NISOC	نگهداشت و افزایش تولید میدان نفتی بینک سطح الارض و ابنیه تحت الارض عمومی و مشترک							
شماره پیمان: ۰۵۳ – ۰۷۳ – ۹۱۸۴	PROCESS DESIGN CRITERIA							شماره صفحه : ۱ از ۶۰
	پروژه	بسته کاری	صادرکننده	تسهیلات	رشته	نوع مدرک	سریال	نسخه
	BK	GNRAL	PEDCO	000	PR	DC	0001	D02

طرح نگهداشت و افزایش تولید ۲۷ مخزن

PROCESS DESIGN CRITERIA

نگهداشت و افزایش تولید میدان نفتی بینک

D۰2	DEC. 2021	AFD	M.Aryafar	M.Fakharian	M.Mehrshad	
D۰1	OCT. 2021	IFA	M.Aryafar	M.Fakharian	Sh.Ghalikar	
D۰۰	July. 2021	IFC	M.Asgharnejad	M.Fakharian	Sh.Ghalikar	
Rev.	**Date**	**Purpose of Issue/Status**	**Prepared by:**	**Checked by:**	**Approved by:**	**CLIENT Approval**

Class: 2 | **CLIENT Doc. Number:**

Status:

- **IDC: Inter-Discipline Check**
- **IFC: Issued For Comment**
- **IFA: Issued For Approval**
- **AFD: Approved For Design**
- **AFC: Approved For Construction**
- **AFP: Approved For Purchase**
- **AFQ:** Approved For Quotation
- **IFI: Issued For Information**
- **AB-R: As-Built for CLIENT Review**
- **AB-A: As-Built –Approved**

REVISION RECORD SHEET

PAGE	D00	D01	D02	D03	D04
1	X	X	X		
2	X	X	X		
3	X				
4	X				
5	X	X			
6	X				
7	X	X			
8	X				
9	X				
10	X				
11	X				
12	X				
13	X				
14	X				
15	X				
16	X				
17	X				
18	X				
19	X				
20	X				
21	X				
22	X				
23	X				
24	X				
25	X				
26	X				
27	X				
28	X	X			
29	X				
30	X				
31	X				
32	X				
33	X				
34	X				
35	X				
36	X				
37	X				
38	X	X			
39	X				
40	X				
41	X				
42	X	X			
43	X				
44	X				
45	X				
46	X				
47	X				
48	X				
49	X				
50	X				
51	X				
52	X				
53	X				
54	X				
55	X				
56	X	X			
57	X	X			
58	X	X			
59	X	X			
60		X			
61		X			
62		X			
63					
64					
65					

PAGE	D00	D01	D02	D03	D04
66					
67					
68					
69					
70					
71					
72					
73					
74					
75					
76					
77					
78					
79					
80					
81					
82					
83					
84					
85					
86					
87					
88					
89					
90					
91					
92					
93					
94					
95					
96					
97					
98					
99					
100					
101					
102					
103					
104					
105					
106					
107					
108					
109					
110					
111					
112					
113					
114					
115					
116					
117					
118					
119					
120					
121					
122					
123					
124					
125					
126					
127					
128					
129					
130					

CONTENTS

1.0 INTRODUCTION

Binak oilfield in Bushehr province is a part of the southern oilfields of Iran, is located 20 km northwest of Genaveh city.

With the aim of increasing production of oil from Binak oilfield, an EPC/EPD Project has been defined by NIOC/NISOC and awarded to Petro Iran Development Company (PEDCO). Also PEDCO (as General Contractor) has assigned the EPC-packages of the Project to "Hirgan Energy - Design and Inspection" JV.

GENERAL DEFINITION

The following terms shall be used in this document.

CLIENT:	National Iranian South Oilfields CLIENT (NISOC)
PROJECT:	Binak Oilfield Development – General Facilities
EPD/EPC CONTRACTOR (GC):	Petro Iran Development Company (PEDCO)
EPC CONTRACTOR:	Joint Venture of : Hirgan Energy – Design & Inspection(D&I) Companies
VENDOR:	The firm or person who will fabricate the equipment or material.
EXECUTOR:	Executor is the party which carries out all or part of construction and/or commissioning for the project.
THIRD PARTY INSPECTOR (TPI):	The firm appointed by EPC CONTRACTOR and approved by GC & CLIENT (in writing) for the inspection of goods.
SHALL:	Is used where a provision is mandatory.
SHOULD:	Is used where a provision is advisory only.
WILL:	Is normally used in connection with the action by CLIENT rather than by an EPC/EPD CONTRACTOR, supplier or VENDOR.
MAY:	Is used where a provision is completely discretionary.

2.0 SCOPE

This document outlines the process/design criteria to be applied as Detail a minimum in the equipment specification for “Binak Oilfield Development – General Facilities Detail Studies Project”. Cases or applications not specifically covered by these criteria shall be handled on an individual basis. All applicable codes and standards (latest edition) shall apply to these cases with following priority: API, NFPA and IPS.

3.0 NORMATIVE REFERENCES

3.1 Local Codes and Standards

- IPS-G-ME-100 — General Standard for Atmospheric Above Ground Welded steel Storage Tanks
- IPS-G-ME-150 — Engineering And Material Standard For Towers, Reactors, Pressure Vessels And Internals
- IPS-E-PR-880 — Engineering Standard for Process Design of Gas(Vapor) – Liquid Separators
- IPS-E-PR-850 — Engineering Standard for Process Requirements of Vessels and Separators
- IPS-E-PR-460 — Process Design of Flare and Blow down Systems
- IPS-E-PR-470 — Process Design of Emergency Measures
- IPS-E-PR-450 — General Standard for Atmospheric Above Ground Welded steel Storage Tanks
- IPS-E-PR-750 — Process Design of Compressors
- IPS-E-PR-450 — Process Design of Pressure Relieving Systems Inclusive Safety Relief Valves
- IPS-E-PR-850 — Engineering Standard for Process Design of Gas (Vapor) – Liquid Separators
- IPS-E-PR-785 — Engineering Standard for Process Design of Air Cooled Heat Exchangers (Air Coolers
- IPS-E-PM-385 — Engineering Standard for Process Machinery Piping

- IPS-E-PR-830 — Engineering Standard for Process Design of Valves and Control Valves
- IPS-M-PI-130 — Material and Equipment Standard for Pig Launching and Receiving Traps
- IPS-E-PR-330 — Engineering Standard for Process Design of Compressed Air System
- IPS-E-PR-170 — Engineering Standard for Process Flow Diagram
- IPS-E-PR-230 — Engineering Standard for Piping & Instrumentation Diagram (P&ID)
- NFPA 15 — Standard for Water Spray Fixed Systems for Fire Protection
- NFPA 20 — Standard for the Installation of Centrifugal Fire Pumps

3.2 International Codes and Standards

- API 617 — Centrifugal Compressors for Petroleum, Chemical, and Gas Service Industry
- API 61۸ — Reciprocating Compressor for Petroleum, Chemical, and Gas Industry Services
- API 620 — Design and Construction of Large, Welded, Low-Pressure Storage Tank
- API 650 — Welded Steel Tanks for Oil Storage
- API 674 — Positive Displacement Pumps – Reciprocating
- API 676 — Positive Displacement Pumps – Rotary
- API RP 520 — Sizing, Selection and Installation of Pressure- Relieving Devices in Refineries, Part I – Sizing and Selection, Seventh edition, January 2000. API Recommended Practice (RP) 520
- API RP 520 — Sizing, Selection and Installation of Pressure- Relieving Devices in Refineries, Part II – Insulation, Fourth edition, December 1994. API Recommended Practice (RP) 520
- API RP 521 — Guide for Pressure-Relieving and Depressurizing
- API RP 526 — Flanged Steel Pressure Relief Valves
- API Standard 2000 — Venting Atmospheric and Low Pressure Storage Tanks", Fifth edition, 1998.API 617 Centrifugal Compressors for Petroleum, Chemical, and Gas Service Industry

- API -661 Air Cooled Heat Exchangers for General Refinary Services

3.3 ENVIRONMENTAL DATA

Refer to "Process Basis of Design; Doc. No. BK-00-HD-000-PR-DB-0001

3.4 ABBREVIATIONS

NISOC	National Iranian South Oil Company
PEDCO	Petro Iran Development Company
API	American Petroleum Institute
IPS	Iranian Petroleum Standard
ASME	American Society of Mechanical Engineers
TEMA	Tubular Exchanger Manufacturers Association
ANSI	American National Standards Institute
PSV	Pressure Safety Relief Valve
DP	Differential Pressure
NPS	Nominal Pipe Size
HHLL	High High Liquid Level
HLL	High Liquid Level
LLL	Low Liquid Level
LLLL	Low Low Liquid Level
LSLL	Level Switch Low-Low
LSHH	Level Switch High-High
ID	Inside Diameter Of Pipe
THK	Thickness

4.0 EQUIPMENT DESIGN BASIS

4.1 Design Pressure and Temperature

4.1.1 Design Pressure for Individual Equipment Items

The design pressure is the maximum and/or minimum pressure for which the mechanical calculation shall be performed. The operating pressure is defined as the maximum/minimum (for vacuum services) anticipated normal operating pressure. The design pressure shall be established according to the following criteria except in special cases approved by the Client. In addition, where, process fluid static head or other appropriate loads significantly increase the internal pressure, the design pressure shall be increased accordingly for the vessel (Note 7) section concerned.

a) The design pressure of vessel shall be at least equal to the maximum operating pressure plus 10 percent or plus 350 kPa, whichever is greater.

b) Vessels subject to external pressure shall be designed for full vacuum.

c) Consideration shall be given to compressor arrangement to determine the settle-out pressure of the isolated system. The settle-out pressure is the equilibrium pressure reached between the suction and discharge isolating valves of the compressor system when the compressor is stopped or shut down. Generally the design pressure of the equipment and piping at compressor suction shall be above this settle- out pressure in order to avoid unnecessary lifting of PSVs. For variable speed compressors, the maximum discharge pressure shall be calculated from the performance curve at the maximum trip speed setting prior to arriving at design pressure considerations.

i) MOP (maximum operating pressure) in centrifugal compressors is defined as follows:

- MOP = Normal Suction Pressure + Differential Pressure at surge point. Whenever vendor data is not available, the Surge Differential Pressure will be determined as follows:

  a. Surge Differential Pressure = 1.2 × Normal Diff. Pressure or,

  b. Surge Differential Pressure = 1.25 × Normal Diff. Pressure for variable motor speeds

MOP in reciprocating compressors is defined as follows:

- MOP = Normal Suction Pressure + 1.2 × normal Differential Pressure

NOTES:

The following design notes shall be taken into consideration for establishing design pressure:

1. The design pressure and maximum allowable working pressure of a vessel shall not be limited by minor components such as flanges, nozzles, manholes, or reinforcing pads.

2. The set pressure of the relief valve must be lower than or equal to the equipment design pressure.

4.1.2 Design Pressure for Complete Systems

When several pieces of equipment are protected by the same relief valve, each piece of equipment shall be designed, at least, for the pressure imposed by the discharge conditions of the relief valve in case of emergency .

4.1.3 Exchangers, Vessels and Other Equipment on the Discharge of a Pump

Equipment which could have to bear the shut off pressure of a pump in case of a valve closing (either control valve or block valve) shall have a design pressure equal to or higher than the shut- off pressure of the pump. Pump shut off pressure shall be estimated according to the following criteria, whichever is greater:

Design pressure of the suction vessel plus liquid height at vessel HLL at pump suction + pump differential pressure at rated flow of the pump.

Normal suction pressure plus liquid height at vessel HLL at pump suction + 120% of pump differential pressure at rated flow of the pump.

Shut off pressure of the centrifugal pumps shall be rechecked when Vendor’s characteristic curves of selected pumps are available. If it exceeds the estimated pump shut off pressure, the design pressure of downstream equipment shall be revised accordingly.

Generally no PSVs are provided at the discharge of centrifugal pumps and the design pressure shall be the discharge pressure of the pumps at no flow with the maximum suction pressure and the maximum specific gravity.

Reciprocating and Rotary Positive Displacement Pump Max. Pressure: Excessive discharge pressures from positive displacement machines can be attained if a discharge valve is inadvertently closed. Therefore, safety valves are mandatory for this class of machines.

Maximum allowable pressure is defined as the highest pressure which can occur in the pump when bypassing the full of the pump through its relief valve with an accumulation of not more than 10% above the maximum set pressure.

4.1.4 Exchangers which are not Subject to Pump Shut-Off

If no control or block valve is installed downstream the heat exchanger, the design pressure shall be calculated as the design pressure of the downstream equipment at the inlet point plus 1.2 times the pressure drop of the circuit between the heat exchanger inlet and the inlet point of the downstream equipment plus static head (if any).

4.1.5 Design Temperature

Unless otherwise specified, equipment design temperature shall be established according to the following criteria:

Operating Temperature(OT)	Design Temperature (DT), Min./ Max
Less than – 100 ºC	Min. Oper. temp./ 85 ºC min.
Between – 40 ºC and –100 ºC	-100 ºC/85 ºC min.
Between – 30 ºC and – 39 ºC	- 45 ºC/85 ºC min.
Between – 29 ºC and +60 ºC	Min. Oper. Temp. / 85 ºC
Between + 60 ºC and 343 ºC	Max. Oper. Temp. +25 ºC.
Above 343 ºC	To be specified according to the selected material and process requirement.

a) The design temperature is determined for the maximum temperature coincident with the design pressure as determined above. Indicate any higher temperatures as alternate design conditions.
b) When, due to the possible loss of flow of the cooling medium in coolers, the tubes, tubes sheets and floating heads may be subject to the full inlet temperature, it shall be indicated on the individual process data sheet and these components shall be designed for the maximum anticipated operating temperature of the hotter medium.
c) The design temperatures for multiple exchangers in series shall be selected in accordance with the maximum temperatures likely to occur on each exchanger in both clean and fouled condition. The design temperature indicated in the process data sheet is the temperature of the hottest exchanger.

Intermediate design temperatures shall be calculated assuming the highest heat transfer coefficient with fouled surface and the lowest heat transfer coefficient with fouled surface for the colder and hotter sections respectively. The irregular heat profiles shall be indicated on the process data sheet.

All calculations shall be based on the information noted on the process data sheet for worse conditions.

d) Heat exchanger and air cooler

The following conditions mentioned hereafter shall be applied generally up to the next piece of process equipment:

- Consideration for design temperature definition shall be given to cooling medium failure when coolers are used. Downstream of an air cooler, the design temperature is determined considering that 20% of the duty is provided by natural draft. Where possible detailed thermal analysis of natural convection cooling under the worst design ambient conditions shall be performed to arrive at the maximum cooler outlet temperature.

- For the bypassed air cooler, the design temperature of the downstream equipment, if any, shall be the maximum upstream operating temperature of the bypassed exchanger. Downstream of other coolers, the design temperature shall be the upstream maximum operating temperature.
- For fixed tube sheet exchangers, if the differential between the average shell metal temperature and the average metal temperature of any one tube pass exceed 28ºC, then mechanical stress shall be rechecked for furnishing expansion joint in case of requirement.
- The overhead receivers and relevant pumps casing shall be designed for operating temperature plus 25ºC or the overhead maximum operating temperature of upstream columns, whichever is greater.

e) Columns with fired feed heater with / without side cut strippers in the zone between the draw off trays of two adjacent side cuts, the design temperature shall be the draw off temperature of the heavier side cut plus 25ºC. In the zone between the heaviest side cut draw off tray and the bottom of the column, the design temperature shall be the flash zone temperature + 25ºC.

f) For the fractionators with Reboilers, the design temperature shall be the Reboilers return temperature plus 25ºC.

g) Maximum design temperature for equipment exposed to solar radiation shall be at least 85°C.This value should be examined case by case for equipment on which dilatation problems can occur (such as double wall tank, fixed tube sheet, plate heat exchanger) and for insulated high pressure vessels (not to increase wall thickness).

For those equipment items not exposed to solar radiation the maximum design temperature for all equipment shall be at least 55°C. This is the maximum estimated temperature that can be achieved in insulated equipment and equipment shaded from the sun after prolonged shutdown.

h) Emergency Depressurizing

The minimum design temperature must take into account any depressurization and depressurization (depending on material selection) of the equipment / piping that may occur either during an emergency or shutdown situation or gas blow- by from one equipment item to another equipment item and to the possible consequence of a change of material.

The emergency depressurizing shall impact the material selection as follows:

- Piping Material
- Piping material shall be selected taking into account the minimum temperature encountered during depressurization. Piping repressurization shall be considered as to be performed with the minimum depressurization temperature.
- Vessel Material
- The minimum temperature due to the blow down conditions shall be associated with design pressure. Although depressurization of any section of the plant cannot be performed unless the section is isolated and permission is obtained, repressurization may take place by operator's error or a valve failure, therefore the minimum temperature shall be associated with design pressure. Credit for special devices to ensure that the plant shall remain isolated and depressurized shall not be considered.
- In addition the above criteria shall ensure safe operation in case of residual piping stress being present (in particular for small diameter nozzle/piping).

i) Exceptional Case

- The exceptional temperature generated by fire shall not be
- Considered for design temperature selection.
- Consideration shall be made for upset and transient conditions such as start-up, shutdown etc. In these cases, both pressure and temperature conditions shall to be specified.

4.1.6 Purging Equipment with Steam

For equipment subject to steam purging at start–up or shut down indication shall be given on the specification sheet.

4.1.7 Cyclic Operating Conditions

For equipment subject to pressure and temperature swings, the magnitude and frequency of these swing will be given on the specification sheet.

4.1.8 Lethal Service Classification for Pressure Vessels

The pressure vessel code requires classification of the equipment in accordance with lethal service. In order to carry out this classification, the mention of “lethal service” shall be specified on equipment data sheets handling a fluid with H2S content higher than 1000 ppm wt. or where Mercaptan level exceeds 100 ppm in any escaping gas. For rotating machinery lethal service is noted on the process data sheet. The same criteria are used for pressure vessels. The purpose of the note is to assist seal selection and indicate items of equipment which may require toxic gas detection.

4.2 Vessels, Reactors and Towers

4.2.1 Vapor Area Sizing

The following excludes the flare/vent drums, Desalter and electrostatic dehydrators.

- If internals are installed, the common vapor internal shall be a wire mesh but for some services a vane pack can be used with Client approval.
- The use of other vapor internals such as cyclones, etc. Requires Client approval.
- The basis of sizing is the critical velocity Vc (m/s)

$$V_C = 0.048\left(\frac{\rho_l - \rho_g}{\rho_g}\right)^{0.5}$$

l = liquid density in kg/m^3

g = vapour density in $k+g/m^3$ V_C = critical velocity in m/sec

The maximum gas velocity is $K \times V_C$

K is a coefficient depending on the service, and the use or the absence of wire mesh. Recommended K values are given hereafter for different services:

Service	Without Wire Mesh	With Wire Mesh
Production separator	1.7	2.2
Fuel gas drum	0.8	1.7
Compressor suction drum	0.8	1.7
Glycol or amine contactor inlet drum	0.8	1.7
Reflux drum	1.7	2.2
Steam drum	-	1.3

- If a vane pack internal is used, the recommended K value is 3.3. This shall be confirmed with the vendor.

- For horizontal vessels without vapor internal (wire mesh, vane pack,…..), the minimum distance between the top of the vessel and the LSHH (level switch high-high alarm) set point is the largest of 300 mm or 0.2 internal diameter.
- Vessels handling paraffinic oil shall not be equipped with gas internals

4.2.2 Hold Up Time and Residence Time of Liquids

Residence time is defined between low liquid level (LLL) and high liquid level (HLL) as per below table.

SERVICE	RESIDENCE TIME (minutes)
Feed surge drum	20
Feed to the columns	10
Columns feeding other units	15 (on net liquid product)
Columns discharging to storage only	5
Columns feeding heat exchangers trains	5 (on net liquid product)
Columns feeding fired heaters	10 (with respect to equivalent flow rates of the vapor generated in the fired heater plus 5 minutes on net bottom product full)
Vacuum column bottom	4 (with quench)
Columns feeding multistage charge pumps (5 or more stages)	20
Drums feeding other equipment for further processing	10
OVHD receivers	5 (on reflux plus net product)
Drums feeding fired heaters	10 (on total liquid)
Re-boiling by thermo siphon	15 to 30 seconds
Gas and water separators	5 (on water flow rate)
Water boots	5 (below normal interface level or 10 minutes on water (HLL-LLL),whichever is greater)
Compressor suction K.O. Drums	240 (on maximum entrained liquid in the inlet line) or 14 inch level range (HLL-LLL), whichever

SERVICE	RESIDENCE TIME (minutes)
	is greater.
Other types of K.O. Drums	A volume corresponding to 15 meters of liquid slug in the inlet line or a 14 Inch level range, whichever is greater.
Desalter	15
Deaerator (note 1)	15
Atmospheric degassing drum	15
Others Drums	3 without pump
	5 with pump

Note 1: Liquid hold up time is based on one deaerator shutdown associated with the normal liquid flow rate.

4.2.3 Two / Three Phase Separators

In case LSLL and/or LSHH are provided, the following additional hold-up times shall be taken into consideration (where, LSHH and LSLL are located above HLL and below LLL respectively):

- Liquid hold-up time between LLL and LSLL shall be minimum 2 minutes based on the total inflow to the vessel (or section of the tower) or 3 minutes based on the liquid stream flow from the vessel, whichever is greater.
- Liquid hold-up time between HLL and LSHH shall be minimum 3 minutes based on the total inflow to the vessel (or section of the tower) or 4 minutes based on the liquid stream flow from the vessel, whichever is greater.
- For vertical vessels, the elevation between feed nozzle and LSHH shall be equal to drum diameter multiplied by 0.3 or 750 mm, whichever is greater (including flash drums and excluding trayed towers) and the elevation between LSLL and bottom tangent line (TL) shall be minimum 300 mm.
- In case LSLL and/or LSHH are not provided, the following criteria shall be considered:
- For vertical vessels, the elevation between feed nozzle and HLL shall be equal to drum diameter multiplied by 0.3 or 900 mm, whichever is greater (including flash drums and excluding trayed towers) and the elevation between LLL and bottom tangent line (TL) shall be minimum 550 mm (200 mm for compressor K. O. Drums).

- For vertical vessels, the elevation between upper tangent line and upper section of mesh pad (Demister pad) shall be equal to drum diameter multiplied by 0.15 or 150 mm, whichever is greater.

4.2.4 Storage Tanks Design Consideration

- The identification of the networking capacity of the storage tanks are the storable tank volume between high liquid level (HLL) and the low liquid level (LLL). The following dead stock has been assumed to calculate the networking volume.

Shell height between HLL and HHLL	0.2 m for all types of tanks
Shell height above HHLL	0.8 m (min) for floating roof tanks 0.45 m (min) for fixed roof tanks
Shell height between LLL and LLLL	0.2 m for all types of tanks (Note 1)
Shell height below LLLL	0.6 m (min) for fixed roof tanks 1.2 m (min) for External floating roof tanks 1.6 m (min) for Internal floating roof tanks

Note 1) Liquid height above LLLL in Three-Minute Suction, or 200 mm (min), whichever is greater

4.2.5 Vessel Diameter

- As a general rule, inside diameter shall be specified on process data sheets (in mm)
- Minimum internal diameter of horizontal vessels shall be 900 mm. Minimum water boot diameter shall be 300 mm.
- For vessels less than 1000 mm ID, flanged heads may be specified.
- Recommended L/D ratio for horizontal vessel:

PRESSURE (barg)	L/D
Lower than 17	3
17 up to 34	4
Higher than 34	5

4.2.6 Manway Sizes

Size of man-way shall be 24” (NPS). Minimum inside diameter shall be 18”. Larger size to be specified when required accommodating internals.

Man ways shall be provided as follows:

<u>Horizontal vessels:</u>

- 900 to 1300 mm ID: Man way on the head, 18” ID or 20” ID on shell.
- Larger than 1300 mm ID: Man way on the side or Top shell, 24” ID

Vertical vessels:

- Under 900 mm ID: Top head flanged
- 900 to 1300 mm ID: Man way, in shell, 20” ID
- Larger than 1300 mm ID: Man way, in shell, 24” ID

Location of manholes

At the opposite side of the utility connection for horizontal vessel

Number of manholes Vessel

For vessel length/height less than 6 m a single manhole shall be provided. For other vessel (length/height > 6m), two manholes shall be provided at least. One manhole shall be foreseen for each 6 m in longer/higher vessel. If vessel is equipped with internals (baffles etc.), one manhole to be provided on each Compartment

Trayed columns:

Manway shall be provided above the top tray, below the bottom tray, at any feed and side-cut draw off tray and at intermediate points so that the maximum number of trays between Manways does not exceed 10 unless otherwise required by the process and / or mechanical designer.

Packed vessels:

Each packed bed shall have a man way at above of bed and a hand hole(s) at bottom for withdrawal.

4.2.7 Handhole

Hand hole size = 8”. Hand hole to be installed on vessel with diameter less than 900 mm or on vessel where severe fouling of internals is expected.

4.2.8 Vortex Breaker

Vortex breaker to be installed for the following services:

Pump suction

Outlet to thermo siphon or kettle Reboilers

Letdown to a low pressure system

A vortex breaker in fouled/dirty service shall have a standoff of 150 mm from vessel wall /bottom.

4.2.9 Drains, Vents and Steam-Out Connection

Location

The drain of the vessel shall always be at the lowest point of a vessel. For vertical vessels they shall be connected to the bottom outlet line at the low point. For horizontal vessels the drain point shall be directly on the bottom of the drum at the lowest point ensured through vessel slope (1:100).

Vent, Drain and Steam-out Connection shall be defined as follows:

VESSEL VOLUME (m3) and ID (mm), (Note-1)	VENT SIZE	DRAIN SIZE	STEAM OUT NOZZLE
V<45, D<1200	DN 40 (1½")	DN 40 (1½")	DN 25 (1")
45<V<75, 1200<D<2500	DN 50 (2")	DN 50 (2")	DN 40 (1½")
45<V<75, 2500<D<3500	DN 80 (3")	DN 80 (3")	DN 40 (1½")
45<V<75, 3500<D<4500	DN 100 (4")	DN 80 (3")	DN 50 (2")
75<V<220, 4500<D<6000	DN 100 (4")	DN 80 (3")	DN 80 (3")
220<V<420, D>6000	DN 100 (4")	DN 100 (4")	DN 80 (3")
V>420, D>6000	DN 150 (6")	DN 100 (4")	DN 100 (4")

Notes:

1. Size of nozzles shall be selected based on vessel volume and vessel inside diameter, whichever to be greater.
2. Drain on vertical vessel may be located on bottom line.
3. Select drain size to be same as process line, when process connection is to be smaller than the above table.
4. Drain number:
5. For horizontal drums having a length greater than 6 m TL to TL, additional drain connections shall be considered. An additional drain is also required on each compartment of a vessel. On toxic service, an open drain connection (washing out) is to be provided with a blind flange. Size of open drain connection shall be of the same diameter as drain connection.
6. For horizontal vessel with a length >= 6m and operating in toxic service, two utility connections shall be provided.

7. If vessel is equipped with internals (baffle), one utility connection shall be provided on each compartment.

4.2.10 Ventilation Nozzle

On unlined horizontal vessels, a man-way shall be provided on the top or side of the vessel at or below the horizontal centerline. If the bottom half of the horizontal vessel is lined, the man-way shall be located on the upper side or the top of the vessel.

Additionally, on horizontal vessels over 3 meters in tangent length, a blanked off ventilation nozzle shall be provided on the top of the vessel near the end, opposite the man-way. The ventilation nozzle shall be sized as follows:

Vessel Tangent Length	Blanked off Nozzle Size
3.0 meters through 4.4 meters	4”
Over 4.4 meters through 7.5 meters	6”
Over 7.5 meters	8”

4.2.11 Nozzle Sizing

The following criteria for vessel and column nozzles design shall be used:

Inlet Nozzle:

- mixed flow: ρmix × (V mix)2 < 6000 kg/(m×s2)
- Vapor inlet: ρ × V 2 < 3750 kg/(m×s2)
- No inlet device: ρ × V 2 < 1000 kg/(m×s2)
- Half open pipe or baffle : ρ × V 2 < 1500 kg/(m×s2)
- Schoepentoeter or other vane pack inlet: ρ×V 2 < 6000 kg/(m×s2)

Vapor Outlet Nozzle

- $\rho_g \times (V_{g,out})^2 < 3750$ kg/(m×s^2)

Liquid Nozzle

- The liquid outlet nozzle velocity, V_L, should be less than 1 m/s.

4.2.12 Trays and Tower Internals

- In trayed columns, minimum distance from the top tray to top tangent line shall be 750 mm or higher as required to accommodate man way, internals or nozzles.
- Minimum trayed column size shall be 900 mm internal diameter.

- Columns shall be designed with the following maximum flooding factors:
  - 75 for vacuum towers,
  - 78 for all fractionators,
  - 70 for column diameters under 900 mm ,
  - 75 for steam stripping and side cuts strippers ,
  - 80 for pump around trays and other services.
- For new towers, recommended minimum tray spacing to be as follows. For revamped towers, where, the tray spacing is limited due to tower height and economical reasons, tray spacing less than the following figures to be approved by Client.

Vessel ID	Tray Spacing
1300 mm ID or less	450 mm
1300 mm to 3000 mm	550 mm
3000 mm ID and larger	600 mm

- Tray spacing shall be greater than the above mentioned minimum values where required for access to column internals, man way location, vapor disengaging, nozzle interference or other reasons.
- Down-comer back-up shall be 50 percent of maximum of tray spacing.

4.3 Control Valve Sizing

Generally, having obtained the control valve's pressure drop allocation from pump head available, the further step is to size the valve. The other factors involved are flow rate and liquid relative density (specific gravity).

Valve sizing shall be based on maximum sizing capacity of 1.3 times the normal maximum flow or 1.1 times the absolute maximum flow, whichever is greater.

The valve should be selected such that the opening of the valve at Cv calculated should not be greater than 75 percent of total travel. For the exceptional cases, the approval of the client shall be obtained.

The pressure drop of a control valve, which is installed at the discharge of pump, should be a minimum of 20% of the system dynamic pressure loss at normal flow rate. This is because, the higher the pressure drop ratio1, the less the distortion.

For control valves, allowable pressure drop specified in data sheets shall be used as a general guideline. If not specified, the following procedure is used as a general guideline.

Whichever greater of the below ∆Pcv is selected as the design pressure drop of the control valve

∆P CV= ∆P friction - ∆P static, Where ∆P friction is assumed 20-25% of circuit friction losses (excluding the control valve) at maximum normal flow rate. ∆P static is assumed as 5-10% of circuit static pressure difference.

∆P CV= Static head of 5m liquid height.

For more information please refer to IPS-E-PR-830.

The following shall be observed on the Control Valves:

The minimum valve body size shall be 1-inch.

For more information please refer to IPS-E-IN-160

Control valves 2 inch and above shall have flanged ends, with the minimum flange and body rating of ANSI 300.

Three way control valves should not be used in the process.

For more information please refer to IPS-E-IN-160.

4.3.1 Orifice Sizing Criteria

The square edge orifice plate with flange taps, which shall be specified in accordance with ISO 5167, shall be generally used for flow measurement.

Orifice plates shall generally be made of 316 S.S material unless otherwise required due to process condition.

Orifice flanges shall be 300 # ANSI as a minimum.

For low differential pressure or high line size pitot tubes (Annubar) can also be used (Gas flow measurement only).

Special flow requirements can call for other type of measuring devices such as vortex meters, target meters, magnetic meters and ultrasonic meters.

Flow rate to be measured shall be kept between 30 % and 90 % of the design flow.

Orifice plates shall be calculated at 110 % of the design process maximum flow rate.

The primary elements shall be sized for use with differential pressure transmitters having one of the following ranges in mbar:

- 0-12.5, 0-25, 0-50, 0-125, 0-250, 0-500, 0-1000.

The preferred range is 0-250 mbar; the range 0-1000 mbar should be avoided where possible. In case of compressible fluids, the selected differential pressure shall preferably not exceed 3.6% of the upstream static absolute pressure.

The beta ratio (d/D) shall be kept between 0.25 and 0.7.

4.3.2 Control valve manifolds

The operation, severity, and maintenance frequency will dictate the manifold configuration. For upstream & downstream & bypass valve size API 550 part I shall be considered. Also the following table is taken as a guideline:

1) Bypass valves shall be globe valves up through 6" and gate valves in larger sizes of manifold. Size of block valve and bypass are in accordance with API RP 550 & table below.
2) One ¾" bleed valve shall be installed between the upstream and downstream block and control valves
3) At least a 1/16" clearance shall be provide at each flange accommodate the gaskets
4) Control valves shall have a minimum ASME rating of 300#
5) A straight run of 8" multiplied by diameter shall be provided downstream of valves, in flashing services, and shall be reported on the respective P & ID
6) All control valves without a bypass and a block valves shall have manual operators or side hand wheel jacks

Table-1: Block Valves and by-pass Sizes up to φ=16

Line dia.		Control valve size												
		½"	¾"	1"	11/2"	2"	3"	4"	6"	8"	10"	12"	14"	16"
½"	Block	½"												
	By-Pass	½"												
¾"	Block	¾"	¾"											
	By-Pass	¾"	¾"											
1"	Block	1"	1"	1"										
	By-Pass	1"	1"	1"										
11/2"	Block	11/2"	11/2"	11/2"	11/2"									
	By-Pass	11/2"	11/2"	11/2"	11/2"									
2"	Block		2"	2"	2"	2"								

Line dia.		Control valve size												
		½"	¾"	1"	11/2"	2"	3"	4"	6"	8"	10"	12"	14"	16"
	By-Pass		2"	2"	2"	2"								
3"	Block			2"	2"	3"	3"							
	By-Pass			2"	2"	2"	3"							
4"	Block			3"	3"	4"	4"							
	By-Pass			3"	3"	3"	4"							
6"	Block				4"	4"	6"	6"						
	By-Pass				4"	4"	4"	6"						
8"	Block						6"	6"	8"	8"				
	By-Pass						6"	6"	6"	8"				
10"	Block							8"	8"	10"	10"			
	By-Pass							8"	8"	8"	10"			
12"	Block								10"	10"	12"	12"		
	By-Pass								10"	10"	10"	12"		
14"	Block										12"	14"	14"	
	By-Pass										10"	12"	14"	
16"	Block											14"	16"	16"
	By-Pass											12"	14"	16"

Full line size block and bypass valves are required for the following:

- Use downstream line size for block valve size when vaporization or volume increase full line capacity.
- On gravity flow with small control value differential.
- When future expansion is predicted / seen in the design
- On higher-pressure drop where cavitation could occur (expansion shall be used immediately at the control valve outlet).
- Excessive noise.

4.3.3 Selection of Valves

The following guides shall be used to select the type of valves for specific application:

Table-1: Selection of Valves

Block valve				
Fluid	150#	300#	600#	900#
Established liquid	Φ<=8" : GATE Φ>=10" : BALL	Φ<=8" : GATE Φ>=10" : BALL	BALL	BALL
Sour HC, non established HC	BALL	BALL	BALL	BALL
Sour gas or toxic product	BALL	BALL	BALL	BALL
Sweet gas	Φ<=8" : GATE Φ>=10" : BALL	BALL	BALL	BALL
Steam	GATE	GATE	GATE	GATE

- Gate valve may be used for on-off purpose especially for liquid lines when throttling and tight shut-off is not required.
- Ball or non-lubricated plug valves may be used at service air hose connections.
- Check valve shall be used for unidirectional flow and when return of flow shall be avoided.
- Globe valves shall be used in the followings:
  a. Water services 1 ½" or smaller
  b. Manual regulation of flow
  c. Mixing
  d. For flow adjustment on lines not exceeding than 8"
  e. Control valve manifold bypass or any service where throttling are expected
- Needle valve may be used for sampling especially for high pressure cases.

4.3.4 Type of Valves

Table-3: Type of Valves

TYPE	SIZE	SERVICE
Ball valves	½" and larger	General service
Gate valves	½" and larger	General service
Butterfly valves, lined	4" and larger	General (water) service, class 150#

TYPE	SIZE	SERVICE
Butterfly valves, lined	4" and larger	150# and 300# corrosive service
Butterfly valves, soft or metal seated (high performance)	3" and larger	General service and special applications, e.g. cryogenic, high temperature
Diaphragm valves, lined	½" to 12"	150# corrosive service
Ball valves, lined	½" to 6"	150# and 300# corrosive service
Plug valves (pressure balanced)	½" and larger	High pressure gas system (e.g. hydrogen)
Needle valves	½" to 1 ½"	Accurate control
Globe valves	½" to 8"	General service
Diaphragm valves, lined	½" to 12"	Low-pressure corrosive service
Butterfly valves, lined	½" and larger	Moderate pressure corrosive service
Choke valves	½" to 8"	For high pressure difference and/or erosive service
Butterfly valves (high performance)	3" and larger	General service
Check valves	½" to 1 ½"	Piston type. Horizontal flow
	½" to 1 ½"	Ball type. Horizontal flow
	2" and larger	Swing type
	2" and larger	Dual plate type, spring energized

4.3.5 Battery Limit Block Valves

All lines crossing the battery limit shall have the following, inside the battery limit.

a. A block valve.
b. A spectacle blind located upstream of block valve.
c. A ¾ "plugged bleed valve located upstream of block valve.

4.3.6 Control Valve Pressure Drop

The control valve normal pressure drop is calculated in three ways:

- 33% of frictional pressure drop or,10% of discharge destination pressure
- The value corresponding to a control valve pressure drop of 0.7 bar at maximum flow.
- The maximum of these three values is inputted into the calculation for the net design discharge pressure.
- For systems operating above 69 barg, the control valve may take less than 10% of the operating pressure, depending on process and control considerations.

- The pressure drop across the control valve at the maximum flow shall be at least 20% of the pressure drop across the control valve at normal flow.
- For control valves in the steam line to Reboilers, allow a pressure drop of 5% to 10% of the initial absolute steam pressure or, when operating with low pressure steam of 2 Bar or less, use a minimum drop of 0.35 bar unless otherwise system operating pressure requires a lower drop. The same criteria are to be applied to vapors and gases other than steam.

4.4 Line Sizing Criteria

4.4.1 General

The fluid quantities to be used in determining line sizes shall be those called for by the maximum process design flow rates and in any case shall not be less than 110% of the unit design throughput. However, line sizes shall be in compliance with the equipment (pumps, exchangers, etc.) design capacity.

For Utility, Mixed flow, Liquid phase and Gas phase line sizing, refer to attachment No.1

4.4.2 Absolute Roughness

The friction loss shall be calculated in accordance with the standards of Hydraulic Institute on the basis of the following figures for absolute roughness of pipe:

Pipe Material	Absolut Roughness(mm)
Carbon Steel	0.05
Corroded Carbon Steel (For Flare Lines)	0.5
Stainless Steel, Duplex Steel, (New, Seamless, Cold Drawn)	0.03
Stainless Steel (Hot Rolled, Longitudinally Welded)	0.05 - 0.1
Titanium, (New, Seamless, Cold Drawn)	0.03
Titanium (Cold Rolled, Longitudinally Welded)	0.05 - 0.1

Pipe Material	Absolut Roughness(mm)
Titanium (Cold Rolled, Longitudinally Welded)	0.05 - 0.1
Galvanized Carbon Steel	0.15
GRP	0.02
Epoxy Lined Pipe	0.15

4.4.3 Winterization and Heat Conservation

- Protection of the process and all associated equipment, lines and instruments against atmospheric temperatures which would cause congealing or freezing of contents, interfere with operation or cause damage to equipment shall be shown on the Piping & Instrumentation Diagrams (P&IDs). However, steam or electrical tracing details shown on the diagrams are indicative and denote only the necessity of tracing in basic design stage. Type of tracing and insulation, use of thermal cement or otherwise numbers and size of steam traps will be determined at detail design stage.
- Protection described by standard nomenclature on the P&IDs should be reviewed in detail engineering to insure that proper standards or requirements in this regard have been met.
- The winterizing should be based on a winterizing temperature as specified in the site conditions of Basic Engineering Design Data.
- Lines in asphalt and liquid sulfur services should be steam jacketed. Valves in these lines are generally steam jacketed wedge plugs.
- The objective temperature for heat traced pipelines and equipment shall generally be the fluid pour point plus 22ºC. The objective temperature for sour gases and reciprocating compressor suction lines and drum shall be minimum 22ºC above the fluid dew point.
- Fuel gas system containing C3 & heavier materials and/or sour gas shall be traced for an objective temperature of 49ºC.
- Fuel oil supply and return lines shall be traced for an objective temperature of 120ºC. The minimum maintaining temperature for the specified commodities shall be according to the following:

Commodity	Minimum Maintaining Temperature (ºc)
Water Aqueous Solution	24
Light Diesel	(*)

Commodity	Minimum Maintaining Temperature (ºc)
Heavy Diesel	(*)
Fuel Gas	49
Base Oil	60
Fuel Oil (Supply & Return)	120
Asphalt	(*) (Steam Jacketed)

(*) Temperature will be determined in basic design phase.

4.4.4 Personnel Protection Insulation

To avoid the possibility of accident caused by the touching of either hot or cold surfaces by personnel, who may be unprepared for a sudden thermal shock, it is recommended that some reasonable protection shall be given.

Where operating temperature of piping, vessels and equipment is above ٥5°C and insulation is not required for heat conservation, those portions of equipment or piping which present a hazard to operating personnel and guard rails or screens not provided shall be insulated for personnel protection. These insulated surfaces shall extend approximately 2 meters above operating levels and 1 meter from edge of platforms, walkways, and ladders. The extent of personnel protection insulation shall be clearly indicated on piping drawings. Valves, flanges and unions shall not be insulated for personnel protection.

Contact with very cold surfaces will also result in thermal shock or skin damage and personnel protection may be required for temperatures of approximately -10°C and below.

4.4.5 Pressure drop and velocity limitation for liquids

Table-2: Pressure Drop and Velocity Limitation for Liquids

	DP(bar/km)		Max. Velocity (m/s)			
	Norm.	Max.	To 2”	3”to6”	8”to18”	From20”
Pump suction						
Liquid at bubble point/ with dissolved gas	0.6	0.9	0.6	0.9	1.2	1.5
Non boiling liquid	2.3	3.5	0.9	1.2	1.5	1.8

	DP(bar/km)		Max. Velocity (m/s)			
	Norm.	Max.	To 2”	3”to6”	8”to18”	From20”
Unit lines						
- Liquid at bubble point/ with dissolved gas	0.6	1.0	0.6	1.0	1.4	1.8
- Non boiling liquid	2.3	3.5	0.9	1.2	1.8	2.4
Pump discharge (1)						
- Disch. Pres.<=50 barg	3.5	4.5	1.5 to 4.5			6.0
- Disch. Pres.> 50 barg	7.0	9.0	1.5 to 4.5			6.0
Gravity flow			0.25	0.45	0.6	0.6
Cooling & service water						
- Large feeders between pumps and units	1.5		1.5 to 3.0 m/s			
- Unit lines (long)		1.5	1.5	2.5	3.0	3.0
- Unit lines (short)		3.5	1.5	2.5	3.0	3.0

Note 1: 3.0 m/s maximum (2 m/s average) at storage tank inlet or in loading.

4.4.6 Pressure Drop And Velocity Limitation For Vapor/Gases

Table-3: Pressure Drop and Velocity Limitation for Vapors/gases

Vapor and steam lines	ρv2 Max (kg.m-1.s-2)	Max.Velocity(m/s)	DP (bar/km)	
			Normal	Maxi
Continuous operation				
P<= 20 barg	6000		Pressure drop must be compatible with corresponding service	
20<P<= 50 barg	7500			
50<P<= 80 barg	10000			
80<P<= 120 barg	15000			
P > 120 barg	20000			
Compressor suction	Compatible with above		0.2	0.7
Compressor discharge	Compatible with above		0.45	1.15

Notes:

1. Vessel suction nozzle is often set by velocity limits to prevent vortex. Therefore, line shall be run at least 1.5 meter straight from nozzle at nozzle size, before size reduction of the line.

2. Water hammer effect shall be checked when maximum limits are used for sizing.

3. In every condition, friction loss in pump suction must be less than friction loss in pump discharge.

4. Changes in pipe’s diameter connected to pump much be 3D to 5D far from suction and discharge of pump.

4.4.7 Liquid Vapor Mixed Phase

Since most multiphase pipelines operate at high-pressure conditions, pressure drop is usually not a governing criterion in selecting a diameter. However, pressure drop may have to be considered for some long flow lines from wells and in most multiphase pipelines. If the available pressure drop allows, the flow velocity shall in general be sufficiently high to prevent liquid accumulation in the pipelines. It is recommended that a minimum flow velocity shall be maintained to keep liquids moving in the line and thus minimize terrain induced slugging of separator or other process equipment. Also, the flow velocity shall in general be kept low enough to prevent problems with erosion, corrosion, noise, vibration, etc. However, in some cases the maximum allowable velocity would be calculated by corrosion/erosion criteria.

- **Corrosion**

For corrosion resistant material (SS, Special alloys ...), no limitation of flowing velocity up to 100 m/s and no requirement for corrosion allowance.

For non-corrosion resistant material, in corrosive fluid service, corrosion allowance for a design service life and corrosion inhibitor injection is required. The flowing velocity is limited by the inhibitor film integrity.

Note that it is not often economical to use corrosion resistant alloys, thus, corrosion inhibitors are widely used as an alternative to protect the lines by formation of a protective layer inside the internal surface. However product and inhibitor layers will not protect the pipe by turbulence and shear stress. Therefore the flow velocity will be limited by the inhibitor film integrity. Where at velocities more than 6 m/sec the integrity of the inhibitor film may be broken by turbulence and result in no protection. In addition corrosion allowance will be added to pipe thickness for assurance. Determination of corrosion allowance for deep-water pipelines should be made using the corrosion inhibitor availability model reflecting actual performance and realistic inhibitor availability, rather than arbitrary inhibitor effectiveness criteria.

- **Erosion**

For Duplex, SS or alloy material, the flowing velocity must be limited to:

- 100 m/s in single phase vapor lines and multiphase lines in stratified flow regimes (65m/s for 13% Cr material),
- 20 m/s in single phase liquid lines and multiphase lines in annular, bubble or hydrodynamic slug flow regime,
- 70 m/s in multiphase lines in mist flow regimes.

For Carbon Steel material:

- In case of continuous injection of corrosion inhibitor, the inhibitor film ensures a lubricating effect which drifts the erosion velocity limit. The corrosion inhibitor erosion velocity limit will be calculated taking into account the inhibitor film wall shear stress.
- In case of uninhibited fluid, the API RP 14 E recommendation should apply:

The flowing velocity must be maintained below the erosional limit:

$$Ve = \frac{1.22C}{\sqrt{\rho_m}}$$

V_e: erosional velocity in m/s

ρ_m: Gas/liquid mixture density at flowing conditions in kg/m^3

The multiphase mixture density ρ_m can be determined by the following equation:

$$\rho_m = \frac{m_m}{\frac{m_L}{\rho_L} + \frac{m_G}{\rho_G}}$$

Where:

m_m :total mass flow rate, kg/sec ($m_m = m_L + m_G$)

m_L :liquid mass flow rate, kg/sec

m_G :Gas mass flow rate, kg/sec

C: empirical constant equal to 122.045 to 152.556 for continuous flow. “C” value up to 244 can be considered on peak flow rate only in case of absence of abrasive (solid) particles such as sand.

It is widely accepted in the industry that above simple criterion is inadequate, where it is for clean service (non-corrosive and sand free) and the limits should be reduced if sand and the limits should be reduced if sand or corrosive conditions are present.

Note:

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

4.5 Shell and Tube Heat Exchangers

4.5.1 Design Standard

Heat Exchangers shall be designed according to TEMA class “R”.

4.5.2 Over Sizing

The following overdesign factors to be considered for the heat exchangers:

1. Overhead condensers: to take into account the greatest of either 10% of the estimated maximum operating duty or the duty increase of the corresponding reboiler.
2. To take into account the risk of under sizing of heat recovery systems (i.e. feed-effluent, feed bottom), the following over sizing to be specified:
    - Effluent cooler (or feed preheater): 10% of cooler duty (or Preheater duty) or 5% of feed / effluent exchange duty, whichever is greater.
    - Reboiler: 5% of feed bottom exchange or 10% of reboiler duty whichever is greater.
    - Bottom cooler: 10% of cooler duty or 5% of feed / bottom exchange duty, whichever is greater.
    - Pump around exchangers: 10% on flow rate.
    - Steam turbines condensers: greater of 10% on duty or 10% on flow rate.
3. For all other cases 10% overdesign on the flow rate shall be considered.

4.5.3 Fouling Factors

The following gives some fouling factors for process and utility fluids which can be reviewed case by case. (IPS-E-PR-771 & TEMA)

Process fluids	m2.°C/W
Acid gas	0.00020

Process fluids	m2.°C/W
Sweet gas	0.00017
Liquid LPG	0.00020
Raw Feed Condensate	0.00035
Stabilised Condensate	0.00020
Process water	0.00035
Stripped water	0.00030
Glycol	0.00040
Refrigerant (propane)	0.00015
Licensed units fluids	by Licensor
Utilities	m2.°C/W
Chilled water	0.00020
Potable water	0.00020
Saturated steam/LP condensate	0.00017
BFW/Demineralised water	0.00017
Nitrogen	0.00017
Instruments air	0.00017
Fuel gas	0.00017
Diesel	Light:0.00030 Heavy 0.00035

4.5.4 Fouling Factors for Plate Exchangers

For Plate & Frame Heat Exchangers Actual fouling resistances, if known, should be given. In the absence of applicable data, a minimum of 10 % fouling margin should be considered as per API 662.

4.5.5 Temperature Approach for Heat Exchangers

The temperature approach shall be optimized for heat exchangers but it shall not be smaller than:

- 5°C for TEMA type heat exchangers Except kettle types (shell and tube)
- 10°C for air coolers
- 3°C for plate type heat exchangers (Generally). For plate type heat exchangers (PHE) and the vendor shall confirm and specify the requirement on a case by case basis.
- 3°-10°C for kettle type

4.5.6 Shell & Tube Heat Exchangers Selection

All shell & tube heat exchangers shall be selected according TEMA instructions which correspond in practice to three general types as fixed Tube sheet, U-tube and Floating head.

Fixed Tube sheet (L, M, N-types) should be provided if:

- There is no overstressing due to differential expansion,
- Mechanical cleaning is not required for the shell side.
- Mechanical cleaning is not required for the tube side if U-tube is selected.
- Floating head should be provided if:
- Untreated cooling water
- Seawater
- All other streams having a fouling resistance greater than 0.000344 m2K/W

4.5.7 Nozzle Condition

The following rules are suggested as a guide for locating heat exchanger nozzles:

- Streams being heated or vaporized should flow from bottom to top, whether on the tube side or the shell side.
- Streams being condensed should flow from top to bottom, whether on the tube side or the shell side.
- The direction of flow for streams being cooled should be specified by piping with regard to economics concerns.

Where pressure drop is not a problem the minimum nozzle size is usually limited by the Maximum allowable fluid velocity. a safe upper limit for most fluids in terms of density times velocity squared (ρv2) is around 5953 kg/ms2 (4000 lb/ft s2).

- For shell side nozzles there is the additional problem of high velocity fluids impinging on the tube bundle. With reference to TEMA:

1. Impingement protection, which would usually be in the form of a square plate, 6 mm (1/4 inch) thick, tack welded to the tube bundle (an 'impingement plate'), to be provided for nozzle ρv2 greater than;
   - 2230 kg/ms2 (1500 lb/ft s2) for non-corrosive, non-abrasive, single phase fluids.
   - 740 kg/ms2 (500 lb/ft s2) for liquids, which are corrosive, abrasive, or at their boiling point
2. Impingement protection is always required for gases, which are corrosive and/or abrasive.
3. Impingement protection is always required for saturated vapors and for two phase mixtures.
4. Shell or bundle entrance or exit flow area (whether impingement protection fitted or not) is to be such that the ρv2

4.5.8 Tube Side Fluid Velocity

Design average velocities in tubes for cooling water shall be kept within the under mentioned operating range. Velocities for fluids other than water in the tubes shall be such to create a turbulent flow but in no case shall exceed 3 meters per second.

Tube Material	Average Speed (m/s)	
	Min.	Max.
Carbon steel	0.9	1.8
Admiralty	0.9	1.8
Aluminum brass	0.9	2.4
Aluminum bronze	1.5	3.1
Cupronickel	1.5	3.1
Aluminum	0.9	3.1
Monel	1.8	3.1
Stainless steel	2.4	3.1

4.5.9 Safety Considerations

When the design pressure of the low pressure side is less than 10/13 of the design pressure of the high pressure side, the design pressure of the low pressure side might be increased to at least 10/13 of the design pressure of the high pressure side.

4.6 Air Coolers

4.6.1 Over Sizing

Air coolers: 10 % on maximum duty and flow rate

4.6.2 Air Cooler Type

Two general classifications of air cooler fans are:

- Forced draft type where air is pushed across the tube bundle.
- Induced draft type where air is pulled through the bundle.

For advantages of Forced or Induced type selection refer to IPS-E-PR-785, APPENDIX D.

4.6.3 Number of Fans

At least two fans shall be provided for each bay. Any deviation shall require prior Approval from Client. Each fan shall be sized such that the area occupied by the fan is at least 40% of the bundle face area served by that fan. The fan diameter shall be at least 1 m (3 ft).

4.6.4 Control of Air Flow

a) Control of air flow is required for one and / or more of the following reasons:
b) Where a close control on heat removal rate is required.
c) Where the possibility exists that a portion of the fluid being cooled or condensed freezes as "frost" on the inside tube surface.
d) Where fluid being cooled may, if overcooled, become so viscous that flow will decrease in coldest tubes and possibly fluid will be congealed on tube walls. This results in increasing of pressure drop, insufficient cooling of fluid through open tubes, and in some cases loosening of tube rolls and subsequent leaking.

4.6.5 Chemical Cleaning Connections

If chemical cleaning maintenance is specified, connections shall be provided according to the following:

- Connections shall be installed only in nozzles DN 100 mm (NPS 4 in.) and larger. For smaller nozzles, connections shall be made in the attached piping.
- The minimum size connection shall be DN 50 mm (NPS 2 in.).
- Connections shall be installed horizontally.
- For bundles in series or series-parallel arrangement, only one chemical cleaning connection need be provided in the inlet nozzle and one in the outlet nozzle of each series group.

4.6.6 Air-Side Design

Environmental factors pertinent to design of the exchanger shall be supplied to the Vendor according to IPS-E-PR-785, Table 1. These factors shall be taken into account in the air-side design.

Air coolers shall be designed for summer and winter conditions, as specified in the job specifications.

For winter design conditions, the minimum tube wall temperature shall be at least 10ºC higher than the pour point temperature for both normal and minimum design.

Pressure drops shall not exceed the maximum allowed values specified. These include total pressure drops across nozzles, headers and tubes.

Fouling factor on the air side of exchangers shall be 0.00035 m2.°C/W (0.002h.ft2. °F/Btu).

4.6.7 General Consideration

Air cooling shall be maximized.

For determination of fan H.P. rating, the calculated static pressure drop over the tube bundle at

Maximum design temperature shall be increased by 20%.

Omit vent and drain connections for "Reactor Condensers" (or coolers) on Hydrogen services.

Manifold piping requirements for single phase and two phase inlet fluids of air coolers shall be according to the properly distribution of the flow and approved by the Client.

4.6.8 Heaters

- Gas burners only, without provision for the future installation of oil burners should be provided for the heaters and combination of oil and gas burners (dual purpose elements) for special cases may be investigated and confirmed by Client.
- Vertical firing is preferred for all heaters unless otherwise specified.
- A pilot burner shall be provided for each burner.
- Solid finned tubes according to API Standard 560 can be used in the convection section of gas fired heaters only. For oil fired heaters bare tubes shall be used. However, in gas fired heaters, minimum two rows in bottom of convection section shall be bare tubes.
- For all heaters, maximum reasonably attainable heater efficiency shall be approached.
- Minimum stack height above grade shall be calculated such that to minimize pollution in accordance with the latest European standards. Moreover, furnace stacks shall reach at least 7 meters above the highest platforms located within 15 m, which may require attendance during operation. Individual stack supported from each heater shall be provided unless otherwise indicated on the heater data sheet.
- Low NOx emission burners shall be used.
- Over sizing shall be considered as following:

- Feed heater: 10% of heater duty or 5% of feed /effluent exchange duty (if any), whichever is greater.
- Reboiler heater: 10% of reboiler duty or 5% of feed / bottom exchange duty (if any), whichever is greater.
- Other heaters: As per process requirements or 10% of heater duty, whichever is greater.
- Snuffing steam connections and lines shall be provided for all heaters.

4.6.9 Burners and Fuel System

- Provision shall be included so that fuel atomizing steam and combustion air to each burner can be manually adjusted from normal operating platforms 25% to 150% of design rates.
- All burners are to be equipped with pilots and suitable strainers in each pilot line. Mesh shall be 18/8 S.S.
- A minimum of three burners shall be used for all fired heaters.
- When combination of oil and gas burners shall be provided, it must be capable of firing any combination of fuel gas, and liquid fuels.
- Multiple burners are preferred on all heaters.
- Burners shall be designed if possible to permit automatic operation from 25 to 125% of design heat release, if practical greater turn-down ratios are desirable.
- Welded U bends for heaters are not acceptable.
- Calculated and guaranteed heater efficiencies shall be based on the design duty, fuel lower heating value, ambient temperature of 25 ºC and 15 percent excess air for fuel gas or 25 percent excess air for fuel oil.
- Oxygen analyzer shall be specified for all heaters.

4.7 Pumps

4.7.1 Overdesign

Over sizing factors (based on the maximum operating flow rate) shall be as follows:

Pump	Overdesign factor
Unit Feed	10%
Feed Booster	10%
Unit Product	10%
OVHD Reflux	20%
Pump-around	20%
Reboiler Feed	20%
Boiler Feed Water	10%

Pump	Overdesign factor
Chemical Injection	20%
Metering Pump	20%
Reciprocating and Rotary pumps	15%
Surface condensers condensate	10%
All other Pumps	10%

To be noted that:

1. When a non-automatically controlled minimum flow protection has been installed, the permanent re-circulation flow (if required) must be added to the net process flow.

2. Normal and rated flows will be identical in such instance as:

   - Intermittent service pumps: sump pump
   - When the pump has been overrated to allow for a centrifugal type and if overrating is >10%
   - Re-circulation flow such as for product loading lines or through amine filtration system.

4.7.2 Automatic Start

Automatic start is determined considering the following rules.

- Personnel safety: for example flare KO drum pump will be started in order to avoid liquid in flare tips. In that case, considering the non-continuous operation of flare drum pumps, the start of the spared pump can be performed by LSH or by DCS logic.
- Equipment safety: for example BFW pump will be started in order to protect the steam drum and the steam coil.
- Severe process upset: pump generating by its shutdown one process unit trip or generating an off spec product shall be spared automatically.

Typical critical services are:

1. Fired reboiler circulating pumps,

2. Steam generation circulating pumps,

3. Refrigeration pumps,

4. Surface condenser condensate pumps,

5. Compressor lubes oil and seal oil pumps.

6. Unit Feed Pumps

7. Distillation tower reflux pumps

8. Boiler Feed Water Pumps

Isolating valves of the pumps with automatic starts shall be locked open or car seal open.

4.7.3 Suction Line Equivalent Length

Equivalent length may be calculated in two ways for the suction lines, either the user inputs straight line length and fitting factor and the Le is calculated by multiplying the two, or the Le is estimated from the pipe diameter d (inches) as follows:

- Pumping temperature < 150° C — Le = (8d+30) m
- Pumping temperature >= 150° C — Le = (12d+30) m

4.7.4 Discharge Line Equivalent Length

For pump discharge lines when fittings and valve count are not available, a reasonable estimate of the total equivalent length can be made by multiplying the approximate run of actual pipe by the multiplying factor.

Line sizes, diameter	Approximate line length m		
	30	60	150
3” NPS and smaller	1.9	1.6	1.2
4” NPS	2.2	1.8	1.3
6” NPS	2.7	2.1	1.4
8” NPS and greater	3.4	2.4	1.6

4.7.5 Net Positive Suction Head Available (NPSHA)

NPSHA is calculated by deducting the vapour pressure of the fluid at pumping conditions from the Suction Pressure and converting it to pressure head in terms of liquid column.

Process engineers shall include a Safety Margin of 1.0 m in the NPSH calculated for:

1. All boiling point fluids either single or multi-component.
2. Fluids that contain dissolved gas.
3. Foaming fluids.

In the case of boiler feed water pumps, a margin of 2.0 m shall be used.

The static head used in calculating the NPSH shall be taken from either the tangent line or bottom invert line in the suction vessel to one of the following:

- The center line of a horizontal or rotary pump.
- The suction impeller on a vertical centrifugal pump.

The design of suction lines from storage tanks shall be based on the NPSH taken from the lowest specified level in the tank at which rated pump capacity is required.

Suction line sizing for reciprocating pumps shall take into account acceleration head.

NPSH calculation considerations:

- The suction line losses shall be based on rated flow capacity of the pump. Pressure drop through any permanent strainer should be 0.61 m Liquid head for NPSHA calculations.
- Fouled condition pressure drop such as vacuum heater / Vis-breaker heater / filter should be added into the variable system pressure drop.
- For sub cooled liquids, the source pressure shall be at the maximum operating pumping temperature.
- For horizontal centrifugal pumps, the elevation of the pump centerline shall normally be as following:

Capacity (m3/hr)	Elevation (m)
Up to 45.4	0.76
45.4 – 227.1	0.91
227.1 - 2271	1.07
2271 - 4542	1.37

4.7.6 Pump Shut-Off Pressure

Equipment which could have to bear the shut-off pressure of a pump in case of a valve closing (either control valve or block valve) shall have a design pressure equal to or higher than the shut-off pressure of the pump. Pump shut-off pressure shall be estimated according to the following criteria, whichever is greater:

Design pressure of the suction vessel plus liquid height at vessel HLL at pump suction + pump differential pressure at rated flow of the pump.

Normal suction pressure plus liquid height at vessel HLL at pump suction + 120% of pump differential pressure at rated flow of the pump.

Shut off pressure of the centrifugal pumps shall be rechecked when Vendor's characteristic curves of selected pumps are available. If it exceeds the estimated.

Pump shut-off pressure, the design pressure of downstream equipment shall be revised accordingly.

Generally no PSVs are provided at the discharge of centrifugal pumps and the design pressure shall be the discharge pressure of the pumps at no flow with the maximum suction pressure and the maximum specific gravity.

Reciprocating and Rotary Positive Displacement Pump Max. Pressure: Excessive discharge pressures from positive displacement machines can be attained if a discharge valve is inadvertently closed. Therefore, safety valves are mandatory for this class of machines.

Maximum allowable pressure is defined as the highest pressure which can occur in the pump when bypassing the full of the pump through its relief valve with an accumulation of not more than 10% above the maximum set pressure.

4.7.7 Pump Cooling Water Requirement

Cooling water, preferably fresh, is used to cool bearings, stuffing boxes, pedestals and glands to safe temperature levels.

The coolant rate varies with temperature and to some extent with pump size. For design purposes, the following rates shall be used:

Casing Design Temp (°C)	m3/h
120	0.25-0.75
120-250	0.75-1.5
250+	1.5-2.5

4.7.8 Equipment Pressure Drops

The following typical pressure drops shall be used in line size calculation when the actual pressure drop data are not available:

Typical Equipment Pressure Drops (bar)	
Coalescer	0.7
Desiccant Drier	1.0
Desalter	1.7-2.7
Exchangers:	
S&T, Double-pipe & Air Cooler	0.35-1.0
Box Coolers	3.5
Fixed Bed Reactors	1.4-3.5
Flow Orifice	0.25
Orifice Mixer	0.35/plate
Rotary & Turbine Flow Meters	0.4
Metering Package	1.0

4.7.9 Sparing Philosophy

All pumps or compressors, where the failure would cause plant shut down or unsafe conditions should have spare installed equipment. One spare unit of pump or compressor should be considered unless stated otherwise.

Note: Main cooling water pumps shall have 50% installed spare.

4.7.10 Safety Valve Consideration on Pumps

Safety relief valves shall be provided in the following cases:

- On discharge of positive displacement pumps.
- On discharge of centrifugal pumps to protect downstream equipment from overpressure based on pump shutoff pressure.

4.7.11 Compressor, Fans and Blowers

Following criteria shall be applied.

The variations of gas compositions, molecular weight, specific heat ratio etc., and the operating conditions (mainly suction pressure and temperature) shall be taken into account to determine the sizing case, and shall be listed on the Process Data Sheet.

4.7.12 Capacity

The volume flow rate capacity shall be determined by the compressor manufacturer from the data sheet provided. The process engineer shall determine the mass flow rate based on minimum, normal and maximum flow conditions.

The compressors over sizing shall be as follows:

- Make-up: 10% plus spill back rates (if any).
- Recycle: depends upon the process but not less than 20% on flow rate.
- Gas quench: 20% (minimum)
- Product gas and other services: 10%

4.7.13 Suction Pressure

Suction pressure is the pressure at the suction flange of the compressor and not before filters, pulsation dampers, etc. The suction pressure must be accurately specified.

4.7.14 Suction Temperature

Suction temperature is to be accurately specified since it is directly related to the volume of gas at suction conditions, the discharge temperature, and the horsepower requirements. It is important for the vendor to know the minimum and maximum temperatures for proper compressor design and selection of correct driver rating

4.7.15 Molecular Weight

Molecular weight is an important consideration in the design of a centrifugal compressor. When this or any type of compressor is to be used in multiple services, the vendor is to be supplied with data on the molecular weight of all the gases.

4.7.16 Specific Heat Ratio

The specific heat ratio is also an important consideration in the design of centrifugal and reciprocating compressor as it affects both power and efficiency of the machines. It should be clearly documented what the basis for the stated Cp/Cv ratio e.g. ideal or polytropic etc.

4.7.17 Compressor Power Estimation

Compressor power estimates shall include gear losses. When a compressor is to be used in vacuum or refrigeration service, peak driver load may be required during start-up and a footnote to this effect is to be added to the specification form. The final determination of compressor power requirements and discharge gas temperatures is part of the vendor’s responsibility.

4.8 Gas Composition

This is to be supplied by the process engineer and is to be expressed on a wet basis if the gas contains moisture.

4.8.1 Discharge Temperature (Maximum Allowable)

This is to be supplied by the process engineer when a known process limitation exists. Discharge temperatures are limited by gas reactions, e.g. polymerization or in the case of air compressors with the lube oil, safe lubrication temperatures. Some compressors are limited by mechanical considerations and these will be defined by the compressor vendor.

4.9 Corrosive Compounds

Corrosive compounds in the gas (such as sulphur oxides, hydrogen sulphides. acidic compounds, chlorides, etc.), are to be specified by the process engineer as these may determine the selection of materials or the compressor manufacturer.

4.10 Start-Up Considerations

Start-up methods are to be considered by the process engineer since items such as anti-surge control systems, bypass lines, valve lifters and pockets on reciprocators, etc., are involved. In addition, compressors generally require a running-in period during which time an alternative feed gas may be used if air is to be used for running-in, then suitable vents, etc. may be an additional requirement.

4.11 Pressure Safety Relief Valves

4.11.1 GENERAL

Pressure relief valves shall be provided as indicated on the P&IDs, required by local authorities, applicable pressure vessel code and as recommended by the referenced codes.

4.11.2 Accumulation

The accumulation used in calculating sizes of relieving devices shall be as follows:

Service	Accumulation
Steam service where ASME power boiler code applies	3 %
Gas and vapor service and liquids except as note 1 and 2 below:	10 %
Note 1 : Fire exposure on unfired pressure vessels	21 %
Note 2: Liquid for thermal relief on pipelines and pump discharges.	25 %

4.11.3 Application

Single pressure relief valve shall be specified for each service unless:

- Multiple valves are necessary because the required capacity cannot be provided in a single valve or are preferred for a particular service.
- Dual valves are required in accordance with the American Society of Mechanical Engineers (ASME) for Boiler and Pressure Vessel Code, Section.

Spare relief valve: a spare relief valve is always installed except:

- If the protected equipment can be isolated and de pressurized / drained without production shutdown.
- If the installed relief valve is only used for fire case, in that case the spare relief valve is stored in warehouse (note on PID to be added).
- For both cases, isolation with bleed is required.

a) Installed spare PSV shall be considered at steam let down stations (Downstream of pressure control valve).
b) For steam service governed by ASME Boiler and Pressure Vessel code, section I, the use of inlet or outlet block valves is not permitted.
c) All pressure vessel pressure relief valves (except as noted in this item) should be equipped with L/O blocked valves at inlet & outlet and by-pass line (when discharging to closed relief header).
d) Criteria for discharging PR valves to closed systems shall be as follows:

- Pressure Relief (PR) valves handling hydrocarbon liquid materials or partially liquid at the valves inlet.
- PR valves normally in vapor service, but which under any single contingency may discharge flammable, corrosive or hazardous liquids.
- PR valves located in the vapor space of partially liquid filled vessels, which could rapidly fill with liquid during a plant upset.
- PR valves in toxic or polluting vapor services where discharge to the atmosphere would result in the calculated concentration at the property line or at any working

area (either at grade or an elevated platform) exceeding the Threshold Limit Value (TLV).

- Release of flammable vapors which, if discharged to atmosphere, would in the event of inadvertent ignition result in radiant heat intensities in excess of the permissible exposure level for personnel.

e) Criteria for discharging PR valves to the Atmosphere shall be as follows:

- The fluid handled must be all vapors at the valve inlet.
- The valve must not fall into any of the criteria noted in above sections.
- The density of the released gas is lower than the air density.
- Such disposal is not in conflict with the current regulations concerning pollution and noise.
- Gas released is non-flammable, non-hazardous and non-condensable.
- The gas velocity at the emission is higher than 150 m/sec.
- The gas does not condense at the ambient temperature.

f) Blow down System for Liquid Relief Stream Disposal for voluntary and involuntary liquid discharges shall be:

- To onsite dedicated liquid blow down drum (separately for each case) if the material discharged contains solvent to be recovered may congeal at low temperatures in closed relief system (flare).
- To oily water sewers only if the material will not cause hazardous conditions and/or will not be congealed at the ambient conditions. The liquid discharged to an oily water sewer shall be non-volatile and non-toxic. The required liquid relief rate shall be within the oil removal capability of the oily water treating system.
- To pump suction if pump will not overheat or can withstand the expected temperature rise. Required liquid relief shall discharge to an upstream liquid reservoir from which the pump takes suction. The liquid relief may discharge directly to the pump suction line if sufficient cooling is provided to prevent a temperature rise of the liquid recycled through the pump when the safety/relief valve opens or when a constant displacement pump is used.

4.12 Pilot Operated Pressure Relief Valves

Pilot operated pressure relief valves shall be specified where:

a) Process operating pressures are close to set pressure of the pressure relief valve.
b) The relieved service fluid is corrosive.
c) When the pressure drop to the inlet of the safety relief valve is greater than 3% of the set pressure (in this case, the remote pressure pickup type should be used).

d) Where the built-up back pressure and variable superimposed back pressure does not exceed 50% of the set pressure.

In general, valves of pop-action type are used. Where minimum loss of fluid or stable operation is required during relief, valves of modulating action type are to be considered.

The pilot operated pressure relief valve design should be such that, in the event of failure of an essential part of the pilot, the main valve opens automatically at the set pressure and discharge its full rated capacity.

4.13 Rupture Discs

Rupture discs shall generally not be used when a safety valve could fulfill the demands.

However, for the following cases, a rupture disc may be considered:

a) for secondary relief
b) If 100% tight shut off is required, rupture disc may be located upstream of the safety valve
c) If fluid is corrosive and standard materials for safety valve trim are not sufficient, a rupture disc of special material or with a coating may be located upstream of a safety valve
d) If over-pressure in liquid systems may rise too fast to open safety valve in time
e) If total de-pressurization is required after relief

A rupture disc shall be provided with a Pressure Switch, suitable for remote alarm in the control room when used as primary or secondary relief.

5.0 Flare and Cold Vent Lines Sizing Criteria

5.1 Lines Upstream Relieving Devices

PSV's:

For the line sizing, the maximum capacity of the PSV (recalculated with the selected orifice), shall be considered even if this figure exceeds the actual maximum flow rate due to process limitations.

ΔP between the protected equipment and the PSV< 3% of PSV set pressure (API RP 520 Part II)

Inlet line diameter $\geq$ PSV inlet diameter

$\rho V^2 \leq 25\ 000$ kg/m/s2 for line $\leq$ 2”

$\rho V^2 \leq$ 30 000 kg/m/s2 for P $\leq$ 50 bar g

$\rho V^2 \leq$ 50 000 kg/m/s2 for P > 50 bar g

Minimum line size 2"

ρV^2 criteria are the same as for PSV's

5.2 Line Downstream Relieving Devices

Flare and cold vent headers and sub-headers:

- Minimum line size 2"
- Back pressure to be compatible with the protected equipment
- Velocity and ρV^2 :

SINGLE PHASE (GAS AT THE RELIEF DEVICE INLET):

- Intermittent flow:
  - ❖ Lines downstream relieving devices and sub-headers: 0.7 Mach maximum and ρV^2<150000 kg/m/s^2 considering the maximum capacity of the relieving devices even if this figure exceeds the actual maximum flow rate due to process limitation and the relevant occurrence.
  - ❖ Headers : 0.7 Mach maximum and ρV^2 < 150 000 kg/m/s^2 considering the maximum flow rate due to process limitations and for the relevant occurrence, however a velocity of 0.8 Mach could be accepted for a long straight line without elbows and connections (e.g stack, lines on bridge)
  - ❖ For a ρV^2 > 100 000 kg/m/s^2 vibration and line support studies are required.

- Continuous flow:
  - ❖ Velocity < 0.35 Mach and $\rho V^2 \leq$ 50 000 kg/m/s^2

MULTIPHASES (2 phase flow at the inlet of relieving device):

- Velocity $\leq$ 0.25 Mach and $\rho mvm^2 \leq$ 50 000 kg/m/s^2

For ρm and Vm definition see below:

Where:

$$\rho m = W/((WL/\rho L)+(WV/\rho V)) \text{ in kg/m}^3$$

W=WL+WV= Total rate in kg/h ρL = liquid density in kg/m3

WL=liquid flow rate in kg/h   ρV = vapour density in kg/m^3

WV=vapour flow rate in kg/h

And the apparent fluid velocity Vm expressed as:

Vm=4W/(3600ρmπ.D2) in m/s

D=internal diameter of the line in m

The sizing shall be done for the line downstream each device with the built-up back pressure for the corresponding occurrence and not with the maximum built-up pressure for the maximum flow rate to the flare or cold vent. The same shall be applied for the header and sub-headers.

5.3 Flare Drum Sizing

For flare drum and cold vent drum, the sizing shall follow API RP 521 method with the following droplets size in microns:

- Vertical flare or cold vent onshore : 600 μm
- Vertical flare or cold vent on platform: 150μm
- Inclined boom offshore > 45º from horizontal: 150μm
- ≤ 45º from horizontal: 400μm
- Remote flare or cold vent offshore: 600μm

5.4 Purge Gas

- N_2 Purge Gas has been considered

The purge gas is provided to prevent:

- Air ingress into the flare or cold vent stack in order to avoid to form an explosive mixture in the stack or header
- For a flare, the risk of burn back which might induce a quicker deterioration of the tip.
- In the case of cold vent, purge gas is not compulsory provided the piping can withstand the surge pressure caused by an explosion.

Since it is recognised that flare suppliers used to underestimate the amount of purge gas, flare suppliers shall be requested to guarantee the purge gas flow rate to avoid air ingress and burn back.

The purge can be eliminated if a liquid seal is installed near the base of the stack.

The purge gas rate can be greatly reduced if buoyancy or velocity seals are installed right upstream of the tip.

Without Seals Case

To avoid air ingress into the flare stack, the purge flow rate shall be calculated as follows:

$Q = 31.25\ D^{3.46}\ K$

Where:

Q is the purge flow rate in normal cubic meter per hour,

D is the flare stack diameter in meters,

K is a parameter depending on the gas composition to be calculated as follows:

$$K = \sum_{1}^{n} C_i^{0.65}\, k_i$$

Where

C_i is the volume fraction of component I,

k_i is a constant depending on the component i. The following give typical values:

- hydrogen : k_i = 5.783
- helium : k_i = 5.078
- methane : ki = 2.328
- nitrogen (no wind) : ki =1.067
- nitrogen (with a wind speed about 7 m/s) : ki =1.707
- ethane : ki = − 1.067
- propane : ki = − 2.651
- CO2 : ki = − 2.651
- $C_4^+ : k_i = -6.586$

The purge gas flow rate to avoid air ingress into the stack is usually too low to avoid back burning of the tip which is known to reduce the service life of the tip and as such should to be avoided as much as possible. The purge gas rate to avoid burn-back is indeed much greater and depends somewhat upon the tip itself: it shall therefore be requested from the tip supplier.

As a first approach, the corresponding burn-back velocity b U (m/s) can be estimated using the following formula:

$$U_b = \frac{(\frac{D}{Mw})^{0.75}\sqrt{LHV}}{15.101})$$

Where:

D (m) is the flare stack diameter,

MW (g/mol) is the molecular weight of the purge gas,

LHV (MJ/kg) is the purge gas Lower Heating Value.

Note 1: For sonic flare, the tip internal diameter is taken as the equivalent diameter corresponding to the exit gas area.

When fuel gas is used for purge gas, the source of purge gas shall be common to the fuel source to the pilots in order to avoid a loss of purging while pilots remain in service.

The heaviest available gas should be preferably used as the normal source of purge gas in order to minimize the vacuum pressure in the flare header for an elevated flare or cold vent. However, the heavy gas tends to give some smoke.

Sometimes, nitrogen could be used as purge gas. In these situations, pilots able to run even in inert gas atmosphere shall be installed (to be studied on a case by case basis with the flare tip supplier).

With Seals Case

Buoyancy seals can help reduce the purge rate needed to avoid air ingress into the stack to values as low as 0.003 m/s.

Velocity seals can help reduce the purge rate needed to avoid air ingress into the stack to values in the range (0.006 m/s and 0.012 m/s).

6.0 Pig Launcher and Receiver

A pig launcher is required at the upstream of the section and a pig receiver at the downstream end. The distance between these pig traps depends on the service, location of pump or compressor stations, operating procedures, and the material used in the pig.

6.1 Barrel, Reducer and Spool

- The spool piece shall have the same nominal size as the connecting pipeline, flanged or beveled end, as specified in requisition.
- The barrel shall have a sufficient length to accommodate three pipeline cleaning pigs.
- Barrels for use in gas transmission system shall be designed in accordance with ANSI B 31.8 and those for use in liquid hydrocarbon transmission shall be in accordance with ANSI B 31.4.

- A thermal relief line shall be provided at locations where shut-in pressure of trapped fluid could exceed the design pressure.
- The reducer should be eccentric for launcher and be concentric for receiver.

6.2 End closure

The end closure shall conform to the general requirements of ASME VIII division 1 section UG-35(b) (quick actuating closures). Attention is drawn to the requirements for a fail-safe design of the opening mechanism, specifically; the failure of any part of the opening mechanism shall leave the closure closed rather than open.

- The end closure shall be of the quick acting type, lever or hand wheel operated, and hinged vertically.
- The quick acting design should allow opening and closing by one man in approximately one minute, without the use of additional devices.
- The design of the end closure shall be suitable for permanent location in open environment.
- Closure 18" and larger shall be hand wheel operated.
- The activation of the seals shall be such that the fluid within the pig trap at any pressure between 1 bar (abs) and the pig trap design pressure is sufficient for this purpose.
- End closures with exposed screw expanders or captive ratchet braces should not be used, because of the high maintenance requirements and the non-fail-safe aspects of some opening mechanism designs.
- The end closure shall have the following safety devices:

  - A pressure locking device to prevent opening of the door when the pig trap is pressurized.
  - A safety bleeder that when released will alert the operator to a possible hazard unless pressure in the pig trap is relieved completely. Opening of the door shall not be possible unless the bleeder is released. Engaging the bleeder shall only be possible when the closure is closed. The bleeder shall be designed such that there is no risk of blockage.

7.0 PRESSURE AND THERMAL RELIEF SYSTEM DESIGN CRITERIA

7.1 Causes of over-pressurization

The faults listed below can lead to over-pressurization; they shall be taken into account for the design of pressure protection and relief systems.

- Blocked outlet, inadvertent inlet valve opening from a high-pressure source, check-valve malfunction

- Loose of power, mechanical failure of fans, etc.
- Fire, excessive heat input, unsteady process, etc.
- Utility failure and / or loss of control (instrument air, power, etc.), uncontrolled depressurization
- Transient pressure surge
- Gas blow-by

Process facilities shall be designed to minimize the probability of occurrence of these causes. The rules and principles contained in this document focused on the mitigation devices to minimize the effects of an over-pressurization.

7.2 Pressure protection systems

Three main approaches will be considered for pressure protection systems:

- Full pressure rated mechanical design: the system design pressure exceeds the maximum possible pressure at design temperature, included in case of process upset, and with due allowance for corrosion being made.
- Relief systems: the system design pressure includes a safety margin above the system maximum operating pressure but, in case of process upset, the pressure prevailing in the system can exceed the design pressure. It is therefore fitted with devices actuated by the system static pressure and designed to open in case of upset conditions.

The pressure system in the plant shall normally be protected following the API 520/521 recommendations.

Storage tanks: the atmospheric and low-pressure storage tanks shall meet the venting requirements of API 2000.

8.0 CRITERIA FOR INSTALLATION OF RELIEF DEVICE

Any vessel shall be equipped with a protection device sized for fire or other contingencies. Pressure relief may consist in one or a combination of PSV, TSV, and rupture disk.

Table-4: Criteria for installation of PSV's and TSV's

	PSV (Process)	PSV (Fire case)	TSV
Piping that cannot be isolated (4): - all fluids	No	No	No
Piping that can be			

	PSV (Process)	PSV (Fire case)	TSV
isolated (4) but cannot be exposed to fire: - flammable gas - liquid HC - crude oil	No (1) No (1) No (1)	No No No	No Yes (6) (5) Yes (6) (5)
Piping that can be isolated (4) and can be exposed to fire: - flammable gas - liquid HC - crude oil	No (1) No (1) No (1)	If > 3 tons (7) If > 2 tons (7) If > 2 tons (7)	No Yes (5) Yes (2) (5)
Vessel that cannot be isolated (4): - all fluids	Yes (3)	No	No
Vessels that can be isolated (4) but can not be exposed to fire: - all fluids	Yes (3)	No	No
Vessels that can be isolated (4) and can be exposed to fire: - all fluids	Yes (3)	Yes	No

Notes

Note 1: assuming piping is protected against the maximum possible pressure under upset conditions (full pressure rated design or PSV installed upstream of it). Otherwise a process PSV is required.

Note 2: the installation of TSV's on piping handling liquid hydrocarbon and crude oil shall be assessed case by case, based on service criticality.

Note 3: as per ASME SECT VIII.

Note 4: any type of isolation, automatic or manual valves.

Note 5: a TSV is not required if a PSV (process or fire case) is already installed.

Note 6: a TSV is required if ambient temperature conditions and / or sun radiation may lead to a prevailing pressure exciding piping design pressure.

Note 7: Mass of encapsulated liquid between isolating valves

Note 8: Piping or vessels shall be considered as being possibly exposed to fire if more than 10% of their external surface can be either engulfed in a pool fire or submitted to a jet fire likely to last more than 3 minutes.

In case of toxic substances, the threshold criteria for the installation of PSV fire case and/or TSV may be made more stringent. This issue shall be assessed on a case by case basis.

8.1 Relief device setting

The setting points and other characteristics of the relief device shall be as per API RP 520 for process equipment, utilities and pressure vessels for storage. API ST 2000 recommendations shall apply for liquid petroleum production tanks.

8.2 Relief system configuration

8.2.1 Number of relief valves

The number of relief valves fitted onto equipment is not driven only by safety related concerns. However, the following rules shall apply on top of other considerations:

- For process pressure safety valves, if n is the number of PSV necessary to ensure 100% relief capacity, then n+1 PSV shall be installed.
- Where for capacity reasons, several pressure relief valves must be provided in parallel, the set pressure should be staggered to avoid chattering during relief. The difference between set points shall be less than 5% of the design pressure.
- A single TSV shall be provided for pipe work thermal relief.

8.2.2 PSV installation

- **Isolation**

  The following rules shall apply:

  - n+1 sets of pressure relief valves shall be associated with car seal procedures for both upstream and downstream isolation valves.
  - Where downstream isolation valves cannot be avoided, they shall be locked open in normal operating conditions.
  - Isolation valves shall be full bore.

- **Location**

  - PSV will be installed directly on vessel.
  - PSV bypass line to be in 2” whatever the vessel capacity is.

8.3 Design basis for flare system

8.3.1 General

The function of the flare system is to collect and burn all gases that are vented from the other units due to emergency operations. Any continues venting operation to flare is avoided.

Two flares will be provided for overall plant

- One LP flare stack

8.3.2 Main characteristics

Flare systems will be provided:

- LP flare (subsonic) is a disposal where the backpressure is maintained very low, for equipment operated at about atmospheric pressure such as production and degassing tanks.

There is one header for gathering vent gases. This is:

- LP flare gas header (fluid symbol LFL)

Pressure relieving system design shall conform to the requirements of IPS-E-PR-450, API-RP-520 and API-RP-521. In addition, IPS-G-ME-150, on "UNFIRED PRESSURE VESSELS" and ASME code section VIII should be consulted.

Some of the special considerations are discussed as follow:

- ➢ A detailed analysis shall be made on every possible situation in order to determine maximum loadings of relief system.

The probability of entirely unrelated failures occurring at the same time is remote, and need not to be considered.

- ➢ Fire proofing of selected equipment shall be considered in order to maintain the relief system's size within acceptable limit, if fire conditions are the controlling conditions of a particular relief system.

- ➢ If a pressure relief header is being sized for fire condition, the fire area shall be limited to 21m (70ft) in diameter within a single process unit.

- ➢ Flare line size above 24 inch in diameter shall be reviewed with project lead engineer.

- ➢ Relief valve header, which connects to a common system outside plot limits, shall be in accordance with IPS-E-PR-460.

- ➢ For liquid systems, proper thermal relief protection shall be provided.

- Installation of relief valves on equipment shall be without requiring the plant shut down during the removal of safety valves.
- Double relief valve system should be used for all equipment, which cannot be removed from service without plant shut down.
- Each valve shall have 100% capacity; with full bore inlet and outlet block valves mechanically locked in open position. When relief system on the above services consists of multiple relief valves, one additional relief valve with the same capacity shall be installed, in order, to permit replacement of any of the other valves.
- Whenever possible, relief valves shall be installed on equipment rather than associated piping.

8.4 Environmental Specifications

8.4.1 FLARE RADIATION LIMITS

The flare system design shall be such that maximum acceptable heat radiation (including solar radiation: 1010 w/m2) in case of flaring shall not exceed following table:

Maximum acceptable heat radiation in case of flaring

Location	Radiation level (kW/m^2)	
	Continuous Flaring	Emergency Flaring
Anywhere at ground level where people have access (1)	9.5	9.5
Between flares stacks and liquid burners	3.2	4.7
Free access road	3.2	4.7
Flare drum/ignition package	3.2	4.7
Process equipment	3.2	4.7
Storage	3.2	4.7
Restricted area	3.2	4.7
Permanently manned area	1.6	2.0

Note1: Exposure should be limited to a few seconds sufficient for escape only.

8.4.2 SURFACE TEMPERATURE FOR PERSONNEL PROTECTION

All exposed parts of equipment and or piping having a surface temperature above 55°C will be insulated or protected to avoid direct contact by personnel.

8.4.3 EMISSIONS TO ATMOSPHERE

The emissions reported in the tables are taken from «Engineering Standard for Air pollution Control» IPS-E-SF-860. The emissions are expressed as concentrations to facilitate monitoring. Dilution of air emissions or effluents to achieve these values is unacceptable.

All of the maximum levels should be achieved for at least 95% of the time that the plant or unit is operating, to be calculated as a proportion of annual operating hours.

Pollutant		
SH_2	10 mg/m^3	6.62 ppm
Carbon monoxide	187.5% mg/m^3	150 ppm
Sulfur oxide	----	800 ppm
Particles	50 (mg/m^3)	----
Hydrocarbons	20% opacity	----
Photochemical	20 mg/m^3	----
Nonphotochemical	300 mg/m^3	----
Nitrogen Oxides	432mg/m^3	210 ppm

Emission Standards

The odor shall not be offensive at receptor end. Hydrogen sulfide at the property boundary shall be less than 5mg/m3.

8.4.4 LETHAL SERVICE

The pressure vessel code requires classifying the equipment in accordance with lethal service. In order to carry out this classification, the mention “lethal service” will be specified on equipment data sheets handling a fluid with H2S content higher than 1000 ppm wt or where mercaptan level is exceeding 100 ppm in release gas .

Carbon steel and low alloy carbon steel equipment and pipe work in lethal service shall receive a Post Weld Heat Treatment.

8.4.5 NOISE LIMITATIONS

The noise level at the plant boundary shall be followed based on related standards.

The noise level at the plant boundary shall be followed based on related standards.

8.5 Burning Pit Criteria

Burning pit flares can handle flammable liquids or gases or mixtures of the two.

The burning pit is simply a shallow earth or concrete surfaced pool area enclosed by a dike wall, a liquid/vapor inlet pipe through the wall, and provided with pilot and ignitor. While the design basis flow is adequate for handling emergency releases, a more conservative approach is recommended for continuous flaring services, incorporating up to twice the calculated pit area.

Burning pit sizing should be accordance to “IPS-E-PR-460”.

9.0 ATTACHMENT:

Attachment 1: Line Sizing Criteria (4 Sheets)