the australian PIPELINE industry association Ltd

APIA

GUIDE TO AS 2885

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FOREWORD

The Guide to AS 2885 is the culmination of the efforts and dedication of several experienced APIA members and demonstrates their desire to pass on this valuable information to the younger generation of pipeline engineers who will be carrying our industry forward. It came about as a result of requests from many APIA members to address a looming skills shortage and encourage more pipeline engineers to increase their skill levels and competency in the pipeline industry. The pipeline industry is expanding in Australia, hence the demand for competent pipeline engineers is increasing and there is a need to ensure that the next generation is prepared to take over from the senior pipeline engineers who are approaching retirement age.

The Guide to AS 2885 is designed to be a useful information resource, particularly for people relatively new to the industry, but also as a reference for more experienced engineers. It contains several useful references such as text books on pipeline design, technical papers, APIA's knowledge base and the papers that were generated by the Standards Australia ME-38-1 Committee to support the current version of AS 2885. It addresses the pipeline design process and documents lessons learnt from previous applications of the Standard, as well as including responses to issues raised by APIA members about parts of the Standard where they have found application difficult.

This Guide has been prepared specifically to assist pipeline engineering training and as a reference document. It is not designed to be a Companion Document such as those available for other standards around the world, including the Canadian pipeline standard. The difference lies in the extent of the document and the purpose. An official Companion Document has the express purpose of assisting users of the Standard in interpreting clauses in the Standard and applying it correctly. This Guide, on the other hand, is written as an informative introduction and ongoing reference to pipeline engineers working on Australian pipelines designed, constructed and operated to AS 2885.

I trust that the APIA Guide to AS 2885 will be essential reading for all new pipeline engineers entering the industry and an invaluable reference for experienced pipeline engineers. APIA is committed to pipeline engineering training and intends to further develop this Guide and to keep it up to date with latest developments. I trust that this Guide will contribute to the provision of a strong foundation for continuing and strengthening Australia's reputation for safe, reliable and efficient energy pipelines.

Peter Cox

APIA President

DISCLAIMER

The content of this Guide to AS 2885 ('the Guide') has been prepared to assist APIA members by providing information on:

(a) the history and background to AS 2885;

(b) the relationship between AS 2885 and the role and responsibility of a pipeline engineer; and

(c) the application of parts of AS 2885 that sometimes may have been difficult to apply in particular pipeline applications.

The information in this guide is general, and it does not constitute, and should not be relied upon as, engineering advice. While every effort has been made and all reasonable care taken by APIA to ensure the accuracy of the information and data contained in the Guide, the information and data should not be used or relied upon for any specific pipeline application or any other use:

- without verification by the pipeline design engineer or other competent engineer of:
  - the accuracy and reliability of such information and data;
  - the suitability or applicability of such information and data for the specific pipeline application or other use.
- as a substitute for independent due diligence and examination by the pipeline design engineer or other competent engineer of all issues and matters relevant to such application or other use.

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The terms and conditions of AS 2885 shall always takes precedence over the Guide, and if any inconsistency between AS 2885 and the information and data in the Guide should arise, or the Guide creates any ambiguity, the meaning and effect of AS 2885 shall prevail.

PREAMBLE

Stage 1 of the APIA Pipeline Engineer Training Project has included the initial development of a Guide to AS 2885 and this has comprised:

- Developing the nature, content and structure of the document, including allowing for elements to be added at future dates
- Researching and drafting information about the historical and philosophical background and rationale for differences with international pipeline standards
- Drafting a section that provides brief background about the key engineering process of pipeline design
- Undertaking a survey of industry members about difficulties with interpreting and applying Part 1 of AS 2885 and drafting responses to the issues raised
- Commence the process of identifying and documenting significant industry lessons for pipeline engineers
- Assembly of a list of useful pipeline design references for pipeline engineers
- Updating of the issues papers that were the basis of the 2007 revisions of Part 1 of AS 2885
- Compiling these into an integrated document that is both ready for immediate use and will continue to be developed

As part of future stages of the project, APIA intends to continue the development the Guide to:

- Include descriptions of the construction and operations pipeline engineering processes
- Extend the coverage of the Industry Issues with interpretation and use of AS 2885 particularly to Parts 3 and 5
- Extend the section on Industry Lessons

At the same time APIA will develop a process for review and update of the Guide to AS 2885. The process will be based on the experiences of APIA members as they increase their use of the Guide.

APIA members who are looking for assistance in the use of this Guide to AS 2885, or wish to provide feedback or suggestions to improve the document should contact the APIA Secretariat.

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1 BACKGROUND AND PURPOSE

This Guide to AS 2885 is the result of the Australian Pipeline Industry Association's (APIA) recognition of a skills shortage in the ranks of pipeline engineers, which can be expected to worsen unless the industry takes action. APIA is working with the industry and developing a number of strategies to address the need to maintain the pipeline engineering skills base. The role of this APIA Guide to AS 2885 in addressing the pipeline engineering skills shortage is best understood in the context of the development of the Australian pipeline industry.

Since the mid 1990s the Australian pipeline industry has grown dramatically, in both number and length of pipelines. Concurrent with this growth, the industry has been subject to a number of external factors:

- Microeconomic reform, including privatisation of government-owned pipelines;
- The introduction of national economic regulation, initially through the National Gas Code[1] and more recently through the National Gas Law and National Gas Rules; and,
- Increased commercial pressure to become more efficient reinforced by a number of mergers and acquisitions.

AS 2885[2], the Australian standard for petroleum pipeline design, construction, testing and operation, has evolved and expanded in order to meet the requirements of the Australian industry to reduce the cost of constructing pipelines as well as maintain the existing high standards of safety and reliability. AS 2885 requires competent persons to make important decisions regarding pipeline design, construction, testing and operation[3].

In 2007, APIA recognised the challenge of maintaining the required number of engineers capable of making these decisions in order to keep pace with the demands of the industry. At the same time, it was clear that many of the pipeline engineers engaged in the industry were approaching retirement age. To maintain the industry's standard of reliability and safety, the skills and knowledge held by these engineers must be transferred to newer members of the industry.

A variety of mechanisms are required to ensure the pipeline industry has sufficient competent pipeline engineers. Because of the critical role AS 2885 in the safe and efficient design,

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[1] That is, the National Code for Third party Access to Natural Gas Pipelines, which together with the Natural Gas Pipelines Act formed the main elements of the National Gas Access Regime. This regime was revised and replaced by the National Gas Law and National Gas Rule in July 2008

[2] AS 2885 is a suite of Standards comprising 6 parts. From here on where AS 2885 is referred to it means the suite of standards, comprising all 6 parts. All other references will be to a particular part, e.g. either as AS 2885.1 or Part 1.

[3] The requirement for competent persons is reflected in state legislation, regulations and licensing regimes.

construction and operation of pipelines and its uniqueness among global pipeline standards, APIA initiated a project to develop a program to aid the training of pipeline engineers. One aspect of this project is development of a document to assist pipeline engineers to better understand and apply AS 2885, hence this Guide to AS 2885, which focusses on two objectives:

i) providing insight into AS 2885 – its background and philosophy and related information - to support understanding and application of the Standard; and,
ii) providing information about the key processes a pipeline engineer contributes to design, construction and operations.

To satisfy the first objective, Section 2 of the Guide provides key background information about the nature and development of the Australian Standard in the context of both the Australian industry and the worldwide pipeline industry. In particular, it identifies the unique features of the Australian Standard compared with common international standards. These differences have been one of the enabling factors for pipeline development in Australia since the late 1980s. It is therefore essential that pipeline engineers understand these differences and their value to the growth and development of the industry and the broader economy.

The Guide seeks to meet its second objective through Section 3, which comprises brief descriptions of the key pipeline engineering processes of design, construction and operations. Because the Guide focuses on design, it includes Section 3.1 on the Pipeline Design Process. Sections 3.2 and 3.3 will be added when available.

In addition to the historical perspective, this first version of the Guide focuses on Part 1 of the Standard, and the design aspects in particular, because Part 1 went through a major revision in 2007. This focus is achieved through inclusion of Section 4.1 – Key Issues for Application of AS 2885, which provides background information on aspects of the Standard for which some pipeline engineers have experienced difficulty in interpretation and application, and through Appendix 2, which comprises the Issues Papers on which the most recent revision of AS 2885.1 was based. This Guide will be expanded to cover the other Parts of the Standard.

Readers of this Guide should understand that <u>there is no substitute for reading the Standard</u> and gaining sound perspective and understanding of its application to specific situations and problems. This Guide provides background to the Standard and advice on its application. This Guide does not seek to interpret the Standard, but it does provide information that will aid in understanding and application.

Section 4.1 and Appendix 2 are designed to be aids to understanding. Should there be a situation where this Guide does not aid sufficiently with interpreting or applying the Standard,

a formal request for clarification/interpretation should be submitted to ME 38 or its relevant subcommittee[4].

Section 4.2 – Industry Lessons also helps to meet the second objective by providing descriptions of important lessons learnt by pipeline engineers over the past 3 decades. Stage 1 has only included one industry lesson, but this section will be added to and will also be expanded to include lessons from construction and operational experiences.

Sections 3 and Section 4 are supported by Appendix 1.1, a comprehensive list of reference materials that can assist an aspiring pipeline engineer in their professional role, whether that be in design, construction or operations.

While the Guide provides valuable understanding of the background to the Standard, it will not fulfil the role of a formal commentary or companion to AS 2885 in the manner of, for example, the *Canadian Standard Z662.1-03 Commentary on CSA Standard Z662-03*, *Oil and Gas Pipeline Systems*[5]. However, APIA trusts that this Guide will be of assistance in the development of a commentary on AS 2885 in the future.

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[4] Each version of the Standard includes a section on "Interpretations". For example, see page of AS 2885.1. Interpretations may be sought from Standards Australia

[5] The Canadian commentary provides "background information about certain clauses and requirements in the Standard, to provide information that may be of assistance to the reader in understanding and implementation of such requirements, and to refer to research materials that were used during the formulation of the requirements of the Standard" – Preface, page xi.

2 BACKGROUND TO THE AUSTRALIAN STANDARD

2.1 THE PURPOSE OF A STANDARD

The purpose of a standard is to provide designers, builders and engineers with mandatory and informative criteria for designing, constructing, testing and operating a product, piece of equipment or structure. Standards are written primarily from a safety perspective, and are often referenced by legislation and may be used as evidence in court actions dealing with public liability and workplace health and safety. If, for a certain application, a requirement in the standard cannot be adhered to, many Australian standards provide a clause where an alternative can be used, based upon sufficient research and modelling to prove that safety and functionality is not compromised. Having standards to which design, construction, testing and operation must comply creates consistency within and between industries.

Standards consist of rules, requirements, principles and factors that must be taken into account in undertaking the design, construction, testing or operation of a product or activity. They are "not to be regarded as being an instruction manual for untrained persons or a complete design specification"[6]. Accordingly they cannot be approached mechanically - as you would a cookbook - but require a certain minimum level of background knowledge and understanding.

"AS 2885 is a single and adequate technical standard that provides an authoritative source of fundamental principles and practical guidelines for use by *responsible and competent persons* or organisations"[7]. It consists of "principles [that are] expressed in practical rules and guidelines for use by *competent* persons". It also identifies key decision points or "Approvals" that must be made by the pipeline Licensee. For such Approvals the pipeline Licensee will depend on a *competent person* in its employ or contracted to it.

It is therefore essential that the *competent person* being relied upon by the Licensee fully understands the necessary engineering principles and the relevance and application of the Standard in relation to that Approval.

2.2 THE INTERNATIONAL PIPELINE STANDARDS

In addition to the Australian Standard for gas and liquid petroleum pipelines there are a number of international pipeline standards that can be drawn upon for use within the pipeline industry. The main international pipeline standards are:

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[6] AS 2885.0 – Foreword, page 4

[7] AS 2885.0 – Section 1.3, page 8

- American Standard - ASME B31 Code for Pressure Piping
- Canadian Standards Association - CSA Z662-07 Oil and Gas Pipeline Systems
- International Standards Organisation, ISO 13623:2009 Petroleum and natural gas industries -- Pipeline transportation systems
- DNV - DNV-OS-F101:2007 - DNV Submarine Pipeline Rules
- United Kingdom - BS EN 14161: Petroleum and natural gas industries – Pipeline transportation systems supplemented by PD 8010:2004 Code of practice for pipelines, which is divided into two parts:
  - Part 1: Steel pipelines on land
  - Part 2: Subsea pipelines

Of the above list, the first of the standards to be produced was the American Standard ASME B31 Code for Pressure Piping. In 1926 it was commissioned to be written and *was tentatively introduced in 1935 as a single all inclusive document for piping design* titled *American Tentative Standard Code for Pressure Piping, ASA B31.1*. This standard became known as the ASME B31 Standard and was divided into sections dealing with specific piping systems in the 1950s using the following codes:

B31.1 – Power Piping

B31.2 – Fuel Gas Piping, WITHDRAWN superseded by ANSI Z223.1

B31.3 – Process Piping, (formerly Chemical Plant and Petroleum Refinery Piping)

B31.4 – Liquid Hydrocarbon Transportation Piping (for example oil cross country pipelines)

B31.5 – Refrigeration Piping

B31.6 – Chemical Plant Piping, never issued as a separate document, folded into B31.3

B31.7 – Nuclear Power Piping, WITHDRAWN, superseded by ASME Code, Section III

B31.8 – Gas Transportation Piping (for example cross country gas pipelines)

B31.9 – Building Services Piping (for example office building hot water heating and air conditioning)

B31.10 – Cryogenic Piping, never issued as a separate document, folded into B31.3

B31.11 – Slurry Transportation Piping (for example cross country coal/water slurries)

The introduction of the refined ASME B31 Code for Pressure Piping of the 1950s opened the way for the Canadian Standards Association, the International Standards Organisation and the Australian Standards to develop their own standards, all of which were based upon the ASME B31 Code.

The Canadian Standard, CSA Z662-07 Oil and Gas Pipeline Systems was initially primarily based on parts B31.4 and B31.8. However, since 1967/1968 it has been maintained separately from the ASME standards.

The International Standards Organisation (ISO) standard for pipelines is ISO 13623:2009 Petroleum and Natural Gas Industries -- Pipeline Transportation Systems. The first version of

this standard was published in 2000. In addition to this main standard there are a number of standards that relate to pipeline components. Although the ISO seeks to develop standards that are applied across the globe, ISO 13623 is rarely applied. The ISO seeks to harmonise pipeline standards with the ultimate goal of a single pipeline standard. The rate of progress toward this goal is slow and harmonisation should not be expected for many years.

With the increasing reach of the European Union, Britain adopted (subject to some modification) BS EN14161 in 2003, which is effectively ISO 13623. However, after some revision it maintained much of the previous version of the British Standard BS 8010 in the form of PD 8010, which acts as an informative document rather than a required Standard.

2.3 THE DEVELOPMENT OF THE AUSTRALIAN STANDARD FOR PIPELINES

The first significant hydrocarbon transmission pipeline constructed in Australia was the DN500 "Lurgi" pipeline, built in 1956 to transport coal gas from gasifiers at Morwell in the Latrobe Valley, to Dandenong (Melbourne). The design standards of this pipeline are not well known but the pipeline remains a part of the Victorian Gas Network.

The first "modern" pipelines were the Moonie – Brisbane oil pipeline (1964), the Savage River magnetite slurry pipeline (1965) and the Roma – Brisbane gas pipeline (1969), the Moomba – Adelaide (1969), Dongara – Pinjarra (1972), Longford – Melbourne (1971) and Moomba - Sydney (1976) pipelines. There were also a number of liquids and gas pipelines constructed in Victoria, in the late 1960s and early 1970s.

The early pipelines were designed to overseas standards, usually ASME B31.4 (liquids) and B31.8 (gas), but the development of major natural gas pipelines provided an impetus for an Australian standard for gas and liquid petroleum pipelines.

The first Australian standard for pipelines was CB 28, which was released in 1972. This standard was based on and largely replicated ASME B31.8.

A new revision of the gas pipeline standard was released in 1975 and redesignated as AS 1697. It was further revised in 1979 and 1981. Again this was largely a clone of ASME B31.8.

1976 saw AS 1958, a submarine pipeline standard, developed. In 1977 a petroleum liquids pipeline standard, AS 2018, was published together with AS 1978, the first standard for field pressure testing of pipelines. AS 1958 and AS 2018 were also revised in 1981.

Up to this point Australian pipeline standards had reflected the approaches adopted in ASME and British standards. Pipelines were largely owned by the public sector. They were expensive having used imported technology, heavily supported by international engineering and construction companies.

Gas resources in Australia are typically remote from load centres. The loads were (and still are by world standards) small and the gas value is relatively low. The land between the gas resource and the load centre is generally sparsely populated. These factors combine to make it difficult to justify development of gas transmission pipelines unless the capital cost can be amortised over a long project life. It was this fact that led the Australian pipeline industry to depart from "traditional" North American and European pipeline designs.

To reduce capital costs the Australian industry adopted higher strength line pipe steels (and reduced wall thickness) and increased operating pressures (initially 7 MPa, then 10.2 MPa, and 15.3 MPa) to increase the gas quantity transported per unit of steel. Combined with newly developed pipe coatings, joint coatings and construction methods they formed the basis for departure of the Australian Standard from the North American model, and the need for development of additional standards relevant to Australian conditions.

As the Australian pipeline industry developed, it faced a set of unique issues requiring research for resolution. The industry began to participate in pipeline research through membership of the US-based Pipeline Research Committee by the Commonwealth Government-owned Pipeline Authority, the SA Government-owned Pipelines Authority of South Australia and the Victorian Gas and Fuel Corporation.

A new Standard, AS 2885, was published in 1987. While still looking much like the American Standard, this standard introduced significant departures from the previous documents including:

- Application to transmission pipelines only (pressures greater than 1,050 kPa)
- Application to gas and liquid hydrocarbons (onshore)
- Definition of a single design factor for determining the pressure design thickness of the pipe
- Definition of a third party protection factor (to recognise the purpose of the mandatory design factors that the earlier standards applied to class locations other than broad rural)

The result was that more understanding and thought was required in both the development and application of the new Standard.

During the 1990s AS 2885 went through a range of developments, which saw the standard separated into several parts. AS 2885.2 covering welding was issued in 1995, AS 2885.1 covering Design and Construction and AS 2885.3 covering Operations and Maintenance were issued in 1997.

AS 1978 was withdrawn, revised and re-published as AS 2885.5 (Field pressure testing) in 2002. After several attempts to revise the old AS 1958 (Submarine Pipelines) it was decided to withdraw the Standard and replace it with AS 2885.4 (Offshore Pipelines) in 2003. Part 4 comprises DNV's offshore pipeline standard OS F101 along with some uniquely Australian requirements.

There are a number of associated standards:

- AS 1518 – Extruded HDPE Coating
- AS 3862 – FBE Coating
- AS 4822 – Field Joint Coating

Revisions since have been:

- Part 1 – 2007 – major revision, including the notable introduction of an 80% design factor and limited provisions for Maximum Allowable Operating Pressure (MAOP) upgrade
- Part 2 – 2007 – a significant revision that provided flexibility in defect acceptance limits
- Parts 3 was revised in 2001 and is currently undergoing significant revision for publication in 2010
- Part 5 is also currently undergoing significant revision for publication in 2010

AS 2885.0 was developed in 2008 to reintroduce and expand on a number of foundational principles that were deleted from the 2007 revision of AS 2885.1 to provide an overarching document that ties all of the parts together.

The timeline in figure 2.1 provides a summary view of the development of AS 2885 alongside the development of pipelines in Australia.

Figure 2.1 - AS 2885 Development Timeline

Major Pipelines	Year	Standard
Lurgi pipeline	**1956**	
	1957	
	1958	
	1959	
	1960	
	1961	
	1962	
	1963	
Brisbane Oil Pipeline	**1964**	ASME B31.4 used
Savage River Slurry Pipeline	**1965**	
	1966	
Roma-Brisbane Pipeline	**1967**	
Longford-Hastings LPG Pipeline	**1968**	
Moomba-Adelaide Pipeline, Roma-Brisbane Pipeline	**1969**	ASME B31.8 used
	1970	
Longford-Melbourne Pipeline	**1971**	
Parmelia Pipeline	**1972**	CB28 developed
	1973	
	1974	
	1975	AS 1697 developed
Moomba-Sydney Pipeline	**1976**	AS 1958 developed
	1977	AS 2018 developed
	1978	
	1979	AS 1697 revised
	1980	
	1981	AS 1697, 1958 & 2018 revised
Sydney-Newcastle gas & petroleum products pipelines	**1982**	
PV-Alice Springs Pipeline, Jackson-Moonie Pipeline	**1983**	
Moomba-Pt Port Bonython Pipeline, Dampier-Bunbury Pipeline	**1984**	
Mereenie-Alice Springs Oil Pipeline	**1985**	
Amadeus-Darwin Pipeline	**1986**	
	1987	AS 2885 developed
	1988	
	1989	
	1990	
Queensland Gas Pipeline	**1991**	
	1992	
	1993	
Riverland Pipeline	**1994**	
	1995	AS 2885.1 & AS 2885.2 developed
Goldfields Gas Pipeline, SW Queensland Pipeline	**1996**	
Carpentaria Gas Pipeline, Moomba-Sydney Ethane Pipeline	**1997**	AS 2995.3 developed
Pilbara Energy Pipeline, NSW-Vic Interconnect	**1998**	
Eastern Gas Pipeline	**1999**	
Iona-Lara Pipeline	**2000**	
	2001	AS 2885.3 revised
SEAGas Pipeline, Tasmania Gas Pipeline	**2002**	AS 1978 replaced by AS 2885.5
	2003	AS 2885.4 developed
Telfer PipelineNQ Gas Pipeline	**2004**	
	2005	
	2006	
	2007	AS 2885.1 & AS 2885.2 revised
	2008	AS 2885.0 developed
Bonaparte Gas Pipeline	**2009**	
	2010	AS 2885.3 & AS 2885.5 under revision

Note: The Standard that is applicable to a particular pipeline may not be that be that which was released in the same year or even several years before because of the pipeline development cycle will have commenced before a the revision was released

Since the inception of AS 2885, a key aspect has been the evolving role of demonstrating the safety of all parts of pipeline design, construction and operation. The 1997 revision of AS 2885.1 introduced a risk assessment process designed to validate the safe design and construction of a pipeline. It was recognised that the quantitative risk assessment techniques applied in the chemical process industries are location specific and therefore not relevant to linear infrastructure where different threats to integrity exist along the pipeline length.

The AS 2885 approach remains consistent with other risk assessment processes (e.g. AS / NZS ISO 31000), but recognises that the pipeline design is a response to an identified threat to the pipeline. The Standard requires that each identified threat be controlled by a combination of physical and procedural methods to reduce the likelihood of that threat causing damage to an *acceptable risk* level. Part 1 of the Standard requires extensive investigation to identify, document and control each threat, and to undertake regular review to ensure that the identified threats are current and the controls applied are effective.

The depth of detail and the level of documentation required by the AS 2885 Safety Management Study (formerly the Risk Assessment Process) is significant.

The AS 2885 Safety Management Study requires validation by a workshop of stakeholders. Validation requires the entire Safety Management Study to be reviewed and the stakeholders to work to form the opinion that all threats are identified, the controls applied are effective, the risk of any threats that are not controlled is not higher than *intermediate*, and that any risks assessed as *intermediate* are reduced to ALARP (as low as reasonably practicable).

The Safety Management Study (which includes a formal risk assessment process) forms the basis of Safety and Operating Plans for the ongoing safe management of a pipeline.

Unlike other standards that apply mandatory requirements for the pipe wall thickness according to location and population density, AS 2885 requires the Pipeline Licensee to demonstrate that the pipeline is safe in each location in which it is installed. This requires the Licensee (and its designer) to consider ten different factors, each of which influences the required wall thickness (such as resistance to penetration) and to select wall thickness at each location accordingly. The Standard has a mandatory requirement for the Licensee to demonstrate that the pipeline will not rupture in populated locations.

The scope of the Standard is restricted to the pipeline (significantly because of the emphasis on thin walled pipe). Consequently, it has nominated that connected station piping be designed to an appropriate pressure piping standard such as AS 4041 or B31.3.

The most recent developments have focussed on increasing the economic efficiency of pipelines through allowing MAOP at a design factor of 80% of specified minimum yield stress (SMYS) and flange ratings at and above Class 900, so long as it is demonstrably safe to do so.

Part 2 has incorporated the most recent research on hydrogen assisted cold cracking (HACC), use of automatic welding processes, and ultrasonic non-destructive testing.

The Australian Standard is characterised by a set of principles that add to its uniqueness:

- Ensuring the protection of the general public, pipeline operating personnel and the environment
- Explicitly recognising that continuity of supply is an important secondary community safety issue
- Requiring suitably qualified, experienced and trained people who take responsibility for their actions in writing
- Designing against actual threats and failure modes
- Auditing design and operations processes
- Ensuring transparency, repeatability and traceability

It seeks to comply with these fundamental principles by defining a **single and sufficient** set of technical requirements.

AS 2885 is developed and reviewed by a committee system consisting of an overseeing committee, ME/38, and a sub-committee for each part. The main committee comprises representatives of the industry, the peak body organisations of associated industries and industry technical regulators.

Typically the subcommittees comprise people drawn from:

- Pipeline owners
- Engineers
- Constructors
- Suppliers
- State technical regulators
- Independent technical specialists

who are selected for their experience and expertise rather than representing any particular viewpoint.

This broad and inclusive group promotes national acceptance and adoption of the Standard and minimises the risk of different regulatory regimes in each state. It also brings a range of expertise to producing a strong and balanced standard.

2.4 SIGNIFICANT DIFFERENCES BETWEEN AS 2885 AND INTERNATIONAL STANDARDS

The Australian pipeline standards started to diverge from the approaches adopted in international Standards during the second half of the 1980s. This path was motivated by a number of related factors, but the overarching need was to drive down the cost of pipelines while maintaining a high standard of safety and reliability.

While seeking to reduce costs would seem to be universally desirable, in Australia marginal cost reductions can mean the difference between a pipeline being built or not, and can therefore have a significant impact on the price and availability of gas. This is because of

Australia's small population size relative to its large geographic area and the tendency of gas resources to be located great distances from gas markets. By way of comparison, the lower 48 states of the USA have a land mass roughly equivalent to Australia's, but a population 15 times Australia's. The economies of scale associated with pipelines mean that pipeline development in Australia has a marked economic disadvantage compared to the USA. Similar comparisons can be made with the UK, Europe and some parts of Asia.

The need to make pipelines as cost efficient as possible required a move from conservative empirical design approaches and reliance on "rules of thumb" to a more intelligent engineering approach to design. This approach has led to decisions that ultimately reduced the cost of building and operating a pipeline over its economic life.

Several broad themes are clearly identifiable in the Australian Standard that are generally either, not present, or less clear in other standards. These tend to distinguish the Australian Standard from the other pipeline standards.

Clear Basis, Purpose and Guiding Principles

Other standards typically provide only general statements about their purpose. While they do point to issues of safety, integrity, environmental protection and security of supply, their treatment within the standards is not particularly clear. AS 2885.0 provides a clear statement of the basis of the AS 2885 series, and sets out the fundamental principles of:

- Safety, environmental protection, security of supply,
- Consideration of all planned and accidental loads over the complete life cycle,
- The basis of approval, and
- The key role of approved safety and operating plans.

In addition, each major section of AS 2885 has a "Basis of Section" clause stating its overall purpose and intent, and guiding principles.

A Single and Sufficient Standard

The development and revision process, called "managed representation", through the Standards Australia committee ME 38 and its subcommittees is not unique, but is a particularly robust process, because it includes members from a full range of industry sectors, including the State regulators.

The result is that AS 2885 holds "single and sufficient" status. That is, AS 2885 is comprehensive in the matters that need to be covered by pipeline technical regulation and there is no need for the state technical regulators to make further or additional technical regulations. This status was adopted by the Council of Australian Governments in its communiqué of 25 February 1994 in which it "agreed to adopt AS 2885 to achieve uniform

national pipeline construction standards by the end of 1994 or earlier"[8]. Accordingly a majority of the State regulators have recognised this and have not added further requirements over AS 2885.

In other jurisdictions the level of reliance on the relevant standard has been variable. While committees, including technical regulators, have developed the Canadian Standard (Z662), some regulators have applied additional regulations with Z662 as the basis. Regulators in the USA have not adopted B31. The ISO standard has not adopted the managed representation process.

Responsibility and Approval

AS 2885 gives responsibility for decisions under it to the pipeline Licensee. Significant decisions require designated Approvals, which must be made consciously by the Licensee and may include obtaining approval from the relevant State regulator.

Approval applies to "important matters related to safety, engineering design, materials, testing and inspection… "[9]. The Standard also requires that accountability rest with a competent person or entity on behalf of the Licensee and that they must document Approvals in writing.

These clear definitions of the Licensee's responsibility and a competent person/entity have at least two benefits. The first is that critical decisions will be made with a high level of awareness of their significance. The second is that regulators are responsible only for those approvals and decisions that can and should be made by regulators. In other words, the accountability lies with the party who is best placed to understand and manage the desired outcomes sought by the Standard. The role of the technical regulator is to ensure the Standard has been properly applied through adherence to the required processes.

Other standards do not make the process of decision-making, accountability and approval so clear.

Safety and Risk Management

AS 2885 seeks to manage issues of safety – occupational health, public or environmental safety – through risk management techniques. This means that protection measures are based on a thorough assessment of sources of risk along the whole length of the pipeline. This has two benefits:

i) risks are eliminated wherever possible and protection measures properly reflect the risks; and,

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[8] Item 5, Attachment B COAG Communiqué, 25 February 1994

[9] AS 2885.1 - 2007 Pipelines – Gas and liquid petroleum, Part 1: Design and construction, page 2

ii) protection measures are sufficient, but not excessive thus minimising the cost of risk elimination or risk management.

In summary, this approach provides a high level of assurance about safety, but at the lowest sustainable cost.

There are a range of specific differences between AS 2885 and the international standards. These are summarised in Tables 2.1 and 2.2.

Table 2.1 - Comparison of AS 2885 with some International Pipeline Standards for Design and Construction

Aspect	AS 2885	ASME B31.8/ API1104	ISO 13623	CSA Z662
Involvement, ownership & usage	• Managed industry sector representation • State regulator participation	• Minimal technical regulator involvement • USA pipeline comply with DOT rules not ASME • "export standard"	• not representative – countries or industry sectors • not known to be used	• technical regulator involved • Accepted by National Regulator
Risk assessment principles	• Meter by meter threat identification • Threats designed out • Only residual risks managed	• Design by rule	• Design by rule • Default use of risk assessment in some situations	• Not mandatory • In Appendix
Wall thickness design	• Greater of: – Pressure design – No penetration design – "No rupture" design – And other issues	• Design factors between 0.8 and 0.4 based on location class and construction type	• design factors based on location class and construction type (0.8 plus a location factor)	• Design factor 0.8 • Location factor 1.0 – 0.5 • Joint factor
Reliability based design	• Not specified in detail • Permitted subject to rigorous justification of alternative standard	• Under consideration	• Permitted	• Permitted (limit state design)
Fracture control	• Fracture control plan required • Controls for propagation and initiation required	• Fracture control requirements – no documented plan	• Fracture control requirements – no documented plan	• Fracture control requirements – no documented plan
External interference design	• Minimum no. of physical and procedural controls by location class	• Suggests options for protection against third party interference	• Silent	• Silent
Hydrostatic strength test	• 4 hr at not less than1.25 MAOP • Volume-strain test near yield	• 2 hr at 1.1 MAOP in Cl 1 locations • Higher test factors other locations	• 1 hr at 1.25 MAOP • 1.20 MAOP for R1	• 4 hr at 1.25 MAOP Min – class 1 – 2 • Other locations - higher test factors
Purpose of qualifying weld	• Demonstrate production welds using weld procedure will meet	• Demonstrate test welds meeting criteria can be made	• Not stated	• Not stated

Aspect	AS 2885	ASME B31.8/ API1104	ISO 13623	CSA Z662
procedures	specified criteria	by the procedure		
Design against Hydrogen Assisted Cracking (HACC)	• HACC must be "designed out" • Normative appendix • Appendix gives ranges of essential variables	• No mention	• Optional provisions	• No mention
Test weld thickness essential variable	• Test weld thickness plus 10%	• Change of wall thickness group – t < 4.8 – 4.8 < t < 19.1 – t > 19.1	• Thickness minus 25% • Thickness plus 50%	• Thickness plus 50% for t < 10 • Thickness plus 25% for t > 10
Test weld preheat essential variable	• Test weld minus 25°C • Plus 75 °C	• Any change	• Test weld minus 0°C • Plus 50 °C	• Test weld minus 25°C • Test weld plus 25 if above 200 °C

Table 2.2 - Comparison of AS 2885 with some International Pipeline Standards

Operations and Maintenance Matters

Feature	AS 2885	ASME B31.8	DOT Regulation 192
Risk Assessment	Metre by metre risk assessment	Not mandated	Provides some elements of a formal risk process
Integrity Management Plan	Required and guidance provided	• Not required • New integrity management supplement	Not required
Safety and Operating Plan	Review and audit timetable required	Technical information provided	• Required • Has an O&M manual

3 PIPELINE ENGINEERING PROCESSES

3.1 THE PIPELINE DESIGN PROCESS

3.1.1 Introduction to the pipeline design process

Designing a pipeline requires an in-depth knowledge and understanding of all aspects of pipeline design and construction, and a sound appreciation of pipeline operation. AS 2885.1 and its supplementary material define a set of compulsory criteria for pipeline design that are essential for a pipeline to be safe, environmentally sound and reliable. However, AS 2885.1 does not attempt to deal with all the matters and expertise required to undertake a complete pipeline design. Instead, it focuses primarily on ensuring that pipelines are safe and environmentally benign. The Standard assumes that those who apply it have the essential engineering design and construction knowledge and expertise.

A pipeline design and its subsequent construction must meet a number of broad criteria:

i) Performance requirements – including hourly, daily and annual capacity
ii) Reliability requirements – including availability and acceptable supply failure risk
iii) Technical soundness – the design is based on sound engineering principles
iv) Safety – including public safety and occupational health and safety
v) Environmental impact – including acceptable impact on flora and fauna, and impact on land owners
vi) Cost effectiveness – including the lowest sustainable costs to meet all the other criteria

AS 2885.1 places particular emphasis on criterion (iii). However, none of these criteria will be met unless the engineers designing and constructing the pipeline have the requisite knowledge and expertise.

This section of the Guide provides an overview of the pipeline design process, the relationships between the main steps and the depth of knowledge required to undertake the process. It is hoped that by having this overview, new and developing pipeline engineers will be well placed to "know what they know and know what they don't know" and in turn work effectively as part of a design team and be able to draw on specialist expertise as required.

Appendix 1 has been designed to complement this section by providing a wide ranging list of references containing a variety of materials (text books, websites, research papers and journals and software that are used by pipeline engineers in performing their roles. It is envisaged that Section 3 will provide a useful starting point for those who engineers who are staring out or for those who just want an appreciation of what is involved in pipeline engineering. The references will be an essential resource in developing real capability and expertise.

3.1.2 The crucial issues of safety and environmental impact

The foremost criterion for pipeline design is safety. When designed and operated properly pipelines are a safe, efficient and environmentally benign means of transporting hydrocarbons. However, if not designed and operated this way a pipeline could leak or fail,

its potential to injure and kill people is real, irrespective of its contents. If hydrocarbons released from a pipeline ignite they may injure or kill people at distances up to 1 km away (depending on pipe size and pressure). Ignition sources may be found in the environment or arise from the inherent violence of the pipe failure. This potentially extreme hazard is not widely appreciated in the community. Therefore, the onus is on pipeline designers and operators to ensure public safety.

The environmental impact of a pipeline is also an important design consideration. The need for an Environmental Impact Assessment to be conducted during the preliminary design phase is important to identify areas of environmental sensitivity. Sensitive areas can include, but are not limited to:

- Culturally significant sites;
- Areas of sensitive ecosystem; and,
- Habitats of endangered flora and fauna.

The pipeline design should endeavour to avoid these sensitive areas as far as practicable. Environmental consideration is required throughout the design phase and not only during construction and operation. A good design will limit the impact of a pipeline on its environment for the life of the pipeline.

AS 2885.1 identifies the necessary safety and environmental management process and the associated administrative requirements such as records, assessments, analyses and other documentation keeping.

The pipeline design engineer must integrate safety, environmental, operational and commercial requirements to effectively design a pipeline. The other elements of pipeline design are as described below. These elements cover the broad range of expertise required by a pipeline engineer and pipeline engineering team.

3.1.3 The beginning - pipeline development process

The need for a pipeline does not appear "out of thin air", but arises from a commercial need. This means that a product needs to be transported from a supply source to a market.

The initial parameters for a pipeline design are:

- the product,
- the rate at which it is delivered,
- its origin, and,
- its destination.

All other design parameters are derived from these parameters.

The design criteria of pipelines, like most capital equipment or infrastructure, will undergo a number of iterations - the larger the project, the greater the number of iterations. This is part of the conceptual development of the project, where the commercial and engineering considerations are refined to meet the needs of the pipeline's stakeholders. Regardless of the number of iterations before a project approval is received the following steps are essential to deliver a pipeline design that can be constructed.

During this process high level design inputs will be used and refined. For instance, design pressure, pipe diameter, pipeline route, use of compression or pumping etc. The level of detail and inclusion of detailed design elements increases along the process from initial concept to project approval. This detail is needed to develop cost estimates used to gain approval for a project from a company Board or other expenditure-approving body.

3.1.4 Pipeline Route Design

Effective pipeline route selection is a critical aspect of pipeline design. Analysis of potential pipeline routes and the final route selection is critical from a safety, environmental, construction, operational and maintenance perspective. It also significantly affects the cost and risk profiles of the project. Good route selection will attempt to minimise the environmental impact and maximise construction feasibility and public safety.

As well as the above, there are many other factors that must be considered during pipeline route selection. These are set out in Section 4.1 of AS 2885.1. However, the critical factors are environmental impact, construction feasibility and public safety, and their importance warrants a more detailed discussion.

Environmental Impact

Installing a pipeline can involve significant clearing of vegetation resulting in reduced ground stability and increased vulnerability to erosion and landslides, particularly during the rehabilitation stage. Temporary damming of rivers and waterways for open trench crossings also increase the vulnerability of the surrounding environment during construction and rehabilitation. Pipeline alignment through sensitive ecosystems, contaminated lands, flora and fauna reserves, areas of cultural significance, steep gullies and hills has implications for both the environment and the budget.

These areas require constant high level monitoring before, during, and after construction and a higher level of rehabilitation. This can lead to significant up-front cost in order to minimise the ongoing cost of maintenance. During the early route selection phase an Environmental Impact Assessment should be undertaken to determine if the pipeline traverses any of the areas outlined above. The Environmental Impact Assessment will also assist in determining the environmental and financial costs and benefits of altering the route to avoid such areas.

Construction Feasibility

An important consideration during pipeline route selection is construction feasibility. A pipeline route should optimise safe access for machinery and the workforce, reduce the public impact of construction activities, and optimise the locations of stockpile yards, site offices and camps, where they are required.

Construction feasibility analysis also considers the potential hazards of laying pipes within close proximity to overhead powerlines or under ground services.

Public Safety

Public safety during the construction and operational life of the pipeline is of utmost importance during route selection. Considerations will include:

- consequence analysis of pipeline contents spill/eruption and pollution;

- future developments on or around the alignment;
- width of the easement available for maintenance and construction; and,
- other services within the construction corridor of the pipeline.

The route should, as much as possible, be chosen to avoid areas that are currently populated or may become populated in the future.

AS 2885 recommends that a preliminary safety management study be done during preliminary design and route selection for a range of reasons, including identification of safety issues before a final commitment is made to a route.

3.1.5 Location Class Assessment

Location Class assessments along a proposed route are critical to evaluate the potential threats both to and from a pipeline along a proposed route. Locations are allocated a primary class based upon the land use surrounding the pipeline alignment. In some cases secondary location classes are required, to draw attention to special land uses and associated special threats.

Location Class assessments also identify the probable future land use along an alignment to determine potential future threats posed to the pipeline. Understanding likely future land use allows the pipeline to be designed against threats to its safety that may arise in the future.

Section 4.3 of AS 2885.1 defines the location classification assessment process and the requirements of such an analysis.

3.1.6 Hydraulic Design

Pipe Sizing

Selecting a pipe size depends on the fluid being transported, the maximum allowable operating pressure (MAOP), demand and flow requirements, and the extent to which compression or pumping is used. The pipe size should be selected to optimise long run cost of transportation over the life of the pipeline.

With increasing development of peak load gas turbine power stations an important consideration for some pipelines is the peak rate at which gas can be delivered. This may be the primary consideration that determines the size of the pipe and the modelling required for these pipelines.

Steady state pressure drop calculations, transient modelling and consideration of gas velocity are used to determine the most cost effective diameter.

Pipe sizing often involves balancing initial capital costs against possible future investments to increase capacity as demand grows. There is no single "correct" design for a pipeline for a given the range of possible demand scenarios. The solution will depend on the investor's perceptions of risk and funding capacity in addition to optimising the long run cost of transportation.

Compressor and Pump Sizing, Pipe Sizing and Selection

Where a pipeline's hydraulic design calls for use of compressors or pumps (i.e. it will not deliver enough product on a free flow basis) they are sized to deliver a specified flow rate at

a specified pressure and often need to operate over a range of flows and pressures. Under-sizing pumps and compressors results in a pipeline not delivering to its design capacity, while over-sizing results in a higher initial cost, but can facilitate future capacity increases.

In addition to determining the size of a pump or compressor, the type of pump or compressor and the type and size of drive must also be considered.

It is common to make provision for future installation of pump or compressor capacity to allow for future growth in pipeline throughput. This provision may comprise space for additional units in the initial station(s) or connections to allow completely new stations along the pipeline. In the latter case, part of the initial hydraulic modelling and route selection work will involve identifying the locations for these future installations.

3.1.7 Pipeline Mechanical Design

Stress and Strain Analysis

A stress and strain analysis is an integral part of the pipeline design process. The analysis models the behaviour of the pipeline subjected to external and internal forces and should identify points of vulnerability within the design.

The main areas where pipe stresses must be considered are:

- Road and rail crossings (external loads)
- Pipeline facilities (thermal and pressure expansion movements)

Particular attention to pipe stress analysis is necessary where pipelines connect to facilities, because a long run of pipeline can generate substantial thermal and pressure expansion forces and movements that may not be tolerated by the piping and equipment within pipeline facilities, especially if there are elevated temperatures involved, such as at a compressor station discharge. The stress analysis at such locations must integrate both the pipeline and the connected facility.

Stress and strain analysis may also be required for other non-standard locations or conditions such as small radius bends, aboveground pipeline sections (e.g. on a bridge), areas subject to land instability, hot oil pipelines, etc.

Design temperatures

Choice of an appropriate design temperature, or temperatures, for different locations or attributes of the pipeline should balance competing needs. Different sections of a pipeline are permitted to have different design temperatures. An excessively high design temperature may have implications for coating supply, have strength-derating effects, and may not capture a critically low temperature for fracture control. A too low temperature may have implications for welding consumable availability, may have expensive fracture control implications and again result in coating cost or choice implications.

When considering fracture control, it is important to be aware that temperature extremes often coincide with low hoop stress conditions. It may be more cost effective to place operational constraints in place for rare temperature excursions rather than rely on the fracture resistance of expensive materials.

Material Selection

Material selection applies to the pipeline and its components. Effective pipeline material selection will satisfy the following:

- Ability to withstand the forces imposed upon the pipeline identified in the stress and strain analysis
- Ability to withstand design temperatures
- Material availability, bearing in mind minimum order quantities for various sections and fracture toughness levels
- Optimise the long run cost of transportation
- Compatibility with the pipeline contents

As well as satisfying the above, the materials selected for the pipeline and its associated components may need to be able to withstand specific environmental effects such as UV radiation, external pressures imposed by flooding, and increased temperature as a result of bush fires.

Section 3 of AS 2885.1 sets out the standard of materials to be used on a pipeline by identifying the following:

- Qualification of materials and components
- Requirements for components to be welded
- Additional mechanical property requirements
- Requirements for temperature-affected items
- Materials traceability and records

Wall Thickness Design Along the Pipeline Route

Wall thickness is an important consideration of a pipeline design. The wall thickness requirements may vary along the length of a pipeline. Optimising the wall thickness along the alignment can substantially reduce the amount of material and result in significant cost savings.

Optimal wall thickness takes into consideration ten factors (listed in AS 2885.1 Clause 5.4.2). Some of these may be constant (e.g. internal pressure) while others may vary considerably along the pipeline (e.g. penetration resistance requirements). Section 5.4 of AS 2885.1 defines the considerations and requirements for safe design for wall thickness.

Fracture Control

Under certain conditions a pipeline can fail via a propagating fracture that in the worst case may run for many hundreds of metres. This is a particularly serious type of failure and AS 2885 contains extensive requirements to ensure that it will not occur.

Except under limited circumstances, all pipelines must have a Fracture Control Plan (FCP), as outlined in Section 4.8 of AS 2885.1. The purpose of the FCP is to specify the pipe properties that will control the initiation and propagation of fractures. Because fracture propagation in a gas pipeline depends on the gas properties, the FCP must also specify the gas compositions

for which it is valid. The FCP must also address the special requirements for "no rupture" and limited leak rate in high consequence areas.

Design for Hydrostatic Testing

Designers are responsible for designing the pipeline, so that it can be hydrostatically tested. This applies to all pipelines, but special consideration must be given to pipelines designed with a design factor of 0.8, which must be subjected to a strength test of not less than the pipe SMYS, and because the pipe is not horizontal, some pipe will be subjected to pressures that will cause stresses greater than Specified Minimum Yield Stress (SMYS).

The pipe maker's obligation (unless specified otherwise) is to deliver pipe with a strength not less than SMYS. The potential for plastic strain in a few pipes in a test section must be considered by the designer, and solutions incorporated in the design.

3.1.8 Safety Management

The safety management process is fundamental to AS 2885. As mentioned previously the principal reason for having standards is to ensure safety, and AS 2885 achieves this through a combination of fixed rules and a flexible process. The fixed rules apply to certain things such as wall thickness, which the safety management study provides the formal – but flexible - process by which an acceptable level of safety can be achieved in a way that is optimised at every point along the pipeline, in both design and operation.

The Safety Management Study process, which is the key instrument for safety management in the design and operation of a pipeline, includes a range of actions, and includes a validation workshop, which is mandatory. Safety management should not be treated as a separate task or afterthought; it should be integrated with all other design activities. Integration of safety management and other design tasks is important, because there is feedback between the activities. It is desirable for the SMS validation workshop to be lead by an experienced facilitator.

A Safety Management Study (SMS) should be undertaken at multiple points in the pipeline life cycle: during preliminary concept development and route selection (to avoid risks that cannot be designed out later), as part of detailed design, review prior to construction, review again prior to commissioning, then review regularly during operation up to the point of abandonment (at least every 5 years or whenever there is a significant change in the risk environment).

Outcomes of the SMS may have significant design and operating implications. Therefore, the entire SMS process must be thoroughly documented, so that the basis of critical decisions is clear, even to those who were not directly involved (such as future operating personnel).

The AS 2885 SMS process applies to pipelines and pipeline facilities. For facilities it is supplemented by a Hazard and Operability Study (HAZOP) to review process-related safety matters and, optionally, by other safety studies such as Safety Integrity Level (SIL) and Control Hazard and Operability (CHAZOP).

3.1.9 Special considerations and locations

Certain aspects of a pipeline alignment may require special consideration during the design phase, in order to provide additional protection from external factors. Such factors may include, but are not limited to:

- Alignment through areas susceptible to extreme weather patterns such as flooding, cyclones, ground movement, and temperature
- Potential for third party interaction
- Alignment through areas that are swampy or subject to tidal fluctuations

A pipeline subject to any of the above may require additional protection (such as either additional wall thickness, specialised coating or concrete encasement) from scouring flood events, or provision for heavy crossings etc.

Specialised crossings such as river crossings, road crossings (either bored, open trenched or existing crossings), and existing service crossings require their own design. The design of these crossings must comply with the requirements of local government authorities and/or the asset owner.

3.1.10 Facility design

Pipeline facilities include:

- Stations (compressor, pumping, meter or pressure regulation);
- Isolation points or main line valves (MLV); and,
- Scraper assemblies (in the case of gas and liquid petroleum pipelines).

The facility location

The location of facilities is largely determined by hydraulic design and can only be determined upon completion of the mechanical design. Final location of a facility is determined by the mechanical design, which identifies the isolation requirements for MLV spacing factoring in location class and site access. In the case of liquids, such as water, there may be the added factor of optimising gravity feeds.

It is important to ensure a location that will be accessible by the owner/operator for the duration of the station's/pipeline's operating life. The proximity of the station to the public will have a bearing on the design of the station through:

- Noise pollution of neighbouring properties
- Aesthetics of surrounding land and properties
- Threats from public (i.e. errant vehicle impact from nearby roads etc.)

Facility equipment operating conditions

Station design will also consider the requirement for safe operation of its onsite equipment. This will include:

- Equipment location
- Station hall ventilation and drainage

- Confined spaces
- Security
- Fire safety design
- Electrical and lighting design and fit out
- Hazardous area determination and the design out thereof as much as possible
- HVAC design
- Shutdown system to allow the safe isolation of equipment/systems within
- Signage and marking
- Drainage: Process fluids, storm water & sewage design

Station equipment set out

Station Equipment and pipework design will consider the following:

- Equipment and pipework vibration
- Location of isolations and valves
- Location of meters, and sensors
- Equipment isolation
- Equipment under ground
- Corrosion protection

The majority of stations are not in enclosed spaces. However, in some cases, such as major compressor or pump stations that contain high energy components, equipment is enclosed to ensure safe and successful operation.

3.1.11 Corrosion mitigation design

Corrosion mitigation must be taken into account when designing a pipeline. Without corrosion protection a pipeline may not achieve its design life. Adjacent powerlines have inherent risks to personnel and additional risks to the pipeline as a result of AC (stray current) corrosion.

The need for a degradation assessment is crucial to a pipeline design, in particular, assessing its susceptibility to corrosion. This assessment will determine the susceptibility of the pipeline to:

- Internal corrosion
- External corrosion
- Environmentally assisted cracking (stress corrosion cracking)
- Microbiological corrosion
- AC (stray current) corrosion

Appropriate methods of corrosion control can be determined from the assessment. This may include using specific linings or pipe coatings, cathodic protection, or corrosion inhibitors. For

steel pipelines with non-corrosive contents there are usually three main elements to corrosion mitigation:

1. A high quality coating to prevent corrosion;
2. A cathodic protection system to control corrosion at coating defects; and,
3. A monitoring program to check the performance of the cathodic protection system and to identify coating and metal loss defects.

AS 2885.1 Section 8 stipulates methods for corrosion protection, the tolerable allowances for corrosion, monitoring requirements and methods for mitigating such corrosion.

Corrosion mitigation design should be undertaken by appropriately qualified and experienced personnel. Early design decisions relating to pipeline and component materials will define the extent of corrosion protection required.

Coating design

External pipeline coatings are primarily used as a means of protecting the pipe from the effects of corrosion. The suitability of pipe coatings is determined based upon a number of factors including:

- Coating type;
- Pipeline environment; and,
- Susceptibility to damage during construction and transit.

The design of internal pipeline linings is also an important consideration. Linings should be chosen for the contents of the pipe and the operating pressure and temperature.

Stray DC current mitigation and interference

The cathodic protection system must be designed to protect against stray currents that can result from telluric effects and stray DC currents from DC powered railway systems. The cathodic protection system must also be designed to protect a pipeline from corrosion without causing electrical interference to other buried pipelines and structures, and without adversely affecting the adhesion of the coating to the pipe.

AC interference

Alternating currents from high voltage powerlines and AC powered railway systems can cause interference with the corrosion protection system and the pipeline must be protected from these as well as ensuring that any induced currents are within personnel safety limits.

3.1.12 Pipeline Protection

About 85% of pipeline damage events in Australia are a result of external interference such as unauthorised excavation. Hence, protection against external interference is paramount in pipeline design and operation.

AS 2885.1 Section 5.5 has extensive rules on the minimum requirements for external interference protection. It distinguishes between physical controls and procedural controls. There are mandatory requirements for both types of protection.

Physical controls are tangible features, which physically prevent damage or failure should an incident occur. They include depth of cover, barriers such as concrete slabbing, and (as an important last resort) wall thickness.

Procedural controls are intended to affect the behaviour of people, who may damage the pipeline, so that the likelihood of an incident is reduced. They include a wide range of things such as danger signs, dial-before-you-dig, pipeline awareness programs, and patrolling.

Pipeline protection measures should always be thoroughly reviewed through the Safety Management Study.

3.1.13 Pipeline control - SCADA and local station control

Pipeline systems will generally incorporate a SCADA (Supervisory Control and Data Acquisitions) system into their design. The effective design of the SCADA system for a pipeline will inform the operator of the operating conditions of the pipeline and any changes to those conditions. This allows the operator to effectively respond to such changes.

The SCADA system communicates with local instrumentation and controls at stations and other remote locations along the pipeline. Instrumentation and control requirements will have to be identified, designed and selected to safely and effectively operate the station and provide information to the SCADA system and receive control signals from the SCADA system. It is essential that the SCADA system meets the requirements of Section 7.4 of AS 2885.1.

Where a pipeline does not have a SCADA system, particular attention will need to be paid to ensuring appropriate control to ensure safety and reliability of supply.

Electrical power is required to operate the instruments and control computers. This must be designed to meet the needs of each site including, where necessary, backup power supplies or default operating modes.

3.1.14 Communications design

A communications system is essential for the effective functioning of a SCADA system. The selection and design of the communications system must support the rapid delivery of data and control signals and enable immediate raising of emergency alarms. An important note for design of such system is to "*consider the need for voice communications between operation centres and field personnel"* in addition to SCADA communications, as identified in Section 7.5 of AS 2885.1.

3.1.15 Welding design

Appropriate welding design is essential to the integrity of the pipeline. The design of welds is crucial to designing a safe pipeline. The complementary step is to ensure the design is reflected in the field during construction. This is achieved through welding inspection and non-destructive examination, typically radiography. Inappropriate welding design and execution may result in pipeline failures. AS 2885.2 outlines the requirements for the design of welds along a pipeline alignment. It is essential that job specific welding procedures are developed and that the welds are performed by trained and qualified personnel.

3.1.16 Inspection and Testing Procedure Design

An inspection and testing program/procedure is essential to establish the integrity of a pipeline and determine the adherence of construction to the design. Such a program must be designed to effectively capture, report and rectify unsatisfactory work.

Field pressure testing is conducted to:

1. demonstrate that the pipeline is free of defects capable of causing a subsequent failure;
2. verify the strength of the pipeline (such that it will safely sustain MAOP); and,
3. demonstrate that the pipeline is leak free.

The design of the pressure testing procedure must take into account the Clause 11.4.4 of AS 2885.1 and AS 2885.5.

3.2 THE CONSTRUCTION PROCESS

[To be developed in a future stage of the project]

3.3 PIPELINE OPERATIONS PROCESS

[To be developed in a future stage of the project]

4 PRACTICAL EXPERIENCES IN PIPELINE ENGINEERING AND APPLICATION OF AS 2885

4.1 KEY ISSUES IN INTERPRETATION AND USE OF AS 2885

4.1.1 Introduction

Despite a thorough and rigorous process of development and review by Standards Australia and the ME-38 committees responsible for AS 2885, pipeline engineers will from time to time have difficulties in interpreting and/or applying the Standard. The answer in many cases will be to seek the advice of an experienced engineer. However, there will be times where the reasons for such a difficulty may be that the issue is particularly complex or obscure, and that it is not simply a matter of expertise or experience. In such situations the engineer should seek a formal clarification or interpretation of the Standard from Standards Australia, because compliance with AS 2885 is a license requirement for most hydrocarbon pipelines in Australia, and non-compliance with the Standard may result in undesirable consequences.

Requests for interpretations also help to improve the Standard, by highlighting to the responsible committee areas where additional clarity, information, or rules may be necessary.

This section of the Guide is designed to assist pipeline engineers in understanding and applying the Standard, by providing assistance through the advice from experienced pipeline engineers about application of parts of AS 2885 that have proven difficult for a number of engineers. The focus is on topics that APIA members have identified as needing explanation or clarification.

> NOTE: In this part 4 any description of the content of a clause of AS 2885 is for the purpose only of discussion contained in Part 4, and is not to be relied on by an engineer or other user of the Guide as a substitute for a proper consideration and understanding of the terms of the relevant clause, nor as an alternative to the meaning and effect of that clause.

4.1.2 Issues with AS 2885.1 – Design and Construction

This section deals with aspects of Part 1 of AS 2885 (AS 2885.1) where APIA members have sought assistance.

Section 3 – Materials and Components

Clause 3.4.3 – Materials and Components – Strength de-rating

Issue

This Clause permits flanges complying with nominated standards to be used without de-rating at temperatures not exceeding 120°C, not withstanding the requirement in the nominated standard that the maximum working pressure must be reduced for design temperatures higher than 30°C (e.g. ASME B16.5). Why is this so? and which standard governs.

Specifically, MSS SP-44 flanges are rated to 121°C, but are restricted to sizes 12 inch and above. ASME B16.5 flanges are de-rated from 38°C. As pointed out in AS2 885.1 Section

3.4.3 NOTE 1, ASME B31.3 allows MSS SP-44 to be used for pressure-temperature ratings under ASME B31.3, but it is clear under ASME B31.3 that this only applies when MSS SP-44 flanges are used. It is not so clear under AS 2885.1. Is it intended under AS 2885.1 that the 120°C limit be applied to both MSS SP-44 flanges (12 inch and above) and to smaller diameter flanges to ASME B16.5 or some other standard?

Response

Clause 3.4.3 applies to all flanges and flanged components supplied to nominated standards. The requirement is common with those in a number of overseas standards including CSA Z662. Although not in common use in Australia, the recently developed Standard ISO 15590.2 (Petroleum and natural gas industries — Induction bends, fittings and flanges for pipeline transportation systems — Part 2: Fittings) also adopts a temperature rating of 120°C.

The designer should satisfy himself of the adequacy of the requirements of this Clause by undertaking a design check of a number of flanges dimensioned and rated to ASME B16.5, using AS 1200 or ASME VIII as the compliance code. Our understanding is that the main reasons for permitting the 120°C temperature limit are:

1. The design stress required by AS 1200 / ASME VII is the lesser of the tensile or yield strength divided by a nominated factor. At temperatures higher than 120°C, the yield strength (which reduces with temperature increase) governs the design. At lower temperatures the tensile strength (which does not change significantly with temperature in this range) governs the design.
2. ASME flange pressure ratings reflect their use over general industry, power, chemical and hydrocarbon processing industries. Pipeline systems complying with AS 2885 (and nominated piping standards) are required to be properly designed, have the design subjected to stress analysis, and to be operated within the design limits to documented procedures. These requirements mean that stresses at flange connections are limited to safe values.

To overcome any inconsistencies between AS 2885.1 and AS 1210 (where a pipe flange is required to mate with a flange on a vessel designed to a pressure vessel standard), designers should consider the following:

1. Undertake a design check of the proposed flange at the vessel design temperature and apply for certification on that basis or;
2. Supply flanges that comply with an alternative standard (e.g. ISO 15990-3); or
3. Continue to use flanges rated at a higher pressure for vessels, and provide matching flanges at each connection.

Clause 3.4.4 - Fracture toughness

Issue

Item (a) of this clause requires "demonstrated" Charpy toughness.

Note 1 to this clause states that API 5L PSL2 product meets the requirements of this clause.

API 5L 44th Ed Clause 10.2.3.3 points the reader to Table 22 and states that it is not necessary to impact test combinations of OD and thickness not covered by Table 22. Such combinations include common pipe sizes such as 114.3x8.6, 141.3x6.5, & 168.3x7.1

Potential exists for imported API 5L product to be certified as PSL2, but lack "demonstrated" Charpy toughness. This has a potential impact on the "pre-qualified designs" of Section 5.6

Response

Previous revisions of AS 2885.1 did not mandate minimum toughness properties for any pipe installed in a pipeline. A basic fracture control requirement in AS 2885 is that fracture initiation must be controlled. A Charpy Impact toughness of 27 J at the design minimum temperature is generally considered sufficient to provide initiation control. Other standards (CSA Z662 and AS 4041) have similar requirements, and this requirement is the basis for API 5L specification of 27 J for PSL 2 pipe.

The designer should consider managing this risk by:

1. Properly specifying the line pipe, and;
2. Properly confirming that the obligations of the specification are appreciated by the supplier prior to order placement, and;
3. Properly monitoring the manufacturing quality tests during production, and;
4. Reviewing the material certificates prior to pipe installation to confirm that they comply with the requirements of the Standard and the Specification.

If these matters are attended to during design, order placement negotiations and during manufacturing quality inspections then the risk of receiving pipe that does not comply with the requirements of Clause 3.4.4 will be low.

NOTE: If the designer doubts the quality of the material or its properties, he should undertake independent tests to either validate the manufacturer's data, or in the event that the data is not supplied, to develop it. Pipe that does not comply with the minimum requirements of this clause must not be installed in the pipeline.

Section 4 – Design General

Clause 4.3.5 Secondary Class Location

Issue

There has been a lot of discussion over what should be classified as heavy industry based on the definition, which includes sites that contain material that could cause a fire to escalate. Examples include petrol stations, remote rural sites with diesel storage tanks etc. Could clarification be give on this aspect of the definition?

Response

General

The main purpose of location classification is to draw attention to pipeline segments where there is increased risk. This means both threats from people to the pipeline and from the pipeline to people.

The Standard has a few mandatory requirements associated with certain location classes (mainly the count of protection measures that must be applied). However, more important is identifying locations of increased risk so that the safety management study can pay proper attention to them. For example, areas of high location class are appropriate candidates for the demonstration of fault tolerance required by Clause 2.3.6.

Below are some clarifications of locations classes that appear not to have been adequately explained or have been poorly understood.

Rural Residential location class (R2)

The Standard defines the requirements for R2 quite narrowly in terms of typical block size (1 to 5 ha). This is unchanged from the previous edition of the Standard. However, the number of people seriously threatened by the full bore rupture of a pipeline in a rural residential area is strongly affected by the pipe diameter, perhaps more than for other location classes.

If the 1-5 ha guideline is applied strictly then a DN 100 pipeline will impact at most a couple of households; in this it is much the same as a pipeline in an R1 location class that passes a couple of isolated houses. However, if the pipeline is DN 1000 then the number of households affected in a fully developed R2 area could be several dozen; this would have consequences as bad or worse than a medium sized pipeline in a suburban area. This very wide range of consequences appears to be an unintended effect of the way that R2 location class is defined. (The examples here assume a gas pipeline operating at around 10 MPa.)

It is suggested that when an R2 location class is being considered the number of households potentially affected should be a factor in the deliberations. There is nothing wrong with taking a more relaxed interpretation of the 1-5 ha guideline if the pipeline diameter is small (e.g. perhaps for DN 100 apply R2 only if the typical block size is 1 ha or less). More importantly, for a very large pipeline (e.g. DN 1000) there is nothing wrong with being conservative and applying T1 (suburban) location class if a rupture could potentially affect dozens of households, even if some block sizes are up to 5 ha.

Industrial location class (I)

The Industrial location class makes provision for areas that do not neatly fit the R2 and T1 definitions based on residential population density, although the definitions do include "land used for other purposes but with similar population density".

Although it is not spelled out in the Standard it is expected that the land development in location class I is based on normal public streets providing access to a number of industrial premises. Hence, most of the threats to a pipeline are similar to those in residential areas (installation and maintenance of buried utilities, etc). The consequences of a pipeline failure are also broadly similar to those in a residential area, because the population density is expected to be roughly the same, at least during working hours. For these reasons Industrial location class is to be treated the same as Residential location class.

Heavy Industrial location class (HI)

The Heavy Industrial location class is intended to allow for atypical industrial developments. These may be very large installations such as mines, ore or coal storage facilities, mineral processing plants, smelters, refineries, petrochemical plants, etc. A characteristic of such installations is that public access is usually limited (hence providing some degree of control over third party excavation activities) and also the number of workers present is often relatively small (so that the death and injury consequences of a pipeline failure may not be as severe as in location classes T1 or I).

The HI location class definition also refers to the potential for a pipeline failure to escalate as a result of either fire or release of toxic materials. For escalation to be a consideration it must be significant relative to the pipeline fire itself. For instance, if a DN 300 gas pipeline were to rupture and ignite and some nearby fuel drums caught fire as a result, the contribution of the burning fuel drums to the overall fire would be relatively minor. However, if the same pipeline were to rupture next to a refinery tank farm then there could be a truly serious escalation of the fire.

The HI location class covers a diverse range of situations. The pipeline engineer is required to use judgement and commonsense, firstly to identify where this location class may be required, and secondly to consider the threats and consequences in each HI location to decide whether it should be treated as equivalent to R2, T1 or T2 location class.

Common Infrastructure Corridor (CIC)

The essence of location class CIC is that the pipeline runs ***parallel*** to other linear infrastructure. That other infrastructure may include roads, power lines, other buried services, etc. It is not necessary to assign location class CIC at crossings of other infrastructure.

Secondary location classes in general

Note that assignment of a secondary location class does not require a change in the primary location class. A secondary location class is a supplementary requirement. For example, a pipeline passing a country school in an otherwise R1 location class would be assigned a secondary location class S (sensitive), but the primary location class remains R1. Nevertheless, the pipeline protection within the S location class is required to be equivalent to that which would be applied in a T2 location class.

Clause 4.5.3 - Design Life

Issue 1

There seems to be broad variation in the system design lives being specified, which range between the licence period and something more engineered. It would be useful to have a guidance note on this.

Response 1

AS 2885 applies to all pipelines, some of which may have a short commercial life (for example, an oil pipeline servicing a small field that will be depleted in a relatively short time), and others (for example – a gas transportation pipeline that may have a commercial life in excess of 50 years).

Usually, the design life selected for any project should reflect the period for which the pipeline is expected to remain in service without requiring significant expenditure to maintain its integrity.

The design life (nominated in the pipeline design basis) then sets the criteria to be used in all aspects of design to:

- Set the location classes along the pipeline, having regard for short or long term expectations of land use changes through the period (for example Australian pipelines that are now approaching 30-40 years of age, and that are experiencing significant regulatory and planning pressure, because of encroachment).
- Selection of the pipe coating and joint coating materials to provide an appropriate level of protection for the design life.
- Specification of the required standard of pipeline installation, inspection and testing to demonstrate that the installed pipeline will deliver the required life.
- Identification (and specification) of those items, which because of technological change, or because replacement can be undertaken without interruption of supply, or significant cost impact, require a different design life from the that of the body of the pipeline. (Note: Allowance for periodic replacement of items like the SCADA or communication system because technological change, must be made in the financial model of a new pipeline project to ensure that provision is made for the money needed for the replacement at an appropriate time).

Consequently this important aspect of the pipeline design requires careful consideration by the project developer and its designer. Inappropriate decisions can have significant cost impacts on the commercial operation of the pipeline and can lead to its premature abandonment.

Issue 2

A pipeline is to be abandoned at the end of its design life, unless an approved engineering investigation determines it is safe for continuing operation. AS 2885.3 lists the issues that the design life review must address. Could guidance be given on the process and how a new design life is to be determined from the engineering investigations?

Response 2

AS 2885.3 2010 addresses this question in detail. The following is provided for additional guidance.

The work needed to demonstrate that a pipeline's integrity is sufficient to justify to the Licensee and the Regulator that a life extension should be approved is pipeline specific.

Pipelines developed prior to the 1990's did not specifically nominate a design life – rather the life was set by the term of the Pipeline Licence, usually 20 years, and the effort applied by a Licensee to demonstrate to the Regulator that the pipeline was suitable for re-licensing was usually modest.

Pipelines developed more recently have separated the design life of the asset from the period nominated by the Regulator for the Licence.

Moreover, there is an obligation on the Licensee to maintain the pipeline integrity in compliance with the requirements of AS 2885 continuously throughout its life. So in principle, at the end of the design life, the pipeline integrity should comply with the requirements of the Standard.

During the pipeline life it may be necessary to demonstrate its integrity at a greater level of detail to provide a basis for the Regulator to issue an extension to the pipeline licence.

At the end of the design life, the effort to justify a life extension will vary with the life extension objective. At one end of the scale, the extension may be for a short period to allow it to transport the last of the oil from a reservoir. This may simply require a basic inspection.

At the other end of the scale it may be desired to extend the life for 20-40 years. This will usually require a detailed investigation, and development of a rehabilitation plan. Using the principles in AS 2885.3, it may not be necessary to restore the pipeline to a "perfect" condition at the commencement of the new life period – some rehabilitation may be delayed if the degradation rate can be established, and the time to the rehabilitation predicted with reasonable confidence.

AS 2885.1 Section 9 provides guidance on one method of demonstrating the integrity of the pipeline. For a short life extension, not all the integrity demonstration methods may be necessary, while for a large life extension, it is probable that all the activities identified in Section 9 would be required.

AS 2885.3 2010 addresses the matters it considers necessary for demonstration of a life extension. It's requirements are similar to those of AS 2885.1, but a little less stringent because it is addressing re-lifing, not MAOP increase.

Clause 4.5.4 - Hydrostatic Strength Test Pressure

Issue 1

The equivalent test pressure factor (F_{TPE}) is computed from Equation 4.5.4(2). When the corrosion allowance (G) represents a significant proportion of the nominal wall thickness, this equation requires a very significant increase in the strength test pressure. In some designs this pressure may be difficult to achieve.

Response 1

A fundamental requirement of AS 2885 is that the strength of the pipe is demonstrated by a hydrostatic test at a pressure 1.25 times the design pressure. This is based on research by the Pipeline Research Committee of the American Gas Association, which concluded that this pressure margin is sufficient to eliminate all flaws that have the potential to grow to failure when the pipe is operated continuously at its maximum allowable operating pressure.

Clause 4.5.4 of AS 2885.1 nominates the method by which the maximum allowable operating pressure is determined. It is the lower of the design pressure, or the pressure limit determined from the hydrostatic strength test pressure.

The pipeline wall thickness may be greater than the minimum required for pressure containment. Where this is a vanishing allowance (such as a corrosion allowance) the Standard requires that the strength test pressure is modified so that the wall thickness at the end of the pipeline life has been subjected to the same stress as it would have been if the corrosion allowance did not exist. The purpose of this is to ensure that the same margin of safety provided by the hydrostatic strength test is available to the pipeline at the end of its life.

Equations 4.5.4(1) and 4.5.4(2) are the basis for calculating the hydrostatic test pressure limit, knowing the nominal wall thickness, the manufacturing tolerance and the corrosion allowance.

These requirements are the basis for pipelines that comply with AS 2885 Part 1 (Onshore Pipelines).

It is recognised that the hydrostatic strength test pressure of a high pressure pipeline that contains a corrosion allowance will be increased by the requirements of Equation 4.5.4(2), and where the corrosion allowance represents a significant percentage of the wall thickness, the increase in the hydrostatic strength test pressure will be significant.

Issue 2

The equivalent test pressure factor (F_{TPE}) is computed from Equation 4.5.4(2). When the corrosion allowance (G) represents a significant proportion of the nominal wall thickness, this equation requires a very significant increase in the strength test pressure. For pipelines that have flanged connections, the increased test pressure may result in the maximum pressure of the flange being exceeded.

Where this is applied to a retest of an operating pipeline, the test pressure determined using F_{TPE} may damage the flanges and associated fittings.

Response 2

Clause 4.5.5.2 addresses this question.

> *Where the value of FTPE calculated from Equation 4.5.4(2) would require a strength test pressure that exceeds the pressure test strength of a flanged valve, the strength test for a new pipeline shall be completed in accordance with this Standard before the flange or flanged valve is attached to the pipeline.*

All flanges and flanged valves not included in the strength pressure test shall have been hydrostatically tested to a strength test pressure of not less than 1.5 times the MAOP of the pipeline before installation.

Fittings shall be designed to withstand the pipeline strength test pressure and shall be hydrostatically tested with the pipeline.

Where an existing pipeline is hydrostatically pressure tested to re-establish its MAOP then the minimum and maximum strength test pressure shall be determined within the constraints of the pipeline system, having regard to the remaining corrosion allowance, the flanges or fittings and any other constraint.

The duration of new MAOP shall be nominated at the time of re-test, based on an analysis of the measured rate of degradation of the pipeline at its expected operating conditions.

> *NOTE: Clause 8.3 provides requirements for monitoring the rate of degradation.*

Section 4.6 - Isolation plan – dispersion calculations

Issue

For natural gas, can a table showing dispersion results for class 600 & 900 operation in a similar format to the Appendix Y radiation contours be provided?

Response

Dispersion of fluids released from a pipeline is fluid, site and release rate specific. For this reason it could be misleading to provide generic guidelines in the Standard. Competent and proven dispersion models are readily available to predict the dispersion. Designers should refer to key texts and use reputable dispersion modelling software operated by trained and competent persons to estimate gas dispersion contours.

Reliable reference texts include:

- Fire, Explosions, and Toxic Gas Dispersions: Effects Calculation and Risk Analysis, Marc J Assael and Konstantinos, E. Kakosimos CRC Press, ISBN 9781439826751
- Fundamentals of Stack Gas Dispersion, Milton R. Beychok, www.air-dispersion.com

Examples of proprietary software are:

- DISPER, www.canarina.com
- GASTAR, Cambridge Environmental Research Consultants
- AUSPLUME, Victorian EPA
- CALPUF (US EPA)
- Shell, FRED
- DNV, Phast and Neptune

Clause 4.8.2 - Fracture Control Plan

Issue 1

Prior to AS 2885.1-2007 Amendment 1 the fracture control plan clearly applied only to line pipe. (It was understood that the components of pipeline facilities (fittings, hot bends, valve bodies, scraper trap closures etc) were not required to arrest a running crack and their individual manufacturing standards embodied toughness provisions suitable to control crack initiation risk). While the amendment also requires the fracture control plan applies only to line pipe, pipeline assemblies are also required in Section 5.9 to be designed to AS 2885.1. Presumably, some form of fracture control is required for pipeline assemblies, particularly if they see low temperatures from pressurisation or depressurisation.

1. How is it intended that fracture control of pipeline assemblies be addressed? Brittle fracture assessment method? Fracture initiation control with CVN?
2. How are no-rupture requirements to apply to above ground assemblies in high consequence areas?

Response 1

The change made in Amendment 1 to Clause (4.8.2(a)) is: *The fracture control plan shall apply only to the pipeline as defined in Figure 4.1. It shall not apply to accessories.*

We understand the amendment to be properly interpreted as:

1. The fracture control plan shall apply to the line pipe portion of the pipeline as defined in Figure 4.1.
2. It shall not apply to accessories. (e.g. scraper launchers)
3. Fracture control of the interconnecting pipe associated with the scraper or MLV assembly designed as part of the pipeline assembly should be considered separately.
4. Fracture initiation shall be controlled in all accessories and associated piping. This may be demonstrated by compliance with Station pipe design (Section 6) for pipe at the design minimum temperature (AS 4041 or ASME B31.3 - low temperature service) and with Clause 3.4.4.
5. Because the length of this pipe is short and the pipe usually contains valves and fittings that act as crack arresters, there is no change in consequence, where fast tearing fracture in this pipe is arrested within the initiating pipe, or in a connecting pipe. Consequently consideration of fast tearing fracture is not required.

   NOTE: Line pipe supplied with a design factor of 0.67 and complying with the pipeline fracture control plan will usually satisfy Point 4 and the no rupture requirement.

Issue 2

We understand that for diameters above DN300 the Battelle Two Curve Model is less accurate than for smaller diameter pipes. Please explain the limitations of fracture control of large diameter high strength pipe and appropriate fudge factors.

Response 2

Fracture control is a complex topic. Extensive research undertaken over the last 40 years has not been able to reduce the topic to a simple set of equations that can be simply applied. The fracture control section of AS 2885.1 2007 Amendment 1, and the accompanying appendix (Appendix L) are considerably more detailed than in the 1997 revision. Moreover, as pipeline design conditions (pressures, gas compositions, pipe material grades and pipe diameters) change more limitations of the design methods become evident.

In particular, the Battelle Two Curve method which uses the Charpy Impact test as an indicator of whether the pipe has sufficient toughness to arrest a fast tearing fracture becomes non-conservative at Charpy toughness values of about 95 J. In part, this is because a significant proportion of the fracture energy absorbed in a Charpy Impact test on high toughness materials is absorbed in initiating the crack. This masks the energy absorbed in propagating the crack through the specimen. While other test methods have been developed, they are complex and time consuming, and not suitable for use in quality control testing required for pipe manufacture.

Consequently "fudge" factors have been developed that attempt to correlate Charpy Impact test toughness with the toughness needed to arrest fracture in full scale burst tests.

Because of the cost to undertake full scale burst tests, and because many full scale tests are undertaken for project specific purposes (and not publicly available) there are few people who have access to a sufficient body of full scale burst test data to make a judgement of the magnitude of the "fudge" factor needed for a particular design, the Standard requires a fracture control plan to be independently validated when the Battelle Two Curve method predicts an arrest toughness of 100 J or greater. Referring to Figure 4.8.2, recent validation of fracture control plans for lean gases in large diameter pipelines have recommended the use of a fudge factor to increase the margin between the predicted arrest toughness and the toughness considered necessary to achieve fracture arrest.

Moreover, recent research undertaken by APIA's Research and Standards Committee in conjunction TransCanada Pipelines and Alliance Pipelines has found that while the GASDECOM decompression velocity prediction software does not accurately account for the effect of the pipe surface roughness, these effects have been shown to be more important where relative roughness (ratio of roughness to pipe diameter) is high. That is, in small diameter pipe than large diameter pipe. This finding will need to be incorporated in software models, and existing fracture control plans may have to be reassessed.

In summary, fracture control is complex. Pipeline engineers are encouraged to develop their understanding of the phenomena by reading some of the referenced texts and a selection of the many research papers published to date, and which will be published in the future.

Clause 4.8.4.1 - Fracture toughness

Issue

Clause 4.8.4.1 mandates the use of the Battelle Two Curve model for the calculation of the Charpy energy fracture arrest toughness for Rich Gas. We understand that this software is being upgraded and not available at present. Is this correct and when is it likely to be available?

Response

This is correct. PRCI has completed additional research into fracture arrest, and has engaged a contractor to revise the two components of the Battelle Two Curve Method, the gas decompression velocity prediction software GASDECOM, and the Battelle Two Curve fracture velocity calculation and curve tangency calculation (DUCTOUGH). These components are integrated into a single application. The application resolves the instability issues that were associated with the original GASDECOM software (The calculation engine of GASDECOM is unchanged in the revised software, and it, and DUCTOUGH produce the same results as the new application, for the same inputs).

The new application (PIPEDEFRAC) has been under PRCI member evaluation.

PRCI has advised that the application will be published and available from its agent, Technical Toolboxes (via www.technicaltoolboxes.com), once PRCI has approved its publication for general use, expected to be about the end of 2010.

Clause 4.8.4.2 - Fracture Control – Seam Weld Toughness

Issue

Clause 4.8.4.2 (a) requires that the test temperature be determined by Clause 4.8.4.1(c).

Clause 4.8.4.1(c) relates to tearing fracture. The test temperature uses the minimum steady state operating temperature of the pipeline rounded down to the nearest 5°C, or where there is an in-line device, the minimum steady state operating temperature downstream of the device, rounded down to the nearest 5°C.

Can you assist us with application of NOTE 2 of Clause 4.8.4.1 (c)(ii). This starts talking about transient events such as repressurisation of a pipeline section and initiation and propagation of brittle fracture rather than ductile tearing fracture. It says that control during activities of this type should be achieved by maintaining pressure such that the hoop stress does not exceed the threshold stress (presumably referring here to 85 MPa) any time that the temperature is lower than the fracture initiation transition temperature (FITT), and refers to Clause 4.8.3.

Clause 4.8.3 determines the test temperature for brittle fracture control as the lowest temperature at which the pipe stress exceeds the threshold stress for brittle fracture, including operating and transient conditions. This test temperature is the temperature at which the brittle fracture DWTT is conducted.

So an interpretation can be made that the weld seam Charpy test must be conducted at the same temperature as the DWTT. Will the seam of ERW line pipe tested at such a low temperature pass the test?

Informative Appendix L Clause L3.3.2 contains the sentence, "Propagating brittle fractures in longitudinal welds (ERW or SAW) have not been recorded in operating pipelines to date". However, an informative appendix doesn't over-rule a mandatory clause that appears to be directing us to perform the weld seam Charpy at the same temperature as the DWTT.

How then is ERW line pipe used on projects in which the DWTT is conducted as low as –25°C, or even lower?

Response

The following points summarise the requirements/guidance of the Standard:

1. The Drop Weight Tear Test is used to demonstrate that a propagating brittle fracture initiated at the notch will be arrested by a change from brittle fracture to ductile fracture and a resulting reduction in fracture velocity.
2. The Charpy V Notch Test is used to demonstrate that the material has sufficient toughness to control fracture initiation (growth to failure) of a flaw under static loading. In most circumstances the initiation mode in the test (and in the structure represented) will be by stable tearing. Subsequent propagation may be either brittle or ductile. The fact that initiation occurs by stable tearing at temperatures well below the FPTT explains why the Maxey plastic collapse solution works well down to the FITT, which is around 30°C below the FPTT (fracture propagation transition temperature).
3. Separately and coincidentally the Charpy test is also used to demonstrate that a fast tearing fracture can be arrested by the inherent toughness of the pipe body. In this test the level of toughness required will be different, and the fracture mode should be ductile.
4. The Charpy test cannot be used to control brittle fracture propagation other than by correlation with DWTT testing.
5. Charpy tests conducted on the weld seam are for the purpose of guarding against initiation, not propagation. As noted in appendix L, AS 2885.2 requires weld seams to be offset, and thus if a propagating fracture does occur in the weld seam due to an unexpectedly large defect due e.g. to mechanical interference, then, provided the fracture propagation controls have been correctly applied, that propagating fracture will be arrested when it runs into the pipe body in the adjacent pipe.

In regard to the test temperatures:

1. Temperature for fracture control – **normal conditions**
2. Appendix L4 provides guidance on the intent of the Standard with respect to temperature.

   Our understanding of the intent of the Standard is that the design minimum temperature(s) for fracture control are those that occur under **normal** pipeline operation or under temperature excursions that may occur as part of **normal** operation. The controlling temperature may be:

   - The minimum soil temperature

- The minimum soil temperature reduced by some Joule-Thompson cooling under maximum flow rate conditions
- The minimum soil temperature reduced by the Joule Thompson cooling as a result of a deliberate operating condition – such as a imposing a pressure reduction of 15-20% by flowing gas through the bypass pipe at a MLV to lower the operating pressure to a safe value while damage to the pipeline is being assessed and repaired.

NOTE: For fast tearing fracture arrest, the decompression velocity should be based on the pressure at which the low temperature occurs, not MAOP, since MAOP and the low temperature caused by pressure reduction cannot coexist.

- Another similar operating condition that may be particular to the pipeline.

It is difficult to understand how the design minimum temperature for a pipeline in Australia is sufficiently low to require DWTT at -25°C.

Under normal conditions the pipeline must resist damage by dynamic loading (DWTT) and by static loading (initiation). It must also be capable of arresting a fast tearing fracture initiated at the maximum operating pressure and minimum operating temperature.

1. Temperature for fracture control – **abnormal conditions**

Abnormal conditions that occur as a result of an intended operation such as blowdown and repressurisation are **abnormal** conditions that can be managed.

Under **abnormal** conditions brittle fracture propagation control is not required because the Standard does not consider that a dynamic (impact) load will occur concurrently with a properly planned and controlled event such as depressurisation or repressurisation.

However it is possible for an existing flaw to grow under static loading and at reduced temperatures that exist under these conditions, and it is important that initiation control by sufficient CVN toughness at the minimum temperature condition is provided. (Refer to Clause L4).

NOTE: If the designer or the SMS identifies a condition for which this guidance is not valid, then an appropriate design decision should be made.

2. Seam Welds

The intent of the Standard with respect to seam welds is described in Appendix L3.3.2. Here again the Standard requires control of initiation on the basis that the long seam welds are offset, and in the unlikely event of weld failure, the next pipe will arrest the fracture.

It appears that the potential problem has arisen from an unnecessarily conservative value of the design minimum temperature together with a misunderstanding of the fracture control requirements of the Standard.

If there is difficulty in specifying a temperature for another test condition, it is suggested that the design pressure and temperature conditions should be reassessed to determine whether they are unnecessarily conservative.

Section 5 – Pipeline Design

General Matters

Issue

Is it possible to avoid much of the detailed requirements in the Standard for the straightforward design jobs?

Response

It is desirable to minimise the amount of time and effort required to design a pipeline. However, it is not possible to avoid the requirement of well-founded knowledge and understanding of the Standard to ensure a safe, reliable, environmentally benign pipeline, particularly to achieve the lowest long run cost. Design of pipelines is a multifaceted and complex task that should be approached with realistic expectations about the amount of thought and effort that is required. However, for those situations where there is little benefit or cost saving to be gained from detailed investigation of all design parameters for a pipeline a pre-qualified design may be applied and subject to the conditions set out in Section 5.6 of the Standard will be deemed to comply.

Section 5.4 - Wall Thickness

Issue

Wall thickness determination is an important aspect of design and an area worthy of attention, particularly in relation to wall thickness determination for matters other than pressure containment.

Response

The determination of wall thickness is a design question. The Standard is clear in requiring that after taking into account the manufacturing tolerance and any allowances (e.g. a corrosion allowance) the wall thickness should be the greatest wall thickness that would result from the range of matters set out in (a) to (j) of Clause 5.4.2. These include pressure containment, penetration resistance, critical defect length, satisfying stress and strain criteria, controlling fast running fractures etc.

Issues Paper No. 4.19 (See Appendix 2.1) provides insight into the approach in Section 5.4.

Particular attention is drawn to design issues related to wall thickness for high strength thin wall pipe. This is discussed in section 4.2.1.

Clause 5.5.2 - Cover

Issue

Clause 5.5.2 requires that *"The depth of cover over a pipeline shall be taken as the vertical distance from the top of the pipeline or casing to the lower side of the finished trench"*. How this should be applied with respect to the point of measurement?

Response

The Standard reflects a requirement that the cover must not be less than stated when measured from the lower side of the finished trench. The requirement covers situations where the trench is installed in flat and in sloping ground.

In a construction environment it may be necessary to modify the natural ground surface to remove and store topsoil, to remove and store side cut or high point cut material before constructing the pipeline.

Consequently it is usually impossible for construction personnel to guess the elevation of the natural ground level, and measure the trench depth from this point – and if they do so, they will probably get the measurement wrong – resulting in costly rework. The definition in the Standard is expressed in terms of the trench because this is the method used by most construction contractors and defined in most construction specifications – because it should eliminate the risk of shallow burial.

The definition may lead to unnecessary excavation – this is acknowledged, however it is usually significantly less costly to slightly over excavate than to repair an installation where the depth of cover does not comply with the specification.

The philosophy of AS 2885.1 is that if additional work can be justified to refine the design or construction, then the work, and the resulting knowledge can be used to advantage. If the construction contractor is prepared to conduct a proper survey of the natural ground level prior to clear and grade, then properly control trenching to the depth calculated from the natural ground surface after clear and grade, and is then prepared to conduct a post restoration survey to confirm that the compacted or consolidated surface is at the same or higher elevation than the original ground elevation, then the construction contractor is in total compliance with AS 2885.1 Clause 5.2.2.

Note: AS 2885 does not permit cover to be achieved by "mounding" over the pipe to achieve depth of cover.

Clause 5.7.3 - Stress & Strain - Soil type for external loading

Issue

Is it possible to minimise the requirement for geotechnical advice on determining the soil type in normal terrain at road and rail crossings for Australian conditions?

Response

Pipe stresses at road and rail crossings are calculated using the procedure in API 1102. This procedure requires some soil property data because of the influence of soil restraint on support of the pipe. Soils that are strong and stiff provide robust support against lateral deflection of pipe walls (ovalling) under vertical load. Because the pipe deflects little the ring bending stresses are minimised. The extreme example of this would be concrete encasement. On the other hand very soft soils offer little resistance to ovalling and result in the highest ring bending stresses. API 1102 contains suggested property values for a range of typical soils.

AS 2885.1-2007 specifies a maximum combined stress at road and rail crossings of 72% SMYS (Clause 5.7.3 c I A). In practice this means that the crossing pipe must be "heavy

wall" – pressure design factor less than 0.72 so that there is some "headroom" between the hoop stress and 72% SMYS to allow for the stresses due to external loads.

For typical Australian pipelines "heavy wall" pipe often has a pressure design factor of 0.6 or less so this "headroom" is substantial. It allows the stresses due to external loads (vehicles) to be quite high (up to 12% SMYS if pressure design factor is 0.6). In this situation the total stress is almost always acceptable even if the calculations assume the weakest soil (highest ring bending stresses).

For this reason it is rarely necessary to acquire real soil property data for road and rail crossings. Commissioning site investigation work would be necessary only if unacceptable stresses were produced by initial calculations assuming weak soil. In any case, it would then be worth comparing the cost of geotechnical investigations against the cost of further increased wall thickness for the affected crossings.

Clause 5.8.6 - Submerged crossings

Issue

The Standard requires that buoyancy calculations be undertaken for submerged crossings? How should these be undertaken?

Response

The Standard specifies minimum safety requirements and is not intended to be a textbook, so it is not appropriate for it to contain details of buoyancy calculation methods. Following is an outline of the overall approach. To implement this approach the engineer requires competency in hydrostatics and basic soil mechanics.

The basic principle of buoyancy calculation is Archimedes' principle – the buoyancy force is given by the weight of the water displaced by the object. So a pipe buoyancy calculation needs to do the following (for unit length of pipe):

- Calculate volume of the pipe based on overall outside diameter including any coatings such as corrosion protection and weight coating where applied
- Calculate weight of water displaced (using water density of 1000 kg/m^3 is sufficiently accurate)
- Calculate weight of pipe steel and all coatings
- Calculate effective specific gravity (SG) of the immersed pipe by taking the ratio of pipe weight (including coatings) to weight of water displaced

If SG < 1 the pipe will float. To provide a margin of safety the normal design practice is to require SG ≥ 1.3, provided that the pipe is not exposed to flowing water in which case special consideration will be necessary.

In rare circumstances there is a possibility that the soil itself will be fluidised at some time in the life of the pipe (e.g. seismic liquefaction, mobilisation of streambed sediments during flood flows, extremely weak soils such as peat). In such cases the density of the fluidised soil should be used instead of the density of water in calculating the weight of fluid displaced. The target SG will depend on the circumstances; it may be necessary to resist hydrodynamic

forces, and sometimes a strongly negative buoyancy may cause the pipe to sink below its installation depth which can be just as undesirable as floating.

The approach described here is suitable for plain pipe and for pipe with continuous weight coating. If discrete weights are applied then the calculation will need to be adapted appropriately.

A frequent concern is whether the weight of backfill is sufficient to provide restraint against the pipe buoyancy force. Often there is no simple answer as soil restraint depends on the soil properties.

For one case the situation is relatively simple: if the trench backfill is a well-drained cohesionless soil the submerged weight of the soil particles will act directly on the top of the pipe to hold it down; the extreme example would be to backfill the trench with coarse gravel. The submerged weight of the soil directly above the pipe can be calculated from broadly the same hydrostatic principles used to calculate the buoyancy of the pipe. It is necessary to estimate the void ratio of the soil.

For more complex soils (particularly those that are very clayey with low shear strength) it may be necessary to obtain geotechnical advice.

Clause 5.9.1 - Pipeline Assembly Fabrication

Issue

What is the purpose of the following paragraphs of clause 5.9.1?

> *Pipeline assemblies shall be designed, fabricated, inspected and tested in accordance with Section 5, unless otherwise approved.*
>
> *Welding procedures complying with AS 2885.2 may be used for shop or field fabrication for pipeline assemblies designed in accordance with this Standard. Where these assemblies are shop fabricated then suitably qualified procedures complying with another approved standard may be used.*
>
> *It is not intended to prevent an assembly being designed and fabricated in accordance with another approved standard (such as a pressure vessel standard). When another standard is used, it shall be used in its entirety.*

Response

Our understanding of the purpose of this Clause is:

1. To encourage the use of pipeline quality materials and fittings to be used in the design and construction of pipeline assemblies including MLV assemblies and Scraper assemblies, as opposed to typical piping materials of lower material grade (See Clause 5.9.1 Paragraph 2).
2. To require pipeline assemblies to be designed, constructed and tested in accordance with AS 2885.1.
3. To permit pipeline assemblies, when fabricated in the field by welders and using procedures qualified to AS 2885.2, to be fabricated in accordance with those procedures.

4. To permit pipeline assemblies, when fabricated in a shop, to be fabricated by welders and using procedures qualified in accordance with another approved standard (usually ASME B31.3 or AS 4041). This recognises that there may be significant effort and cost to qualify the number of procedures required by AS 2885.2, and to train welders in the required methods and the procedures. Furthermore it recognises that the requirements of AS 2885.2 are imposed so that high quality welds are produced reliably in high productivity field construction. This constraint is not present in shop welding and procedures developed and qualified for pressure pipe welding – and for the materials used - are appropriate for that fabrication environment.
5. To recognize that there are situations (usually size, unique design needs, or fabrication location) where this equipment may be more cost effectively be designed to another standard (usually a pressure vessel standard), and in these situations, to permit the alternative standard.

Attention is drawn to AS 2885.2, which states in the Scope section:

> *This Standard is applicable to the welding of joints in or on pipelines, and the field welding of pipeline assemblies. This Standard may be applied to the factory fabrication of pipeline assemblies manufactured from pipes and fittings. See Figure 1.1 for examples.*
>
> *NOTE: The welding of fittings may present special difficulties when using typical pipeline welding procedures (see Appendix E).*

This requirement is aligned with AS 2885.1 Clause 5.9.1 requirements.

Section 6 - Station Design

General matters

Issue 1

AS 2885.1 has undergone a series of significant changes with respect to station piping design, including above ground and below ground piping. What are the differences in design requirements for above ground and below ground piping?

Response 1

This issue is the reason that AS 2885.1 1997 deleted the requirements in earlier revisions for station piping, and required that the pipework for stations comply with the requirements of an appropriate pressure piping standard. It nominates that the design shall comply with AS 4041 – Pressure Piping or ASME B31.3 – ASME Code for Pressure Piping, regardless of whether it is above ground or below ground.

All other pipework such as pipe assemblies, including scraper assemblies, mainline valve assemblies, isolating valve assemblies and branch connection assemblies are required to comply with the relevant section of AS 2885.1 (ie not AS 4041 or ASME B31.3), apart from welding of such assemblies for which Section 5.9.1 permits use of other standards, where necessary (as discussed previously in this Guide).

Issue 2

How does AS 2885.1 interface with the other piping, pressure equipment and fittings codes, including what details AS 2885.1 covers, and what details are required from related standards?

Response 2

Wherever AS 2885.1 relies on another standard it specifically refers to that standard. In addition each referenced standard is listed in Appendix A. Clause 3.2.2 lists the relevant standards referenced in respect of materials and components. In respect of pressure piping AS 4041 or ASME B31.1 applies. In respect of pressure vessels AS 1210 applies. For fittings and materials various ASME B31 and B16 standards apply along with relevant ASTM materials standards.

Clause 6.2.4.8 - Station Shutdown Systems

Issue

Clause 6.2.4.8 of AS 2885.1 does not restrict itself to compressor stations, but many of the requirements have not traditionally been applied to simple gate stations. How should this clause be interpreted when the station is a simple static facility such as a MLV Station? and are the requirements of this clause applicable to an existing pipeline station?

Response

Several parts of the Standard must be considered:

1. Clause 1.3 – Retrospectivity: Existing pipelines that complied with an earlier revision of the Standard are not required to comply with the requirements of a new revision

except in relation to Operating and Maintenance Procedures, nominated exemptions, and new design that modifies an existing installation.

2. Irrespective of any interpretation of Clause 6.2.4.8, Clause 1.3 would allow a Licensee to continue to safely operate an existing facility without modification if it still complied with the revision of the Standard to which it was designed, and it was operated and maintained to the current revision of AS 2885.3
3. Section 2 – Safety: If the pipeline is operated and maintained to AS 2885.3, there is an obligation to undertake a Safety Management Study (SMS) at 5 year intervals, and for the installation to satisfy the requirements of a properly constituted HAZOP, and other safety studies that may be identified in the SMS as contributing to demonstrating that the facility complies with current safety standards.
4. Clause 4.3 – Location Classification, and consideration of the implications of the shutdown system for the surroundings, particularly if they include high consequence areas,.
5. Section 4.6 - Isolation Plan compliance is required
6. Clause 4.7 – Special Provisions for High Consequence Areas: If Section 4.3 identifies the installation as being within a T1, T2, S, I or if failure of the installation would result in escalation of the consequence, HI, compliance with this Section is required.
7. Clause 7.2 – Control and Management of the Pipeline System: While the retrospectivity provisions of AS 2885 would not require an existing pipeline complying with an earlier revision of the Standard to be modified to comply with this Section in AS 2885.1 2007, any departure from these requirements would need to be justified in the SMS.
8. Clause 7.4 – SCADA: The requirements of this section should be considered.

Each of the above Clauses and Sections assist in reaching a decision on the application of Clause 6.2.4.8 to a specific installation.

Clause 6.2.4.8 is a sub-clause of Clause 6.2.4 Safety. Therefore the obligations for provision of a shutdown system must be considered under the general obligations of safety. These include any obligations identified by a HAZOP.

The essence of Clause 6.2.4.8 is to prevent escalation of a potentially unsafe situation.

The last paragraph in the Clause requires that where the shutdown system is required to operate automatically, the consequence of immediate cessation of supply on downstream processes shall be considered.

To satisfy the Clause 6.2.4.8, a sound analysis of the safety of the Station, and of personnel who may be required to work within the station, and of the obligations in relation to maintenance of supply are considered for each site in the network. Where this analysis considers that the safety obligations are satisfied with manual isolation and depressurisation "systems", then these are all that are required.

Where this analysis considers that the safety obligations require either a manual "system", or an automated "system", or a remotely controlled and automated "system", it must be provided and maintained in an operable state.

The application of Clause 6.2.4.8 may be required retrospectively to an existing installation where encroachment or changed operating conditions results in the consequence of a failure being significantly different from those for which the Station was originally designed. In this regard, compliance is required with Clause 4.7.4, Change of Location Class.

> NOTE: A typical misunderstanding about terminology used in AS 2885 relates to the use of the term "Station". "Stations" are defined (Clause 6.1) as "facilities that allow for control, measurement, storage or pressure maintenance ...". The question refers to an "MLV Station". On the basis of the definition of a station it can seen that "MLV Station" is a misinterpretation - MLVs (and scraper "stations" and branch connections) are all defined in Clause 5.9 as "pipeline assemblies", not stations.

Clause 6.4.3 - Proprietary Equipment

Issue

Failure of oversized regulators and poor specification of regulators and PCVs in particular for on/off service (i.e. Peaking power stations) is becoming a common issue. How should sizing and specification of regulators and PCVs be approached?

Response

This matter is outside of the scope of the Standard and is in fact a design problem. The Standard clearly sets out what is required for compliance. The design engineer's role is to develop specifications that both meet the performance criteria for the function the equipment is required to perform and the requirements of the Standard. It is up to the design engineer to identify which equipment best meets the specification.

Where a manufacturer proposes equipment for which compliance with the specification is unclear, the design engineer must seek adequate clarification to determine whether the proposed equipment meets the specification.

In the particular case of regulators and PCV's for on/off service, the specification should provide sufficient background information on the service requirements and context (to assist the manufacturer) and determine what features of the regulator or PCV are necessary to meet the requirements of on/off service e.g. rate of response, operation at the range of expected flow rates, etc.

Section 7 – Instrumentation and Control Design

Clause 7.2.1 – Pipeline Pressure Control

Issue

How are the transient pressure obligations under this clause (and sub clauses) applied?

Response

1. A pipeline is permitted to operate continuously at its MAOP (Clause 7.2.1.1).
2. If the pipeline is intended to be operated continuously at MAOP then it must be provided with a control system that will limit the maximum excursion above the MAOP set point to +1% of the MAOP (Clause 7.2.1.1). This is usually relatively easy to achieve for a gas pipeline, but it may be more difficult in a liquid pipeline.
3. At least two independent methods of pressure control are required in all cases (Clause 7.2.2).
4. Any other pressure excursion above MAOP is a hydraulic "transient" (Clause 7.2.1.3). Guidance is provided as to the duration of transient pressure waves in typical gas and liquid pipeline systems.
5. In steady state conditions, and when the pipeline is operated at MAOP, the maximum pressure at any point in the pipeline, including low points along the length of the pipeline is MAOP, plus 1% of MAOP permitted for control system perturbations.
6. The maximum pressure at any point in a pipeline as a consequence of a transient event shall not exceed 110% of MAOP (Clause 7.2.1.1). Typical conditions that cause hydraulic transients include valve operation, pump start and stop. Analysis using appropriate software is usually required to demonstrate compliance with this requirement.
7. The performance and reliability of the pressure control system must be evaluated and shown to be suitable for its intended service. (Clause 7.2.1.4).

Pipeline shut-in conditions must be considered in designing the pressure control system. For most pipeline systems the hydraulic gradient along the pipeline means that the "settle-out" pressure following pipeline shut down is less than MAOP, even if the pipeline is at MAOP at the injection point. In liquid pipelines, and to a lesser extent in gas pipelines, the static head between high and low points, and between high points and the isolation point can result in the combination of the residual operating pressure and the static pressure exceeding MAOP.

The design must ensure that this does not occur in operation or shutdown.

The designer should identify the credible operating conditions and analyse the pressure distribution along the pipeline during operation and shutdown. If required, controls and pressure relief devices must be installed to limit the pressure at any part of the pipeline to MAOP. The operating and shutdown scenarios are likely to differ for liquid and gas pipelines.

NOTE: For an operating gas pipeline the compressible nature of the fluid means that there usually is a time delay between terminal valve closure, and the pipeline being packed to its maximum pressure. During this period, operating controls should be capable of limiting the gas injection so that by the time that the pipeline is shut-in (inlet and outlet valves closed) the settle out pressure will be sufficiently low to accommodate the static head generated by an elevation change).

Clause 7.2.1.2 - MAOP under steady state conditions

Issue

Designing a pipeline to operate at a set point equal to MAOP (as permitted) appears difficult given the requirement that the control system controls the maximum pressure within a tolerance of 1%, and the requirement to have two independent means of pressure control. How can the design requirement be achieved?

Response

At least one major gas transmission pipeline with multiple compressor stations operated in series along the pipeline operates at the conditions nominated in the Standard. An investigation undertaken by the operator determined that the tolerance nominated in the Standard is both appropriate and achievable.

It is important to differentiate between the behaviour of a gas and a liquid pipeline, and to appreciate the hydraulic response to changes in operating conditions.

Because a gas is compressible, the pressure change in response to a change in operating conditions is usually relatively slow. A well designed and tuned pressure control system should be able to manage the operation of a compressor within the nominated tolerance. This usually counts as one method of pressure control. A separate high pressure switch that trips the compressor at a set point higher than MAOP, and not greater than 110% of MAOP will provide a second method of pressure control that will respond to transient events.

An analysis on the rate of pressure change should be undertaken to select the shutdown pressure setpoint to identify any specific performance characteristics of the pipeline system that require specific pressure control. This may determine that more than two levels of pressure control may be necessary in some instances.

Where the fluid being transported is an essentially incompressible liquid, it may not be practicable to operate the pipeline at MAOP and still satisfy the transient overpressure control requirements of the Standard. Transient hydraulic behaviour of a liquid pipeline system is significantly more complex than for a gas system, the response times are significantly shorter and the magnitude of pressure changes are significantly greater. For this reason it is mandatory to undertake a transient hydraulic analysis of a liquid pipeline for compliance with AS 2885.1.

Clause - 7.2.1.3 Transient Conditions

Issue

The application of the allowance of 110% transient excursions with the time limit of "seconds" for liquids and "seconds or minutes" for gases appears difficult. How should this requirement be understood to enable the pipeline and its control system be designed to confirming that transient excursions that fit within this criterion?

Response

An event in a gas or liquid pipeline that raises the pressure in the pipeline to more than 110% of MAOP for any duration is not permitted under any circumstance. The guidance on the event duration does not change the maximum overpressure limit permitted by the Standard.

The Standard considers that small perturbations around a setpoint in response to control actions are not "transient" events (the ±1% tolerance).

Other events that cause rapid changes in pressure are transient events. Such events are always of short duration and not cyclic. The references to durations of "seconds" and "minutes" clearly differentiate between longer periods such as hours. What this does is make it clear that for such situations as where there are daily load cycles for which there are temporary pressure excursions of a few hours cannot be considered as a "transient" for the purposes of this clause and pipeline operation above the MAOP is prohibited.

It was considered that guidance on the duration of the event would prevent this misunderstanding.

Events that initiate hydraulic transients usually include:

- Rapid valve closure (including slam shut valves in pressure regulators)
- Rapid cessation in flow (for example, a trip of a downstream gas turbine power station)
- Rapid change in a pressure or flow control setpoint or pump / compressor speed
- Pump start and stop
- Pressure relief or bursting disk operation (usually affects only liquids pipelines).

There may be many other events, depending on the design of a particular pipeline.

The design engineer should identify each event that could potentially initiate a hydraulic transient and determine in each case whether the magnitude of the hydraulic response is likely to exceed the transient limit, and if so must undertake a competent transient analysis of the event. This must be informed by a sound understanding of the particular transient and the principles of identifying pipeline transient behavior that distinguish them from longer term variations in pressure.

For a sound understanding of transient behaviour the pipeline engineer should refer to an appropriate reference. Some suggestions are:

- Hydraulic Transients, Wylie and Streeter 1965
- Fluid Transients in Systems, Wylie and Streeter, Prentice Hall, 1993

- Fluid Transients in Pipeline Systems, second edition, A.R.D Thorley, Professional Engineering Publishing, UK, and ASME Press, ISBN 07918092108

Clause 7.3.2 - Gas Venting

Issue

AS 2885.3 Clause 7.3.2 Venting of Gas refers to the recommendations of UK IGE/SR/23 for venting of natural gas from pipelines and associated facilities.

AS 2885.1 does not reference any standards in the design of station vents. AS 2885.1 refers to API RP 521 (Guide for Pressure Relieving and Depressuring Systems), however only for determining the radiation levels from an ignited rupture or leak from a pipeline. There are no specific references to a standard for designing station vents in Clause 6.2.4.7, only general guidance for safe vent design.

1. Is there any standard that should be considered as being superior or specifically relevant to the design of vents at pipeline facilities, including compressor station vents?
2. Are there are reasons to recommend for or against the use of UK IGE/SR/23 as an appropriate standard for the design of station vents?

Response

The questions raised are questions of process. The following responses are provided as guidance on factors that should be considered in developing designs for discharging gas from a pipeline or pipeline facility.

1. It should not be necessary to develop specific rules or obligations relating to the design of pipeline vent and station vents, principally because:
   - Venting, whether of a pipeline or a station is a planned event that is undertaken rarely (for a pipeline), and occasionally for a station (or sections thereof). Emergency Shutdown (ESD) accompanied by a station vent is an unplanned event and may require special consideration.
   - In the case of a Station, the volume released is usually small. Stations designed with vent restrictions may require 20 minutes for the station to be depressurised.
   - Natural gas is buoyant in air.
   - There is an overriding obligation for a pipeline to be designed to control each threat from the pipeline to the people, and from people to the pipeline. The design must be undertaken by a competent person (see the definition in the Standard).
   - The flame front velocity of natural gas is approximately 0.4 m/s. Natural gas discharging from a pipeline vent has a velocity 2 to 3 orders of magnitude higher than this, and ignition is not credible, except in the final stages of depressurisation when additional precautions may be required. (See last note to Question 2)

- For pipelines, world wide experience is that simple vertical vent systems satisfy practically all safe design obligations. These release gas directly to the atmosphere through a simple vertical vent stack. Where there are specific site parameters that could affect the safety of this design, then the best approach is to move to another location, because when venting must be done, it must be done quickly.
- For Stations, most are located in remote locations with no buildings, pits or other traps that could accumulate gas and create a hazardous location. Where a station has specific site parameters that increase the risk of a simple discharge to atmosphere, specific designs may be required to control those threats. (NOTE: The most frequent threat that requires specific control at a station is that of odour emitted with venting odorised gas).
- For compressor stations, station and unit piping vents are usually carried to a cold vent on a remote part of the site where gas can be released with minimal risk of the gas being entrained in the compressor engine air intake. In addition to the design location, compressor station vents may be required to incorporate devices to control the depressurisation rate for compliance with an equipment specification.

  NOTE: Station piping is usually constructed from thick-walled pipe, and, because of the relatively short lengths of pipe within a station, the volume contained within a section being vented is usually relatively small. The thermal mass of the pipe is usually sufficient to prevent unsafe combinations of pressure and temperature during depressurisation because of the small volume released.

2. There is nothing in AS 2885.1 to prevent a designer from adopting IGE/SR/23 (or referencing it as a guidance document) if the Licensee considers that it is an appropriate basis for part or all of a design.

The following observations are made:

- IGE/SR/23 appears to be a reasonable guidance document for natural gas. In particular, it recommends designs provide simple, high velocity vertical vents, and it provides practical guidance and rules of thumb useful to an Operator.
- IGE/SR/23 recommends that permanent vents are designed to trap condensed liquids and incorporate a seal that prevents air ingress to the vent line. This appears unnecessarily conservative for an installation where venting occurs only rarely, and for gases where there is insufficient separable condensate for it to collect.
- It is noted that IGE/SR/23 recommends that vents are designed for a minimum velocity of 60 m/s – this velocity is sufficient to transport any condensate and discharge it through the vent. The recommendation may be appropriate under special circumstances where the composition and vent velocity is shown to result in formation of a liquid phase that can be collected.

- It can be shown that if a pipeline containing a gas mixture does ignite, the maximum overpressure is 10 times the pressure in the pipeline at the time of ignition. For the vent illustrated in IGE/SR/23, air ingress can only occur when there is no gas flow, and hence no pressure.
- The pressure ratio of ten to one is the basis for AGA "Purging Principles and Practice" recommendation that the maximum purge pressure when clearing air from a pipeline with gas, is limited to 100 psi. (Refer to the AGA document and the supporting research paper published by GRI.)
- The IGE document limits its application to a maximum discharge of 40 kg/s. This may be appropriate to stations venting, but is too low for pipeline venting.
- To the extent possible, station pipe work should be designed to use carbon steels to simplify construction, and to avoid a future risk that future maintenance fails to recognise the presence of special steel.
- The designer should consider the requirements of the site when determining whether to adopt the "constant discharge rate" recommendation of the IGE document. An orifice will produce relatively constant flows for the period that the pressure ratio results in sonic orifice velocity. When the pressure ratio falls to a value where discharge is sub-sonic, an orifice may unnecessarily increase the time to depressurisation, which may in turn increase the risk to the facility.
- If a restriction orifice is installed in a station vent, the designer should consider installing it as close as practicable to the vent stack. If this is not possible, the low pressure vent pipe should be sized to that the temperature and pressure combinations are outside the range where brittle fracture can occur (refer to ASME B31.3, AS 4041 for guidance), or limit operating the hoop stress to be less than threshold stress of 85 MPa (AS 2885).
- The noise levels predicted are roughly similar to values predicted by acoustic engineers for pipeline projects, but analysis of a specific installation may be required to satisfy Licence or Environmental requirements.
- The ignition risk for a well designed vent in an open location is low. The designer should consider the ignition risk toward the end of the venting (when the velocity is well below 60 m/s) when locating the vent. For pipeline facilities in a remote location this risk is extremely low. It should be recognised that the mass flow rate at this time is low, and hence the potential energy release if ignition should occur is low.

Some observations from experienced pipeline engineers:

- One person commented that his organisation had an event where a vent valve had a slow leak which was ignited by some event, thought to be lightning, and which, when the station vent was activated caused a large fire at the cold vent.
- One person cautioned the comment on high velocity venting with – "I've seen the gas cloud rising from an atmospheric vent, condense, then fall back to earth despite the vertical near sonic velocity as it exits the vent. Ignition may therefore be credible especially at the fringes of the affected area".

- One person noted that "Clearly the industry is lacking operational experience that is driving designs to be very conservative and very costly. The progressive change from a prescriptive standard to one that requires competent (experienced) design is resulting in designs that are too conservative in many respects".

Appendices

Appendix G – ALARP

Issue

What treatments may be used to achieve or demonstrate ALARP?

Response

The Standard includes a formal definition of ALARP (Clause 1.5.3) and there is a reasonably extensive discussion in Appendix G. The concept arises from UK case law and has been well developed by the UK Health & Safety Executive (HSE). There is useful information on the HSE web site: http://www.hse.gov.uk/comah/alarp.htm.

There are a number of common misunderstandings about the ALARP concept. ALARP is NOT:

- A risk rank (as in "the risk was reduced to ALARP")
- The objective of the Safety Management Study (SMS) (Low or Negligible risk is better)
- "We haven't bothered thinking much about further mitigation, so we'll call the risk ALARP"

The correct view of ALARP is that it is a supplementary step in the SMS process when the risk rank is Intermediate. Intermediate risks are only borderline tolerable and can be accepted only if it is shown that further risk reduction is not practicable. The definition (Clause 1.5.3) clearly requires a cost-benefit analysis to assess whether risk reduction is practicable: "ALARP means the cost of further risk reduction measures is grossly disproportionate to the benefit gained from the reduced risk that would result."

Putting ALARP into the broader context of the SMS process, there is a hierarchy of possible outcomes for a threat:

1. Threat not credible (no further attention required; note this means that the *threat* itself is not credible, NOT that failure as a result of it is not credible)
2. Controls considered as effective (failure as a result of the threat removed for all practical purposes at that location); accepted threat
3. Controls not effective but no failure; threat accepted on the basis of no significant consequence
4. Failure, risk Low or Negligible; threat accepted on the basis of tolerable risk
5. Failure, risk High or Intermediate; intolerable risk, apply more controls until risk is reduced

6. Failure, risk Intermediate and cannot be reduced; do a study to demonstrate ALARP; threat accepted if ALARP successfully demonstrated

It must be remembered that where ALARP is used as the basis for accepting an Intermediate risk threat as being controlled, and the controls fail, and the consequence is death or major or catastrophic loss, the Licensee may be required to justify that decision in a court of law. In this situation, the analysis used to justify ALARP must be robust if it is to be considered by the court as having any reliability as evidence.

A decision by an SMS workshop to accept that an Intermediate risk has been demonstrated to be ALARP imposes an additional obligation on the Licensee, because it recognises that the threat cannot be adequately controlled. Not all Licensees recognise that an SMS has assigned these additional responsibilities to him.

Appendix G provides guidance on the basic questions that must be asked in the process of assessing whether an intermediate risk can be accepted as being reduced to ALARP:

> *An important part of the process of demonstrating ALARP is the identification and evaluation of alternative designs that offer lower risk. Two questions illustrate the process:*
>
> *(a) What else could we do to reduce risk?*
>
> *(b) Why have we not done it?*
>
> *ALARP has been demonstrated when the answer to the second question, for each physically possible alternative, is 'because the cost is grossly disproportionate'.*

The cost is grossly disproportionate when it exceeds a value known variously as the maximum justifiable spend or the hurdle cost ("hurdle" because ALARP is not demonstrated until all available mitigation options have costs that are above the hurdle value). This cost depends on the characteristics of the risk:

Hurdle cost = (cost of failure) x (probability of failure) x (proportionality factor)

Determining the cost of failure means putting a dollar value to human life if the consequences of failure include fatalities. In the UK a value of M£1 is routinely used (around M$1.5 - 2); at least one Australian road authority uses a value of M$4. Each safety management study will need to make its own judgement on this matter. Where applicable the cost of failure may also include the cost of supply interruption, the cost of damage to both the pipeline itself and other property, and the cost of environmental damage (which poses another challenge to translate into dollars).

The probability of failure must be estimated numerically, even though the AS 2885 SMS process uses only qualitative frequency bands. Short of a full quantitative risk assessment it will be necessary to make some judgements using available data. The summary incident rates from the APIA/POG pipeline incident database may be a useful starting point, but may need to be modified depending on the location of the threat and its nature.

The proportionality factor (PF) varies from 1 to 10 depending on where the risk lies within the Intermediate ("tolerable if ALARP") band. A risk that is only just below High (intolerable)

certainly requires a PF of 10. For a risk that is only slightly higher than Low (acceptable) a PF of 1 may be justifiable.

Further information on this cost-benefit analysis approach is available on the UK HSE website referenced above. Expanded details of its application to AS 2885 SMS were presented at an APIA POG seminar in April 2009, and more details are available in the presentation that can be downloaded from the APIA web site (Safety Management Studies for Existing Pipelines, by Peter Tuft).

By way of example, consider a threat in an urban area that could potentially result in up to 10 deaths (there may be other costs associated with damage and supply interruption, but ignore them for this example). If the value of avoiding a fatality is taken as M$2, the cost of failure is M$20.

The average incident rate in T1 areas (from the APIA/POG data) is 0.42 incidents per 1000 km.yr, but that is for all damage (coating damage, gouges, dents, etc), not just loss of containment. Assume that this particular threat has an average likelihood of occurrence (deviations from this assumption can be justified in some cases). However, less than one in four impacts results in loss of containment, so that would reduce the frequency to 0.1 failures per 1000 km.yr. Further, not all losses of containment result in fatalities (nil to date in Australia from pipeline incidents), so for incidents causing fatality it seems reasonable to reduce the frequency by a further factor of 10 to 0.01 failures per 1000 km.yr. If the threat applies to a section of pipeline 1 km long and the pipeline life is 40 years, the probability of failure is estimated to be $4x10^{-4}$.

Assume a PF value of 10 for the purpose of this example (the full risk evaluation of the specific threat might provide justification for a different value).

Hence the hurdle cost is M$20 x $4x10^{-4}$ x 10 = $80 000. Risk reduction measures that cost less than this must be implemented under the ALARP principle. This particular risk will have been demonstrated to be ALARP when all available mitigation measures have been considered and either been adopted or found to cost more than $80 000. In other words, there has been a thorough examination of "what else can we do to reduce risk?" and for every option not adopted the answer to "why haven't we done it?" is "because the cost is more than $80 000, which has been shown to be grossly disproportionate".

It is important to recognise that the calculation of hurdle cost is not precise, relying as it does on what can only be described as rough estimates for both the consequences and the likelihood of failure. The hurdle cost should not be viewed as a hard criterion, but as a guideline to support judgements on whether further mitigation is justifiable.

To continue the example, if a certain mitigation measure was found to have a cost of say $100 000 it would not be clear-cut that it passed the "grossly disproportionate" test. But a mitigation cost of M$1 is so far above the hurdle cost that we can be much more confident in rejecting it.

Appendix L – small diameter pipes

Issue

Appendix L5 refers to "small diameter" pipes. Which pipe sizes constitute as being "smaller diameter"?

Response

Figure 4.8.2, the Fracture Control Plan Decision Tree, shows the requirements of the Standard in relation to "small" diameter pipe operated under various pressure and fluid conditions.

Notwithstanding this, the designer may at his discretion specify material properties intended to improve pipe quality and response to failure.

Appendix L is an Informative appendix. Clause L5.1 draws attention to certain pipes that are designed to AS 2885, which operate at conditions that are beyond those typical of oil and gas pipelines, and whose diameter, thickness and operating pressure combinations have not been considered in any recognized or published research program available to the Committee responsible for development of the Standard.

The Standard does not have any specific requirements for pipes that fit into this category.

In the absence of specific requirements the designer is required use the principles and procedures of the Standard to analyse the problem and to develop solutions that in the first place, are approved by the Licensee, and if required, the Regulator.

The principles of the Standard are presented in Section 1.3 of AS 2885 Part 0.

Appendix N – Fatigue

Issue

1. Appendix N is easy to work with for cyclic hoop stress rates of up to 165 MPa. Beyond that point, for larger diameter pipes, there is reference to a fracture mechanics approach in BS 7910. Are there any alternative approaches than applying fracture mechanics?
2. Appendix N states that a fatigue life assessment should be included in the design life investigation. As AS 2885.3 does not nominate fatigue as an issue, does it need to be considered as part of the design basis?

Response

1. Fatigue analysis of pipelines is complex, and specialist advice should be sought if the subject pipeline does not satisfy the conservative basis in Appendix N (or where it may not be practicable to change the pipe design to reduce the stress range).
2. In addition to circumferential pressure induced stress cycles for the consideration of fatigue of seam welds, temperature induced axial stresses where present will create cyclic loads that should be considered to add to the axial pressure induced cycles for the consideration of the fatigue life of girth welds.
3. If the pipeline is expected to be subjected to cyclic loadings (including depressurisation and repressurisation) during its operating life, the requirement must be included in the pipeline design basis and analysed.
4. If a pipeline that was operated within relatively narrow pressure ranges is modified to operate at cyclic pressures that change counts as a *changed operating condition*. AS 2885.3 includes specific requirements for changed operating conditions that must be

complied with, irrespective of whether it specifically mentions the condition that changes.

Appendix T – Guidelines for tensioning of bolts in the flange joints of piping systems

Issue

Part 15 of Appendix T provides a worked example of the bolt torque calculation for bolts in flanged joints. T15.9 deals with the calculation of fatigue stress levels during operation. What would this look like in detail using a graphical presentation?

Response

The following explanation extends the example given in Clause T15.9 of the Standard. In particular a graph is provided to show calculated fatigue stress on the Soderberg Diagram. The Soderberg Diagram was cited in Clause T9 of the Standard. Any other suitable diagram could be used instead.

The stress ranges in the bolts are given in Clause T15.9 as follows:

The stress range in each bolt from the applied moment is (quote):

$$S_{C1} = 35{,}995/(644.19) = 55.88\,MPa$$

The stress range in each bolt from the applied force is, quote:

$$S_{C2} = \frac{0.97 \times 10^6}{20(644.19)} = 75.29\,MPa$$

The stress amplitudes are half these values or 27.94 MPa for the moment and 37.65 MPa for the force.

Using these values as inputs, the maximum and minimum values of stress are as follows:

$$S_{\max} = 366.36 + 55.88/2 + 75.29/2 = 431.95\,MPa$$

$$S_{\min} = 366.36 - 55.88/2 - 75.29/2 = 300.78\,MPa$$

The mean stress is:

$$S_{av} = (431.95 + 300.78)/2 = 366.36\,MPa$$

The total fatigue stress (T9(5)) is:

$$S_{tf} = S_{av} + (S_y / S_e) K_f S_r$$

$$S_{tf} = 366.36 + (724/(0.504 \times 862)) \times 2.5 \times (55.88/2 + 75.29/2)$$

$$S_{tf} = 641.79\,MPa$$

The intensified stress range from the alternating stress

$$S_E = K_f (S_{\max} - S_{\min})$$

$$S_E = 2.5(431.95 - 300.78)$$

$$S_E = 327.93 MPa$$

The intensified alternating stress amplitude is 327.93/2 or 163.97 MPa.

The endurance limit Se is:

$$S_e = 0.504 \times 862 = 434.45 MPa$$

Using these calculated values, together with a suggested factor of safety of 1.25 (The reciprocal factor of 1.25 is 0.80), the Soderberg Diagram has been constructed and given on the following page.

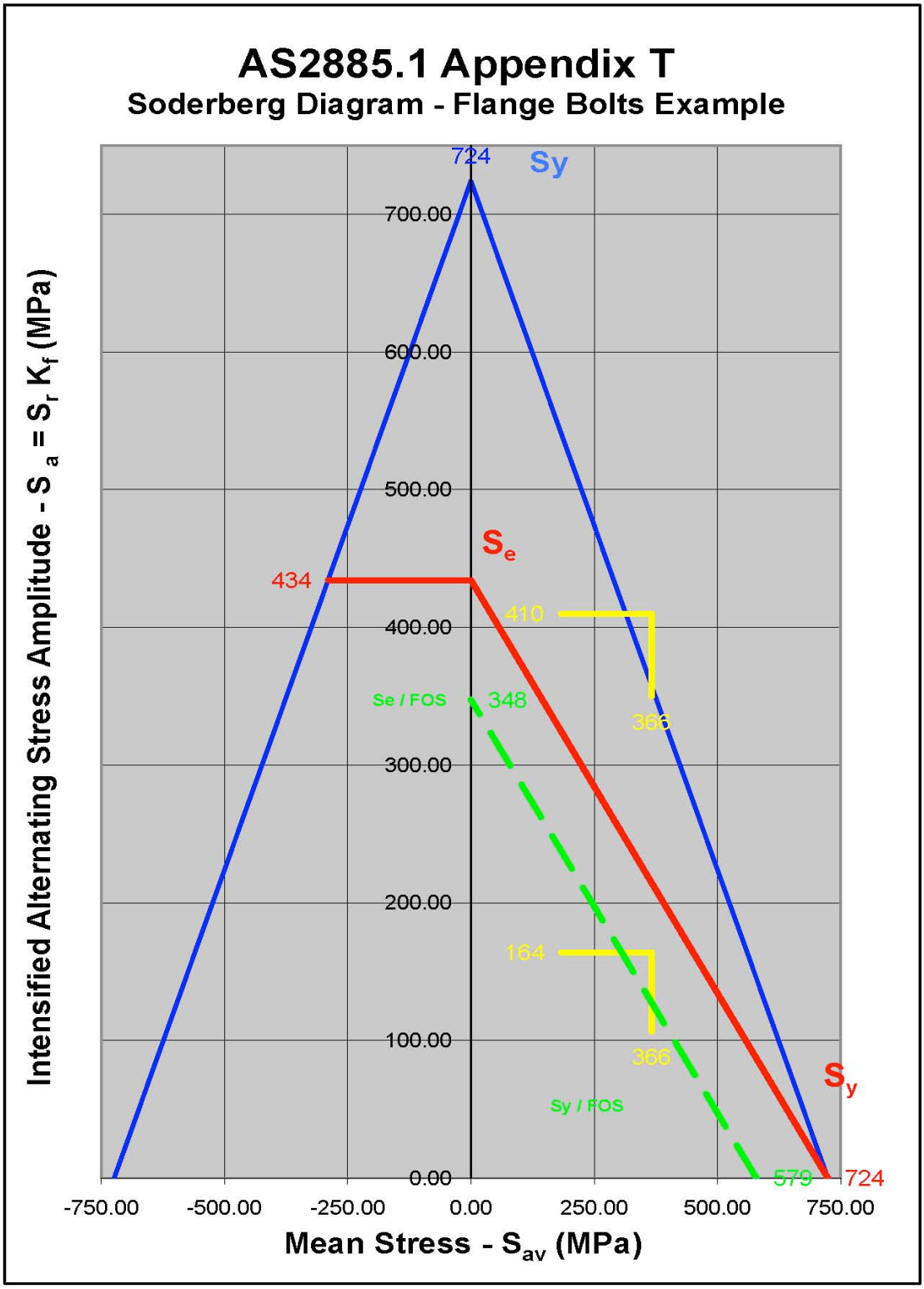
The example shows that the bolts have a factor of static safety (T9(1)) of

$$F_S = \frac{1}{[\frac{S_r K_r}{S_E} + \frac{S_{av}}{S_y}]} = \frac{1}{[\frac{163.97}{0.504 \times 862} + \frac{366.37}{724}]} = 1.13$$

The reciprocal (of 1.13) is 0.89, which is greater than the required factor of 0.8, and the solution does not therefore have the suggested factor of safety for a static analysis.

For a fatigue analysis, consideration should be given to the stress intensification from the possibility of a small crack emanating from the thread root. Applying the conservative stress intensification factor in Appendix T of 2.5 to the alternating stress component gives the following:

$$F_S = \frac{1}{[\frac{S_r K_f}{S_E} + \frac{S_{av}}{S_y}]} = \frac{1}{[\frac{163.97 x 2.5}{0.504 \times 862} + \frac{366.37}{724}]} = 0.69$$


AS2885.1 Appendix T
Soderberg Diagram - Flange Bolts Example
Intensified Alternating Stress Amplitude - S a = S r K f (MPa)
Mean Stress - S av (MPa)
724
Sy
700.00
600.00
500.00
Se
434
410
400.00
Se / FOS
348
366
300.00
200.00
164
100.00
366
Sy
Sy / FOS
0.00
579
724
-750.00
-500.00
-250.00
0.00
250.00
500.00
750.00

4.1.3 Part 2 Issues

[To be developed in a future stage of the project]

4.1.4 Part 3 Issues

[To be developed in a future stage of the project]

4.1.5 Part 5 Issues

[To be developed in a future stage of the project]

4.2 INDUSTRY LESSONS

This section contains lessons learned by pipeline engineers over the past 3 decades and represents the passing on of key experiences that should be a benefit to the industry.

4.2.1 Design lessons

Lesson 1: Use of ASTM A106 steel pipes for station piping

Lesson Summary

Caution must be used in specifying material for station piping with low minimum design temperatures. This particularly applies where ASTM A106 pipe is being considered, because it is generally not suitable for temperatures below 20°C. If it is to be used, it must first satisfy toughness testing requirements established by AS 4041.

Overview

The purpose of this industry lesson is to draw attention to a potentially significant design matter relating to Station Pipe designed to AS 2885.1 using one of the nominated standards (AS 4041 or ASME B31.3). It relates to design using ASTM A106 Grade B materials and associated ASTM A105N flanges and ASTM A234 WPB fittings at design temperatures below ambient.

Possibly unknown to most, the title of Specification ASTM A106 is *Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service.* Yet there is a commonly held opinion that it is suitable for use at design temperatures between -29°C and 200°C for all wall or reference thicknesses.

Clause 2.11 of AS 4041 clearly shows that it is not. Design for low temperature is required if the design minimum temperature is less than 0°C. Below this temperature, pipe (and fittings) toughness is required to be demonstrated, with the requirements varying with the design temperature, wall or reference thickness and the pipe grade. ASME B31.3 has generally similar requirements.

It is likely that as a consequence of somewhat arbitrary nomination of station piping design temperatures, and an assumption that ASTM A106 materials are suitable for - 29°C, may have resulted in the station pipe not complying with the requirements of the design standard.

Background

Until the publication of the 1997 revision of AS 2885.1, station pipe design was covered by the AS 2885.1. Like its predecessors (tracing back to ASME B31.8 / B31.4) the 1987 revision permitted (and encouraged) the use of line pipe and high test fittings for design and construction of station pipe.

The 1997 revision of AS 2885.1 deleted the previous rules for station piping and instead nominated that it be designed in accordance with an appropriate pressure piping design standard. AS 4041 and ASME B31.3 were nominated as appropriate standards.

Unfortunately the piping standards are intended for general plant use and unlike the pipeline standards, did not provided any incentive for designers to use API 5L grades, because the design stress for grades higher than X52 were pegged at X52.

About the same time, construction contracting strategies started separating the construction of stations from the construction of the pipeline – and the station designer was no longer part of the overall project strategy (which in the past, included procurement of line pipe and high test fittings for stations). Consequently, ASTM A106 Grade B (and associated fittings) became the default material for station pipe.

This "default" became embedded as consultancies moved into more advanced piping design methods, but as a matter of standardisation only populated the CAD design database with pipe and fittings complying with ASTM A106 Grade B (and associated fitting) materials.

The Material Difference

The significant difference between ASTM A106 and API 5L materials is that A106 pipe is intended for general use at temperatures where the risk of brittle fracture is negligible, and a performance requirement may be resistance to creep.

Pipe manufactured to API Specification 5L (PSL2) is alloyed and processed to produce fine grained microstructure that provides significantly improved mechanical and toughness properties, and is required to have a Charpy Impact test toughness of at least 27 J at 0°C. (Pipe manufactured to PSL1 may also have fine grained microstructure, but it is not a requirement). Pipe manufactured to project specifications often has higher toughness, and is subjected to increased toughness testing, including Drop Weight Tear Tests, to demonstrate its ductility at the design minimum test temperature.

Materials intended for low temperature service (ASTM A333 materials) are also manufactured to deliver controlled microstructure, and are required to comply with minimum Charpy Impact toughness (e.g. ASTM A333 Grades 1 and 6 are required to exhibit minimum toughness of 18J (full size) at a test temperature of -45°C).

AS 4041 2006

AS 4041 – 2006 removed the impediment to using line pipe in Station pipe, by recognising the increasing strength of pipe complying with API Specification 5L in grades between X42 and X80. This revision provides significant incentive to designers by allowing station pipe thickness that may be similar to the thicknesses of heavy wall pipe (the design stress permitted varies from 58% of SMYS for Grade X46 to 50% of SMYS for Grade X70).

High Test Fittings

High test fittings are manufactured from pipe or forging material whose properties are consistent with the properties of API 5L materials. While they are not usually stocked in Australia, with a little thought and planning by designers, fittings can usually be sourced from stocks held in the USA, or manufactured to order well within the time frame of practically all pipeline construction projects.

These materials offer significant benefit through the use of significantly improved material properties, but also through improved weldability provided by the lower carbon equivalent of the high test fittings.

Low Temperature Fittings

If required, fittings from low temperature materials (ASTM A420 Gr WPL6) and flanges (ASTM A350 LF2), together with low temperature pipe (ASTM A333 of the appropriate grade)

may be available from Australian stockists or may be sourced from overseas suppliers – there is usually a cost penalty compared with the higher temperature grades.

Designers Beware

Designers (and Licensees) must take care to understand the obligations imposed by nomination of the design minimum temperature, not only for line pipe design, but also for station pipe design.

Care must be taken to research and nominate the appropriate design minimum temperature. (NOTE: For brittle fracture to initiate, the stress must exceed a threshold value – this, together with the thermal mass of the pipe is usually sufficient to accommodate transient temperatures associated with depressurising and repressurising station pipe).

A design temperature lower than ambient (20°C) may require special testing of A106 grade pipe and fittings, and these tests may show that the material does not comply with the design requirements of the piping standard (AS 4041 / ASME B31.3).

Where the design minimum temperature requires special testing, designers are encouraged to consider using high quality material complying with a nominated line pipe specification, together with associated high test fittings, because these fine grained materials have significantly improved toughness. With some planning, such pipe and fittings can be purchased as part of a project order. Alternatively, pipe complying with a low temperature specification (like ASTM A333) may be appropriate.

Obligation to Appreciate the Requirements of Nominated Standards

AS 2885.1 nominates a number of standards as being suitable for design, and manufacture of materials, components and fittings.

In specifying materials, components, fittings (and design) to a nominated standard, each designer has an obligation to have read and understood the scope and limitations of the nominated standard as it is applied to his design. Simply requiring compliance with a nominated standard may result in failure.

4.2.2 Construction Lessons

[To be developed in a future stage of the project]

4.2.3 Operations Lessons

[To be developed in a future stage of the project]

Appendices

Appendix 1. - References for the Pipeline Design, Construction and Operations Processes

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AutoPipe, Bentley, Pipe Stress Analysis & Design

CRACKWISE, TWI Software, Fatigue analysis for structures with flaws

PDS (Plant Design System), Intergraph Corporation, Plant Design System

PIPESTRAIN, ANSTO, Stress/Strain analysis software

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APPENDIX 2 - Issues papers prepared in the development of AS 2885.1

Appendix 2.1 - Issues papers prepared in the development of AS 2885.1

Appendix 2.2 - Issues papers prepared in the development of AS 2885.2

[To be developed in a future stage of the project]

Appendix 2.3 - Issues papers prepared in the development of AS 2885.3

[To be developed in a future stage of the project]

Appendix 2.4 - Issues papers prepared in the development of AS 2885.5

[To be developed in a future stage of the project]