STANDARDS RESEARCH

Assessment of Natural Gas Pipeline Materials for Hydrogen Service

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Executive Summary

There is significant interest in pursuing hydrogen as a low-carbon fuel to contribute to decarbonization of Canada's energy systems. As with other gases, pipeline transportation will enable large volume transportation of hydrogen to end-use locations. And converting existing natural gas pipelines for hydrogen service is viewed as an efficient and cost-effective means to enable large-scale use of hydrogen in Canada. Whether as a natural gas-hydrogen blend or pure hydrogen gas, the suitability of pipeline materials designed for natural gas must be evaluated when converting a pipeline for hydrogen service. Through literature review, industry scan, and analysis, this research provides insights into standard gaps and recommendations for future updates of relevant standards to support operators contemplating conversion of their pipeline infrastructure into hydrogen service.

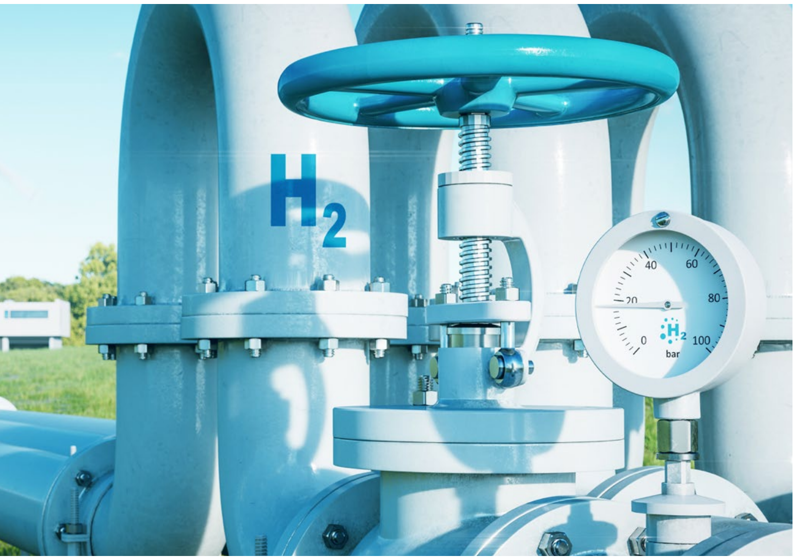
Most Canadian natural gas transmission pipelines are made of carbon steels, which, when exposed to hydrogen environments, can experience, to varying degrees, material degradation, including reduced fracture toughness and accelerated fatigue crack growth rate. Carbon steel pipelines' susceptibility to such degradation is influenced by various factors such as steel grade, metallurgical characteristics, hydrogen partial pressure, subsurface anomalies, pipe welds, steel hardness, residual strain, operating temperature, presence of inhibiting compounds, sulfur and phosphorus content, carbon equivalent, existing pipeline defects (e.g., pipe dents), and heat treatment application.

Transporting hydrogen through carbon steel pipelines is not a new concept, with standards in existence. Hydrogen pipeline use has been prevalent in North America for several decades in purpose-built pipelines for hydrogen service, pipelines converted from other services like crude oil gathering pipelines, and numerous hydrogen blending demonstration projects involving the addition of hydrogen to natural gas pipelines.

While carbon steels are predominantly used in natural gas transmission pipelines, other materials such as stainless steels, aluminum alloys, cast iron, copper alloys, and non-metallic materials are also employed within the systems to a lesser extent. The suitability of these materials for hydrogen service varies and requires comprehensive evaluation. In the case of natural gas distribution mains, polyethylene (PE) pipes are commonly used. Significant research demonstrates PE pipes' suitability for hydrogen service evaluating hydrogen permeation and pipe ageing, but only limited relevant standards for hydrogen service exist.

As of June 2023, Canadian federal and provincial pipeline regulations do not specifically reference hydrogen or hydrogen blended pipelines. These regulations typically incorporate CSA Z662 as a reference for the design, construction, operation, modification, discontinuation, and abandonment of pipelines. The 2023 edition of CSA Z662 includes additional provisions specific to hydrogen gas service through Clause 17, applicable to pipelines used for hydrogen or hydrogen blend service. These provisions require operators to conduct engineering assessments that encompass various topics such as material selection and pipeline design to address the potential adverse effects of hydrogen on pipeline materials. Current CSA Z662 edition also references ASME B31.12 as an additional guidance document for hydrogen service, which is widely regarded as the applicable standard for high-pressure hydrogen pipelines. However, pipelines originally constructed for natural gas service are unlikely to meet the minimum requirements for hydrogen service outlined by ASME B31.12. Various requirements between the current edition of CSA Z662 and ASME B31.12 are compared in this report followed by recommendations on addressing the gaps to accelerate the hydrogen economy development.

In summary, the transition to hydrogen as a low-carbon fuel in Canada is gaining traction, with a focus on repurposing natural gas pipelines for hydrogen transport. This shift necessitates careful evaluation of pipe materials, especially carbon steels, due to potential hydrogen-induced degradation. While established standards exist, gaps between requirements for hydrogen and natural gas services should be addressed to accelerate the hydrogen economy rollout.



"The standards to which natural gas pipeline systems were originally designed and built generally do not align with the applicable standards for hydrogen pipelines."

1 Introduction

To contribute to decarbonization of Canada's energy systems, there has been a significant interest in pursuing hydrogen as a low-carbon fuel. Hydrogen transportation via repurposed existing natural gas pipelines is being evaluated to transport large volumes of hydrogen, either in the form of natural gas/hydrogen blend or hydrogen gas. The standards to which natural gas pipeline systems were originally designed and built generally do not align with the applicable standards for hydrogen pipelines (see Section 3.3). Additionally, exposure to hydrogen has potentially detrimental effects to pipeline materials such as reduced fracture toughness on commonly used pipeline materials [1] and accelerated fatigue crack growth rate (FCGR) in carbon steels [2]. Therefore, the integrity and risk considerations associated with hydrogen transport must be thoroughly evaluated to ensure safe, reliable, and efficient pipeline operations.

Knowledge and data gaps regarding the impact of hydrogen on pipeline materials are the subject of ongoing research. Furthermore, these gaps may prevent current Canadian standards from providing prescriptive guidance for repurposing infrastructure for hydrogen service. This study was intended to be used for assisting the development of practical guidance within Canadian regulations, codes, and standards (RCSs) by identifying the gaps, current practices, prioritization, and recommended pathways. First, a summary of natural gas pipeline materials commonly used in Canadian natural gas infrastructure and an overview of potential hydrogen impacts on pipeline materials are provided. Second, lessons learned from in-service hydrogen and hydrogen blend pipeline activities and the current state of applicable RCSs as well as identified gaps are summarized. Third, the results of a gap assessment and recommendations based on insights emerging from the first two parts of the study are presented.

2 Methods

This section provides methodologies used to gather information and conduct the overall assessment in this study covering material considerations, hydrogen blending activities, and standards gap assessment and recommendations.

2.1 Information and Data Collection Methods

2.1.1 Information on Natural Gas Pipeline Materials

A summary of natural gas pipeline materials within the Canadian oil and gas industry was developed based on publicly available literature and discussions with subject matter experts and CSA Group stakeholders. In this report, pipelines were categorized into three groups: **intraprovincial transmission pipelines** covering the natural gas transmission pipelines within a province; **interprovincial transmission pipelines** covering the federally regulated natural gas transmission pipelines crossing two or more provinces or international borders; and **distribution pipelines** covering natural gas distribution pipelines, which generally operate at lower pressures and have smaller diameter compared with the transmission pipelines.

Intraprovincial Transmission Pipelines. The information and statistics of natural gas transmission pipelines within the province of Alberta was used as a proxy for commonly used natural gas transmission pipelines within a province in Canada. Alberta was chosen because a relatively complete database containing relevant pipeline information for hydrogen impacts assessment was publicly available through the Alberta Energy Regulator's (AER) [3] *Enhanced pipeline graphics file* dataset. According to AER, the database excludes low pressure distribution pipelines. The database was further filtered to only include in-service (operating) natural gas pipelines.

Interprovincial Transmission Pipelines. An extensive database of pipelines for federally regulated interprovincial natural gas transmission pipelines within Canada appears to be unavailable in literature. Therefore, the information on these pipelines was gathered through various documents available on Canada Energy Regulator's (CER) regulatory database for activities and transactions [4] pertaining to material specifications for segments of ten major pipelines listed below:

- Alliance
- Emera Brunswick
- Foothills
- Many Islands
- Maritimes & Northeast
- NOVA Gas Transmission Ltd.
- TransCanada's Canadian Mainline
- Trans Québec & Maritimes
- Vector
- Westcoast

Distribution Pipelines. An overview of pipeline materials for natural gas distribution mains in Canada has been developed by the Canadian Gas Association (CGA) [5] and is referenced in this report.

2.1.2 Information on Hydrogen Impacts on Pipeline Materials

A broad review of scientific publications on hydrogen impacts on pipeline materials was conducted and a summary of discussions relevant to pipe materials commonly found in existing Canadian natural gas infrastructure (e.g., carbon steel grade 483) is provided. More than 100 publications, including journal articles, technical reports, and conference papers were compiled and reviewed. After review, the publications deemed relevant were cited throughout the report.

2.1.3 Information on Research and Pilot Projects for Hydrogen Blending Pipelines

Information pertaining to research and hydrogen blending pilot projects within Canada and worldwide pipelines has been gathered using published literature, pipeline operators' websites, and regulators' database available to the public. The summary includes both hydrogen blending pipelines and in-service hydrogen pipelines as well as in-service synthetic natural gas pipelines containing hydrogen resembling hydrogen-natural gas blend service when common practices around the material of construction and operations can deliver insights for converting existing Canadian natural gas infrastructure to hydrogen blend service.

2.1.4 Information on Regulations, Codes, and Standards

The RCSs relevant to hydrogen service in pipelines within Canada and worldwide were reviewed to develop formulating guidance for Canadian operators contemplating utilizing existing natural gas infrastructure for hydrogen service. CSA Z662:23 *Oil and gas pipeline systems* [6] incorporates hydrogen service through an engineering assessment approach. Other relevant RCSs for hydrogen service in gas transmission pipelines and distribution mains have also been reviewed to assist on identifying the potential gaps and recommendations considering the existing Canadian natural gas infrastructures, impacts of hydrogen in pipeline materials, experiences with in-service hydrogen and hydrogen blend pipelines, and current applicable RCSs for gas services.

2.2 Conducting Standards Gap Assessment

The standards gap assessment was based on aforementioned reviews of Canadian natural gas infrastructures, Canadian standards and regulations, worldwide RCSs relevant to hydrogen, operator experiences publicly available, and potential hydrogen adverse effects on pipeline materials. Gaps were identified and prioritized, and recommendations to address them were provided for consideration.

3 Results and Discussion

3.1 Natural Gas Pipeline Design, Materials, and Hydrogen Impacts

3.1.1 Natural Gas Pipeline Design Parameters

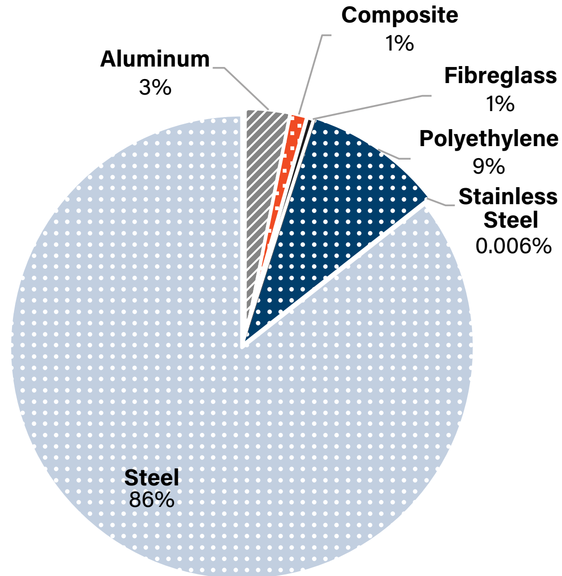
The design parameters of natural gas transmission pipelines as well as distribution pipelines are specific to their operations. Natural gas transmission pipelines are intended to move larger volumes of gas and long distances, while natural gas distribution pipelines are used to deliver natural gas to the consumers [7]. Transmission pipelines are generally larger in diameter (from 219 to 1,219 mm) and operating at high pressures (from 1.4 to 10.3 MPa), while distribution pipelines have diameters between 50 and 219 mm and typically operate at 1.4 MPa or lower pressures [8]. The operational pressure of these pipeline systems along with hydrogen blend levels are important when determining pipe material suitability for hydrogen blend transport, as hydrogen impacts on pipe materials have been shown to partly depend on hydrogen partial pressure (i.e., the product of system pressure and hydrogen blend level in the natural gas–hydrogen blend) [9] [10] [11], further discussed in Section 3.1.2.1.3. Therefore, assessing the material's suitability for hydrogen service solely based on hydrogen blend level without accounting for the system pressure should be taken with a precaution.

3.1.1.1 Natural Gas Transmission Pipelines

3.1.1.1.1 Intraprovincial Transmission Pipelines

Alberta's natural gas transmission pipelines are used as representative examples of intraprovincial transmission pipelines. The publicly available data compiled by AER on these pipelines includes gas service containing H2S (sour) and non-sour service.

Figure 1: Alberta intraprovincial natural gas transmission pipelines by materials [3]



Total length = ~209,000 km

Figure 1 shows the proportional representation of materials used in intraprovincial transmission pipelines in Alberta: the total length is approximately 209,000 km, where 86% of pipelines use carbon steels and the rest utilize polyethylene, aluminum, composite, fibreglass, and stainless steels. In the hydrogen environment, carbon steels have been observed to experience material degradation such as reduced fracture toughness and accelerated FCGR. Concerns related to hydrogen impacts on non-carbon steel materials also exist such as increased hydrogen permeation in polyethylene pipes. These material impacts will be further discussed in Section 3.1.2.

The grade of carbon steel based on the specified minimum yield strength (SMYS) in the standards such as CSA Z245.1 [12] and API 5L [13] has been observed to influence the severity of the hydrogen adverse effects, with a general trend reported of decreasing fracture resistance with increasing SMYS (i.e., higher grade) [14].

Table 1 shows that at least 89% of Alberta intraprovincial carbon steel pipelines utilize low- to medium-strength steels with SMYS less than or equal to 359 MPa (i.e., pipe grade less than or equal to 359) and only approximately 4% utilize higher strength carbon steels.

The AER database does not contain additional parameters relevant to hydrogen impacts assessment such as pipe seam types, material certificates, and test data (e.g., impact toughness, hardness, and non-destructive testing [NDT]). Additionally, the database contains vastly incomplete data on Location Class, a significant parameter used by various standards, including CSA Z662, to determine the pipeline design requirements for a location needing specific measures to mitigate risk to public safety such as rural or urban areas.

Table 2 shows the design parameter for carbon steel pipelines in Alberta pertaining to the maximum pipe hoop stresses (i.e., the stress that occurs along the pipe's circumference when internal pressure is applied). Pipe hoop stress is a contributing factor to pipe crack initiation and propagation. Improved pipe fracture properties and limiting maximum hoop stress can both aid in fracture control and arrest of a pipeline.

Table 2 shows about one-third of Alberta intraprovincial carbon steel pipelines allow maximum pipe hoop stresses up to 30% SMYS, another third allow 30% to 50% SMYS, and the final third allow over 50% SMYS. Table 3 shows the ratio of Location Classes for Alberta intraprovincial carbon steel transmission pipelines, as per CSA Z662. Most information in the database on these pipelines have unknown Location Class (Table 3), a parameter required to determine the pipeline design requirements such as pipe hoop stress limits (see Section 3.3.2.1). Hydrogen pipeline stress-based design (Option A) of ASME B31.12 [15] imposes more restrictive limits on allowable pipe hoop stresses compared with standards for natural gas pipelines due to potential hydrogen adverse effects; hence, the Alberta intraprovincial transmission pipelines operating at high hoop stresses under natural gas service generally would not meet the hydrogen pipeline design requirements specified in Option A of ASME B31.12 [15] unless maximum operating pressure (MOP) reduction was applied. Alternatively, ASME B31.12 [15] performance-based design (Option B) could be used to allow existing pipelines to continue operating at high pipe hoop stresses. However, this option requires additional material testing such as material fracture toughness testing in a hydrogen environment and more thorough analysis compared with Option A.

Table 1: Alberta intraprovincial natural gas carbon steel transmission pipelines by grade [3]

Carbon steel grade	SMYS [MPa]	Line Pipe specification standards	% of Total carbon steel pipeline length (~180,000 km)
359	359	CSA Z245.1	41%
290	290	CSA Z245.1	33%
X42	290	API 5L	9%
B	245	API 5L	3%
483	483	CSA Z245.1	3%
X52	359	API 5L	3%
414	414	CSA Z245.1	1%
Others	Various	Various	7%

Table 2: Alberta intraprovincial natural gas carbon steel transmission pipelines by maximum pipe hoop stress [3]

Maximum hoop stress [%SMYS]	% of Total carbon steel pipeline length (~180,000 km)
≤ 30%	36%
> 30 and ≤ 50%	32%
> 50%	31%
Unknown	0.3%

Table 3: Alberta intraprovincial natural gas carbon steel transmission pipelines by pipeline Location Class [3]

Location Class as per CSA Z662	% of Total carbon steel pipeline length (~180,000 km)
Class 1	6%
Class 2	0.14%
Class 3	0.03%
Class 4	0.04%
Unknown	94%

Table 4 shows that only 3% of these carbon steel operating pipelines were constructed or tested prior to 1970 (also referred as "vintage" pipes). Vintage pipes can be more susceptible to hydrogen effects than modern pipes due to differences in alloy composition such as high carbon content as well as higher likelihood of manufacturing and construction defects [16], which will further be discussed in Section 3.1.2.1.8.

Table 4: Alberta intraprovincial natural gas carbon steel pipelines by year of last construction, test or status change [3]

Year of last construction, test, or status change	% of Total carbon steel pipeline length (~180,000 km)
Pre-1970	3%
Post-1970	96%
Unknown	1%

3.1.1.1.2 Interprovincial Transmission Pipelines

Table 5 shows commonly used pipeline materials and design parameters for natural gas interprovincial transmission pipelines of ten major interprovincial natural gas transmission pipelines according to CER pipeline documentation [4] compared with the Alberta intraprovincial transmission pipelines.

With higher pipe hoop stress limits and the use of higher steel grades, interprovincial transmission pipelines would be less likely to meet requirements set by hydrogen pipeline standards such as ASME B31.12 [15] compared with intraprovincial transmission pipelines. The use of higher steel grades and higher pipe hoop stress limits in interprovincial transmission pipelines is typically driven by the longer transportation distances compared with intraprovincial transmission pipelines.

Table 5: Pipeline specifications comparison between segments of ten major Canadian interprovincial and Alberta intraprovincial transmission pipelines

Parameters	Segments of ten Canadian interprovincial transmission pipelines	Alberta intraprovincial transmission pipelines
Pipe material	All carbon steels	Mostly carbon steels
Carbon steel grade	Medium- to high-strength carbon steels Commonly Cat. II CSA Z245.1	Low- to medium-strength carbon steels
	Mostly Gr. 359 to 448, up to Gr. 690	Mostly ≤ Gr. 359
Maximum pipe hoop stress (% of SMYS)	50%–80%	Mostly ≤ 50%

3.1.1.2 Natural Gas Distribution Pipelines

A summary of pipeline materials within natural gas distribution systems in Canada has been developed by the Canadian Gas Association and shown in Table 6. Table 6 suggests that most pipes in distribution mains consist of polyethylene pipes, followed by carbon steel, while a small fraction (less than 1% of the total pipeline length) utilize aluminum, PVC, and composite pipes. Other pipe materials such as bare steel and cast iron commonly used for pipeline construction in the 1950s to 1980s have been phased out over time but may still exist within legacy assets.

Table 6: Pipeline materials for Canada's natural gas distribution system [5]

Material	% of Total pipeline length (~405,000 km)
Polyethylene	71%
Carbon steel	28%
Other (Aluminum, PVC, and Composite)	1%
Bare steel and cast iron	Unknown (Phased out)

3.1.2 Hydrogen Impacts on Pipeline Materials

A summary of potential hydrogen impacts on materials commonly used for the existing Canadian natural gas infrastructure is provided in this section. The discussion includes both metallics (carbon steel, stainless steel, aluminum, and cast iron) and non-metallics (polyethylene, polyvinyl chloride, and composite) materials.

Hydrogen embrittlement (HE) is a damage mechanism specifically referring to the loss of ductility and fracture toughness and increase of FCGR of a metal or alloy due to introduction and diffusion of atomic hydrogen.

Fracture toughness describes a material's ability to resist propagation of a crack-like flaw under stress. The introduction of hydrogen into pipelines can cause reduced fracture toughness in susceptible materials, resulting in a reduction in critical crack size (i.e., the size of a crack at which a failure criterion is exceeded). While not an actual measure of toughness, some standards such as API 5L [13], CSA Z245.1 [12], and ASME B31.12 [15] use Charpy impact energy as a proxy for estimating fracture toughness following empirical correlations.

However, as susceptibility of HE is dependent on the strain rate for a given crack-like flaw, Charpy v-notch (CVN) values are not a reliable indicator of fracture toughness properties in hydrogen [17].

FCGR can accelerate in hydrogen-containing environments. The presence of hydrogen can have a more severe effect on fatigue behaviour than fracture toughness; even low concentrations of hydrogen at a given testing condition can cause significant reductions in fatigue life [18]. An increase in FCGR can result in a shorter time for a crack to reach critical size, reduced fatigue life of the pipe, and more frequent inspections during operations.

3.1.2.1 Carbon Steel Line Pipe

Carbon steels have been observed to experience material degradation in a hydrogen environment, with HE as the widely cited phenomenon [1], [2].

Carbon steel pipelines are affected by exposure to hydrogen gas through various mechanisms, including dissociation into hydrogen atoms on the steel surface via adsorption, hydrogen atom diffusion into the steel, and accumulation in trapping sites. Many interacting variables contribute to a material's susceptibility to HE, including, but not limited to:

a. steel pipe grade [14],

b. metallurgical characteristics (e.g., type of microstructure and grain size) [19],

c. hydrogen partial pressure [9] [10] [11],

d. subsurface anomalies (e.g., laminations, large inclusions, and embedded weld flaws) [20],

e. pipe welds [21],

f. steel hardness [15],

g. residual strain [22],

h. operating temperature [23],

i. presence of adsorption inhibiting compounds (e.g., oxide films) [24],

j. sulfur and phosphorus content [15],

k. carbon equivalent [15], and

l. heat treatment [8].

3.1.2.1.1 Carbon Steel Pipe Grades

Steel grade is commonly used as a starting point to assess HE. Standard pipe grades in accordance with CSA Z245.1 [12] and the equivalent API 5L [13] based on SMYS can be found in Table 7. It should be noted that even though there is a pipe steel grade equivalence between CSA Z245.1 and API 5L based on SMYS, there are differences in the other pipe characteristic requirements (e.g., tensile strength and strain values) imposed for a grade classification by these two standards. For example, CSA Z245.1 [12] specifically allows for three different pipe categories within the same grade (Cat. I, II, and III) based on the requirements of impact and fracture appearance testing. ASME B31.12 [15], *Hydrogen piping and pipelines*, recommends pipe grades with SMYS 359 MPa or lower, but allows higher grades with SMYS up to 550 MPa (80 ksi) with additional considerations [15].

In a hydrogen environment, a general trend was reported showing a greater reduction in fracture resistance of steel with higher yield strength [14]. Overall, lower grade steels are less affected by HE compared with higher strength steels [25]. Chatzidouros *et al*. [1] observed a greater reduction of fracture toughness in tested X70 (Grade 483) than in X52 (Grade 359). When introduced to hydrogen, both tested X52 (Grade 359) and X70 (Grade 483) grade steels showed comparable FCGR up to 1.5 order of magnitude over the FCGR values in air [2]. Both tested steel grades showed an increase in FCGR as system pressure increased.

However, the relationship between HE susceptibility and steel grade remains unclear, as other studies indicated that in hydrogen environments, higher grade X70 (Grade 483) steel could have fracture toughness [1] and FCGR performance [26] comparable to X52 (Grade 359) or lower steels. As the steel grades are based on minimum property requirements of the base metal, the same grade steels can have large differences in metallurgical properties. Due to this variability, pipe grade alone is not sufficient criteria to assess susceptibility to HE.

Most intraprovincial transmission pipelines appear to meet the ASME B31.12 [15] favourable steel grades (less than or equal to Gr. 359) requirements, but additional considerations will be likely for interprovincial transmission pipelines where medium- to- high-strength steel grades are commonly used. Furthermore, Gr. 690 pipes used in some interprovincial transmission pipelines exceed the maximum SMYS limit of ASME B31.12 [15].

Table 7: CSA Z245.1 [12] steel pipe standard grades and their equivalent based on SMYS

CSA Z245.1 Standard grades	API 5L Equivalent grades (based on SMYS)	SMYS (MPa)
241	B	241
290	X42	290
359	X52	359
386	X56	386
414	X60	414
448	X65	448
483	X70	483
550	X80	550
620	X90	620
690	X100	690
825	X120	825

3.1.2.1.2 Steel Microstructures

The steel microstructure has a significant effect on hydrogen trapping and diffusion rates, which influences the susceptibility to HE. As Thomas and Szpunar [19] found, metallurgical characteristics, microstructural variations, and subsurface anomalies can all serve as hydrogen accumulation trap sites. There are two categories of hydrogen trap sites: reversible and irreversible. Hydrogen traps with an activation energy greater than 60 kJ/mol are considered irreversible [19]. Internal voids, where atomic hydrogen can recombine as molecular H_2, are also considered irreversible.

As Chatzidouros *et al*. [1] found, steel microstructure can be the decisive parameter for pipeline steel selection for hydrogen service. For instance, microstructural banding, which is caused by alloy segregation during steel casting solidification and cooling, has been demonstrated to decrease fracture toughness in tested X70 (Grade 483) and X52 (Grade 359) base metals and can act as a potential hydrogen trapping site [1], [27].

3.1.2.1.3 Hydrogen Partial Pressure

Some publications present the pipe materials susceptibility to HE based on the hydrogen percentage in the hydrogen-natural gas blend [28], [29], though system pressure has also been shown to influence the hydrogen effects on pipe materials [9], [10], [11]. A combined effect of these two factors led to the use of the term hydrogen partial pressure. For instance, significant fracture toughness reduction of carbon steel has been shown even at low hydrogen partial pressure (less than 100 kPa) [11], [30]. This 100 kPa hydrogen partial pressure can exist in presence of 100% hydrogen in a gas distribution pipeline operating at 100 kPa pressure, or 1% hydrogen in a gas transmission pipeline operating at 10,000 kPa pressure. Therefore, the material's suitability for hydrogen service should not be assessed solely based on hydrogen blend level without accounting for the system pressure.

3.1.2.1.4 Subsurface Anomalies

Subsurface anomalies or defects (e.g., laminations, large inclusions, embedded weld flaws) can increase the pipe's susceptibility to HE. Subsurface anomalies can act as trap sites for hydrogen atoms to accumulate and cause irreversible HE [19]. In extreme cases, hydrogen atoms within the traps can recombine as H_2 molecules, leading to high gas pressures that can cause hydrogen blisters or result in hydrogen-induced cracking (HIC) [31]. Irreversible traps include carbides, inclusions, and incoherent precipitates. However, some subsurface anomalies act as reversible traps, including interstitial sites, dislocations, lath boundaries, grain boundaries, and coherent precipitates [20].

3.1.2.1.5 Pipe Welds

Some weld types can be more vulnerable to hydrogen degradation due to formation of hard heat-affected zones (HAZ), variations in material properties, and potential formation of susceptible brittle microstructures [32], [33]. Weld zone susceptibility to HE depends on several variables, including developed microstructures, hydrogen content, and the magnitude of residual stresses in the weld zone. In a study of X70 (Grade 483) pipe, welds exposed to 1% hydrogen mixture at 10 MPa showed a higher susceptibility to HE compared with the base material [19]. Additionally, the weld metal often has the highest hardness and highest carbon equivalent, and thus, the highest susceptibility to HE. Therefore, welding consumables must be carefully selected to ensure desired weld properties, including the requirements for maximum weld hardness and minimum fracture toughness.

3.1.2.1.6 Steel Hardness

Steel compositions with a higher level of alloys, usually expressed in carbon equivalent (CE), can lead to high hardness in the HAZ for a wide range of pipe grades and vintages. High hardness can be indicative of martensitic (a type of crystalline) microstructure, which is the most susceptible steel microstructure to HE. The level of conservatism built into hardness limits for steel in hydrogen systems recommended by references such as CGA G-5.6 [34] and ASME B31.12 [15] can vary, as the material susceptibility to HE is not only a function of material factors but also the specific operational parameters for a given system, including temperature and hydrogen partial pressure. Also, hardness values can vary significantly within a single location, making point measurements potentially unreliable for assessing hardness variability; hence, relying on a fixed hardness limit based on a single maximum value may overlook local variations [35], [36].

"Vintage pipelines can be more prone to hydrogen degradation than modern pipes."

3.1.2.1.7 Residual Strain

Steel's capacity to deform in response to high tensile stress (referred to as ductility) has been observed to reduce in hydrogen service [11]. This results in more brittle behaviour, where high pre-strain (e.g., caused by activities such as pipeline installation, bending and pulling the pipe into alignment, ground deformation, cold expansion during pipe manufacturing, and third-party damage) can increase the susceptibility to HE [15], [37]. Additionally, this reduction in ductility requires operators using strain-based pipeline design to re-evaluate the strain capacity for pipeline subject to geohazards and other high-strain conditions.

3.1.2.1.8 Vintage Pipelines

Vintage pipelines can be more prone to hydrogen degradation than modern pipes [8]. This is not only because of their higher CE and variabilities in their metallurgical properties but also an increased likelihood of manufacturing defects such as hard spots, poor girth and seam weld quality, and arc burns. Moreover, certain types of flaws that are uncommon or completely absent in modern pipes such as seam weld stitching flaws, can make vintage line pipes even more vulnerable to hydrogen damage.

3.1.2.1.9 Operating Temperature

Susceptibility to HE has been shown to vary as a function of temperature. Typically, HE occurs below 95 °C [19] and is most severe at room temperature for metallic materials [38]. At temperatures above 230 °C, the susceptibility to HE and cracking are eliminated [19] as hydrogen diffusion rates are very high, which prevents high localized hydrogen concentrations that are required for cracking to occur. However, gas transmission and distribution pipelines do not typically operate at temperatures this high.

3.1.2.1.10 Inhibitors

Impurities such as oxygen (O_2) and carbon monoxide (CO) in high-pressure gas streams have been shown in some laboratory tests to form surface oxides on steel, which potentially inhibits HE [19], [25] [38]. The presence of O_2 can inhibit HE by interfering with the catalytic activity of steel [39]. However, the applicability and reliability of using O_2 or CO as degradation inhibitors requires further evaluation through research into the conditions under which oxide films form, robustness of the film, factors that could break down or damage thin films, and the time scale in which films inhibit HE. Recent testing indicates these effects may be temporary, and therefore, not a reliable mitigating factor for an operating pipeline [40]. Specifically, effects observed at laboratory time scales (i.e., hours to days) have been shown to diminish or absent at longer durations of exposure (i.e., weeks to months) [41].

3.1.2.1.11 Sulfur and Phosphorus Content

Sulphur (S) and Phosphorus (P) are undesirable impurities in steels, as they tend to form brittle inclusions and may impact greater susceptibility to HE [42]. ASME B31.12 [15] Option B explicitly limits the maximum P content to 0.015% by weight, although no limits are provided for S content.

3.1.2.1.12 Carbon Equivalent

CE is a parameter used to estimate the cold cracking susceptibility of steel for welding, based on the steel chemical composition. This parameter represents the hardenability of the steel and is an indicator of undesired brittle microstructures [43]. ASME B31.12 [15] Non-mandatory Appendix G, specifies the CE limits of 0.15% maximum for Gr. 359 to Gr. 414, and 0.17% maximum for Gr. 448 to Gr. 551 to help obtain desired steel microstructures to achieve higher fracture toughness in presence of hydrogen.

3.1.2.1.13 Heat Treatment

Heat treatment of steel is used to temper hard brittle martensite, which has high susceptibility to HE, into more desirable softer ductile microstructures [8]. CSA Z245.1 [12] requires electric welded pipe seams to be heat treated to obtain microstructures and mechanical properties similar to the pipe parent material. However, vintage electric welded pipe seams may not have been heat treated, resulting in higher susceptibility to HE.

3.1.2.1.14 Stainless Steels

Stainless steel is a steel alloy with at least 10.5% chromium and can contain other elements like nickel, molybdenum, or titanium for specific properties. It is categorized into five types based on the predominant metallurgical phase: austenitic, ferritic, martensitic, duplex (austenitic-ferritic), or precipitation hardened. Each type has different grades of varying chemical composition, corrosion resistance, and mechanical properties. For hydrogen service, some austenitic stainless steels grades (e.g., ASTM A312/A312M grades 304, 304L, 316, 316L [44]) are resistant to HE and generally provide the best performance among stainless steels [15]. HE in austenitic stainless steels is primarily correlated with two metallurgical variables: alloy composition and presence of second phases such as ferrite (a resultant of material processing) and martensite (induced by mechanical straining) [15]. Alloy composition has been correlated with a wide range of embrittlement resistance among austenitic stainless steels; in particular, higher nickel content correlates well with resistance to HE (e.g., grade 316 with nickel content greater than 12% by weight). Ferrite and strain-induced martensite render austenitic stainless steels can be more vulnerable to HE since they are intrinsically more susceptible to hydrogen-assisted fatigue than the austenite matrix [15].

Duplex stainless steel is susceptible to HE as it contains significant levels of ferrite. A study of hydrogen embrittlement on duplex stainless steel consisting of 54% ferrite and 46% austenite [45] found it to be susceptible to HE, particularly loss of ductility and toughness. Hydrogen diffusivity is 104 to 105 times higher in ferrite than austenite, while hydrogen solubility is 2 to 3 orders of magnitude higher in austenite. In some tested samples, most hydrogen entered and diffused into the steel microstructure through the ferrite bands and accumulated in the ferrite-austenite interfaces, leading to interface cracking.

3.1.2.2 Aluminum Alloys

Information on aluminum alloys in hydrogen is limited, but the information available indicates that it is highly resistant to HE when exposed to dry hydrogen gas. However, according to ASME B31.12 [15], wet gas (either pure hydrogen or hydrogen-natural gas blend containing water vapour) can create conditions for HE in aluminum alloys, although the standard does not specify the acceptable level of moisture content for the use of aluminum alloys in hydrogen service.

3.1.2.3 Cast Iron

Studies have been performed on the effect of hydrogen on cast iron (i.e., iron-carbon alloys with carbon content greater than 2% by weight). Cast iron with graphite flakes in the ferrous matrix, referred to as grey cast iron, which is typically used for pipes, has been proven particularly susceptible to HE [46]. The increase in graphite flakes diameter sizes resulted in greater concentrations of hydrogen absorption, leading to increased HE and decreased overall ductility. ASME B31.12 [15] Non-mandatory Appendix A states that the use of cast iron is not acceptable for hydrogen pipelines.

3.1.2.4 Copper Alloys

Copper alloys containing oxygen can experience adverse hydrogen effects, as hydrogen may form water when reacting with oxygen in solid solution or oxide inclusions [38]. However, commonly used copper alloys are deoxidized and unlikely to experience HE [45].

"Hydrogen exposure risks to non-metallics include permeability, physical stability, frictional wear, rapid cycling effects, and material contamination."

3.1.2.5 Non-Metallic Pipes

Non-metallic materials are used in a variety of pipeline infrastructure, including compressors, seals, valves, and actuators. Polyethylene (PE), polyvinyl chloride (PVC), and acrylonitrile butadiene styrene are typically used as pipe materials for gas distribution lines. Hydrogen exposure risks to non-metallics include permeability, physical stability, frictional wear, rapid cycling effects, and material contamination [47].

3.1.2.5.1 PE Pipes

Kane [48] showed that PE pipe did not exhibit any degradation when exposed to pure hydrogen. In PE pipes, the permeation rate of hydrogen is five-times higher than that of natural gas, however, the overall loss of hydrogen is generally small and considered safe provided proper venting is achievable [49]. This loss due to permeation through the pipeline walls was deemed insignificant in comparison to the losses associated with poor joints and other defects [50]. Laboratory testing, as part of the NaturalHy project, also showed that the long-term exposure effects of hydrogen on ageing PE pipes were insignificant and the permeation coefficients slightly increased [28].

A study of hydrogen permeability in PE at pressures 0.1 to 0.7 MPa and temperatures from 3 to 37 °C by Zheng *et al.* [51] found that hydrogen permeability increases with increasing temperature. This study also suggests that insulating PE piping might reduce the influence of surrounding temperature on hydrogen permeability; however, influence of pressure on hydrogen permeability was found to be negligible.

3.1.2.5.2 PVC Pipes

Similar to PE pipes, no major concern pertaining to ageing effects on PVC pipe materials has been observed in the hydrogen environment [48]. However, hydrogen leaks due to gas permeation appear to be higher compared with methane (the major component of natural gas), but not as alarming from an engineering perspective as observed in PE pipes [28], [51]. However, these leaks should be considered when assessing the economics and environmental impacts of a project.

3.1.2.5.3 Composite / Fibreglass

Fibre Reinforced Polymers (FRP) are composite materials typically consisting of carbon fibre or glass fibre embedded in a resin matrix (also referred as fibreglass). A study by Humpenöder [52] suggests lower hydrogen permeation through both glass fibre / epoxy crossplies and carbon fibre / epoxy crossplies than through high-density PE and PVC pipes at 20 °C. The same study also concludes no significant thermal and mechanical cycling effects on the permeation. FRP pipeline service life has been estimated to exceed 50 years in hydrogen service [53]; however, there does not appear to be service history to prove out this estimated life.

3.2 Hydrogen and Hydrogen Blend Pipelines Activities

Hydrogen transportation via pipelines is not new and numerous standards have been developed to support the industry (discussed in Section 3.2.2.2). For many years, various pipeline operators have successfully and safely transported hydrogen as a feedstock to refineries and chemical industries [54]. The hydrogen pipelines network is not as extensive and interconnected as a natural gas network. For example, in Canada, at least 150 km of hydrogen pipelines (see Section 3.2.1.1) compared with ~50,000 km of gas pipelines regulated by the CER [55].

Converting existing natural gas pipelines for transportation of hydrogen either pure or blended with natural gas is viewed as an immediate and cost-effective step toward decarbonization [56]. Although it has been done in the past [54], [57], pipeline conversion from other services to hydrogen service is less common than purpose-built pipelines [58]. Furthermore, pipelines constructed to requirements of natural gas service generally would not meet the minimum requirements of ASME B31.12 [15] for hydrogen service (discussed in Section 3.3).

A summary of currently in-service hydrogen/hydrogen blend pipelines and applicable RCSs is provided to compare pipeline design for natural gas and hydrogen service as well as to identify the potential gaps and recommendations when considering conversion of pipelines for hydrogen service.

3.2.1 In-service Hydrogen and Hydrogen Blend Pipeline Material and Design

3.2.1.1 In-service Hydrogen Pipelines

In-service hydrogen pipelines transport gases with a high concentration of hydrogen, typically almost pure hydrogen. Within North America, these pipelines have been primarily operated by industrial companies such as Air Liquide, Air Products, and Linde in the United States [58], [54], [57] since 1970 [57] and at least three pipelines in Canada [57], [59]. Not all these pipelines were originally designed for hydrogen service; some were successfully converted from other services such as crude oil gathering pipeline by Air Liquide [54]. For the converted hydrogen pipeline, Air Liquide limited pipe hoop stress and pressure and implemented other safety precautionary measures such as thorough inspection, cleaning, and hydrotesting prior to the pipeline conversion into hydrogen service [54].

As of 2005, Air Liquide's hydrogen pipelines in Germany, France, Belgium, and the United States use electric-resistance welded (ERW) pipe, steel grade lower than Gr. 414, shielded metal arc welding (SMAW), and have an operating pressure from 1.72 to 9.6 MPa [54].

In 2005, prior to the publication of the first edition of ASME B31.12, Air Liquide's new pipe specifications included the following [54]:

- Pipe hardness less than 250 BHN. ASME B31.12 [15] does not allow hot tapping when the pipe hardness is 225 BHN or higher.
- CE less than 0.43%.
- Carbon steel grade lower than Gr. 359, aligned with ASME B31.12 [15] guidance on the use of lower-strength steels.
- Sulfur and phosphorus content lower than 0.015%, aligned with ASME B31.12 [15] on phosphorus content when Option B is used.
- Charpy impact energy greater than 35 J, more stringent than the requirements of ASME B31.12 [15].
- Normalized heat treatment.

In the United States, information about hydrogen pipelines can be obtained from the Pipeline and Hazardous Materials Safety Administration (PHMSA) database [60]. The database contains information on over 2,400 km of hydrogen pipelines, with a typical nominal pipe size of 20" (508 mm) or less. According to the database, most pipelines were installed after 1970, and most have a pipe hoop stress lower than 50% of SMYS. The carbon steel of the hydrogen pipelines in the United States are typically low- to medium-strength grade steels (Grade B, X42, and X52) [58]. In general, the aforementioned attributes of the US hydrogen pipelines, namely hoop stress relative to pipe SMYS, steel grade, and vintage, appear to be similar to the existing Canadian natural gas intraprovincial transmission pipelines discussed in Section 3.1.1.1.1.

“In Canada, there are currently at least three in-service hydrogen pipelines.”

In Canada, there are currently at least three in-service hydrogen pipelines: Air Products’ 48-km pipeline in Alberta and 31-km pipeline in Ontario [57], [59], and a 60-km pipeline in Alberta operated by Linde [59]. The 48 km pipeline consists of 305-mm and 406-mm systems with MOP of 6,723 kPa gauge pressure using Grade 359 Category II pipes [61]. No information on pipeline material and design specifications were found for the other two hydrogen pipelines.

Information on in-service hydrogen pipelines in Australia is unavailable. However, a feasibility study [62] on conversion of a 43-km transmission pipeline to pure hydrogen service is currently underway. This study could provide valuable information for the conversion of Canadian natural gas transmission lines since the pipelines’ steel grade and maximum allowable operating pressure (MAOP) are similar to Canadian intraprovincial natural gas transmission pipelines. The study reports that the assessed pipe segments consist of API 5L X52 steel with 355.6 mm diameter and 5.56 to 7.92 mm wall thickness. The pipeline’s current MAOP is 5.6 MPa gauge pressure, and the current operating pressure is below 4.1 MPa gauge pressure. The pipe hoop stress is up to 50% SMYS. The first phase of testing confirmed the technical viability of the pipeline to transport hydrogen; the second phase appears to be ongoing and is expected to prove the operational capacity of the existing gas transmission pipeline to transport pure hydrogen or hydrogen-natural gas blend.

3.2.1.2 In-service Synthetic Natural Gas Pipelines (SNG)

SNG is composed mainly of methane (i.e., the primary component of natural gas), with a small amount of hydrogen. This composition is similar to that of hydrogen-natural gas blends at hydrogen blend levels of 12% or lower hydrogen in the gas admixture. In the United States, at least two companies operate SNG pipelines: Hawaii Gas and Dakota Gasification Company (DGC).

Hawaii Gas operates a 35-km SNG transmission line consisting of X52 (Gr. 359) carbon steel pipes operating at lower than 40% SMYS pipe hoop stresses, and distribution lines with 161 km total length consisting of low- to medium- carbon steel grade (less than or equal to X52 [Gr. 359]) and PE pipes [63]. The MAOP of the transmission line is 3.5 MPa, and the system typically operates between 2.4 to 3.1 MPa corresponding to 25% to 32% of SMYS pipe hoop stress [64]. The transported SNG contains approximately 12% hydrogen [63]. From the standpoints of pipe materials (carbon steel and PE), steel grades, and maximum pipe hoop stresses relative to the pipe SMYS, the Hawaii Gas transmission line appears to be similar to existing Canadian intraprovincial transmission pipelines discussed in Section 3.1.1.1.1.

DGC operates two transmission SNG pipelines built in 1984: a 56 km, 24″ (610 mm) pipeline and a 6.4 km, 10″ (254 mm) pipeline [65]. The SNG consists of 95%

methane, 3.1% hydrogen, and 1.1% CO_2 with an MAOP of 9.9 MPa [66]. The PHMSA database [60] indicates that both pipelines operate at 60% to 72% SMYS. These pipelines appear to have similar pipe size, MAOP, and pipe hoop stresses relative to the pipe SMYS as some Canadian natural gas interprovincial transmission pipelines discussed in Section 3.1.1.1.2. However, the material specifications such as steel grade for the DGC pipelines are unknown.

3.2.1.3 Hydrogen Blending Demonstration Projects

Hydrogen-natural gas blending demonstration projects involve purposely adding hydrogen to natural gas pipelines to create hydrogen-natural gas blends. Currently, only a few in-service transmission pipelines transport hydrogen-natural gas blends. Examples include:

- The Gasunie 7-km pipeline in the Netherlands transporting pure hydrogen and 70% hydrogen blend with methane, converted from a natural gas pipeline [67]. The 1996-built pipe is 16″ (406 mm) in diameter and 0.24″ to 0.3″ (6.1 mm to 7.6 mm) in wall thickness. The L415MB and St.E 415.7 TM steel grade pipes meet the requirements of EN 10208-2 [68] and have the equivalent SMYS as CSA Z245.1 Gr.414 steel pipes. The pipeline's design pressure is 960 psi (6.6 MPa), and it operates up to 55% of SMYS [67]. This example shows that a transmission pipeline conversion is possible, although the pipe hoop stresses relative to the pipe SMYS and the steel grade are lower than typical Canadian natural gas interprovincial transmission pipelines discussed in Section 3.1.1.1.2.
- A Snam pipeline in Salerno, Italy, blends 5% hydrogen into their transmission network [69]. The system's operating conditions and pipe specifications could not be compared with typical Canadian pipelines due to lack of available information.

Hydrogen blending projects in distribution systems are more common and have a larger body of in-service examples. Within Canada, notable examples include:

- Enbridge's Low Carbon Energy Project (LCEP) in Markham, Ontario, injects up to 2% hydrogen into the 168.3-mm external diameter with 4.78-mm wall thickness pipeline meeting CSA Z245.1 Gr. 359 requirements [70]. The pipeline MOP of 1,200 kPa corresponds to 6% of pipe SMYS. The hydrogen blended gas is also transported in a PE pipe meeting the requirements of CSA B137.4. The PE pipe segments are 219.1 mm (NPS 8) external diameter, 16.23 mm wall thickness, and 440 kPa MOP [70]. The pipeline, pressure-regulating facility and associated metering equipment in this project would be designed in accordance with CSA Z662:19 [71], which was prior to the inclusion of provisions addressing hydrogen service in the standard. ASME B31.12 [15] was part of the project's design considerations [70].
- As of October 2022, ATCO began blending 5% hydrogen into a natural gas distribution system in Fort Saskatchewan, Alberta, which serves 2,100 customers [72]. However, the system's operating conditions and pipe specifications were not found.

3.2.2 Regulations, Codes, and Standards on hydrogen pipelines

3.2.2.1 Regulations

3.2.2.1.1 Canada

Pipelines in Canada are regulated at the federal or provincial level. Currently, federal and provincial regulations within Canada do not make specific reference to hydrogen or hydrogen blended pipelines, yet each typically references CSA Z662 for design, construction, operation, modification, discontinuation, and abandonment of pipelines.

Federal Regulations

Federally regulated pipelines are required to adhere to the requirements of the Onshore Pipeline Regulations (OPR) SOR/99-294 [73]. While the OPR contains no specific reference to hydrogen or hydrogen blended pipelines, it states that design, construction, operation, or abandonment of pipelines that transport liquid or gaseous hydrocarbons must be in accordance with the latest edition of CSA Z662. CSA Z662:23 [6], through Clause 17, provides additional provisions specific to hydrogen gas service, both for new pipelines designed for hydrogen or hydrogen blend service.

Provincial Regulations

Provincially regulated pipelines are required to adhere to the requirements of the provincial regulations outlined in Table 8.

Table 8: Summary of Canadian provincial pipeline regulations

Province	Regulator	Act/Regulation	Description
British Columbia	British Columbia Energy Regulator (BCER)	Energy Resources Activities Act (SBC 2008, c 36) [74] / Pipeline Regulation (BC Reg 281/2010) [75]	No specific reference to hydrogen or hydrogen blended pipelines. Requires permit holders to design, construct, operate, maintain, deactivate, reactivate, or abandon in accordance with CSA Z662. Under Bill 37 Energy Statutes Amendment Act, 2022, the definitions of "energy resource" and "natural gas" per the Energy Resources Activities Act (formerly Oil and Gas Act) were added or changed to include hydrogen.
Alberta	AER	Pipeline Act (Revised Statutes of Alberta 2000 c P-15) [76] / Pipeline Rules (Alberta Regulation 91/2005) [77]	No specific reference to hydrogen or hydrogen blended pipelines. Requires that permit holders design, construct, operate, maintain, deactivate, reactivate, or abandon in accordance with CSA Z662.
Saskatchewan	Ministry of the Economy	The Pipelines Act (Statutes of Saskatchewan c P-12.1) [78] / The Pipelines Administration and Licensing Regulations (Statutes of Saskatchewan c P-12.1 Reg 2) [79] / Saskatchewan Pipelines Code (Directive PNG034) [80]	No specific reference to hydrogen or hydrogen blended pipelines. Requires that design, construction, operation, modification, discontinuation, and abandonment of pipelines are in accordance with CSA Z662.
Manitoba	Manitoba Public Utilities Board	The Public Utilities Board Act (C.C.S.M. c. P280) [81], The Gas Pipe Line Act (C.C.S.M. c G50) [82] / The Oil and Gas Act (C.C.S.M. c O34) [83] / Drilling and Production Regulation (M.R. 111/94) [84]	No specific reference to hydrogen or hydrogen blended pipelines. The Public Utilities Board Act and Gas Pipe Line Act require adoption of relevant codes, rules, or standards prepared and published by the Canadian Standards Association. Order No. 178/19 requires that operators comply with CSA Z662:19 [71]. The Oil and Gas Act contains no specific reference to hydrogen or hydrogen blended pipelines and no reference to CSA or other standards. Regulations under the Oil and Gas Act apply to upstream (drilling and production) pipelines and flowlines; no reference was found to transmission or distribution pipelines.
Ontario	Ontario Energy Board / Technical Standards and Safety Authority	Technical Standards and Safety Act (S.O. 2000 c 16) [85] / Oil and Gas Pipeline Systems Code Adoption Document Amendment (FS-253-20) [86] / Oil and Gas Pipeline Systems (Ontario Regulation 210/01) [87]	No specific reference to hydrogen or hydrogen blended pipelines. Oil and Gas Pipeline Systems Code Adoption Document requires that companies comply with CSA Z662:19 [71].

Province	Regulator	Act/Regulation	Description
Quebec	Régie de l'énergie Québec	Regulation respecting petroleum exploration, production and storage licenses, and pipeline construction or use authorization (CQLR c S-34.1, r. 3) [88]	No specific reference to hydrogen or hydrogen blended pipelines. Requires that any authorization holder who designs, constructs, uses, maintains, or temporarily or permanently ceases to use a pipeline must comply with CSA Z662.
New Brunswick	New Brunswick Energy and Utilities Board	Pipeline Act (c P-8.5) [89] / Pipeline Regulation (NB Reg 2006-2) [90]	No specific reference to hydrogen or hydrogen blended pipelines. Requires permit holders to design, construct, operate, maintain, deactivate, reactivate, or abandon pipelines that transport liquid or gaseous hydrocarbons or minerals in accordance with CSA Z662.
Nova Scotia	Nova Scotia Utility and Review Board	Pipeline Act [91] (R.S., c. 345, s. 1.) / Pipeline Regulations [92] (Nova Scotia) (N.S. Reg. 199/2004)	No specific reference to hydrogen or hydrogen blended pipelines. Requires that permit holders design, construct, operate, maintain, deactivate, reactivate, or abandon pipelines that transport liquid or gaseous hydrocarbons in accordance with CSA Z662.
Newfoundland and Labrador	N/A	N/A	There are no natural gas pipelines in this province [93]. The Petroleum and Natural Gas Act does not apply to onshore pipeline distribution [94].
Prince Edward Island	N/A	N/A	This province is not connected to a natural gas distribution system [93]. The Oil and Natural Gas Act does not apply to onshore pipeline distribution [94].
Northwest Territories	Office of the Regulator of Oil and Gas Operations	Oil and Gas Operations Act (SNWT 2014,c.14) [95]	No specific reference to hydrogen or hydrogen blended pipelines or CSA Z662. Several active pipelines in the Northwest Territories are regulated by the CER. A local distribution company is regulated by the Northwest Territories Public Utilities Board [93].
Yukon	N/A	N/A	This territory does not have any natural gas pipelines currently in operation [93].
Nunavut	N/A	N/A	This territory does not have any natural gas pipelines [93].

3.2.2.1.2 United States

In the United States, Title 49 of Code of Federal Regulations (CFR) Part 192 Minimum Federal Safety Standards for Transportation of Natural and Other Gas by Pipeline were promulgated with prescriptive requirements based on ASME B31.8 [96] for pipelines transporting gas. CFR Part 192 broadly defines "gas" as natural gas, flammable gas, or gas that is toxic or corrosive. Hence, as a flammable gas, hydrogen meets the definition of "gas," and pipelines transporting blended and pure hydrogen gas are required to meet the requirements of CFR Part 192. However, CFR Part 192 does not contain specific hydrogen requirements, except an exemption from odorization requirements if it is being used as feedstock for manufacturing [97]. As of April 2023, no US state appeared to have additional safety requirements for pipelines for hydrogen service.

3.2.2.1.3 United Kingdom

In the United Kingdom, the Pipelines Safety Regulations 1996 [98] apply to utility pipelines, including gas transmission and distribution pipelines. The regulations are performance-based rather than prescriptive and contain a general set of provisions for all pipelines, plus additional requirements to identify hazard prevention methods and develop emergency response plans for pipelines carrying "dangerous fluids."

Pipelines carrying hydrogen and blended gas are therefore included implicitly, as the gases are considered "dangerous fluids" if flammable in air and conveyed in the pipeline at an absolute pressure above 8 bar (800 kPa). Hydrogen does not meet the other definitions of "dangerous fluid" laid out in Schedule 2 of the Pipelines Safety Regulations 1996.

However, the Gas Safety (Management) Regulations 1996 [99] apply to gas distribution networks, including pipelines that transport gas to a distribution network. These regulations require that the hydrogen content of the gas be less than 0.1% (molar). Exemptions may be allowed if the regulatory agency "is satisfied that the health and safety of persons" will not be negatively affected by gas containing higher hydrogen concentrations.

To purposely address gas containing hydrogen, efforts to establish standards have been undertaken by organizations such as the Institution of Gas Engineers and Managers (IGEM). Developed standards include the HY Series for hydrogen, the TD Series for transmission and distribution (listed in Section 3.2.2.2), and others pertaining to other aspects of natural gas utilization. However, these standards appear not to have been adopted by the regulations.

3.2.2.1.4 European Union (EU)

In the EU, pipelines are regulated at the EU and national level. Extensive review of EU pipeline regulations is beyond the scope of this study. However, it appears that there is an ongoing effort by the European Committee for Standardization (CEN) [100] technical committee CEN/TC 234 to standardize hydrogen blend pipelines, particularly the injection of hydrogen and the mixture of hydrogen with natural gas in the gas infrastructure.

3.2.2.2 Standards and Codes

This section includes the summary of relevant transmission and distribution standards and codes for natural gas and hydrogen pipelines. The summary is intended to provide insights when comparing existing infrastructure, blending pilot projects, and in-service hydrogen pipelines with hydrogen service requirements in this study.

3.2.2.2.1 Transmission Pipelines

Introducing hydrogen into an existing federally regulated pipeline system is considered a change of service according to the Canadian OPR (SOR/99-294) [73], which necessitates changes to the design requirements in accordance with CSA Z662. SOR/99-294 references "CSA Standard Z662 entitled Oil and Gas Pipeline Systems, as amended from time to time" [73], meaning that it adopts the latest edition of CSA Z662, which is CSA Z662:23 [6], as of the time of this publication.

CSA Z662:23 [6] specifies that operators shall perform engineering assessments that include material selection and pipeline design addressing the potential adverse effects of hydrogen on pipeline materials. CSA Z662:23 [6] also cites ASME B31.12 [15] or IGEM/TD/1 Supplement 2 as additional guidance for hydrogen service.

"As hydrogen can have detrimental impacts on pipeline materials, current standards that do not specify material requirements for hydrogen services will need to be updated with supplemental requirements."

ASME B31.12 [15] is widely considered the applicable standard for high-pressure hydrogen pipelines. ASME B31.12 [15] Non-mandatory Appendix A also refers to EIGA Doc 121 [38] as guidelines on tailoring the metallurgy of carbon steels for hydrogen service and good practices for hydrogen gas pipelines. While ASME B31.12 [15] is cited in some country-specific standards, it does not appear to be mandated in regulations for pipelines containing hydrogen in any jurisdiction in Canada and the United States, as discussed in Section 3.2.2.1. Table 9 depicts a non-exhaustive list of standards and codes for gas pipelines worldwide. Table 9 shows some international and region/country-specific pipeline standards such as BS EN 14161 [101] (UK), NEN 3650-1 [102] (the Netherlands), BSI PD 8010-1 [103] (UK), and ISO 13623 [104] (international) allow hydrogen service but do not specify the applicable material requirements. As hydrogen can have detrimental impacts on pipeline materials, current standards that do not specify material requirements for hydrogen services will need to be updated with supplemental requirements. These requirements would be applied to ensure the infrastructure integrity. Operators in countries where the national standards do not address hydrogen such as Australia appear to be attempting to meet the ASME B31.12 [15] requirements as discussed by APA Group pertaining to their and Australia's first hydrogen pipeline conversion project [62]. Other standards such as IGEM/TD/1 Supplement 2 [105] (UK) and DVGW G 409 [106] (Germany), while allowing and specifying material requirements for hydrogen, refer to the requirements of ASME B31.12 [15], either as published or with some adjustments.

ASME B31.12 [15] provides guidance on steel pipeline conversion to hydrogen service, however, existing pipeline systems designed to meet the minimum requirements of natural gas service generally do not meet the hydrogen pipeline requirements, further discussed in Section 3.3. For instance, many transmission lines operate at maximum pipe hoop stresses as high as 80% of SMYS in Class 1 Locations (e.g., segments of Canadian interprovincial transmission pipelines), while the ASME B31.12 [15] prescriptive stress-based design approach (Option A) allows only up to 50% of SMYS in Class 1 Locations for fracture control, depending on factors such as location, steel grade, and pipe seam types. This will require a pipe MOP reduction or replacement, or both. Further discussion on standards gaps and potential challenges can be found in Section 3.3.

Prior to the first edition of ASME B31.12 in 2008, some hydrogen pipelines were constructed to the sour service requirements of ANSI/NACE MR0175 [107], developed for the H_2S environment. Also, the SNG transmission pipelines resembling natural gas-hydrogen blend service discussed in Section 3.2.1.2 were built in the United States in 1974 (Hawaii Gas pipeline) and 1984 (DGC pipelines), designed primarily for conventional natural gas pipeline practices.

Table 9: Summary of standards and codes for gas pipelines

Standards	Publication year	Country of Adoption	Allow transportation of H_2	Material Requirements for H_2
CSA Z662 [6] Oil and Gas Pipeline Systems	2023	Canada	Yes	Yes, through engineering assessment
ASME B31.8 [96] Gas Transmission and Distribution Piping Systems	2022	International	Not addressed	No
ASME B31.12 [15] Hydrogen Piping and Pipelines	2019	International	Yes ≥ 10%	Yes
EIGA Doc 121 [38] Hydrogen Transportation Pipelines Note: EIGA Doc 121 was prepared and intended for use by all International Harmonization Council members: AIGA, CGA, EIGA, and JIMGA, with regional editions of AIGA 033 [108], and CGA G-5.6 [34]	2014	International	Yes	Yes
IGEM/TD/1 [109] Steel Pipelines for High Pressure Gas Transmission	2021	UK	Not addressed	No
IGEM/TD/1 Supplement 2 [105] High Pressure Hydrogen Pipelines	2021	UK	Yes	Yes, cites ASME B31.12 [15]
DVGW G 409 [106] Conversion of High Pressure Gas Steel Pipelines for a Design Pressure of more than 16 bar for Transportation of Hydrogen	2020	Germany	Yes	Yes, cites ASME B31.12 [15]
AS/NZS 2885.1 [110] Pipelines - Gas and Liquid Petroleum, Part 1: Design and Construction	2018	Australia and New Zealand	Not addressed	No
BS EN 14161 [101] Petroleum and Natural Gas Industries Pipeline Transportation Systems	2011	EU	Yes	No
NEN 3650-1 [102] Requirements for pipeline systems – Part 1: General requirements	2020	Netherlands	Yes	No
ISO 13623 [104] Petroleum and Natural Gas Industries – Pipeline Transportation Systems	2017	International	Yes	No
BS PD 8010-1 [103] Pipeline Systems – Part 1: Steel Pipelines on Land – Code of Practice	2015	UK	Yes	No
ANSI/NACE MR0175/ISO 15156 [32] Petroleum and natural gas industries – materials for use in H_2S-containing environments in oil and gas production	2021	International	Not addressed	No
ISO/TS 10839 [111] Polyethylene pipes and fittings for the supply of gaseous fuels Code of practice for design, handling, and installation	2022	International	Yes	No

Table 10: Summary of standards and codes for gas pipelines specific to distribution systems

Standards	Edition	Country of adoption	Allow transportation of H_2	Material Requirements for H_2
IGEM/TD/3 Supplement 1 [112] Repurposing of Natural Gas (NG) pipelines with MOP not exceeding 7 bar for NG/Hydrogen blends	2022	UK	Yes, up to 20%	Yes
IGEM/TD/13 Supplement 1 [113] Pressure regulating installations for Natural Gas/Hydrogen blended mixtures at pressures not exceeding 7 bar	2021	UK	Yes	Yes

3.2.2.2.2 Distribution Pipelines

CSA Z662:23 [6] also provides requirements for gas distribution pipelines, and as for transmission pipelines, no specific prescriptive requirements for hydrogen service are provided. The requirements of standards and codes such as ASME B31.12 [15] for hydrogen service discussed for transmission pipelines also apply to distribution pipelines. However, many requirements intended for high-pressure pure hydrogen service can be overly conservative and impractical due to the differences in typical pipeline designs and operating conditions of transmission and distribution pipelines (see Section 3.3 for more details).

Additionally, distribution pipelines have more diverse pipeline materials (e.g., PE, PVC, and FRP pipelines) compared with almost exclusively carbon steels in transmission lines and these materials are not covered by ASME B31.12 [15]. Distribution pipelines' specific standards, in addition to standards listed in Table 9, can be found in Table 10. Although IGEM/TD/3 Edition 5 Supplement 1 [112] and IGEM/TD/13 Supplement 1 [113] apply to hydrogen-natural gas up to 7 bar (700 kPa) and 20% hydrogen, distribution mains operate at higher than 700 kPa. One example of such a pipeline is the high-pressure portion of Enbridge's LCEP hydrogen blend project in Markham, Ontario, which operates at 1,200 kPa MOP [70].

3.3 Standards Gap Assessment and Recommendations

This section summarizes the standards gaps and recommendations based on reviewing the existing Canadian natural gas infrastructure, potential hydrogen adverse effects on pipeline materials, research and pilot projects of hydrogen blending pipelines, and applicable RCSs. Table 11 shows the list of identified gaps, with further discussions also provided. The high-priority gaps in Table 11 represent issues that impact a significant portion of Canada's existing natural gas infrastructure or can be potential showstoppers in hydrogen service conversion or both. Medium-priority gaps in Table 11 affect a smaller portion of the existing Canadian natural gas infrastructure or can have moderate impacts on hydrogen service conversion, or both.

3.3.1 Hydrogen – Natural Gas Blends at Low Hydrogen Partial Pressure

CSA Z662:23 [6] defines a hydrogen blend pipeline as a natural gas pipeline system where hydrogen has been added (Clause 17.3.2) [6]. These definitions encompass a broad range of hydrogen concentration in the hydrogen-natural gas mixture from a trace amount of hydrogen to nearly pure hydrogen. CSA Z662:23 [6] requires an engineering assessment prior to introducing hydrogen into an existing pipeline, and also cites ASME B31.12 [15] or IGEM/TD/1 Supplement 2 [105] for additional guidance for hydrogen pipelines.

Table 11: List of identified high and medium gaps

Identified gaps	Priority	Discussion provided in section
Hydrogen–natural gas blends at low hydrogen partial pressure	High	3.3.1
Pipeline design requirements: CSA Z662:23 [6], ASME B31.12 [15], IGEM/TD/1 Supplement 2, and Existing Canadian Infrastructure		
Maximum pipe hoop stress	High	3.3.2.1
Maximum gas moisture content	Medium	3.3.2.2
Material sampling rate	High	3.3.2.3
Pipeline data necessary for hydrogen service conversion	High	3.3.2.4
Pipeline materials and testing requirements		
Charpy absorbed energy of pipe, weld, and HAZ	High	3.3.2.5
Fracture shear area	High	3.3.2.5
SMYS and ultimate tensile strength (UTS)	High	3.3.2.5
Hardness of pipe, weld, and HAZ	High	3.3.2.5
Pipeline materials other than carbon steels		
Transmission pipeline: PE pipe	High	3.3.3.1
Transmission pipeline: composite and fibreglass	Medium	3.3.3.1
Distribution pipeline: PVC and composite	Medium	3.3.3.2

ASME B31.12 [15] excludes gas with less than 10% hydrogen by volume (PL-1.3), which suggests that the guidance does not apply to a gas mixture with less than 10% hydrogen. Meanwhile, IGEM/TD/1 Supplement 2 [105] suggests there is no evidence to confirm that blends containing up to 10% hydrogen by volume do not cause material degradation, although the risk is considered low by the standard [105].

As discussed in Section 3.1.2.1.3, from the material suitability standpoint, system pressure has also been shown to influence the hydrogen effects on pipe materials in addition to hydrogen concentration. Hence, hydrogen concentration by itself may not fully characterize the potential hydrogen effects, and it is the hydrogen partial pressure that should be used for the assessment of material applicability. Hydrogen has been shown to have adverse effects on carbon steel pipe material at low hydrogen partial pressures [11], [114], which could be a result of high system pressures and low hydrogen concentrations. Hence, low hydrogen concentration service can impose material integrity risks, but test data pertaining to hydrogen adverse effects on pipe material at low hydrogen partial pressures is limited and currently considered a data and knowledge gap in the industry.

Recommendation
To address this gap, as further research is conducted, guidance on hydrogen blend service at low hydrogen partial pressure should be developed, including in future CSA Z662 editions. This guidance is crucial for the industry, especially during the initial stages of hydrogen rollout, where projects are likely to transport hydrogen blend at lower hydrogen concentration partly due to emerging hydrogen supply and demand factors.

3.3.2 Pipeline Design Requirements: CSA Z662, ASME B31.12, IGEM/TD/1 Supplement 2, and Existing Canadian Infrastructure

Differences between design requirements for natural gas and hydrogen services must be understood prior to operators repurposing existing infrastructures constructed to meet the requirements of CSA Z662:23 [6] for natural gas pipelines into hydrogen service.

An exhaustive list of differences is not within the scope of this report. Therefore, readers are encouraged to carefully review CSA Z662:23 [6] provisions for hydrogen service and other applicable hydrogen standards such as ASME B31.12 [15] when envisioning hydrogen service conversion to understand where the requirements are different and where they overlap. Important differences and, as applicable, recommendations to address these findings in future updates to CSA Z662:23 [6] are discussed in sections 3.3.2.1 to 3.3.2.3.

3.3.2.1 Maximum Pipe Hoop Stresses

The comparison of maximum pipe hoop stress requirements in Table 12 shows that the limitations of CSA Z662:23 [6] gas application are higher than for ASME B31.12 [15], both for ASME B31.12 [15] Option A and Option B, under typical pipeline temperature (i.e., less than 120 °C) and commonly used materials of construction (i.e., ERW carbon steel pipe).

Therefore, natural gas pipelines meeting CSA Z662:23 [6] requirements generally would not meet ASME B31.12 [15] requirements and operators should anticipate the potential need for MOP reductions unless material fracture properties can be well defined and a detailed engineering assessment can demonstrate sufficient crack tolerance with exposure to hydrogen. For example, in Location Class 1, CSA Z662:23 [6] allows pipe hoop stress up to 80% of SMYS, while ASME B31.12 [15] allows 50% and 72% of SMYS for Option A and Option B, respectively. In this example, the MOP of a pipeline with 10,000 kPa MOP in natural gas system would have to be reduced to 6,250 kPa (with Option A) and 9,000 kPa (with Option B) to meet ASME B31.12 [15] requirements. ASME B31.12 [15] Option B lessens the required MOP reductions, but additional testing such as fracture properties testing under hydrogen environment associated with this option could be impractical for some systems and operators.

The values listed in Table 12 are based on the following pipeline design parameters:

CSA Z662:23 [6]

- Location Factor (L) for gas (non-sour service) general application.
- Design Factor (F) = 0.8.
- Joint Factor (J) = 1.0 for Electric Welded Pipe.
- Temperature Factor (T) = 1.0 for up to 120 °C.
- Maximum pipe hoop stresses (%SMYS) = F x L x J x T.

ASME B31.12 [15]

- **Option A**
  - Design Factor (F) based on Table PL-3.7.1-1.
  - Longitudinal Joint Factor (E) = 1.0 for ERW.
  - Temperature derating factor (T) = 1.0 for up to 250 °F (121 °C).
  - Material performance factor (Hf) from ASME B31.12 [15] Table IX-5A for system pressure less than 2,000 psig (13,789 kPag).
  - Maximum pipe hoop stresses (%SMYS) = F x E x T x Hf.
- **Option B**
  - Same as above, except for design Factor (F) from Table PL-3.7.1-2 and Hf = 1.0.

Table 12: Examples of maximum allowable pipe hoop stress calculations based on CSA Z662:23 [6] gas application, general location and ASME B31.12 [15]

Examples of maximum allowable carbon steel pipe hoop stresses (in %SMYS) CSA Z662:23 [6] and ASME B312.12 [15] Option A and Option B						
Location Class	CSA Z662:23 [6]	ASME B31.12 [15] Option A				ASME B31.12 [15] Option B
		≤ Gr. 359 (X52)	Gr. 414 (X60)	Gr. 448 (X65)	Gr. 483 (X70)	
1	80%	50%	43.7%	38.8%	38.8%	72%
2	72%	50%	43.7%	38.8%	38.8%	60%
3	56%	50%	43.7%	38.8%	38.8%	50%
4	44%	40%	35%	31%	31%	40%

Recommendation

Guidance on applicable maximum pipe hoop stress for hydrogen and hydrogen blend service in Canada should be developed. Particularly for existing natural gas pipelines with higher hoop stresses (30% of SMYS or higher), where the ASME B31.12 [15] Option A requirement would not be met, a path forward should be developed.

3.3.2.1.1 Canadian Intraprovincial Transmission Pipelines

By comparing Table 12 data with the Canadian intraprovincial transmission pipelines data shown in Table 2, Table 13 shows the likelihood that Canadian intraprovincial transmission pipelines made out of carbon steel would meet the ASME B31.12 [15] maximum pipe hoop stress requirements.

ASME B31.12 [15] guidance for steel pipeline conversion, paragraph PL-3.21(l), requires the MAOP selection to limit hoop stresses to 40% SMYS of the pipe at all points on the pipeline if the pipe material cannot be qualified to meet Option A or Option B. This particular guidance was likely developed due to the low risk of a pipeline rupture when operating at low pipe hoop stresses. Intraprovincial transmission pipelines with maximum pipe hoop stress less than 40% SMYS would meet this requirement, although requirements from Option A or Option B should still be considered when possible. Albeit less common, pipeline ruptures in low-stress pipes have occurred in the industry [115], and therefore, the risk is not necessarily zero, especially for low-toughness pipes, and likely in hydrogen service where reduction of carbon steels fracture toughness has been observed.

3.3.2.1.2 Canadian Interprovincial Transmission Pipelines

Interprovincial transmission pipelines utilizing medium- to high-strength carbon steels with greater than 50% SMYS pipe hoop stresses at MOP would exceed the ASME B31.12 [15] Option A hoop stress limits, as discussed in Section 3.1.1.1.2. ASME B31.12 [15]. Option B or MOP reductions, or both, might be the only options of assessment for repurposing these pipelines to hydrogen service. However, even with ASME B31.12 [15] Option B, some segments of interprovincial transmission pipelines might still not be suitable assessment criteria for hydrogen service pipelines such as those utilizing carbon steel Gr. 690, as Option B limits the SMYS of the pipe to 80 ksi (551 MPa).

3.3.2.1.3 Canadian Distribution Mains

Standards containing requirements for hydrogen conversion specific for natural gas distribution mains are limited and not as widely cited as standards developed primarily for transmission pipelines such as ASME B31.12 [15] and IGEM/TD/1 Supplement 2 [105].

Table 13: Alberta intraprovincial transmission pipelines pipe hoop stresses compared with ASME B31.12 [15] Option A and Option B limits

Maximum hoop stress [%SMYS]	% of total pipeline length (~180,000 km)	Meeting ASME B31.12 [15] requirements	
		Option A	Option B
≤ 30%	36%	Likely	Likely
> 30 and ≤ 50%	32%	Depends on Location Class, steel grade, joint type, and temperature	Depends on Location Class, steel grade, joint type, and temperature
> 50%	31%	No	Depends on Location Class, steel grade, joint type, and temperature
Unknown	0.30%	Unknown	Unknown

Recommendation

To inform future updates to CSA Z662:23 [6] for natural gas distribution infrastructure, further review of the applicability of the provisions provided by standards such as ASME B31.12 [15] and IGEM/TD/1 Supplement 2 [105] and the technical basis for these provisions should be undertaken.

When developing guidance or identifying opportunities for standard harmonization, the requirements provided by IGEM/TD/3 Supplement 1 *Repurposing of Natural Gas (NG) Pipelines with MOP Not Exceeding 7 Bar for NG/Hydrogen Blends* [112] could also be considered. While the pressure range in this standard (less than or equal to 700 kPa) likely covers most distribution mains, there are instances where distribution pipelines pressure exceeds this range, and supplemental guidance would need to be developed or directed to the high-pressure pipeline standards. Note that distribution mains operating at pressure higher than 700 kPa may still operate at less than or equal to 30% SMYS pipe hoop stress, lower than the pipes addressed by high-pressure hydrogen pipeline standards such as ASME B31.12 [15], which typically operate at 40% SMYS or higher. ASME B31.12 [15] guidance for steel pipeline conversion, paragraph PL-3.21 (l), requires that the MAOP be selected so to limit hoop stresses to 40% SMYS of the pipe at all points on the pipeline if the pipe material cannot be qualified to meet Option A or Option B. Hence, these low-stress distribution pipelines are not required to meet the requirements of ASME B31.12 [15] Option A or Option B. However, where possible, these requirements should be considered as pipeline ruptures in low-stress pipes have occurred in the industry, although less common [115]. Moreover, despite the low pipe hoop stresses, the risk of distribution pipeline failure still exists. This is because material sampling may be impractical, as many distribution lines cannot accommodate in-line inspections or hydrotesting, resulting in an unknown state of pipe flaws. These flaws could pose a potential risk of failure under hydrogen service. Therefore, until sufficient data are available, and more industry experience has been established, any gas distribution operators contemplating the conversion of existing lines into hydrogen service should perform an engineering assessment, as required by CSA Z662:23 [6].

For pipeline materials in distribution mains other than carbon steels, the IGEM/TD/3 Supplement 1 also covers PE pipes. However, the standard does not cover other pipeline materials found in a small portion of Canadian distribution mains (1% of total length) such as aluminum, PVC, and composite shown in Table 6. While still important to have standards for these materials for hydrogen service, this may be a lower priority compared with the steels and PE pipes that constitute most Canadian distribution mains.

3.3.2.2 ASME B31.12 Gas Moisture Content Exclusion

ASME B31.12 [15] paragraph PL-1.3 (d) states that the standard's requirements do not apply to pipeline systems with a moisture content greater than 20 ppm. Natural gas systems can have an acceptable moisture content up to 88 ppm (65 mg/m^3) [116], thus, a moisture content of 20 ppm limit is considered low. This can cause potential ambiguity regarding the applicability of ASME B31.12 [15] requirements and guidance to natural gas pipeline systems contemplated for conversion to hydrogen or hydrogen blend service.

> **Recommendation**
> To address this ambiguity in future updates to CSA Z662:23 [6], further assessments of the technical basis for gas moisture content requirements should be considered to determine the applicability, conservatism, and potential alternatives.

3.3.2.3 ASME B31.12 Material Sampling Rate for Conversion

CSA Z662:23 [6] does not provide explicit requirements on the material sampling frequency (i.e., the number of pipe material sample collected per certain distance) for the engineering assessment prior to hydrogen conversion. ASME B31.12 [15], cited by CSA Z662:23 [6], provides guidance on this issue. ASME B31.12 [15] paragraph PL-3.21 subparagraphs (k) and (n) require the sampling rate of one examination per 1.6 km of pipeline for material characterization. Material verification testing is important, but the reasoning behind the recommendation of one examination per 1.6 km (one sample per mile) within ASME B31.12 [15] is unclear. Distance-based sampling may not accurately characterize the populations of line pipe in the pipeline system. For instance, if a transmission line is built by a single manufacturer in a similar manner, one sample per 1.6 km may provide a large and unnecessary statistical sampling size, testing similar material. Yet if the pipeline has multiple pipe sizes, grades, vintages, or manufacturers, one sample every 1.6 km may not be enough to capture the material variation. This requirement can be impractical, especially for long-distance transmission pipelines (e.g., several hundreds of kilometres).

> **Recommendation**
> To clarify and provide more practical material sampling frequency requirements in future updates of CSA Z662:23 [6], the practicality of the ASME B31.12 [15] requirement for the engineering assessment required in CSA Z662:23 [6] Clause 17 should be evaluated. If applicable, alternative guidance such as utilizing a statistical approach instead of distance-based approach could be developed.

3.3.2.4 Pipeline Data Necessary for Hydrogen Service Conversion

Natural gas pipelines designed to meet the minimum requirements of CSA Z662:23 [6] using CSA Z245.1 [12] Cat. I and II pipes are unlikely to have complete data to conduct an engineering assessment when the requirements of ASME B31.12 [15] are considered. Table 14 provides examples of potentially available data from pipelines designed to CSA Z662:23 [6] and CSA Z245.1 [12] compared with ASME B31.12 [15] requirements. Table 14 shows that CSA Z662:23 [6] and CSA Z245.1 [12] for natural gas service do not require operators to collect data on parameters such as impact energy in the girth weld and girth weld HAZ, as required by ASME B31.12 [15] and CSA Z662:23 [6] Clause 17 for hydrogen or hydrogen blend service. Hence, it is likely that the operator would need to collect additional data to evaluate the pipes against the ASME B31.12 [15] requirements discussed in Section 3.3.2.5. The data collection typically involves excavation, pipe sample collection, and laboratory testing. Combined with the sampling rate of one sample every 1.6 km discussed in Section 3.3.2.3, data collection, testing, and assessment could be impractical.

> **Recommendation**
> To balance the needs for representative material characterization, public safety, and practicality of the effort, the pipeline data requirements for the engineering assessment should be evaluated to determine the potential of providing guidance on alternative solution(s). Guidance in addressing potential data gaps such as impact energy for girth welds in existing natural gas infrastructures would be useful for the operators to further accelerate the engineering assessment required by CSA Z662:23 [6] Clause 17.

Table 14: Examples of data collection requirements of CSA Z662:23 [6] and CSA Z245.1 [12] compared with ASME B31.12 [15]

Parameter	Location	Required by CSA Z662:23 [6] and CSA Z245.1 [12] for natural gas service		Required by ASME B31.12 [15]
		Cat. I	Cat. II	
Impact energy	Pipe body	No	Yes	Yes
	Seam weld	No	Yes	Yes
	Seam weld – HAZ	No	Yes	Yes
	Girth weld	No	No (see Note)	Yes
	Girth weld – HAZ	No	No (see Note)	Yes
Hardness	Pipe body	No	Yes	Yes
	Seam weld	No	Yes	Yes
	Seam weld – HAZ	No	Yes	Yes
	Girth weld	No	Yes	Yes
	Girth weld – HAZ	No	Yes	Yes

Note: *Required by CSA Z662:23 [6] Clause 17 specific for hydrogen or hydrogen blend service.*

3.3.2.5 Pipe Materials and Testing

Differences between line pipe specifications for natural gas or blended natural gas service designed to CSA Z662:23 [6] and ASME B31.12 [15] in a form of a line-by-line comparison are outside the scope of this study. However, a non-exhaustive list of the relevant differences can be found in Table 15. Table 15 shows that existing natural gas pipeline designed to minimum requirements of CSA Z662:23 [6] and CSA Z245.1 [12] generally would not meet the pipe and weld hardness, Charpy absorbed energy, and minimum fracture shear area requirements set by ASME B31.12 [15]. Additionally, pipelines using higher strength steels such as grades higher than Gr. 550 would exceed the maximum SMYS set by ASME B31.12 [15] and also would be unlikely to meet the limits on UTS.

Recommendation
To address differences in line pipe specifications between CSA Z662:23 and ASME B31.12 [15], the requirements and their technical bases should be further evaluated to determine the potential of providing solutions or alternatives to allow existing pipeline conversion to hydrogen service.

Table 15: Pipe material and testing requirements comparison between CSA Z662, CSA Z245.1, and ASME B31.12

Parameters	CSA Z662:23 [6], CSA Z245.1 [12] Gas Service	ASME B31.12 [15]		Note
		Option A PL-3.7.1 (b) (1)	Option B PL-3.7.1 (b) (2)	
Charpy test temperature	CSA Z662 Clause 5.2.1.2 Lower or equal than expected metal temperature	Lower of 0 °C or min. operating (or min pressure testing temperature)	Same as Option A	1
Fracture shear area %	CSA Z662 Table 5.1 CSA Z245.1 Clause 8.4.4.1 ▪ Cat. I – No requirements ▪ Cat. II – 85% (lot average) 60% (test average), 50% (individual)	▪ Charpy – At least 80% (average) for full-size Charpy ▪ Drop weight tear testing (DWTT) – At least 40% (average)	Same as Option A	2
Charpy base metal absorbed energy	CSA Z662 Table 5.1 requirements for pipe body align with CSA Z245.1 Clause 8.4.4.2 ▪ Cat. I – No requirements ▪ Cat. II – 27 J (OD < 457 mm), 40 J (OD ≥ 457 mm) CSA Z662 does not require notch toughness for pipe with < 114.3-mm OD, 6.0-mm WT, or operating stress < 50 MPa (Clause 5.2.2.1) or design temperatures ≥ -30 °C if design stress ≤ $PTSV_1$ (Table 5.1 of CSA Z662).	$CVN = 0.008\ (\sigma^2)\ (RT)^{0.39}$ Where: CVN = full-size specimen CVN energy, ft-lb σ = hoop stress due to design pressure, ksi R = radius of pipe, in. T = nominal pipe wall thickness, in. toughness testing is not required for pipe with < 114.3-mm OD	Same as Option A	3
Charpy weld (weld metal and HAZ) absorbed energy	As stated in the CSA Z662 Table 7.3 Commentary, there are no mandatory requirements for girth weld notch toughness. Pipe weld seam requirements are specified in CSA Z245.1, Clause 8.5 Submerged arc welded pipe with test temp < -5 °C, Cat. II: weld metal and HAZ, 18J Electric-welded pipe Cat. II: Weld zone of pipe with test temp < -5 °C, 27J for OD < 457mm, 40J for OD ≥ 457mm; Weld fusion line, 18J	27 J full-size (average)	Same as Option A	4
Fracture toughness and stress intensity, K_{IA} and K_{IH}	CSA Z662 requires fracture toughness only in specific cases, primarily for engineering critical assessment to determine acceptability of imperfections, as detailed in Annexes J, K, and O.	Not addressed	Tested per KD-1040: Calculated max K_{IA} and K_{IH} may not be less than 50 ksi $\sqrt{in.}$ Values may come from "similar" steels as grouped by Table PL-3.7.1-4 and strength does not exceed material used in qualification tests by more than 5%.	5

Parameters	CSA Z662:23 [6], CSA Z245.1 [12] Gas Service	ASME B31.12 [15]		Note
		Option A PL-3.7.1 (b) (1)	Option B PL-3.7.1 (b) (2)	
UTS	Not addressed	689.5 MPa max (pipe)	758.4 MPa max (pipe & weld)	6
SMYS	Up to 690 MPa	482.6 MPa max	551.6 MPa max	7
Pipe hardness	CSA Z245.1, For non-sour service, pipe seam weld zone hardness is max. 24 HRC (Clause 5.4.4.2) or 30 HRC for grades ≥ 483 (Clause 5.4.4.3). For electric-welded pipe, hardness tests shall be conducted every shift for weld zone and base metal (Clause 8.6) Welded pipe ≥ 323.9 mm OD, max. surface hardness in pipe body is 225 HV and at weld seam is 300 HV (Clause 11.5.7) Sour service requires max. 248 HV in the weld metal and HAZ on weld procedure qualification (Clause 16.3) and max. 22 HRC for pipe body (Clause 16.4) and 248 HV for electric welded pipe weld zone (Clause 16.5)	Hot tapping is not allowed if hardness exceeds 225 BHN (20 HRC) (227 HV)	Same as Option A	8
Production weld hardness	CSA Z662 Fillet and branch welds, weld metal and HAZ max. hardness, cellulosic electrode root pass branch welds is 300 HV, low-hydrogen practice is 350 HV (Clause 7.17.5.2) Sour service requires max. 22 HRC, 250 HV, or 70 HR15N in weld metal and HAZ (Clause 16.6.4)	237 BHN (241 HV) (22 HRC)	Same as Option A	9

Notes

1. The expected metal temperature for pipelines in Canada is likely less than 0 °C, hence, pipelines designed to CSA Z662:23 [6] would be likely to meet ASME B31.12 [15] Charpy test temperature requirement.
2. The Charpy minimum fracture shear area requirements of CSA Z245.1 [12] notch toughness Cat. I and II (required by CSA Z662:23 [6] for gas service) are less stringent (i.e. lower than ASME B31.12 [15] requirements).
3. The minimum required Charpy absorbed energy described in ASME B31.12 [15] is dependent upon hoop stress, pipe wall thickness, and pipe diameter, but the calculated values tend to be lower than 20 J for hoop stress values not greater than about 60% of SMYS. However, if CSA Z245.1 [12] Cat I pipe is used, compared with impact properties with ASME B31.12 [15], would not be possible, and therefore, material verification would be required.
4. CSA Z662:23 [6] requirement on weld fusion line Charpy absorbed energy are less stringent (i.e. lower than ASME B31.12 [15]).
5. In specific cases where CSA Z662:23 [6] requires fracture toughness, the imperfections deemed acceptable in natural gas might no longer be acceptable in hydrogen service due to potential reduction in fracture toughness and accelerated FCGR under hydrogen service. The engineering assessment would have to be done for hydrogen service for these cases.
6. ASME B31.12 [15] limits the allowable UTS, therefore some pipes meeting CSA Z662:23 [6] with high UTS (758.4 MPa or greater) would not meet ASME B31.12 [15].
7. Pipeline segments designed to CSA Z662:23 [6] with pipe grade higher than Gr. 550 would not meet the requirements of ASME B31.12 [15].
8. CSA Z245.1 [12] requirements on pipe hardness are less stringent than ASME B31.12 [15], and therefore, if ASME B31.12 [15] requirements were to be met, hot tapping would not be allowed for line pipes designed to CSA Z245.1 [12].
9. For non-sour service, CSA Z662:23 [6] requirements are less stringent (i.e. higher than ASME B31.12 [15]). For sour service, the requirements of both standards are comparable.

3.3.3 Pipeline Materials Other Than Carbon Steels

3.3.3.1 Transmission Pipelines

Pipeline materials such as aluminum, composite, fibreglass, and stainless steels have been used for intraprovincial transmission pipelines, though less commonly than carbon steels as discussed in Section 3.1.1.1.1. Table 16 shows insufficiency of standards addressing composite, and fibreglass pipes for hydrogen service in transmission lines and considered as a pipeline standard gap in the industry. As discussed in Section 3.1.1.1.1, PE pipes comprise 9% of Alberta's intraprovincial transmission pipelines, and therefore, can be considered as a high priority for further guidance for use in hydrogen service following carbon steels. ISO/TS 10839 [111] appears to be the only PE pipe standard that includes hydrogen service in its scope. Only 2% of Alberta intraprovincial transmission pipelines use composite and fibreglass pipe, so while it is important that these materials be addressed in standards, these updates are expected to be of lower priority than PE and carbon steels.

> **Recommendation**
> Considering the use of PE pipe in intraprovincial transmission pipelines and distribution pipelines, Canadian standards specific for PE pipe for hydrogen / hydrogen blend service should be established. ISO/TS 10839 [111] could serve as a starting point and its adoption in Canada may require further evaluation.

Table 16: Relevant standards for transmission pipelines with materials other than carbon steels

Pipe material	Relevant standards for hydrogen service other than CSA Z662:23 [6]
Stainless Steels	ASME B31.12 [15]
Aluminum	ASME B31.12 [15]
Composite	N/A
Fibreglass	N/A
PE	ISO/TS 10839 [111]

3.3.3.2 Distribution Pipelines

CSA Z662:23 [6] provides considerations for operators when undertaking engineering assessments for converting existing distribution pipelines for hydrogen service. Additional guidance from other standards specific for hydrogen service might also be required. Most natural gas distribution lines utilize carbon steels and PE pipes covered by standards such as IGEM/TD/3 Supplement 1 for hydrogen service, however, other materials such as PVC, aluminum, composite, and cast iron (legacy pipe) are also present in the pipelines. Table 17 shows that currently no relevant standards address PVC and composite for hydrogen service; however, these two materials combined comprise less than 1% of total distribution pipeline lengths as discussed in Section 3.1.1.2.

> **Recommendation**
> While it is important that materials other than carbon steels and PE be addressed in standards, these updates are expected to be of lower priority compared with carbon steels and PE pipes.

Table 17: Relevant standards for distribution pipeline materials for hydrogen service other than carbon steels and PE

Pipe Material	Relevant Standards for Hydrogen Service other than CSA Z662:23 [6]
PVC	N/A
Aluminum	ASME B31.12 [15]
Composite	N/A
Cast Iron	Not allowed by ASME B31.12 [15]

Conclusion

This report highlights the following major findings and recommendations to support standardization efforts for hydrogen and hydrogen blend service utilizing the existing Canadian natural gas infrastructure:

1. Most existing Canadian natural gas pipeline infrastructure uses carbon steel for transmission pipelines and PE pipe for distribution pipelines.

2. The main concerns with PE pipes in hydrogen service include a higher hydrogen permeation rate through the pipe wall. However, hydrogen loss due to permeation through the pipe wall has been observed to be insignificant compared with losses associated with poor joints and other pipe defects. PE pipes have not shown degradation when exposed to hydrogen.
3. Carbon steels, when exposed to hydrogen environments, can experience material degradation, commonly referred to as HE, which includes reduced fracture toughness and an accelerated FCGR.
4. The susceptibility of carbon steel pipelines to such degradation is influenced by various factors such as steel grade, metallurgical characteristics, hydrogen partial pressure, subsurface anomalies, pipe welds, steel hardness, residual strain, operating temperature, presence of inhibiting compounds, sulfur and phosphorus content, CE, and heat treatment.
5. Despite potential hydrogen adverse effects, transporting hydrogen through carbon steel pipelines is not a new concept. The use of purpose-built and converted hydrogen pipelines has been prevalent in North America and worldwide for several decades.
6. As of June 2023, Canadian federal and provincial pipeline regulations do not specifically reference hydrogen or hydrogen blended pipelines, but reference CSA Z662:23 [6] for the design, construction, operation, modification, discontinuation, and abandonment of pipelines. The 2023 edition of CSA Z662:23 [6] includes additional provisions specific to hydrogen gas service through Clause 17 and references ASME B31.12 [15] as an additional guidance document.
7. Differences exist between the requirements of ASME B31.12 [15] and CSA Z662:23 [6], including maximum pipe hoop stress, minimum Charpy absorbed energy, maximum hardness, as well as maximum SMYS and UTS. Pipelines originally designed and constructed for natural gas service are unlikely to meet ASME B31.12 [15]'s minimum requirements for hydrogen service.
8. Recommendations to address the identified gaps include:
   a. Develop guidance on hydrogen blend service at low hydrogen partial pressure.
   b. Guidance on applicable maximum pipe hoop stress for hydrogen and hydrogen blend services should be developed. Particularly for existing natural gas pipelines with higher hoop stresses (30% of SMYS or higher), a path forward should be developed.
   c. Specific for natural gas distribution infrastructure, further review of the applicability of the provisions provided by standards such as ASME B31.12 [15] and IGEM/TD/1 Supplement 2 [105], and the technical basis for these provisions, should be undertaken.
   d. Further assessments of the technical basis for gas moisture content requirements, as stated by ASME B31.12 [15] to not exceed 20 ppm, should be considered to determine the applicability, conservatism, and potential alternatives.
   e. To clarify and provide more practical material sampling frequency requirements in future updates of CSA Z662:23 [6], the practicality of the ASME B31.12 [15] requirement for the engineering assessment required in CSA Z662:23 [6] Clause 17 should be evaluated. If applicable, alternative guidance such as utilizing a statistical approach instead of distance-based approach could be developed.
   f. To balance the needs for representative material characterization, public safety, and practicality of the effort, the pipeline data requirements for the engineering assessment for hydrogen and hydrogen blend services should be evaluated to determine the potential of providing guidance on alternative solution(s).
   g. To address differences in pipeline requirements between CSA Z662:23 [6] and ASME B31.12 [15], the requirements and their technical bases should be further evaluated to determine the potential for providing solutions or alternatives to allow existing pipeline conversion to hydrogen and hydrogen blend services.
   h. Considering the use of PE pipe in intraprovincial transmission and distribution pipelines, standards specific to PE pipe for hydrogen and hydrogen blend services should be established.

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In order to encourage the use of consensus-based standards solutions to promote safety and encourage innovation, CSA Group supports and conducts research in areas that address new or emerging industries, as well as topics and issues that impact a broad base of current and potential stakeholders. The output of our research programs will support the development of future standards solutions, provide interim guidance to industries on the development and adoption of new technologies, and help to demonstrate our on-going commitment to building a better, safer, more sustainable world.

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