

SIMULATION OF SEVERE SLUGGING FORMATION AND CONTROL IN OFFSHORE RISER

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ABSTRACT

In this paper, available elimination techniques are assessed. OLGA2000 software is used to simulate severe slugging formation mechanism in certain offshore riser. The simulation results show that pressure fluctuations of riser base and riser top is very large and severe slugging easily forms. Sensibility analysis shows that the measures and methods which include properly reducing pipe riser diameter, reducing water cut, increasing terminal pressure, decreasing the height and inclination of riser and increasing GOR can eliminate or control severe slugging in riser pipe.

Keywords: Offshore riser, Severe slugging, Control technique, Software simulation.

INTRODUCTION

With the further development of offshore oil and gas fields in China, the trends of oil and gas production of CNOOC will be towards deeper and marginal offshore fields. Long distance offshore multiphase flow pipelines are often encountered, especially riser height can reach hundreds of meters, which can lead to severe slugging which liquid length can be over the height of riser. Severe slugging is a kind of the most serious fluctuating flow, which can cause large dangers to downstream equipments. Large dangers are shown as following.

- (1) Severe slugging can cause large pressure drop.
- (2) Severe slugging can increase the corrosion degrees of pipeline, especially for riser corrosion.
- (3) Severe slugging can cause overflow or break of terminal slugcatcher which lead to trouble operations
- (4) Severe slugging can cause mechanical destroy of pipeline connections and supports, and result in cavitation erosion of pumps and compressors, and decrease pump efficiency and reliability.
- (5) Severe slugging can cause large temperature drop which can cause gas hydrate formation
- (6) Severe slugging can increase wellhead backpressure and decrease production rate of oil and gas wells.

Currently, there are three basic elimination methods that have been proposed, namely, backpressure increase, gas lift, and choking. All other proposed techniques such as pumping method, differential pressure transmitter, methods with small separator,

self-supply gas lifting and active feedback control methods^[1-5], are based on these three elimination methods. The backpressure increase method eliminates severe slugging by increasing the system pressure, and thereby significantly reducing the production capacity. In gas lifting, external gas is injected either into the riser or pipeline at the riser bottom to reduce the hydrostatic head in the riser or increase the gas flow rate in the pipeline. Gas-Lift equipment requires a large footprint on the platform and large amounts of gas to accomplish the elimination. The operational cost of gas lifting can be very significant.

The applicability of current practices for prediction and elimination of severe slugging in deep-water developments is very much in question. Different techniques can be suitable for different types of problems and production systems^[6,7].

Due to the complexities of multiphase flow mechanism, especially severe slugging in offshore riser, theoretical basis of all these control methods above introduced are not very distinct. In this paper, OLGA2000 transient multiphase software which is the one of the most famous multiphase flow software in the world, is used to simulate slug flow formation condition and influence factors analysis for severe slugging control technologies which can supply basis for fully putting forward to effective control measures.

SEVERE SLUGGING PHENOMENON

Physical Description

The severe slugging phenomenon occurring in multiphase transport system is illustrated^[8-10] in Figure 1.

It occurs for low velocity of gas and liquid phases. Schematically it is a cyclic phenomenon that can be split into 4 steps. In the first one, the liquid accumulates in the low point due to its low velocity and to the liquid that falls down and forms a slug. In the second step there is a blockage until the pressure becomes sufficient to lift the liquid column. In the third step, the liquid slug starts to go upward along the riser. The gas begins to flow in the riser and so accelerates the liquid. Finally, the gas arrives at the top of the riser and the pressure rapidly decreases causing liquid flow down. And so on...

Steps 3 and 4 can damaged the process facilities if the separator has not been correctly designed. But the pipeline can also be damaged: during the liquid acceleration if the fluid contains solid

particles; during the liquid accumulation if the fluid contains some eroding substances like salt for instance.

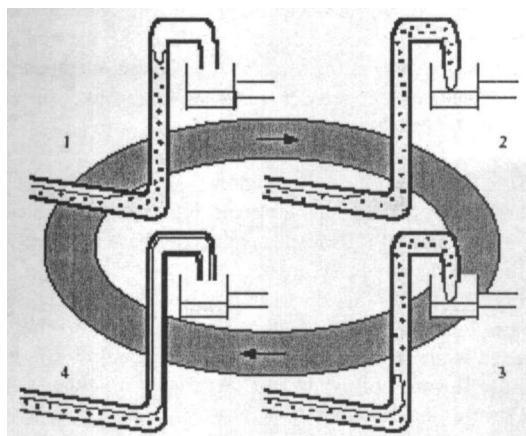


Figure 1 Severe slugging phenomenon

Operator behavior

Usually, the operators try not to operate in the severe slugging region. But, the inlet conditions of a production pipeline are linked to the number and the capacity of the producing wells, the availability of wells and also to some undesirable operation such as shut down or restart. The natural trend when dimensioning a production line is to do whatever is possible to avoid critical flooding of the separator, and therefore to over dimension the separator unit. But in offshore production, over dimensioning the installation is very costly and not always possible. So, the petroleum engineers require more and more transient simulations to correctly design and dimension their production scheme, and to be able to propose new concepts suitable to every situation they can be faced to.

APPLICABILITY OF AVAILABLE ELIMINATION TECHNIQUES

A discussion on the applicability of existing elimination methods to deep water systems is given here⁽¹¹⁾.

Back-pressure Increase

This is not a viable option even for shallow water systems since production capacity reduction is experienced due to back-pressures imposed. The reduction in production capacity is expected to be worse for deep-water production systems.

Gas Lifting

It is one of the most used methods for the current applications. For deep waters, increased frictional pressure loss and Joule-Thompson cooling are potential problems resulting from high injection gas flow rates. The necessity of injection gas and gas injection system can be considered as the other shortcomings.

Choking

Although this is a proven technique to reduce or eliminate severe slugging, careful choking is needed to have the least back-pressure increase for not to experience production reduction. Only one reported successful field application could be found in the literature. For deep water systems, the back pressure increase could even be more important due to potential production losses.

Gas-Lift and Choking Combination

Although it is suggested to be a viable method by academia, no field application was reported for current pipeline-riser systems. It might alleviate some of the cooling and excessive frictional pressure loss problems by requiring less injection gas. It will require injection gas and the necessary gas lift installation.

Riser Base Pressure Control with a Surface Control Valve

This technique was successfully applied in Totals Dunbar 16" pipeline-riser system. In principle, this technique is very similar to choking. The field data indicated significant overall system pressure increase. It may pose potential production reduction problems for deep-water productions.

Flow Rate Control

The principle of the system is to keep the mixture flow rate constant throughout the operation with a control valve. Experimental studies showed that back-pressure was tripled when the stable flow was achieved. For deep waters, this system will inherently have the problems of significant reduction in production capacity due to increased riser base pressure and the longer travel times of the information from riser base to the top side causing delays in the responses of the control system.

Smaller Diameter Pipe Insertion

It is a retrofit gas lift method. The same concerns of the gas lifting are expected to be equally valid for this technique. For deep waters frequent pigging is considered to be one of the wax management techniques. Therefore, pipe insertion may not be a suitable solution due to its inherent intrusiveness.

Multiphase Riser Base Lift (MRBL)

This method requires nearby high capacity multiphase lines that some part of their production could be diverted to a pipeline-riser system to either eliminate severe slugging or startup the production after a shutdown period. It is proposed as a better alternative to RBGL since the lift fluids will not cause cooling, and no injection gas and related apparatus will be required. This method requires availability of other multiphase lines. Therefore, it is a system specific solution and could be feasible for limited cases.

Subsea Separation

This is a viable solution that does not impose back pressure on the system. But it requires two separate flow lines and a liquid pump to pump the liquids to the surface.

Foaming

Hassanein and Fairhurst originally mentioned this method without providing any details. To the best of our interpretation, this method requires foaming agents and a way to form the foam. It is clear from the available literature that the elimination of severe slugging for deep waters is an unresolved issue although there are some attempts to address the issue. Different techniques can be suitable for different type of problems and production systems.

OLGA2000 SOFTWARE SIMULATION FOR SEVERE SLUGGING FORMATION IN RISER PIPE

OLGA2000 software is adopted to simulate severe slugging formation and influence factors for given offshore pipeline. Production fluid compositions are given in Table 1.

Table 1 Production fluid compositions

Components	Mole Percent(%)
N2	0.1
CO2	1.64
C1	87.39
C2	5.75
C3	2.30
iC4	0.48
nC4	0.85
iC5	0.26
nC5	0.30
nC6	0.28
C7	0.65
C8	1.1e-4
C9+	1.5e-4

Pipeline profiles used in the modeling are illustrated in Figure 2

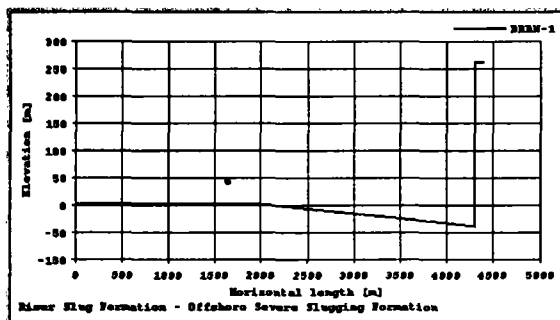


Figure 2 Pipeline profiles

Pipeline Specifications are shown as Table 2.

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Nominal Size inch	9
Pipe Wall Thickness mm	9
Roughness mm	0.028
Material Heat Capacity J/kg/K	500
Material Thermal Conductivity W/m/K	50

Terminal pressure and temperature are kept constant for 5 MPa and 22 °C respectively while simulation.

SENSITIVE INFLUENCE FACTORS ANALYSIS

(1) Effects pipe diameter on slug formation

When inlet mass flowrate varies from 4 Kg/s to 6 Kg/s within 15 minutes, pipeline diameter keeps 5in, 7in and 9in respectively, riser top pressure variation with time is illustrated as Figure 3.

Figure 3 shows that fluctuate range of riser top pressure will decrease with pipeline diameter reduction, namely slugging may be weakened while pipeline diameter is properly reduced. But the reduction of pipeline diameter will cause backpressure increase resulting in the reduction of production rate. Therefore, optimum pipeline diameter should be determined based on economic and safety factors.

(2) Effects choking valve opening on slug formation

When inlet mass flowrate varies from 4 Kg/s to 6 Kg/s within 15 minutes, choking valve opening in the terminal keeps 0.2, 0.5 and 1 respectively, riser base pressure variation with time is illustrated as Figure 4.

Figure 4 shows that fluctuate range of riser base pressure will decrease with choking valve opening in the terminal reduction, namely slugging may be weakened while choking valve opening is properly reduced. But the reduction of choking valve opening will also cause backpressure increase resulting in the reduction of production rate. This is the same as the choking methods. But it is very difficult to properly adjust choking valve opening for controlling severe slugging.

(3) Effects flowrate on slug formation

When others factors keep constant, inlet mass flowrate keeps 4 Kg/s, 6 Kg/s and 10 Kg/s respectively, riser base pressure variation with time is illustrated as Figure 5.

Figure 5 shows that fluctuate range of riser base pressure will decrease with inlet flowrate increasing, namely slugging may be weakened while inlet flowrate is properly increased. But generally speaking, flowrate of fields can decrease with time, which can result severe slugging formation.

(4) Effects water cut on slug formation

When others factors keep constant, inlet water cut keeps 0%, 5% and 10 % respectively, riser top pressure variation with time is illustrated as Figure 6.

Figure 6 shows that fluctuate range of riser top pressure will increase with inlet water cut increasing, namely slugging may be more serious while inlet water cut is properly increased. Generally speaking, water cut of fields can increase with time, which can result severe slugging formation.

(5) Effects pipeline pressure on slug formation

When others factors keep constant, terminal pressure keeps 5MPa, 6MPa and 7MPa respectively, riser base liquid holdup variation with time is illustrated as Figure 7.

Figure 7 shows that fluctuate range of riser base liquid holdup will decrease with terminal pressure increasing, namely slugging may be weakened while terminal pressure is properly increased. Increasing pipeline pressure will lead to high cost of compressor and pump. Consequently, economic and safety analysis must be carried out.

(6) Effects riser height on slug formation

When others factors keep constant, riser height keeps 50 meters, 150 meters and 300 meters respectively, riser base liquid holdup variation with time is illustrated as Figure 8.

Figure 8 shows that fluctuate range of riser base liquid holdup will increase with riser height increasing. With the development of deeper and marginal offshore fields, riser height will more and more high resulting in more serious slug flow.

(7) Effects GOR on slug formation

When others factors keep constant, GOR keeps 1000, 3000 and 5000 meters respectively, riser base liquid holdup variation with time is illustrated as Figure 9.

Figure 9 shows that fluctuate range of riser base liquid holdup will weaken with GOR increasing, namely slugging may be weakened while GOR is properly increased. This is the same as gas lifting controlling slugging.

CONCLUSION

In this paper, available elimination techniques are assessed. OLGA2000 transient multiphase software is used to simulate slug flow formation condition in condensate gas pipeline. The results of OLGA2000 simulation for severe slugging in the offshore riser show the techniques and measures including properly reducing riser diameter, properly choke valve openings of terminal, properly reducing water cut and increasing terminal pressure, properly decreasing riser height and inclination degrees and increasing GOR may be adopted to eliminate or control severe slugging in the offshore riser. In the future, based on results of software, severe slugging flow mechanism and theoretical study of control measures should be studied, finally economic and effective control methods are screened.

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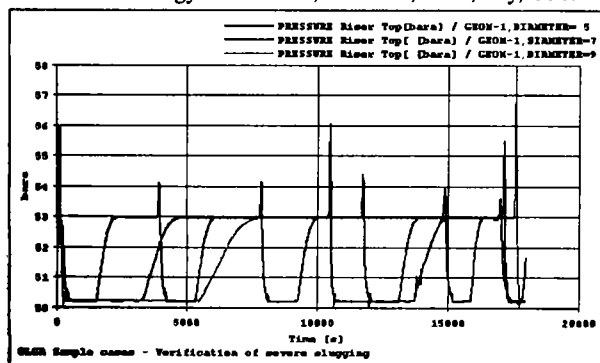


Figure 3 Riser top pressure variation with time for different pipe diameters

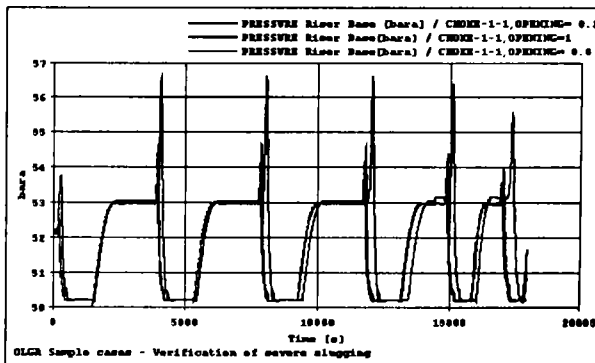


Figure 4 Riser base pressure variation with time for different choking valve openings.

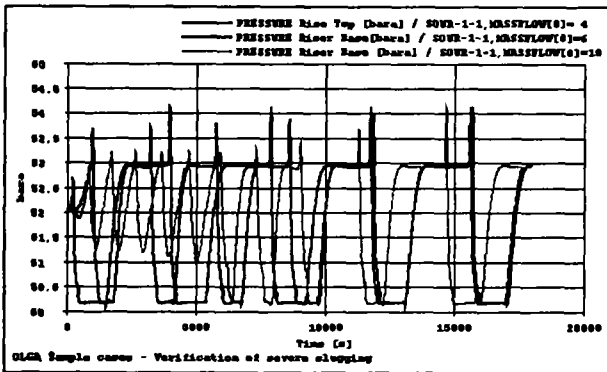


Figure 5 Riser base pressure variation with time for different flowrate

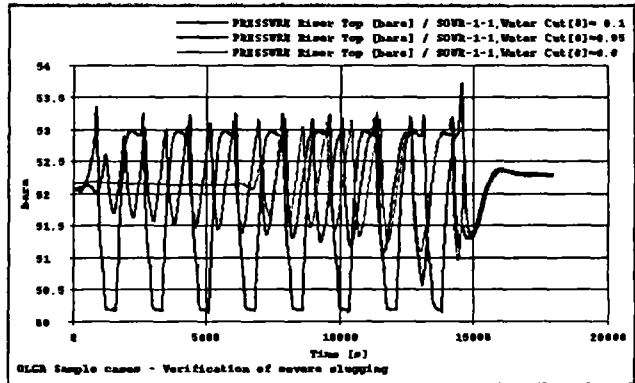


Figure 6 Riser top pressure variation with time for different water cut

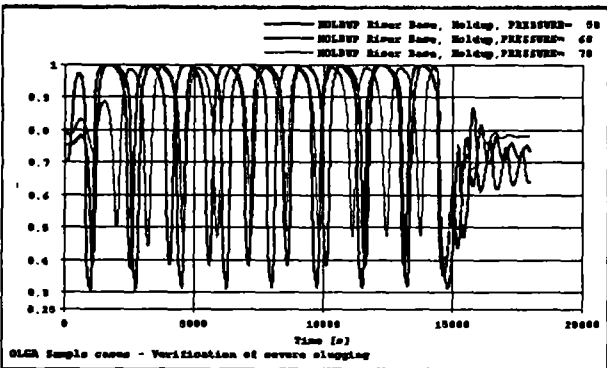


Figure 7 Riser base pressure variation with time for different terminal pressure

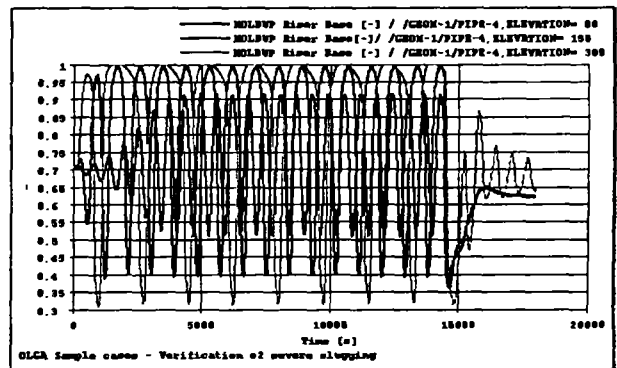


Figure 8 Riser top pressure variation with time for different riser heights

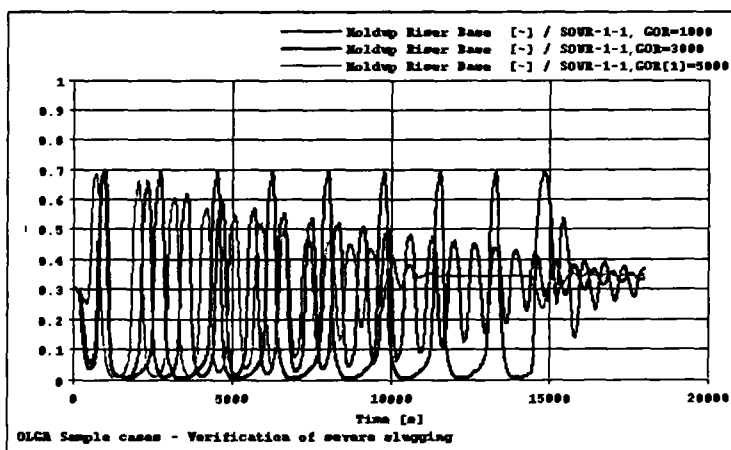


Figure 9 Riser base pressure variation with time for different GOR