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Guidance on Practice for Hydraulic Design of Pipeline Systems

GP 43-09

**BP GROUP
ENGINEERING TECHNICAL PRACTICES**

Foreword

This is the first issue of Engineering Technical Practice (ETP) BP GP 43-09. This document will be updated on a periodic basis to include new BP experiences and any additional mandatory requirements. This is not a standalone document; it must be used in accordance with the requirements of ETP document PR 43: Status of ETP Pipeline Documents. In addition to the requirements for this document, those of relevant BP group standards such as getting HSE right policy (gHSEr) and Process Safety/Integrity Management standard (PS/IM) must also be fulfilled. This Guidance on Practice (GP) is based on parts of heritage documents from the merged BP companies as follows:

British Petroleum

[BP Exploration Multiphase Design Manual](#)

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1. Scope

This document gives guidance on critical areas of hydraulic design of a single phase or multiphase pipeline system. While the practice is not overly prescriptive in areas in which a range of design tools exists e.g., for steady-state multiphase modelling, it does stipulate certain specific sub-system parameters e.g., which multiphase pressure drop and hold-up correlations are to be used. If a range of alternative software packages exists to carry out certain specific tasks e.g. hydraulic surge analysis, this document does make certain specific recommendations. This is not intended to reflect an opinion as to the quality or reliability of certain packages (although these could be matters of concern when Technical Quality Assurance is considered), rather it reflects a requirement for EPTG to be able to review contractors work and possibly support design models throughout an asset life. This task is made much easier if the chosen package is available within BP. There are also certain packages that deploy BP recommended design technologies that differentiate them from some of the alternatives.

2. Normative references

The following normative documents contain requirements that, through reference in this text, constitute requirements of this technical practice. For dated references, subsequent amendments to, or revisions of, any of these publications do not apply. However, parties to agreements based on this technical practice are encouraged to investigate the possibility of applying the most recent editions of the normative documents indicated below. For undated references, the latest edition of the normative document referred to applies.

BP

[BP Exploration Multiphase Design Manual](#)

GP 06-14 Guidance on Practice for Erosion Control.

GP 43-26 Guidance on Practice for Offshore Surveys.

3. Terms and definitions

For the purposes of this GP, the following terms and definitions apply:

Water cut

water content expressed as a volume percentage

4. Symbols and abbreviations

For the purpose of this GP, the following symbols and abbreviations apply:

GOR	Gas Oil Ratio
SG	Specific Gravity
NBP	Normal Boiling Point
MW	Molecular Weight
PVT	Pressure Volume Temperature
BWRS	Benedict-Webb-Rubin-Starling
SRK	Soave-Redlich-Kwong



5. Basic hydraulic design principles

The commentary in this section is intended to give the user necessary background on the most basic principles of the hydraulic design of pipeline systems. This background, important in its own right, also aids in the understanding of the remainder of this document.

5.1. Concepts

The majority of pipelines are sized by use of three primary design criteria: available pressure drop; allowable velocities; and, for multiphase systems, flow regime. Line sizing is usually performed by use of steady state simulators, that assume that the pressures, flowrates, temperatures, and, if relevant, liquid holdup in the pipeline, are constant with time. This assumption is rarely true in practice, but line sizes calculated from the steady state models are usually adequate.

For a more rigorous pipeline sizing, the simulations could be done using transient simulators. Transient simulators allow changes in parameters such as inlet flowrate and outlet pressure as a function of time, and calculate values for the outlet flowrates, temperatures, liquid holdup, etc. as a function of time. If a multiphase line is operating in slug flow, the line size calculated from the transient model might be different from that calculated from a steady state simulator.

5.2. Pressure drop

Frictional pressure losses in single and multiphase systems are usually derived from a D'Arcy-Weisbach or Moody friction factor. A key parameter in calculating frictional pressure drop is the pipe wall roughness.

For untreated steel pipe a roughness of 46 microns (1,8 mils) is often used, and represents some deterioration from new during the early years of service. Specially treated pipe can have a roughness as low as 5 to 10 microns (0,2 to 0,4 mils). Pipe that has seen many years service, or that has developed wax deposits, on the other hand, may have a roughness as high as 500 microns (20 mils) or more.

No clear-cut criteria exist for determining the amount of pressure drop to be allowed in a pipeline design. Allowable pressure drop is a function of the parameters of the system being designed. The following are some guidelines for specific systems.

5.2.1. Gathering system simulations

In the design of a gathering system, the way used to choose allowable pressure drops should be to simulate the system from the reservoir through the flowline(s) to the processing plant, as a function of time.

This approach will account for the changes in reservoir pressure, flowrate, and composition that the gathering system must handle during the life of the field.

5.2.2. Rule of thumb for long distance gathering systems

- a. If it is not feasible to do the rigorous simulations for a gathering system, the allowable pressure drop may be estimated from the initial wellhead pressure and the processing plant inlet separator pressure.
- b. In this case the allowable pressure drop in the pipeline should be taken as 1/3 of the difference between the initial wellhead pressure and the separator pressure.

The remainder of the difference would equal the initial choke pressure drop. This approach allows for future operation at reduced reservoir pressures.



5.2.3. Rule of thumb for long distance gas/condensate pipelines

- a. The allowable pressure drop for long distance gas/condensate pipelines should be 0,4-0,8 bar/km (10-20 psi per mile) for frictional pressure drop at design rates.
- b. The predicted pressure drops in the line, as the diameter is varied, should be compared with the allowable pressure drop.

It should be pointed out that pressure drop is not always a maximum at the highest flowrate. If the pipeline contains inclined or vertical elements, it is possible that the highest pressure drop may occur at a low flow condition due to high elevational losses at low flows due to liquid loading.

5.3. Velocity

Liquid lines typically operate between 1 m/s and 5 m/s (3 ft/s and 16 ft/s).

Gas lines typically operate between 2 m/s and 15 m/s (7 ft/s and 49 ft/s).

The velocity in multiphase flow pipelines should be kept within certain limits to ensure proper operation. Operating problems can occur if the velocity is either too high or too low, as described in the following sections. It is difficult to accurately define the point at which velocities are "too high" or "too low." This section of the guide tries to quantify limits, but these limits should be considered as guidelines and not absolute values.

Since the 1950s the industry has used API RP 14E to evaluate erosional velocity limits. It has been realised for some time that this approach can give rise to very conservative results. In recent years BP has sponsored research work at Harwell and Tulsa University in order to develop improved erosion models. BP has now abandoned the API RP 14E approach with its associated C-factors and instead has introduced a new "BP erosion model" to enable a first pass assessment to be made of erosion rates. This model, which is applicable to gas, liquid and multiphase systems, uses a simplified version of the Harwell erosion model and is being made available to all engineers in BP.

The new BP erosion guidelines (Revision 3 2004) provide an easy to use flow chart for engineers to assess erosion issues and velocity constraints. The flow chart considers gas/liquid/multiphase fluids, systems with and without solid present, systems with and without corrosion inhibitor, and different types of pipe material. Within the flow chart the engineer can access the new BP erosion model to perform simplified erosion calculations.

- a. The BP erosion model should be used to assess whether erosion rates at the particular conditions being considered are acceptably low ($< 0,1$ mm/y (4 mpy)).
If this is the case flowing conditions are acceptable.
- b. If erosion rates are predicted to be $> 0,1$ mm/y (4 mpy) then the engineer should contact the IM team erosion specialists to carry out an erosion study using the full erosion model.
- c. The concept of a minimum velocity for the pipeline is an important one and should be considered in the design of the line.

Turndown conditions frequently govern the design of the downstream equipment. Velocities that are too low are frequently a greater problem than excessive velocities, so that the designer's natural tendency to add "a bit of fat" to the design by increasing pipe diameter can cause severe problems in the operation of the line and the downstream facilities.

At low velocities, several operating problems may occur:



- Water may accumulate at low spots in the line. If there is an appreciable amount of CO_2 or H_2S in the well stream, this water may be very corrosive.
- Liquid holdup may increase rapidly at low mixture velocities. A large accumulation of liquid may cause problems in downstream separators or slugcatchers if the line is pigged or the rate is changed rapidly.
- Low velocities may cause terrain induced slugging in hilly terrain pipelines and pipeline-riser systems.

It is not possible to give a simple formula quantifying the velocity when the phenomena discussed above occur. The minimum velocity depends on many variables, including: topography; pipeline diameter; gas-liquid ratio; and operating conditions of the line. A ballpark value for the minimum velocity would be a mixture velocity of 1,5-2,5 m/s (5-8 ft/sec). The actual value of the minimum velocity can only be quantified by simulation of the system using the methods discussed.

In systems such as water injection lines, there may also be a minimum velocity criterion to consider in order to prevent the deposition of sand particles being transported with the re-injected water.

5.4. Flow regimes in multiphase systems

In multiphase pipeline systems, it is important to consider the various flow regimes that may prevail throughout the system, both geographically and as a function of time. For many multiphase oil and gas systems, it proves virtually impossible to avoid the hydrodynamic slug flow regime. Given properly designed facilities, this need not give rise to major operating difficulties. Nevertheless, the presence of slugging flow in the pipeline may well have a significant impact on the efficiency of corrosion inhibitors. Additionally, the mechanical support of relevant pipeline sections needs to take account of the slugging flow regime.

In pipeline-riser systems, other forms of slugging flow can exist – severe or riser-induced slugging. Slugging of this type inevitably causes major operational difficulties and can have a serious impact on production rates.

6. Physical properties (see Design Manual Section 2)

6.1. Fluid model selection

- Before starting any package of work on system design, the fluid properties should be defined as fully as possible.
- The most appropriate of the fluid models shall be selected on a project by project basis.

For single phase gas or liquid systems, compositional models can potentially give the most accurate results. Many single phase hydraulic software tools permit the use of simpler fluid models. In gas systems, the fluid can be defined by something as simple as a gas gravity and average compressibility. For a simple liquid system, fixed values of density and viscosity enable first pass calculations to be performed, although this approach would not model a system that could operate in slack line mode. In multiphase systems, fluid properties are typically modelled using either compositional, or so-called black-oil, models.

- Whether a compositional or black oil model is employed, the predictions of the model shall be tuned using laboratory physical property data.

