AUTOMATIC SYSTEM FOR MEASURING GAS STREAM VELOCITY IN GAS COLLECTION SYSTEM FLOW-LINES

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Abstract. When transporting raw gas through the gas collection system flowlines, moisture in the gas facilitates formation of hydrates during winter, which is not just impairs efficiency of gas transportation from well to gas treatment unit, but also may lead to an emergency. To prevent hydrate formation, special inhibitors are added into the gas stream, usually methanol-water solution (MWS) of a certain concentration. The process of methanol carry-over with production fluid is rather complex, as it is a two-phase mixture whose phases have different mechanism of interaction with methanol. To estimate the period after which a necessary methanol concentration is achieved throughout the length of the pipeline, one shall know the gas stream velocity in the flowline. This paper proposes to determine it from velocity of a pressure wave, which is artificially created by receiver when introducing the MWS into the stream. Fast-response pressure transmitters and recorders are used to register pressure changes, while operation of the system as a whole is synchronized with the help of GPS signals. Identification of the artificial wave proceeds following a special signal processing algorithm for pressure transmitters. Application of the system allows increasing efficiency of gas field control.

1. Introduction
Hydrate formation is a major problem for development of gas condensate fields (GCF). It is especially acute for northern fields, which currently provide 90% of natural gas produced in Russia [1].

Hydrates of hydrocarbon gases are unstable compounds of hydrocarbons and water that appear as white ice-like crystals. They consist of one or more molecule of gas (methane, propane, carbon dioxide, etc.) and water. Hydrate formation at a certain segment of a gas collection system (GCS) depends largely on thermobaric conditions, gas composition and density, as well as its percentage humidity, that is, water cut of the production fluid [2]. If hydrate formation conditions arise, the hydrate plug quickly grows in such a gas pipeline segment as more water and more hydrate-forming substance (methane, ethane, propane, etc.) inflows, that is, more produced natural gas. Besides reducing the amount of transported gas due to pipeline constriction, hydrate plugs may lead to its complete plugging which is an emergency [3]. More often gas pipelines become plugged during the winter due to extreme cooling of the gas stream moving through the pipeline. Various methods are employed to prevent hydrate formation [4], the most efficient currently is injection of some hydrate formation inhibitor (usually methanol) into the gas stream. It is injected directly at the gas wellhead and then distributed along the flowline, being carried with the gas stream. As total length of GCS pipelines may reach tens of kilometers, transportation of methanol from its injection point to the hazardous point may take a signifi-
cant amount of time. Thus, a special methanol pipeline is run along the common gas collection header, and the inhibitor is injected into the gas stream in several points along the flowline with the help of methanol distribution panels. It shall be noted, that efficiency of inhibitor application directly depends on accuracy of calculation, first, the amount of methanol injected, and second, its movement velocity along the pipeline. There are several techniques to calculate the optimal methanol consumption, including a regulatory document of Gazprom [5, 6]. Several studies were dedicated to methanol movement through flowlines, such as [7-9]. In [7], it is shown, that the methanol transfer time (a period of time after which a required methanol concentration is attained throughout the length of a pipeline) largely depends on the flowline mode of operation: either liquid removal or liquid collection, at that for the same inputs, the period of pipeline saturation with methanol may vary from 20 – 50 minutes to 270 hours after starting the injection. At that, water cut diagnostics in a flowline is a complex task [10, 11], thus, this factor is not deterministic when modeling methanol movement along the flowline.

Thus, measuring the current value of gas stream velocity in flowlines is a current scientific and technical problem, as it allows optimizing arrangement of methanol injection points and periodicity of its supply.

2. Problem statement
Measurement of gas well production fluid velocity is a much more complex task, compared to, e.g., pressure or temperature measurement. This is due to the fact that the production fluid (raw gas) is a multiphase medium: gas, liquid, mechanical impurities, while operation of the wells connected to the flowline may be unstable. Installation of flowmeters on the flowlines is out of the question, due to both technical and economic considerations. Thus, the problem of the study is to develop a method for on-line measurement of gas stream velocity in flowlines without flowmeters.

3. Theoretical Part
As it is known, pressure squeeze velocity in a gas stream is equal to the sum of the speed of sound in the immobile gas and the gas velocity in the pipeline. This dependency is often employed to detect damaged sections of gas pipelines: when a leak appears, a pressure wave arises which reaches pressure transmitters installed in the pipe while propagating with a certain velocity. Distance to the leak is determined by various algorithms [12, 13].

For process pipelines of gas collection system, the speed of sound is approximately 420 – 450 m/s. An important property of gas flow is that disturbances propagate with a finite speed. Small disturbances of pressure propagate through gas with the speed of sound. If the source of the small disturbance is placed in a uniform flow of gas moving with the velocity of \( \frac{v}{c} < 1 \) (Mach number \( M = \frac{v}{c} < 1 \)), then the disturbances propagate in all directions and may reach any point of the stream. If the stream velocity is supersonic \( (M > 1) \), then, the disturbances drift downstream and do not go beyond the disturbance cone (Fig. 1).

The velocity of gas stream in flowlines depends on pressure, local resistance, flow rate of connected wells, phase ratio of the production fluid and does not exceed 7 – 10 m/s. In this case, a pressure wave having arisen due to any reason (e.g., due to opening of injection valve) will propagate in both directions from the disturbance point. By measuring the time it spent to cover a certain distance along the stream and against it, it is possible to determine the stream velocity.
The structural diagram of the proposed system to measure gas velocity in flowlines is given in Figure 2.

To create the pressure wave, a receiver is employed, its pressure being built up from a methanol line. Thus, when opening the receiver's injection valve, gas-methanol mixture is injected into the process pipeline, creating a local pressure wave.
The system consists of several units. Measuring units I, II and an actuator unit III are located directly on the flowline. Measuring units are installed at the ends of the selected meter run, while the actuator unit is installed between them. Any section of flowline without local resistances may be selected as the meter run. However, speaking from convenience of integrating the system into existing equipment, it is practical to select the meter run basing on location of methanol-water solution injection valve. Its length may vary from 1 to 5 km. The shorter is the meter run, the more strict requirements are imposed to reaction time of the pressure transmitters. Maximum length depends on the flowline topology and presence of local resistances in it. The central unit IV is located in the control room.

Each measuring unit includes two pressure transmitters (T1 and T2, T3 and T4), which are installed pairwise on the flowline at a certain distance from each other, a process recorder (PR1 and PR2) and a master timer (MT1 and MT2) in the form of GPS receivers. In each unit, one of he transmitters, located on the meter run side is considered interior one, while the second, on the side of the rest of the flowline, is considered external one. The distance between the transmitters may be from 10 to 50 meters, depending on the distance between the measuring units. The actuator unit consists of a receiver, a radio-controlled valve V1 and backflow valves V2 and V3. The receiver is connected to the methanol pipeline and together they form a pressure wave-creating device. The central unit, consisting of a base station and operator's WS (a PC) is connected with the rest of the system by wireless communication means.

Local nodes (process recorders PR) are installed at the boundaries of the meter run of the flowline (in the area of paired pressure transmitters), the central unit is installed in the control room.

The pressure in the receiver is constantly measured by the PR3 recorder; the receiver is constantly filled with gas from the flowline. When it is necessary to measure gas stream velocity, a signal from the WS central computer is issued to the V1 radio-controlled valve, and methanol-water solution starts to enter the receiver. When the receiver pressure reaches a predefined value, the V3 valve is engaged. The methanol-water solution is injected into the flowline and a pressure wave is created.

Determination of propagation velocity of this wave along the flowline proceeds in the following way. During stable operation of the flowline, both PRs of the measuring units constantly get time stamps with a predefined regular intervals with their GPS receivers. All the pressure transmitters also perform continuous pressure measurement in the gas stream at two sections at the ends of the flowline meter run. The results of measurements from interior and exterior transmitter are compared in each pair. This procedure is necessary to identify artificial pressure wave, because pressure waves may also arise due to natural causes, e.g., when the flowline mode of operation changes. The pressure wave created by the device is identified by the following algorithm.

As the gas velocity is significantly lower than the speed of sound, the pressure wave propagates in both directions from the point of disturbance. The PRs of the measuring units register passing of the wave through the both pressure transmitter pairs. Then, synchronism of a stepwise change in pressure at both ends of the flowline meter run is assessed. The synchronism is registered if the absolute value of difference between the time stamps obtained from the GPS receivers of each pair of transmitters and corresponding to compared pressure values as measured by transmitters Д1 to Д4 does not exceed a predefined lag value. At the next stage, the sequence of pressure changes is analyzed for each transmitter of the respective pair: at both ends of the meter run the stepwise pressure change shall happen first at the interior section of the flowline, and then at the exterior one.

Thus, the WS central controller registers passing of the artificial pressure wave. Decision that it is the same pressure wave is made from the following conditions:

- both process recorders PR1 and PR2 have detected the signs of increased (reduced) pressure;
- time difference between these events does not exceed the value allowed for this meter run length and possible speed of sound in the gas, i.e., the pressure measurement were synchronous;
- propagation of the pressure wave is directed from the meter run to the exterior part of the flowline at both ends of the meter run.
To determine the pressure wave propagation speed $C$ in the gas stream, the time stamps are used corresponding to the stepwise change in pressure as registered by transmitters T1 – T4 at both ends of the flowline meter run:

$$C = \frac{L_2 - L_1}{T_2 - T_1},$$

where $L_1, L_2$ are coordinates of the flowline meter run end with respect to the entrance, m; $T_1, T_2$ are time stamps marking the passing of the pressure wave at the ends of the run, s.

Comparison of pressure values for two sections at each end of the meter run and determination of wave propagation direction takes place in measuring units. Each PR checks the pressure wave direction from a pair of neighboring pressure transmitters and transmits the corresponding time stamps to the central controller via wireless communications. The central unit uses these data to determine the pressure wave propagation speed $C$ and to check whether the value obtained is within allowable limits:

$$C_{\text{min}} \leq C \leq C_{\text{max}},$$

where $C_{\text{min}}, C_{\text{max}}$ are predefined limits of the wave speed.

At the final stage, the gas stream velocity is calculated with the formula

$$v = \frac{C_1 - C_2}{2},$$

where $C_1$ and $C_2$ are pressure wave propagation speed values downstream and upstream the gas stream.

Momentary velocity values are archived, where they may be used to evaluate average velocity over a period of time.

4. System Test Results

A test bench simulating operation of a process pipeline section was assembled for experimental testing of the theoretical assumptions; design solution in [14] was taken as a base. The meter run was a horizontal 22 m long plastic pipe, with an internal diameter of 26 mm. Operating pressure during the testing was 1 MPa. At the inlet of the meter run, a receiver with gas-liquid mix (water and air) was installed, as well as a solenoid valve to create a pressure wave. Three high frequency pressure transmitters Type 23/25 with a bandwidth up to 10 kHz, manufactured by Izmerenie i Kontrol LLC, were used to register the pressure wave passage. The first transmitter (T1) was located at a distance of 100 mm from the solenoid valve connection to the operating length of the pipe. Other transmitters were installed at a distance of 10 m (T2 transmitter) and 20 m (T3 transmitter) from the beginning of the meter run. The transmitters were connected to separate amplifiers whose outputs were polled by a multifunctional high-speed ADC board with a L-783M signal processor, a product of L-CARD with the maximum sampling frequency of 3 MHz.

The testing comprised of forming a pressure wave and recording the transmitters reading for two modes: when the operating medium was at rest and when the stream velocity was 5 m/s. The obtained pressure measurement trends are shown in Fig. 3.
5. Conclusions

The automatic system for measuring gas stream velocity in gas collection system pipelines allows obtaining velocity values in real time. Technological importance of this parameter is determined by several factors. First, that knowledge of the gas stream velocity in flowlines allows for more accurate calculations of methanol travel time along the pipeline, which in its turn allows selecting optimal methanol injection points and periodicity of methanol injection in the gas stream. Second, the production fluid velocity together with temperature and pressure allows for indirect assessment of the flowline conditions.

A sure advantage of this system is possibility to use measurement equipment and valving already installed at the pipeline: radio-enabled process recorders, methanol injectors, etc.

In practice, this system is a subsystem of gas field APCS. Its application allows improving efficiency of gas condensate field operation, especially at the final stage of operation, when probability of water accumulation and hydrate formation in flowlines increases several-fold.

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