ADNOC GROUP PROJECTS AND ENGINEERING

PROCESS DESIGN CRITERIA

Guideline

AGES-GL-08-001

ص ب 898، أبوظبي، الإمارات العربية المتحدة
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GROUP PROJECTS & ENGINEERING / PT&CS DIRECTORATE

CUSTODIAN	Group Projects & Engineering / PT&CS
ADNOC	Specification applicable to ADNOC & ADNOC Group Companies

Group Projects & Engineering is the owner of this Specification and responsible for its custody, maintenance and periodic update.

In addition, Group Projects & Engineering is responsible for communication and distribution of any changes to this Specification and its version control.

This specification will be reviewed and updated in case of any changes affecting the activities described in this document.

INTER-RELATIONSHIPS AND STAKEHOLDERS

a) The following are inter-relationships for implementation of this Specification:

   i. ADNOC Upstream and ADNOC Downstream Directorates and

   ii. ADNOC Onshore, ADNOC Offshore, ADNOC Sour Gas, ADNOG Gas Processing. ADNOC LNG, ADNOC Refining, ADNOC Fertilisers, Borouge, Al Dhafra Petroleum, Al Yasat

b) The following are stakeholders for the purpose of this Specification:

   ADNOC PT&CS Directorate.

c) This Specification has been approved by the ADNOC PT&CS is to be implemented by each ADNOC Group company included above subject to and in accordance with their Delegation of Authority and other governance-related processes in order to ensure compliance

d) Each ADNOC Group company must establish/nominate a Technical Authority responsible for compliance with this Specification.

DEFINED TERMS / ABBREVIATIONS / REFERENCES

"**ADNOC**" means Abu Dhabi National Oil Company.

"**ADNOC Group**" means ADNOC together with each company in which ADNOC, directly or indirectly, controls fifty percent (50%) or more of the share capital.

"**Approving Authority**" means the decision-making body or employee with the required authority to approve Policies & Procedures or any changes to it.

"**Business Line Directorates**" or "**BLD**" means a directorate of ADNOC which is responsible for one or more Group Companies reporting to, or operating within the same line of business as, such directorate.

"**Business Support Directorates and Functions**" or "**Non- BLD**" means all the ADNOC functions and the remaining directorates, which are not ADNOC Business Line Directorates.

"**CEO**" means chief executive officer.

"**Group Company**" means any company within the ADNOC Group other than ADNOC.

"**Guideline**" means this Process Design Criteria.

"PSR" means Process Safety Requirement

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1 PURPOSE

1.1 Introduction

This guideline provides design criteria, recommendations and best practice input for determining the design conditions and sizing of process equipment and lines. It is intended that it should be used across all business units within ADNOC.

This guideline is applicable to the following:

i. Design and installation of new plants and facilities;

ii. Modifications of existing plants and facilities.

2 SCOPE

This Process Design Criteria covers the following:

i. Design Pressure;

ii. Design Temperature;

iii. Design Margins;

iv. Fluid Categorization;

v. Equipment Sparing;

vi. Equipment Design Criteria;

vii. Insulation;

viii. Line Sizing.

3 DEFINED TERMS / ABBREVIATIONS / REFERENCES.

Abbreviations	
ASV	AntiSurge Valve
BEDD	Basic Engineering Design Data
BFW	Boiler Feed Water
CFD	Computational Fluid Dynamics
D	Diameter (m)
DDP	Design pressure at pump discharge (barg)
DP	Design Pressure (barg)
DPB	Design pressure at bottom of column (barg)
DPT	Design Pressure at top of column (barg)
DT	Design Temperature (^oC)
EPC	Engineering, Procurement and Construction
FBE	Fusion Bonded Epoxy Coating Steel Pipe
FEED	Front End Engineering Design
GFR	Glass Fibre Reinforced
GHS	Globally Harmonised System
GRE	Glass Reinforced Epoxy
H_c	Pump Rated differential head (m)
HC	Hydrocarbon
HDPE	High Density Polyethylene
HGO	Heavy Gas Oil
HIPPS	High Integrity Pressure Protection System
H_{max}	Pump shut off head (m)
HP	High Pressure

Abbreviations	
KO	Knock Out
LAHH	Level Alarm High High
LGO	Light Gas Oil
LP	Low Pressure
LPG	Liquefied Petroleum Gas
MAWP	Maximum Allowable Working Pressure
MDMT	Minimum Design Metal Temperature
MP	Medium Pressure
MOP	Maximum Operating Pressure (barg)
NGL	Natural Gas Liquids
NPSH	Net Positive Suction Head
NPSHa	Net Positive Suction Head available
NPSHr	Net Positive Suction Head required
P	Pressure (barg)
ρ	Density kg/m^3
PAHH	Pressure Alarm High High
PDA	Safety valve set pressure (barg)
PSA	Pressure Swing Absorption
PSV	Pressure Safety Valve
PVRV	Pressure Vacuum Relief Valve
RAM	Reliability, Availability, Maintainability
SDP	Design pressure at pump suction (barg)
SDV	Shut Down Valve
U/G	Underground

Abbreviations	
SG	Specific Gravity
SO	Shut Off
TS_{Max}	Maximum continuous operating temperature (ºC)
TS_{Min}	Minimum continuous operating temperature (ºC)
W	Gas flowrate (kg/hr)

4 NORMATIVE REFERENCES

International Code(s) and Standards

5 REFERENCE DOCUMENTS

References
1. API Standard 521 Sixth edition Pressure Relieving and Depressuring Systems
2. API Standard 520 Pt I Ninth edition Sizing, Selection and Installation of Pressure-relieving Devices – Sizing and Selection
3. API Standard 520 Pt II Sixth edition Sizing, Selection and Installation of Pressure-relieving Devices - Installation
4. API 14E Fifth edition (reaffirmed September 2019) Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems
5. API 14J Second edition Recommended Practice for Design and Hazards Analysis for offshore production facilities
6. ST/SG/AC.10/30 Globally Harmonised System (GHS) of Classification and Labelling of Chemicals (Issued by United Nations Economic Commission for Europe Information Service)
7. API 618 Fourth edition Reciprocating Compressors for Petroleum, Chemical and Gas Industry Services
8. API 2000 Seventh edition Venting Atmospheric and Low Pressure Storage Tanks

This is a live document and the impact of future revisions of International Standards to be reflected in this document in subsequent revisions / factored in by FEED Engineer and Contractors in Design.

5.1 ADNOC Specifications

References
9. AGES-PH-08-002 Flare & Blowdown Philosophy
10. AGES-SP-09-001 Piping Basis of Design
11. AGES-SP-05-001 Centrifugal Pumps (API 610) Specification

5.2 Standard Drawings

None

5.3 Other References (Other Codes/IOC Standards) etc.

None

6 DOCUMENTS PRECEDENCE

The specifications and codes referred to in this specification shall, unless stated otherwise, be the latest approved issue at the time of project award. .

It shall be the CONTRACTOR 'S responsibility to be, or to become, knowledgeable of the requirements of the referenced/related Codes and Standards.

Resolution and/or interpretation precedence shall be obtained from the COMPANY in writing before proceeding with the design.

In case of conflict, the order of document precedence shall be:

- UAE Statutory requirements
- This philosophy document
- Project documents
- International codes and standards

7 DESIGN PRESSURE

7.1 Design Pressure Selection

Except for specific items such as thin wall equipment (vessels open to atmosphere, storage tanks, pipeline etc.), the following design criteria shall be applied defining design pressure according to:

MOP: maximum operating pressure (barg)
DP: design pressure (barg)

Table 7.1: Maximum Operating Pressure and Design Pressure

MOP (barg)	DP (barg) Min - Max
< 0	Full vacuum (2) and 2.0 or 3.5 barg (3) (6)
0-10	Full vacuum (2) and PSM + 1 (3) (4) (5)
10-35	Full vacuum (2) and PSM x 1.1
35-70	Full vacuum (2) and PSM + 3.5
> 70	Full vacuum (2) and PSM x 1.05

Notes:.

1. *Where applicable, maximum liquid density and maximum liquid height in vessel shall be specified on the process data sheet for use in mechanical thickness calculations.*
2. *Full vacuum design conditions shall be applied to equipment that fulfil one of the following conditions:*

   i. Normally operates under vacuum;

   ii. Is subject to vacuum during start-up, shut-down or regeneration;

   iii. Normally operates full of liquid and can be blocked in and cooled down;

   iv. Can undergo vacuum through the loss of heat input;

   v. Equipment subjected to steam out (LP Steam at 3.5 barg) shall be designed for full vacuum conditions and 150ºC. If full vacuum conditions dictate the thickness of the vessels, partial vacuum may be used on a case by case basis evaluation. Company approval will be required for reduction of thickness in such cases.

Partial vacuum design conditions are normally not considered, except for the following cases:

   i. When the sub-atmospheric pressure is determined by the vapour pressure of the vessel fluid. Then the vapour pressure corresponding to the minimum ambient temperature must be considered.

3. *A minimum set pressure of safety valves is as follows:*

   i. 3.5 barg for a safety valve discharging to flare;

   ii. For non-hydrocarbon services where the vessel is open to atmosphere, design pressure can be lower than 3.5 barg.

4. *For equipment floating on/relieving to the flare system (flare KO drum, closed drain drums) the design pressure shall be as follows:*

   i. 3.5 barg when a liquid seal drum is located between KO drum and flare stack;

   ii. Minimum of 8.6 barg, if there is no liquid seal drum in the system (for deflagration and flashback protection inline with API 14J [5] and API 521 [1])

5. *For hydrocarbon vessels open to atmosphere, (in scenarios at remote locations such as well head towers, non-sour services etc), the minimum design pressure shall be 8.6 barg to prevent deflagration in line with API 14J [5].*

7.2 Design Pressure Profile for Columns and Reactors

The same design pressure shall be selected for the top of a fractionation column and associated condenser, reflux drum and interconnected piping.

The design pressure at the bottom of a fractionation column/ reactors shall be determined as follows:

$$DPB = DPT + \Delta P_1 + h \times \rho \times g/100000$$

Where:

DPB: Design pressure at the bottom including applicable pressure due to maximum operating liquid level (barg)

DPT: Design pressure at the top (barg)

ΔP_1 : Column pressure drop* (bar)

h:. Maximum operating height of liquid (m)

ρ: .Density of liquid (kg/m^3)

g : .Acceleration due to gravity (9.81 m/s^2)

The maximum liquid flowing density and the maximum liquid height shall be indicated on the Process Data Sheet for use in the mechanical thickness calculations. *Column pressure drop shall be provided / confirmed by Column Vendor/Licensor.

The designer shall evaluate the potential overfill scenarios for the columns and in case this results in overpressure, the design shall mitigate this either by designing it for that pressure or providing the required relief system / SIS as appropriate.

The designer shall validate the design (foundations, supports, structures, etc) consistent with the potential overfill scenarios.

7.3 Atmospheric Tanks

The design pressure criteria for tanks can be divided into two sections:

i. API 650 tanks – up to 0.172 barg

   Design pressure shall be Maximum Allowable Working Pressure (MAWP) based on internal pressure approximating atmosphere pressure, generally to a maximum of 0.172 barg.

ii. API 620 tanks – from 0.172 barg to 1.03 barg

Design pressure = MOP

MOP is the internal pressure to a maximum pressure of 1.03 barg.

The design pressure for atmospheric tanks shall be decided, on a case by case basis, considering the following:

a. Blanketing pressure requirements;

b. Tank flare backpressure;

c. Liquid flashing considerations;

d. Margins between operating pressures and the set pressure of the high pressure alarms, trips and PVRVs;

e. Tank full of liquid for tank bottom design and foundation design.

Venting requirements are specified per API 2000 [8]

The set pressure of the PVRV and the emergency vents shall always ensure tank design pressure is never exceeded during relieving [PSR].

7.4 Heat Exchangers (Tube rupture protection)

All new design heat exchangers shall preferably comply with the 10/13 rule (based on current corrected hydrotest pressure) for the design pressure of the heat exchangers where the design pressure of the high pressure side shall not exceed the corrected hydrotest pressure of the low pressure side. This provides an inherently safe design and avoids the requirement for tube rupture relief devices.

If there is a substantial difference between the operating pressure and the design pressure of the high pressure system then API 521 [1] allows considering the ratio based on the high pressure system maximum operating pressure.

Wherever, the above requirement cannot be practically achieved, the design measures explained by API 521 [1] Section 4.4.14 for additional design measures, shall be considered when tube rupture PSV is provided as part of the design.

For establishing the boundaries for the low pressure system design pressure, up to which the design pressure shall be increased, consider the system up to the first isolation valves from the exchanger side (upstream and downstream) with the necessary administrative controls in place to ensure isolation is achieved only through these valves and not from any farther valves. This is provided the downstream piping after the first isolation valve (design for high pressure) is open to flare or atmospheric pressure.

7.5 Centrifugal Pumps (& associated piping/equipment)

It is recommended that the design pressure of piping / equipment at the discharge of centrifugal pumps shall be designed for the shut off pressure in order to achieve an inherently safe design. The systems where this can not be practically achieved (revamps, long cross country pipeline etc) suitable overpressure protection means shall be evaluated on a case by case basis.

The shut off pressure value, for a fixed speed pump, is calculated by the two following formula when the pump's performance curves are available:

$DDP = MOP + (H_{max} .x\ \rho_{max}\ x\ g/100000)$ (equation 1)
$DDP = SDP + (H_c\ x\ \rho_{max}\ x\ g/100000)$ (equation 2)

Where:

DDP: Design pressure at the discharge of the pump (barg)

SDP: Design pressure at the suction of the pump (barg) which corresponds to suction system design pressure

MOP: Maximum operating suction pressure (barg)

H_{max}: Pump shut off head of the pump, (no flow condition) (m)

H_c: Rated differential head (m)

ρ_{max}: Maximum pumped fluid density (kg/m3) ,

g : Acceleration due to gravity (9.81 m/s^2)

In order to ensure the above, at the early stage of the project development, when the maximum differential head of the fixed speed centrifugal pump is not available, the design pressure at the discharge of the pump shall be set as follows:

$DDP = PDA + (1.2x\ H_c\ x\ \rho_{max}\ x\ g/100000)$ (equation 3)

PDA: Safety valve set pressure for the suction vessel (barg) + Maximum static head (considering LAHH with maximum SG) at pump suction (m) x ρ_{max} x g) / 100000

For variable speed pumps, a differential head multiplier of 1.3 shall be considered on top of the normal differential head, with maximum relative density, to account for the maximum speed of the pump.

For the above case where the pump performance curves are not available, a 5% margin is to be applied on the above estimated shut off pressure to account for potential future pump upgrade.

Pump suction side design pressure up to the upstream suction isolation valves shall be the same as the discharge side design pressure. Spec break shall be accordingly defined.

In case of two pumps in series, the maximum differential head shall be the sum of the maximum differential head of each pump.

During the detailed engineering stage, pump curves shall be used to validate system design pressure after adding the SO (Shut Off) head at the maximum speed to the maximum static head (LAHH with maximum specific gravity) and suction vessel PSV set point.

On cooling water, fire water, chilled water systems (large water networks), surge pressure due to water hammer / sudden closure / stoppage of valves / pumps shall be estimated through detailed analysis and that pressure shall be within system design pressures. Necessary pressure relieving systems shall be designed and incorporated if increasing system design pressures is not economically justified.

7.6 Reciprocating and Rotary Positive Displacement Pumps (& associated piping/equipment)

Due to the characteristics of positive displacement pumps, it is not practical to design equipment in the discharge of the pump for the maximum discharge pressure developed due to incompressible nature of liquids. Instead, maximum design pressure for downstream equipment shall be based on maximum "continuous operating pressure" with a margin applied.

A relief valve at pump discharge, set at downstream design pressure shall be provided [PSR]. Generally this PSV is set based on the discharge pressure as per the following guidelines:

i. 2 bar above the discharge pressure if the discharge pressure is less than or equal to 10 barg;

ii. 120% of discharge pressure if the discharge pressure is more than 10 barg;

iii. 110% of the discharge pressure if the discharge pressure is above 200 barg and below 400 barg;

iv. 105% if the discharge pressure is 400 barg and above.

In all cases, relief valve set pressure shall not be set higher than the downstream system design pressure.

7.7 Centrifugal Compressors (& associated piping/equipment)

7.7.1 Centrifugal Compressor Suction Equipment/Piping

The design pressure of compressor suction and intermediate stage systems e.g., coolers, condensers, knock-out drums, shall be sufficiently high to prevent the opening of pressure relief valves through pressure equalization/ “settle out” after the compressor has shutdown.

Design pressure of the suction equipment shall be determined by the compressor settle-out pressure plus a margin or by the design pressure upstream of the machine whichever is greater.

The compressor suction design pressure shall be as below:

Suction equipment design pressure = 1.05 x settle out pressure (as a minimum).

Refer to Section 12.3.1 for the calculation of settle out conditions. The maximum compressor settle-out pressure shall be verified during detailed engineering based on piping layout and equipment volumes in the compression circuit.

7.7.2 Centrifugal Compressor Discharge Equipment/Piping

The maximum operating pressure at the compressor discharge shall be confirmed by vendor data at an early stage of FEED design. In the absence of compressor vendor curves, the following criteria can be used for setting the discharge design pressure for the centrifugal compressors:

i. For the system downstream of the last stage of a multi-stage compressor, the discharge design pressure shall be 110% of the maximum discharge pressure considering relief valves are provided at the discharge side of the compressor to protect the downstream facilities.

ii. For intermediate compression stages preceding the final compression stage, the respective stage discharge design pressure shall preferably be 120% of the maximum compressor discharge pressure of that particular stage. Lower margin can be adapted on a case by case basis evaluation based on the vendors feedback, if available, during the early stage of the project/FEED stage.

The above shall be verified during the detailed design stage, when compressor performance curves are available (fixed and variable speed), considering the speed variation up to the maximum allowable speed, molecular weight variations etc. In addition, dynamic simulations that are usually performed for the machines shall verify the adequacy of the discharge design pressures.

It is highly recommended that preliminary vendor compressor curves are obtained, in order to validate the above criteria, based on the variable speed limits and considering scenarios such as blocked outlet or blocked suction etc along with maximum molecular weight. Dynamic simulations will be used to validate the selected discharge PSV set points for the various dynamic scenarios.

7.8 Reciprocating Compressors

Reciprocating Compressors are capable of producing a discharge pressure higher than the normal equipment design pressure. The maximum design pressure for equipment in the discharge of the reciprocating compressor shall be protected by a pressure safety device. For the margins to be considered for the discharge relief valve set pressure, please refer to Table 7.2 from API 618 [7]:

Relief valves shall be set to operate at not more than the maximum allowable working pressure, but not less than the values listed in Table 7.2

Table 7.2: Relief Valve Settings

Rated Discharge Gauge Pressure (Each Stage)	Maximum Relief Valve Set Pressure Margin above Rated Discharge Gauge Pressure
barg	
≤10	1 barg
>10 to 170	10%
>170 to 240	8%
>240 to 345	6%
>345	See footnote a.
a. For rated discharge gauge pressures above 345 barg the relief setting shall be agreed on by the purchaser and the vendor.	

Note:

1. The design pressure of the suction equipment of the reciprocating compressor shall be rated for the discharge design pressure of the compressor, if there is potential for pressure equalization between the suction and design pressure and if there is no other mitigation available

7.9 Pipeline Design Pressure Criteria

Pipelines shall be designed for the maximum upstream system design conditions for an inherently safe design. Wherever this cannot be adapted due to economic considerations, a high integrity pressure protection (HIPPS) system shall be provided to safeguard against overpressure.

8 DESIGN TEMPERATURE

8.1 Maximum Design Temperature

As a general rule the design temperature shall be:

$DT = TS_{Max} + 15°C$

Where:

DT: Design temperature (°C)

$TS_{Max:}$ Maximum operating temperature (°C)*

The design temperature shall not be less than 85°C for any metallic equipment (exposed to solar radiation) which normally operates at temperatures above 0°C. For buried sections of the pipeline, the design temperature may be relaxed below 85°C depending on the actual process operating conditions.

*The Process Engineer shall evaluate all the possible scenarios including normal operation, start-up, shutdown and upset scenarios including but not limited to the following:

i. Utility failures;

ii. Air cooler failure;

iii. Bypass operation;

iv. Regeneration requirements etc.

Coincident design pressure & design temperature may be specified on the data sheets where cyclic operations occur such as molecular sieves, reactors & regenerators etc.

The final design temperature shall be rounded up to the nearest higher multiple of 5°C.

Notes:

1. The exceptional temperature generated by a fire should not be considered for design temperature selection.

2. Steam out conditions (where applicable) shall be specified on process data sheet.

8.2 Minimum Design Temperature

As a general rule the lower design temperature shall be the minimum of the following:

$DT = TS_{Min} - 10°C$

Where:

DT: Design temperature (°C)

TS_{Min}: Minimum continuous operating temperature (°C).

Or:

MDMT= Minimum inner wall temperature resulting from Depressurization –3 °C

MDMT: Minimum Design Metal Temperature (°C).

9 DESIGN MARGINS

This section discusses the facilities name plate capacity overdesign margins as well as individual equipment design margins for the various units within ADNOC Group of companies. The margins are summarized in Table 9-1 below:

Table 9.1: Design Margins

System/Equipment	Upstream Business Units		Downstream Business Units			Remarks
	Crude Production Facilities	Non-Associated Gas Production Facilities	Crude Production 'Related' Facilities	Non-Associated Gas Production 'Related' Facilities	Refinery, Petrochemicals and Fertilizers	
Facilities Name Plate Capacity	'Nominal' Capacity – per Production Profiles (Sustainable Capacity)	'Nominal' Capacity – per Production Profiles	'Nominal' Capacity – per Production Profiles	'Nominal' Capacity – per Production Profiles	Nominal Capacity	
Facilities Design Capacity	Technical Capacity= 1.2 x Sustainable (Nameplate/Average) capacity (See Remarks-1)	Name Plate Capacity (i.e. No Overdesign Margin to be applied)	Technical Capacity= 1.2 x Sustainable (Nameplate/ Average) capacity (Note-1)	Name Plate Capacity (i.e. No Overdesign Margin to be applied) (Note-1)	Name Plate Capacity (i.e. No Overdesign Margin to be applied) (See Remarks-2)	1) Upstream business units are required to produce sustainable/average oil production as mandated by the development plans and Shareholders. Reported 20% Margin for associated oil and gas production facilities is to account for planned and unplanned outages so as to meet the

System/Equipment	Upstream Business Units		Downstream Business Units			Remarks
	Crude Production Facilities	Non-Associated Gas Production Facilities	Crude Production 'Related' Facilities	Non-Associated Gas Production 'Related' Facilities	Refinery, Petrochemicals and Fertilizers	
						mandated sustainable production targets over the period. No further margins are required to be added on capacity over and above the 20% margin stated above. 2) Unless specified otherwise by the process licensors
Heat Exchangers / Air coolers	10 % on Design (Flow) capacity	10 % on Design (Flow) capacity	10 % on Design (Flow) capacity	10 % on Design (Flow) capacity	10 % on Design (Flow) capacity	No further margins to be added on duty or Area
Reboiler and Overhead Condenser	15% on Design (Flow) capacity	10% on Design (Flow) capacity	15% on Design (Flow) capacity	15 % on Design (Flow) capacity	10% on Design capacity	No further margins to be added on duty or Area
Process pumps	No Margin over Design (Technical) Capacity 10% Margin over Capacity – Applicable where facilities are	10% on Design capacity	No Margin over Design (Technical) Capacity	10% on Design capacity	10% on Design capacity	

System/Equipment	Upstream Business Units		Downstream Business Units			Remarks
	Crude Production Facilities	**Non-Associated Gas Production Facilities**	**Crude Production 'Related' Facilities**	**Non-Associated Gas Production 'Related' Facilities**	**Refinery, Petrochemicals and Fertilizers**	
	designed for Nameplate (Sustainable) only					
Utility Pumps	10% on Design capacity	10% on Design capacity	10% on Design capacity	10% on Design capacity	10% on Design capacity	
Reflux Pump and Boiler Feed Water Pump	No Margin over Design (Technical) Capacity 10% Margin over Capacity – Applicable where facilities are designed for Nameplate (Sustainable) only	10% on Design capacity	10% on Design capacity (Reflux Pump) 20% on Design capacity (Boiler Feed Water Pump)	20% on Design capacity	20 % on Design capacity	

System/Equipment	Upstream Business Units		Downstream Business Units			Remarks
	Crude Production Facilities	Non-Associated Gas Production Facilities	Crude Production 'Related' Facilities	Non-Associated Gas Production 'Related' Facilities	Refinery, Petrochemicals and Fertilizers	
Export Pumps to Pipelines	No Margin over Design (Technical) Capacity 10% Margin over Capacity – Applicable where facilities are designed for Nameplate (Sustainable) only	10% on Design capacity	No Margin over Design (Technical) Capacity	10% on Design capacity	5% on Design capacity (e.g. Condensate / Refinery Products)	
Process gas compressors	No Margin over Design (Technical) Capacity 10% Margin over Capacity – Applicable where facilities are designed for Nameplate (Sustainable) only	10% on Design capacity	No Margin over Design (Techilical) Capacity	10% on Design capacity	10% on Design capacity	

System/Equipment	Upstream Business Units		Downstream Business Units			Remarks
	Crude Production Facilities	Non-Associated Gas Production Facilities	Crude Production 'Related' Facilities	Non-Associated Gas Production 'Related' Facilities	Refinery, Petrochemicals and Fertilizers	
Nitrogen Generation Package	20% on Capacity (See Remarks)	20% on Capacity (See Remarks)	20% on Capacity (See Remarks)	20% on Capacity (See Remarks)	20% on Capacity (See Remarks)	Margin on normal continuous demand flow.
Instrument air System/Compressors	30% on Calculated Capacity (See Remarks)	30% on Calculated Capacity (See Remarks)	30% on Calculated Capacity (See Remarks)	30% on Calculated Capacity (See Remarks)	10% on Calculated Capacity (See Remarks)	Capacity is calculated as sum of all consumers as continuous demand and including up to two maximum intermittent users
Fired Heaters and electrical heaters	10 % on Design (Flow) Capacity	10 % on Design (Flow) Capacity	10 % on Design (Flow) Capacity	10 % on Design (Flow) Capacity	10 on Design (Flow) Capacity	No further margins to be added on duty or Area
Fractionation Columns, Absorbers & Regenerators	No Margin over Design (Technical) Capacity 10% Margin over Capacity – Applicable where facilities are designed for Nameplate (Sustainable) only	10% on Design capacity	No Margin over Design (Technical) Capacity	10% on Design capacity	10% on Design capacity	Margin on flow capacity is used for tray loading and packing height as applicable

System/Equipment	Upstream Business Units		Downstream Business Units			Remarks
	Crude Production Facilities	Non-Associated Gas Production Facilities	Crude Production 'Related' Facilities	Non-Associated Gas Production 'Related' Facilities	Refinery, Petrochemicals and Fertilizers	
Production Separators /Scrubbers/Reflux drums/Other Process Vessels	No Margin over Design (Technical) Capacity 10% Margin over Capacity – Applicable where facilities are designed for Nameplate (Sustainable) only	10% on Design capacity	No Margin over Design (Technical) Capacity	10% on Design capacity	5 % on Design capacity	
Other Equipment such as Molecular sieve adsorbers, filters etc.	No Margin over Design (Technical) Capacity 10% Margin over Capacity – Applicable where facilities are designed for Nameplate (Sustainable) only	10% on Design capacity	No Margin over Design (Technical) Capacity	10% on Design capacity	10 % on Design capacity	

System/Equipment	Upstream Business Units		Downstream Business Units			Remarks
	Crude Production Facilities	**Non-Associated Gas Production Facilities**	**Crude Production 'Related' Facilities**	**Non-Associated Gas Production 'Related' Facilities**	**Refinery, Petrochemicals and Fertilizers**	
Multiphase Pipelines (Transfer Lines/Trunklines)	No Margin over Design (Technical) Capacity 10% Margin over Capacity – Applicable where facilities are designed for Nameplate (Sustainable) only	10% on Design capacity	No Margin over Design (Technical) Capacity	10% on Design capacity	NA	Upstream multi-phase pipelines shall be designed to cater to field development profiles considering technical rates and no further margins to be applied on flow.
Product Export Pipeline	10 % margin over Design(Technical) Capacity	10% on Design capacity	10 % margin over Design(Technical) Capacity	10% on Design capacity	10% on Design capacity	Business case justification is required for any margin above 10%.

Notes:

1. Process Facilities/ units receiving both associated gas from upstream oil production facilities & non-associated gas facilities, will be designed considering technical rate (i.e., overdesigned by 20%) for associated gas and no over design on non-associated gas
2. Piping and Instrumentation: Margins shall be in line with associated equipment
3. Equipment loaded with catalysts and molecular sieves: The system design (equipment design and catalyst/ mol. sieve material quantity selection) shall ensure minimum four years' service life. Design margin shall be accordingly decided to meet this requirement.

10 FLUID CATEGORISATION

10.1 Hazardous Process Fluids

Systems containing Hazardous process fluids can be split into categories depending on the H_2S content in the fluid mixture:

i. Non-Toxic: H_2S in vapour phase below 500ppmv

ii. Toxic/Lethal: H_2S in vapour phase 500ppmv and above

Additionally, hazardous flammable fluids are identified as the fluids that burn in the presence of air (above their flash point).

To determine the toxicity level of materials containing substances other than H_2S, internationally agreed standard managed by UN, GHS system may be used (globally harmonized system for classification and labelling of chemicals) for guidance/reference [6].

The above stated values of H_2S and Toxicity classification is for the purpose of Engineering (Process/Mechanical) design only. For limits of H_2S level and its toxicity classification from the Occupational Health perspectives, refer to HSE document titled' Management of H_2S Standard, HSE– OS-ST21.

11 EQUIPMENT SPARING

The following shall be used as a general guideline for deciding upon the sparing requirements for different equipment/other items. This shall be reconfirmed, by individual projects, based on the RAM study outcomes. It is recommended that the RAM study be conducted in the early part of the project cycle, preferably at concept stage or early FEED stage.

i. Generally, for all static equipment, no spare to be provided;

ii. Filters / coalescers to be provided with a spare for maintenance and cleaning;

iii. Process centrifugal compressor, no spare to be provided. However, compressor auxiliaries such as lube oil pumps, lube oil filters etc to be spared;

iv. Process and Utility pumps and fans/ blowers, N+1 configuration to be provided. Higher sparing shall be justified by RAM study;

v. Fired heater not to be spared;

vi. Instrument air compressor / dryers to be provided with N+1 configuration;

vii. Nitrogen generation package (membrane technology) to be spared with installed membrane only. Nitrogen generation package PSA technology to be spared with N+1 configuration;

viii. Process reciprocating and rotary/positive displacement type compressors, a spare compressor may be considered depending on availability considerations/RAM study;

ix. Only critical control valves where the outage will lead to total shutdown of the facilities/units to be spared. Other control valves, if decided to be spared, shall be justified from business continuity perspective;

x. All relief devices shall have an installed spare with the following exceptions:

a. Spared equipment (such as filters, reboilers etc.);

b. Thermal expansion relief valves;

c. PSVs installed on equipment which are not normally in operation e.g. pig traps.

12 SPECIFIC EQUIPMENT DESIGN CONSIDERATIONS

12.1 Heat Exchanger

12.1.1 Fouling Factors

Refer to Appendix-1 for the fouling factors of various services within the different Business units.

Plate heat exchangers generally have higher turbulence and shear rates than shell and tube heat exchangers. Usually plate heat exchanger designs use over design margins instead of fouling factors and these should be discussed with the equipment supplier.

12.1.2 Approach Temperatures

For economic heat exchanger design the following minimum approach temperatures are recommended:

Table 12.1: Approach Temperature for Different Types of Heat Exchangers.

Type of heat exchanger	Approach temperature
Shell and Tube exchangers	10°C
Plate Heat exchangers	5°C
Printed Circuit Heat exchangers	3°C
Brazed Aluminium:	2°C
Kettle type heat exchangers	5°C
Air Cooled exchangers	10°C

In plants where sea water is used as a cooling medium, it shall be ensured that the maximum skin temperature and maximum bulk temperature on the cooling water side do not exceed 54ºC and 43ºC respectively (skin temperature is defined as the tube wall temperature on the cooling water side in clean condition). One of the possible ways of ensuring these criteria are met, could be to install an air cooler upstream of the cooling water exchanger.

Ambient air temperature for the design of air coolers shall be based on site specific environmental data.

12.1.3 Pressure Drop

The allowable pressure drop specified on the heat exchanger process data sheet shall be applied as the maximum pressure drop in the exchanger’s fouled condition.

Table 12.2 provides an estimate of the pressure drops required for pumped liquids, with the exception of cooling water, to achieve the target velocities. These may be considered for initial hydraulic sizing.

Table 12.2: Allowable Pressure Drop for Heat Exchangers

Viscosity Allowable cP	Allowable pressure drop Shellside (bar)	Allowable pressure drop Tubeside (bar)
< 1.0	0.20	0.35
1.0 to 5.0	0.35	0.50
5.0 to 15.0	0.50	0.70
15.0 to 25.0	0.70	1.00
25.0 to 50.0	1.00*	1.70*
Greater than 50 cP*		

* Advice from heat exchanger specialist should be taken in case of highly viscous fluids.

Notes:

1. Values are estimated based on experience to allow the required minimum velocities to be achieved, and to provide an optimised heat exchanger design. The values shown are per heat exchanger, when multiple exchangers in series are used.

2. For tube side fluids with liquid viscosity > 5cP, further review is required. The pressure drop should be sufficient to achieve the minimum velocity, and to avoid laminar and/or transitional flow where possible.

3. For shell side fluids with liquid viscosity > 50cP, further review is required. The pressure drop should be sufficient to achieve the minimum velocity, and to avoid laminar flow where possible.

12.1.4 Allocation of Fluid Sides:

The following can be used as an initial design guideline for the allocation of the fluid services between the shell and tube sides of heat exchangers:

Table 12.3 Stream Placement

Service	Shell	Tube
Sea water or brackish water		X
Cooling tower water		X
Lower allowable pressure drop	X	
Larger flow with similar properties	X	
High pressure		X
Corrosive fluids		X
Slurry service		X
High viscosity	X	
Suspended solids		X
Streams requiring water wash		X
Oxygen service		X

12.2 Pumps

12.2.1 NPSH (Net positive suction head)

Process Engineer is responsible for calculating NPSHa (Net Positive Suction Head Available) and for coordinating all aspects of system design required to ensure that adequate NPSH is available for pumps.

The NPSHa is the net head of liquid, after all losses are subtracted, at the pump suction nozzle above the vapour pressure of the liquid at the pump inlet conditions. NPSHa calculations shall consider LALL at the suction vessel.

12.2.2 NPSH Margin

NPSHa shall exceed NPSHr by 1m throughout the operating range from the minimum continuous flow up to the rated capacity and by 0.3 m at end of curve operation

For pumps in vacuum, low temperature service (below 0 °C), boiler feed water, cooling water and LPG services, the margin between NPSHa and NPSHr is 2 m from the minimum continuous flow up to rated flow and at least 1 m at end of curve operation

Ensure process data sheets specify the requirement of NPSH margin at end of the curve operations, as applicable.

For process licenced units (typically applicable for downstream such as Borouge units), the process licensor shall be consulted for any specific NPSH margin requirements other than what is stated above.

Pump motor sizing shall include end of curve operation. For any additional margins, refer to centrifugal pumps specification AGES-SP-05-001 [11].

12.2.3 Minimum Continuous Flow

All centrifugal pumps shall be provided with a minimum continuous flow line back to suction vessel. Minimum continuous flow lines shall preferably be automatic based on flow or differential pressure across pump, to avoid over sizing of pumps (forward flow and minimum continuous flow).

Where suction vessels are not applicable (such as pipeline pumps), then flow can be routed back to pump suction but with a precaution that operation of pump in closed loop with minimum continuous flow line shall be based on temperature rise of fluid.

12.3 Compressors

12.3.1 Settle-Out Pressure

When a centrifugal compressor trips or is shutdown, the pressure equalizes, or settles out, in the connecting systems between the unit’s automated boundary shutdown valves.

The settle out pressure is calculated, at an early stage of the project, to define suction equipment /system design pressures. The class break for the settle out pressure rating starts from the upstream inlet SDV of the compression stage. The estimated settle out pressure is based on preliminary equipment and piping volumes. When actual volumes are available to confirm the settle out pressure calculation, equipment design pressure changes are difficult to make and, in some cases, may not be possible. The settle out pressure is also important in designing the seal gas system as well as the driver start-up gas inertial load.

While designing the system, it is advised to reduce settle out as much as possible by increasing suction side volumes, this will have multiple benefits, such as lower design pressures and lower impact on starting torque requirements on compression equipment

Therefore, the initially calculated settle out pressure should include reasonable margins on the estimated system volumes or settle out pressure depending on the accuracy / level of the information available during early stage of the project. Settle out conditions shall be confirmed during the EPC stage.

12.3.2 Minimum Design Pressure and Settle Out Pressure Considerations

The minimum design pressure of the compressor suction equipment and piping shall be determined as follows:

i. The initial pressure for estimating the compressor settle-out pressure shall be considered as PAHH (high pressure trip setting) at the discharge side of the compressor and assuming simultaneous initiation of PAHH at the compressor suction with the associated operating temperatures;

ii. The minimum design pressure of the compressor suction scrubber (and set-point of the relief device) shall be as a minimum 105% of the settle out pressure;

iii. Individual stage settle out pressure shall be calculated and considered for fixing the design pressure of the respective suction side. However, considerations to be given for the combined settle out of the compressor stages that may be installed in common casing due to potential leaks across the seals. It is advised to have such information on compressor configurations from the vendors at early stage/FEED;

iv. Suction and discharge side volumes shall be considered at the respective operating temperatures.

12.4 Anti-Surge Control

To prevent surging on centrifugal compressors, an anti-surge control is required to recycle the gas from the discharge to the suction side to keep the operating point to the right of the surge control line.

Anti-surge valve shall be sized by the compressor vendor, however, for initial estimates during engineering stages, ASV may be sized for full rated flow at maximum speed.

Anti-surge flow must be cooled before returning to the compressor suction to prevent temperature increases that will eventually cause the compressor to shut down. The options of taking the anti-surge flow from downstream of the discharge cooler instead of directly from the compressor discharge to the compressor suction air cooler shall be evaluated on a case by case basis.

13 INSULATION AND TRACING

Thermal insulation for hot or cold services is required for:

i. Heat or cold conservation of equipment and piping;

ii. Personnel protection of equipment for operating temperatures above 70°C and below -10°C;

iii. Temperature control to avoid condensation, solidification or a too high viscosity;

iv. Anti-external condensation;

v. Steam or electrical tracing provided to prevent freezing or to keep gas temperature above the dew point;

vi. Steam or electrical tracing provided to prevent solidification for liquids such as sulphur.

Heat Conservation of Process piping, equipment and instruments is required whenever the pour point of the fluid is above the normal operating temperature or when it would be desirable to maintain certain fluid temperatures.

14 LINE SIZING

14.1 General

14.1.1 Standard & Minimum Line Sizes

i. The line sizes shall be limited to available standard sizes of pipes.
½", ¾", 1", 1½", 2", 3", 4", 6", 8", 10", 12", 14", 16", 18", 20", 24", 30", 36", 40", 42", 48"

ii. The following nonstandard lines sizes shall not be used:
- 1 ¼", 2 ½", 3 ½", 5", 7", 9" etc.

iii. Piping smaller than 1'' should not be used.

iv. Nominal pipe size in sleeper ways and pipe racks shall not be less than DN 50 (2'').

The following guideline shall be used when selecting the minimum line sizes:

Table 14.1 Minimum Sizes for Various Applications.

Size ("NB)	Criteria	Application
2"	Minimum	Nozzle size for Vessels, Tanks, Heat exchangers
2"	Minimum	Process (Hydrocarbon) Line Size
1½"	Minimum	Utility Line Size
1"	Minimum	Chemical injection, Bridle Drain or Pump casing vent / drain
2"	Minimum	On Pipe Rack or Pipe Sleeper
3''	Minimum	for U/G GRE piping
4"	Minimum	For (Wrapped and Coated) underground lines
4	Minimum	For Storm Water Runoff sewer drain lines

This specification does not apply to relief piping (upstream and downstream of pressure relieving devices). (Refer to Reference 9 for details).

14.2 Pipe Roughness

The following pipe roughness values shall be used as guidance:

Table 14.2 Pipe Roughness for Various Materials.

Pipe Material	Roughness (mm)
Carbon Steel (CS) Corroded	0.46 (Note 1,3,4)
Carbon Steel (CS) non-Corroded	0.046 (Note 2)
SS	0.046
Titanium and Cu-Ni	0.046
Glass fibre reinforced (GFR)	0.02
Glass fibre reinforced with liner	0.005
Galvanized carbon steel	0.15
Carbon Resistant Alloys	0.046
Polyethylene, PVC	Vendor to provide
Flexible Hose	Vendor to provide
Cladded Pipes (Weld overlay)	Vendor to provide
GRE	0.005 (Vendor to provide)
FBE lined	Vendor to provide
HDPE	0.0015 (Vendor to provide)

Notes:

1. The value of 0.46 mm shall be used when hydraulic calculations are performed for existing pipe installations.

2. The value of 0.046 mm shall be used when hydraulic calculations are performed for new pipe installations.

3. For critical lines (for example, very low-pressure flare systems such as tank flare, vapour recovery systems, systems operating under vacuum etc) consider a roughness factor for the new piping design to be same as corroded carbon steel. This will provide inherent additional margins of safety for any potential inaccuracies in pressure drop estimations at such pressures. This however shall be evaluated on a case by case basis.

4. For cladded pipe, confirm the roughness factor with the vendor. In absence of information consider a preliminary value of 0.457 mm.

14.3 Line Length

During the preliminary stage of a project or in a proposal, line length shall be estimated from the available plot plan. As the number of fittings etc. is not known in the preliminary stage, the straight length can be multiplied by a factor to get the total length.

i. Use a factor of 1.3 for on plot areas;

ii. Use a factor of 1.1 for off plot areas.

The above factors are for guidance and the designer can use different values based on the level of available information.

14.3.1 Single Phase

The piping sizing criteria are based on the following main parameters

i. Pressure drop;
ii. Velocity;
iii. Vibration and noise.

Table 14.3: Line Sizing Criteria for Liquids

SERVICE	LINE SIZE	Maximum VELOCITY	PRESSURE DROP	
			Normal	Maximum
		(m/s)	(bar/100m)	(bar/100m)
Pump suction, bubble point (Note 1,3)	≤ 2”	0.6	0.06	0.09
	3” – 10”	0.9	0.06	0.09
	12” – 18”	1.2	0.06	0.09
	≥ 20”	1.5	0.06	0.09
Pump suction, subcooled (Note 3)	≤ 2”	0.9	0.23	0.35
	3” – 6”	1.2	0.23	0.35
	8” – 18”	1.5	0.23	0.35
	≥ 20”	1.8	0.23	0.35
Pump discharge P ≤ 50 barg		1.5 to 5	0.35	0.45
Pump discharge P > 50 barg		1.5 to 5	0.7	0.9
Re-boiler lines				
Trap out / Inlet		0.9-1.5	0.03	0.07
Return		Note 5	Note 5	0.07
Gravity flow		0.6	0.025	0.045
Column side-stream draw-off (Note 2)	≤ 2”	0.6	0.06	0.09
	> 3”	0.9	0.06	0.09
Cooling water (Note 6)		4.6	0.11	0.34
Cooling Seawater (Note 6)		4.6		
BFW		6	0.35	0.45
Service water	1” – 4”	3		
	≥ 6”	4.5		
Sea water/injection water		2.1		
Brackish Water		2.1		
Sour water, > 120ºC Carbon Steel		1.5		
Sour water, > 120ºC Stainless Steel		3		
Sour water, < 120ºC Carbon Steel		3		
Sour water, < 120ºC Stainless Steel		4.6		
Amine solution (Note 4)				
Rich Amine – Stainless Steel		6		
Rich Amine – Carbon Steel		1.5		
Lean Amine – Stainless Steel		6		
Lean Amine – Carbon Steel		2		

SERVICE	LINE SIZE	Maximum VELOCITY	PRESSURE DROP	
			Normal	Maximum
		(m/s)	(bar/100m)	(bar/100m)
Caustic soda or Na OH solution, > 5% by weight – Carbon Steel		1.2		
Potassium Hydroxide (KOH) solution, 40-60% by weight @ 66ºC		1.8		

Notes:

1. Applicable to liquids containing dissolved gas.

2. Provide a vertical run of 3 metres minimum from nozzle, at nozzle size, before reducing the size of the line.

3. For high pumping temperatures, extra margin shall be considered to compensate for the pressure drop of piping expansion devices.

4. Licensor recommended velocity, if different, will govern.

5. Line sizing criteria is constrained by only the maximum pressure drop and not maximum velocity or normal pressure drop.

6. For cement lined cooling water, maximum velocity to be limited to 3 m/s.

7 GRE velocity criteria (obtained from vendor inputs): 3-5 m/s to be evaluated based on project's design life and fluid service.

8. Minimum liquid velocity for

- *i. Cooling water (open recirculated cooling tower) 1.5 m/s*
- *ii. Cooling water 1.0 m/s (closed loop)*
- *iii. Brackish Water 1.2 m/s*
- *iv. Raw surface water 1.5 m/s*
- *v. Seawater 1.5 m/s*

9. For all lined pipe, the calculation of inner diameter shall consider the liner thickness provided by vendor. For cladded pipes, include clad/weld overlay thickness of 3mm when calculating the internal diameter of the pipe.

Table 14.4: Line Sizing Criteria for Gases & Steam

SERVICE	PRESSURE (barg)	LINE SIZE	MAXIMUM VELOCITY (m/s)	PRESSURE DROP Normal (bar/100m)	PRESSURE DROP Maximum (bar/100m)	MAXIMUM ρV² (kg.m.s⁻²)
Gases, General (Note 1)	P < 20		(Note 2)			15000
Gases, General (Note 1)	20 < P ≤ 50		(Note 2)			15000
	50 < P ≤ 80		(Note 2)			15000
	P > 80		(Note 2)			15000
Compressor Suction Reciprocating			(Note 2)	0. 02	0. 07	3000
Compressor Suction Centrifugal			(Note 2)	0. 02	0.07	6000
Compressor Discharge					0.22	
Compressor Anti Surge Line				(Note 3)		25000
Tower Overhead (Note 4)				0.023	0.11	
Vacuum Service				0.005	0.068	
Steam supply to drivers, heat exchangers, heating coil						
Steam mains:						
< 34.5 barg				0.11	0.34	
≥ 34.5 barg				0.23	0.45	
Steam Distribution let down lines:						
< 34.5 barg				0.23	0.45	
≥ 34.5 barg				0.34	0.68	
Steam distribution lines for stripping, aeration, etc.			(Note 5)	(Note 5)	(Note 5)	
Exhaust						
Exhaust steam lines, excluding vacuum exhaust (Note 6)				0.045	0.11	
Nitrogen/ Instrument Air header (Note 7)		≥ 2”		0.023	0.23	
Fuel Gas (Note 7)				0.023	0.23	

Notes:

1. The above indicated line sizing criteria are valid for continuous operation. The following criteria must be met:

- *i. Pressure drop in bar/100m shall be less than 5% of the static absolute pressure for long headers and 10% for short headers. For intermittent operation, these limits may be relaxed on a case by case analysis. For steam let down stations, when sufficient pressure drop is available, the pressure drop limit of 10% for short headers may be increased to 30%, and the ρV^2 limit of 15000 may be increased to 25000.*
- *ii. If pressure drop in a pipe segment exceeds 10% of the upstream pressure, the pipe shall be divided into segments to keep the pressure drop in each segment to below 10% of the upstream pressure (for each segment). This is usually done to account for changes in the vapour physical properties due to pressure changes in the pipeline.*

2. Maximum velocity shall be determined from ρV^2 based on vapour/steam density at the operating conditions.

*3. Maximum velocity shall be less than (1/3 * Sonic Velocity).*

4. Based on available pressure drop.

*5. To be sized for available pressure drop. Maximum velocity shall be less than (1/3 * Sonic Velocity).*

6. Vacuum exhaust steam lines shall be sized for approximately 0.017 bar total line loss, with a maximum velocity of 140 m/s.

7. Apply pressure drop criteria based on user requirements and location (distance from pressure source).

8. In addition to above criteria, flowing velocity effects on noise are also to be considered.

14.4 Pipelines

For hydraulic analysis of pipelines, the following requirements shall apply:

- i. For dry or non-condensing gas and solids free: Pipelines conveying gas should be sized so that the normal range of flow velocities is 5 m/s – 10 m/s.
- ii. For dry or non-condensing gas and solids free: Continuous operation of gas pipelines above 20 m/s shall be avoided.
- iii. Pipelines conveying a liquid should be sized so that the normal range of flow velocities is 1 m/s – 2 m/s.
- iv. Continuous operation above 4 m/s shall be avoided for pipelines conveying a liquid;
- v. Incidental operation of liquid pipelines above 4 m/s shall be evaluated and documented (e.g. surge analysis);

14.5 Two-Phase Flow

14.5.1 Sizing Criteria for Gas/Liquid Two-Phase Lines

For preliminary mixed phase fluid line sizing calculations, the average density method shall be used while considering the following criteria:

i. V_M: 10 to 23 m/s;

ii. ρ_M x V_M^2: 5000 to 10000 Pa;

iii. ρ_M x V_M^3: 100000 to 150000 kg/s^3

Where

V_M: average fluid velocity

ρ_M: mixed density.

Avoid undesirable flow regimes within the maximum allowable pressure drop. Review possible turndown cases. Undesirable flow regimes are not limited to slug flow.

i. For horizontal lines, stratified, mist, annular or bubble flow is acceptable. Slug and plug flow regimes shall be avoided to prevent “bowing”.

ii. For vertical lines, mist, annular or bubble flow is acceptable. Slug flow regime shall be avoided.

iii. Turndown flow rate cases must be checked for flow regime changes (e.g. annular flow regime at design flow may turn into slug flow at turndown rate).

14.5.2 Erosional Velocity

Flow Lines, production manifolds, process headers and other lines transporting gas and liquid in two-phase flow should be sized primarily on the basis of flow velocity.

Loss of piping wall thickness occurs by a process of erosion/corrosion. This process is accelerated by:

i. High fluid velocities

ii. Contaminants such as CO_2 and H_2O

The velocity above which erosion may occur can be determined by the following empirical equation:

$$V_e = \frac{C}{\sqrt{\rho_M}}$$

Where:

V_e = fluid erosional velocity, m/s

C = empirical constant

ρ_M = gas / liquid mixture density at flowing pressure and temperature, kg/m^3

The fluid velocity must be lower than the erosion velocity.

API 14E [4] reflects the C factor values in English units, conversion as below:

For solid free fluids, C = 100 for continuous service and C = 125 for intermittent service are conservative.

For solids-free fluids, where corrosion is not anticipated or when corrosion is controlled by inhibition or by employing corrosion resistant alloys, values of C = 150 – 200 may be used for continuous service. Values up to C = 250 have been used successfully for intermittent use.

The C values specified above are in empirical units, to obtain SI values, multiply the C value by 1.22.

If solids production is anticipated, fluid velocities should be significantly reduced.

The design of any piping system where solids are anticipated should consider the installation of sand probes, cushion flow tees, and a minimum of three feet of straight pipe downstream of choke outlets.

Mixture Density

The density of the gas/liquid mixture may be calculated using the following derived equation:

$\rho_M = (\rho_L * R_L) + (\rho_G * R_G)$

where:

ρ_L = Liquid density, kg/m^3

R_L = Liquid hold up, ratio of the volume of liquid in a pipe segment occupied by liquid to the volume of the pipe segment.

ρ_G = Gas density, kg/m^3

R_G = Gas hold up, remainder of the pipe segment which is occupied by gas.

14.5.3 Minimum Velocity

In multiphase (HC+water) pipeline, the minimum mixture velocity shall not be less than 1 m/s to avoid separation. In case this can’t be fulfilled, proper corrosion mitigation measures (pigging, chemical injection etc) shall be developed as part of the project.

14.5.4 Two Phase Flow Routing & Distribution Guidelines

Critical two phase vertical and horizontal lines subject to splitting may require CFD analysis to address the issues of maldistribution.

14.6 Sizing Criteria for Very Low Pressure Gas Systems

The Spritzglass equation is to be used for near-atmospheric pressure lines, operating at less than 1 psig). It is derived by making the following assumptions

$$f = (1 + \frac{3.6}{d} + 0.03xd)\ x1/100$$

T = 520ºR

P_1 = 15 psia

Z = 1.0 for ideal gas

ΔP = <10% of P_1

With these assumptions and expressing pressure drop in terms of inches of water, the Spritzglass equation can be written

$$Qg = 0.09x\ [\frac{\Delta hwxd^5}{(SxLx(1+\frac{3.6}{d}+0.03xd))}]^{1/2}$$

Where

f = friction factor

h_w = pressure loss, inches of water

S = gas specific gravity at standard conditions

Q_g = gas flow rate, MMSCFD (at 14.7 psig and 60ºF)

L = length, feet

d = pipe ID, inches

SECTION A (APPENDICES)

APPENDIX 1

Typical fouling factors for the various services in heat exchangers are given in the following table, and shall be applied to all heat transfer data sheets. The following fouling resistances shall be applied to all heat transfer data sheets.

Fluid Type	Fouling Factor $m^2.^oC/W$
Upstream	
Sour Natural Gas	0.00017
Sweet Gas	0.00017
Liquid NGL	0.00017
Liquid LPG	0.00017
Raw Feed Condensate	0.00035
Stabilised Condensate	0.00017
Process Water	0.00035
Stripped Water	0.00035
Glycol	0.00035
Amine (filter/strainer required)	0.0004
Downstream	
Crude, Vacuum & Condensate Distillation Units	
Crude	0.00061
Condensate	0.00061
Vacuum Overheads	0.00035
Naphtha Overheads	0.00026
Top Pump Around	0.00020
Kerosene	0.00022
Kerosene Pump Around	0.00022
Light Gas Oil (LGO)	0.00035
LGO Pump Around	0.00035
Heavy Gas Oil (HGO)	0.00052
Light Vacuum Gas Oil	0.00035
Heavy Vacuum Gas Oil	0.00052
Slop Wax	0.00175
Atmospheric Residue	0.00088
Vacuum Residue	0.00175
Hydrocracker/ Hydrodesulphuriser/Hydrotreater	
Reactor Feed	0.00026
Reactor Effluent	0.00026
Stripper Feed	0.00026
Stripper Overhead Vapour	0.00026

Fluid Type	Fouling Factor
	$m^2.^oC/W$
Dryer Overhead Vapour	0.00026
Platformer	
Reactor Charge	0.00026
Reactor Effluent	0.00026
Stabiliser Platformate	0.00017
Stabiliser Feed	0.00017
Stabiliser Overhead Vapour	0.00017
H_2 Rich Gas	0.00017
Catalytic Cracking & Coking Streams	
Overhead Vapours	0.00036
Light Liquid Products	0.00036
Light Cycle Oil	0.00036
Heavy Cycle Oil	0.00051
Light Coker Gas Oil	0.00051
Heavy Coker Gas Oil	0.00071
Bottom Slurry Oil (1.4 m.s minimum)	0.00051
Amine Treating	
Rich Amine: Tube side	0.0004
Lean Amine: Shell or Tube side	0.0004
Overhead Vapour (mainly steam condensation)	0.00017
Isomerisation	
Reactor Feed	0.00026
Reactor Effluent	0.00026
Regenerant	0.00026
Raffinate	0.00026
Extract	0.00026
Isomerate	0.00026
Light Naphtha Hydrotreater	
Combined Feed	0.00026
Reactor Effluent	0.00026
Hydrotreated Light Naphtha	0.00026
Sour Water Stripper	
Sour Water	0.00035
Stripped Water	0.00035
Polyolefins Unit	
Process fluid	
- clean	0.0001
- medium	0.0002
- fouling	0.0005
Pelletiser Water	0.0003
Air (unfiltered)	0.0004
Air (pneumatic conveying)	0.0002
Glycol Water	0.0002
Propylene Refrigerant	0.0002

Fluid Type	Fouling Factor m^2.°C/W
Ethylene Unit (Cracker)	
Dilution Steam System	0.00053
Ethane Feed	0.00026
Light Fuel Oil	0.00070
Quench Water	0.00053
Compressor Cracked Gas	0.00035
Last CGC Stage Condensate	0.00044
C2 Hydrogenation (Front End)	0.00018
Demethaniser Overheads	0.00009
Regeneration Gas System	0.00018
Deethaniser Bottoms	0.00053
Deethaniser Overheads	0.00018
C2 Tower Overhead	0.00009
C2 Tower Reboiler and Bottoms	0.00009
C2 Product	0.00009
C3 Hydrogenation System	0.00018
C3 Tower Overhead	0.00009
C3 Tower Bottoms	0.00026
Debutaniser Bottoms	0.00053
Debutaniser Overheads	0.00035
Propylene Refrigerant	0.00009
Ethylene Refrigerant	0.00009
Blowdown Water	0.00053
Process Water	0.00053
UTILITIES	
Sea Cooling Water	0.00045
Fresh Cooling Water	0.00027
Chilled Water	0.00017
Potable Water	0.00017
Refrigerated Water	0.0002
Saturated Steam	0.00017
Superheated Steam	0.00009
LP/MP/HP Condensate	0.00017
Boiler Feed Water	0.00017
Demineralised Water	0.00017
Methanol	0.00009
Hydrogen	0.00009
Nitrogen	0.0002
Instrument Air	0.00017
Fuel Gas	0.00017
Diesel	0.00035
Fuel Oil	0.00070

Fluid Type	Fouling Factor $m^2.^oC/W$
Gasoline	0.00053
Lube Oil	0.00020
Air side fouling factor for air cooled heat exchangers (desert environments)	0.0003 – 0.00035

Notes

1: All fluids which are part of a licenced process shall have their fouling resistances confirmed by the relevant process licensor.