the pipeline to the gathering station, resulting in a further drop in gas temperature. The second choke is operated at automated motion to maintain the gas pressure both upstream and downstream of the choke as designed.

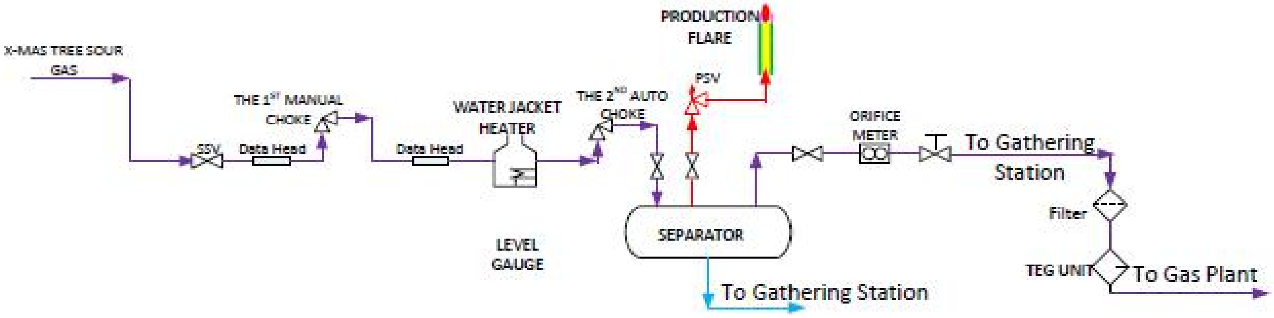

Figure 3—Schematics of two-choke production system.

Note that the sour gas reservoir has high H_2S and CO_2 content. This, together with the pressure and temperature profiles and condensed water along the surface process, introduce risk of hydrate formation for the surface facilities.

Because methane hydrates consist of geometric lattices of water molecules containing cavities occupied by methane and other gaseous components, and H_2S and CO_2 have higher solubility in water than methane, it's easier for H_2S and CO_2 to combine with water to form hydrate with than it is for methane at the same pressure and temperature conditions. More is shared in the next section.

At the gathering station, sour gas is filtered using a filter cartridge (**Figure 4**) to ensure clean gas to the inlet of TEG dehydration unit to dry the sour gas. Temperature drops as gas is flowing through the cartridge due to friction pressure loss. Next, dry and clean sour gas enters the pipeline to the gas plant to remove the hydrogen sulphide.

Figure 4—Filter cartridge.

Although the condensed water volume is small it raised up the risk of hydrate formation in the downstream of the two chokes and the filter separator, as the pressure and temperature (P/T) in the three positions may fit the requirement to form hydrate.

Hydrate inhibitor (MEG) is injected upstream of the first choke to prevent hydrate formation in the surface facilities.

Hydrate Pressure Temperature P/T Curve. A typical hydrate formation curve (phase diagram) is illustrated in **Figure 5**, which clearly shows that hydrate formation is favored by low temperature and high pressure.

Point Q_1 typically occurs at 32 °F which is the water freezing point. Hydrocarbon gas and water form hydrate at the region above the P/T curve Q_3-Q_1-Q_2. In other words, the region below the curve with higher temperature and lower pressure is free of hydrate risk.

The factors that affect the hydrate P/T curve are gas composition, gas rate, water-gas-ratio (WGR), inhibitor type and inhibitor volume. The sour gas is dry gas, without condensed oil or condensed gas. The produced water is condensed water vapor formed in the surface facilities, not produced from formation aquifer. Condensed water has much lower salinity than the formation aquifer, resulting in a higher risk of hydrate formation, because an increase in the salinity shifts the methane-hydrogen sulfide hydrate equilibrium condition to lower equilibrium temperatures at a given pressure (Ballard et al. 2011; Bulbul et al. 2014; Avaldsne 2014).

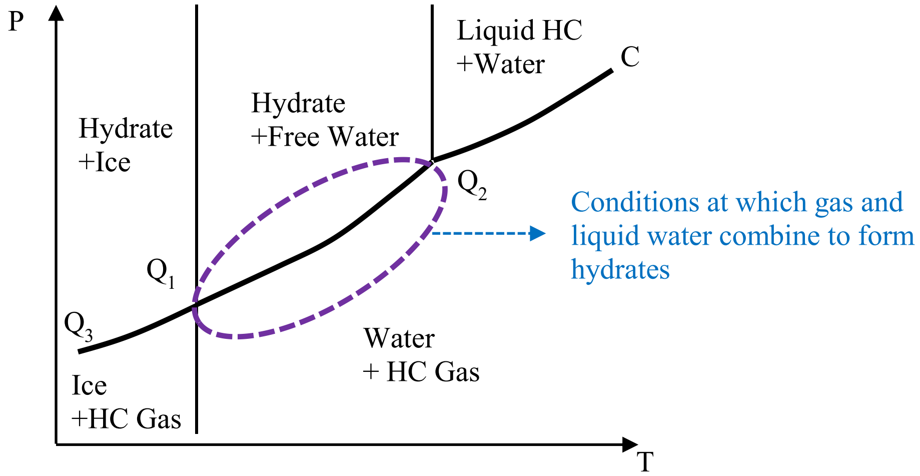

Figure 5—Phase diagram for water/hydrocarbon mix (PSU 2017).

Using the SRK-HV model and SRK-Peneloux model, the P/T curve is generated based on the sour gas composition, as in **Figure 6** and **7**. For example, when P/T data are plotted in the area above the curve, it indicates a hydrate formation risk (e.g., point A), and no risk if the data are plotted below the curve (e.g., point B with the same pressure).

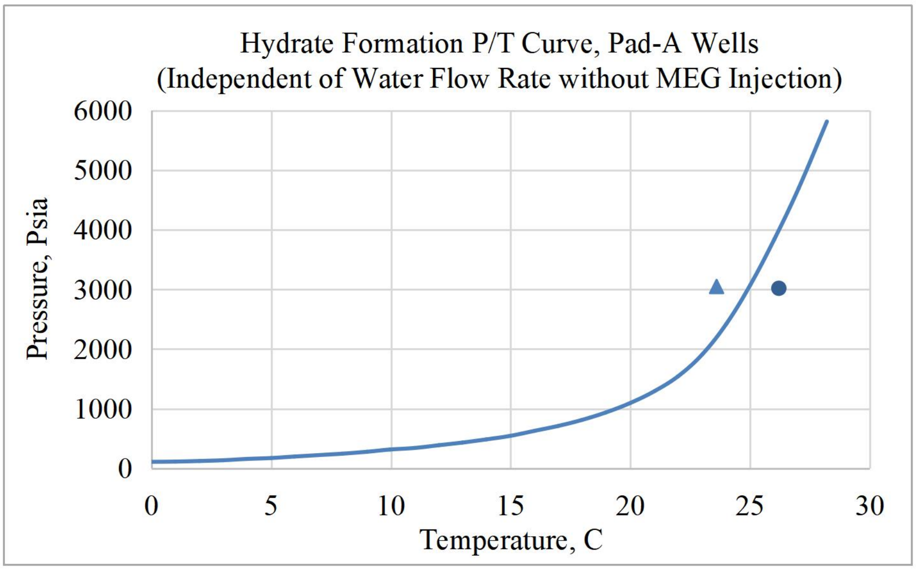

Figure 6—Hydrate formation curve without MEG injection.

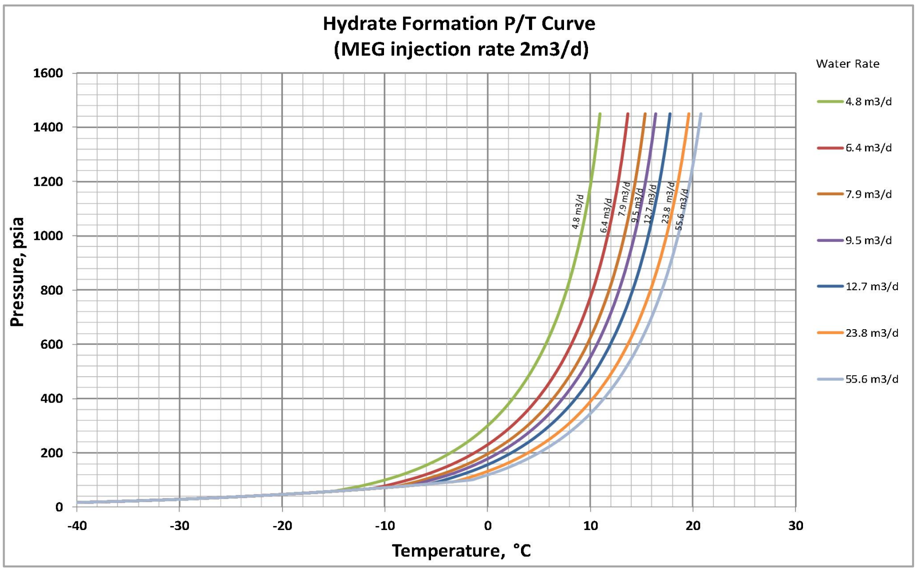

Figure 7—Hydrate formation curve with MEG injection.

Without inhibitor injection, the P/T curve is independent of water production rate. Because inhibitor has the effect of preventing gas molecules from being caged by water molecules, the ratio of inhibitor to water volume affects the P/T curve. Without inhibitor, water volume will not affect the hydrate formation pressure and temperature, but affect the hydrate quantity.

MEG injection mitigates the hydrate risk. For example, if the condensed water rate is 24 cubic meter per day, at 13 MPa pressure (megapascal), the hydrate formation temperature is around 3 ^{o}C lower than that without MEG injection. Additionally, with the same MEG injection rate, higher condensed water rate, higher hydrate formation temperature at the same pressure, thus a higher hydrate risk.

Carbon dioxide, hydrogen sulfide and nitrogen are the main impurities in natural gas affecting the hydrate formation. At a specific temperature, nitrogen increases the required hydrate formation pressure while both carbon dioxide and hydrogen sulfide lower the required hydrate formation pressure (Rajnauth et al. 2010).

Figure 8 shows the impact of gas composition on the P/T curve. With a higher H_2S concentration, the hydrate formation temperature is higher at the same pressure. For instance, at the same pressure 10 MPa, the hydrate formation temperature for pure methane is 13 ^{o}C, but it is 18.5 ^{o}C for a mixture of 95 mol% of methane and 5 mol% of H_2S. In another similar view, when looking at the impact of CO_2, H_2S has a much bigger impact than CO_2 on the P/T curve, for instance, hydrate formation temperature differential is 5 ^{o}C at 10 MPa.

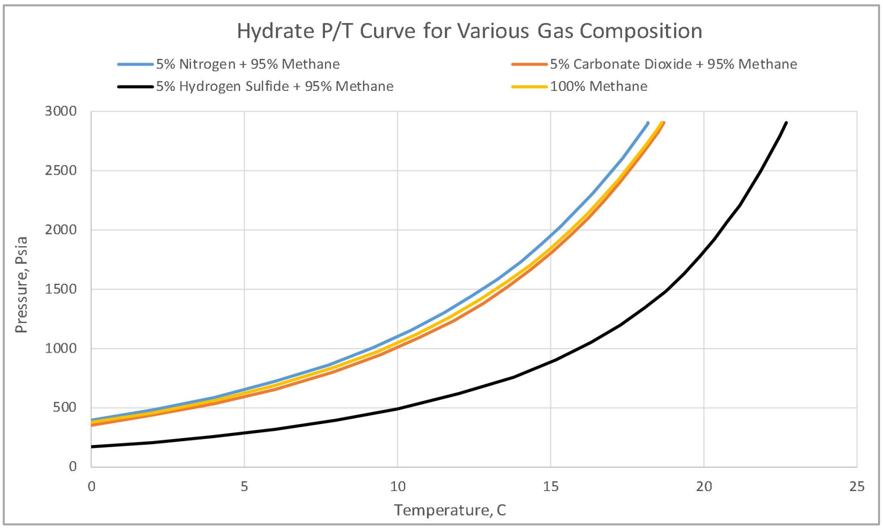

Figure 8—Hydrate formation curve for various gas composition without MEG injection.

Hydrate Forms in Liquid Phase. Not only hydrocarbon gas and liquid water can combine to form hydrate; gas components dissolved in water can form hydrate as well at favorable pressure and temperature conditions. For instance, the water outlet of sour gas compressors, used to compress the flashed sour gas from the TEG system, is operating at 3 MPa and 25 ºC, and the solubility of each gas component is calculated using the internal PVT analysis software as illustrated in **Table 1**. Therefore, hydrate P/T curve can be calculated for the specific solution as per **Table 1**, to evaluate if the risk exists. **Figure 9** indicates the hydrate forming temperature at 3 MPa is around 10 ºC, so the compressor's water outlet operating at 25 ºC has no hydrate risk in the liquid phase. In other words, normal operations need to ensure that the water outlet temperature shall be above 10 ºC.

Table 1—Solubility of each gas component in water.

Solubility, mol %	P at 3 Mpa, T at 25 ºC
CO_2	0.104
H_2S	0.446
C_1	0.055

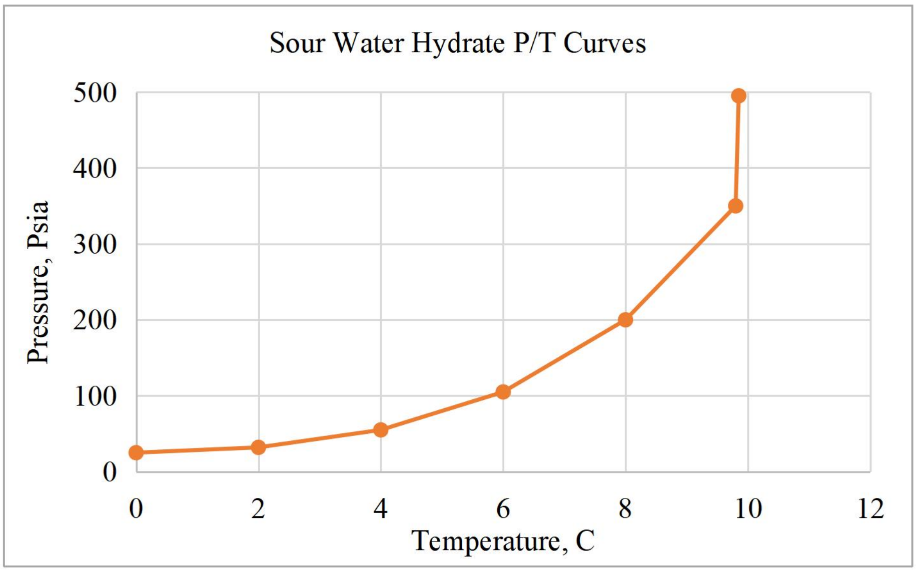

Figure 9—Hydrate P/T curve for sour water without MEG injection.

Real Time Data Visualization System. Pressure and temperature transmitters and gauges are installed in all the hydrate risk areas:

- Downstream of the first choke and of the second choke on the well pads,
- Downstream of the filter separator on the gas gathering station, and
- Water phase of the sour gas compressor.

Because all the real-time data is recorded and displayed on the computer screen in the central control room, the next step is to develop a real-time monitoring system, which can be used to displace all the information available and conditions that hydrate formation risk could be obvious. Furthermore, it is to help Operators see a trend of a parameter or set up an alarm to catch abnormal operating conditions.

At this JV Gas Project, the team has worked together and a hydrate monitoring module has been developed, and incorporated with the central control system to manage the real-time hydrate risk and MEG consumption.

As illustrated in **Figure 10**, an alarm will be triggered by real time pressure and temperature along the surface process, to notify operators by audio and red color twinkling. The operators will click the "plot" button to analyze the hydrate formation temperature curve, as **Figure 11**.

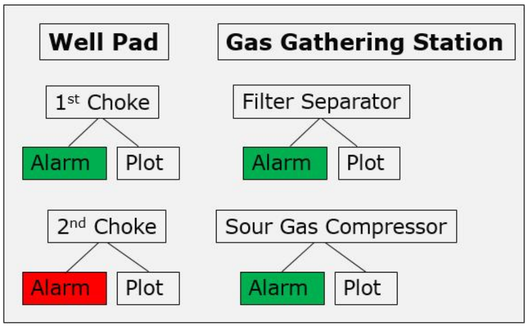

Figure 10—Conceptual schematic of real-time hydrate management and monitoring interface.

More specifically, the systematic design of the downstream pressure of the second choke is a constant value to ensure stable gas flow from well-pads to the gathering station. **Table 2** shows the basic data for hydrate risk analysis at the second choke downstream, such as water production rate, MEG injection rate and downstream temperature. The basic data is plotted in **Figure 11** to visually compare to the hydrate formation temperature curve.

Table 2—Primary well data for hydrate management.

Well	Water production rate, m^3/d	Temperature at second choke downstream, C	MEG injection rate, m^3/d
A	5.2	23.7	0.2
B	4.9	19.0	0.7
C	2.8	17.2	0.4

Well A data point locates far above the hydrate temperature curve with 10 m^3/d water rate, so there is no hydrate risk at the second choke downstream for Well A. Indeed, with such high temperature 23.7 °C, there is no need to inject MEG, so 200 litres/d of MEG can be saved.

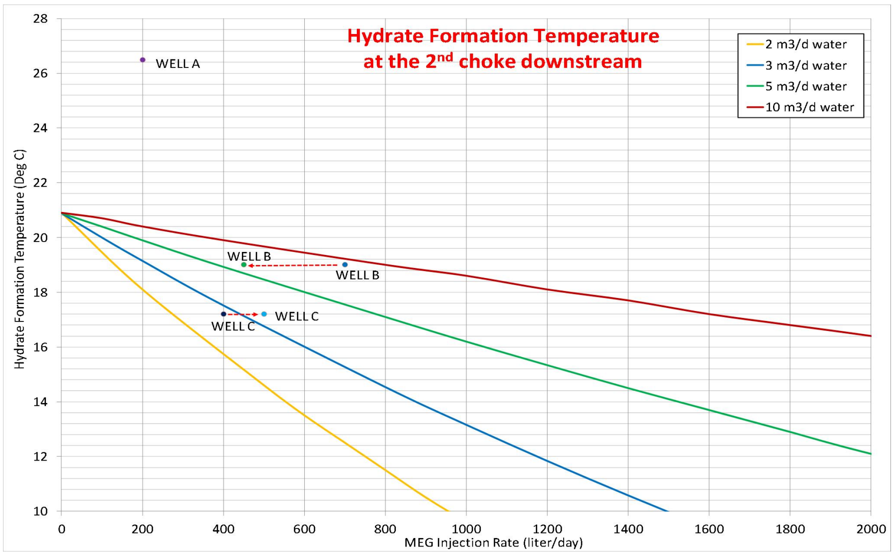

Figure 11—Sour gas hydrate formation temperature at the second choke downstream at fixed pressure and various MEG injection rate.

The required 700 litres/d of MEG is injected upstream of first choke of Well B. With the second choke downstream temperature 19 °C, the MEG injection rate can be cut to 450 litres/d as the new data point will still locate above the green curve with 5 m^3/d water rate, as illustrated by the red arrow for Well B.

However, Well C data point locates below the blue curve, with 3 m^3/d water rate, indicating hydrate formation risk, so MEG injection rate needs to be increased to 500 litres/d, as shown by the red arrow for Well C.

Figure 12 shows the hydrate formation temperature at the pipeline inlet from one pad to the gas gathering station. Sour gas from several wells in the same pad flows into the same pipeline, so the pipeline inlet temperature is the average temperature from all the wells. Each well has the same two-choke surface system as described in Figure 3. However, even the wellhead gas temperature is similar among the wells at the same gas rate, the working efficiency of the water jacket heaters equipped for each well could be different. Therefore, in addition to monitoring the hydrate risk downstream of the first and/or the second chokes of each well, the hydrate formation curve needs to be monitored at several critical areas, specifically at the pipeline connection after all gas streams from the wells are combined.

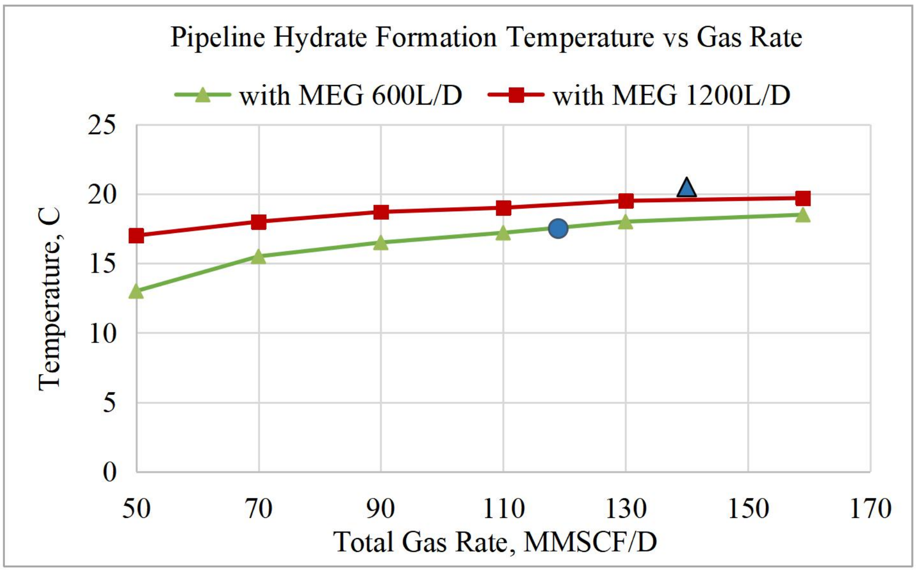

Figure 12—Sour gas hydrate formation temperature at pipeline inlet at a given pressure & various MEG rates.

Data point A locates below the curve with 600 liters/d MEG rate, indicating the MEG rate is insufficient for preventing hydrate risk, and shall be increased up to 1,200 liters/d (for reliability) to ensure hydrate-free condition in the pipeline. Data point B represents higher gas rate and higher pipeline inlet temperature, because the wellhead gas temperature is higher due to higher gas production rate from the reservoir. For point B, 600 liters/d MEG injection rate into the pipeline is sufficient to prevent hydrate risk.

Care must be taken as ambient temperature variation (i.e., in winter and summer) can affect the temperature profile of the surface facilities, so normally higher MEG rate is required in winter than summer.

Lessons Learned

Higher gas production leads to higher gas temperature at the wellhead, resulting in a corresponding higher J/T cooling effect through the chokes.

The designed constant pressure profile both upstream and downstream of the second choke, which is maintained by the automatic adjustment of the choke, prevents agitation and pressure pulsations along the surface process. That can accelerate the hydrate formation, because turbulence can serve as a catalyst.

When adjusting gas production from each well, care must be taken to analyze the hydrate formation curves in various locations because the P/T profiles of the surface process change simultaneously with gas rate.

Conclusions

With the visualization system in place, operators can easily see and understand where would be potential areas for hydrate formation risk, what conditions are required for hydrate formation, presence of water and hydrate formers, and the prevention method to manage hydrate risk.

- The visualized monitoring module, integrated with the central control system, makes the work easier to monitor and to analyze the hydrate risk, and to optimize the MEG injection rate for cost management.
- This is to support our operations team at field site to develop Best Practices and Focus Areas for an effective hydrate prevention and management.

Acknowledgment

The authors thank UECSL and CNPC for their permission to publish this paper. The authors also thank all the personnel, particularly field operators, who involved in the data collection at the field site and providing suggestions to the design of the real-time visualization system.

Conflicts of Interest

The author(s) declare that they have no conflicting interests.

References

Avaldsne, O.G. 2014. An Analysis of CO_2, CH_4 and Mixed CO_2-CH_4 Gas Hydrates: Experimental Phase Equilibria Measurements and Simulations with State-of-the-Art Software. https://pdfs.semanticscholar.org/6d1c/3b10e3758bcd64d156060036af586ad42a2e.pdf

Ballard, A., Shoup, G., and Sloan, D. 2011. Industrial Operating Procedures for Hydrate Control. *Natural Gas Hydrates in Flow Assurance* **23**(2): 145-162.

Bulbul, S., Parlaktuan, M., Mehmetoglu, T., et al. 2014. Hydrate Formation Conditions of Methane Hydrogen Sulfide Mixtures. *Energy Sources, Part A: Recovery, Utilization, and Environmental Effects* **12**(3):2527-2535.

King, H.M. Methane Hydrate. Downloaded 10 November 2017. http://geology.com/articles/methane-hydrates/.

Rajnauth, J.J., Barrufet, M.A., and Falcone, G. 2010. Hydrate Formation: Considering the effects of Pressure, Temperature, Composition and Water. Paper presented at SPE EUROPEC/EAGE Annual Conference and Exhibition, Barcelona, Spain, 14-17 June. SPE-131663-MS.

The Hydrate Problem. Pennsylvania State University (PSU). Downloaded 10 November 2017. https://www.e-education.psu.edu/png520/m21_p3.html.

Jianjiang Lv, SPE, is production engineer in Unocal East China Sea Ltd., where he has worked for 7 years. His research interests are in production and reservoir engineering. He holds master's degree and Ph.D. from Southwest Petroleum University, both in petroleum engineering.

Jianbo Yuan, SPE, is drilling and completion engineer in Unocal East China Sea Ltd., where he has worked for 7 years. His research interests are in drilling and completion engineering. He holds master's degree from China Petroleum University Beijing in drilling engineering.

Minh Vo, SPE, is currently subsurface manager in Unocal East China Sea Ltd., where he has worked for the last 4+ years. He has had 25 years of experience in the oil and gas industry with multiple global locations. His research interests are in reservoir engineering, production optimization, and systems engineering. He holds several master's degrees from UNSW in petroleum engineering, from RMIT in systems engineering, and MBA from NYU.

Junliang Zhang, SPE, is a production engineer in Southwest Oil & Gas Field Company, where he has worked for 13 years. His research interests are in production engineering and daily field operations. He holds master's degree from Southwest Petroleum University in petroleum engineering.