

PETRONAS TECHNICAL STANDARDS

DESIGN AND ENGINEERING PRACTICE

MANUAL

DESIGN OF MULTIPLE-PIPE SLUG CATCHERS

PTS 31.40.10.12

FEBRUARY 2010



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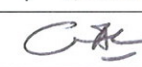
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This revision of PTS **31.40.10.12 – Design Of Multiple-Pipe Slug Catchers** has been updated incorporating PETRONAS Lessons Learnt, Best Practice and new information issued by relevant industry code and standards. All updates in the document are highlighted in *italic* font.

The previous version of this PTS (**July 1998**) will be removed from PTS binder/ e-repository from herein onwards.

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PREFACE

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1. INTRODUCTION

1.1 SCOPE

This PTS specifies requirements and gives recommendations for the design and application of pipe supports in piping systems.

This PTS is a revision of the PTS of the same number dated December 1997. A set of Standard Drawings is available which includes the most commonly applied pipe supports, giving their allowable loads and identification.

This PTS is a revision of the PTS of the same title and number dated December 1997; a summary of the main changes from that edition is given in (1.5). A set of Standard Drawings is available which includes the most commonly applied pipe supports, giving their allowable loads and identification. For support selection charts, see Appendices 1 to 7.

1.2 DISTRIBUTION, INTENDED USE AND REGULATORY CONSIDERATIONS

Unless otherwise authorised by PETRONAS, the distribution of this PTS is confined to companies forming part of or managed by PETRONAS, and to Contractors nominated by them.

This PTS is intended for use in oil refineries, chemical plants, gas plants, exploration and production facilities and supply/marketing installations.

When PTS are applied, a Management of Change (MOC) process should be implemented. This is of particular importance when existing facilities are to be modified.

If national and/or local regulations exist in which some of the requirements may be more stringent than in this PTS, the Contractor shall determine by careful scrutiny which of the requirements are the more stringent and which combination of requirements will be acceptable as regards safety, economic and legal aspects. In all cases the Contractor shall inform the Principal of any deviation from the requirements of this document which is considered to be necessary in order to comply with national and/or local regulations. The Principal may then negotiate with the Authorities concerned with the object of obtaining agreement to follow this document as closely as possible.

1.3 DEFINITIONS

1.3.1 General Definitions

The **Contractor** is the party which carries out all or part of the design, engineering, procurement, construction, commissioning or management of a project or operation of a facility. The Principal may sometimes undertake all or part of the duties of the Contractor.

The **Manufacturer/Supplier** is the party which manufactures or supplies equipment and services to perform the duties specified by the Contractor.

The **Principal** is the party which initiates the project and ultimately pays for its design and construction. The Principal will generally specify the technical requirements. The Principal may also include an agent or consultant, authorised to act for, and on behalf of, the Principal.

The word **Shall** indicates a requirement.

The word **Should** indicates a recommendation.

1.3.2 Specific definitions terms of slug catcher parts

Bottle, primary	Pipe-type part of a multiple-pipe slug catcher for separation of the fluid and storage of the liquids, sloping down under small angle(s) from the lower end of the downcomer to the liquid outlet header (see Figure 3).
Bottle, secondary	Pipe-type part of a multiple-pipe slug catcher for storage of the liquids only, sloping up from the liquid outlet header, and ending at the gas risers (see Figure 3b).
Downcomer	Vertical or steeply sloping pipes of a multiple-pipe slug catcher between the inlet header and the primary bottles (see Figures 3 and 5).
Entrance length	<i>The section of a primary bottle from the inlet to the gas risers.</i>
Gas outlet header	Part of a multiple-pipe slug catcher on top of and connecting all risers for collection of the out going gas streams (see Figures 3 and 7).
Inlet header	Part of a multiple-pipe slug catcher in which the fluid is evenly distributed before entering the downcomers and in which fluid flow conditions are further improved for separation (see Figure 3). Also called distribution header.
Liquid outlet header	The lowest part of the multiple-pipe slug catcher, in which the liquid is collected for export (see Figure 8). Also called liquid header.
Gas riser	Vertical pipe on top of a bottle, through which gas exits (see Figures 3 and 7).
Separator	Equipment for separating gas and liquids or various liquids of a mixed fluid.
Slug catcher	Part of a multi-phase pipeline system for separation of the gas and liquid phases and for temporary storage of the liquids.
Slug catcher, multiple-pipe type	Slug catcher, made of several parallel pipe bottles.
Slug catcher, parking-loop type	Slug catcher, where the separator is located apart from the storage part. The separator can be a vessel type and the storage part is made of pipeline material, which can be located away from the separator.
Slug catcher, vessel type	Slug catcher of limited dimensions and capacity, where separator and storage parts are combined within one or a combination of vessels (see Figure 1).
Splitter	Inlet of a multiple-pipe slug catcher in which the fluid stream is split up for even distribution over the inlet header. (see Figures 3 and 4).

1.3.3 Symbols

A	Cross-sectional area
C_w	Drag coefficient
d	Diameter of droplet (m)
D	Diameter (m)
H	Hold-up fraction
g	Gravity constant (m/s^2)
L	Length (m)
m	Number of risers per bottle
n	Number of bottles
V	Velocity (m/s)
Vol	Volume (m^3)
Q	Gas flow rate (m^3/s)
Re	Reynolds number

Greek symbols

η	Dynamic viscosity ($N.s/m^2$)
λ	Load factor (m/s) or Volumetric fraction of liquid in two-phase flow
θ	Angle between bottle and horizontal plane
ρ	Density (kg/m^3)

Subscripts

b	Bottle
buffer	Buffer
C	Constrictor
G	Gas
IH	Inlet header
int	Intercept
L	Liquid
goh	Gas outlet header
loh	Liquid outlet header
outlet	Outlet
pb	Primary bottle
pipeline	Pipeline
$R1$	First riser on a bottle (from inlet)
$R2$	Second riser on a bottle (from inlet)
$riser$	Riser
s	Settle
sb	Secondary bottle

SC	Slug catcher
SG	Superficial gas
SL	Superficial liquid

1.3.4 Abbreviations

<i>BLEVE</i>	<i>Boiling Liquid Expanding Vapour Explosion</i>
<i>CFD</i>	<i>Computational Fluid Dynamics</i>
<i>PTS</i>	<i>Petronas Technical Standards</i>
D_{bottle}	Internal diameter of the multiple-pipe slug catcher bottles
$D_{\text{downcorner}}$	Internal diameter of the downcomer
D_{goh}	Internal diameter of the gas outlet header
D_{outlet}	Internal diameter of the gas outlet
D_{riser}	Internal diameter of the gas risers
dP	Differential pressure
<i>GtL</i>	<i>Gas to Liquids</i>
<i>HEMP</i>	<i>Hazards Effect Management Process</i>
<i>KHI</i>	<i>Kinetic Hydrate Inhibitor</i>
<i>LNG</i>	<i>Liquefied Natural Gas</i>
MAOP	Maximum Allowable Operating Pressure
MEG	Mono Ethylene Glycol
PSV	Pressure Safety Valve
SMYS	Specified Minimum Yield Strength
SGV	Sphere-generated Volume

1.4 CROSS-REFERENCES

Where cross-references to other parts of this PTS are made, the referenced section number is shown in brackets. Other documents referenced in this PTS are listed in (6).

1.5 SUMMARY OF MAIN CHANGES

This is a revision of the PTS of the same number dated July 1998. The main non-editorial changes are:

- Addition of requirements for slugcatchers being fed by water-wet pipelines.
- Extensive revision of the slugcatcher sizing method.
- Change of pipeline code from ASME B31.8 to ISO 13623.
- Re-write of the hazard and risk management requirements.

2. GENERAL DESIGN ASPECTS

2.1 INTRODUCTION

A multi-phase flow pipeline is intended for transporting the gas and liquid phases simultaneously. The slug catcher situated at the end of the pipeline is intended to separate the phases and to provide temporary storage for the liquid received. There are different modes under which liquid can be produced from the pipeline. These include: the continuous liquid flow production mode under normal steady flow conditions; the intermittent or transient liquid production mode occurring when flow rates are varied; and the pigging or sphering mode when liquid is displaced from the pipeline into the slug catcher in a relatively short time.

It has become common to allow water to flow into the transportation pipelines and hence for there to be both aqueous and hydrocarbon liquid phases in the slugcatcher. An additional effect of this is that there could be significant quantities of solids (precipitates and corrosion products) entering the slugcatcher, making it effectively a four-phase separator. This PTS describes the additional measures required to deal with the additional phases.

2.2 TYPES OF SLUG CATCHER

Slug catchers can be broadly classified into the three following categories:

1. vessel type;
2. multiple-pipe type;
3. parking-loop type.

2.2.1 Vessel-type slug catcher

The geometry of the vessel-type slug catcher could range from a simple knock-out vessel to a more sophisticated lay-out (Figure 1). Since the overall length of vessel-type slug catchers is relatively short for a given volume this type is preferred in the case of limited plot sizes (e.g. offshore platforms). When larger liquid volumes, e.g. more than 100 m³, have to be accommodated, the multiple-pipe type shall be selected *(or the parking-loop type if approved by the Principal)*.

2.2.2 Multiple-pipe slug catcher

An example of a typical multi-pipe slug catcher is shown in Figure 2.

Multi-pipe slug catchers can be made to the incoming pipeline design code. Besides having a cost advantage over the high-pressure vessel design, this type allows for a greater flexibility in design possibilities to cope with wide ranges of flow situations and geometrical configurations with different shapes of the available ground area.

A definition and description of the main parts of this type of slug catcher is given in (3.3.3).

The advantage of a multiple-pipe slug catcher is that it is easy to operate since no flow controls are required.

2.2.3 Parking-loop slug catcher

Parking-loop slugcatchers are not recommended and shall not be selected unless approved by the Principal.

In parking-loop slugcatchers the separating and storage parts are virtually disconnected. A parking-loop slugcatcher consists basically of a separator with the liquid outlet connected to a long single pipe-loop. The incoming gas/liquid stream is separated in the vessel. When a slug arrives, it is rapidly emptied from the separator into the parking loop, from where it can be processed at a lower flowrate by the plant. This type of slug catcher is particularly suited to offshore applications where the separator can be placed on the platform and the parking loop on the sea-bed. All valves and controls would be on the platform. The advantage of the concept is the possibility to save space.

A disadvantage of the method is the high reliance on strict operational procedures.

It can also be difficult to process non-pigged slugs (e.g. ramp-up surges and terrain induced slugs) as they arrive in a very variable manner with a wide distribution of slug sizes and slug frequencies.

3. HYDRAULIC DESIGN

3.1 GENERAL

Guidelines for the hydraulic design of different parts of a multiple-pipe slug catcher are preceded in this Section by a description of the important hydraulic function of a slug catcher, the separation of the gas and liquid phases.

The hydraulic design is based on theoretical and experimental work and field experience with existing slug catchers.

The design method presented here is suitable for the Concept Identification and Concept Selection phases of a project. In Project Specification, the design could be simulated with Computational Fluid Dynamics (CFD) to confirm details such as constrictors in downcomers and risers and inlet flow splitters. Expert advice is needed to define the CFD scope of work and to interpret the results.

3.1.1 Condition of liquid to be separated

There are several conditions under which the slug catcher has to perform as a separator, namely:

3.1.1.1 Liquid arriving with sphere or pig

Depending on the condition of the pipeline before pigging, the quantity of liquid arriving can be large. The rate of liquid arrival is dictated by the speed of the pig, *which can be at full pipeline design velocity*. As the liquid is separated from the gas by the pig or sphere, the amount of gas, either resulting from bubbles in the liquid slug body or flow bypassing the pig, will be relatively small and the mixture will generally be in the form of slug or bubble flow.

3.1.1.2 Liquid arriving under steady flow condition

The ratio of liquid to gas arriving at the slug catcher will be the same as for the steady flow condition of the system and the liquid will be arriving at a continuous rate. It will be either in the form of entrained droplets, slugs or a steady stratified stream depending on gas/ liquid ratio, pipeline profile and the prevailing flow rate of the pipeline. If in the form of droplets, their sizes will be influenced by velocity and become smaller at higher velocities.

3.1.1.3 Liquid produced as a result of flow rate increase

When the flow rate in the pipeline is being increased, the corresponding volume of liquid holdup under equilibrium will be reduced and the excess quantity will be displaced, giving so-called ramp-up surges. The liquid will arrive in the form of slugs or surges of droplets depending on the prevailing gas velocity. The instantaneous liquid-to-gas ratio at the outlet will be greater than the steady flow liquid-to-gas ratio.

3.1.2 Separation mechanisms

In a slug catcher the separation of liquid from the gas can occur in different manners, including:

1. Stratification in the inlet manifold, downcomers and primary bottles
2. Droplet settling in the primary bottles
3. Deposition in bends and primary bottles
4. Tee-junction separation at entry into a gas riser

These separation mechanisms are described below

3.1.2.1 Stratification

Stratification generally occurs when velocity is reduced. To create such conditions, the pipe diameter can be increased, or the flow can be split over multiple pipes. Separation by stratification can be encouraged by inclining the flow downwards.

3.1.2.2 Droplet settling

Settling of droplets can occur by gravitation in a primary bottle when flowing at low velocities, typically at less than 2 m/s, towards the gas riser, provided sufficient residence time is allowed for it to happen.

3.1.2.3 Deposition in bends and first section of primary bottle

Settling velocity of a droplet decreases with its size so that smaller droplets need more time to settle. Therefore separation by settling due to gravity will become difficult at increased velocities. However, the effect due to turbulence at increased velocities can have a positive influence on the separation of smaller droplets. They tend to follow turbulent fluctuation paths, thus increasing the chances of collision with pipe walls for deposition. This can be expected to occur particularly in bends and where a downcomer expands into a primary bottle with the jet of flow impinging obliquely against a wall.

3.1.2.4 Tee-junction separation at entry to a riser

If the tee-branch on a horizontal pipe is oriented in the upward direction, e.g. the gas riser on a primary bottle, efficient separation will be possible provided less than 80 % of the gas exits through that branch. Laboratory tests have shown that almost no liquid will be carried up the riser if not more than 80 % of the gas flow is directed through it. Liquid in the horizontal pipe in the stratified pattern will continue in the horizontal direction. Entrained droplets will also continue with the remaining gas flow in the horizontal pipe. However, this separation tendency will be reduced when the gas flow through the riser is increased beyond 80 % of the total.

3.1.3 Flow scenarios in the slugcatcher

There are two distinct flow scenarios and associated design cases in the slugcatcher:

- *Gas dominated feed. This is the case for normal operation, when the incoming fluid is predominantly gas, and the gas has liquid droplets entrained in it. As the mixture flows along the entrance section of the bottles, the small amount of liquid separates and then flows down the bottles to the liquid outlet. The gas (which is the bulk of the stream) then flows up the gas risers to the gas outlet.*
- *Liquid dominated feed. This is the case when a very large slug arrives, such as a sphere-generated slug. The feed to the slugcatcher is predominantly liquid, and as it flows along the entrance section of the bottles, the liquid stratifies and forms a layer flowing along the bottom of the bottle. The liquid proceeds to flow down the bottles to the liquid outlet, and because the liquid flow is so great compared to the liquid take-off, it fills the bottle up. In filling up the bottle, it displaces gas, and this gas flows back up the bottle, against the downward flowing liquid, and then flows out the gas risers.*

In the gas dominated feed case, the design shall allow liquid to separate as the mixture flows down the bottle's entrance section to the gas risers.

In the liquid dominated feed case, the design shall prevent the displaced gas from entraining liquid as it flows up the bottle (against the liquid flow) and exits via the gas risers. The design shall also allow the slug to be able to flow down the bottle without choking. This means that the liquid shall remain as a stratified layer with enough room kept above it for the gas flowing in the reverse direction. If the liquid level rises too high, even transiently, the flow can become unstable (Kelvin-Helmholtz instability at the gas-liquid interface) and the liquid can form waves which block the pipe. This prevents the gas from flowing freely up the bottle, which in turn prevents the liquid from freely going down the bottle. The slug will then overflow the bottle through the gas risers. This overflowing is called flooding. Whether choking occurs depends on (a) the velocity difference between the liquid (which is flowing downwards) and the gas (which is flowing upwards) and (b) the height of the interface between the flowing gas and liquid. These in turn depend upon (i) the downward slope of the bottle and (ii) the volumetric flowrate of liquid entering the bottle.

3.2 SLUG CATCHER SIZE

The size of a slug catcher (Vol_{SC}) is directly related to the maximum liquid volume it has to hold. It shall be able to intercept the maximum possible slug or surge (Vol_{int}) emerging from the multi-phase pipeline at any part of its agreed operating envelope. It should also contain a buffer volume (Vol_{buffer}) in order to guarantee liquid supply to treating facilities downstream of the slug catcher. Hence:

$$Vol_{SC} = Vol_{int} + Vol_{buffer}$$

The decision on slugcatcher intercepting capacity is part of a the overall project concept selection which will also take account of:

- Alternative concepts, including multiple smaller diameter pipelines, wet and dry pipelines, use of bye pass pigs
- Plot area available for a slugcatcher
- The required turn down of the pipeline
- The rate at which the pipeline is required to be turned up (after being at low flow and building up the steady state hold-up for that low flow)
- The need to sphere (or pig) the pipeline. If frequent sphering is required (e.g. for cleaning or for the application of corrosion inhibitor) then the slugcatcher should be able to deal with the sphere-generated volume that can accumulate between the pigging runs. If only infrequent sphering is necessary, then special procedures may be feasible, allowing a smaller slugcatcher to be used, perhaps at the cost of some production deferment.
- Plant availability
- Economic and HSE comparison of the alternatives

The determination of Vol_{SC} is outside the scope of this PTS. Steady state and dynamic simulation tools for multiphase flow in pipelines as available within Shell shall be used for this purpose. Further details are given in GS.06.50701 (or a more recent updated version of these guidelines, if available).

The size of Vol_{buffer} is largely determined by the characteristics of the liquid-treatment facilities and required plant flexibility. Its determination is outside the scope of this PTS, but it is typically 25 % of the liquid intercepting capacity (Vol_{int}).

For a fully filled slug catcher, the maximum liquid level in a multi-pipe slug catcher should be at the point where the centreline of the last gas riser intersects with the bottom wall of the primary bottle (see Appendix 1, Figure 1-1). It cannot be excluded that some liquid will be entrained into the gas riser at high velocity conditions in a 'fully filled slug catcher' by some film entrainment effect. Instead of modifying design rules for the riser conservatively, the period of operating conditions involving high liquid levels in the slug catcher should be kept as short as possible, also for safety reasons.

3.3 SLUG CATCHER GEOMETRY AND COMPONENTS

A multiple pipe slugcatcher comprises of the following sections:

- *Inlet section*
- *Bottle section*
- *Gas outlet section*
- *Liquid outlet section*

These sections are illustrated in Figure 2.

3.3.1 Inlet section

The inlet section comprises the following subsidiary parts:

- *End of the pipeline*
- *Splitters*

- Inlet header
- Constrictors
- Downcomers

The inlet section's functions are to distribute the incoming mixture over the bottles, and to begin the gas/liquid separation by promoting the occurrence of stratified two-phase flow. The splitters distribute the feed along the inlet header, and the downcomers distribute it to the bottles.

The constrictors reduce the maldistribution over the downcomers (and hence over the bottles). Sloping the downcomers promotes segregation of gas and liquid, and an angle of 45° has been found to be the best.

To prevent unwanted acceleration of the incoming gas/liquid mixture, the inlet pipe should be sized to maintain approximately constant fluid velocity up to the inlet of the slug catcher. (So if there is only one supplying pipeline, the diameter should be maintained upto the inlet. If there are several pipelines, then after their join the diameter should be increased to preserve fluid velocity.)

The inlet pipe shall also be configured to avoid flow maldistribution in the inlet header. The inlet pipe shall have a straight length of 10 pipe diameters with no bends in the horizontal plane before it connects to the inlet header. Bends in the vertical plane are acceptable as they do not induce lateral flow maldistribution. Similarly, it is not necessary for the inlet pipe to connect horizontally to the inlet header.

Splitters are sized to maintain constant flow velocity and to create back pressure for even flow splitting. Splitter configurations are shown in Figure 4.

The inlet header is the same size as the pipeline.

The inlet header should be at the same elevation as the gas outlet header.

The constrictor areas are determined by the following equation:

$$A_C = \frac{1.8A_{IH}}{n_{pb}}$$

For example, a DN 900 (36") inlet header with 6 bottles requires DN 500 (20") constrictors. As the number of downcomers (and hence of primary bottles) per inlet manifold increases, it becomes more difficult to evenly distribute the fluid over them. If there are more than eight downcomers, the splitter arrangement shall be confirmed with Computational Fluid Dynamics (CFD). Expert advice is needed to define the CFD scope of work and to interpret the results. CFD may also be usefully used to confirm the effect of the inlet pipe on flow distribution and also if there are less than eight bottles.

The swage connecting the constrictor to the downcomer pipe should be eccentric with the flat side down. This helps promote stratified flow in the downcomer.

The downcomer pipes are sized to be approximately two-thirds the diameter of the primary bottles.

The downcomer pipes are connected to the primary bottles via a bend and a swage. There is a preference for this swage to be eccentric with flat side down to avoid disturbing the stratified flow, however a concentric reducer is also acceptable if the transition is not abrupt. A typical downcomer is illustrated in Figure 5.

3.3.2 Bottle section

The entrance section is from the bottle inlet to the gas risers and is meant for the separation of liquid from the gas before the gas leaves the bottle via the gas risers. The sizing of the entrance section is given in Appendix 2.

The part of the bottle downstream of the gas risers is meant for liquid storage.

If the bottle does not slope enough, then, as described in (3.1), an incoming liquid slug will not remain in stratified flow when encountering the displaced gas flowing up the bottle and the bottle will become choked, causing flooding. The recommended slope that is robust against choking is 2.5 %.

However having a whole bottle at this slope will result in the inlet header being greatly elevated, which requires expensive supporting steelwork. The compromise solution is the dual slope configuration. The first part is sloped to provide good stratification and to avoid

choking. The remainder is at a reduced slope whilst still being able to avoid choking. The bottle section therefore comprises of the following subsidiary sections:

- Entrance section at 2.5 % slope
- Initial part of storage section at 2.5 % slope
- Remainder of storage section at 1 % slope

These sections are shown in Figure 6.

The most robust solution is the single slope configuration, with the whole of the bottle at 2.5 % slope. In locations where the ground slopes anyway, the single slope slugcatcher can be located to take advantage of the sloping ground, eliminating the need for expensive supporting steelwork.

Definitions for maximum liquid holding capacities in slug catcher bottles are given in Appendix 1.

3.3.2.1 Choice of primary and secondary bottles

The choice of the number of primary bottles (n_{pb}) and secondary bottles (n_{sb}) to be used in the multiple-pipe slug catcher depends on several factors:

1. Gas flow rate in the pipeline
2. Required liquid storage volume of the slug catcher
3. Plot size available (length available for bottles)
4. Diameter of the bottles to be used
5. Slope of the bottles
6. Choice between single or dual slope concept slug catchers.

It is important first to determine the number of primary bottles needed to fulfil the gas liquid separation. If this number of bottles results in a bottle length that exceeds the available plot length, it is tempting to use secondary bottles to make up the storage volume. However secondary bottles take up as much plot width as primary bottles yet add nothing to gas processing capacity. Bearing in mind the warning about future debottlenecking capability (3.8), secondary bottles should only be used with extreme caution as it is very difficult to later convert them to primary bottles. It is usually better to just install primary bottles and accept that the installed gas handling capacity is greater than the design value.

The approval of the custodian of this PTS shall be sought for any design which uses secondary bottles.

3.3.3 Gas outlet section

The gas outlet section comprises the gas risers and the gas outlet manifold, see Figure 7. The gas risers are intended to allow the gas to leave the primary bottles without excessive entrainment of liquid droplets. They have to so function for the two extreme operating cases of gas dominated feed and liquid dominated feed.

The separation capability of a riser is determined by the load factor defined as:

$$\lambda = V_{SG} \sqrt{\frac{\rho_g}{\rho_l - \rho_g}} \quad \text{m/s}$$

The design value of λ is 0.20 m/s.

It is assumed that the gas can be maldistributed such that any bottle can receive 120 % of its share.

$$V_{SG} = \frac{1.2Q_{\text{pipeline}}}{n_{pb}(A_{R1} + A_{R2})} \quad \text{m/s}$$

The resulting requirement is:

$$V_{SG} \leq 0.2 \sqrt{\frac{\rho_l - \rho_g}{\rho_g}} \quad \text{m/s}$$