

RP 44-1

OVERPRESSURE PROTECTION SYSTEMS

November 1992

Copyright © The British Petroleum Company p.l.c.

All rights reserved. The information contained in this document is subject to the terms and conditions of the agreement or contract under which the document was supplied to the recipient's organisation. None of the information contained in this document shall be disclosed outside the recipient's own organisation without the prior written permission of Manager, Standards, BP International Limited, unless the terms of such agreement or contract expressly allow.

BP GROUP RECOMMENDED PRACTICES AND SPECIFICATIONS FOR ENGINEERING											
Doc. No. RP 44-1		Issue Date November 1992	Latest Amendment Date								
Document Title OVERPRESSURE PROTECTION SYSTEMS (Replaces BP CP 14)											
APPLICABILITY Regional Applicability: International											
SCOPE AND PURPOSE This Recommended Practice presents specific requirements for overpressure protection systems, up to the relief device discharge flange, based on API RP 520 (5th edition) and RP 521 (3rd edition) and states BP requirements for documenting relief information to achieve BP group stated standards for safety and environmental considerations. It is partnered by BP Group RP 44-3 relief disposal systems, which specifies requirements for the safe disposal of relieved materials i.e. from the relief device discharge flange. The text book style is necessary to give the essential background to the very condensed API RPs for practical use, and to incorporate BP Business collective experience. Business specific versions of this may be the way forward when revisions become necessary.											
AMENDMENTS <table border="0" style="width: 100%;"> <tr> <td style="width: 15%;">Amd</td> <td style="width: 25%;">Date</td> <td style="width: 25%;">Page(s)</td> <td style="width: 35%;">Description</td> </tr> <tr> <td colspan="4"> </td> </tr> </table>				Amd	Date	Page(s)	Description				
Amd	Date	Page(s)	Description								
CUSTODIAN (See Quarterly Status List for Contact) Chemical Engineering, BPE											
Issued by:- Engineering Practices Group, BP International Limited, Research & Engineering Centre Chertsey Road, Sunbury-on-Thames, Middlesex, TW16 7LN, UNITED KINGDOM Tel: +44 1932 76 4067 Fax: +44 1932 76 4077 Telex: 296041											

CONTENTS

Section	Page
FOREWORD	ii
1. INTRODUCTION.....	1
1.1 Scope.....	1
2. OVERALL PHILOSOPHY	1
2.1 General	1
2.2 Reference to Other Codes	2
3. DOCUMENTATION.....	3
3.4 Register of Safety-Related Devices.....	4
3.5 Design Philosophy.....	5
3.6 List of Relieving Devices.....	6
3.7 Summary of Relief Loads	6
3.8 Fire Areas and Fire Loads	7
3.9 Principal Flare Loads.....	7
3.10 Relief Device Process Specifications.....	8
3.11 Header Pressure Profiles.....	8
3.12 Pipeline Equivalent Lengths.....	8
3.13 Control Valve/Restriction Orifice Data	8
3.14 Locked-Open Block Valves.....	9
3.15 Pump Impeller Data	9
3.16 Category 1 Trip Systems	9
3.17 Fire-Resistant Insulation	10
3.18 Distributed Control Loop Segregation.....	10
4. DESIGN PRACTICE.....	11
4.1 General	11
4.1.3 Catalysed Reactions	13
4.2 Relief Limitation by Design	16
4.3 Pressure-Limiting Instrumentation.....	16
4.4 Use of Reliability Analysis.....	18
4.5 Implication of Changes in Design Conditions.....	18
4.6 Emergency Depressuring.....	19
4.7 Vacuum Relief	20
4.8 Cold Service	20
4.9 External Fire Condition	21
4.10 Thermal Relief.....	23



5. DESIGN PROCEDURE FOR PROTECTION OF EQUIPMENT, TANKAGE AND PIPING	25
5.1 General Requirements	25
5.2 Shell-and-Tube Heat Exchangers.....	27
5.2.1 General	27
5.2.2 Burst Tube Condition.....	27
5.2.3. External Fire Condition	27
5.3 Air-Cooled Heat Exchangers.....	28
5.4 Centrifugal Pumps.....	29
5.5 Turbine Drivers.....	29
5.6 Main Transmission Pipelines and Associated Equipment.....	30
5.6.1 General	30
5.6.2. Design.....	31
5.6.3. Surge	31
5.6.4 Static Head	32
5.6.5 Fluid Expansion	32
5.6.6 Intermediate Stations and Terminals	32
5.6.7. NGL Pipelines.....	33
5.7 Process and Utility Piping.....	33
5.8 Atmospheric Storage Tanks	33
5.9 LPG/LNG Storage	33
5.10 Cascade Effects.....	34
6. PRESSURE RELIEF DEVICES	34
6.1 General	34
6.2 Pressure Relief Valves.....	34
6.2.1. Types of Pressure Relief Valve	34
6.2.1.1 Conventional Type	35
6.2.1.2 Balanced Type	35
6.2.1.3 Pilot-Operated Type.....	35
6.2.1.4 Pilot-Assisted Type	36
6.2.2. Use of Easing Gear	36
6.3 Rupture Discs	36
6.3.1. Types of Rupture Disc	36
6.3.2. Use of Rupture Discs	37
6.4 Sizing of Pressure Relief Devices	38
6.5 Installation of Pressure Relief Devices.....	38
6.5.1. Use of API RP 520	38
6.5.2. Isolation of Pressure Relief Devices.....	39
6.5.3. Location of Pressure Relief Devices	40
6.5.4. Inlet Piping to Pressure Relief Devices	40
6.5.5. Installation of Rupture Discs	41
7. RESPONSIBILITIES OF OWNER/OPERATOR.....	42
APPENDIX A.....	44
DEFINITIONS AND ABBREVIATIONS.....	44



APPENDIX B.....	46
LIST OF REFERENCED DOCUMENTS	46
APPENDIX C.....	49
REGIONAL ANNEX.....	49
APPENDIX D.....	50
APPENDIX D.....	51
RELIEF DESIGN GUIDELINES FOR LET-DOWN STATIONS.....	51
D1. INTRODUCTION	51
D2. DEFINITIONS	51
D2.1 .A Let-Down Station.....	51
D2.2 .A High Reliability Trip System	51
D3. RELEVANT STANDARDS	51
D4. LET-DOWN STATION RELIEF DESIGN CONSIDERATIONS	52
D4.1 .Design for Gas Breakthrough	52
D4.3 .Operating Conditions	52
D4.4 .Control Valve Sizing	53
D4.5 .Credit for Open Outlets.....	53
D4.6 .Credit for Operator Intervention.....	53
D4.7 .Credit for Instrumentation	53
D4.8 .Design for Multiple Jeopardy	54
D4.9 .Bypass Sizes and Restrictors	54
D4.10 Temperature Effects.....	54
D4.11 Interconnecting Pipework	54
D5. REGISTER OF SAFETY RELATED DEVICES.....	54
D6. LET-DOWN STATION MODIFICATIONS	55
D7. HAZOP REVIEWS	55
D8. PROJECT SAFETY REVIEWS	56
D9. DESIGN CONTINUITY	56
D10. ACKNOWLEDGEMENTS.....	56
ADDENDUM 1 - HOW TO DESIGN FOR GAS BREAKTHROUGH	57
APPENDIX E	59
SUPPLEMENTARY COMMENTARY	59
E1.OVERALL PHILOSOPHY	59
E2.DESIGN PRACTICE	60
E3.RELIEF LIMITATION BY DESIGN.....	62
E4.PRESSURE-LIMITING INSTRUMENTATION	64
E5.USE OF RELIABILITY ANALYSIS	65
E6.DESIGN PROCEDURE FOR PROTECTION OF EQUIPMENT, TANKAGE AND PIPING.....	66
E7.CENTRIFUGAL PUMP	67
E8.TURBINE DRIVERS.....	69
E9.PRESSURE RELIEF DEVICES	70
E10. .SIZING OF PRESSURE RELIEF DEVICES	75



APPENDIX P	79
DESIGN FOR LIQUID RELIEF	79
FIGURE P1.....	81
LIQUID RELIEF LOGIC DIAGRAM.....	81
APPENDIX Q	82
FAILURE MODES OF INSTRUMENTATION.....	82
Q1. CONTROL INSTRUMENTATION	82
Q1.1 .Measurement and Detection System	82
Q1.2 Controller	82
Q1.3.Regulating System.....	83
Q1.4 Other Factors	84
Q1.5 Control Technology	84
Q2. SHUT-DOWN SYSTEMS.....	85
Q2.1 .Sensing System	86
Q2.2 .Logic	86
Q2.3 Actuating System	87
Q2.4.Override and Test Facilities	88
Q2.5.High-Security Systems	88
Q2.6.Systems De-energised in Normal Operation.....	89
Q3. CONCLUSION	89
FIGURE Q1	91
SIMPLIFIED TYPICAL ELECTRONIC CONTROL LOOP.....	91
FIGURE Q2	92
TYPICAL SHUT-DOWN LOOP	92
APPENDIX R.....	93
SIZING PRESSURE RELIEF VALVES	93
R1. ..INTRODUCTION	93
R2. ..SIZING FOR FLASHING TWO-PHASE FLUID FLOW	93
R2.2 .Liquid at it's Bubble point at Inlet.....	94
R2.3 .Liquid Subcooled at Inlet	97
R2.4 .Two-Phase Fluid at Inlet	98



FOREWORD

Introduction to BP Group Recommended Practices and Specifications for Engineering

The Introductory Volume contains a series of documents that provide an introduction to the BP Group Recommended Practices and Specifications for Engineering (RPSEs). In particular, the 'General Foreword' sets out the philosophy of the RPSEs. Other documents in the Introductory Volume provide general guidance on using the RPSEs and background information to Engineering Standards in BP. These are also recommendations for specific definitions and requirements

Value of this Recommended Practice

The International Industry Standards [API RP 520](#) and [RP 521](#) must of necessity provide more flexibility than is required by the BP Group and does not include specific BP Group experience.

This Practice also states the BP Group requirements for documenting relief related information to achieve the BP Group's stated standards with respect to Safety and Environmental considerations.

Application

Text in *italics* is Commentary. Commentary provides background information which supports the requirements of the Recommended Practice, and may discuss alternative options. It also gives guidance on the implementation of any 'Specification' or 'Approval' actions; specific actions are indicated by an asterisk (*) preceding a paragraph number.

This document may refer to certain local, national or international regulations but the responsibility to ensure compliance with legislation and any other statutory requirements lies with the user. The user should adapt or supplement this document to ensure compliance for the specific application.

Feedback and Further Information

Users are invited to feed back any comments and to detail experiences in the application of BP RPSE's, to assist in the process of their continuous improvement.

For feedback and further information, please contact Standards Group, BP Engineering or the Custodian. See Quarterly Status List for contacts.



1. INTRODUCTION

1.1 Scope

* This BP Group Recommended Practice specifies BP general requirements for the protection of pressured systems against overpressure. It is generally applicable to the following:-

- (a) Processing plants, including refineries, gas installations, and chemical plants.
- (b) Steam generating plant and ancillary equipment.
- (c) Terminals, including jetty and loading facilities.
- (d) Offshore installations.
- (e) Petroleum production facilities, including crude oil and gas gathering centres.
- (f) Main transmission pipelines, and associated equipment. (As defined in 5.6.)
- (g) Storage installations.
- (h) Vacuum systems, and systems relieving at a pressure less than 1 bar (ga) (14.5 psig).

It does not apply to pressure relief for systems in ships or road/rail tanks, unless the system is a special purpose-built facility which would normally be considered to be a processing plant.

This Recommended Practice shall be applicable to all new installations, and to changes in overpressure protection systems required as a result of changes in design conditions or modifications in existing installations. The extent to which any part of the Recommended Practice is applied retrospectively to an existing system shall be subject to approval by BP.

2. OVERALL PHILOSOPHY

2.1 General

- 2.1.1 This Recommended Practice recognises that the general safety of all installations using pressured systems is mainly dependent on good practice in the design, operation and maintenance of overpressure protection systems. In the various installations covered by this



Recommended Practice, there may be some differences of emphasis in design or in the equipment employed, but the same general principles will apply.

- 2.1.2 It covers the installations stated in the Foreword with the objective of providing in their design and operation a level of safety acceptable to BP. This shall be equivalent, as far as practicable, for all these installations.

It includes BP general requirements on the use of pressure-limiting instrumentation.

These are based broadly on:-

- (a) Continuation of the use of pressure relief devices, wherever practicable, as the main method of overpressure protection.
- (b) The developing use of pressure-limiting instrumentation as an initial method of overpressure protection in most cases, and as the sole method in a limited number of cases. (refer to BP Group [RP 30-2](#))

- 2.1.3 Overpressure protection practice in processing installations is a complex subject in which differing opinions and interpretations of code requirements are particularly encountered. Based on a recommendation of [API RP 521](#), it is emphasised that this Recommended Practice in particular shall be used in conjunction with sound engineering judgement.

- 2.1.4 A full description of the relief design philosophy shall be written into the Plant Operating Manual, the Project Technical Specification, and the Register of Safety-Related Devices (see also 2.4).

See Appendix E.

2.2 **Reference to Other Codes**

- 2.2.1 This Recommended Practice is based on [API RP 520](#) Part I (Fifth Edition, 1990), [API RP 520](#) Part II (Third Edition 1988) and [API RP 521](#) (Third Edition 1990), interpreting and supplementing them as necessary to provide BP requirements. It shall therefore be used in conjunction with all the provisions of those documents. References to text of these API documents are as in the dated editions shown above.

Additionally, for offshore installations, the design, installation and testing of overpressure protective systems shall conform generally with the recommendations of [API RP 14C](#).



API RP 14C requires that each safety system comprise two levels of protection to prevent or minimise the effects of an equipment failure within the process. The two levels of protection should be independent of, and in addition to, the control devices used in normal process protection. The first or primary method of protection is normally instrument based, the secondary method is normally provided by self acting devices such as relief valves.

Where a Category 1 system is used to prevent hazards arising, this may be adequate acting alone providing:-

- (a) The system used complies with the requirements for Category 1 systems defined in BP Group [RP 30-6](#).
- (b) A full integrity analysis has shown that an acceptable standard of safety has been achieved.
- (c) The effects of common cause failure has been considered in the reliability analysis.

2.2.2 Note that the external design codes referred to in BP Group [RP 46-1](#) for pressure vessels, BP Group [RP 42-1](#) for piping systems, and BP Group [RP 43-1](#) for transmission pipelines, have pressure relief requirements.

3. DOCUMENTATION

The BP Group considers adequate documentation essential to a continued safe operation of its assets. Therefore the BP Group Health Safety and Environment Committee has imposed the following mandatory requirements for all new plant. Where plant is modified the same requirements shall apply. Existing plant should have their documentation upgraded as soon as is practical.

- * 3.1 Where a contractor is responsible for the design of an overpressure protection system, this shall be completed as early as possible, and should be reviewed independently in detail by or on behalf of BP. The design shall then be finalised following discussion between the respective companies.
- * 3.2 Before the Piping and Instrumentation Diagrams are classified as 'Approved for Design', the contractor shall submit to BP his design basis for any overpressure protection system in the following form:-
 - (a) Statement of design basis. (Item 3.5)
 - (b) List of pressure-limiting instrumentation with schedule of maintenance and testing requirements, and supporting integrity assessment if required. (Item 3.16).



The design of pressure limiting instrumentation occurs in two basic stages; the process design and the instrument design. The process design needs to be complete at the 'Approved for Design' stage, whilst converting that into a hardware design with an Integrity Assessment will take some time longer.

- (c) Pressure relief device summary table, giving flow rates, back-pressure, temperature and molecular weight or specific gravity for each device, for each overpressure case. (Item 3.7)
- (d) Pressure relief flow diagram. (Item 3.11)

BP may, at its discretion, call for back-up information such as calculations and other details.

The final version of the above information shall be included in the plant operating instructions and in the Register of Safety-Related Devices (items 3.5 to 3.18), and shall be subject to approval by BP.

- 3.3 Pressure relief devices, and other integral parts of overpressure protection systems shall be identified with their item number and test details.

3.4 Register of Safety-Related Devices

The Register shall contain an outline design philosophy and the pertinent data on which the design has been based. In order to make the Register data practically accessible its size shall be kept to reasonable proportions (i.e. no more than 100 mm thick per unit) and it shall contain only data and no calculations.

To achieve this objective, the Register shall contain items 3.5 to 3.18. Where an item is not applicable a clear statement as to why it is not applicable shall be included under item 3.5.

It is intended that the Register will be consulted during the process design of any future unit modification and updated as necessary following completion so as to maintain a comprehensive up-to-date record of the design basis for the relief system

The Register is a key safety document and it is of the utmost importance that it is kept up to date so that engineers will confidently accept and use the data it contains. See also section 7.

On most major projects, it will be the responsibility of the Detailed Engineering Design Contractor to produce the Register and ensure that it contains the necessary information in a comprehensive form. The BP Project Team has the responsibility of ensuring that the information contained is complete and that it reflects the final engineering design. For subsequent unit modifications, the Owner or Operator must ensure that any changes which affect the relief system are

recorded in the Register and that the design of the modifications is consistent with the design basis in the Register.

For it to be of practical use, it is essential that the document be comprehensive to use and easy to update. It is therefore important that it includes only the data indicated (surplus information will tend to make it unnecessarily bulky).

The Register of Safety Related Devices is intended to be a record of what relief devices are installed and why they are installed. It should be the primary record to allow easy checks of the adequacy of the overpressure protection systems and to be able to ensure that any modifications do not prejudice the original design. It must be updated as a part of the plant modification procedures.

3.5 Design Philosophy

An outline summary of the philosophy adopted in the process design which shall address in particular (but not be limited to) the following:-

- (a) Types of utility failures considered, i.e. total, unit, partial, etc.
- (b) Whether multiple failure cases have been considered and if so, where and why.
- (c) Accommodation of fire relief from shell and tube exchangers where individual relief valves have not been provided.
- (d) Basis for the calculation of fire loads for air coolers and condensers.
- (e) All instances where credit has been taken for operator intervention.
- (f) Maximum fire areas considered and how they relate to the design of the surface and fire water drainage systems.
- (g) Philosophy for sparing relief valves.
- (h) Basis for the sizing of discharge lines, i.e. the maximum back-pressure and velocity which have been considered.
- (i) Values of pipe roughness used to size lines.
- (j) The assumed position of bypass valves when control valves fail open.

Since bypass valves can significantly increase the cost of relief systems (especially in the gas breakthrough case), the need for and size of bypass valves should be critically reviewed.

- (k) Unit capacities, feedstock and severity on which the design is based.

3.6 List of Relieving Devices

A list of every relieving device installed on the unit, containing the following information:-

Tag No.
Manufacturer
Type
Location
Set Pressure
Size
Manufacturer's Capacity Factor
Discharge Location

In addition to relief valves, the list shall include bursting discs and thermal relief valves.

3.7 Summary of Relief Loads

A tabulation of the relief loads generated for all identified causes of overpressure, indicating the case which sizes the relief device.

The summary shall include, for each relief device:-

Tag No.
Location
Set Pressure
Discharge Location
Relief Load for each cause of overpressure
(flow, molecular weight/specific gravity and temperature).

The basis for each relief load shall be clearly defined. Thus, when recording power failure it should be stated whether this is refinery wide, local (i.e. one unit or group of units), partial (affecting part of the supply distribution within a unit or group of units) or individual (single item of equipment). When specifying gas breakthrough, for example, the summary should state

- (a) the source of overpressure, including the control valve tag number
- (b) whether the control valve bypass has been assumed open or closed

- (c) the assumed liquid level in the low pressure vessel if this has any impact on the relief case.

Where a relief valve is provided to protect more than one item of equipment, all the equipment protected shall be clearly indicated. Where there is a fire relief case to be considered, a separate breakdown shall be included showing the loads generated within each of the equipment items protected.

The summary of relief loads is the key document in the whole Register and has been a BP requirement for many years. It is vital for any HAZOP to have this table to hand, otherwise they cannot confirm that the relief cases they identify have been considered. It is vital for all the other tables in the Register. It will also save much work or guessing any time a modification is considered since it immediately shows what the impact will be.

3.8 Fire Areas and Fire Loads

A list of the fire areas which have been considered in arriving at flare fire loads, indicating which relief valves are considered as relieving simultaneously. The tabulation shall include:-

Fire area considered.

Equipment item.

Tag No. of relief valve through which load is discharged. (May not be located on equipment)

Fire load (flow, molecular weight, temperature).

Total load for area (flow, molecular weight, temperature).

The section shall include a plot plan of the unit marked up to show the fire areas considered.

3.9 Principal Flare Loads

A breakdown of the flare load for each of the major utility failure cases and the worst fire case. This will possibly include relief loads from other units not under consideration, which may be relieving at the same time.

If relief valve discharges from the unit or units can be directed to more than one flare according to the flare sparing philosophy, then loads for each flare shall be included.

The Principal Flare Loads table is the one which shows the impact of the whole range of relief situations on the relief disposal system. Since this is where the major costs lie, it is vital in containing the costs of a Project and ensuring the overall safety of a site.

3.10 Relief Device Process Specifications

This section contains a complete set of final process specifications (data sheets only) for relief valves and bursting discs. In general, for each device these shall include the limiting vapour and liquid sizing cases but may include data for additional cases where deemed appropriate (e.g. for a high temperature relief case).

Often a great deal of time is wasted searching for information on the physical information of relief devices for reordering or spares data.

3.11 Header Pressure Profiles

A series of layout drawings showing the back-pressure at junctions and key points in the relief system pipe network for each of the major utility failure and fire cases.

3.12 Pipeline Equivalent Lengths

A tabulation of the piping equivalent lengths used for the purpose of estimating relief valve back-pressures. Also included for each line and header is a breakdown of the number and type of fittings providing the basis for the equivalent length. This data shall be for the final as-built design and reference the number of the piping isometric or general arrangement drawing for the line.

The same data shall be included for the relief device inlet lines.

3.13 Control Valve/Restriction Orifice Data

This section contains process data sheets for all control valves and restriction orifices which limit relief loads. The sheet shall specify manufacturer, type, size and rated conditions (including Cv) at normal and fully open positions. A brief process sketch shall also be included, showing the location of the valve or orifice plate.

By recording the data important to the overpressure protection system design it should immediately become apparent when changes to these important items will have influences greater than normal. It also allows an easy check to be made at a later date that unsafe changes have not occurred.

Whenever a control valve or restriction orifice is replaced, this section of the Register must be reviewed to ensure that there has been no change which can give rise to an increased relief load. If an increased load can result, it is essential that the capacity of the associated relief valve and the header system be checked to ensure that the system is adequately sized. The Register must then be updated to reflect the change.

3.14 Locked-Open Block Valves

A set of unit flowsheets marked up to show block valves which must be locked open during normal unit operation to safeguard the integrity of the relief system as designed. This may be required either to ensure a free vapour path from a relief valve to the flare, or to prevent the occurrence of an overpressure situation within the unit.

These locked open block valves shall be so designated on the final Process and Instrument flowsheets.

By identifying those block valves which have an impact on the safety of the plant, operational management can make operational decisions with confidence that they are not jeopardising the safety of the plant.

3.15 Pump Impeller Data

A list of all pumps with their shut-in heads and the corresponding impeller sizes as used in the relief design. It shall include:-

Manufacturer
Type designation
Shut-in head
Fluid density
Impeller diameter

As plant throughputs are increased, pumps sometimes need uprating. There are many instances where equipment design pressures are decided by the maximum head that pumps can generate (when a downstream valve could be closed). Once again this table records what has been used in the overpressure protection system design, so that it is immediately obvious whether additional relief might be required for such a modification.

3.16 Category 1 Trip Systems

This contains details of any Category 1 trip systems which have been provided to limit overpressure as an alternative to a relieving device. The information shall include a list of component instrumentation, manufacturer, type, testing frequency and reference to the reliability analysis report. (see BP Group [RP 30-6](#) and para 4.3 of this Practice)

This shall also include details of any fusible links mounted below aircoolers to reduce the heat input in the fire case (see para 4.9.3 and 4.9.4).

This table effectively records the process engineering data for any instrumented trip system just as is normal for any other protective device. Since the paperwork is normally bulky it is intended that only the basic information is detailed so that a check can be made that the designed equipment system is still in place and the correct testing frequency achieved.

3.17 Fire-Resistant Insulation

A list of vessels equipped with fire-resistant insulation to limit the fire relief load. Credit may only be taken for insulation if it is specified 'fire-resistant' and is suitably installed so that it will not be dislodged by the impact of fire water. (see para 4.9.6)

Where fire-resistant insulation is used to reduce relief loads, a similar approach to item 3.16 is used. This section identifies where the insulation is used and gives the basic information so that checks can be made that it is still in place. It also allows management to easily check where such special arrangements are needed.

3.18 Distributed Control Loop Segregation

Where a distributed control system is installed, a tabulation shall be provided indicating the way in which the distributed control system components are segregated to reduce the potential relief loads which might arise from failure of the distributed control system. The critical requirement here is that for any system with more than one output an analysis shall be carried out to determine all reasonably foreseeable failure modes which result in more than one output going to the non fail safe state. The relief loads which may arise from these failures shall be determined. Where relief loads exceed design capability it may be possible to re-assign system outputs to reduce the relief load. In all cases a tabulation (see section 3.7) shall be provided showing relief loads associated with the system outputs linked to the common cause failure.

All items should be included, whether or not failure can result in overpressure.

With any form of distributed control, new relief cases could arise. This is because the items of the distributed control themselves have failure modes. Some failure modes will result in the instrument signal becoming zero - giving a 'fail-safe' signal, but there are other modes where the signal will become a maximum - giving a 'fail dangerous' situation. Control engineers will consider a failure rate of one in 10 or 100 years as being very reliable. If an unrecognised and large relief case is created on this frequency it is definitely not a reliable situation. Therefore, it is necessary to identify such failure scenarios with the designers of the distributed control system and address them in the Register. The normal solution is to segregate the control loops that can be linked in this manner so that they are not linked in process terms.

This review of the relief effects of the distributed control loops often leads to a conflict with an operational requirement to keep segments of the control system matching segments of the process. In such cases, an analysis of the costs and consequences of different segregation approaches will be needed.

This table records the final result of the design team so that maintenance and modifications can be appropriately checked so that they do not create a hazardous situation.

- 3.19 Test dates and reports for all pressure relief valves, rupture discs and components of Category 1 instrumentation systems shall be recorded, and be readily accessible for inspection.

4. DESIGN PRACTICE

4.1 General

At an early stage in a project, a study of the relief requirements shall be made in sufficient depth to establish the basic design philosophy. This shall then be considered in relation to the constraints of the proposed siting and statutory requirements. The subsequent design for overpressure protection shall then be developed in detail within this design philosophy (refer to 5.1.2).

The basic philosophy of protection should be fully developed before the design specification stage of the Project Safety Review to prevent costly rework or additions.

Late design of the relief system has repeatedly caused significant additions to Project costs as well as a less than ideal technical and cost solution.

- * 4.1.1 All anticipated emergency conditions leading to possible overpressure shall be taken into account during design. The contractor shall refer to [API RP 521](#) and Appendix D of this BP Recommended Practice before starting an overall consideration of any relief system. In particular, the contractor shall consider the full range of operating scenarios, from purging, through pre-start-up and start-up procedures, to shut-down and gas freeing. The contractor shall list in detail the operating cases which he has considered, and submit these to BP for approval before proceeding with the detailed design of the relief system.

The contractor shall consider the outline operating procedures in preparing the basis for this list of anticipated emergency conditions.

The contractor shall consider the following specific cases and such other cases as are possible using the HAZOP approach:-

- (a) General power failure.
- (b) Cooling water failure.
- (c) Steam failure.
- (d) General instrument failure.



- (e) External fire.
- (f) Individual valve failure, open or closed.
- (g) Gas breakthrough.
- (h) Equipment failure.
- (i) Heat exchanger tube failure.
- (j) Reverse flow.
- (k) Individual item failure in distributed control system.
- (l) Partial utility failure.
- (m) Runaway reaction.

See Appendix E.

*

4.1.2

A summary of operational difficulties and relief rates is given in Table 1 of [API RP 520](#) Part I. The contractor shall ignore these relief rates and calculate the relief rates, together with the relieving temperature and molecular weight, by performing heat and mass balance calculations for the conditions applying in the relieving condition. This should include such factors as:-

- (a) Reflux drum emptying or flooding.
- (b) Dry-out of column sections causing loss of circulating reflux.
- (c) Change of duty in air coolers or exchangers due to different temperature differentials.
- (d) Change in latent heat and temperature due to increased pressure.

The methods of calculation shall be submitted to BP for approval at an early stage of design.

The rigorous prediction of relief conditions within a tower is in practice particularly difficult. For example:-

- (a) *With regard to normal base composition, the raised temperature at relief pressure may so reduce heat transfer that reboil ceases. Designers may then be tempted to provide only for the smaller fire relief load resulting from liquid vaporisation.*

This principle of 'stall out' is potentially hazardous, as once reboil falls away, tower tray contents of more volatile material would dump, and 'chill' the base contents so that reboil is re-established.

- (b) *In an upset condition fractionation could be impaired, and concentration profiles differ markedly from normal conditions. As in the particular case in 4.1.2(a), base compositions could markedly affect the temperature driving force and hence vaporisation rate, even beyond design.*

4.1.3 Catalysed Reactions

Where catalyst or a chain termination agent is added to either batch or continuous reactor systems, all specific non normal condition shall be considered in designing the overpressure protection system. This shall include, but not be limited to:-

- (a) Too much reactant, wrong composition.
- (b) Too much catalyst.
- (c) Overfilling, insufficient ullage for expansion.
- (d) Loss of agitation.
- (e) Loss of cooling.
- (f) Failure to terminate the reaction.
- (g) Loss of control.

See Appendix E.

- * 4.1.4 Particular attention shall be paid to items 12 & 13 of Table 1 of [API RP 520](#) Part I, where the normal type of relief devices cannot afford protection against internal explosion or runaway chemical reactions. Any special requirements for emergency depressuring, for halting reactions, or otherwise controlling these situations shall be subject to approval by BP (refer to BP Group [RP 30-6](#)).
- * 4.1.5 The probability of two or more entirely unrelated failures occurring at the same time need not normally be considered in design, except where the consequences are particularly serious. In such cases the hazards shall be quantified. Proposed design measures for limiting the hazard shall be subject to approval by BP. Para. 2.2 of [API RP 521](#) provides guidance on coincident failure situations.

The question of identification of possible failure modes, their probabilities and consequences should be the responsibility of a design team. In addition to Hazard



and Operability Studies, other formal procedures such as Hazard Analysis, and Failure Mode and Effects Analysis may be applied, as deemed necessary.

There may be conditions where fluids are particularly hazardous, or the consequences of failure are so disastrous that the norm of not considering two unrelated and coincident failures may not be acceptable.

It has normally been accepted that a single relief device has a sufficiently high reliability that failure of it coincident with a requirement for relief is sufficiently infrequent for this combination not to be included in the design.

- * 4.1.6 No credit shall be taken for an operator responding and taking the necessary action to prevent equipment within battery limits being overpressured. However, where the consequence of this approach is the overpressuring of a vessel with liquid, and it is difficult to provide liquid relief, a hazard quantification procedure may justify not providing liquid relief. Omission of liquid relief in such cases shall be subject to approval by BP.

A strict interpretation of the philosophy of 'no operator intervention' leads to the need for infinite knock-out facilities in the disposal system. Since this is both impractical and unnecessary the hazard-quantification approach has been invoked. This approach puts values on the frequency and consequences of an incident. Where the likelihood of an incident is slight, due to high levels of indication and to a long time being available for operators to notice and correct the fault, it may not be necessary to provide relief facilities. Some details on how and where to design for liquid relief are given in Appendix P.

- 4.1.7 The causes of overpressure to be considered shall include, but not necessarily be limited to those listed in Section 2 of [API RP 521](#). The situation known as 'gas breakthrough' shall be specifically addressed.

'Gas breakthrough' is the condition which can come about where the liquid from a gas/liquid separation passes to a lower pressure system. If the liquid level is lost, gas can pass into the lower pressure system. Since a much greater volume of gas can pass through a control valve than the liquid for which it was sized, the lower pressure system could be overpressured, if the relief were not sized for this case.

The calculation basis is given in Appendix D of the main text.

- * 4.1.8 Since vessel design takes into account both temperature and pressure, the possibility that departures from the normally expected operating temperature range may occur during emergencies shall be recognised. In these circumstances, the allowable stress of constructional materials may be so much reduced that failure occurs at pressures below the set pressure of the relief device.

Overheating either due to process control failure or fire, or auto-refrigeration from the presence of light hydrocarbons are typical examples. These may require provision of temperature-limiting or emergency depressurising systems, the design of which shall be to BP Group [RP 44-4](#) and BP Group [RP 30-6](#).



The danger with auto-refrigeration is that the materials of construction may be embrittled by the resultant low temperature. BP practice on vessels and piping is covered by BP Group [RP 46-1](#) and BP Group [RP 42-1](#) respectively.

4.1.9 Calculation of the quantity and properties of any vapour or liquid to be discharged under relief conditions shall be determined on the basis of a knowledge of the complete operating system, including process conditions, instrumentation, and utilities systems. Reference should be made to [API RP 521](#) Section 3 for guidance on general principles, but calculation shall be specific to the system under consideration.

4.1.10 Attention is drawn particularly to the following conditions (Paragraph references in brackets are to [API RP 521](#) Section 3):-

- (a) Changes in feedstock or other process conditions.
- (b) The effect of a very large capacity source such as a wellhead or long pipeline.
- (c) Properties of process fluids under relief conditions (Para. 4.3). For example, blockages may occur due to freezing or hydrate formation.
- (d) Effect of closed outlets (Para. 4.5).
- (e) Failure of automatic controls (Para. 4.10). The possible failure of instrument systems shall be taken into consideration, including all trip systems. Modern instrument systems may rely on distributed shared loop systems; the possibility of simultaneous failure of more than one control loop shall be considered.

Due consideration shall be given in the relief system design to the ability of any distributed control systems to introduce ways for otherwise unrelated control systems to be driven simultaneously to the dangerous position.

Ways of approaching this problem, and solutions to it are addressed in ETC Safety Report ETC.87.SR.001.

- (f) Utility failure (Para. 4.6). Note that the contractor shall not assume partial cooling water failure ([API RP 521](#) Para. 2.3.6) unless it can be shown that all cooling water exchangers continue to receive water when part of the cooling water pumping capacity is lost. Note that partial power failure can be worse than total power failure.

In a cooling water distribution system some exchangers are mounted in elevated positions. On the loss of some of the cooling water pumps, the change in the pump-head/flow relationship can mean that elevated exchangers are starved of water and

lose all cooling. Similarly, some hot exchangers may have insufficient flow to prevent boiling, which can cause vapour lock. Only if it can be shown that the water continues to be split evenly between exchangers is it reasonable to assume a reduced rate of cooling throughout the system.

It has been found that failure of an electrical sub-system often creates a larger relief case than total electrical failure. Therefore, it is necessary for the designer to analyse the power distribution system to determine which component parts of the system could fail without loss of the whole system. These sub-system failures should then be analysed for their relief implications.

(g) Runaway chemical reaction (Para. 4.13).

(h) External fire (Para. 4.15).

4.2 Relief Limitation by Design

4.2.1 Basic design measures shall be considered to minimise the magnitude and frequency of relief.

See Appendix E.

4.3 Pressure-Limiting Instrumentation

A clear distinction shall be made in all documentation between pressure-limiting instrumentation and Category 1 trip systems.

See Appendix E.

4.3.1 This Recommended Practice is concerned with any protective instrumentation that can be considered as 'pressure-limiting instrumentation', i.e. acting to minimise or eliminate the operation of pressure relief devices whether or not provided specifically for that purpose.

Protective instrumentation can be used for such purposes as:-

- (a) *Machinery protection, e.g. by stopping pumps and compressors.*
- (b) *Fire limitation.*
- (c) *Emergency shutdown, e.g. by shutting off feed and heat supplies.*
- (d) *Protection of vessels and equipment against overpressure and underpressure.*
- (e) *To avoid complete unit shutdown and possible consequential shutdown of associated units, e.g. by automatic start-up of stand-by equipment or introduction of a stand-by utility.*

4.3.2 Pressure-limiting instrumentation should be used wherever practicable, subject to the need to minimise the frequency and magnitude of

spurious plant shut-downs. However, complete relief system capacity or a Category 1 instrument system shall be provided as the final protection for individual equipment items (subject to 5.1.2).

Category 1 trip systems can be used:-

- (a) *To reduce any environmental nuisance from atmospheric relief to a level acceptable to local authorities.*
- (b) *To reduce possible hazards of atmospheric relief (refer to BP Group [RP 44-3](#)).*
- (c) *To minimise loss of material arising from pressure relief device operation.*
- (d) *To minimise the cost of any closed system that has to be provided. (Subject to the requirements of BP Group [RP 44-3](#)).*

4.3.3 The reliability of any Category 1 instrumentation, depends on the magnitude of the hazard involved and the Category established in accordance with BP Group [RP 30-6](#).

There has been considerable discussion on the failure modes of instrumentation, particularly with regard to the sizing of closed relief systems (see BP Group [RP 44-3](#)). It is important to distinguish between the roles of control and protective instrumentation.

Appendix Q - Failure Modes of Instrumentation describes probable failure situations with both control and shutdown instrumentation.

4.3.4 The action settings of any Category 1 instrumentation, preceded by alarms as required, need to be below the lowest relief device set pressure in the system under consideration, in order to be effective. This can require an increase in the vessel design pressure over that required by BP Group [RP 46-1](#), which gives a guide figure of 10% above maximum operating pressure, with a minimum 1 bar (ga) (14.5 psig) margin. The design margin shall take account of the response of control systems and the process. See also 4.2.1.

The design margin should be defined to allow for:-

- (i) *The tolerance of the set pressure of the relief device under actual working conditions.*
- (ii) *The setting of the trip switch or amplifier and its switching differential.*
- (iii) *The setting of the pre-alarm and its switching differential.*
- (iv) *The maximum working pressure under normal process conditions.*

4.3.5 Pressure-limiting instrumentation systems (Category 1) shall be designed to facilitate regular testing and strict control over bypassing or

deactivation, and shall be fully documented in accordance with 3.16 and the requirements of [BP 30-6](#).

Pressure-limiting instrumentation may, where appropriate, include automatic actuation of the following:-

- (a) *Feed or pipeline transmission pump or compressor trips.*
- (b) *Fuel shut-off valves.*
- (c) *Reboiler heating medium bypasses and shut-off devices.*
- (d) *Fired reboiler shutdown and heating medium circulating pump trips.*
- (e) *Pressure and temperature-limiting systems to protect reactors.*
- (f) *Start-up of stand-by pumps and compressors.*
- (g) *Stand-by cooling water sprays to air coolers.*

A philosophy of automatic turndown using partial heat-off may be applied to permit time for effective operator action in order to avoid both the operation of relief devices, and widespread shutdown.

It is essential that pressure-limiting instrumentation receives regular maintenance and proof testing at defined intervals in accordance with BP Group [BP 32-5](#).

4.3.6 The following circumstances will normally give rise to instrument systems on Category 1 duty.

- (a) Systems where overpressure protection is provided solely by instrumentation, because for whatever reason the equipment cannot be protected by conventional pressure relief devices.
- (b) Systems having relief valves discharging to a closed system sized by taking credit for the operation of automatic pressure limiting instrumentation.

4.4 Use of Reliability Analysis

Integrity assessment and Quantified Risk Analysis shall be used where appropriate in accordance with BP Group [BP 30-6](#) and BP Group [BP 50-2](#).

See Appendix E.

4.5 Implication of Changes in Design Conditions

- * 4.5.1 If there is any change in the design conditions that could result in an additional case of overpressure, check calculations for the revised conditions shall be carried out by the contractor, and submitted for



approval by BP, to ensure that BP requirements for overpressure protection are fully met. The Register of Safety-Related Devices shall be modified accordingly. In the case of a modification to a closed relief system, refer to BP Group [RP 44-3](#).

Change in pump impeller size would be a typical common change in system design (see para 3.15).

4.5.2 It shall be recognised that a change in a control system design or philosophy could necessitate a corresponding change in the design of an overpressure protection system and in the Register of Safety-Related Devices. For example:-

- (a) Modification to a Category 1 trip system (see BP Group [RP 30-6](#) and para 3.1.4).
- (b) Replacing a system of single control loop integrity by a distributed shared loop system (see para 3.18).
- (c) Computer optimisation linking control loops in a manner not envisaged in the original design (see para 3.18).
- (d) Changing control valve trim size, or the removal or repositioning of limit stops (see para 4.13).

Additional information on 'Failure Modes of Instrumentation' is given in Appendix Q of this Supplement.

4.6 Emergency Depressuring

4.6.1 Means for emergency depressuring may be necessary in certain conditions (see BP Group [RP 30-2](#) and BP Group [RP 44-4](#)). These include:-

- (a) Potentially uncontrollable reaction conditions where rapid depressuring systems will be more effective than normal pressure relief devices, i.e. pressure relief valves and rupture discs.
- (b) Uncontrolled temperature rises which could lead to possible equipment failure at or below design pressure.
- (c) Fire conditions, where the equipment is uncooled by process liquid contact, again leading to failure at or below design pressure.

- (d) Units operating at a pressure above 17 bar (ga) (250 psig) for refining or oil production facilities. For chemical plant these limits do not necessarily apply.

For fire and other potential emergency conditions, emergency depressuring facilities may be considered to give rapid reduction of pressure. Since this requires additional flare system capacity, etc., it is restricted to those units where the accrued benefit justifies such facilities. On refinery units, a convenient working rule for deciding whether or not to include such facilities has been a break-point of 17 bar (ga) (250 psig) operating pressure. The availability of hazard assessment techniques could change the position in the future, and this traditional break-point should not be used as rigid practice.

For chemical reactions depressuring may be the only way of countering a potentially dangerous situation when the process system has become unstable. In these situations the 17 bar (ga) rule would not apply.

- 4.6.2 For 4.6.1(a), instrumentation shall be provided to sense potentially hazardous conditions, and initiate the necessary corrective action in accordance with BP Group [RP 30-2](#).
- 4.6.3 In calculating the capacity of a depressuring system, it shall be assumed that during a fire there is no feed to or product from a system, and that all normal heat inputs have ceased.
- * 4.6.4 The auto-refrigeration effect of depressuring shall be considered, in the case of high-pressure gases and liquefied gases, in accordance with BP Group [RP 46-1](#) and BP Group [RP 42-1](#). Calculation procedures for estimating the temperature of vessels and pipework are given in BP Group [RP 44-4](#), but other suitable procedures may be used subject to approval by BP.
- 4.7 Vacuum Relief**
- 4.7.1 The possible need for vacuum relief on all vessels and systems shall be considered. Suitable protection may be provided by vacuum-breaking systems, inert (non-condensable) blanketing systems etc. The basis of protection shall be included in the documentation required by 3.4.
- 4.7.2 As an alternative to vacuum relief, pressured equipment may be designed to be suitable also for full vacuum conditions.
- 4.8 Cold Service**
- 4.8.1 Where auto-refrigeration or freezing of released vapours may occur, e.g. from low-temperature storage of methane to butane hydrocarbons, fluorocarbons or other low-boiling materials, the pressure relief device shall be constructed of materials suitable for the minimum temperature

encountered. Reference shall also be made to BP Group [RP 44-2](#) and BP Group [RP 44-4](#).

4.8.2 Any non-flammable non-toxic liquefied gas, e.g. CO₂, capable of forming solid particles on discharge, shall be vented directly to atmosphere with no piping downstream of the pressure relief device.

4.8.3 Where the discharging process fluid may result in ice formation such as to prevent the reclosing of a valve, the valve shall be heated and insulated as necessary.

4.9 External Fire Condition

4.9.1 Pressure relief devices shall be provided for the fire relief condition on all vessels and equipment that could be subjected to a sustained external fire. Calculation methods shall be in accordance with [API RP 520](#) Part I and [API RP 521](#).

It should be noted that the Third Edition of [API RP 521](#), Appendix A gives more precise advice on fire heat input than previously, in particular:-

The heat input rate is dependant on good drainage, otherwise the commonly accepted heat input rate of 21000 Btu/hr.ft² becomes 34500.

For column bases the level of the wetted surface should be based on the normal liquid level plus a level equivalent to all the liquid on all the trays. (on the assumption that all the trays dump their liquid into the base of the column. If there are total trap out trays, this obviously has to be modified.)

4.9.2 A closed system for the fire relief case shall be sized to handle the simultaneous discharge from all pressure relief devices that are judged to be affected. This judgement shall be based on the maximum fire relief discharge rate from a plot that can be isolated by fire-fighting personnel and their equipment.

This plot area shall be determined by reference to the plot plan, making allowance for adjacent roads, bund walls and drainage conditions. It is important to ensure that the areas considered are consistent with the design of the surface water drainage system, and that it is not possible for the fire to be spread further as a result of burning hydrocarbons being carried along on top of draining fire water. In the case of offshore platforms, account shall be taken of plant above and below the plot area.

An arbitrary fire circle should not be used to define the area which can be affected by a fire. [API RP 520](#) recommends determining the area which can be affected by a single fire on the basis of the slope of the ground, drainage gullies and other natural fire breaks. There is no justification for deviating from this approach.

4.9.3 For each fire relief area, as defined in 4.9.2, two separate cases shall be considered:-

For the continued operation fire case the following shall be taken as the basis:-

- (a) Normal process duties for equipment except aircoolers.
- (b) Fire heat input to all equipment in the postulated fire area.
- (c) All aircoolers within 8 m (25 ft) of a surface which can support a pool fire having heat input according to [API RP 521](#).
- (d) Where aircoolers are more than 8 m (25 ft) above a surface which can support a pool fire, a judgement must be made as to whether the flames can be sucked into the aircooler.
- (e) Where a reliable fusible link system is fitted below an aircooler to trip the fans and the aircooler is more than 8 m (25 ft) above a surface which can support a pool fire then no heat input from the fire shall be considered, but the normal process cooling shall be considered to be lost.

For the shut down condition fire case the following shall be taken as the basis for calculation:-

- (f) No process heat input or removals.
- (g) Fire heat input load on all equipment except aircoolers.
- (h) For aircoolers that are less than 8 m (25 ft) above a surface than can support a pool fire heat input shall only be added if there are downstream block valves which could result in liquid in the aircooler. The calculation shall then be on the basis of the expected liquid inventory in accordance with [API RP 521](#).
- (i) For aircoolers which are more than 8 m (25 ft) above a surface which can support a pool fire, no heat input.

For the continued operation fire case.

It must be assumed that the aircooler fans are still operational and that there is liquid in the air-cooled tubes. Thus the normal fire heat input criteria apply if the bundle is within 8m of grade or a surface on which a pool fire can be sustained. If the bundle is higher the fans will suck up the flames into the bundle if the fire is within a suitable angle. Investigations are continuing into what angle is appropriate but 45 degrees seems reasonable, subject to investigations.

For the shutdown case.



The aircooler fans will be shutdown so that a bundle more than 8 m above a fire supporting surface will not be affected. If the bundle has drained down, there is no material to vaporise and there will be no heat input regardless of its height above a fire. However, many aircoolers have block valves in their outlets which may be closed (deliberately to isolate the fire or for operational reasons), if so liquid could be trapped in the fire affected area.

- 4.9.4 Where a fusible link is used to reduce the relief capacity from the aircooler fire load case, it shall be treated as a Category 1 or 2A instrumented trip system and subject to the requirements of BP Group [RP 30-2](#). It shall be recorded in the Register of Safety-Related Devices (Item 3.16 of this Practice).

One way of reducing the effect of fans in sucking flames into a bundle is to ensure that they stop when there is a fire. The only reliable way of achieving this is to have a fusible link across the base of the bundle which fails when hot gases or flame impinge upon it. This is a Category 1 trip system if the relief capacity is reduced because of it and must therefore be subject to all the requirements of such a trip as detailed in BP Group [RP 30-2](#). It must also be recorded in the Register of Safety-Related Devices (Item 3.16 of this Practice).

- 4.9.5 For any particular plot area, where fire conditions require relief capacity in excess of that required for any other emergency conditions, insulation or cladding of selected equipment against fire shall be applied, where economical, to reduce the discharge rate and the size of any closed relief system. Where the pressure relief device is sized on this basis, the insulation and cladding shall be specifically designed and installed to resist the forces of fire hose streams, and to maintain its insulation properties for an extended period. Details of the insulation shall be included in the Register of Safety-Related Devices, see 3.17.

- 4.9.6 BP general requirements for passive fire protection by insulation and cladding, are specified in BP Group [RP 24-1](#).

Note that BP requirements for shell-and-tube and air-cooled heat exchangers during external fire conditions are covered in 5.2.3 and 5.3.4 respectively.

Where fire resistant insulation is required, it is often much cheaper to use intumescent materials than conventional insulation systems. This is particularly true on LPG spheres where a water sprinkler system is also required.

4.10 Thermal Relief

- 4.10.1 Thermal relief is not normally required in short isolatable sections of piping within battery limits or where the trapped volume is less than 0.4 m³ except for LNG and LPG. However, liquid lines that can be blocked-in during normal operation whilst subject to heat input from external sources such as ambient conditions, heat tracing or steam

jacketing, adjacent hot lines, or radiation from flares, shall have thermal relief valves if the increase in fluid pressure so caused will increase pressures beyond those permitted by the relevant piping design code. The expansion of the trapped fluid shall be calculated, and the pressure relief device sized accordingly. In the case of most systems, an NPS 3/4 x NPS 1 (DN 20 x DN 25) relief valve can be used, even though it will commonly be oversized.

If thermal relief valves are installed everywhere that a small quantity of liquid could be trapped between block valves there would be a multiplicity of thermal relief valves, all of which would have a tendency to leak. On balance there is less hazard created by the slight risk of discharge of a small quantity of material on failure compared to the greater risk of a multitude of small leaks from a multitude of thermal relief valves.

- 4.10.2 Thermal relief shall be provided on equipment where fluid can be trapped between inlet and outlet valves, and where sufficient heat can be supplied to the fluid to increase the pressure above the equipment design pressure. Such equipment shall include fired heaters, heat exchangers, vessels, pumps, compressors, piping and vessels.

This shall not apply when the valves are locked open during operation and closed only under permit (see also 5.1.4).

Where relief is to the process, the thermal relief valves shall discharge to a location which is always capable of absorbing the relieved material. The location of other valves and their possible positions at the time of discharge of the thermal relief valve shall be taken into account.

A heat exchanger shall be provided with a pressure relief device for thermal expansion if the cold side can be blocked-in between inlet and outlet valves with flow on the hot side. Note however the dispensation permitted by 5.1.4 of this Recommended Practice.

The sizing of the thermal relief shall assume that:-

- (a) *The fluid is initially at the most severe operating conditions.*
- (b) *The ratio of gas, vapour and liquid is the most arduous of the predicted design conditions over the life of the plant for the assumed flow, pressure and temperature.*
- (c) *Pumps and compressors on the process fluid continue to operate unless there is an automatic shutdown initiated by the blocking-in, for example, on low flow. Relief devices on pumps and compressors and kickback systems will operate. Non-return valves will be effective in stopping the flow.*
- (d) *Heat input will continue at the design operating rate. Where temperature sensors are located so that the blocking of the process flow will give a low*

temperature at the sensor, then the heat input will be the maximum possible.

This will be based on the maximum flow of fuel to fired heaters or of heating medium to the other equipment. Control valves on heater fuel or heating fluids will be assumed to be fully open.

- 4.10.3 Where thermal relief valves discharge into a closed system the effects of back-pressure shall be considered.

5. DESIGN PROCEDURE FOR PROTECTION OF EQUIPMENT, TANKAGE AND PIPING

5.1 General Requirements

- 5.1.1 When considering protection against overpressure of individual equipment items, definitive guidance on taking credit for any provision of automatic pressure-limiting instrumentation cannot be obtained from any interpretation of major pressure vessel design codes. This is because their scope is essentially concerned with vessel design rather than the system conditions that can cause overpressure, and they refer mainly to protection by normal relief devices i.e. pressure relief valves and rupture discs. It is [API RP 521](#) that gives major code guidance for system design against overpressure as distinct from the vessel design requirements. However [API RP 521](#) requires interpretation in detail and currently does not give sufficiently detailed guidance on the role of pressure-limiting instrumentation.

Basically, it is the function of the contractor designing the pressured system to:-

- (a) Identify all primary causes of overpressure.
- (b) Assess the reliability of any means provided in the system to limit this pressure.
- (c) Specify to the vessel designer the resulting design case pressure relief device size(s).

It is then the function of the process/instrument designer to provide either pressure relief devices of the specified size(s) or Category 1 or 2A instrumentation systems.

- 5.1.2 In applying the principles of BP practice to the protection of individual equipment items or plant sections of process plant, relief devices shall be provided, taking no credit for any provision of automatic pressure-limiting instrumentation, except in special circumstances which shall be

in accordance with BP Group [RP 30-2](#). Examples of such circumstances are:-

- (a) Where there is no practicable location to which relief can be discharged.
- (b) For protection against internal explosion.
- (c) For protection against uncontrolled chemical reaction.
- (d) Highly toxic, non-flammable material.

Note that to satisfy the requirements of the main pressure vessel design codes, the pressure relief device set pressure, or lowest set pressure in the case of multiple devices, has to be not greater than the vessel design pressure, or maximum allowable working pressure if applicable.

5.1.3 For action settings of any pressure-limiting instrumentation, refer to 4.3.4.

- * 5.1.4 Where intermediate isolating valves are provided for maintenance purposes to be used only during plant shut-down, they may be taken as locked open, subject to approval by BP. Such valves shall be recorded in the Register of Safety-Related Devices (see para 3.14). In this case, relief capacity need not be provided between the isolating valves. The plant operating instructions shall state that such valves shall be closed only after issue of a permit, under supervision. If applicable to an exchanger both sides shall be vented and drained immediately after isolation.

Note that this paragraph does not apply to the isolation of pressure relief devices, which is covered by 6.5.2.

If isolating valves are installed around an exchanger so that it can be isolated, then either relief capacity should be installed or the exchanger must be vented and drained immediately after it has been isolated. Where the option of venting and draining is adopted, consideration should be given to erecting a warning notice stating that the exchanger must be vented and drained immediately after being isolated.

- * 5.1.5 Overpressure as a result of reverse flow from a high-pressure system shall be considered. No credit shall be taken for the presence of a non-return valve or steam trap in a line unless a reliability analysis shows that the non-return valve, or trap, and the system have an acceptable failure rate. The maximum acceptable failure rate will be specified by BP.

The installation of a second device of different design in series, without performing a reliability analysis, does not constitute adequate protection against overpressure.

Maximum acceptable failure rates are process and Business specific. Some attempt has been made to generate generic values by Health, Safety and Environment group in BP Engineering, but the provision of such data is a specific Business responsibility.

5.2 Shell-and-Tube Heat Exchangers

5.2.1 General

5.2.1.1 In exchanger systems consisting of more than one shell, both shell or tube sides interconnected without intermediate isolating valves may be considered as single systems for the purpose of overpressure protection design, except where severe fouling could occur.

5.2.1.2 Overpressure conditions to be considered shall include all the possibilities set out in [API RP 521](#) Section 2, and any other specific plant emergency condition. In particular the blocked-in and burst tube conditions shall be allowed for, together with any implications of more gradual tube leakage. These overpressure conditions shall be met by designing for pressure containment whenever this is economical.

5.2.2 Burst Tube Condition

5.2.2.1 A complete single tube failure shall be taken for design purposes, with calculation in accordance with [API RP 521](#), Para 3.18. Note that this specific case is regarded as sufficiently infrequent such that relief protection to meet it is not required unless the design pressure on the high pressure side is greater than the hydrostatic test pressure on the low-pressure side of the exchanger and the associated pipework and equipment. It should be noted that the ratio of two thirds referred to in [API RP 521](#) is the ratio between design and test pressure for the ASME pressure vessel Codes. If any other pressure vessel Code is used in the design the appropriate ratio should be substituted.

5.2.2.2 Credit for excess material escaping via the normal process system shall only be taken when it can be demonstrated that the low pressure process system has the capacity for the material and there is little risk that operators would block in the low pressure side.

See Appendix E.



- 5.2.3 External Fire Condition
- 5.2.3.1 Pressure relief capacity shall be provided on heat exchangers for the external fire condition on both sides where they can be isolated without draining, if in an area where a fire could be sustained. This applies even if the exchangers are designed for pressure containment.
- 5.2.3.2 Sizing for the shell side shall be in accordance with [API RP 520](#) Part I. Sizing for the tube side shall be based on the heat input to the channel area exposed to the fire.
- 5.2.3.3 On water-cooled exchangers with hot fluid on the shell side, pressure relief devices need not necessarily be for steam formation if the maximum temperature of the shell fluid is below the boiling point of water at the tube side design pressure. However, relief capacity shall be made available for any steam generated by heat input into the channel and/or bonnet, possibly through pressure relief valves provided for thermal relief.
- 5.2.3.4 Where chemical cleaning is required on a routine basis during normal operation, pressure relief devices for the fire condition shall be sized not only for the normal process fluid but also for water, to represent a chemical cleaning fluid.
- 5.2.3.5 For sections of plant containing air-coolers two relief scenarios shall be calculated in accordance with para 4.9.3.

See Appendix E.

5.3 Air-Cooled Heat Exchangers

- 5.3.1 Because of their high surface area, air-cooled heat exchangers are capable of absorbing large quantities of heat during a fire. However, because of their relatively small capacity, the high calculated maximum rates of vapour release can only be sustained for approximately one to two minutes, and in the case of free-draining condensers, there is only a very small liquid hold-up.
- [API RP 521](#) Appendix A now gives more specific advice in the fire loads to be used for aircoolers. Reference should also be made to the advice given under 4.9.3 of this Practice for the heat input for the fire case.*
- 5.3.2 The use of isolating valves between the heat exchanger and associated vessels should be avoided. The relief capacity on such vessels shall be checked to ensure that it is adequate for the fire condition of the exchanger.

5.3.3 Where vessels are located below air-cooled heat exchangers, e.g. in modular plant construction, the intermediate floor shall be of solid construction, sloped and drained so that it will not provide liquid hold-up to sustain a fire. The pressure relief devices should then be sized on the basis of hot air passing over the exchanger tubes.

5.3.4 If fire relief is to be provided for air-cooled heat exchangers, the relief orifice area shall be calculated by one of the methods given in [API RP 520](#) Part I.

5.4 Centrifugal Pumps

5.4.1 Where stand-by pumps are installed for centrifugal pumps, it may be possible to overpressure the suction side of a stand-by pump between the pump and the suction block valve. This can arise from the operating pump, or possibly from seal-oil or flushing-oil connections.

See Appendix E.

5.4.2 For such pumps, where the suction side can be overpressured following inadvertent closure of the suction block valve, the suction line and fittings, from and including the suction block valve to the pump suction, shall be given the same line specification as the pump discharge.

See Appendix E.

5.4.3 As an alternative to uprating, pressure relief devices may be fitted on the suction lines between block valve and pump, relieving upstream of the block valve or to other safe location. However, this is normally a more expensive design, and shall not in any case be used for highly viscous or coking liquids.

Note that in the case of a relief device, a detailed check must be made to ensure that the relief route is acceptably safe. The relief device set pressure will correspond to the maximum allowable suction system pressure or stationary seal pressure, whichever is less. For the seal, the exact set pressure will require agreement with the pump manufacturer. The discharge rate must be the maximum estimated flow possible through the non-return valve bypass or other pressurising line under the relieving condition.

For any case where the suction lines and valves are very large and expensive, the relief device alternative might be economical, even though pump seal and flanges may be adequate for uprating.

5.5 Turbine Drivers

5.5.1 With certain types of turbine driver, e.g. back-pressure steam, recovery gas and recovery hydraulic turbines, it may be possible to overpressure

the exhaust side of the casing and the exhaust line back to the exhaust side block valve, by subjecting it to full inlet pressure.

Incidents have occurred in BP Group plants where the exhaust side of steam turbine drivers has been overpressured, resulting in equipment damage and hazard to personnel. Action was taken on existing installations to prevent further occurrences.

Similar situations on centrifugal pumps are covered in 5.4 and D5.4 of this Practice.

In some backpressure steam turbine drivers, the exhaust side can be overpressured from the inlet side. When a backpressure steam turbine driver is stopped, either accidentally or as normal shutdown procedure, the exhaust side block valve may then be closed in error. The exhaust side of the casing and exhaust line back to the block valve is then subjected through the turbine to the full inlet steam pressure.

- 5.5.2 For such back-pressure turbines, where the exhaust side can be overpressured following inadvertent closure of the exhaust side block valve, a pressure relief device shall be fitted between the turbine and the exhaust block valve, (refer also to BP Group [RP 34-1](#)). This device shall be sized for full design turbine flow (the final rated flow supplied by the turbine vendor for the equipment actually installed) and be set at the casing exhaust-side pressure rating or the allowable exhaust-piping pressure, whichever is lower.

See Appendix E.

5.6 Main Transmission Pipelines and Associated Equipment

5.6.1 General

- * 5.6.1.1 For the purposes of this Recommended Practice, this equipment shall be defined as follows:-
- (a) Oil or gas transmission pipelines both on land and offshore, but excluding processing plant.
 - (b) Pipelines other than included in 5.6.1.1(a), where specified by BP; in general these will be lines where BP Group [RP 43-1](#) applies.
 - (c) Departure and arrival terminals immediately associated with transmission pipelines plus any intermediate stations as required. This includes pig launchers/receivers and slug catchers, but not processing facilities associated with a terminal.

Pig launchers/receivers are normally designed as vessels and hence the relief devices, manufacture and inspection are governed by pressure vessels rather than pipeline Codes.



- 5.6.1.2 In these installations the provision of pressure relief devices may not be acceptable or effective, apart from any provision for thermal expansion.
- 5.6.1.3 Design of transmission pipelines shall be in accordance with BP Group [RP 43-1](#), which is based on [ANSI/ASME B31.4](#), [ANSI/ASME B31.8](#), [BS CP 2010](#), and the IP Model Code of Safe Practice Part 6. These codes permit the use of pressure-limiting instrumentation for overpressure protection, and this Recommended Practice (BP Group RP 44-1) shall additionally apply. Note that in addition many countries have their own local and national requirements.
- 5.6.1.4 When considering overpressure protection, all types of protective devices should be considered, including overpressure controls, automatic shut-down equipment, and pressure relief devices.
- 5.6.2 Design
- 5.6.2.1 Note that transmission pipelines are normally designed to operate at a higher permissible stress level than piping systems covered by BP Group [RP 42-1](#), and can possibly be subject to greater variations in internal pressure during operation.
- 5.6.2.2 Conditions that can cause overpressure of a pipeline system include the following:-
- (a) Surge pressure during operation.
 - (b) Excessive static head at certain points in the line during any shut-down period.
 - (c) Fluid expansion due to variations in temperature of any static section.
 - (d) Starting up of pumps, including any installed spares.
 - (e) Connection to an additional high-pressure source.
- 5.6.3 Surge
- 5.6.3.1 The effect of pressure surges are usually significant in long transmission pipelines or marine loading lines with quick shut-off facilities.
- 5.6.3.2 The maximum pressure in the system which can arise as the result of operating conditions plus any surge pressure shall be evaluated and taken into consideration in the design, after allowing for the effect of all practical methods for surge protection, e.g. expansion vessels, slow-

closing valves, etc. If the operating pressure plus the resultant surge pressure exceeds that permitted by the appropriate code, then either overpressure devices or pressure-limiting instrumentation shall be installed.

It should be noted that pressure relief devices in liquid service have specific response times. Typically they are:-

Grove valve	10-50 millisecond
Bursting disc	10-100 millisecond
Normal relief valve	1/2 to 1 second
Pilot operated relief valve	1 - 3 second

These times are often significant in hydraulic surge calculations and the manufacturer should be consulted for more precise data for specific types. The times need to be correctly considered in the hydraulic surge analyses.

5.6.3.3 Common causes of surges in pipelines include the following:-

- (a) Valve closure against flow.
- (b) Pump or pump station start-up or shut-down.
- (c) Any sudden change of flow conditions in the system.

Determination of actual surge conditions which may arise in a pipeline system can involve detailed calculations using either analytical or graphical methods. The contractor shall evaluate if such pressures are likely to be significant and provide for them in the design, either by reducing the level of permitted operating pressure, or by the provision of protective devices to keep the maximum pressure within that permissible.

5.6.4 Static Head

- 5.6.4.1 When a pipeline which crosses undulating or mountainous terrain (whether or not it is designed for slack line operation) can be shut down under pressure, means of overpressure protection shall be provided to limit any static head pressures due to differences in elevation, to within the maximum permitted internal design pressure at any point of the system.

5.6.5 Fluid Expansion

The effects of fluid expansion on internal pressure, due to temperature changes in any static section that can be isolated, shall be considered and pressure relief devices installed if required. If main line isolating valves are provided with bypasses incorporating a pressure relief device, the cumulative pressure increase shall be considered.



5.6.6 Intermediate Stations and Terminals

- 5.6.6.1 Surge protection and relief facilities shall be provided where necessary to ensure that both upstream and downstream line pressures do not exceed the design pressure.

It should also be noted that hydraulic surge can also create negative pressures. In low vapour pressure systems these can lead to vacuum conditions which have collapsed piping in the past. In higher vapour pressure systems, vapour cavities can be formed which can be collapsed when systems are restarted, often leading to higher surge pressure than previously considered.

- 5.6.6.2 Relief storage shall be provided of sufficient capacity to accommodate all relief discharges and drainage. Pumping facilities shall be provided wherever necessary to return relieved fluids to the system.

- 5.6.6.3 Facilities for depressuring shall be provided at compressor stations. Gas compressors shall be fitted with a pressure-relieving system fully sized for the shut-in condition, installed in the discharge line from each compressor.

- 5.6.6.4 Pressure-relieving systems, flares, and surge tanks shall be designed and located to meet the requirements of BP Group [RP 44-3](#).

5.6.7 NGL Pipelines

In the special case of NGL pipelines, changes in ambient conditions can cause wide variations in pressure. High day temperatures can lead to a large increase in pressure in an isolated section. Equally, a low night temperature can cause condensation and even to the drawing of a vacuum. The effect of such changes shall be calculated, and protective systems provided as necessary.

5.7 Process and Utility Piping

- 5.7.1 The pressure relief devices should preferably be set at the design pressure as defined in [ANSI/ASME B31.3](#), but in no case shall the pressure setting exceed the allowances for variations from normal operating conditions permitted by [ANSI/ASME B31.3](#), or the maximum design pressure of the weakest component in the system.

5.8 Atmospheric Storage Tanks

Pressure-relieving arrangements for storage tanks to operate at or near atmospheric pressure shall be in accordance with [API Std. 2000](#) and BP Group [RP 58-1](#).



5.9 LPG/LNG Storage

LPG and LNG spheres can have very high fire case relief loads. It has been normal practice to reduce this by the application of automatic fire deluge systems. Recent (1992) studies have shown that the use of fire resistant insulation is often a safer and cheaper option. (See para 3.17 of this Recommended Practice and BP Group [RP 24-1](#)).

- 5.9.1 The overpressure protection of LPG storage systems shall be in accordance with the IP Model Code of Safe Practice, Part 9 (note that this IP document is not applicable to LNG storage).
- 5.9.2 Refrigerated LPG and LNG tanks shall be protected against low-pressure (partial vacuum) conditions.
- 5.9.3 Non-refrigerated LPG tanks shall be protected against low pressure partial vacuum conditions caused by extreme low ambient temperature conditions.

5.10 Cascade Effects

Where there are process connections from one part of a unit to another part of the same or another unit, the need for overpressure protection due to an upset on one causing an overpressure on the other shall be addressed. This shall particularly be examined for all cases where gas generated in one process is supplied to another.

Cascade Effects

Utility systems such as fuel gas often have pressure controllers from the generating equipment which open when the pressure rises. In the event of a major upset in the generating vessel, large quantities of gas can be discharged at a much higher pressure than the downstream equipment design pressure. This case is normally recognised in the generating equipment and appropriate relief will normally be included. However, the downstream equipment can still be overpressured if its design pressure is lower.

The same problem occurs on any of the locations where material is taken as a product of one part of a unit to provide feed for another.

A particularly difficult problem arises where a liquid overflow condition can occur on the generating equipment where gas is the normal product. In such a case liquid knock out facilities will be required in the transfer system unless a Category 1 or 2A trip system is provided against the eventuality.

6. PRESSURE RELIEF DEVICES

6.1 General

- * The following requirements relate to pressure relief valves and rupture discs. The use of other pressure relief devices is not excluded, but shall be subject to approval by BP.

6.2 Pressure Relief Valves

6.2.1 Types of Pressure Relief Valve

See Appendix E.

With balanced bellows relief valves specified for back-pressure over about 30%, many manufacturers will supply a weaker spring than would be used if a lower back-pressure were specified. This reduces the pressure at which the valve reseats at low back-pressures. Thus, in this situation with cases producing a low back-pressure, the valve could reseat at a pressure significantly below the set pressure. This can lead to a greater discharge of valuable or toxic material than would otherwise be expected. There is no easy solution and the system and equipment needs to be re-designed to prevent this occurrence.

6.2.1.1 Conventional Type

- * 6.2.1.1.1 Conventional-type pressure relief valves shall be of the nozzle-entry type having enclosed springs and conforming with [ISO 4126](#), [BS 6759](#) Parts 1, 2 or 3, [API Std. 526](#), or other national standard approved by BP, except for steam or hot condensate when open bonnets should be used. Bodies shall be of carbon or alloy steel and trims of 12% Cr alloy or other corrosion-resistant alloy suitable for the service conditions.

See Appendix E.

6.2.1.2 Balanced Type

See Appendix E.

- * 6.2.1.2.1 Bonnet and bellows vents from balanced-type pressure relief valves shall be led with minimum restriction to a safe location, as approved by BP.

6.2.1.2.2 In bellows-type pressure relief valves, the bonnet shall be vented separately from the discharge.

See Appendix E.

6.2.1.2.3 Bellows-type valves shall not be used in fouling conditions.

- * 6.2.1.2.4 In the auxiliary balancing piston type, vapour leakage into the bonnet, on bellows failure, is restricted and the valve continues to operate as a balanced pressure relief valve. This type should be used for critical and fouling services as specified by BP.

See Appendix E.

6.2.1.3 Pilot-Operated Type

- * Pilot-operated pressure relief valves, i.e. where the major flow device is combined with and controlled by a self-actuated auxiliary pressure relief valve, are liable to failure in fouling or high-temperature service. (This covers the majority of BP Group applications.) Such valves will therefore be acceptable to BP only on non-fouling service, and their use shall be subject to approval by BP.

See Appendix E.

- 6.2.1.3.1 The discharge from the pilot valve shall be to a suitable low pressure location. The main valve discharge rarely meets this requirement.

On some designs of pilot-operated relief valves a high back-pressure on the pilot discharge could cause the main valve to reclose. For this type the pilot discharge line must always be vented to atmosphere rather than the main valve discharge.

6.2.1.4 Pilot-Assisted Type

See Appendix E.

- 6.2.1.4.1 A pilot-assisted pressure relief valve, in which the valve is still capable of operating as a normal spring-loaded valve in the event of pilot or actuator failure, is preferred to a pilot-operated valve.

- * 6.2.1.4.2 Pilot-assisted valves should be considered for use where accuracy of setting is important, or rapid opening and closing are required. They may also be used to give a full-bore discharge to maintain specific velocities when venting to atmosphere. However, their use shall be subject to approval by BP (see BP Group [RP 44-3](#)).

6.2.2 Use of Easing Gear

Easing gear on pressure relief valves is not required, unless called for by statutory regulations.

6.3 Rupture Discs

The margins between normal operating and design pressures are larger than for relief valves and shall be accommodated in the design.

6.3.1 Types of Rupture Disc

- * 6.3.1.1 Dependent on the application, various types of rupture disc may be used, i.e. domed, reverse buckling, or composite, subject to approval by BP.

However, the reverse buckling type should only be used if no other type is suitable.

Reverse-acting discs should not be fitted to liquid-filled systems since there is insufficient energy in the overpressured liquid to 'flip' fully the disc. Provision should always be made for a gas pocket to be within the system, preferably beneath the disc. Reverse buckling bursting discs can be 'flipped over' without failing if the pressure approaches the burst pressure. Since they are several times thicker than the equivalent conventional domed bursting disc they may not fail in this condition until several times their rated burst pressure.

- 6.3.1.2 Where normal domed rupture discs may be subject to vacuum, under any operating conditions, a vacuum support conforming to [BS 2915](#) shall be fitted.

- 6.3.1.3 Discs shall be non-fragmenting, and shall be provided with means of retaining the disc after failure.

6.3.2 Use of Rupture Discs

- 6.3.2.1 The generally preferred method of providing pressure relief is with pressure relief valves. However, rupture discs are the preferred or only reasonable method for the following cases:-

- (a) For the relief of a pressure which is rising too fast for normal pressure relief valves, typically in a reaction vessel, or in the case of potential explosions in a powder silo.
- (b) In services where the operation of a pressure relief valve may be affected by corrosion or corrosion products, or by the deposition of material that may prevent the valve from lifting in service.
- (c) With highly toxic or other materials where leakage through a pressure relief valve cannot be tolerated.
- (d) For low positive set-pressures where pressure relief valves tend to leak.
- (e) Where it is necessary to provide for rapid depressuring to atmospheric pressure.

Rupture discs would be used here because much larger capacities can be provided for a sensible capital cost.

A rupture disc venting to atmosphere will not give the high velocity required for safe discharge of flammable or toxic vapours for the complete duration of the discharge. As the pressure falls so will the flow and consequently the discharge velocity fall. In such circumstances there are two options:-

- (a) Do not use a rupture disc.
- (b) Use a pressure relief valve in series with, and downstream of, a rupture disc.

- 6.3.2.2 The bursting pressure and creep properties of a metallic disc may be affected by temperature variation. Note that when a disc is specified to protect a system at an elevated temperature, the disc may not give adequate protection at a lower temperature. The manufacturer's advice shall always be sought when selecting a disc for a particular system.

Be careful in the specification of burst temperature where the disc has a long inlet line. Atmospheric cooling may mean that the disc experiences a temperature considerably less than the process temperature.

- 6.3.2.3 The tolerance range of rupture disc failure shall be recognised. This is normally about + or - 5% of the normal bursting pressure. The vessel or system design shall take account of this.

- 6.3.2.4 Rupture discs shall not be used for pulsating flows or at working pressure too close to the design bursting pressure. Normal domed rupture discs can be operated at working pressures up to 70% of the bursting pressure. Reverse-acting discs can be operated at up to 90% in special circumstances. [API RP 520](#) section 2.5.2 details the maximum suitable operating pressures for the various types of bursting disc.

6.4 Sizing of Pressure Relief Devices

See Appendix E.

- 6.4.1 The calculation of required free area for relief valves and rupture discs should be in the appropriate National Code. In the absence of such a Code they should be sized in accordance with the methods described in [API RP 520](#) Part I Section 4, or other appropriate sizing method.
- 6.4.2 In sizing relief devices, the set pressure and accumulation pressure is covered by the applicable pressure vessel design code. Note that some national pressure vessel codes restrict the overpressure to 10% above design with the relief valves fully lifted.

See Appendix E.

- 6.4.3 The design of all pressure relief devices discharging to a closed relief system shall take into account the maximum back-pressure arising at the discharge of the device for the particular overpressure case under consideration. Additionally, the mechanical design shall be suitable for the maximum back-pressure to which a device can be exposed as a result of other devices relieving.

6.5 Installation of Pressure Relief Devices

6.5.1 Use of [API RP 520](#)

Pressure relief devices shall be installed generally in accordance with Part II of [API RP 520](#) as amplified and amended below.

- 6.5.1.1 Relief devices intended to relieve vapour shall be connected to the highest point of the equipment to be protected. Where this is not possible and there is the possibility of liquid above the relief device inlet line the relief device shall be sized for an equivalent volumetric rate of liquid.

6.5.2 Isolation of Pressure Relief Devices

- * 6.5.2.1 The installation of block valves or spades in any location where they could isolate a vessel or system from a pressure or vacuum relief device or downstream flare system shall not be permitted without the prior approval of BP. Their use shall be permitted only where they are considered essential to safeguard the operation of the unit, and shall be subject to the provisions of 6.5.2.2. All such valves shall be locked open during normal operation. See also 8.2.4 to 8.2.6 of BP Group [RP 44-3](#).

Operating centres may wish to consider a formal means of identification (by colour or notice), in addition to the requirement of including them in the Register of Safety-Related Devices (see 3.14), of those valves which should be locked open or shut during normal operation.

It shall be recognised that some block valves or spades are vital to the maintenance of items on operating units. These should be kept to a minimum identified and a procedure put in place for controlling their use.

- 6.5.2.2 The installation of block valves to isolate pressure relief devices is acceptable to BP where relief devices must be inspected or need to be maintained during the protected equipment operation, provided that an additional relief device is installed so that 100% design relieving capacity is available with any relief device out of service.



Such block valves shall be fitted at the inlets to all the relief devices, and also at discharge if this is to a closed system. Isolation valves are also acceptable downstream of single relief valves to isolate them from a closed disposal system.

All such block valves shall be locked open or interlocked, by a system approved by the operating management. A physical means of securing the isolating valve is preferred.

Often changeover valves are a much better way of arranging the valving where a spare relief device is installed to allow on-line maintenance of the device. See also 6.5.4.2.

6.5.2.3 A valved and blanked drain connection of minimum size NPS 3/4 (DN 20) shall be provided between the relief device and any upstream block valve. A similar vent connection shall be provided between the relief device and any downstream block valve.

6.5.3 Location of Pressure Relief Devices

6.5.3.1 Pressure relief devices shall be installed in such a manner that the inlet drains back to the equipment being protected, subject to the need to drain the discharge side to a header. Wherever possible, they should be placed directly on the equipment or pipeline they are protecting.

Pressure relief devices for fractionating columns should not be fitted to reflux drums or to overheads piping in such a way that reflux pump failure can cause flooding of the inlet to the device. They should normally be fitted between the fractionating column and the overheads condenser.

* 6.5.3.2 Unless otherwise specified by BP, permanent access shall be provided to the following:-

- (a) All rupture disc locations.
- (b) Those pressure relief valves which require inspection and/or maintenance between major plant shut-downs.

6.5.3.3 Pressure relief devices discharging into a closed system shall be located such that there is a continuous fall from the devices to the downstream knock-out drum, so that the lines contain no liquid traps.

6.5.3.4 Relief valves shall be mounted in a vertical position.

6.5.4 Inlet Piping to Pressure Relief Devices

6.5.4.1 Where pressure relief devices are not placed directly on the equipment or pipeline they are protecting, their inlet piping should be as short as



possible, and shall have a bore area at least equal to that of the pressure relief device inlet, and shall drain back to the equipment being protected.

- 6.5.4.2 The total pressure loss between the equipment or pipeline protected (including the pipe-entrance loss) and a pressure relief valve inlet shall not exceed 3% of the set pressure of the valve for the flow corresponding to the installed valve area, i.e. the maximum rated flow for the valve.

API RP 520 Part II requires that the pressure drop in the inlet lines shall be less than 3% of the relief valve set pressure. This is to prevent the pressure drop causing the pressure at the valve to drop sufficiently for the valve to attempt to reseal, causing chattering and mechanical damage. Since installed valves are normally larger than needed, the calculation should be done on the basis of the flow which is possible through the installed relief valve. This recognises that, when connected to large gas volumes, the flow through the valve for short periods will be that possible through the valve, rather than that which is required to be relieved.

Particular care should be taken where two or more relief devices are teed off a single vessel nozzle. The pressure drop introduced by a tee in a line one size larger than the relief device inlet will often introduce a pressure drop of more than 3% of set pressure.

- 6.5.4.3 Inlet piping shall be heat traced where the fluids handled have pour or freezing points above the lowest ambient temperature, or where fluids which become viscous when cold are handled. (See also 7.5).

- 6.5.4.4 Inlet piping shall not be susceptible to blockage in the event of failure of other equipment such as level-control float balls.

- 6.5.4.5 Isolating valves shall be so selected as to minimise the pressure loss in the inlet line. This is particularly important when providing ball valves for LPG service, in which case the valves shall be full-bore.

- 6.5.5 Installation of Rupture Discs

- 6.5.5.1 The effects of the recoil resulting from the bursting of a disc shall be taken into consideration in the design of the vessels and piping to which rupture discs are fitted. Discharge lines should, so far as practicable, be straight.

- 6.5.5.2 Correct fitting of a rupture disc is essential to ensure satisfactory operation. Installation shall be to the manufacturer's instructions.

Consideration should be given to the use of discs fitted with an interference-type locating device to prevent fitting of the unit upside down.

Extreme care should be taken when fitting reverse-acting bursting discs, since irreversible damage (e.g. knocks) to a metallic disc will cause premature bursting.

This should also be borne in mind when working on a vessel with a fitted disc (e.g. dropping a bolt down a stack or damaging the disc with tools during routine vessel cleaning etc.).

6.5.5.3 Discharge from rupture discs may, where appropriate, be to atmosphere, subject to the requirements of BP Group [RP 44-3](#). Where it is desirable to reduce the loss of contents of a vessel or system, a pressure relief valve in series with a rupture disc may be used, normally downstream of the disc. Alternatively, two bursting discs in parallel with a 3-way valve may be used, to permit a change to the second disc upon failure of the first.

* 6.5.5.4 Where a rupture disc is installed in series with a relief valve, or where two discs are installed in series, a local pressure indicator shall be installed between them, and a permanent vent, directed to a safe location, shall be provided between the two. Where specified by BP, the vent shall be fitted with an excess flow valve.

Where two relief devices are fitted in series, the space between the two must be vented to prevent slight leaks from the first device causing the second to open. However, if there is a vent the flow must be stopped in the case of the first device operating as designed. Thus the excess flow preventor is used to allow the second device to open fully when required, by allowing it to experience the full pressure and flow.

6.5.5.5 If a burst rupture disc is likely to discharge solid material such as polymer, arrangements should be made to pass the discharge directly to a second vessel where the solid material may be retained, the gaseous element being discharged to atmosphere, to treatment, or to flare, as appropriate.

7. RESPONSIBILITIES OF OWNER/OPERATOR

The Owner or Operator has always had responsibilities for the safety of his employees and the general public. He also has a responsibility for the security of the assets entrusted to his keeping. This Practice now records the specific actions which are required of him to enable him to discharge those responsibilities. In line with other safety procedures this allows a clearly defined, auditable and limited action plan to be created.

7.1 The Owner/Operator shall ensure that the contractor has produced an adequate Register of Safety-Related Devices before commissioning a new unit or starting up a modified unit.

7.2 The Owner/Operator shall ensure that there is an adequate management system for updating the Register of Safety-Related Devices when any pertinent modification to equipment or throughput is made.



- 7.3 The Owner/Operator shall ensure, prior to construction, that it is possible and convenient to operate the unit with the requirements for:-
- (a) Locked open block valves
 - (b) Category 1 or 2A trip systems, especially with respect to their reliability, testing, prevention of bypassing and maintenance.
 - (c) Any statutory or local requirements for relief device maintenance.
 - (d) Draining of heat exchangers upon blocking in while the unit is in operation.
 - (e) Maintenance of heat resistant insulation in an adequate condition.
- 7.4 The Owner/Operator shall ensure that it is possible to meet the needs of shutting down units for maintenance with respect to the needs to isolate and gas free the relief disposal system.
- 7.5 The Owner/Operator shall ensure that there is an acceptable disposal route for hydrocarbon liquids from disposal system knock out drums and water from knock out drums and water seal drums at all times.
- 7.6 The owner/operator shall institute and update as necessary a management system for ensuring that all parts of the overpressure protection system are in place, performing to requirements and tested at the required frequency while the plant is operating. This shall include:-
- (a) Any blocked valves identified as being locked open or closed.
 - (b) All relief devices which are in the Register.
 - (c) All Category 1 or 2A trip systems.
 - (d) All control valves, bypasses and restriction orifices identified in the Register as being significant for the overpressure protection system design.
 - (e) Any fire-resistant insulation.

To achieve these objectives, many sites have found it useful to have a colour coding or tagging system to readily identify these items. For restriction orifices, it has also been found useful to include the orifice in a spool piece to make its omission obvious during maintenance.

DEFINITIONS AND ABBREVIATIONS

Definitions

Standardised definitions may be found in the BP Group RPSE Introductory Volume.

The technical terms used in this Recommended Practice have the meanings as defined in Para. 1.2 of [API RP 521](#). Note, however, that rupture discs are referred to in [BS 2915](#) as bursting discs.

The following additional technical definitions also apply:-

category 1 trip systems:	these are very reliable trip systems intended to prevent unsafe situation such as pressure relief. They are defined in BP Group RP 30-6 .
closed disposal system:	a closed disposal system is a system of piping to which relief flows from more than one relief or pressure control device can be directed. It may terminate in an atmospheric vent, combustion device or other specialised treating equipment. See BP Group RP 44-3 .
heat-off:	stopping the heat input to a plant or section of a plant with either manual or automatic initiation.
let-down station:	a flow restriction where the upstream operating pressure is greater than the downstream design pressure. It normally consists of an arrangement of valves and orifice plates.
pressure-limiting instrumentation:	instrument systems which act to minimise the size or frequency of relief loads by automatically adjusting process conditions when they tend towards a relief situation. These are not Category 1 trip systems.
reliability analysis:	a mathematical technique for assessing in probabilistic terms the performance of a component, system or plant.
relief device:	a relief device is any device (mechanical or instrumentation) which acts automatically and reliably to relieve material on pressure rise. It normally refers to pressure relief valves and

bursting discs, but explosion hatches, water seals, buckling pin devices and pressure/vacuum breather valves are among the devices which meet this requirement. Normal process control instrumentation of single loop type do not.

Abbreviations

ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
BS	British Standard
DN	Nominal diameter
EEMUA	The Engineering Equipment and Materials Users Association
HAZOP	Hazard and Operability Study
IP	Institute of Petroleum
ISO	International Organisation for Standardisation
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
NGL	Natural gas liquids
NPS	Nominal pipe size
TUV	Technische Verwachungs Vereine (Technical Supervisory Societies)
UK	United Kingdom
UKOOA	United Kingdom Offshore Operators Association.
US	United States of America

LIST OF REFERENCED DOCUMENTS

A reference invokes the latest published issue or amendment unless stated otherwise.

Referenced standards may be replaced by equivalent standards that are internationally or otherwise recognised provided that it can be shown to the satisfaction of the purchaser's professional engineer that they meet or exceed the requirements of the referenced standards.

International Documents

[ISO 4126](#) Safety valves - General Requirements.

UK Documents

[BS 2915](#) Bursting discs and bursting disc devices.
[BS 5500 : 1988](#) Unfired fusion welded pressure vessels.
[BS 6759: Part 1](#) Safety valves. Part 1. Specification for safety valves for steam and hot water.
[BS 6759: Part 2](#) Safety valves. Part 2. Specification for safety valves for compressed air or inert gases.
[BS 6759: Part 3](#) Safety valves. Part 3. Specification for safety valves for process fluids.
[BS CP 2010](#) Code of practice for pipelines.

[IP Model Code of Safe Practice: Part 6](#) Pipeline safety code.
[IP Model Code of Safe Practice: Part 9](#) Liquefied petroleum gas.

American Documents

[ANSI B16.5](#) Pipe flanges and flanged fittings.
[ANSI/ASME B31.3](#) Chemical plant and petroleum refinery piping.
[ANSI/ASME B31.4](#) Liquid transportation systems for hydrocarbons, liquid petroleum gas, anhydrous ammonia, and alcohols.
[ANSI/ASME B31.8](#) Gas transmission and distribution piping systems.
[API RP 14C](#) Recommended practice for analysis, design, installation and testing of basic surface safety systems for offshore production platforms.

[API RP 520: Part I](#) Sizing, selection and installation of pressure-relieving devices in refineries. Part I - Sizing and Selection.
 Fifth Edition 1990



API RP 520: Part II Third Edition 1988	Sizing, selection and installation of pressure-relieving devices in refineries. Part II - Installation
API RP 521 Third Edition 1990 API Std. 526 API Std. 2000	Guide for pressure-relieving and depressuring systems. Flanged steel safety-relief valves. Venting atmospheric and low-pressure storage tanks. (Non-refrigerated and refrigerated).
ASME VIII : 1986	Boiler and pressure vessel code. Section VIII. Rules for construction of pressure vessels.

UK Documents

EEMUA Publ. No. 160	Safety related instrument systems for the process industries (including programmable electronic systems)
ETC Safety Report ETC.88.SR.001	Prevention of overpressure on the suction side of centrifugal pumps.
UK Health and Safety Executive PES 1	Programmable electronic systems in safety related applications. 1 An introductory guide.
PES 2	Programmable electronic systems in safety related applications. 2 General technical guidelines.

BP Group Documents

BP Group RP 12-1 to RP 12-19	Electrical systems and installation (replaces BP CP 17)
BP Group RP 24-2	Passive fire protection of structures and equipment (replaces BP CP 16)
BP Group RP 30-1	Instrumentation (replaces BP CP 18)
BP Group RP 30-6	Protective instrumentation systems (replaces BP CP 48)
BP Group RP 32-3	Inspection and testing of plant in service (replaces BP CP 52)
BP Group RP 34-1	Rotating machinery (replaces BP CP 10)
BP Group RP 42-1	Piping systems



	(replaces BP CP 12)
BP Group RP 43-1	Pipelines and associated installations (replaces BP CP 43)
BP Group RP 44-3	Flare systems (replaces BP CP 25)
BP Group RP 44-4	Guide to depressurisation (replaces BP CP 37)
BP Group RP 46-1	Unfired pressure vessels (replaces BP CP 8)
BP Group RP 50-2	Guide to reliability and risk analysis (replaces BP CP 62)
BP Group RP 58-1	Non-refrigerated petroleum and petrochemical storage (replaces BP CP 11)
BP Group GS 134-7	Special purpose steam turbines to API 612. (replaces BP Std 198)
Note:	EEMUA publications are available from:- The Engineering Equipment and Materials Users Association 14-15 Belgrave Square LONDON SW1X 8PS



REGIONAL ANNEX

Local Regulations

This Recommended Practice does not necessarily include the requirements of all local statutory regulations. However, note that the UK and many other countries have regulations affecting overpressure protection, which must be complied with. The most important examples are:-

- (a) The provision of pressure relief devices in steam-raising and compressed air installations.
- (b) Such restrictions as may be imposed on atmospheric discharge.
- (c) The method of sizing pressure relief devices.

It has been established as a principle throughout the BP Group RPSEs that they should not necessarily incorporate or pre-empt the statutory requirements of any particular country, unless these reflect economical practice in their own right.

This applies particularly to the subject of overpressure protection. However, it must be recognised that there are restrictions on atmospheric relief discharge in a number of countries, e.g. Canada, The Netherlands, West Germany and Sweden, and it is therefore realistic to have an economical basic design policy available if total atmospheric relief restrictions are imposed.

This entails particularly taking credit for the operation of pressure-limiting instrumentation to reduce the frequency of discharge, thus avoiding criticism on the pollution aspect, and also taking credit in the actual sizing of closed systems for such pressure-limiting instrumentation.

APPENDIX D

This Appendix contains the text of a BP document signed by B.L. Wright - Chairman BP Protective System Working Party, and having the following title:-

WORKING PARTY ON PROTECTIVE SYSTEMS

RELIEF DESIGN GUIDELINES FOR LET-DOWN STATIONS

Issued May 1988



RELIEF DESIGN GUIDELINES FOR LET-DOWN STATIONS**D1. INTRODUCTION**

After the incident on the Grangemouth Hydrocracker in March 1987, a Working Party was established to examine the important let-down and other lessons the BP Group should take from that event. Representatives from BP Exploration, BP Oil International, BP Chemicals, Group Safety and the Engineering and Technical Centre made up the team. The most important of those lessons are presented below as design and operational guidelines. A full Report will follow. Businesses should give serious consideration to applying these guidelines retrospectively. (BP Group RP 44-1 Editorial note: The Report is restricted to BP Personnel. It does not add to or modify these Guidelines in any way.)

D2. DEFINITIONS**D2.1 A Let-Down Station**

A let-down station is a flow restriction where the upstream operating pressure is greater than the downstream design pressure. It normally consists of an arrangement of control valves, valves, and/or orifice plates.

'Choke' valves in Exploration and Production operations are Let-Down Stations.

Less obvious situations could include reverse flow through pumps or non-return valves, drains to closed drain systems, heat exchanger tube failures.

D2.2 A High Reliability Trip System

High reliability trip systems are those systems which are used in place of, or to reduce the size of relief systems. They are normally composed of multiple detectors and shut-down valves with signal voting systems. They require a full reliability analysis and regular testing under strict supervision. They are referred to as Category 1 systems in BP Group RP 30-2.

D3. RELEVANT STANDARDS

The Practices containing the guidelines for the design of relief systems in general are [API RP 520](#), [API RP 521](#), BP Group RP 44-1 and BP Group [RP 44-3](#). Generally, these Practices are adequate; these guidelines are intended to amplify those Codes.



D4. LET-DOWN STATION RELIEF DESIGN CONSIDERATIONS

In considering process systems where fluids pass through a let-down station, as defined above, from a high pressure system to a low pressure system, the low pressure system must be protected from overpressure. Relief devices should be sized to take into account the fluid conditions and all undesirable circumstances in the operation of the let-down station.

D4.1 Design for Gas Breakthrough

The circumstances should include all valves across the let-down station being open and gas breakthrough in liquid systems. Any bypass valves across the station should be assumed to be fully open and not simply to have the equivalent opening to normal process operation. This latter requirement may require smaller bypass valves or restriction orifices (in the case of existing plant) to be installed consistent with normal process flows. Detailed design data are given in Appendix 1 of this working party document.

D4.2 Design for Liquid Overfill

In addition to the gas breakthrough case, the opening of the letdown valve from the normal, liquid containing, operating situation could displace the high pressure vessel liquid inventory into the low pressure vessel. If this occurrence could cause overfilling of the low pressure vessel, when starting from normal operating levels, then full liquid relief capacity will also need to be provided from the low pressure vessel. This can take two forms:-

Either

Full liquid relief capacity shall be provided, together with suitable means of disposing and holding a sufficient quantity of liquid. (see BP Group [RP 44-3](#))

Or

A high reliability trip shall be provided to stop further liquid inflow a sufficient time before the equipment space is filled.

In addition, normal process trips to reduce the frequency of demand on these ultimate safety systems are a sensible precaution.

D4.3 Operating Conditions

The designer shall consider the full range of operating conditions from purging, through pre-start-up and start-up procedures to shut-down,

regeneration and gas freeing. If there is a range of operating conditions, then the extreme must be used in the calculation.

The calculation of gas flow where gas breakthrough is possible should be based on gas at the normal operating conditions and properties unless it is known that there are situations (e.g. at startup) where more arduous conditions are possible.

D4.4 Control Valve Sizing

In designing the relief system, the size of the let-down valves is one of the limiting factors. It is vital that the installed valve size is reflected in the relief calculations and that the basis is clearly defined. Since the control valve trim size and the size of any orifice plate in the bypass are central to the relief case, this data should be listed with the relief valve data as part of the relief system and should not be changed without appropriate resizing calculations. In new plant design control valve definition often comes late in the programme. Relief valve checks must be made after control valve selection.

D4.5 Credit for Open Outlets

The HAZOP approach is needed to specify the operating scenarios under which relief conditions including gas breakthrough could occur. Among these conditions there normally will be one (e.g. at start-up) where the normal outlets would be blocked, preventing any credit being allowed for the flow through these outlets.

D4.6 Credit for Operator Intervention

In the design of relief systems on let-down stations in either vapour or liquid relieving situations, no credit shall be taken for operator intervention on the process plot.

D4.7 Credit for Instrumentation

Where conventional design leads to an impractical or grossly uneconomic solution, e.g. offshore or pipelines, then a high reliability instrumented system may be considered as an alternative to providing relief.

Consideration should be given to minimising the frequency and extent of relief valves operating. Any instrumentation (which is not high reliability) used for this purpose shall not contribute to a reduction in the design capacity of the relief system.

D4.8 Design for Multiple Jeopardy

Relief design philosophy has considered, and still considers that it is unrealistic to design systems for simultaneous occurrence of two unrelated emergency conditions. The application of the thought processes included in the HAZOP approach often identifies that conditions which might otherwise be considered as separate have, in fact, a common cause. Such identification requires these conditions to be included in the design.

D4.9 Bypass Sizes and Restrictors

Where existing units need to be modified to meet the requirements of this guide then the options available for change are:-

- (a) To remove the bypass.
- (b) To install smaller bypass valves.
- (c) To add restriction orifices.
- (d) To lock the bypass valves closed.

These are in descending order of acceptability.

D4.10 Temperature Effects

Since there can be appreciable temperature effects when hydrocarbon gases are reduced in pressure, the significance of these temperature changes need to be considered in both relief valve sizing and the suitability of the materials of construction.

D4.11 Interconnecting Pipework

Normally in design, pipework lengths and valve sizes are such that the flow is determined by pressure drop through the valve rather than through the piping. However, this is not necessarily so in all retrofit cases and checks should be made.

Where credit is to be taken for the influence of piping pressure drops, the relevant data needs to be recorded in the Register of Safety Related Devices.

D5. REGISTER OF SAFETY RELATED DEVICES

A Register shall be furnished by the designer for new plant and should be created from existing data on all units before modifications are agreed. The register of safety related devices on each site should be updated to reflect all modifications.

It should include:-



- (a) A list of all the relief valves with their size, type, set pressure and design capacity. In addition, the relief summary table [see BP Group RP 44-1 para 3.7.2 (c)] should be completed for new plant and provided for existing plant on a selected basis. (BP Group RP 44-1 Editorial note: The paragraph reference in the May 1989 issue of BP Group RP 44-1 is 3.6.2(c).)
- (b) A list specifying the data pertinent to a let-down station. This should include the size, type and fully open flow coefficient of the limiting valves or orifices in every route between the high and low pressure systems.
- (c) High reliability trip system data. For each system it should include a schematic with every component specified together with the testing frequency and a reference to the study report which defined the system's reliability.
- (d) A list of all equipment whose relief design capacity has been reduced as a result of insulation. It should include the type, thickness and thermal conductivity of the insulation, together with details of the cladding and fixing methods.
- (e) Where distributed control is fitted annotated diagrams showing the segregation which prevents common cause instrument component failures producing unacceptable process relief loads.
- (f) Where credit is to be taken for the pressure drop in interconnecting pipework to reduce the gas flow for the gas breakthrough situation, then the pipe lengths, diameters and fittings shall be included.

D6.

LET-DOWN STATION MODIFICATIONS

Since modifications to any of the items contained in this Register could jeopardise the safety of the plant, systems must be in place to prevent unauthorised modifications and to authorise modifications after suitable review of the implications.

One way of assisting such a system is to mark all safety devices and/or paint all relevant equipment a specific colour.

D7. HAZOP REVIEWS

A HAZOP review should always be included as a part of the Stage 3 of the Project Safety Review or the equivalent stage of a site modification procedure. In addition, all existing units which have not previously been subject to a HAZOP review should be reviewed on a selective basis.

D8. PROJECT SAFETY REVIEWS

Every business should check that it has set up such systems as will enable it to be confident that all six stages of the Project Safety Review Procedure are carried out on every Project in its area of responsibility.

D9. DESIGN CONTINUITY

Businesses should make every effort to ensure that the process engineering staff involved with a design should remain with the Project from the conceptual stage through to commissioning.

D10. ACKNOWLEDGEMENTS

The Working Party would like to thank a range of contacts for their contributions to these Guidelines.

If users and designers have comments or suggestions to improve the Guidelines, then BP Engineering would be pleased to receive them.

ADDENDUM 1 - HOW TO DESIGN FOR GAS BREAKTHROUGH

To calculate the amount of gas breakthrough from a high pressure system to a low pressure system with the letdown valve fully open, the high pressure system should be assumed to be at its normal operating pressure and temperature and with its normal molecular weight gas. These values should be modified if there is a known condition where distinctly different values prevail. Particular effort should be made to ensure that all possible operating conditions have been considered. The C_g (the valve sizing coefficient for gas) of the actual letdown valve(s) and any bypass valves in their fully open position should be determined. (Control valves have different loss/flow coefficients for gas or liquid flow and since the valve will have been installed and sized for liquid, it may be necessary to contact the manufacturer for the information.) With this data the manufacturer's equation for gas flow can be used to calculate the volume flow between the high pressure system operating pressure and the low pressure system relieving pressure.

In addition to the gas breakthrough case, thought needs to be given to the effect of displacement of large quantities of liquid from the high pressure system and piping into the low pressure system. If the low pressure system gas space is not large enough to accommodate this liquid, then the relief valves and relief lines need to be sized to accept this liquid.

It should be noted that where manual bypasses are installed around the letdown valve they are often much larger than the control valve. Therefore, the gas flow by this route could be several times greater than through the control valve alone, requiring a corresponding increase in relief capacity. The gas flow should be calculated on the basis of all control valves and the bypass valve being open simultaneously. Since it is unlikely that such a large extra flow capacity is needed operationally, it is sensible to reduce the flow possible through the bypass by removing the valve, modifying the valve size or installing a restriction orifice. Having determined the quantity of material which can be presented to the low pressure system it is first necessary to check the capability of the existing or intended relief valve to cope with the flow. In many existing cases it will be found that the relief valve(s) is not sized for this case. Each country has its own National Code specifying the equations and coefficients to be used in sizing relief valves. Therefore, the appropriate equation must be used.

If a larger relief valve is needed, a check must also be made of the relief valve inlet and outlet line sizes required.

[API RP 520](#) Part II requires that the relief valve inlet pressure loss should be less than 3% of valve set pressure at the flow possible through the installed valve area to prevent valve chattering. Generally, the inlet line needs to be at least as large in diameter as the relief valve inlet flange to satisfy this requirement. Often on modifications the existing vessel nozzle is smaller. If the relief valve inlet line is very short and has no other fittings (particularly tees) it is sometimes acceptable to have a vessel nozzle one size smaller than the relief valve inlet flange but detailed calculations are necessary to check this.



This relief case may not be concurrent with other relief flows. In this case, pressure drop calculations only need to consider the one case. It is a Code requirement that the size of the relief line is not smaller than the relief valve discharge flange. If other systems may relieve concurrently into the same downstream pipework as a result of common cause failure (e.g. utility failure) then the resultant total relief load must be taken into consideration.

Typically for refinery process plant, the low pressure system will have a design pressure of at least 7 bar (ga). At this design pressure the allowable backpressure would be about 0.7 bar (ga) for a conventional valve or 3 bar (ga) for a balanced bellows relief valve.

It is worth noting that the discharge lines should slope continuously to the Knock Out Drum to prevent liquid accumulations which would increase the pressure drop significantly. If liquid can accumulate on the discharge side of a relief valve it will increase the pressure at which the valve will lift, perhaps endangering the vessel.

The answer to the choice of disposal route for the relief (to flare or blowdown) must depend on the most practical individual solution. Since the gas breakthrough case may not be coincident with other relief flows, there will normally be adequate flare capacity. Thus it would be the first choice for consideration. In newer units there will normally be a large enough line feeding the flare within a few tens of metres of the low pressure system to make the cost of this route relatively low.



SUPPLEMENTARY COMMENTARY

E1. OVERALL PHILOSOPHY

This Commentary relates to clause 2.1

It should be noted that BP Group RP 44-1, though not covering practice for flare systems, (this is covered by BP Group [RP 44-3](#)) establishes an outline of basic BP design practice for overpressure protection of plant in petroleum production areas, both offshore and onshore, with separate consideration for main transmission pipelines and associated equipment.

Offshore protection devices include diverter systems.

The background to present BP practice is that up to the late 1960s (roughly before the publication of [API RP 521](#)), refinery designs for closed relief systems were commonly based on separate units with no integration. Process units were generally smaller than at present (1989) and water was the important cooling medium.

Emergency pressure relief to atmosphere was accepted by BP, provided that it was below 1-2% H₂S content, below a molecular weight of 72, and permitted by statutory regulations. Other reliefs were taken to flare, the flare system being then sized on total discharge from the 'largest relieving unit'.

With the development of the 'integrated refinery' design approach, the increased use of air cooling and much larger process units, the BP philosophy was modified accordingly. To adopt a conservative interpretation of API recommended practices involves limited cost where safety relief devices discharge to atmosphere, but considerable cost, both capital and operating, where relief is to flare.

This led to a development of the principle that emergency hydrocarbon reliefs should be taken to atmosphere wherever this could be regarded as 'safe'. The general criteria for this were 1-2% H₂S content, condensibility (associated with a generally-accepted increased molecular weight of 100) and restrictions on location and velocity of discharge. A nominal restriction was placed on flare line size, i.e. NPS 24 (DN 600) preferred maximum. Further, 'heat-off' or machinery trip systems, actuated manually or automatically by pressure rise, were introduced to cut off heat sources or feed to systems being relieved, thus avoiding or severely limiting the relieving flow.

However, it should be noted that, apart from Category 1 or 2A instrumentation, no automatic relief-limiting systems are accepted by BP in any way as viable alternatives, as such, to the provision of pressure relief devices in accordance with our interpretation of the API recommended practices. The point has arisen in numerous cases and to meet it has entailed considerable cost. The design basis,

criteria for acceptability and specific equipment and other requirements for Category 1, 2A and 2B instrumented trip systems are now defined in BP Group [RP 30-2](#).

Where atmospheric relief was permitted, the practice developed of using primary relief to flare and secondary relief to atmosphere with additional protection by 'heat-off' devices. Where no atmospheric relief has been permitted, 'heat-off' devices were used to minimise the relief to flare, and in some installations, the operation of 'heat-off' systems was assumed in reducing the capacity and size of the flare line.

It became generally accepted that a refinery closed relief system should be designed to accommodate a single emergency or related group of emergencies, affecting the entire refinery, i.e. the 'largest single risk' instead of the largest relieving unit. The identification of the former is much more open to interpretation.

It has been considered in BP Group [RP 44-1](#) that the earlier practice of requiring or preferring any basic arbitrary size restriction on a closed relief system is not in accordance with the best principles of safe design, and should be discontinued (see BP Group [RP 44-3](#)). So also should the 'double-relief' approach, never written in BP practice, to which restriction of the size of a closed relief system appears to have led, i.e. initial relief, arbitrarily sized, to the closed system followed by further relief, sized for 100%, to atmosphere. However, a double-relief approach might be accepted, if there are separate causes of overpressure that can be distinguished in magnitude and frequency.

The closed disposal system pressure profiles are generated from the Principal Flare Loads and the Pipeline Equivalent Lengths. Apart from demonstrating that the system is adequately designed they enable a designer to determine immediately where there is spare capacity for upgrades and modifications, or the scale of costs involved in such modifications.

E2. DESIGN PRACTICE

This Commentary relates to clause 4.1.1

Apart from the normal operating mode all units have a range of other operating conditions which are either necessary for maintenance or occur as a result of upsets. These include:-

- (a) *Pressure and tightness testing.*
- (b) *Pre-start-up and start-up.*
- (c) *Catalyst conditioning.*
- (d) *Normal and emergency shutdown.*
- (e) *Depressuring.*
- (f) *Catalyst regeneration/passivation etc.*
- (g) *Removal of inventory from unit.*
- (h) *Gas freeing.*



In the failure cases listed the following explanations may help.

- (i) Equipment failure includes: the loss of pumps, aircooler fans or compressors.*
- (j) Reverse flow normally gives a relief case where a feed pump to a gas/liquid system stops and the high pressure gas can flow into the low pressure liquid system. It is normally less of a problem if the system is liquid only since very little material needs to be released, but calculations need to be performed to check this.*
- (k) On distributed control systems there is the possibility of several control loops to be driven in the opposite direction to the 'fail-safe' position if an item of the control system fails in a particular manner. The control system failure modes need to be examined to check this possibility. If this is possible the normal solution is to segregate the loops which can be affected to different parts of the process. Such segregation then needs to be recorded on the 'Distributed Control Loop Segregation' table of the Register of Safety Related Devices (para 3.18).*
- (l) Partial utility failure cases include the loss of one part of the utility system. This can be the total or partial loss of one voltage on electrical systems or one arm of a piped utility. It will often produce a larger relief case than a total utility failure.*

This Commentary relates to clause 4.1.3

Those processes (mainly petrochemical) which require the addition of catalyst or chain termination agents have very specific and difficult to calculate relief situations when either too much or too little of these agents is added or the temperature control mechanisms fail to perform properly.

In bringing a new process from pilot plant to full scale the designers will attempt to tailor the process so that it can become self controlling to a large degree. Even so, some or all of the upsets listed can cause excessive vapour generation causing overpressure. As far as possible the design temperature and pressure of the equipment should be such as to contain or suppress these reactions. This may not be possible and relief or Category 1 or 2A instrumented trip systems may be necessary.

This list of possible upsets in 4.1.3 may not be exhaustive and a thorough knowledge of the process and its reaction kinetics is vital in identifying the possible upsets so that a safe plant can be designed.

- (a) A knowledge of the reaction kinetics and the equipment which adds the reactants should enable a simulation to be performed to determine the amount of excess material which needs to be relieved.*

- (b) *It should be possible from the design of the catalyst addition system to identify how much excess catalyst could be added from a single failure scenario. The reaction kinetics should then enable a simulation to be made of the result and the quantity and properties of the excess material that must be removed.*
- (c) *A loss of agitation will reduce cooling allowing exothermic reactions to speed up. It may also allow local high concentrations of reactants with side reactions or local heating. It is most likely that pilot plant studies are needed to quantify the scale of relief needed in this situation.*
- (d) *A loss of cooling will probably result in the reaction occurring at a higher temperature. Pilot plant work should have identified the results of this situation and what is the appropriate response. The most likely actions that are required are quenching or depressuring. Either of these solutions will require a Category 1 or 2A instrument system.*
- (f) *The solution for 4.1.3.2 will apply here.*
- (g) *One of the above scenarios would fit this circumstance.*

E3. RELIEF LIMITATION BY DESIGN

This Commentary relates to clause 4.2

As a contrast with the question of the application of pressure-limiting instrumentation in pressure relief design, on which there continues to be discussion and controversy, it should be noted that there has never been any serious objections put forward to the application of basic design measures as exemplified in 4.2 of this Recommended Practice. However, they must of course be basically economical and be considered at a very early stage in the design.

This Commentary relates to clause 4.2.1

Some of the design measures that can be used are:-

- (a) *The design of vessels and equipment for pressure containment in emergency, rather than relief, if reasonably practicable and economical.*

For some services, pollution and flaring restrictions should be considered in establishing the differential between operating pressure and pressure at which the pressure relief device operates or a control valve discharges to flare. For example, a higher separator relief valve set pressure would accept pressure fluctuations which would otherwise cause excessive gas flaring.

- (b) *Independent subdivision of utility facilities, imported and/or generated on site, e.g. power, steam and compressed air, so that partial failure rather than total failure may be considered as a controlling design condition.*

The segregation of utilities to reduce relief should consider the impact of a failure of one independent part of the system on the relief system.

- (c) *The provision of two or more electrical feeders or generators to a site or part of a site requiring power supplies, the loss of which may give rise to overpressure conditions. Electrical feeders and generators shall be so rated, connected and protected, that failure of any single element will not interrupt continuity of supply from other sources (refer to BP Group RP 12 for general electrical requirements).*
- (d) *The design, selection and protection of control equipment and other service systems to minimise the possibility of simultaneous failure of otherwise independent systems.*
- (e) *The use of auxiliary sources of power, such as diesel engines or steam turbines, to provide cooling water under emergency conditions.*
- (f) *Provision of automatic re-acceleration schemes for electric motor drivers, the loss of which may give rise to overpressure conditions. These schemes may re-accelerate motors simultaneously or sequentially depending on the capability of the power supply.*
- (g) *The use of the same utility for cooling as for heat supply, e.g. steam or steam/hydraulic drivers for air coolers and reflux pumps, where steam-driven feed pumps and reboiler pumps or steam-heated reboilers are used.*

It may be noted that in the design of one UK refinery (Conoco, Humberside), hydraulic drivers, with steam as a centralised power medium, were used for air-cooled heat exchangers to maintain cooling in the worst emergency case, i.e. electrical power failure. This was as a direct result of a policy of avoiding atmospheric relief discharge, leading to a need to keep the size of the closed relief system to reasonable proportions. However, there is no indication that such systems are likely to be widely regarded as economical practice.

- (h) *Consideration of the effect on relief systems when selecting all process and auxiliary drivers. All types of driver may be initially considered.*
- (i) *The provision of cooling water stand-by tanks to give a period of assured water supply, normally 30 minutes.*
- (j) *Consideration of layout for the external fire condition (refer to 4.10.2).*

- (k) *Protection by insulation of selected equipment against fire, if fire conditions require capacity in excess of that required for any other emergency conditions, so that the discharge is kept within acceptable limits (refer to 4.9.6).*

E4. PRESSURE-LIMITING INSTRUMENTATION

This Commentary relates to clause 4.3

The installation of the type of protective instrumentation referred to in BP Group RP 44-1 as 'pressure-limiting instrumentation' has been developed for some years in the context of 'heat-off', shutdown and depressuring systems. Its application as a direct policy of overpressure protection represents, however, a distinct change in emphasis. Its justification may be summarised as follows:-

- (a) *It is basically the most economical and safest pressure relief policy to discharge to atmosphere in emergency, subject to the safeguards required by BP Group [RP 44-3](#). However the attitudes of local authorities and fears of pollution must be anticipated by reducing the frequency of relief.*
- (b) *Any discharge from pressure relief devices results in a loss of product, and there is a financial incentive to minimise its occurrence. Discharge via a closed system to a flare not only involves loss of product but substantial capital expenditure to provide the system, and a significant revenue expenditure in providing purge gas, pilot lights, and possibly steam injection facilities. There is thus an even greater incentive to minimise its occurrence and magnitude.*

However, the following points should not be ignored when applying instrumentation as an alternative to relief devices, to supplement relief devices, or to minimise atmospheric discharge:-

- (a) *What appears to be a relatively straightforward trip system as drawn on a Piping and Instrumentation diagram and basic logic diagram can, when fully engineered, result in a complex logic system. This is particularly true in multi-column or multi-vessel systems where, say, cutting the feed to one column on high pressure can have a 'snowballing' effect on preceding vessels, columns and pumps.*
- (b) *Any savings made in the cost of plant, relief valves and rupture discs must be offset against the capital cost of the pressure-limiting instrumentation, and associated test facilities, and the on-going cost of maintenance and routine proof testing of the trip system.*
- (c) *Instrumentation on which the safety of the plant depends must be clearly identified from all other instrumentation, including trips, backed up by relief*

devices. This identification should appear in all documentation, from design through to operation. (Register item 3.16)

E5. USE OF RELIABILITY ANALYSIS

This Commentary relates to clause 4.4

BP Group [RP 30-2](#) - Protective Instrumentation Systems is in the course of preparation and this will supersede the Commentary below. However, until that time the information below is offered to help the process engineer understand the intricacies of the subject area.

Attention is drawn to the increasing use of the reliability analysis technique in quantifying the reliability of both operators and protective systems. It has become accepted as a valid engineering design technique in establishing the requirements for overpressure protection systems, and is taught as a technical university subject.

In this context, 'reliability' is defined here as:-

'That characteristic of a person or item expressed by the probability that they will perform their required functions in the desired manner under all the known relevant conditions and on the occasions or during the time intervals when they are required so to perform'.

In the use of this technique for design against overpressure, it is suggested that emphasis at present (1991) should still be placed on its general value in quantifying the factors involved, its use in comparing the reliability of alternative protective systems and in supporting cases for atmospheric discharge.

Imperial Chemical Industries p.l.c. in the UK have put forward a line of thought that considers the use of Category 1 instrumentation as an alternative to pressure relief devices, and considerable effort has been made to quantify relative reliability of pressure relief devices and automatic trips, also hazards in terms of probability and consequences, for design purposes. This leads to the philosophy that suitable instrumentation, adequately maintained and tested, can be used instead of pressure relief devices for equipment protection, and in fact can offer a higher degree of protection. This is considered as not contrary to the intent of the main pressure vessel design codes.

BP's approach to the use of instrumented trip systems and the consequential need for reliability analysis is defined in BP Group [RP 30-2](#).

Guidance on the use of BP Group [RP 50-2](#) is available from BP Engineering.

Category 1 instrumentation systems will not necessarily be of equal reliability for all installations. Throughout this Recommended Practice the term 'Category 1 or 2A'



has been used in preference to 'High Reliability' and 'High Integrity', to mean those instrumented trip systems that meet the requirements of BP Group [RP 30-2](#).

Guidance on hazard quantification (the assessment of the likelihood and consequences of hazards), is available from BP Engineering and BP Corporate Safety Services. This should be sought in all cases of significant, potential hazards.

Some sites will not have the number and quality of staff to support the level of maintenance and testing work arising. In such cases, Category 1 or 2A instrument systems cannot be employed.

E6. DESIGN PROCEDURE FOR PROTECTION OF EQUIPMENT, TANKAGE AND PIPING

This Commentary relates to clause 5.2.2.

Where tube failure produces the controlling relief case, the process design should be reconsidered to check if it is economical to eliminate the relieving requirement, e.g. by uprating the design pressure of the low-pressure side of the exchanger so that its test pressure equals the design pressure of the high-pressure side (see [API RP 521](#)). However, the other items connected to the low pressure side shall also be considered for uprating if they could be overpressured by a tube failure.

Although relief device sizing should be on the basis of a blocked-in exchanger, the steam or water system design must allow for the block valves not being closed, or leaking.

In assessing the behaviour of steam and cooling water systems for the burst tube and external fire conditions (see 5.2.2 and 5.2.3) the following should be noted:-

- (a) On steam systems, inlet non-return valves and downstream steam traps, where fitted, shall be taken as equivalent to closed valves, i.e. the steam side is completely blocked in.
- (b) On cooling water systems, although a downstream pressure escape route may normally be open, any isolating valves in it shall be regarded as closed in emergency, e.g. particularly if light flammable fluid is found to be leaking into a cooling water system. Accordingly in such cases, these systems should normally be regarded as blocked-in.

Each case for the possible fitting of pressure relief devices for this condition should be considered individually.

For example, where the pressure differential and potential leakage is great, such as with high-pressure gas coolers, or in any other case where a high pressure can rapidly build up on the low-pressure side with a tube failure during normal

operation, then a relief device should be fitted, but where a pressure leak can be accommodated in normal flow, a relief device should not be automatically fitted. Duplication of emergency conditions, e.g. tube failure together with shut-in head on the low-pressure side is not normally considered.

It may be taken that any tube failure will occur during normal operation with the low-pressure lines open. If the pressure on the low-pressure side is provided by centrifugal pumps, and the postulated leakages are small compared with the normal low-pressure side flow, it is not possible for the low-pressure side pressure to exceed the shut-in pump pressure for which the exchangers should be designed.

Accordingly, pressure relief for the tube failure case may be omitted unless there is a frequent possibility of a closed low-pressure side discharge line during normal operation. The possible need for thermal relief (see 4.10 of this Recommended Practice) should not of course be overlooked in any case.

Note that a coil fitted into a vessel needs also to be considered for the burst tube condition, depending on the design and construction of the coil.

Where the high-pressure side operating pressure is appreciably greater than the low-pressure side hydrostatic test pressure, there is a potential for significant hydraulic surge effects following a tube failure. Where the ratio of the pressures is more than two, it is possible for a relief device to respond too slowly to prevent the risk of equipment failure. In such cases, hydraulic surge analyses are necessary for the production of an acceptable design.

This Commentary relates to clause 5.2.3.

For high boiling-point liquids, vaporisation due to external fire may not need to be considered. However, pressure relief devices for thermal expansion should be provided. High boiling-point liquid is taken as anything heavier than heavy gas oil. Consideration should be given to the thermal decomposition of high boiling point liquids during a fire.

E7. CENTRIFUGAL PUMP

This Commentary relates to clause 5.4.1.

A number of incidents have occurred in BP Group refineries where the suction side of centrifugal pumps has been overpressured, resulting in flange leakage and unit shutdown. ETC Safety Report [ETC.88.SR.001](#) refers to these incidents. Note that this Report was originally issued in 1975 with the number EDR/200/S/772. Action was taken on existing installations to prevent further occurrences.



There are other situations which can lead to similar incidents on other machinery, and a number of these have also been encountered. These are covered in 5.5 of the main text and this Commentary.

On centrifugal pumps, the suction side of a pump back to the suction block valve can be overpressured from the discharge side of an operating machine or from other pressure source. Where stand-by pumps are installed for centrifugal pumps on hot service, it is typical practice for each pump to have suction and discharge block valves, and discharge non-return valves fitted with manual bypass. The stand-by pump is warmed through from the operating pump by opening both suction and discharge block valves and the non-return valve's bypass. If the suction block valve on the stand-by pump is inadvertently closed, the suction side of the pump, suction line and fittings back to the block valve is subjected through the pump to the full discharge pressure. This can lead to leakage, e.g. at suction strainer flanges and subsequent fire, since the liquid being pumped in this case is commonly above its auto-ignition temperature.

Other line configurations are possible for warming-through, giving the same basic hazard; also seal oil or flushing oil connections may be provided which could lead to the same problem. In these cases the hazard applies to machines with no stand-by.

It has also been the practice in some locations to modify non-return valves on site so that they permit a bleed back for warming-through, in effect creating the same condition as a non-return valve bypass.

Boiler feed pumps do not give rise to a hazard of this kind, since non-return valve bypasses for warming-through are not usually fitted and, in addition, a discharge pressure bleed-off line is always installed.

Designers and operators should be aware of the danger of overheating when pumps are run blocked in. This is particularly a problem on large pumps. Relief devices cannot help in this situation.

This Commentary relates to clause 5.4.2.

Many design contractors simply rate all the pump suction system for the highest suction pressure and the discharge system for the pump shut-in pressure, thus making the line 'specification break' at the pump suction flange itself. Other contractors make some allowance in their practice for the condition in question.

BP design practice does not call for the rating of all pump suction lines for the discharge conditions. On pump design, all parts in contact with the pumped fluid are normally rated for the maximum discharge pressure.

However, this is not invariably the case, particularly for high-pressure multi-stage pumps, and there may be a specific requirement for the fitting of pressure relief devices in such circumstances.



It should be noted that BP operating practice normally requires opening suction block valves before warming through lines, as a good operating procedure rather than a specific safety measure.

In a constant-speed centrifugal pump, the pressure should be determined from the following set of considerations:-

- (a) Maximum suction head in normal operation.*
- (b) Shut-in differential head.*
- (c) Maximum specific gravity in normal operation.*

In checking the pressure thus obtained against the pressure ratings of the suction line and fittings, it is permissible in this instance to add 20% to the ratings for the maximum allowable non-shock working pressure given in [ANSI B16.5](#) for flanges (including the pump casing suction flange) and fittings, or to add 20% to the maximum allowable stress for other components. It is necessary to check also against the pump seal allowable pressure.

Note that the 20% allowance is based on a condition lasting not more than 50 hours at any one time, or 500 hours/year in accordance with [ANSI/ASME B31.3](#), and should not be used for cast iron or similar non-ductile material.

E8. TURBINE DRIVERS

This Commentary relates to clause 5.5.2.

Where backpressure turbines have intermediate takeoffs, the relief arrangements must ensure that no section of the turbine casing or interconnecting pipework is subject to overpressure under conditions of wide open throttle valves, full design throttle pressure, and closed intermediate takeoff valves.

Condensing turbines should be protected from overpressure by the provision of either atmospheric relief valves or bursting discs. The minimum area of relief should be such that, when the turbine throttle valves are wide open with the turbine inlet pressure at its design value, no section of the turbine casing, condenser or interconnecting pipework should exceed its design pressure.

This provision should also apply to condensing turbines with intermediate takeoff connections.

A variety of turbine configurations is possible, and it is important that each case is subject to detailed review.

Typical good present practice by design contractors is to fit safety relief devices to guard against this condition. Normal discharge is to atmosphere.

Steam turbine casings on the exhaust side are not normally designed for full inlet steam pressure. For these cases, BP Group [RP 34-1](#) calls for pressure relief valves to be fitted, capable of passing the full flow of steam. Sentinel warning valves giving audible alarm have not been normally required. For special-purpose steam turbines BP Group [GS 134-7](#) requires exhaust high-pressure alarms on a local panel.

However, cases were encountered in the past where casings were not designed for full inlet steam pressure, and sentinel valves alone were fitted, sometimes being replaced by small nominally-sized relief valves. There were probably even cases of this kind where no warning or safety relief valves were fitted.

In this service, safety relief valves present no problem from a corrosion and disposal viewpoint. BP preferred design procedure is thus to fit these as required, rather than rate the exhaust side for the inlet steam pressure.

In checking the manufacturer's rating for the exhaust side of the casing and also the maximum pressure rating for the exhaust line, it is permissible in this instance to add 20% to the ratings for the maximum allowable non-shock working pressure given in [ANSI B16.5](#) for flanges (including the casing exhaust flange) and fittings, or to add 20% to the maximum allowable stress for other components, provided however that all components are of ductile material.

Note that the 20% allowance is based on a condition lasting not more than 50 hours at any one time, or 500 hours/year in accordance with [ANSI/ASME B31.3](#), and should not be used for cast iron or similar non-ductile materials.

E9. PRESSURE RELIEF DEVICES

This Commentary relates to clause 6.2.1.

The selection of types of pressure relief valve is unique to each individual application. However, the following general guidelines can be given:-

This Commentary relates to clause 6.2.1.1.

For flammable service or for toxic service, bonnets of conventional-type pressure relief valves should be vented to the discharge side of the valve.

Most conventional pressure relief valves have discs which have a greater area (A_D) than the nozzle seat area (A_N), see [API RP 520](#) Part I Figure 18. If the bonnet is vented to atmosphere, the backpressure acts with the vessel pressure to overcome the spring force, thus making the relieving pressure less than when set with atmospheric pressure on the outlet. If the bonnet is vented to the valve discharge, as is more usual, the backpressure acts with the spring pressure to increase the opening pressure. If the backpressure were constant, it could be taken into account in



adjusting the spring pressure to give the correct set pressure for the valve. In practice, backpressure is not constant when a number of valves discharge into a manifold.

Conventional pressure relief valves show unsatisfactory performance under variable backpressure (both superimposed and built-up) as indicated in [API RP 520](#). The capacity correction factors of balanced bellows type are given in [API RP 520 Part I Figure 27](#) and the capacity factors will be similar.

Conventional type valves are suitable for operation where:-

(a) Backpressures (superimposed and built-up) are constant.

or

(b) Superimposed backpressure is less than 5% and built-up backpressure is less than 10% of the set pressure when operating with 10% overpressure.

or

(c) Superimposed backpressure is less than 12% and built-up backpressure is less than 20% of the set pressure when operating with 20% overpressure.

The most frequent applications of conventional type valves are as follows:-

(a) For discharge to atmosphere through short tailpipes.

(b) Where set pressure is high.

(c) Where discharging to a low-pressure manifold system.

Constant backpressure may be experienced when the relief stream is returned to some other part of the process; in this case conventional type valves are preferred. Constant backpressures are never experienced when discharging to a closed system. Conventional type valves therefore have limited application where relief streams are discharged to a closed system, the backpressures being limited to relatively low levels.

In all possible cases the backpressure should not exceed the maximum pressure rating on the outlet side of the conventional valve (refer to [API Std. 526](#) or manufacturers' data). If the backpressure limits are exceeded, a special valve must be made and a specific manufacturer's guarantee is required. These also take much longer to make than normal.

This Commentary relates to clause 6.2.1.2.

Balanced Type

Balanced-type pressure relief valves are those in which the backpressure has very little influence on the set pressure, see [API RP 520](#) Part I Figure 27. These valves are of three types:-

- (a) The piston type.
- (b) Bellows type.
- (c) Bellows with auxiliary balancing piston type.

In the piston type, the guide is vented so that the backpressure on opposing faces of the valve disc cancels itself. The top face of the piston, which has the same area (AP) as the nozzle seat area (AN), is subjected to atmospheric pressure by venting the bonnet. The bonnet vent gases from balanced piston-type valves should be disposed of with a minimum restriction and in a safe manner.

In the bellows-type of balanced valves the effective bellows area (AB) is the same as the nozzle seat area (AN) and, by attachment to the valve body, excludes the backpressure from acting in the top side of that area of the disc. The disc area extending beyond the bellows and seat area cancel so that there are no unbalanced forces under any downstream pressure. To provide for possible bellows failure or leak, the bonnet must be vented separately from the discharge.

In the bellows with auxiliary balancing-piston type both a bellows and a balancing piston are incorporated. On bellows failure, the leakage of vapours into the bonnet is restricted by the piston, and the valve continues to operate as a balanced safety relief valve.

Reference should be made to the particular manufacturer's data for:-

- (a) The effect of backpressure on capacity.
- (b) The maximum backpressure to which the valves can be subjected. This is determined by the mechanical design of the bellows.

Balanced-type valves are suitable for operation under variable or constant backpressure, either superimposed or built-up. The maximum backpressure which a balanced-type valve may be subjected to should not exceed the lower of:-

- (a) 50-60% of the valve set pressure. At higher backpressures, the valve capacity reduction becomes appreciable and if operation is required at these higher backpressures, the particular valve manufacturer should be consulted.
- (b) The maximum pressure rating on the outlet side of the balanced valve (refer to [API Std. 526](#)).

A bellows seal is usually installed on a pressure relief valve that discharges into a closed system, e.g. a flare line or another part of the process. A bellows seal is used:-

- (a) *To compensate for the effects of backpressure on the valve disc so that the pressure in the vessel at which the valve commences to discharge is not influenced by the backpressure, either constant or variable.*

or

- (b) *To protect the valve spring, guides and top works from corrosion or fouling by the environment on the discharge side of the valve.*

An example of such use is where the valve discharges to a closed system that handles sour gases although the backpressures are not sufficiently high to require the installation of balanced-type valves for this reason.

This Commentary relates to clause 6.1.2.2.

There have been instances of bellows failure on relief valves, leading to potentially hazardous atmospheric discharges. Bellows failure can also result in the ingress of air into a flare system, with equally hazardous consequences. It should be noted that the subject has a number of aspects that may have to be considered, and caution is needed in applying any arbitrary rules, even if any local authorities seek to impose these.

A failure of a bellows can lead to unsafe conditions as regards both the opening (relieving) pressure at which the valve will commence to discharge, and the accidental discharge of flammable or toxic fluids from a pressure relief valve bonnet vent hole. The space within the bellows is connected to the bonnet of the valve and thence, via a bonnet vent, to atmosphere. To retain the correct pressure balance, this bonnet vent must always be open.

When a bellows failure occurs, leakage of liquid or vapour takes place through the point of failure into the bonnet space and hence to atmosphere. This can occur not only when a valve has lifted and is discharging, but also when a valve is closed, due to the backpressure in a downstream system. When this accidental discharge is a vapour it may be possible to allow this discharge to continue subject to:-

- (a) *Being led to an acceptably safe location.*
- (b) *Environmental considerations.*
- (c) *The condition being rectified as soon as possible.*

When this accidental discharge is a liquid, the discharge must be led to a suitable drain or collection point, particularly when the liquids are at or above their auto-ignition temperature. Consideration will have to be given to the possibility of the solidification of heavy or viscous liquids in a small drain line and its subsequent blockage. Again, this course is subject to the same conditions of discharge, environmental considerations and early rectification.

When a bellows failure occurs, the pressure balance within the safety valve will be upset unless the bonnet space is vented and held at a pressure substantially the same as atmospheric. Should this bonnet vent have been closed by plugging, the consequences of a higher discharge pressure of the safety valve must be considered. The discharge pressure in these circumstances will now be the set pressure plus the backpressure (both constant and variable) and the accumulation necessary to achieve the rated discharge capacity of the valve.

It may be that the proposed system design pressure is sufficiently in excess of the valve set pressure that this margin can contain the increase in discharge pressure caused by the continued effects of the backpressure plus accumulation. If this is not so, steps must be taken to provide an adequate pressure balance.

This Commentary relates to clause 6.2.1.2.4.

Where a situation is identified such that a pressure imbalance could occur which would lead to the discharge pressure of the pressure relief valve exceeding the system design pressure (or maximum allowable working pressure) at design temperature, and/or where the discharge of flammable or toxic fluids from a bonnet vent hole in the event of bellows failure must be reduced to the absolute minimum, a pressure relief valve should be fitted which incorporates both a balanced bellows seal and a balance piston. This type of valve will, in the event of bellows failure, retain the pressure balance characteristics of the valve as designed and will, in addition, severely curtail possible leakage by restricting the leakage path because the piston/piston chamber clearance is held to a minimum.

Although some designs of pressure relief valve incorporate an elastomer seal in the balance piston which could eliminate leakage totally, their use should be avoided due to the possibility of the seals sticking. Valves incorporating a labyrinth seal on the piston are to be preferred.

In those few cases where a pressure relief valve discharge is routed to atmosphere and yet is fitted with a bellows seal to protect the spring, guides and top works from atmospheric corrosion or fouling, the failure of the bellows will not affect the pressure at which the valve commences to lift. However, corrosion or fouling may affect the discharge capacity through restricting the lift of the disc, and consideration should be given to this aspect.

A pilot-operated pressure relief valve is one that has the major flow device combined with and controlled by a self-actuated auxiliary pressure relief valve. This type of valve does not utilise an external source of energy. The general principles of operation of a typical valve (shown in [API RP 520](#) Part I Figure 6-10) are as follows.

In a pilot-operated valve, a differential piston is loaded by the process pressure through an orifice. When the set pressure is reached, the small spring-loaded pilot valve opens, venting the pressure above the piston of the main valve, which then

rapidly opens wide. When the blowdown is completed, the pilot valve closes, restoring the process pressure above the piston and closing the main valve rapidly.

These valves have a large number of static and moving seals which must all function, and have small clearances in the pilot mechanism. The valves are therefore prone to failure especially on dirty service or high-temperature service.

Pilot-operated valves should therefore only be considered for use on clean non-corrosive fluids, and thus have somewhat limited application in the petroleum industry. Advantages of pilot-operated pressure relief valves are:-

- (a) A pilot valve can be set more accurately than a pressure relief valve.*
- (b) Both valve opening and closing are more rapid than orthodox pressure relief valves.*

If some form of pilot control is desirable, then the pilot-assisted type should be chosen in preference to pilot-operated because such a valve will still operate, though at a slightly higher pressure, in the event of a pilot failure.

In the US, pilot-operated valves have been used for high-pressure service (hydrocrackers). Their use was instigated because normally they can hold pressure at 5% above operating rather than 10% above operating pressure as considered minimum for spring operated valves. Appropriate non-metallic gaskets were considered necessary.

This Commentary relates to clause 6.2.1.4.

The pilot-assisted safety relief valve (conventional or balanced) is fitted with a simple, rugged air-operated diaphragm type actuator to which an air or gas signal is fed from a suitable pneumatic pressure pilot. When the set pressure is reached in the vessel, an air signal from the pilot is fed to the underside of the diaphragm, enabling it to apply full lift to the spindle of the pressure relief valve. The valve then opens rapidly. When relieving is complete, the air is vented from the underside of the diaphragm and the valve closes rapidly.

Normally, the pressure relief valve spring set pressure will be approximately 5% higher than the pilot set pressure. If the pilot or actuator fails for any reason, the valve will still be capable of operating as an orthodox spring-loaded valve which will lift at a pressure approximately 5% higher than the pilot set pressure.

This type of valve is therefore preferred to pilot-operated valves with the additional advantage that failure of the pilot does not render the valve inoperative. The valves should be considered for use where:-

- (a) Accuracy of set pressure is important.*
- (b) Rapid opening and closing are required.*

Generally they find limited application within process units.

E10. SIZING OF PRESSURE RELIEF DEVICES

This Commentary relates to clause 6.4.

When the type of valve has been selected and the backpressures are known, the required orifice area may be calculated using formulae listed in the API recommended practice and Appendix R of this Commentary. This orifice area may be provided by one or more valves. In calculating the orifice areas, correction factors, where required, should be obtained from the particular manufacturer's data.

Problems have been experienced by BP with pressure relief valves for low and high set pressures on hydrocarbon gas service.

In some cases, original water seal trap relief devices were replaced with pressure relief valves. In selecting suitable valves for subcritical flow, discharge areas 25% greater than normal were found necessary at the low pressures involved. Not all manufacturers or users may be aware of this phenomenon. It is hoped that guidance on sizing valves for subcritical flow and relieving pressures less than 1 bar (ga) (15 psig) is considered in future revisions of [API RP 520](#).

In other cases, difficulties were experienced in selecting replacement high-pressure spring-loaded pressure relief valves with the aim of minimising the number of valves required, due to the set pressure limitations of [API Std. 526](#). Problems with high set pressure and capacity were resolved by selecting valves not complying with [API Std. 526](#) set pressure limitations, but proved acceptable for service by suitable tests.

This Commentary relates to clause 6.4.2.

For sizing relief valves, the UK and US pressure vessel codes, [BS 5500](#) and [ASME VIII](#), require the following pressures to be used, where p = design pressure:-

	BS 5500 (1988)	ASME VIII (1986)
Set Pressure		
Single valve	p	p
Multiple (additional) valves	$1.05 p$	$1.05 p$
Fire (or external heat)		$1.10 p$
Accumulation		
Single valve	$1.10 p$	$1.10 p$
Multiple (additional) valves		$1.16 p$
Fire (or external heat)		$1.21 p$

Inlet and outlet flange sizes and pressure-temperature ratings for pressure relief valves (orifice D-T inclusive) conform to the data contained in [API Std. 526](#) (Tables 2

to 15 in the Third Edition (1984)). Inlet pressure limits are governed by inlet flange pressure limits or by manufacturer's spring design limits, whichever is the lower. Outlet pressure limits are determined by valve design. These data are usually presented in manufacturers' catalogues. It should be noted that the pressure and temperature used in valve selection are the set pressure and the normal operating temperature, not the relieving temperature.

Information on other valve sizes should be obtained from the relevant manufacturer's catalogue.

TABLE E1
SAFETY RELIEF VALVE DATA WORK SHEET

[illegible]

RELIEF CONDITIONS (COLUMN 6)

1. ELECTRIC POWER FAILURE
2. STEAM FAILURE
3. COOLING WATER FAILURE
4. INSTRUMENT AIR FAILURE
5. TOP TOWER REFLUX FAILURE
6. SIDE STREAM REFLUX FAILURE
7. AIRCOOLER FAILURE
8. CONTROL (VALVE) FAILURE
9. CLOSED OUTLET

10. EXPANSION OF FLUID IN HEAT

- EXCHANGERS AND HEATERS
a. LIQUID EXPANSION ONLY
b. VAPORISATION
11. OVERFILLING SURGE OR STORAGE VESSEL
12. ENTRANCE OF VOLATILE MATERIAL
13. CHEMICAL REACTION
14. EXTERIOR FIRE
15. TUBE RUPTURE

FLARE SYSTEMS (COLUMN 19)

- V=VET FLARE
 D=DRY FLARE
 T=TOXIC FLARE
 A=TO ATMOSPHERE
 P=BACK INTO PROCESS SYSTEM
ABBREVIATIONS (COLUMN 18)
 CS=CARBON STEEL
 SS=STAINLESS STEEL
 X=
 Y=

REMARKS

PL (NO.

* ADD APPROPRIATE
CONSISTENT UNITS

REV	BY	DATE	CHG	DATE	APPRO	DATE

DRG N° -----
TITLE -----

SAFETY RELIEF VALVE
DATA WORK SHEET

*This Commentary contains the text of a
BP Engineering file note Reference [PTD/1/175](#)
dated 30th January 1989
having the following title:-*

DESIGN FOR LIQUID RELIEF

DESIGN FOR LIQUID RELIEF**General**

The Working Party on Protective Systems recommended that it was inappropriate to consider operator intervention in the design of relief systems within the battery limits. When considering potential liquid relief situations a strict interpretation of this recommendation leads to high reliability trips being the only acceptable solution. (Outside the battery limit it is impractical to ignore operator intervention and allowing for such intervention is worldwide practice which is considered acceptable.) A re-examination of the recommendation concluded that a hazard quantification approach similar to that which justifies high reliability trip systems could yield a more balanced design.

This note and diagram are the initial attempt at defining such an approach.

In this note 'relief' is used to mean either relief capacity or an equivalent means of protection such as a high reliability trip.

The approach we are recommending is based on the quantification of hazards. This depends both on the frequency of the occurrence and the consequences of an incident.

The frequency of the occurrence is influenced by the conditions necessary to create the situation and the likelihood of the error being noticed and corrected. This is a function of the protective system adopted. The type of consequences depends primarily upon the nature and volume of the material being handled, the ratio of applied pressure to design pressure and the vulnerability of people and plant in the locality. The cost of the resultant loss of production should also be considered in such assessments, since a reduction in commercial risks can often be a factor in the justification of safety improvements.

To quantify all these factors on generic data is a lengthy and difficult process. In order to produce guidance which can be applied on current designs, the advice below is given in advance of such rigorous calculation.

Logic Diagram

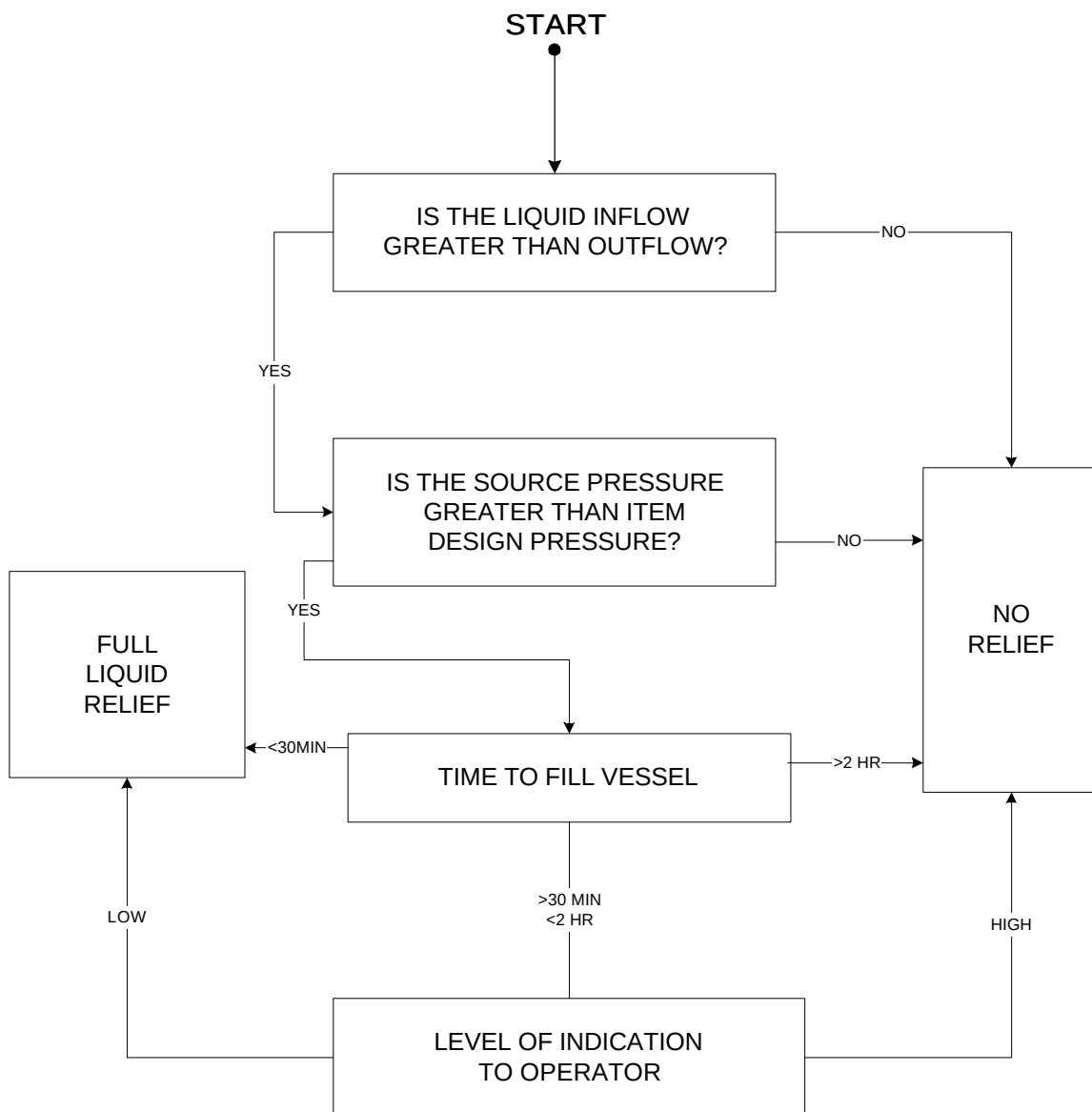
The initial part of the logic diagram (Figure P.1 in this Supplement to BP Group RP 44-1) indicates that relief is not needed unless there is a case where the inflow is greater than the outflow and the source pressure is greater than the design pressure of the equipment.

Thereafter, the design of relief capacity depends on the length of time before a potential incident can occur. If the time is less than 30 minutes, there is insufficient time to ensure that operators can take corrective action and relief capacity or a high reliability trip is required.



If the time is greater than two hours, it is extremely unlikely that operators will not take the appropriate action. This naturally relies on the operators being aware that a problem is occurring. Therefore, it is vital that there are instruments which would warn the operators that something is amiss and that the instruments are in operation before any equipment is commissioned.

When the time is between 30 minutes and 2 hours (which encompasses most of our cases) the relief design for different hazard rates will depend on the level of indication. On the assumption that the materials handled are flammable but not excessively toxic and that the causal scenario is not a frequent occurrence, it is recommended that an appropriate level of indication is 3 independent alarms. If there is an excessive hazard, then a higher level of indication or relief capacity would be required.



NOTE: LEVEL OF INDICATION TO OPERATOR.

TO PREVENT RELIEF, AN OPERATOR MUST HAVE AN ADEQUATE NUMBER OF SEPARATE INDEPENDENT INDICATORS - FROM LEVEL ALARMS, QUALITY OR FLOW VARIATION ALARMS ETC. + TIME TO REALISE AND REACT. IN TYPICAL REFINERY SITUATIONS, 3 INDEPENDENT INDICATORS SHOULD BE ADEQUATE. THIS WILL DEPEND ON THE HAZARD CREATED BY FAILURE.

FIGURE P1
LIQUID RELIEF LOGIC DIAGRAM

FAILURE MODES OF INSTRUMENTATION**Q1. CONTROL INSTRUMENTATION**

A typical control loop can be broken down into three parts, shown in Figure Q1:-

Measurement/Detection System

Controller

Regulating System.

Q1.1 Measurement and Detection System

This comprises the equipment making the primary measurement and sending a pneumatic (3-15 psig) or electrical (4-20 mA and/or digital) signal to the indication and control equipment; for example, a differential flow element and differential pressure transmitter. Generally, the value of the transmitted signal increases with an increase in the parameter measured. Sometimes, auxiliary equipment such as a converter from a pneumatic to an electrical signal (or vice versa) is required.

Each element in the system may fail to a low signal, a high signal or, more rarely, to any value between. Likewise, a blocked tapping may lock-in the pressure, or prevent the transmitter sensing an increase or decrease in measured property. Loss of air or electrical supply will cause the transmitted signal to fall to zero, as normally will a cable or air line fault. On balance, there is probably a greater chance that, on measurement system failure, the signal will fall to zero than any other state.

Q1.2 Controller

The controller receives the measured value signal and drives an output having a mathematical relationship to the input and set point value. Controllers may be direct acting (i.e. the output increases as the input increases), or reverse acting (i.e. the output decreases as the input increases).

As with the measurement system, the controller may fail to zero output, maximum output or any value in between, the controller itself probably being more likely to fail to zero (e.g. supply fuse blowing). However, should the fault be on the measurement system and a reverse-acting controller is being used, then a zero signal input may cause the controller to drive to full output (i.e. fail dangerous), unless any in-built error detection initiates some override action.

Typical examples of potential fail-dangerous situations are fired heater outlet temperature controllers, flow controllers, back-pressure controllers, and level controllers regulating the flow into a vessel.

In the absence of error detection, a reverse-acting transmitter may help to alleviate the problem. However, nothing can give a guaranteed failure mode (e.g. in the case of a blocked tapping).

Failure of the master controller in a cascade or advanced control loop can have the similar effect of driving the secondary controller to call for a high set point (e.g. a heater outlet temperature controller resetting a furnace gas pressure controller). Again, error detection may initiate protective action (e.g. switch the secondary controller to internal set point).

Q1.3

Regulating System

The regulating system takes the controller output and drives the final control element, most commonly an air-operated valve, but sometimes an electrically or hydraulically operated valve. In BP, electrically operated valves are normally only used for 'on-off' duty (e.g. sequence control, line routing, feed isolation). However, they are available for modulating control. The controller output may be pneumatic (3-15 psig) or electric (4-20 mA and/or digital). In the latter case, an electro-pneumatic or electro-hydraulic converter requiring a local supply is incorporated to convert the electrical signal into an equivalent pneumatic or hydraulic signal.

Most control valves are the pneumatic spring-return type, and move to a stated position on supply failure (i.e. fail closed or fail open). Some larger valves have double-acting actuators which are inherently fail-fixed, but sometimes incorporate a reservoir tank/accumulator and control system to drive the valve to a set position should its supply fall below some predetermined value.

Many spring-return, and all double-acting control valves, rely on a valve positioner to drive the valve to the appropriate position in relation to the signal received from the controller. Positioners require an air or hydraulic supply for motive power to the valve.

The regulating system may fail in a number of ways. On loss of controller signal, cable or signal line failure, or loss of the local air/hydraulic supply, spring-return valves would move to their supply-failure position in most foreseeable cases, except:-

- (a) Mechanical damage or seizure of the valve.*
- (b) Mechanical failure of the actuator (e.g. under fire conditions).*

- (c) *If a reverse-acting valve positioner was fitted (e.g. on split range duty).*

Double-acting valves would behave similarly, but could fail to move due to failure of the reservoir tank/accumulator or associated valve control system.

Fail-fixed valves are sometimes specified. Apart from electric motor operated valves and double-acting cylinder operated valves, the fail-fixed device relies on a pneumatic/hydraulic lock-in system which itself may fail.

Other failures could result in the valve being driven to positions other than its air-failure position. Examples are positioner failure, electro-pneumatic converter failure, and failures discussed under the headings of Measurement and Detection System (Q1.1) and Controller (Q1.2).

As electric motor operated valves require an external power source, they are inherently fail-fixed on loss of primary power. To comply with electrical codes they always have a local 'stop' button which, if operated, freezes the valve at its last position. Sometimes, they are also equipped with local controls which override remote operation.

Q1.4 *Other Factors*

In complex systems (e.g. advanced controls), loops may be interconnected in a variety of ways, e.g. signal selectors, computing functions (e.g. summers, multipliers) and feed-forward schemes. Failure modes of individual systems may be affected by other connected loops. Note that functions may be hard-wired or configured in software.

Q1.5 *Control Technology*

Control systems prior to about 1980 were generally designed on the single loop integrity principle. All components were mounted in discrete boxes applicable only to that loop. All electrical components in a loop were driven, as far as possible, from one power supply source and via a single loop fuse. Likewise all field components were supplied, as far as possible, from the same section of air header (note that since air distribution is by site-run pipework it is possible that the transmitter and valve may be supplied from different isolatable sections of supply header). Thus on power failure to the plant or loop, the valve is driven to its air-failure position (unless a reverse-acting positioner is used).

Similarly, on air failure the valve would drive to its air failure position (qualified by the comment regarding the same air header supplying the transmitter).

Thus, it is reasonable to assume that, apart from common mode failures such as the result of damage to electronics by lightning, complete or partial loss of instrument power, air, or hydraulic supply, loops would fail on an individual basis, but possibly to any valve position. The chance of more than one loop failing at the same time is statistical from the total number of loops on the plant.

Systems in common use since about 1980 are not compatible with single loop integrity. Power supplies are distributed on a 'function' rather than a 'loop' basis. This applies to some individual instrument systems, as well as video systems such as Honeywell TDC 2000/3000, Foxboro Spectrum and Intelligent Automation series, Fisher Provox, programmable logic controllers (PLCs), and many supervisory control and data acquisition (SCADA) systems. Many such systems operate on a shared component/shared loop basis.

Measurement circuits are powered in groups; thus, on fuse failure, all inputs within a group would fail to zero and drive the respective controllers to zero or maximum output, according to the controller action and built-in error detection.

Shared-loop controller functions are in groups, typically of eight to more than thirty, and on failure a large number of outputs could drive to unwanted states. However, most shared systems have a high degree of back-up and internal error detection, and the probability of common-mode failure is very low. Nevertheless, although remote, the feasibility of multiple failure is present and must be considered when designing a relief system.

Output modules may be powered in groups, typically two to ten, such that several outputs could be lost or drive to danger simultaneously.

The subject, together with guidance to engineers, is covered in depth in ETC Safety Report [ETC.87.SR.001](#).

Q2. SHUT-DOWN SYSTEMS

Shut-down systems designed in accordance with BP Group [RP 30-1](#) are totally independent from the measurement and control system, except in some systems of lesser importance when a regulating control valve may be incorporated as the final element. Note, however, that plant on sequential control (e.g. batch processes) may

require different shut-down action at different steps of the sequence. Shut-down systems are powered from one or more dedicated high-security power supplies.

A shut-down loop can be broken down into three parts, shown in Figure Q2:-

- (a) Sensing system.
- (b) Logic.
- (c) Actuating system.

Q2.1 Sensing System

The sensor is normally arranged such that the contact driving the logic opens to trip. The sensor may be a device driven directly by the process media, such as a pressure switch or float-operated level switch. It may involve other mechanical components such as a filled-system temperature switch, or include electronic circuitry such as a thermocouple and trip amplifier. Sometimes an analogue output from a transmitter may initiate trip action.

Failure modes of the sensing system are carefully considered during the design, and every effort is made to make the system fail-safe. However, there are many factors which can cause a fail-to-danger situation and are not easily designed out. Examples are:-

- (a) Blocked tapping, or device valved-off.
- (b) Failed filled system on high-temperature trip.
- (c) Mechanical failure of switch.
- (d) Short circuit in cable to logic.
- (e) Trip amplifier failure.

Q2.2 Logic

Logic systems receive signals from the sensors, determine the necessary protective action, and send action signals to actuating device(s). Current logic systems are usually electric/electronic in operation. However, existing plant and simple systems for new plant may still employ pneumatic or hydraulic logic.

Electrical/electronic systems may be based upon:-

- (a) Electro-mechanical relays.
- (b) Solid-state electronic discrete logic.
- (c) Programmable electronic systems.

Each system has advantages and disadvantages for any job and the subject is addressed in Sections 1 and 12 of BP Group [RP 42-1](#).

Whichever method is adopted, the overall system integrity has to be addressed in relation to the account taken of instrument-based protection in the overall overpressure protection system design. Redundancy may be built in to the system to decrease the probability of both failure to initiate trip action on demand, and spurious tripping. However, this has a cost penalty, and also increases equipment size, weight and complexity.

Modern equipment can incorporate error detection facilities to monitor the health of the logic system, and may take automatic action (e.g. initiate a trip, or switch logic from 'two out of three' mode to 'one out of two' mode). Detected failures are displayed to the operator.

Safety systems incorporating programmable electronic systems have come under the scrutiny of both the UK Health and Safety Executive (notably for onshore) and the UK Department of Energy (for offshore). Both have issued strict Guidelines, which may prove difficult to meet. Industry associations (e.g. UKOOA and EEMUA) are currently (May 1989) producing advisory documents to assist industry in interpreting these Guidelines. The UKOOA document is in an early stage of development. [EEMUA Publication No. 160](#) is written as a companion to the Health and Safety Executive documents 'Programmable Electronic Systems in Safety Related Applications' - [Parts PES 1 and PES 2](#), and is expected to be published in mid 1989.

Q2.3

Actuating System

The actuating system usually drives a pneumatically or hydraulically-operated valve, or trips a contactor in electrical switchgear (e.g. to pump motor or electrically-operated valve).

(a) Pneumatic and Hydraulic Operation

The output from the logic is usually a d.c. voltage applied to a solenoid-operated valve. The solenoid valve in the energised state applies air pressure to the diaphragm or piston of an air-operated spring-return valve. A trip signal from the logic de-energises the solenoid valve, which vents the air directly from the diaphragm. This solenoid valve overrides any regulating control action which may be applied to a control valve.

In the case of double-acting pneumatically or hydraulically-operated valves, the solenoid drives a control system involving other mechanical parts, and a source of hydraulic or pneumatic motive power is required to drive the valve.

Considerations are generally the same as for this type of valve on regulating control duty (Q1.3)

(b) Electric Motor Operated Valves

The output from the logic is usually a d.c. voltage applied to the control coil of a contactor built into the actuator. The coil is held energised by the logic system during normal operation. A trip condition removes this control voltage and hence the contactor causes the valve motor to drive to the desired position. Note that the valve motor requires a mains supply present (usually 380/440 volt, 3 phase) before it can move to the safe position. For this reason electric motor operated valves are not normally used for important trip actuators. The comment under Q1.3 regarding power isolation switches and local controls also apply to electric motor operated valves on trip service.

Again, every precaution is taken to try and ensure the system fails to safety. However, it may fail dangerous. Examples are:-

- (i) Mechanical failure of valve.*
- (ii) Loss of motive power in double-acting and electric motor operated valve cases.*
- (iii) Damage to actuator (e.g. by fire).*
- (iv) Foreign body lodged in valve.*
- (v) Seizure of the solenoid valve.*
- (vi) Seat damage in tight shut-off cases.*

Q2.4 Override and Test Facilities

Override and test facilities are normally provided for system proof testing. These may partially or completely render the system inoperative. Therefore, strict control of operations and maintenance is necessary for override-key discipline. Misuse must also be addressed in any failure modes and effects analysis, or reliability analysis (see also BP Group [RP 50-2](#)).

Q2.5 High-Security Systems

Over and above aspects described under Q2.2, where duplicate logic and/or voting systems can improve the logic reliability, the same

techniques can be used to improve the reliability of the complete system. For example, three sensors may be connected to triplicate logic and duplicate valving.

Q2.6 *Systems De-energised in Normal Operation*

BP's normal policy is to use an 'energised in normal operation' - 'de-energised to trip' basis for instrument protection system design. Proper detailed design and later maintenance in operation should ensure that on system failure the actuators will move to the trip condition. This will result in lost production, but will normally give the best protection to plant and personnel.

Occasionally, however, a spurious trip may be potentially more dangerous than failure to operate in an emergency, particularly if in a normal manned facility there is time for manual intervention. In this situation, normally a 'de-energised in normal operation' - 'energised to trip' basis may be specified. Examples are:-

- (a) Offshore platform Evacuation/Red Shut-down.*
- (b) Steam raising plant on refineries and chemical works. Steam is a utility used during plant emergency situations.*

Systems de-energised in normal operation should include in-built health monitoring to ensure that as far as is practicable the system will properly respond to operational demands made upon it.

Q3. CONCLUSION

Control systems, and more particularly shut-down systems, are designed to reduce the possibility of a fail-to-dangerous situation occurring. Duplicate or triplicate channel shut-down systems reduce the possibility still further. However well designed the system is, and whatever precautions are taken, the possibility still exists that at some time the system may fail to an unacceptable state.

Control systems currently being used have a high order of reliability. However, on failure they are capable of causing simultaneous failure of several loops.

Pressure is increasing for more and more application of Category 1 protective instrumentation, often due to greater integration of plant, environmental pressure on flaring, containment of inventory where there is no ready disposal (e.g. offshore crude oil vessel/pipeline pressure relief), and for cost effective engineering (e.g. reduced flare system capacity).

Modern technology is capable of providing Category 1 protective instrumentation. However, great care is essential to ensure that the overall reliability is in fact good enough for the purpose, and that the process, relief, and control system designers appreciate the interrelationship of their disciplines in achieving an acceptably safe overall design. One must always be aware of the unforeseen fault or unforeseen circumstances.

The importance of trip systems within the overall pressure protection system must be brought to the end operating management's attention (i.e. in manuals) to ensure that they receive an equivalent degree of on-going maintenance and testing as relief valves. Similarly, design modifications to plant or control/trip systems must be properly documented and audited throughout the life of the plant.

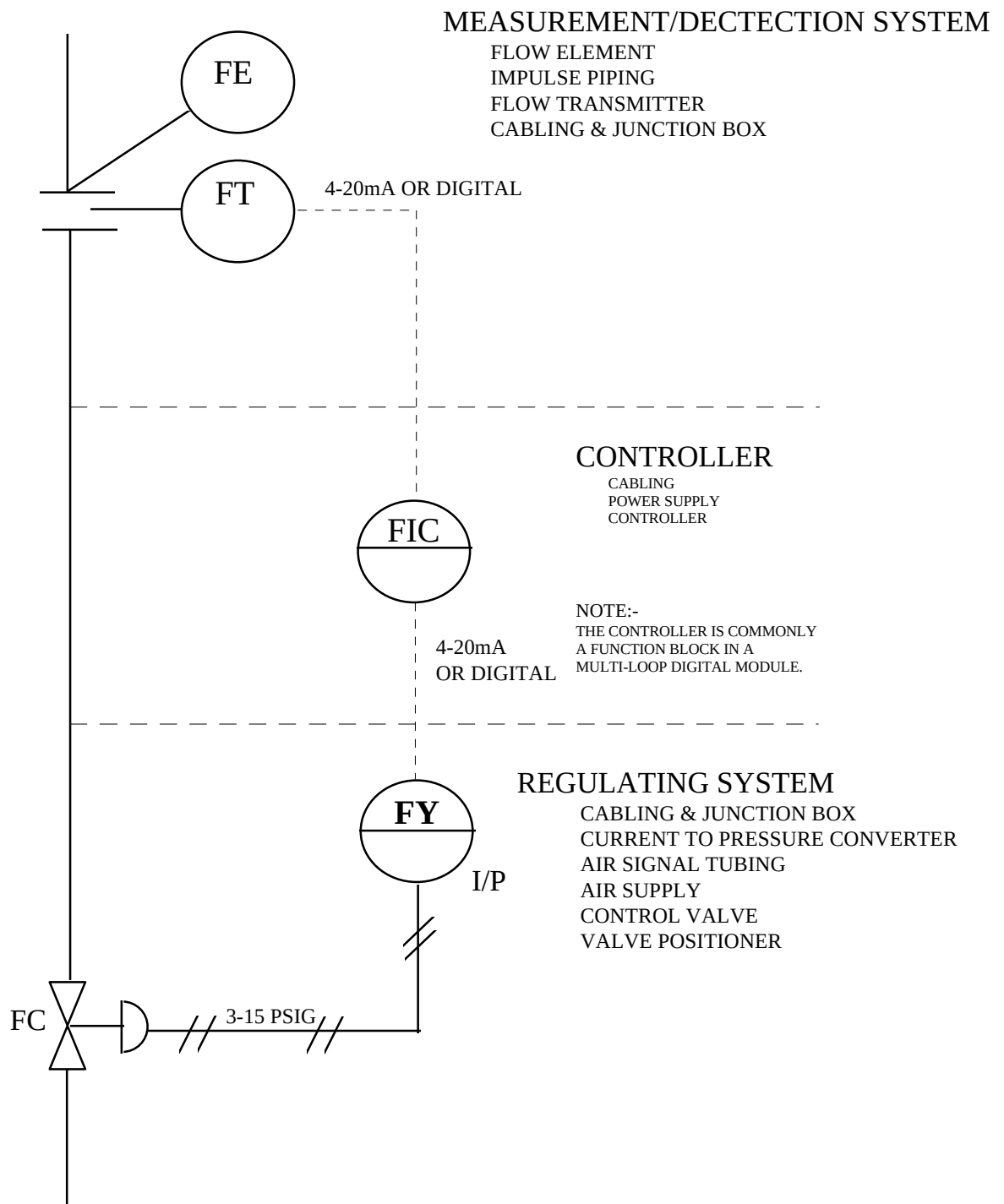


FIGURE Q1
SIMPLIFIED TYPICAL ELECTRONIC CONTROL LOOP

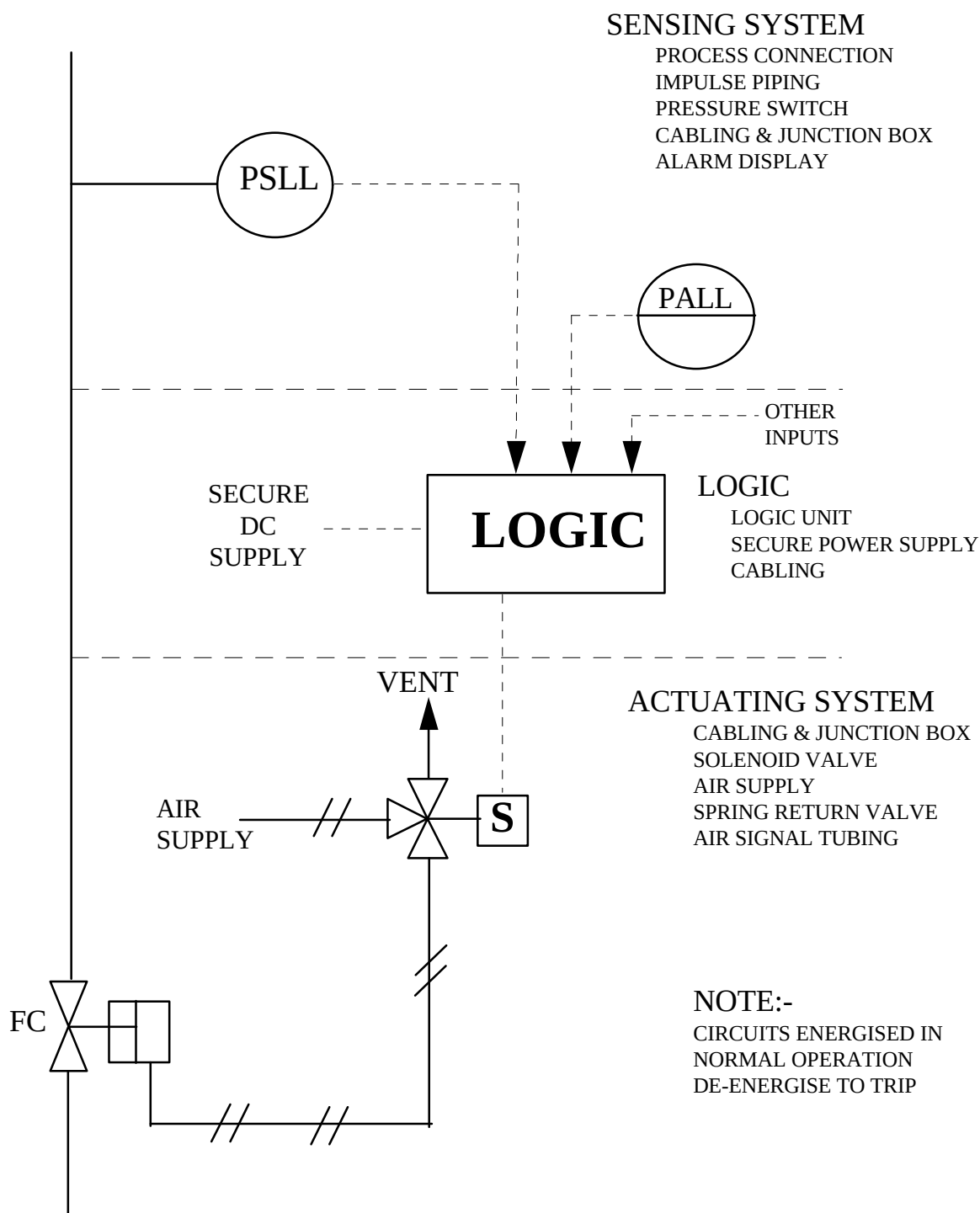


FIGURE Q2
TYPICAL SHUT-DOWN LOOP

SIZING PRESSURE RELIEF VALVES

R1. INTRODUCTION

Certain national authorities, for example TUV in Germany, have their own procedures for sizing pressure relief valves. Where applicable, these will have to be used.

API RP 520 Part I, Appendix C gives sizing procedures for gas or vapour relief, gas expansion due to external fire, liquid relief, and steam relief. In sizing pressure relief valves, capacity correction factors may be required and these should be obtained from the particular manufacturer's data. The data contained in *API RP 520* should be used only as a guide.

R2. SIZING FOR FLASHING TWO-PHASE FLUID FLOW

R2.1 A pressure relief valve handling a liquid at vapour liquid equilibrium or a two-phase fluid will produce flashing with vapour generation as the fluid moves through the valve. This vapour generation can reduce the effective mass flow capacity of the valve and must be taken into account.

API RP 521 presents a method for determining the required pressure relief valve area which is as follows:-

- (a) Calculate the quantity of flash vapour, assuming adiabatic flashing from relieving pressure to either critical downstream pressure or back-pressure, whichever is the higher.
- (b) Calculate the orifice area required for this vapour flow using the same pressure drop.
- (c) Calculate the orifice area required for the remaining liquid flow using total pressure drop, i.e. relieving pressure minus actual back-pressure.
- (d) The orifice selected should have an area equal to or greater than the sum of proceeding areas.

API RP 521 Bibliography presents references for sizing control valves for flashing fluids. One reference states that the standard valve sizing procedure for mixed phase flow, which has been to add together the C_g and C_v (the valve sizing coefficients for the gas and liquid phases respectively) can result in undersized valves. The error in sizing can be as high as a factor of two. The preferable method is the 'lower-

density technique', so called because the valve sizing correction is based on the lower density of the vapour-liquid mixture that exists after flashing.

It would seem reasonable to assume that the flashing of fluid across a pressure relief valve would be similar to the flashing of a fluid across a control valve. Therefore, the total required orifice area for a pressure relief valve obtained by summing the two areas obtained for the vapour and liquid phases could be in error. The lower-density method may therefore have to be used to size pressure relief valves and this method is detailed below for the three cases of:-

- (a) Liquid at it's bubble point at upstream conditions.
- (b) Liquid subcooled at upstream conditions.
- (c) Two-Phase fluid at upstream conditions.

R2.2 Liquid at it's Bubble point at Inlet

The steps involved, where the liquid is at it's bubble point at the inlet to the pressure relief valve and the downstream pressure is not greater than the critical pressure, are detailed below. Any reduction in downstream pressure below this critical pressure yields no increase in flow.

Step 1

Note:- Steps 1, 2 and 3 involve a trial-and-error procedure and step 2 is the starting point. However, when dealing with Hydrocarbons where the specific heat of the liquid phase is approximately equal to the specific heat (at constant pressure) of the vapour phase, step 1 becomes $k_m = k = C_p / C_{vol}$

Evaluate K_m , the specific heat ratio of the two-phase mixture as follows:-

$$C_m = C_1(1-X_c) + C_p X_c$$

C_m = Average specific heat of two-phase mixture Btu/lb °F

C_1 = Specific heat of liquid phase Btu/lb °F

C_p = Specific heat at constant pressure of vapour phase Btu/lb °F

X_c = Weight fraction of vapour at critical downstream pressure

$$K_m = \frac{C_m}{C_{vol}}$$

Where

C_{vol} = The Specific heat at constant volume of vapour phase Btu/lb °F

Step 2

Evaluate P_2 The critical downstream pressure.

$$\frac{P_1}{P_2} = \left(\frac{2}{K_m + 1} \right)^{\left(\frac{K_m}{K_m - 1} \right)}$$

P_2 = Downstream Pressure (psia)

P_1 = Upstream Pressure (psia)

In the trial - and - error procedure $(P_2 / P_1) = 0.5$ is a convenient starting point

Step 3

Evaluate X , the weight fraction of vapour at the critical downstream pressure, P_2 .

$$\frac{H_{l1} - H_{l2}}{H_{v2} - H_{l2}}$$

Where

H_{l1} = Liquid enthalpy at upstream conditions Btu/lb °F

H_{l2} = Liquid enthalpy at downstream conditions Btu/lb °F

H_{v2} = Vapour Enthalpy at downstream conditions Btu/lb °F

Step 4

Evaluate ρ_{m2} , the average density of the two-phase mixture at outlet condition.

$$\rho_{m2} = \frac{1}{\frac{X_c}{\rho_{v2}} + \frac{1-X_c}{\rho_{l2}}}$$

Where



ρ_{m2} = Average Density (lb/ft³)
 ρ_{v2} = Vapour density at downstream conditions (lb/ft³)
 ρ_{l2} = Liquid density at downstream condition (lb/ft³)
 X_c = Weight fraction of vapour.

Step 5

Evaluate ρ_A , the mean of the inlet and outlet densities.

$$\rho_A = \frac{\rho_{l1} - \rho_{m2}}{\log_e \left(\frac{\rho_{l1}}{\rho_{m2}} \right)}$$

Where

ρ_{l1} = Liquid density at upstream conditions
 ρ_{m2} = Average density as defined above
 Evaluate GA the average specific gravity

$$GA = \rho_A / 62.4$$

Step 6

Evaluate C_v , the valve sizing coefficient for liquid.

$$C_v = \frac{W}{500 \sqrt{GA \cdot DP}}$$

Where

W = Weight Flow (lb/h)
 $DP = P_1 - P_2$ (psi)

C_v is the equivalent quantity of water which the valve will pass with a pressure drop of 1 psi across it.

Step 7

Evaluate A , the required pressure relief valve orifice area

$$A = \frac{C_v}{38.2 \cdot K}$$

Where

A = Orifice area in square inches

K = Discharge coefficient which should be obtained from the valve manufacturer; if K is not known a value of 0.62 is recommended.

R2.3 Liquid Subcooled at Inlet

A liquid may be subcooled at the pressure relief valve inlet but flashing will still occur across the valve. The sizing method detailed in R2.2 must be modified as follows.

In the initial expansion stage, subcooled liquid at pressure P_1 and temperature T_1 becomes saturated at pressure P_v and temperature TL_1 (assume isenthalpic expansion). During this stage the average density of the liquid is taken as an arithmetic average i.e.

$$\rho_l = \frac{\rho_{l1} + \rho_{l2}}{2}$$

Where

ρ_{l1} = Density at T_1 (lb/ft³)

ρ_{l2} = Density at TL_1 (lb/ft³)

In the final expansion stage, saturated liquid at pressure P_v and temperature TL_1 becomes a two-phase mixture at pressure P_2 and temperature T_2 . During this stage, the average density of the flashed portion of the fluid is:-

$$\rho_v = \frac{\rho_{l1} - \rho_{v2}}{\log_e \left(\frac{\rho_{l1}}{\rho_{v2}} \right)}$$

Where

ρ_{v2} = Density of saturated vapour at the outlet pressure P_2

The average density for the entire two-stage process is found by arithmetically averaging the densities calculated above over two pressure ranges.

$$\rho_A = \frac{\rho_l(P_1 - P_v) + \rho_v(P_v - P_2)}{P_1 - P_2}$$

And $GA = \rho_A / 62.4$

The above derivation of GA replaces that in R2.2. otherwise the sizing procedure is the same.

R2.4 Two-Phase Fluid at Inlet

The method detailed in section R2.2. may be used provided GA, the average specific gravity is determined as below. From X_1 , the weight fraction of vapour present at the inlet, the mixture density ρ_{m1} is calculated

$$\rho_{m1} = \frac{1}{\frac{X_1}{\rho_{v1}} + \frac{1-X_1}{\rho_{l1}}}$$

Where

ρ_{m1} = Mixture density at inlet conditions (lb/ft³)

ρ_{v1} = Vapour phase density at inlet conditions (lb/ft³)

ρ_{l1} = Liquid phase density at inlet conditions (lb/ft³)

X_1 = weight fraction vapour.

X_f , the flashing that occurs across the valve, is calculated from a heat balance and weight fraction of vapour in the outlet mixture is then

$$X_2 = X_1 + X_f$$

The density of the outlet mixture is

$$\rho_{m2} = \frac{1}{\frac{X_2}{\rho_{v2}} + \frac{1-X_2}{\rho_{l2}}}$$

Where

ρ_{v2} = Density of saturated vapour at outlet pressure (lb/ft³)

ρ_{l2} = Density of liquid phase at outlet temperature (lb/ft³)

ρ_A , the average density is

$$\rho_A = \frac{\rho_{m1} - \rho_{m2}}{\log_e \left(\frac{\rho_{m1}}{\rho_{m2}} \right)}$$

And $GA = \rho_A/62.4$