

**COMPARISON OF  
API AND CSA OFFSHORE PIPELINE  
STRESS AND STRAIN DESIGN CRITERIA**

**by**

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The documents referenced in the preparation of this presentation include:

- . Reference 1, Chapter 11, Offshore Steel Pipelines, CSA Z662-99, Oil and Gas Pipeline Systems
  
- . Reference 2, API Recommended Practice 1111, Design, Construction, Operation, and Maintenance of Offshore Hydrocarbon Pipelines (Limit State Design), API RP 1111 Revision Task Force for the 3rd Edition, Final Draft Copy
  
- . Reference 3, Chapter 4, Design, CSA Z662-99, Oil and Gas Pipeline Systems
  
- . Reference 4, Chapter 8, Clause 8.2, Tensile Properties, CAN/CSA-Z245.1-M90, Steel Line Pipe
  
- . Reference 5, Chapter 11, Clause 11.5.4, Wall Thickness Tolerance, CAN/CSA-Z245.1-M90, Steel Line Pipe
  
- . Reference 6, Appendix C, Limit States Design, CSA Z662-99, Oil and Gas Pipeline Systems

In order to compare the API Recommended Practice and the CSA Standard for the design of offshore steel pipelines, a pipeline typical of that used in practice was selected as the example to be used for illustration purposes in this presentation. The physical dimensions, mechanical properties and (internal) design pressure requirements of the example pipeline are specified as follows:

Specified: Outside Diameter,  $D$  = 24.0 in (610 mm)

Specified: Grade 414 steel. For Grade 414 steel (see Table 8.1 - Reference 4):

the Yield Strength (minimum) = 60 ksi (414 Mpa), and

the Tensile Strength (minimum) = 75 ksi (517 Mpa)

Modulus of Elasticity of Steel,  $E$  = 30,000 ksi (207,000 Mpa)

Specified (Internal) Design Pressure,  $P_d$  = 1650 psi (11,377 kPa)

Unit Conversion: 1000 psi = 6895 kPa

Assumptions for the example pipeline are:

1. Pipeline is installed in very shallow water. Therefore internal design pressure is approximately equal to the differential pressure (ie. internal design pressure minus external hydrostatic pressure)
2. Stresses due to thermal effects, static loads (ie. weight of pipe, coating weight, appurtenances and attachments), effects of spanning, differential settlement, soil pressure (if buried), etc. are not considered in the design. In any event, the incremental increase in the stresses should be the same for both API and CSA designs.

General Note: Apart from the determination of loads and load effects, the Limit States Design method defined in Reference 6 for the design of pipelines is not applicable to the design of offshore pipelines due to the specification of very restrictive (ie. conservative) **strain limits**.

## HOOP STRESS ANALYSIS - CSA

The simplest and most commonly used procedure for determining the initial wall thickness of a pipeline, be it onshore or offshore, is to calculate it based on the specified (internal) design pressure. If other design criteria or other stress limits or strain limits such as combined stresses, hydrostatic collapse, or the occurrence of local buckling or wrinkling during the installation process do not result in a need to increase the pipe wall thickness, then the hoop stress determination of the pipe wall thickness determined on the basis of the specified (internal) design pressure will also represent an optimum pipeline design.

In this example, the specified (internal) design pressure will be used to determine the required wall thickness of the pipeline. As such, the (internal) design pressure for a given wall thickness or the design wall thickness for a given (internal) design pressure can be determined from a slightly modified design formula (see Reference 3, Clause 4.3.3.1.1) as follows:

$$P_d = (2)(t)(S)(F_d)(J)(T)/(D) \quad \text{Formula 1}$$

or

$$t = (P_d)(D)/(2)(S)(F_d)(J)(T) \quad \text{Formula 2}$$

In regard to the use of design **nominal** wall thickness vs design **minimum** wall thickness, the following is noted.

1. For onshore pipeline design, (Reference 4 - CSA), the design wall thickness determined from Formula 2 is the design **nominal** wall thickness..
2. For offshore pipeline design, (Reference 1 - CSA), the design wall thickness determined from Formula 2 is the design **minimum** wall thickness..
3. For offshore pipeline design, (Reference 2 - API), the design wall thickness determined from Formula 2 is the design **nominal** wall thickness..

For the example pipeline, in order for it to be in compliance with the design requirements of Reference 1 - CSA, it is appropriate to determine the design **minimum** wall thickness in accordance with Reference 1.

Therefore:

$t$  = design **minimum** wall thickness, in (mm)

$P_d$  = 1650 psi (11,377 kPa), specified (internal) design pressure

$D$  = 24.0 in (610 mm), outside diameter

$S$  = 60 ksi (414 Mpa), specified minimum yield strength (SMYS)

$F_d$  = 0.72, (internal pressure) design factor (see Table 11.1 - Reference 1)

$J$  = 1.0, joint factor

$T$  = 1.0, temperature derating factor

Substituting into Formula 2 gives

$$t \text{ (minimum)} = (1650)\text{psi}(24.0)\text{in}/(2)(60,000)\text{psi}(0.72)(1.0)(1.0)$$

$$\mathbf{t \text{ (minimum)} = 0.46 \text{ in}(0.45833 \text{ in}) (11.7 \text{ mm})}$$

From Table 11.2 of Reference 5, the minus tolerance on nominal wall thickness can be as high as minus 8%. This implies that the **allowable** design minimum wall thickness can be as low as 92% of the design nominal wall thickness. The design nominal wall thickness can therefore be determined from the following relationship:

$$(0.92)(\text{design nominal wall thickness}) = \text{design minimum wall thickness}$$

or the

$$\text{design nominal wall thickness} = (\text{design minimum wall thickness})/(0.92)$$

Therefore:

$$t \text{ (nominal)} = (0.46)/(0.92)$$

$$\mathbf{t \text{ (nominal)} = 0.50 \text{ in} (12.7 \text{ mm})}$$

Note: The nominal wall thickness is that which would be ordered from the manufacturer.

Now, the hoop stress, at any given pressure, is defined by the formula

$$\sigma = (P)(D)/(2)(t) \quad \text{Formula 3}$$

where

$\sigma$  = hoop stress, psi

P = internal pressure, psi

D = outside diameter, in

t = nominal or minimum wall thickness, in

Therefore, at the (internal) design pressure, the hoop stress based on minimum wall thickness using Formula 3 should be

$$\sigma_d = (1650)\text{psi}(24.0)\text{in}/(2)(0.45833)\text{in}$$

$$\sigma_d = \mathbf{43,200 \text{ psi} (=72\% \text{ SMYS})}$$

And, at the (internal) design pressure, the hoop stress based on nominal wall thickness using Formula 3 is

$$\sigma_d = (1650)\text{psi}(24.0)\text{in}/(2)(0.50)\text{in}$$

$$\sigma_d = \mathbf{39,600 \text{ psi} (=66\% \text{ SMYS})}$$

## **(BURST) PRESSURE DESIGN - API**

In API RP 1111, a **Limit State Design** approach has been incorporated into the RP to provide a uniform factor of safety with respect to rupture or burst failure as the primary design condition.

In Clause 2.3.1, Reference 2 - API, the hydrostatic test pressure, the internal design pressure, the incidental overpressure and the maximum operating pressure are determined in relation to the calculated minimum burst pressure.

### **Minimum Burst Pressure, $P_b$**

The minimum burst pressure,  $P_b$  is determined by one of the following formulae:

$$P_b = 0.45(S+U)\ln(D/D_i) \quad \text{Formula 4}$$

or

$$P_b = 0.90(S+U)(t/(D-t)) \quad \text{Formula 5}$$

where

$P_b$  = minimum burst pressure, psi

$S$  = 60 ksi, specified minimum yield strength (SMYS)

$U$  = 75 ksi, specified minimum ultimate tensile strength

$t$  = 0.50 in, nominal wall thickness

$D$  = 24.0 in, outside diameter

Now, for  $D/t > 15$ , the two formulae (4 and 5) for the minimum burst pressure are equivalent.

For the example pipeline,  $D/t = 24.0/0.50 = 48$  which is greater than 15. Therefore, the minimum burst pressure of the pipe can be determined by substituting into Formula 5 as follows:

$$P_b = (0.90)(60,000+75,000)\text{psi}(0.50)\text{in}/(24.0-0.50)\text{in}$$

$$P_b = \mathbf{2585.1 \text{ psi}}$$

Therefore, at the minimum burst pressure, the equivalent hoop stress based on nominal wall thickness using Formula 3 is

$$\sigma_b = (2585.1)\text{psi}(24.0)\text{in}/(2)(0.50)\text{in}$$

$$\sigma_b = \mathbf{62,042 \text{ psi } (=103\% \text{ SMYS})}$$

### Hydrostatic Test Pressure, $P_t$

The hydrostatic test pressure,  $P_t$  is given by the formula

$$P_t = (F_d)(J)(T)(P_b)$$

Formula 6

where

$P_t$  = hydrostatic test pressure, psi

$F_d$  = 0.90, internal pressure (burst) design factor

$J$  = 1.0, longitudinal weld joint factor

$T$  = 1.0, temperature de-rating factor

$P_b$  = 2585.1 psi, minimum burst pressure

Substituting into Formula 6 gives

$$P_t = (0.90)(1.0)(1.0)(2585.1)\text{psi}$$

$$P_t = \mathbf{2326.6 \text{ psi}}$$

Therefore, at the hydrostatic test pressure, the equivalent hoop stress based on nominal wall thickness using Formula 3 is

$$\sigma_t = (2326.6)\text{psi}(24.0)\text{in}/(2)(0.50)\text{in}$$

$$\sigma_t = \mathbf{55,838 \text{ psi } (=93\% \text{ SMYS})}$$

### Design Pressure, $P_d$

The design pressure,  $P_d$  is given by the formula

$$P_d = (0.80)(P_t)$$

Formula 7

where

$P_d$  = design pressure, psi

$P_t$  = 2326.6 psi, hydrostatic test pressure

Substituting into Formula 7 gives

$P_d = (0.80)(2326.6)\text{psi}$

**$P_d = 1861.3 \text{ psi}$**

Therefore, at the design pressure, the equivalent hoop stress based on nominal wall thickness using Formula 3 is

$\sigma_d = (1861.3)\text{psi}(24.0)\text{in}/(2)(0.50)\text{in}$

**$\sigma_d = 44,670 \text{ psi} (=74\% \text{ SMYS})$**

The results of the hoop stress analyses can be summarized as follows:

1. The specified (internal) design pressure was used as the basis for the pipeline design using Reference 1 - CSA and was specified at a pressure of 1650 psi. The minimum pipe wall thickness was then determined to satisfy the provisions of the CSA Standard.
2. Using the design wall thickness required to be in compliance with the provisions of the CSA Standard, the design pressure was then determined based on the nominal wall thickness using the design method provided in Reference 2 - API. This (maximum allowable) design pressure was calculated to be 1861.3 psi. This value represents a 12.8% higher allowable design pressure using the API Recommended Practice over the CSA Standard, while based on the same nominal pipe wall thickness. In this respect, on the basis of hoop stress analyses and associated **stress limits**, the API Recommended Practice has, what may be termed, a clear advantage over the CSA Standard in that it permits the inherent strength of the pipeline to be more fully utilized during normal pipeline operating conditions. In other words, the provisions of the CSA Standard impose **stress limits** which for normal pipeline operations lead to a more conservative design for an offshore pipeline.

## **MAXIMUM OPERATING PRESSURE (MOP) REQUIREMENTS - API vs CSA**

**API** (Reference 2) - In the API recommended practice, the maximum operating pressure (MOP) should not exceed any of the following:

- a) (Clause 2.2.2.1) the design pressure of the pipe, or
- b) (Clause 2.2.2.1) 80% of the applied hydrostatic test pressure.

**CSA** (Reference 1) - In the CSA standard, the maximum operating pressure (MOP) shall be the lesser of either:

- a) (Clause 11.6.3.3) the maximum internal fluid design pressure, or
- b) (Clause 11.6.3.3) 80% of the hydrostatic test pressure.

The provisions of both API and CSA in respect of maximum operating pressure (MOP) are essentially the same.

## COMBINED LOAD/STRESS REQUIREMENTS - API vs CSA

**API** (Reference 2) - In the API recommended practice, the combination of primary axial load and internal pressure load shall not exceed that given by the formula (Clause 2.3.1.2):

$$\left( \left( \frac{P_i - P_e}{P_b} \right)^2 + \left( \frac{T_e}{T_y} \right)^2 \right)^{0.5}$$

where

$P_i$  = internal pressure, psi

$P_e$  = external hydrostatic pressure, psi

$P_b$  = minimum burst pressure, psi

$T_e$  = effective tension in pipe, lbs

$T_y$  = yield tension in pipe, lbs

The value of the above expression for **combined loads** shall not exceed:

- a) 0.90 for operational loads
- b) 0.96 for extreme loads, and
- c) 0.96 for hydrotest loads

It is noted that the formula presented in Clause 2.3.1.2 for combined loads is an expression based on the Tresca hypothesis for combined loads and utilizes the minimum burst pressure in its formulation.

**CSA** (Reference 1) - In the CSA standard, the maximum combined effective stress,  $S_c$  based on the design **minimum** wall thickness, due to internal and external pressures, bending, axial loads, ovality, and torsion, acting simultaneously with any other stresses, shall be determined using the following formula (Clause 11.2.4.2.3.1):

$$S_c = \left( (S_l)^2 + (S_h)^2 - (S_l)(S_h) + (3)(\hat{\sigma}_{hl}) \right)^{0.5}$$

where

$S_c$  = maximum combined effective stress, ksi

$S_l$  = total longitudinal stresses, ksi

$S_h$  = total hoop stress, ksi

$\hat{\sigma}_{hl}$  = tangential shear stress, ksi

The above formula is an expression of the plasticity hypothesis of Hüber, von Mises, and Hencky and includes the tangential shear stresses in its formulation. The allowable stress,  $S_{ca}$  shall be determined using the following formula (Clause 11.2.4.2.3.3):

$$S_{ca} = (F)(S)(T)$$

where

$S_{ca}$  = allowable stress, ksi

$F = 1.0$ , design factor for combined stresses

$S$  = specified minimum yield strength, ksi

$T$  = temperature de-rating factor (see Table 4.3 - Reference 4) (Note:  $T = 1.0$  for temperatures of 120°C or less).

The provisions of API in respect of combined loads and the provisions of CSA in respect of combined stresses require full consideration of all loads and load effects which may contribute to the maximum hoop stress and to the maximum longitudinal stress. Although, each of the formulations are based on slightly different combined stress hypothesis, Tresca vs Hüber, von Mises, and Hencky, and different pipe wall thicknesses, nominal vs minimum, if the longitudinal stress contributions are significant then the allowable maximum operating pressure determined in accordance with the **stress limits** defined by each design practice will probably be very similar in magnitude. However, in situations where the longitudinal loads or longitudinal stress are small or insignificant, then the **stress limits** established from hoop stress analyses will control the design of the pipeline, which of course leads to the conclusion that the API Recommended Practice is somewhat more beneficial in that it permits the inherent strength of the pipeline to be more fully utilized during normal operating conditions of the pipeline.

## HYDROSTATIC TEST PRESSURE REQUIREMENTS - API vs CSA

**API** (Reference 2) - In the API recommended practice, the after-construction strength test (ie., the hydrostatic test pressure):

- a) (Clause 6.2.4.1) should not be less than 125% of the pipeline maximum operating pressure, and
- b) (Clause 6.2.4.1) should not result in combined loads exceeding 96% of capacity as described in Clause 2.3.1.2 (Combined Load Design).

**CSA** (Reference 1) - In the CSA standard, pipelines:

- a) (Clause 11.6.3.2) shall be subject to strength test pressures of at least 1.25 times their intended maximum operating pressures, and
- b) (Clause 11.2.4.2.1.2.2) shall be designed to withstand strength test pressures in accordance with the requirements of Clause 11.6.3.2 such that, during pressure testing, the maximum combined effective stress shall not exceed the allowable stress (see Clause 11.2.4.2.3). The allowable stress is based on a design factor for the hydrostatic test pressure equal to 1.0 (see Table 11.1).

The requirements of both API and CSA in respect of hydrostatic test pressures are, in essence, the same since the conclusions drawn in regard to the API provisions for combined loads and the CSA provisions for combined stresses provide approximately the same **stress limits**.

## STRAIN CONSIDERATIONS AND STRAIN LIMITS - API vs CSA

In instances where pipelines are subject to extremely large deformations which may result from massive slope failures or seabed movements or are subject to extremely large deformations and/or stresses which may result from iceberg/pipeline interaction phenomenon or multi-year ice/pipeline interaction phenomenon or are subject to extremely large dynamic stresses as a result of seismic activity or the possibility of vortex shedding, then of course, the pipeline does and will fail.

However, pipelines are often subject to large inelastic deformations without failure or loss of operational suitability or serviceability and as such may readily be classified to be occurrences of **strain-controlled** loading. Strain-controlled loads may arise from seismic activity, frost heave, liquefaction, subsidence, thaw settlement, loss of support (ie. spanning), slope movements and general soil movement of the seabed.

From a practical point of view, strain-controlled loads are not associated with the absorption by the pipeline of excessively large loads or excessively large stresses. The fundamental principle or philosophy connected with the application of strain-controlled loads is that they normally impart large deflections and/or movements of the pipeline which in turn impose large deformations, that is, deformations of the pipeline which extend into the inelastic range. These large deformations are then accommodated or absorbed by the inelastic response behaviour of the steel in its inelastic strain range, that is, by imposing large plastic strains into the pipe material.

**API** (Reference 2) - The API recommended practice does not specifically address or define provisions for the design of pipelines subject to large inelastic deformations (ie. strain-controlled loads). It does however mention in Clause 2.4.2 that the effects of natural phenomena such as earthquakes, hurricanes, cyclones, typhoons and gross sea bottom movement can expose an offshore pipeline to unusual forces and that the design of the pipeline should consider such forces in regard to the stability and safety of the pipeline. However, the recommended practice provides no specific requirements as to how this may be achieved, and in particular does not deal directly or indirectly with the application of a **strain limit** in order to allow the operation of the pipeline

when it has been subject to large inelastic deformations without failure.

**CSA (Reference 1)** - The CSA standard specifically addresses strain-controlled loads and defines provisions in terms of **strain limits**.

In Clause 11.2.4.2.1.1, Design Criteria for Installation, the CSA standard specifies that for installation, the maximum permissible strain in the pipe wall, in any plane of orientation, shall not exceed 0.025 (ie. 2.5%). These strains may be either tensile or compressive in nature and arise in connection with the pipeline installation technique. A cautionary note has been added to the effect that where plastic strains are anticipated, the ability of weldments (ie. both longitudinal and joint welds) to undergo such strains without detrimental effect should be considered. Depending on the type of pipeline lay method used to install the pipeline, the plastic strains may vary in magnitude from as little as 1% up to and greater in magnitude than 2%. Inelastic strains in the order of 1% or more can, if not properly accounted for, lead to a local buckling. As such, this mode of failure will then control the design of the pipe wall thickness of the pipeline. Therefore, to prevent the occurrence of local buckling or wrinkling of the pipeline during installation, the design wall thickness will normally have to be increased.

In Clause 11.2.4.2.2, Design Criteria for Operation, the CSA standard specifies that during operation and where strain-controlled loads may occur or exist, the resultant tensile strain, in any plane of orientation in the pipe wall, shall not exceed 0.025 (ie. 2.5%) less any strain residual from installation. This implies that the total tensile strain, that is the residual tensile strain from installation combined with the tensile strains arising from strain-controlled loads are limited to 2.5% in any plane of orientation in the pipe wall.

The use of a **strain limit** approach for strain-controlled loads in the CSA standard is a very significant and practical benefit in the design, installation and operation of an offshore pipeline. It is well recognized that offshore pipelines are often subject to loadings and deformations which result in large inelastic strains without failure. In circumstances where a design standard or a

recommended practice does not appropriately provide for or even recognize the substantial benefits to be gained in the application of **strain limits** for the design of the pipeline, it is not unreasonable to expect that the regulatory body may very well be placed in a position where it must request remedial actions in the form of its removal or repair. Such remedial measures may often be unnecessary and subject the pipeline operator to significant unwarranted costs even though the integrity, reliability, serviceability and overall safety of the pipeline may not have been, in any measurable or quantifiable way, impaired or jeopardized.

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