

COATING AND LINER FOR HYDROGEN AND NATURAL GAS (H₂-NG) BLENDED GAS NETWORK

BY
MOHAMMED SOFIAN ALI KHALID

A Thesis Presented to the
DEANSHIP OF GRADUATE STUDIES

KING FAHD UNIVERSITY OF PETROLEUM & MINERALS

DHAHRAN, SAUDI ARABIA

In Partial Fulfillment of the
Requirements for the Degree of

MASTER OF SCIENCE

In

PETROLEUM ENGINEERING

DECEMBER 2023

KING FAHD UNIVERSITY OF PETROLEUM & MINERALS

DHAHRAN- 31261, SAUDI ARABIA

DEANSHIP OF GRADUATE STUDIES

This thesis, written by Mohammed Sofian Ali Khalid under the direction of his thesis advisor and approved by his thesis committee, has been presented and accepted by the Dean of Graduate Studies, in partial fulfillment of the requirements for the degree of MASTER OF SCIENCE IN PETROLEUM ENGINEERING.



Dr. Dhafer A. Al Shehri
Department Chairman

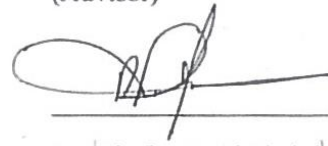


Dr. Suliman Saleh Al-Homidan
Dean of Graduate Studies

Date



Dr. Bashirul Haq
(Advisor)



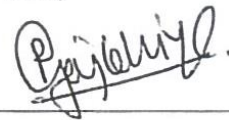
Dr. Dhafer A. Al Shehri
(Co-Advisor)



Dr. Mohammad Mizanur
Rahman
(Member)



Dr. Shirish Patil
(Member)



Dr. Rahul N. Gajbhiye
(Member)



© MOHAMMED SOFIAN ALI KHALID

2023

Dedication

With thanks to Allah for granting me the strength to complete this journey, I dedicate this thesis to my beloved family. Your unwavering support has been my source of strength and inspiration throughout this academic journey. I am profoundly thankful for the love and encouragement you have offered me.

ACKNOWLEDGMENTS

I am deeply grateful to King Fahd University of Petroleum and Minerals (KFUPM) for providing me with the priceless opportunity to be part of their esteemed graduate studies program. Special thanks to the College of Petroleum and Geosciences (CPG), my second home, for offering state-of-the-art facilities that have greatly contributed to my academic achievements. My heartfelt appreciation extends to the faculty, staff, and lab engineers at the CPG for their kindness and support since day one.

I extend boundless gratitude to my advisors, **Dr. Bashirul Haq** and **Dr. Dhafer Al Shehri**, for their invaluable insights, unwavering support, and patience throughout the research process, which has made this academic journey smooth and enriching. I would also like to acknowledge the support and guidance of my committee professors, and express special appreciation to **Dr. Mohammad Rahman** for his relentless efforts and insightful guidance in this work.

I also want to acknowledge my colleagues in the Petroleum Engineering Department for sharing memorable moments and fostering a collaborative academic environment. I extend my heartfelt appreciation to **Mr. Asaad Barri** for his unwavering kindness, invaluable support, and solid presence during challenging times.

Lastly, to my Sudanese mates, your companionship has made this journey not only bearable but also truly enjoyable and livable. Each of these entities has played a significant role in shaping my academic and personal growth, and for that, I am sincerely thankful.

TABLE OF CONTENTS

ACKNOWLEDGMENTS	V
LIST OF TABLES	IX
LIST OF FIGURES	X
LIST OF ABBREVIATIONS	XII
ABSTRACT	XIV
ملخص الرسالة	XVI
CHAPTER 1 INTRODUCTION	1
1.1 Carbon Emissions	1
1.2 Hydrogen Blending in Gas Pipelines (H ₂ -NG)	2
1.3 Knowledge Gaps	3
1.4 Research Objectives	3
1.5 Motivation	4
CHAPTER 2 LITERATURE REVIEW	6
2.1 Research Status in H ₂ -NG Blending	6
2.2 Simulation-Based Studies in H ₂ -NG Blending	11
2.3 H ₂ -NG Blending Projects	12
2.4 Bibliometric Analysis of H ₂ -NG Blending Literature	13
2.5 Hydrogen Safety	19
2.5.1 Production	20
2.5.2 Transportation	21
2.5.3 Storage and Utilization	22
2.6 Corrosion in Pipelines	23
2.6.1 Internal Corrosion	24

2.6.2	External Corrosion	29
2.7	Hydrogen Embrittlement	29
2.7.1	Types.....	30
2.7.2	Hydrogen Source.....	30
2.7.3	Mechanism	30
2.7.4	Consequences.....	31
2.7.5	Protection	32
2.8	Coatings and Liners.....	32
2.8.1	Coatings.....	32
2.8.2	Liners	36
CHAPTER 3 METHODOLOGY		38
3.1	Gas Network Simulation	39
3.1.1	PIPESIM Software	39
3.1.2	Pipeline Description	39
3.1.3	Model Description.....	44
3.2	Coating Development	47
3.2.1	Materials.....	48
3.2.2	Polyurethane (PU) dispersion preparation.....	48
3.2.3	Polyurethane Phosphol (PU/PP) dispersion preparation	49
3.2.4	MOF prepartation and addition to PU/PP dispersion	49
3.2.5	Preparation of Polymer Film	50
3.2.6	Coating application on metal sheets	50
3.2.7	Exposure to hydrogen.....	51
3.2.8	Characterization	53
CHAPTER 4 RESULTS AND DISCUSSION.....		54
4.1	Gas Network Simulation	54
4.1.1	Model Validation.....	54
4.1.2	H ₂ Sensitivity analysis.....	57
4.2	Coating Development	64
4.2.1	Stability of dispersion.....	64
4.2.2	Polymer Identification.....	65
4.2.3	Coating dispersions properties	66
4.2.4	Fire Retardancy	72
4.2.5	UV Resistance	74
4.2.6	Corrosion Resistance.....	77
4.2.7	Coating Exposure to H ₂ -CH ₄ blends	77
CHAPTER 5 CONCLUSIONS AND RECOMMENDATIONS		81
5.1	Conclusions.....	81

5.1.1	Gas Network Simulation	81
5.1.2	Coating Development.....	82
5.2	Recommendations	83
5.2.1	Gas Network Simulation	83
5.2.2	Coating Development.....	83
REFERENCES.....		84
VITAE		112

LIST OF TABLES

Table 1: Summary of the literature on H ₂ -NG blending.....	8
Table 2: The top 10 cited articles in H ₂ -NG blending in gas networks.	16
Table 3: Most productive countries in H ₂ -NG blending in gas pipelines.	18
Table 4: Temperature ranges for some PO coatings.	35
Table 5: GGP general information.....	41
Table 6: Compression stations data.	43
Table 7: Gas specifications and characteristics for Mondarra and GGP.	44
Table 8: Gas composition used in simulation (base case).	44
Table 9: BCs of GGP nodes used in the model.	45
Table 10: Higher Heating Value limits of WA gas transmission networks.....	45
Table 11: Formulation of pristine PU coating.	48
Table 12: Formulation of coating with defined Phosphol content.....	49
Table 13: Formulation of coating with defined MOF content.	50
Table 14: GGP capacities reported between AUG 2022 - 2023.....	54
Table 15: Comparison between real capacity data and model results for P-specified nodes.	55
Table 16: Flow rates and pressures at system nodes of the base case (validated case). ...	56
Table 17: Relative change in gas properties with multiple H ₂ fractions compared to base case.....	59
Table 18: Pressure losses between compressors with different H ₂ fractions.....	61
Table 19: Properties of coating dispersions.	67

LIST OF FIGURES

Figure 1: CO ₂ emissions from multiple industries.....	1
Figure 2: Schematic of integrated energy system for hydrogen production and blending.	6
Figure 3: Geospatial distribution of H ₂ -NG blending projects.	13
Figure 4: The global publications trend of H ₂ -NG blending in gas pipelines.	15
Figure 5: Journals with at least two publications in H ₂ -NG blended gas networks.....	17
Figure 6: Contribution of the top countries to the total H ₂ -NG blended networks documents.	18
Figure 7: Network visualization of all H ₂ -NG blending keywords (from VOSviewer). ..	19
Figure 8: Energy content regarding heating values for H ₂ and other fuels.....	20
Figure 9: The proportion of incidents occurrence through LH processing.....	21
Figure 10: The potential causes of pipeline failure incidents in hydrogen transportation.....	22
Figure 11: Global hydrogen consumption by industries in 2021.....	23
Figure 12: Mesa corrosion of tubular steel induced by CO ₂ -rich hydrocarbon streams. .	25
Figure 13: Mechanism of SSC.....	27
Figure 14: HIC initiation mechanism.	28
Figure 15: SCC mechanism.	29
Figure 16: Factors that induce initiation of HE processes.	31
Figure 17: Hydrogen-induced damage on steel: A. Cracking. B. Blistering.	32
Figure 18: The evolution of pipeline coatings from 1940 to 2000.	33
Figure 19: Application of FBE coating in pipelines.	34
Figure 20: 3LPO coating system.....	34
Figure 21: HPCC cross-section schematic.....	35
Figure 22: Polymerization reaction for PU synthesis.	36
Figure 23: Methodology schematic to fulfill research goals.	38
Figure 24: GGP pipeline features and nodes schematic.	40
Figure 25: Snapshot from PIPESIM software for the developed GGP Model.	42
Figure 26: Elevation profile changes along GGP mainline.	43
Figure 27: Mixing PU/PP dispersion with MOF. A&B: Before mixing, C: After mixing.	50
Figure 28: PU/PP-MOF films preparation.	50
Figure 29: PU/PP-MOF coating after being applied in Metal sheets.	51
Figure 30: Coated specimen for hydrogen environment aging. (A) HDPE liner (B) Mild steel.	51
Figure 31: System set up for H ₂ -CH ₄ aging.....	52
Figure 32: Flow rates of real data and model results at P-sepcified nodes.....	55
Figure 33: Pressure profile along GGP for the basic case (without hydrogen).	57
Figure 34: Variation in the pressure of Q-specified nodes with multiple H ₂ fractions.....	58
Figure 35: The effect of changing H ₂ content in gas density and viscosity.....	59
Figure 36: Effect of H ₂ concentration in compression ratio (A), and pressure drop (B)..	60

Figure 37: Pressure profile of GGP with multiple H ₂ fractions.....	62
Figure 38: The effect of changing H ₂ fraction in the phase envelope.	63
Figure 39: Changes in Z-factor with different H ₂ content.	64
Figure 40: FTIR spectra of PU4/PP4, MOF, and PU4/PP4-MOF dispersions.	66
Figure 41: Changes in water swelling with multiple coating dispersions.	68
Figure 42: Changes in water contact angle with multiple dispersions.....	69
Figure 43: Changes in hardness and tensile strength with multiple dispersions.....	70
Figure 44: Changes in Young Modulus and Elongation at break with multiple dispersions.	71
Figure 45: TGA results of multiple coating dispersions.	72
Figure 46: Char residues of coating dispersions from TGA analysis.	73
Figure 47: Changes in LOI with multiple polymeric dispersions.....	74
Figure 48: XPS spectra and photographs of PU4/PP4-MOF4 coating before and after UV exposure.	75
Figure 49: Changes in fire-retardancy characteristics after one-year exposure in atmospheric conditions. (A) Char residue. (B) Limited Oxygen Index.....	76
Figure 50: PDP test set up (A), and Tafel plot result (B).	77
Figure 51: FTIR spectra before and after H ₂ -CH ₄ aging for PU4/PP4-MOF4 dispersion.	78
Figure 52: XRD spectra for PU4/PP4-MOF4 dispersion before and after aging under H ₂ - CH ₄ conditions.....	79
Figure 53: SEM images of unaged coating (0%), and aged coatings in H ₂ -CH ₄ environment (10-100 %).	80

LIST OF ABBREVIATIONS

H₂-NG	:	Hydrogen-Natural Gas blends
GGP	:	Goldfields Gas Pipeline
WA	:	Western Australia
CO₂	:	Carbon dioxide
H₂S	:	Hydrogen Sulfide
NO_x	:	Nitrous Oxides
SMR	:	Steam Methane Reforming
LH	:	Liquid Hydrogen
SSC	:	Sulfide Stress Cracking
HIC	:	Hydrogen Induced Cracking
SCC	:	Stress Corrosion Cracking
MIC	:	Microbial Induced Cracking
HE	:	Hydrogen Embrittlement
HID	:	Hydrogen-Induced Decohesion
AIDE	:	Adsorption-Induced Dislocation Emission
HELP	:	Hydrogen-Enhanced Localized Plasticity
CTE	:	Coal Tar Enamel
FBE	:	Fusion-Bonded Epoxy
3-LPO	:	Three-Layer Polyolefin
PE	:	Polyethylene
PU	:	Polyurethane
BC	:	Boundary Condition
GIS	:	Global Information System
MAOP	:	Maximum Allowable Operating Pressure
HHV	:	Higher Heating Value
CS	:	Compression Station

MMSCF/D	:	Million Standard Cubic Feet per Day
H₁₂MDI	:	4,4-dicyclohexylmethane diisocyanate
TEA	:	Triethylamine
EDA	:	Ethylene Diamine
PTMG	:	Poly(tetramethyleneoxide) glycol
DMPA	:	Dimethylolpropionic Acid
MEK	:	Methyl Ethyl Ketone
DBTDL	:	Dibutyltindilaurate
PP	:	Poly Phosphol
MOF	:	Metal Organic Framework

ABSTRACT

Full Name : Mohammed Sofian Ali Khalid
Thesis Title : Coating and Liner for Hydrogen and Natural Gas (H₂-NG) Blended Gas Network
Major Field : Petroleum Engineering
Date of Degree : December 2023

Climate change is the most pressing challenge faced today. Carbon emissions from industry, transport, and other forms of energy continue to threaten the future. Industrialized countries are desperately considering achieving carbon-neutral goals by 2050. Among the strategies under consideration, integrating hydrogen into natural gas streams, known as hydrogen blending with natural gas (H₂-NG), has achieved substantial attention from academia, industry, and governmental bodies.

This study investigates the operational performance of various H₂-NG blends (up to 80% hydrogen) on the Goldfields Gas Pipeline, using real natural gas composition in PIPESIM software. Changes in pressure profiles and H₂-NG blend characteristics were comprehensively analyzed. Simultaneously, the research explores the suitability of an organic coating for dual purposes: serving as an external coating for flame retardance and as an internal coating for reducing gas diffusion rates, particularly for hydrogen or hydrogen-methane blends. The possible changes in the chemical and microstructure of the coating under a hydrogen environment were also evaluated. The fire retardancy deviation of aged coating is also evaluated to confirm this coating's suitability in real transmission pipelines.

Simulation findings reveal that the introduction of hydrogen lowers pressure losses and reduces power needs at compression stations. Higher hydrogen content shifts the phase envelope towards infinity and increases the compressibility factor, while significantly lowering viscosity and density. Alternatively, the in-house formulated polyurethane (PU) coating demonstrated promising results in terms of fire retardance and a slower gas diffusion rate. Coating protective properties were similar after natural weather exposure for 1 year and 1 month of aging in high-pressure hydrogen environment.

ملخص الرسالة

الاسم الكامل: محمد سفيان علي خالد

عنوان الرسالة: الطلاء والبطانة لشبكات الغاز الطبيعي المخلوطة بالهيدروجين (H₂-NG).

التخصص: هندسة البترول

تاريخ الدرجة العلمية: ديسمبر - 2023

تغير المناخ هو التحدي الأكثر خطورة اليوم. استمرار انبعاثات الكربون من الصناعة ووسائل النقل وغيرها من أشكال الطاقة يستمر في تهديد المستقبل. تحاول الدول الصناعية بشكل ملح لتحقيق أهداف الحياد الكربوني بحلول عام 2050. ومن بين الاستراتيجيات التي تخضع للاعتبار، استخدام الهيدروجين في خطوط نقل الغاز الطبيعي، المعروف باسم مزج الهيدروجين مع الغاز الطبيعي (H₂-NG)، قد نال اهتماماً كبيراً من الأوساط الأكاديمية والصناعية والهيئات الحكومية.

تقوم هذه الدراسة بفحص الأداء التشغيلي لخط نقل الغاز الطبيعي (قولدفلدز-Goldfields) باستخدام نسب مختلفة من الهيدروجين والغاز الطبيعي الحقيقي (H₂-NG) (تصل إلى 80٪ هيدروجين) في برنامج المحاكاة PIPESIM. تم تحليل التغيرات في فقدان الضغط وخصائص الغاز الطبيعي بعد إضافة الهيدروجين (H₂-NG) بشكل شامل. في الوقت نفسه، يستكشف البحث ملاءمة طلاء عضوي لأغراض مزدوجة: العمل كطلاء خارجي لتنشيط الاشتعال وانتقال الحرارة وطلاء داخلي لتقليل معدل انتشار الغاز عبر الطلاء، خاصة بالنسبة للهيدروجين أو خليط الهيدروجين وغاز الميثان. تم تقييم التغيرات المحتملة في التركيب الكيميائي والهيكل الدقيق للطلاء تحت تأثير بيئة الهيدروجين أيضاً. تم أيضاً تقييم التغيرات في مقاومة الحريق للطلاء بعد غمره في بيئة ضغط وهيدروجين عاليين لتأكيد ملاءمته في خطوط الأنابيب الفعلية.

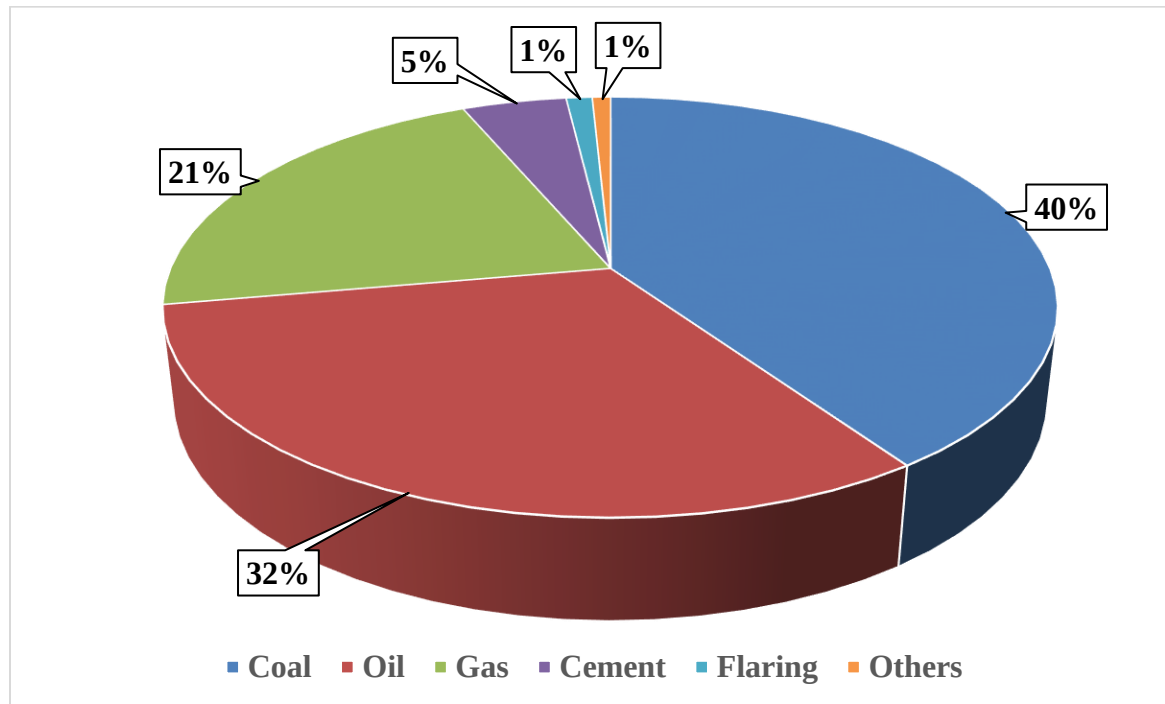
تكشف نتائج المحاكاة أن إدخال الهيدروجين قلّل من فقدان الضغط ومن الاحتياجات الطاقة في محطات الضغط. زيادة محتوى الهيدروجين أدى إلى تحريك مخططات الطور (phase envelope) إلى ما لا نهاية وزاد من عامل الانضغاط (Z-factor) بينما قلل بشكل كبير من لزوجة وكثافة الغاز الطبيعي. على صعيد آخر، أظهر الطلاء بوليوريثين (PU) نتائج واعدة في مقاومة الحريق وحدّ من انتشار الغاز عبره مما يوفر حماية قصوى لمواد الأنابيب. كانت خصائص حماية الطلاء مماثلة بعد تعرضه للطقس الطبيعي لمدة عام، وشهر واحد من الغمر في بيئة الهيدروجين عند ضغط عال.

CHAPTER 1

INTRODUCTION

1.1 Carbon Emissions

Recent advances in climate change and rising carbon dioxide (CO₂) emissions globally demonstrate that, while the percentage of renewable energy (RE) supply is increasing, all nations must significantly boost their initiatives in the future to decarbonize the energy market [1]. Fossil fuels account for around 93% of the world's total CO₂ emissions from industries, as depicted in [Figure 1](#) [2]. Notably, natural gas alone contributes to approximately 21% of these emissions. These data highlight the critical need for the implementation of decarbonization strategies.



[Figure 1: CO₂ emissions from multiple industries.](#)

However, RE systems pose a challenge due to their substantial budgetary requirements for investment and infrastructure development [3]. While hydrogen, known for its environmentally friendly combustion, could eventually replace natural gas in power and heat generation [4], transitioning from natural gas to hydrogen would necessitate adjustments to the existing technical equipment, and the current gas transmission pipelines and facilities must be repurposed for this resolution [3]. One strategy for

achieving this resolution is to employ hydrogen with natural gas streams, allowing a diverse spectrum of energy users to benefit from the reduced greenhouse gas (GHG) emissions [5].

1.2 Hydrogen Blending in Gas Pipelines (H₂-NG)

Hydrogen blending in natural gas networks (H₂-NG) refers to mixing hydrogen and natural gas within the distribution system. This process allows for the controlled introduction of hydrogen into the existing natural gas infrastructure, creating a blended gas mixture [6,7]. Hydrogen blending aims to enhance the environmental sustainability of the gas supply by reducing carbon emissions and transitioning towards cleaner energy sources. This method enables the utilization of existing natural gas pipelines to transport hydrogen, and thereby facilitating a gradual transition to a hydrogen-rich energy mix while utilizing the existing infrastructure [8].

The primary challenge influencing the widespread adoption of hydrogen pertains to the safety of hydrogen infrastructure, encompassing production, transportation, storage facilities, and diverse applications. The risks inherent in hydrogen utilization can be categorized into physiological, physical, and chemical hazards [9]. Nevertheless, hydrogen has not garnered comparable prominence to alternative fuels, primarily due to its historical involvement in significant accidents resulting in substantial economic and social ramifications [9,10]. In all sectors of the hydrogen industry, emphasizing incident assessments and lessons is vital for safer hydrogen handling [11].

The transportation of hydrogen through pipelines entails inherent risks, notably HE and pipeline corrosion, due to its high flammability and susceptibility to ignition, even with low energy input [12–14]. HE occurs when hydrogen atoms permeate the steel structure, resulting in diminished ductility and material failure or rupture [15,16]. On the other hand, corrosion within the gas pipelines represents a critical challenge in the petroleum industry that leads to significant system damage and operational shutdowns [17]. Significantly, pipeline corrosion can also induce HE due to hydrogen generation through corrosion reactions [18]. The presence of H₂-NG blends amplifies this concern, as a considerable amount of hydrogen is available for diffusion, coupled with the potential for natural gas impurities to trigger HE [19]. This dual impact on the transportation network can lead to material degradation and losses within the pipeline.

Pipeline coatings are crucial in mitigating the twin challenges of HE and corrosion, especially in H₂-NG blends. Pipeline coatings function as barriers, shielding metal surfaces from environmental exposure and preventing corrosion-induced electrochemical reactions. Also, using thin-wall thermoplastic liners [20,21] has recently gained more attention for improving pipeline coatings during transportation. These liners serve a dual

purpose: deployable in new pipelines for proactive corrosion management or in existing pipelines to rehabilitate and curtail ongoing corrosion damage.

While several countries are exploring the integration of hydrogen into natural gas pipelines to reduce costs and carbon emissions [22], determining the ideal hydrogen blending ratio poses a significant challenge for researchers aiming to advance the transition towards hydrogen adoption. Given the prevalent safety concerns and the lack of suitable blending technologies, adopting natural gas pipelines to handle higher hydrogen proportions is very important. Thus, addressing these concerns is crucial to ensuring hydrogen's secure and efficient transport through existing natural gas infrastructure. Researchers studying hydrogen transport within these systems must fully understand the issues related to hydrogen-blended gas networks, including their advantages, disadvantages, and optimization for pipeline suitability. The current literature on this subject is limited and often narrowly focused.

1.3 Knowledge Gaps

H₂-NG blends will affect network performance depending on several parameters and operating conditions. There have been contradictory results for the pressure profiles when hydrogen is introduced into the gas network system.

H₂ has higher flammability compared to NG, and by increasing the H₂ fraction, the flammability levels of the blend will be elevated. Increasing flammability levels will pose several safety concerns that should be tackled or addressed through pipeline protection system improvements. In addition, H₂ is known to attack metallic structures, reduce their ductility, and eventually cause their cracking. This is known as hydrogen embrittlement (HE), or hydrogen induced cracking (HIC). HE has higher susceptibility when both H₂ concentration and pressure are increased. H₂-NG blends in transmission networks are high-pressure H₂-rich streams, making the steel pipes more vulnerable to H₂ attacks. However, coatings are a vital part of the pipeline's protection system and should be adapted to handle H₂-NG blends. To the best of the authors' knowledge, none of the studies have tested the effects of H₂-NG blends on coatings or evaluated their suitability. On the other hand, limited investigations have been conducted to investigate the effect of H₂-NG blends on steel pipes [23–25].

1.4 Research Objectives

The project aims to (a) simulate the existing gas network to investigate its performance and suitability for H₂-NG blends; (b) develop a fire-retardant polymer-based coating (external); and (c) utilize a coated liner (internal) for the pipe network.

The specific objectives of the study are as follows:

- Evaluate the performance of natural gas pipelines with blended hydrogen. This objective will involve the development of gas network models using PIPESIM software to simulate existing transmission lines under various blending ratios ranging from 10% to 80%.
- Develop an external fire-retardant coating to protect the pipeline from degradation and to slow down heat transfer from the surrounding environment. The developed coating will be tested under different conditions to ensure its functionality.
- Utilize a commercial liner and apply the developed coating to enhance its protection against harsh conditions, such as high-pressure H₂-rich conditions. The coated liner will be tested against these environments to ensure its protection capabilities against internal conditions.

The findings of the study will have significant implications for the energy industry, as blending hydrogen into natural gas pipelines has the potential to reduce GHG emissions and secure the energy supply chain [26,27]. The research will also contribute to the development of safer and more reliable transmission networks for hydrogen, which is crucial for the low-carbon energy transition.

1.5 Motivation

Injecting hydrogen into the natural gas pipeline system can have significant impacts on the infrastructure and appliances that use the gas. This can create challenges for the existing network, and these challenges can occur at various points throughout the pipeline system. Without addressing these challenges, hydrogen injection could lead to negative consequences for the pipeline's safety, reliability, and economic viability. Therefore, before considering hydrogen blending opportunities, modifications to equipment and changes to network operating procedures must be made to ensure safety, reliability, and economic viability at both the network and equipment levels for transmission and distribution networks. A report by the National Renewable Energy Laboratory (NREL) [28], 2022, has stated the concerns associated with blending hydrogen with natural gas streams in the pre-existing transmission and distribution pipelines. One of the most challenging impacts that is going to be encountered is related to pipeline material and its ductility in H₂-rich environments. Hydrogen is well known to cause severe damage to the steel structure through a phenomenon known as hydrogen embrittlement (HE). HE is simply the diffusion of hydrogen atoms through metal structure, which leads to cracking and pipeline failure. In order to avoid such ramifications caused by H₂-NG blends, the study aims to develop a coating that can withstand the H₂-rich environment in the transmission pipelines that normally operate at high pressures. The coating is not just aimed at being anti-embrittlement; it also has another advantage when applied externally. It will be developed to withstand extreme temperatures in case of surrounding fires and flames. Additionally, the surrounding environment of the pipelines is normally corrosive; therefore, the coating will be synthesized to protect the pipe from corrosion as well.

Lastly, most of the catastrophic hydrogen-related incidents were attributed to corrosion issues and pipeline ruptures at the beginning, followed by fires from surrounding sources. Hence, our proposed coating is multi-functional for hydrogen safety concerns and pipeline integrity assurance.

CHAPTER 2

LITERATURE REVIEW

2.1 Research Status in H₂-NG Blending

Numerous investigations have explored H₂-NG blends through analytical and numerical approaches employing diverse tools. The impact of hydrogen in gas networks has been extensively assessed in multiple research projects [7,29–43]. A notable portion of these studies has been primarily dedicated to integrated energy systems (IES) [30,35–41], incorporating green hydrogen production and blending into existing gas networks, as depicted in [Figure 2](#) [44]. Hydrogen is generated via electrolyzers by splitting water into oxygen and hydrogen in these systems. This hydrogen is blended with natural gas (NG) before being reinjected into the network.

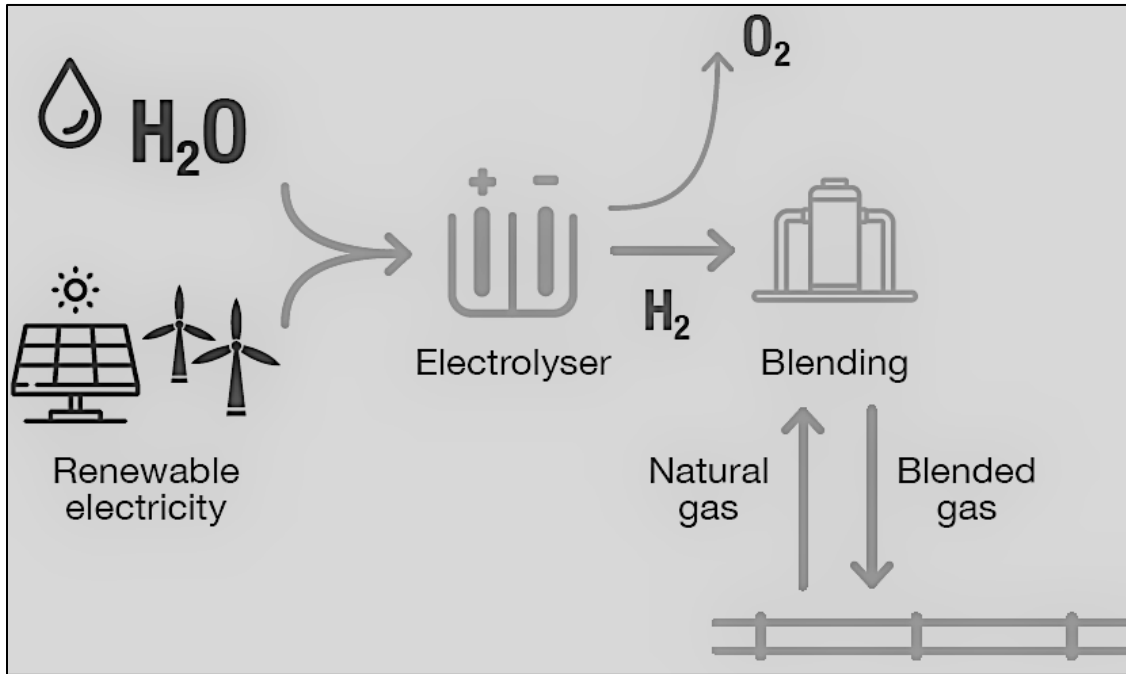


Figure 2: Schematic of integrated energy system for hydrogen production and blending.

Green hydrogen refers to emission-free hydrogen from clean sources [45]. Most studies used actual gas network cases for evaluation. A significant focus has been on the impact of pipeline pressure, as it directly affects network functionality and compatibility with hydrogen streams [7,29–35,43]. Findings suggest that the pressure pattern of blended networks highly depends on the networks' layout, operational factors, and hydrogen

fraction. Various pipeline components, such as compressors, valves, and fittings, exhibit distinct thresholds for accommodating hydrogen concentrations [46].

The flow behavior of the H₂-NG mixture is significantly influenced by the injection method and blending techniques [7,47]. Given hydrogen's lower density compared to natural gas [48], improper mixing could result in stratification issues, potentially leading to the separation of gas streams (i.e., H₂ and NG) within the pipeline, which may lead to severe damage in pipeline materials if not effectively addressed [7,47].

Alternatively, specific studies have assessed the thermodynamic properties of H₂-NG blends, outlining the blended gas quality [30,32,34,36,38,46,47,49]. Notably, hydrogen's lower energy density leads to reduced volumetric energy content [50]. Metrics like lower and higher Wobbe Indices (LWI and HWI) and lower and higher heating values (LHV and HHV) were utilized to address changes in gas quality and energy content post-hydrogen mixing [34,49]. Nevertheless, maintaining a consistent consumer energy supply proves challenging when employing H₂-NG blends. For safety reasons, large H₂ fractions in H₂-NG blends are suitable only for low-pressure networks [6]. The energy supply can be preserved by increasing the network flow rate or pressure to balance energy content variations [47].

Furthermore, researchers have demonstrated decreased carbon emissions from the blending process [36–39,51]. This reduction is attributed to the clean combustion of hydrogen, which produces only heat and water [52]. Conversely, introducing additional H₂ fractions has slightly increased nitrous oxide (NO_x) emissions [39]. Certain studies concentrated on assessing pipeline materials under various concentrations and pressure levels of H₂-NG environments. In high-pressure blends (≥ 1450 psi), the strength of steel has generally decreased even at low hydrogen concentrations [23,24,53]. Conversely, for low-pressure H₂-NG blends, both metallic and polymeric materials have exhibited resilience against the blended gas without experiencing deterioration [25]. Regarding economic feasibility, specific investigations concentrated their attention on such evaluations of cost analysis [40,54]. Furthermore, several researchers have authored comprehensive review articles on H₂-NG blended gas networks [8,28,34,55–63]. [Table 1](#) summarizes the main findings of the preceding literature surveys and other publications in this field.

Table 1: Summary of the literature on H₂-NG blending.

Objectives	Country	H ₂ %	Methodology	Key Findings	Refs.
Assess H ₂ -NG blends in a high-pressure transmission network.	China	30%	Simulation (ASPEN HYSYS)	- Reduced pressure drops for single-point H₂ injection. - Increased pressure drops for multi-point H₂ injection.	Liu et al. [29]
Utilize surplus wind energy in H ₂ production and blending with NG in the transmission network.	Ireland	15%	Simulation (MATLAB)	- Pressure of the network increased. - No operational issue. - Reduction in Energy Content of the mixture.	Ekhtiari et al. [30]
Evaluate H ₂ -NG flow characteristics in pipelines with different gas compositions and operating conditions.	China	10%	Simulation (MATLAB)	- H₂ injection caused a minor increase in pressure drop. - Stabilization of H₂ concentration will be reached after 33.3 hours from injection.	Zhou et al. [31]
Develop a dynamic model of H ₂ -NG in energy-based boundary conditions. Study H ₂ -NG effect on energy supply to consumers.	Italy	5%	Analytical Model Simulation (MATLAB)	- Negligible effect on pressure profile. - Gas quality deteriorated by adding more H₂.	Guandalini et al. [32]
Modelled H ₂ -NG blends using different gas laws and compared their accuracy.	Germany	0-100%	Simulation (MYNTS)	- GERG-2008 law is better for H₂-NG blends. - Minor H₂ fractions affected the pressure profile of the network considerably.	Clees et al. [33]
Develop H ₂ -NG steady-state flow model in pipelines.	Italy	10%	Analytical Model	- H₂ increased pressure drop of the network. - H₂ affected gas quality indicators (Gravity, WI).	Pellegrino et al. [34]
Develop IES to produce and blend H ₂ in the NG network. Effects of H ₂ -NG in gas network.	China	Not Available	Simulation (MATLAB MANPOWER)	- Pressure losses increased with H₂-NG. - Pressure losses caused by H₂-NG depend on network layout, and H₂ fraction.	Zhou et al. [35]

Modelling steady state and transient isothermal flow of H ₂ -NG blend in looped gas network.	Not Available	0-100%	Simulation (COMSOL Multiphysics)	• H₂-NG blend raised pressure in both flow modes. • A 30% H₂ blend is deemed secure for the network. • Pipeline integrity was jeopardised with 60% and 100% H₂ fractions.	Hafsi et al. [43]
Using Helical Static Mixers (HSM) with H ₂ -CH ₄ blends.	China	20%	Experimental Simulation (FLUENT 19, SIMPLE)	• H₂ stratification reduced by HSM. • Optimized conditions for HSM were determined. • A slight increase in Pressure drop was observed.	Kong et al. [7]
Modelling H ₂ -CH ₄ in gas network.	UK	4.8-20%	Analytical Model Simulation (OpenFOAM)	• P or Q must be increased to keep the same energy supply to end-users. • H₂ stratification due to poor mixing or gravity will enhance pipe failure (HE) chances.	Eames et al. [47]
Perform a thermo-physical assessment for H ₂ -NG blends.	Iran	1-10%	Analytical Model	• Increasing H₂ % raised flammability and compressibility, but it dropped LHV, HHV, LWI, HWI, and relative density. • 10% H₂ lowered gas consumption by 3.5%.	Deymi-Dashtebayaz et al. [49]
Review and investigate the effect of H ₂ -NG on pipeline systems, end-user appliances, and gas quality.	Pakistan	2 & 10%	Simulation (PIPELINE STUDIO)	• Transmission pipelines can handle 50% H₂, while compressors (10%), gas turbines (20%), and end-user appliances (20-50%). • Calorific value of gas reduced by 10% H₂.	Gondal, [46]
Perform cost and thermodynamic analysis for IES for H ₂ -NG blends.	Turkey	20%	Experimental Simulation (HOMER PRO)	• H₂-NG has lower volumetric energy content. • Off-grid set-up has higher cost and efficiency. • CO₂ emissions are higher for on-grid set-up.	Sorgulu and Dincer, [36]
Study the economic feasibility of green H ₂ -NG blending in the NG network.	China	-	Analytical Model	• With the defined capital and operating costs, the profitability has been proven within	Liu et al. [37]

				22 22-year lifetime. - CO₂ emissions will be reduced considerably.	
Investigate the GHG emissions for different H ₂ -NG blends.	Canada	15%	Analytical Model Simulation (FUNNEL-GHG)	- Transportation GHG emissions increased. - Combustion GHG emissions decreased. - The mixture's energy value decreased. - Low-pressure pipes have less emissions.	Lullo et al. [51]
Develop an IES for cleaner combustion. Study H ₂ -NG emissions reduction.	Turkey	0-20%	Simulation (ASPEN PLUS, EES)	- CO₂ emissions from combustion are reduced by H₂ inclusion. - Average energy and exergy efficiencies were 63% and 49%, respectively.	Ozturk and Dincer, [38]
Develop an integrated green H ₂ -NG energy system. Study effects on gas consumption and emissions after blending H ₂ .	Turkey	20%	Simulation (NREL SAM, ASPEN PLUS)	- Reduction in NG consumption. - Reduction in carbon emissions (CO, CO₂). - Increase in No_x emissions.	Ozturk and Dincer, [39]
Assess green H ₂ blending opportunities in the Eastern Australian gas network. Techno-economic analysis for H ₂ production scenarios and blending	Australia	3, 10 & 100%	Analytical Model (MS Excel)	10% H₂ can be achieved with the existing EA infrastructure and low green H₂ costs. 3% H₂ is reachable for premium green H₂. - Green power-to-gas can help achieving 100% H₂ at lowered cost.	Gurieff et al. [40]
Evaluate green H ₂ -NG in the transmission network.	Italy	10%	Analytical modelling	750,000 sm³/yr. 1% contribution to EU hydrogen strategy.	Pellegrini et al. [41]
Evaluate X70 grade steel pipe against H ₂ -NG at high pressure.	USA	100%	Experimental	H₂ reduced fracture toughness of the pipe.	Martin et al. [23]

Study HE susceptibility for X80 grade steel pipes using H ₂ -Nitrogen blends.	China	0-20%	Experimental	- Increasing H₂% led to substantially reducing the flexibility of X80 steel. - A safe limit for X80 blended pipelines is determined to be 10% H₂.	Wang et al. [53]
Evaluate X80 grade steel specimens against H ₂ -N ₂ environments. (notched & smooth samples)	China	0 & 5%	Experimental	- Higher H₂ fraction resulted in more deterioration in the mechanical properties of the steel. - The notched sample degraded more than the smooth one.	Zhou et al. [24]
Assess metallic, polymeric, and elastomeric materials in H ₂ -CH ₄ environments.	UK	20 & 100%	Experimental (6-week soaking at 2 bar, 20 °C)	- H₂-NG blends at low pressure did not affect the integrity/properties of the tested materials. - Polymeric material did not deteriorate.	Birkitt et al. [25]
Model H ₂ -NG leaks and diffusion in buried pipelines.	China	0-20%	Analytical Model & Simulation (ANSYS Fluent)	The H₂ ratio does not significantly influence the degree of risk for urban buried H₂-NG blended pipelines.	Su et al. [64]
Evaluate costs and economics for pure H ₂ through NG networks.	Germany	100%	Economic Analysis	80% of the examined pipelines are eligible for repurposing. Repurposing pipelines reduces H₂ transmission expenses by over 60%.	Cerniauskas et al. [54]
Evaluate the energy and technical aspects of H ₂ -NG blends in NG networks.	Belgium	17%	Analytical / Experimental	- Mixing H₂ in distribution networks is achievable, while transmission networks have limitations. - End-use and pipeline infrastructure significantly affect the blending feasibility.	Haeseldonckx and D'haeseleer, [6]

2.2 Simulation-Based Studies in H₂-NG Blending

H₂-NG blending was proposed in the 20th century in the US [65]. Hydrogen was blended with natural gas to deliver pure hydrogen to end-users after downstream extraction and purification [62]. Multiple studies assessed the efficiency of H₂-NG blended gas networks through simulation. Liu et al. [29] investigated the Chinese pipeline with increased H₂ concentrations using ASPEN-HYSYS software. Ekhtiari et al. [30] simulated an Irish network with 15% H₂ content through MATLAB. Zhou et al. [31] created a MATLAB

dynamic model for NG pipelines, investigating H₂-NG blend dynamics. Guandalini et al. [32] used a similar dynamic model, validated by Italian gas network data, showing negligible pressure drop with 5% H₂. Clees et al. [33] used MYNTS software to simulate H₂-NG blends in German gas networks, incorporating multiple gas laws. Zhou et al. [35] employed MATLAB for an integrated sustainable H₂-NG energy system, optimizing injection points and highlighting the benefits of centralized blending. Kong et al. [7] utilized FLUENT and SIMPLE softwares to analyze the performance of helical static gas mixer with H₂-NG streams. Eames et al. [47] studied hydrogen concentration changes along the pipeline for H₂-CH₄ mixtures using OpenFOAM software. Gondal [46] analyzed hydrogen's impact on power-to-gas systems and home appliances in Mingora, Pakistan, using PIPELINE-STUDIO. Sorgulu and Dincer [36] performed energy, exergy, and cost evaluations of H₂-NG blends HOMER-PRO. Di Lullo et al. [51] used FUNNEL software to address the changes in GHG emissions with multiple H₂-NG blends. Ozturk and Dincer [38] employed ASPEN-PLUS and EES software to develop an eco-friendly H₂-NG system and assessed the energy, exergy, and combustion emissions of the system. Ozturk and Dincer [39] evaluated the effect of H₂-NG blending on Turkish gas consumption and reserves through ASPEN-PLUS and NREL-SAM software.

2.3 H₂-NG Blending Projects

Various projects have evaluated the economic aspects of integrating hydrogen into natural gas pipelines. They vary in their scope and objectives, with some incorporating physical modelling of the gas pipeline network, electricity grid, and techno-economic analysis of hydrogen production technologies and pipeline upgrades. Broadly, these efforts can be categorized into two groups: those focusing on the economic benefits of hydrogen blending for renewable integration and emission reduction, and those examining the costs associated with upgrading natural gas pipelines to accommodate hydrogen [28]. In Europe, numerous long-term projects have effectively implemented trials of hydrogen blending in small communities, whereas the United States has seen fewer comparable initiatives to date [59]. The geographical distribution of countries implementing projects involving the mixing of hydrogen with natural gas is shown in [Figure 3](#) [28,59]. Hydrogen blending projects in natural gas pipelines have predominantly occurred in Europe, particularly in the UK, where 12 projects have been implemented. Germany and France have also made significant contributions, with a combined total of 10 projects.

Australia has also demonstrated notable engagement with multiple projects in this domain, highlighted by the successful Hydrogen Park South Australia (HyP-SA) project. This project achieved a noteworthy accomplishment by blending 5% hydrogen in distribution networks [59,66]. In Albury-Wodonga, Australia, the HyP Murray Valley (HyP-MV) project is set to develop 10 MW electrolyzers to produce renewable hydrogen for blending into the local gas network [67,68]. This endeavor by AGIG aims to deliver

up to 10% renewable hydrogen by volume to around 40,000 existing residential, commercial, and industrial customers, supporting the decarbonization of the gas supply. The Western Sydney Green Gas (WSGG) Project, located in New South Wales, Australia, involves a trial power-to-gas facility funded by Jemena and the Australian Renewable Energy Agency (ARENA) [69]. The project aims to convert surplus renewable electrical energy into hydrogen gas for blending in gas networks, storage, power generation, and potential transportation and industrial applications. The facility has commenced operations, initiating the blending of hydrogen into the New South Wales gas network in November 2021. ATCO's Clean Energy Innovation Hub (CEIH) in Australia undertook another initiative that involved the assessment of blending hydrogen produced through electrolyzers within a distribution network [70]. The hydrogen concentration ranged from 5% to 25%, utilizing electrolyzers with a capacity of up to 1.2 MW. The ongoing HyP Gladstone project, currently in the developmental phase, will undertake trials of a 10% hydrogen blend. This initiative aims to provide approximately 800 residential, commercial, and industrial customers in Gladstone, situated in central Queensland, with the blended hydrogen supply [59].



Figure 3: Geospatial distribution of H₂-NG blending projects.

2.4 Bibliometric Analysis of H₂-NG Blending Literature

Bibliometric analysis, or scientometric analysis, is a widely systematic approach to analyzing and evaluating numerous scientific articles and information (e.g., science mapping). This method helps unravel the intricate developments within a particular field

and gain insights into its emerging areas. Additionally, it enables the examination of the intellectual framework of that field as depicted in existing literature [71,72]. Researchers employ bibliometric analysis in different subject areas, including identifying emerging articles and journal performance patterns, collaboration dynamics, and research participants [72–78].

Several software programs have been used in science mapping and bibliometric analysis, such as BibExcel, Leydesdorff's Software, IN-SPIRE, VOSviewer, VantagePoint, and others [79]. This research utilizes open-source VOSviewer software (version 1.6.19) [80] since it is suitable for such analysis [81,82].

Bibliometric analysis was conducted for H₂-NG blends. The bibliometric database was retrieved from Scopus since it is one of the highly comprehensive databases in energy, engineering, and other subject areas [78,83,84]. The search output on Scopus highly depends on keywords used to fetch the data [78,84]. To the study's objectives, the bibliometric data retrieval process involved using specific search keywords' syntax ("Hydrogen blend*" OR "Hydrogen blend* with natural gas" OR "hydrogen-natural gas blend*" OR "Hydrogen mix* with natural gas" OR "hydrogen-natural gas mix*" AND "gas pipeline*" OR "gas network*"). These keywords were applied with the search functionality of (Article Title, Abstract, and Keywords). That means only the articles that include the above keywords in their Title, Abstract, or Keywords section will be shown in search results. More information about search techniques and data collection can be found on the Scopus website [85]. The keywords selected are based on the review articles in [Table 1](#). The data were refined and restricted to only journal articles and review document types [84,86]. Moreover, search restrictions considered only English-language publications [78]. Seventy-one articles fulfilled the abovementioned criteria (as of May 26, 2023).

[Figure 4](#) depicts the yearly publication pattern of articles concerning H₂-NG blending in NG pipelines. This topic has just one publication till 2007, which dates back to 1994. Seven publications were issued in 2020, marking a turning point in reporting H₂-NG blended gas networks. The number of publications in 2022 (29 documents) was almost identical to the cumulative number of publications before that year (30 documents). That represents another transitional era in H₂-NG blending research. Publications increased dramatically in 2022 compared to the previous two years, by 123% and 314%, respectively.

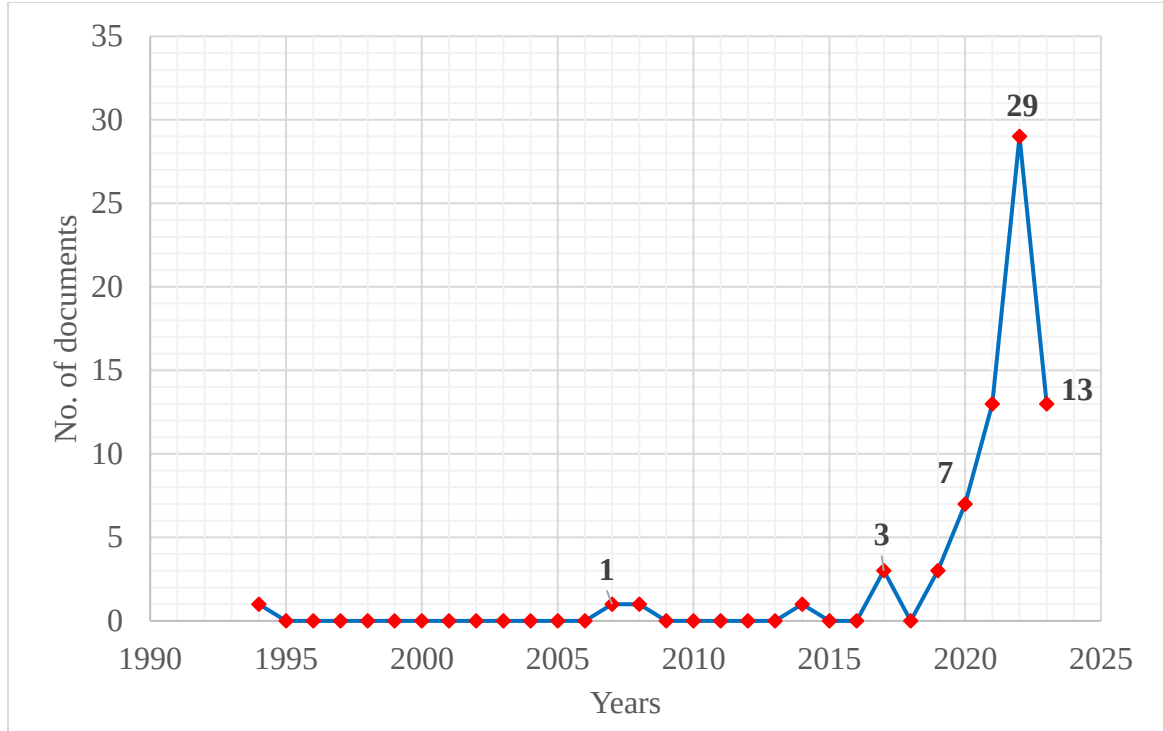
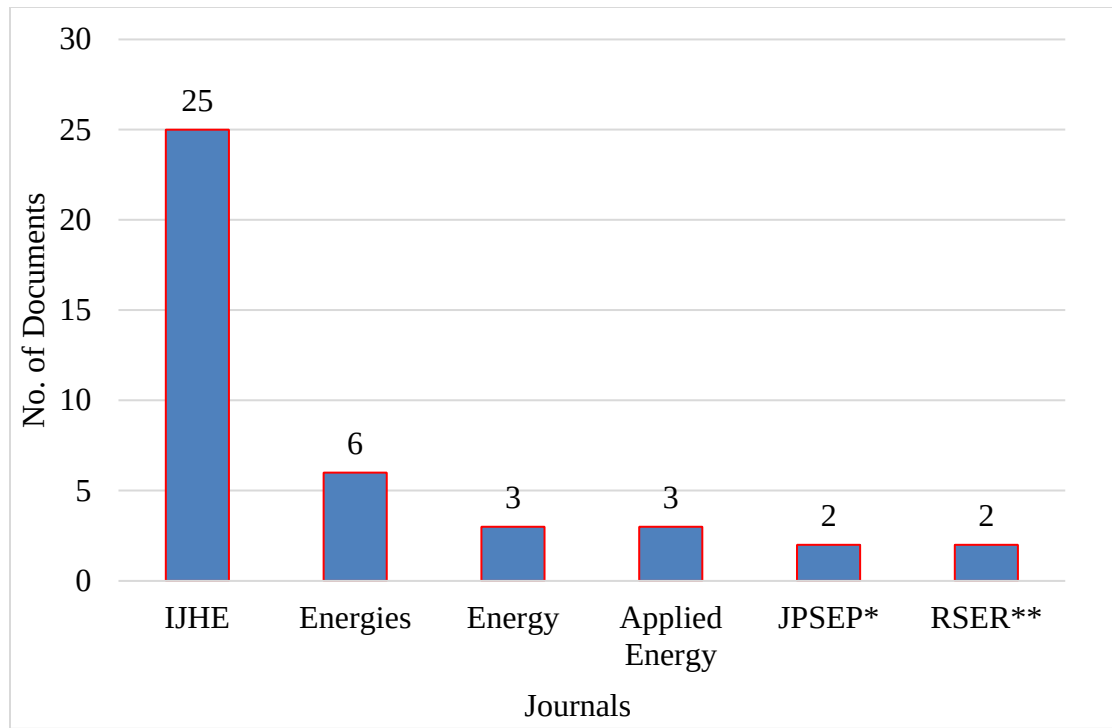


Figure 4: The global publications trend of H₂-NG blending in gas pipelines.

Table 2 lists the top 10 cited documents related to H₂-NG blending in NG pipelines. The paper with the most citations (192 citations) was issued in 2007 by the University of Leuven, Belgium [6]. The report provided an in-depth review of the technological and structural factors influencing the transition to hydrogen-based energy. However, the first publication (i.e., Öney et al. 1994) has been cited 46 times [87]. 7 out of 10 papers listed in Table 2 were published in the International Journal of Hydrogen Energy (IJHE). That is proved in Figure 5, which shows the top 6 journals in this area. A total of 25 documents from IJHE represent around 35% of the total documents since 1994. This highlights the significant contribution of IJHE in the research of H₂-NG blending in gas networks.

Table 2: The top 10 cited articles in H₂-NG blending in gas networks.

	Title	1st Author	Year	Cited	REF
1	The use of the natural gas pipeline infrastructure for hydrogen transport in a changing market structure	Haeseldonckx D.	2007	192	[6]
2	A mathematical framework for modelling and evaluating natural gas pipeline networks under hydrogen injection	Tabkhi F.	2008	93	[42]
3	Economic study of a large-scale renewable hydrogen application utilizing surplus renewable energy and natural gas pipeline transportation in China	Liu B.	2020	80	[37]
4	Options of natural gas pipeline reassignment for hydrogen: Cost assessment for a Germany case study	Cerniauskas S.	2020	75	[54]
5	Greening the gas network – The need for modelling the distributed injection of alternative fuels	Pellegrino S.	2017	64	[34]
6	HyDeploy: The UK's First Hydrogen Blending Deployment Project	Isaac T.	2019	58	[88]
7	Computational modelling of natural gas flow in the looped network: Effect of upstream hydrogen injection on the structural integrity of gas pipelines	Hafsi Z.	2019	49	[43]
8	Evaluation of pipeline transportation of hydrogen and natural gas mixtures	Öney F.	1994	46	[87]
9	The experiment study to assess the impact of hydrogen blended natural gas on the tensile properties and damage mechanism of X80 pipeline steel	Zhou D.	2021	35	[24]
10	From the perspective of new technology of blending hydrogen into natural gas pipelines transmission: Mechanism, experimental study, and suggestions for further work of hydrogen embrittlement in high-strength pipeline steels	Wu X.	2022	33	[61]



* Journal of Pipeline Systems Engineering and Practice

** Renewable and Sustainable Energy Reviews

Figure 5: Journals with at least two publications in H₂-NG blended gas networks.

On the other hand, China accounts for 3 out of the top 10 documents shown in [Table 2](#), which implies the efforts that Chinese researchers have made in this subject. That is confirmed by [Figure 6](#), which demonstrates the contribution percentages of the top 10 countries in this research area. China, with 29 publications in total, accounts for almost half of cumulative publications since 1994 (i.e., 41%). The United States comes in the second position with seven documents, less than one-third of China's documents. The total number of publications of the top 10 countries can be found in [Table 3](#).

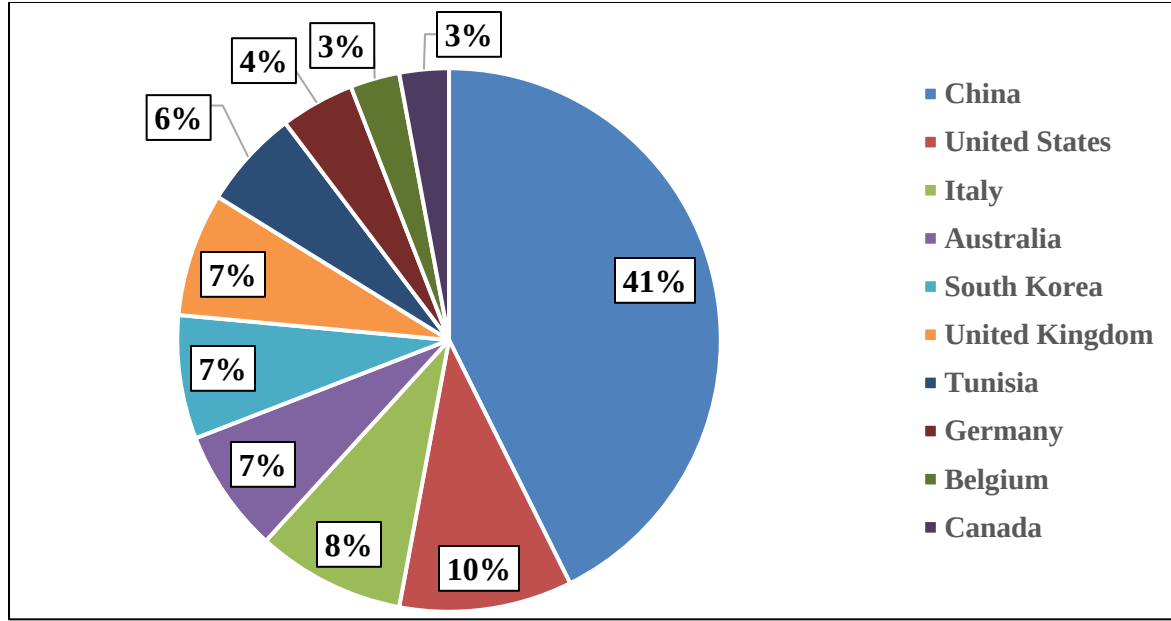


Figure 6: Contribution of the top countries to the total H₂-NG blended networks documents.

Table 3: Most productive countries in H₂-NG blending in gas pipelines.

Country	Total Publications
China	29
United States	7
Italy	6
Australia	5
South Korea	5
United Kingdom	5
Tunisia	4
Germany	3
Belgium	2
Canada	2

Figure 7 visualizes the co-occurrence of all keywords in the 71 documents (from VOSviewer). The minimum number of occurrences threshold was set to 3. Only 63 keywords (out of 799 detected keywords) met the threshold criteria. The keywords with the most occurrences (i.e., large circles) are natural gas, gases, hydrogen, blending, and natural gas pipeline. Each of these top index keywords appeared at least 31 times. To prevent label overlap, some keywords may not have their labels displayed. The visualization of co-citation ties represents the relationship between keywords, where the distance between them indicates their level of relatedness [73]. Keywords that are positioned closely are considered to have a significant connection. That can also be observed with distinguished colors of each cluster of keywords. Mainly, seven groups have been identified automatically by VOSviewer according to their co-occurrence.

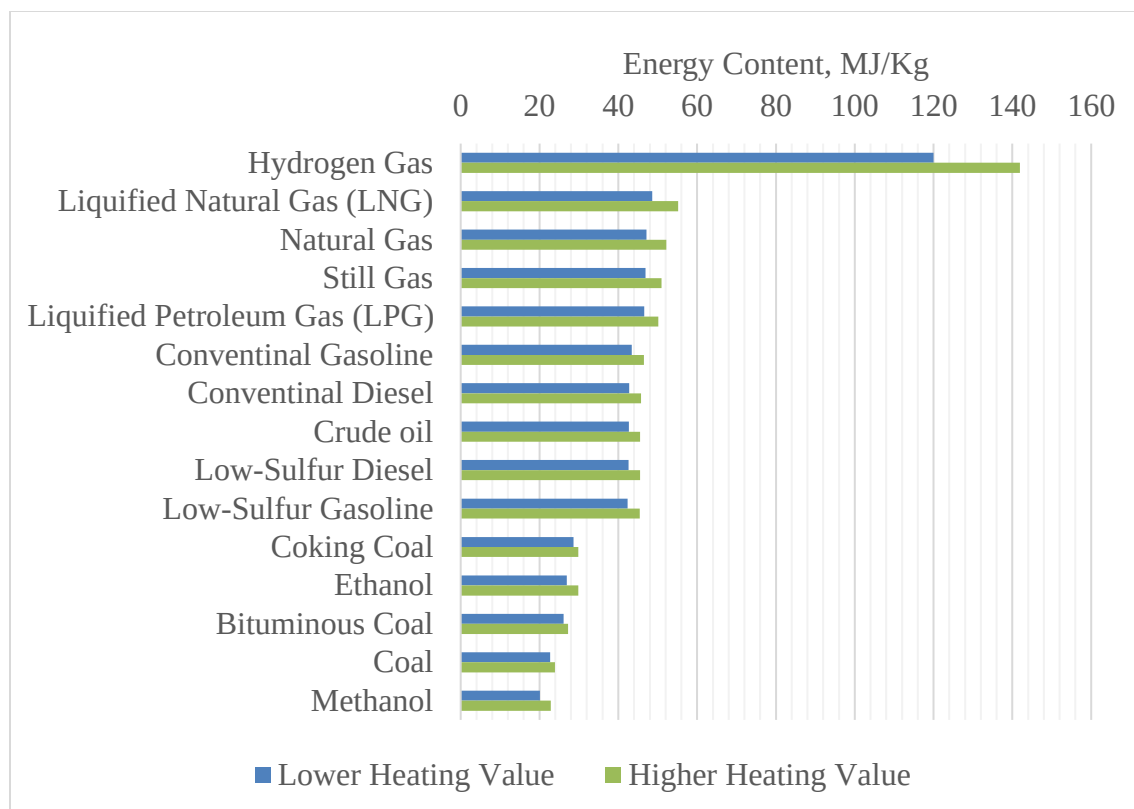


Figure 8: Energy content regarding heating values for H₂ and other fuels.

2.5.1 Production

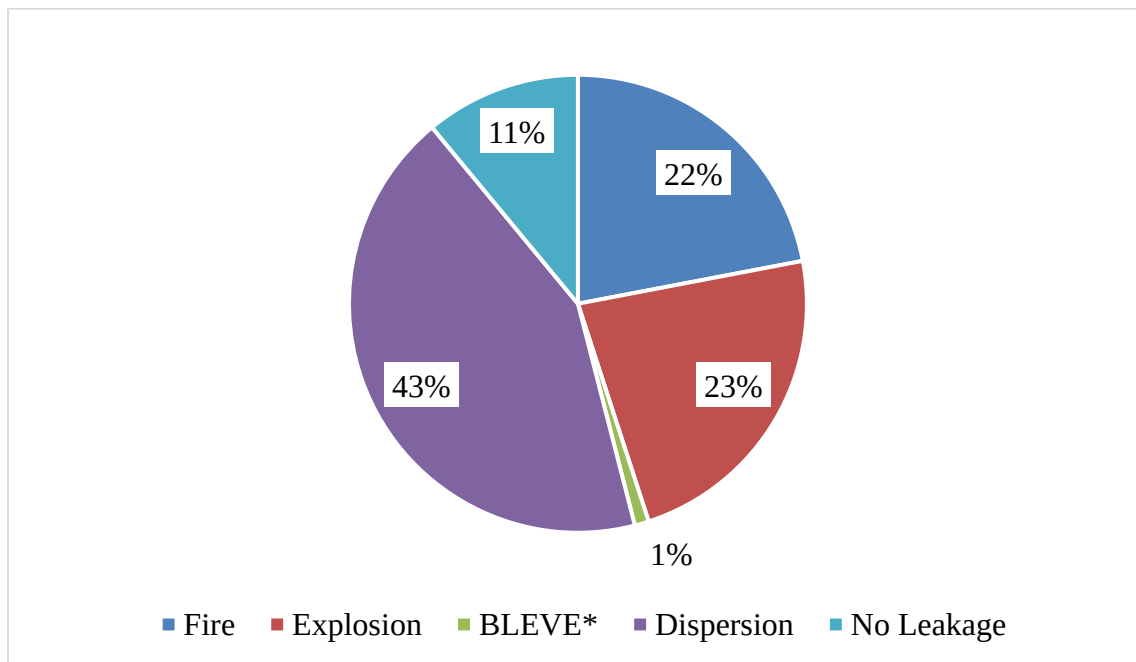
Pure hydrogen production requires substantial energy. Hence, it is termed an "energy carrier" [97]. Fossil fuels have been its primary source due to lower production costs, but carbon-free production methods like electrolyzers are gaining traction to reduce emissions [98,99].

A study assessed 19 hydrogen production systems for their environmental, economic, social, and technological performance [100]. An analysis of hydrogen production technologies found steam methane reforming (SMR) favored productivity, safety, and established infrastructure, while electrolyzers posed safety risks due to system defects and equipment failures [101]. Another investigation comprehensively analyzed the established hydrogen production methods based on source, purity, capacity, and safety. All technologies handled combustible and hazardous mixtures, with coal gasification and electrolysis managing them at lower temperatures. Larger systems had safety protocols, but smaller-scale ones required stricter measures [102]. A study focused on hydrogen's safety aspects, addressing ignition, burning properties, physical risks, and physiological dangers. Challenges in storage and transportation were highlighted, emphasizing safety in the hydrogen economy [9]. The safety implications of combining nuclear energy and hydrogen production systems were studied, stressing comprehensive safety assessments for integrated approaches to manage potential risks [103]. The Acid Gas to Syngas

method was evaluated in hydrogen production to minimize CO₂ emissions, showing a 3% reduction in natural gas usage and CO₂ emissions compared to the conventional way [104].

2.5.2 Transportation

Transporting hydrogen safely is challenging due to its flammability, propensity for leakage, and ability to penetrate metallic structures [105]. Various studies have examined the safety aspects of hydrogen transportation infrastructures for future economies, addressing design concepts, systems, and hazards [95,106–111]. Recommendations for public safety monitoring were discussed [106]. Assessments have been conducted on hydrogen pipeline transportation safety, identifying potential risks from failures [107]. Research into hydrogen leak diffusion, combustion mechanisms, and material damage suggests refining kinetic tools, turbulence models, and expansion patterns of hydrogen clouds for future studies [108]. Safety standards for liquid hydrogen handling emphasize advancements in liquefaction methods [109]. Projects like IDEALHY have investigated large-scale liquefaction processes and transportation hazards with incident evaluations [110]. Figure 9 shows incidents in Transport, Liquefaction, and storage causing releases, with 50% resulting in ignition—ignited releases led to fires, explosions, and a BLEVE in one case.



BELIEVE * Boiling Liquid Expanding Vapor Explosion.

Figure 9: The proportion of incidents occurrence through LH processing.

Injecting hydrogen into natural gas grids raises safety concerns, with equipment failure as a prominent issue [95]. Figure 10 depicts the primary causes of pipeline hydrogen failures, underlining equipment failure as the most common incident. Safety measures in

hydrogen road transport encompass risk criteria, probabilistic safety data, and utilization of test results for safety assessments [111].



SOP* Standard Operating Procedure

Figure 10: The potential causes of pipeline failure incidents in hydrogen transportation.

2.5.3 Storage and Utilization

For nearly a century, hydrogen has found application in sectors like oil refining, ammonia production, and ironmaking [112–114]. Figure 11 illustrates hydrogen consumption across industries in 2021 [114]. Notably, oil refining and ammonia production dominate hydrogen usage. Around 42% (40 Mt) is used in refineries, with ammonia and methanol making up 36% and 15%, respectively. The iron industry accounts for just 6% of hydrogen use.

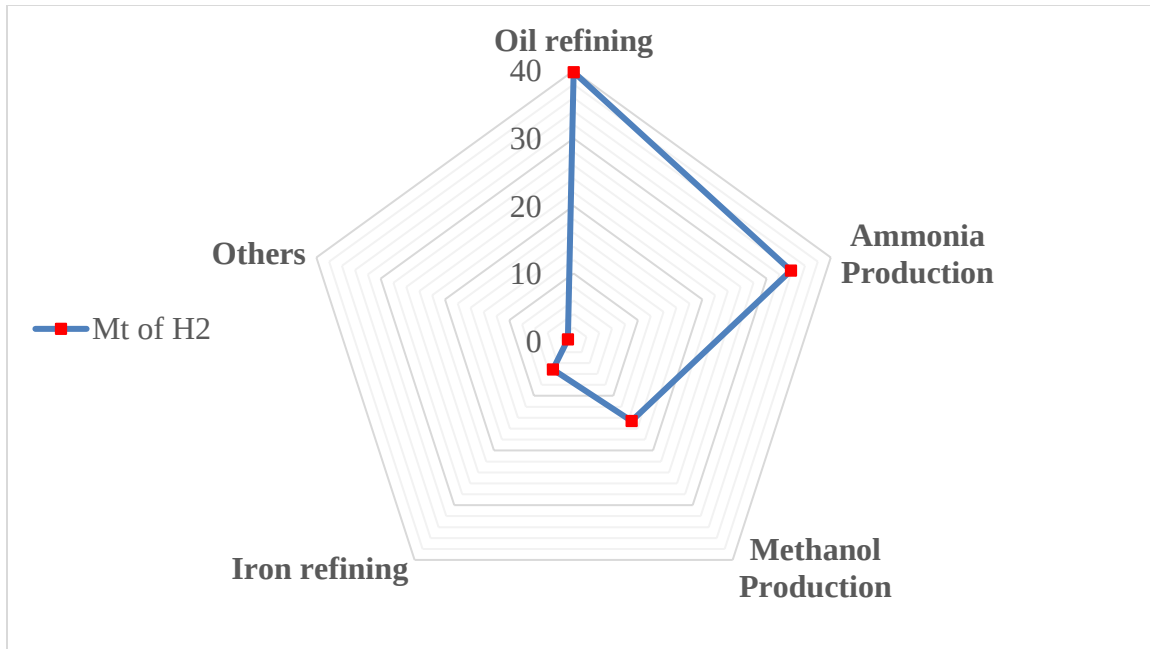


Figure 11: Global hydrogen consumption by industries in 2021.

Hydrogen as a fuel has caused historical disasters with significant economic and social consequences, such as the Hindenburg catastrophe in New Jersey, hydrogen leakage during repair in Houston, and a hydrogen tank burst in Frankfurt [115–118].

Studies explored hydrogen storage systems and refueling stations for safety concerns [119–127]. Innovative methods like metal hydrides reduced hazards [119]. Safety evaluations of refueling stations analyzed high-pressure equipment and safe distancing [120,121]. Comprehensive assessments utilized Computational Fluid Dynamics (CFD) modelling for risk analysis [122,123], while others performed experimental evaluations [124]. Analyzing over 100 accidents, hydrogen system failures emerged as a common cause of these incidents [125]. A comparison between hydrogen and other fuels safety issues was conducted [126]. The research investigated fuel cells' safety, particularly fire and explosion risks [127].

Handling and storing hydrogen safely are crucial due to its flammability, the risks of leaks and spills, and HE. Despite their environmental advantages, proper equipment, training, and monitoring are necessary when using hydrogen-natural gas blends.

2.6 Corrosion in Pipelines

Pipelines transport crude oil and natural gas to refineries and processing plants for distillation and production. While some are above ground, most are buried underground [128]. Corrosion poses a significant and enduring threat to the petroleum industry, leading to unscheduled downtime and costly repairs. A U.S. Federal Highway Administration report estimates yearly losses of around \$1.4 billion due to corrosion in

U.S. oil and gas production [129]. Impurities like sulfur, chloride, CO₂, and water contribute to pipeline corrosion. Solutions such as coatings, inhibitors, and cathodic protection help mitigate these challenges [130,131]. Corrosion is essentially electrochemical metal deterioration [132]. Steel pipe corrosion is categorized into internal and external types, often impacting pipelines concurrently. External corrosion is influenced by the environment, mechanical stress, and other factors [133]. However, its rate is lower than internal corrosion. Internal corrosion depends on stream composition, temperature, pressure, and flow [134].

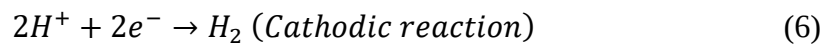
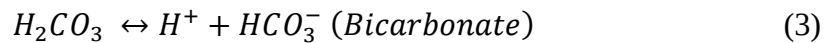
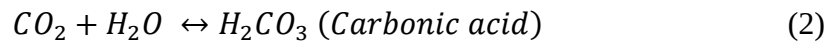
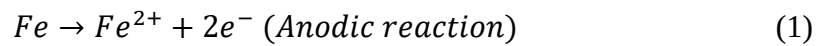
2.6.1 Internal Corrosion

Internal corrosion stems from water coupled with acid gases (CO₂ or H₂S) or sulphate-reducing bacteria, encompassing three primary types: sweet, sour, and microbiologically induced corrosion (MIC) [135].

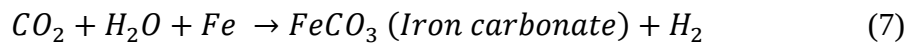
2.6.1.1 Sweet Corrosion

Sweet corrosion arises when both CO₂ and water are present in the pipeline. Carbonic acid forms due to CO₂ dissolution in water, interacting with the metal and leading to corrosion. Uncoated steel reacts with carbonic acid to form an iron carbonate (FeCO₃) layer on the steel surface, slowing corrosion rates [136]. Variables such as system temperature, pressure, CO₂ content, pH, and flow velocity influence the corrosion rate [137]. Sweet corrosion underlies mesa corrosion at the pipeline bottoms. Electrochemical reactions of sweet corrosion process are illustrated by Eqs. 1-6 [138,139].

Eqn.



The preceding reactions can be summarized in Eq. 7 below:



2.6.1.1.1 Mesa Corrosion

Mesa corrosion forms extended furrows at the bottom of the pipe where water and carbonic acid accumulate. This is accelerated when the protective FeCO₃ layer is

disrupted, leading to rapid corrosion expansion [18,140]. [Figure 12](#) shows a photograph of a steel tubular depicting mesa corrosion, featuring a central uncorroded area surrounded by corroded regions [141].

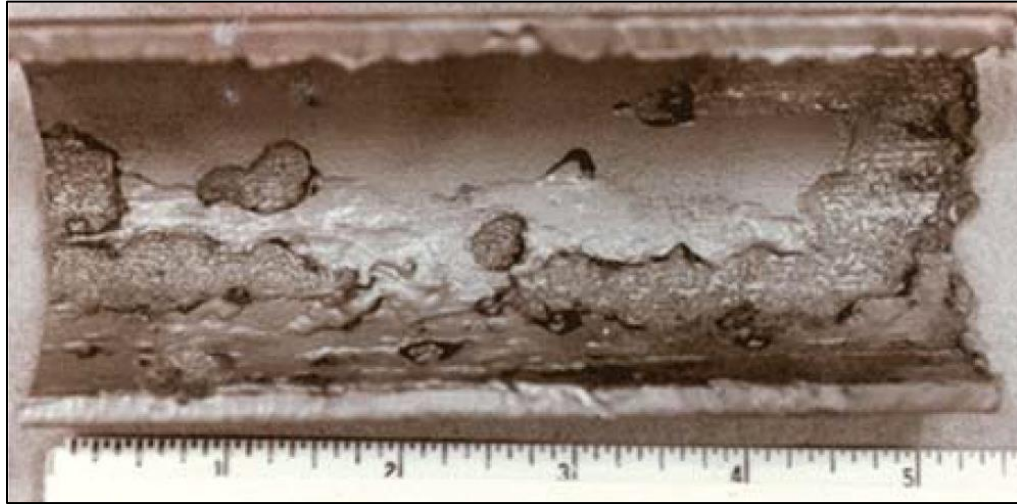


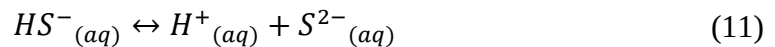
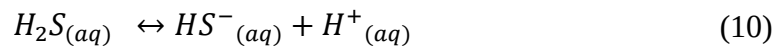
Figure 12: Mesa corrosion of tubular steel induced by CO₂-rich hydrocarbon streams.

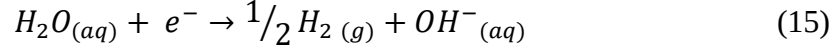
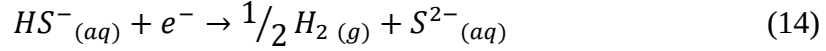
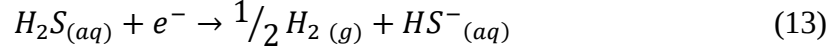
2.6.1.2 Sour Corrosion

Sour corrosion happens when pipeline fluids contain water and H₂S, leading to various issues such as metal loss, sulphide stress cracking (SSC), Hydrogen Induced Cracking (HIC), and Stress Corrosion Cracking (SCC) [142].

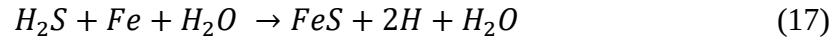
2.6.1.2.1 Metal Loss

H₂S corrosion follows a similar process to CO₂ corrosion, resulting in an iron sulphide (FeS) layer, which partly coats the pipe and reduces the corrosion rate. However, local breakdown of this layer can cause small cracks [139,143–145]. The electrochemistry of this process is illustrated by [Eqs. 8-15](#). Anodic reaction corresponds to [Eq. 8](#), while dissociation reactions are characterized by [Eqs. 9-11](#), and cathodic responses by [Eqs. 12-15](#).





Subsequently, iron sulphide forms through Fe^{2+} and S^{2-} bonding, evident in [Eq. 16](#). The overall reaction characterizing the sour corrosion process is captured by [Eq. 17](#).



2.6.1.2.2 SSC

SSC can occur under sour conditions and high stress levels, leading to embrittlement and potentially catastrophic failure. Factors influencing SSC include steel composition, microstructure, mechanical properties, pH, H_2S pressure, load, temperature, and time [139,146–150]. SSC development in pipes has multiple stages, starting with pre-existing stress-deepening cavity tips, then brittle material fracturing and hydrogen charging at the fracture tip, leading to rupture [151]. [Figure 13](#) outlines SSC stages [152]. Pre-existing stress deepens the cavity's tip. This may result from pipeline weight or fluid pressure. Brittle material fractures at a defined tensile stress, forming a crack. Fracture stops in a ductile zone. Hydrogen charging occurs at the tip, leading to further spreading and material breakage, potentially causing unforeseen pipeline rupture.

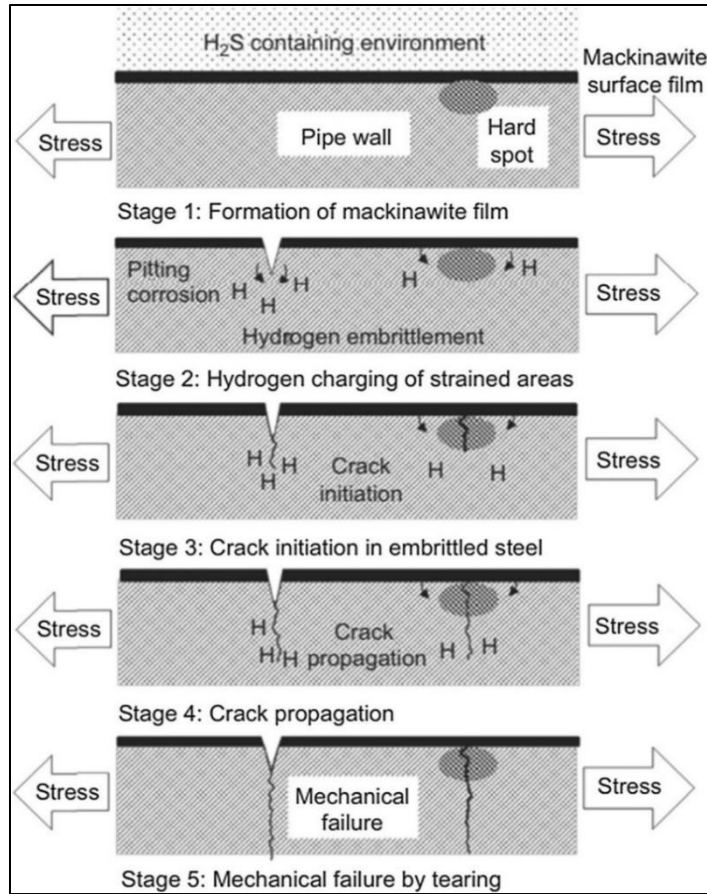


Figure 13: Mechanism of SSC.

2.6.1.2.3 HIC

HIC is common in steel pipes with iron sulphide deposits, affecting areas around residual manganese sulphide particles from steel processing [18]. Corrosion produces hydrogen atoms that accumulate in microstructural deficiencies of the pipe [153,154]. Environmental factors, like pH and temperature, influence the HIC process [155,156]. The steel's microstructure plays a crucial role in providing potential crack sites. Because of their sharp geometry, manganese sulphide inclusions trap hydrogen atoms, causing fracture initiation [157–159]. Steel's crystalline structure, grain size, and boundary feature impact HIC susceptibility. Smaller grains provide more hydrogen migration channels, but some studies suggest grain boundaries can inhibit HIC [160,161]. Micro-alloying elements also influence HIC, with controlled phosphorus, copper, and manganese levels enhancing HIC resistance [161–163]. According to Figure 14, HIC starts in stages driven by hydrogen atoms. They initially diffuse between inclusions and the metal surface. Then, atoms combine to form H_2 molecules, increasing pressure in the area. Elevated pressure initiates cracks in that area [153,164].

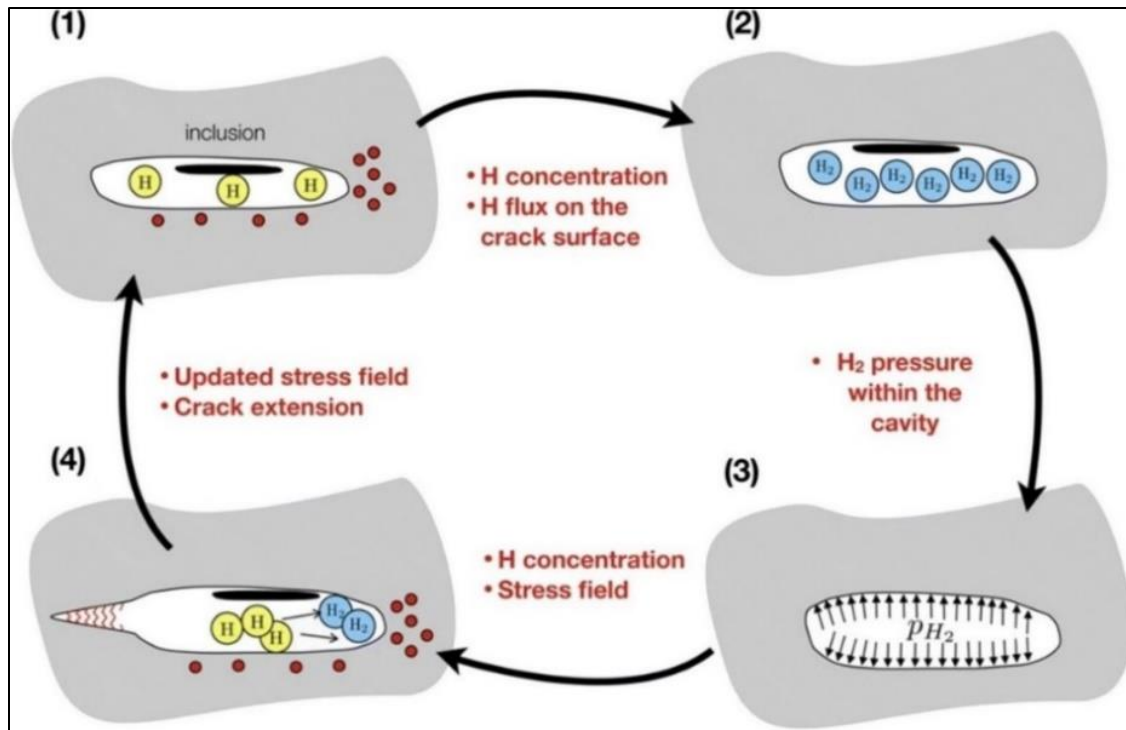


Figure 14: HIC initiation mechanism.

2.6.1.2.4 SCC

SCC is a complex and hazardous corrosion involving multiple factors [159]. It emerges when three elements coexist: (1) mechanical stress, (2) susceptible alloy, and (3) corrosive environment. SCC is related to HE, where hydrogen acts as an environmental factor inducing SCC initiation and propagation mechanisms, as shown in Figure 15 [165–167]. It starts slow crack growth under safe mechanical loads, yet critical size attainment, combined with applied loads, can lead to abrupt and catastrophic fast fracture. SCC poses a significant risk to engineering applications, endangering plants, and equipment integrity.

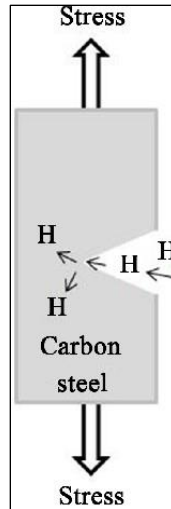


Figure 15: SCC mechanism.

2.6.1.3 MIC

MIC arises due to microbes like bacteria and fungi. MIC likely contributes to 20 – 30% of underground pipeline external corrosion. Microorganisms on steel surfaces don't immediately impact or induce a distinct corrosion type. Their products trigger various corrosion forms, such as pitting, cracking, and under-scale corrosion. Microbial by-products interact with corrosion products, affecting their natural coating layer or prompting further reduction reactions that accelerate breakdown. Aerobic and anaerobic bacteria expedite subsurface pipe corrosion. Obligate aerobic and anaerobic bacteria thrive in the presence or absence of oxygen, respectively [135,168].

2.6.2 External Corrosion

External pipeline corrosion can be caused by ambient or underground environments, with the latter being more damaging. Cathodic protection and pipeline coating can mitigate subsurface corrosion [169]. This corrosion leads to metal loss, reducing pipe wall thickness and ductility, potentially causing failure if not maintained. Various factors, like electrochemical cells, differential aeration, soil characteristics, and galvanic cells, can lead to external corrosion in buried oil and gas pipelines [170–173].

2.7 Hydrogen Embrittlement

Affordable hydrogen delivery is vital for a viable hydrogen-based future. While pipeline transportation is highly efficient, boosting distribution requires added energy and cost [174–176]. Gas pipelines primarily use low-carbon iron-based steels, vulnerable to hydrogen attacks (e.g., HE) [62,177]. HE degrades metals' mechanical properties, making them brittle and prone to fracture. Exposure during processes like electroplating triggers hydrogen diffusion, forming voids and stress concentrations, ultimately causing material failure [178,179].

2.7.1 Types

HE has two categories based on hydrogen origin: external and internal. External HE results from prolonged hydrogen exposure in the surrounding environment, absorbed from the atmosphere or generated through corrosion [180]. On the other hand, internal HE stems from hydrogen within the flowing fluid [181]. Fracture depth can indicate the type of HE [182].

HE takes two forms: reversible and irreversible. Reversible HE involves hydrogen atom migration to potential crack sites, retarding metal fracture propagation. Irreversible HE, however, requires hydrogen atom bonding to create molecules, forming high-pressure hydrogen gas that accelerates metal cracking [183].

2.7.2 Hydrogen Source

The hydrogen sources can originate from external sources (such as corrosion, H₂ gas, and H₂S environments) or internal sources (like metal treatment practices) [183,184]. Hydrogen atoms on metal surfaces due to corrosion, electrochemical charging, or hydrogen gas streams can diffuse into the metal structure, a process known as Hydrogen Dissolution [184]. The quantity of dissolved hydrogen is denoted by Sievert's Law, as shown in Eq. 18 [185].

$$C_H = S \sqrt{P_{H_2}} \quad (18)$$

Where S is the solubility constant, P_{H_2} is hydrogen's partial pressure.

2.7.3 Mechanism

Hydrogen diffuses into metals in atomic form, releasing electrons and forming positive-charged hydrogen ions (H⁺). HE development requires the presence of diffusible hydrogen, high-strength steel, micro-cracks, and a sufficient diffusion period [186,187]. HE is triggered by material susceptibility, mechanical stress, and hydrogen-rich environments, as shown in Figure 16. Various mechanisms were discussed in the literature, including hydrogen-induced decohesion (HID), adsorption-induced dislocation emission (AIDE), and hydrogen-enhanced localized plasticity (HELP) [25,188–190].

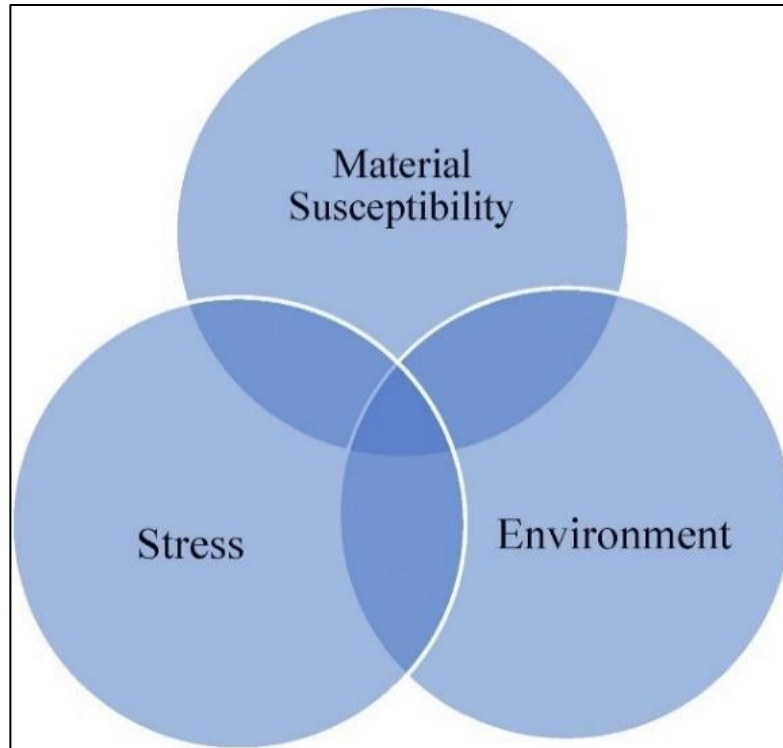


Figure 16: Factors that induce initiation of HE processes.

2.7.3.1 HID

It occurs when dissolved hydrogen accumulates at sites within the metal, weakening cohesive forces holding metal ions. This diminishes tensile properties, making it prone to fracture.

2.7.3.2 AIDE

It happens when hydrogen on the metal surface triggers dislocation emission. Dislocations are defects within the lattice, and their emission weakens the material.

2.7.3.3 HELP

Creates localized dislocation groups due to hydrogen. These groups can rupture at dislocation tips due to increased stress caused by hydrogen, weakening the material.

Hydrogen diffuses rapidly in metals, leading to HE, particularly in thin metal structures. The diffusion is driven by hydrogen concentration and can occur through thermal or temperature-driven mechanisms [191].

2.7.4 Consequences

HE reduces material elasticity, yield strength, and ultimate tensile strength and can lead to internal cracking and surface blistering, as depicted in

Figure 17 [192,193]. Blistering occurs when hydrogen atoms recombine near the surface, generating pressure that exceeds material yield strength, forming blisters [25].

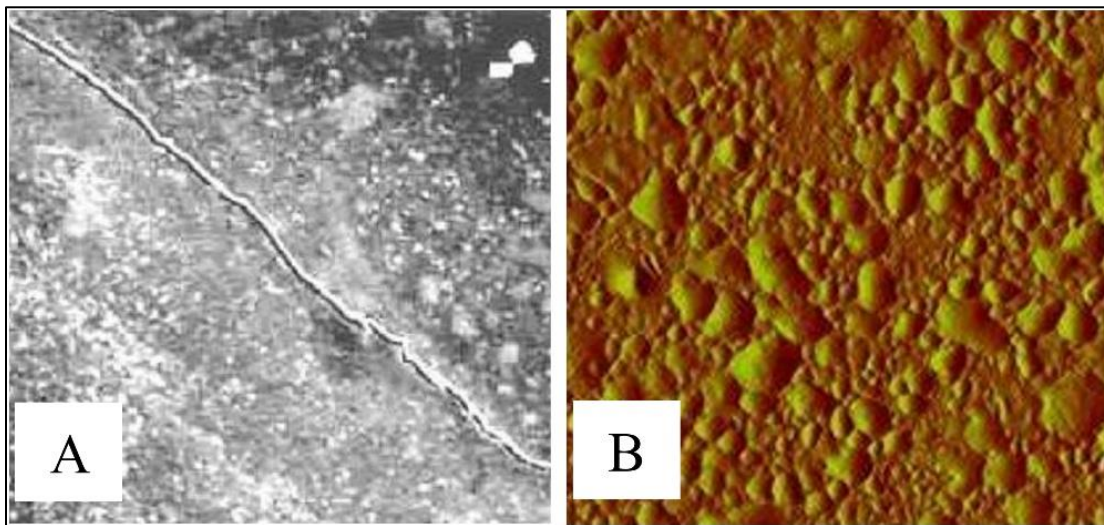


Figure 17: Hydrogen-induced damage on steel: A. Cracking. B. Blistering.

2.7.5 Protection

Protection measures include using materials less permeable to hydrogen, applying coatings and liners, employing cathodic protection, modifying manufacturing processes, and applying post-manufacturing treatments like heat treatment and electrochemical hydrogen removal [194–199].

Numerous studies have extensively analysed HE across various hydrogen processing stages, encompassing transportation, utilisation, and storage [200–208].

2.8 Coatings and Liners

2.8.1 Coatings

Coatings prevent corrosion by acting as barriers between metals and surroundings by inhibiting electrochemical reactions. Organic, inorganic, and metallic layers are used [209–211]. H₂-NG blend safety alters pipeline performance and poses safety concerns due to hydrogen's high flammability and low ignition threshold. Coatings must withstand H₂-NG blend conditions and protect against material damage. Despite comprising just 5% of costs, coatings play a vital role in ensuring the longevity of pipelines [212]. Different types of coatings have been used in the petroleum industry, including coal-tar enamel (CTE), fusion-bonded epoxy (FBE), three-layer polyolefin (3LPOs), high-performance composite (HPCC), and polyurethane-based (PU) coatings. FBE and 3LPO coatings have been predominant in the coating evolution in the last three decades, as depicted in

Figure 18 [213].

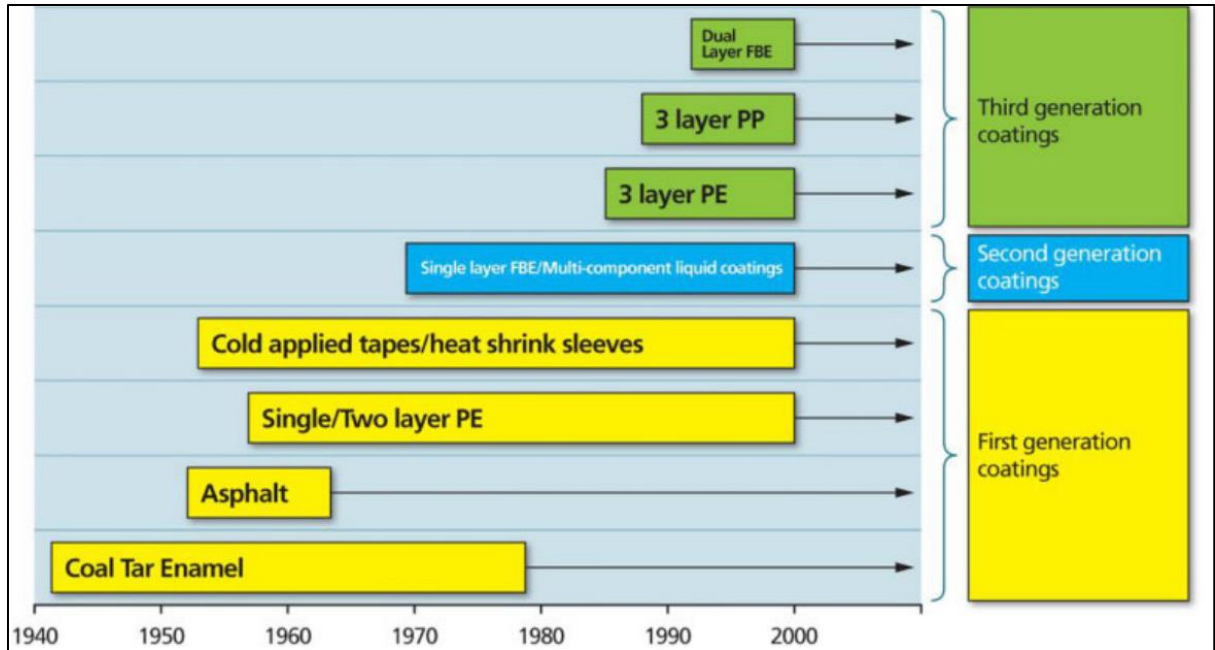


Figure 18: The evolution of pipeline coatings from 1940 to 2000.

2.8.1.1 CTE

CTE coatings have been extensively used for several decades as anticorrosion coatings on petroleum pipelines [213]. They adhere well to most surfaces, tolerate poorly treated surfaces, and require low maintenance [214]. Composed of plasticized coal tar pitch, coal, and refined products with additives, CTEs offer toughness, UV resistance, and thermal stability [215,216]. Their resistance to moisture makes them suitable for offshore pipelines working at ambient temperatures [216]. Increased mechanical strength is achieved by adding fiberglass, which enhances their resistance to stress and damage during transportation and installation [215]. Nonetheless, it has been claimed that coal tar has specific negative health impacts [213].

2.8.1.2 FBE

FBE coatings are used in the oil and gas industry for their excellent corrosion resistance properties. Since the 1960s, they've been applied to metallic structures exposed to harsh conditions that accelerate corrosion [217–219]. FBE coatings provide a durable protective layer against these conditions, extending the lifespan of equipment and structures [220,221]. FBE coatings are applied electrostatically as a powder mixture, forming a durable coating within minutes [222]. They are flexible, allowing thermal contraction and expansion without damaging the coating [223,224]. Figure 19 depicts applying FBE on steel pipes [225].

FBE coatings are employed in hydrogen piping networks for storage and distribution [226]. They offer a robust barrier against hydrogen-induced degradation, ensuring piping

system integrity and reliability. Early FBE coatings had flaws, but progress by resin manufacturers, pipeline operators, and formulators led to significant enhancements [227].

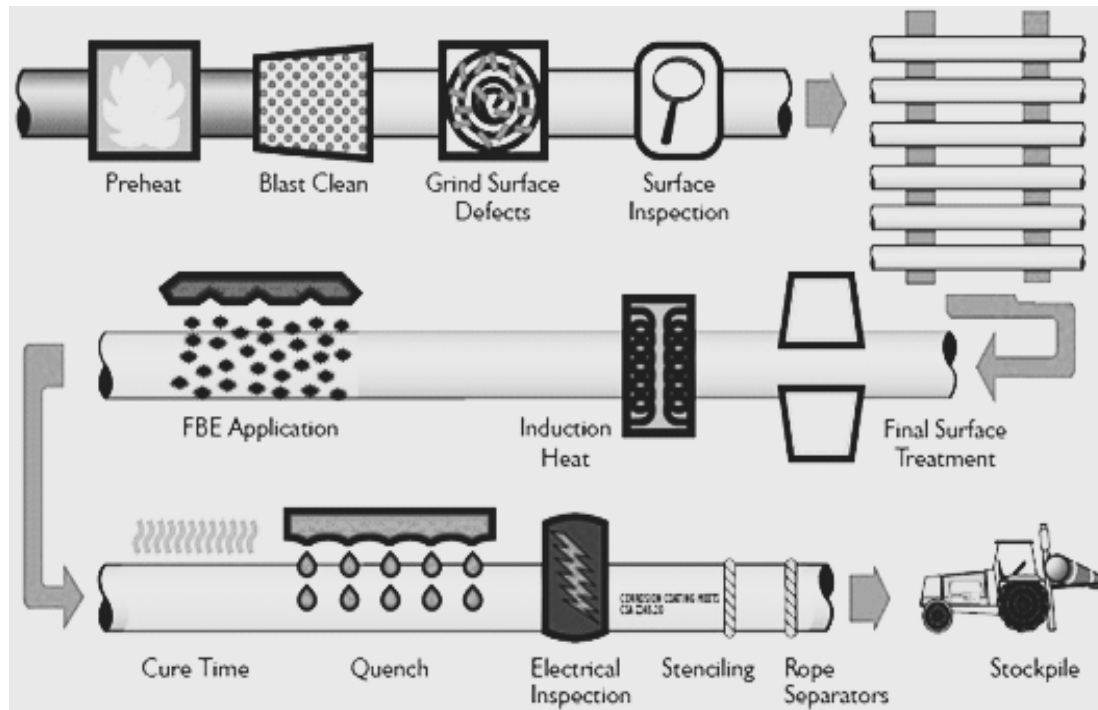


Figure 19: Application of FBE coating in pipelines.

2.8.1.3 3LPO

3LPO coatings are applied over FBE coatings, which are sensitive to water and easily damaged by mechanical impacts [228]. Polyolefin resins, such as Polyethylene and Polypropylene, provide a flexible, damage and moisture-resistant layer over the FBE coating [229]. An adhesive layer is used to bond POs and FBE, often involving a polar group-interacting PO resin [230]. The 3LPO coating layering is illustrated in Figure 20. However, compromises during surface treatment can undermine the long-term durability of these coatings [231].

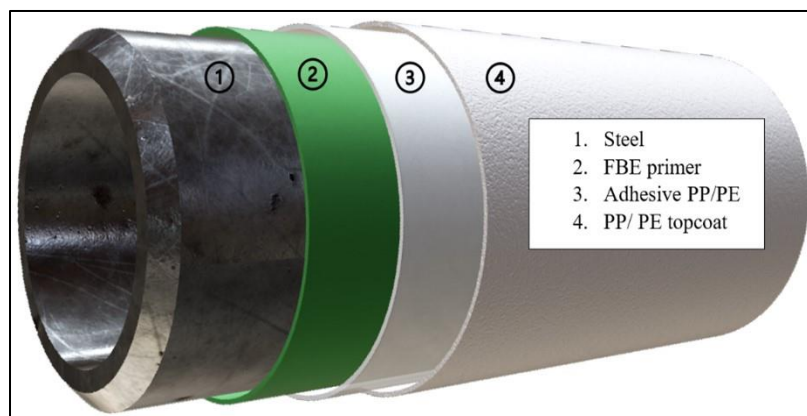


Figure 20: 3LPO coating system.

ISO-21809-1 standard outlines PO coating application with quality tests and inspection procedures [232]. Application temperature range details are provided in [Table 4](#).

Table 4: Temperature ranges for some PO coatings.

Coating material	Temperature Ranges (°C)
Low-Density PE	- 20 —40
Medium-Density PE	- 40 —60
High-Density PE	- 40 —60
Polypropylene	- 20 —90

2.8.1.4 HPCC

HPCC is a single-layer, multicomponent coating system, including FBE base, medium-density PE, and chemically modified PE adhesive [233]. These components are electrostatically applied in a powder-coating process, as shown in [Figure 21](#). Coating effectiveness hinges on type, application method, and metal characteristics [234]. Proper surface preparation, rust removal, and contaminant cleaning are crucial for adhesion and effectiveness [235].

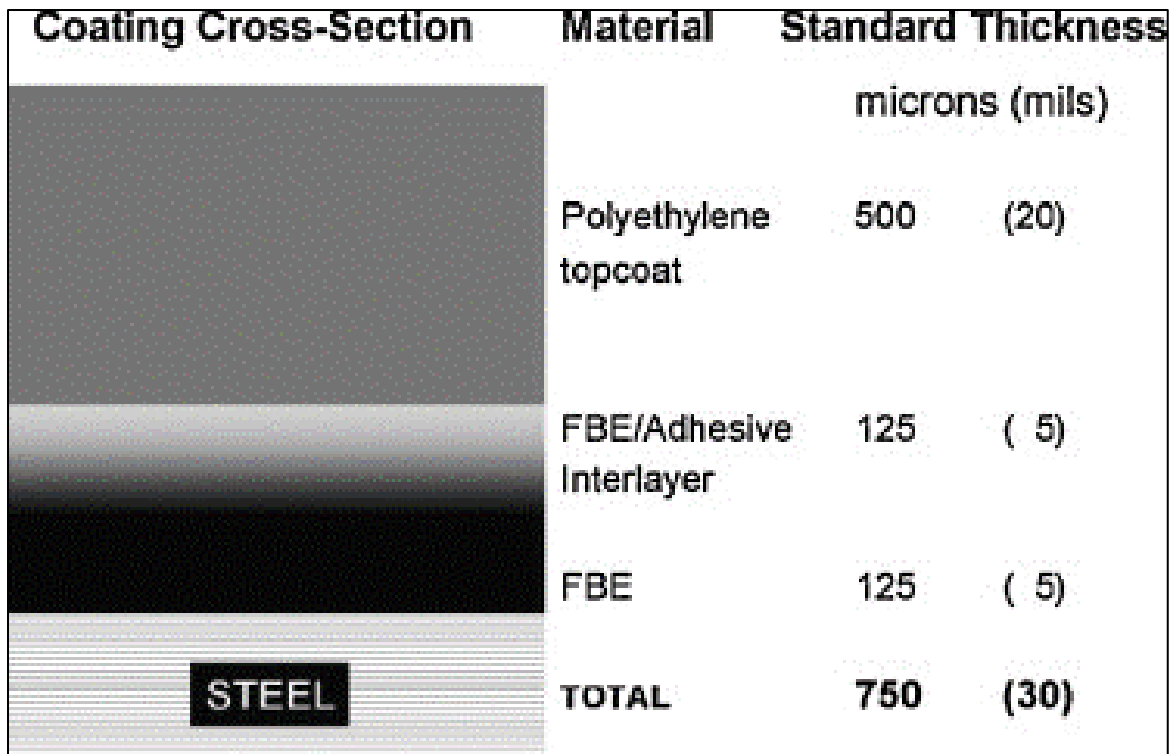


Figure 21: HPCC cross-section schematic.

2.8.1.5 PU

PU coatings are polymerizing di-isocyanates and polyols [236–240]. [Figure 22](#) illustrates the polymerization reaction [241]. The polymerization methodology affects PU's final

structure and properties [242,243]. They are known for their durability, flexibility, and resistance to chemicals, corrosion, and UV. They can be applied as a liquid or spray and serve as a topcoat to increase the durability of other coatings [244–246]. PU coatings can be prepared using either a one-component [247,248] or a two-component system [249,250], depending on the specific application and desired properties. They offer strong adhesion, friction and impact resistance, and high-temperature resilience, making them suitable for diverse coating needs, including the oil and gas pipelines industry [251].

In the last few decades, researchers have combined PU with multifunctional groups in a drive to develop materials for broad industrial applications [252]. Following through the PU resin has attracted increasing interest in the coating sector. The nature of the monomers and their ratio decide the ultimate performance of the coating. By selecting the monomers and the appropriate synthesis conditions, PU performed as anticorrosion, antifouling, and anti-flammable coatings. The significance of this trend is conditioned by the ability of hydrophobic surfaces or complexes to order the macromolecular chains, as well as affect the mechanical properties of PU. From the standpoint of designing materials with protective PU properties, it is promising to form a PU coating with hydrophobic, less permeable, and flame-retardant.

PU versatility in monomer selection makes it really applicable in a wide range of coatings. PU develops an exceptionally tailored property, good mechanical characteristics, an anti-corrosive nature, high hydrophilicity, controllable biodegradability, and solvent resistance. In the last decade, it has been acknowledged by many scientists, engineers, and researchers to be applied in several fields including but not limited to medicine, food processing, construction, marine, membrane, and health [253].

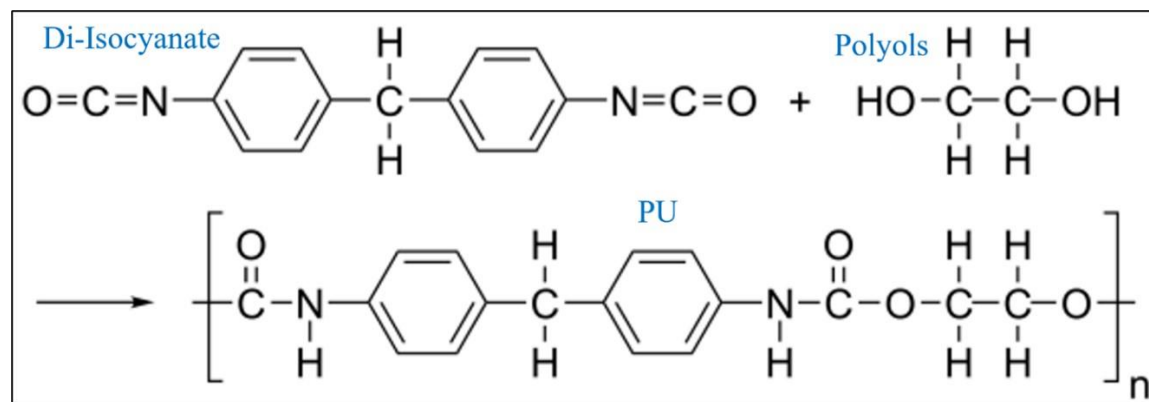


Figure 22: Polymerization reaction for PU synthesis.

2.8.2 Liners

Internal pipeline corrosion can be addressed through various methods, including material selection, corrosion inhibitors, and the application of liners or coatings. Liners are substantial barriers, thicker than coatings, positioned between steel pipes and the

surrounding environment. These liners can be categorized into two types: polymer-only and polymer-composite liners, with the latter offering enhanced protection through the integration of composites into the liners' structure [254]. Presently, polymer-only liners, synthesized from materials like polyethylene and polyamide, are employed to combat internal corrosion in natural gas pipelines [255]. Composites utilized in liners fall into two categories: Fiber-reinforced plastic (FRP) and Fiber-reinforced epoxy (FRE), which are particularly beneficial in harsh, corrosive environments during downhole and upstream applications. Furthermore, thermoplastic liners (TPL), such as High-density polyethylene (HDPE), polyamide (PA11, PA12), and polyvinylidene fluoride (PVDF), have been cost-effective tools in controlling downhole failures within the oil and gas production sector, as evidenced by numerous case studies [254,256]. Gas molecules can permeate polymers through a solution-diffusion process. Initially, the gas dissolves within the polymer, followed by diffusion through the polymer membrane. Finally, the gas desorbs from the polymer, resulting in permeation [257]. In comparison, polymer-composite liners, featuring impermeable metallic layers, provide superior protection against corrosive gases than polymer-only liners. This mechanism aids in reducing the steel corrosion rate by mitigating the reactive gas flux to the internal surface of a pipeline [254].

Pipeline integrity is vital when introducing hydrogen due to safety concerns. Coating and lining failure incidents can lead to pipeline failure, and H₂-NG blend explosions. Higher hydrogen concentrations increase susceptibility to HE, intensifying pipeline damage. Liners in high-pressure hydrogen storage vessels aim to reduce HE vulnerability, but hydrogen can still permeate these materials due to their small size. Hydrogen's small size leads to approximately three times more annual leakage than natural gas, particularly in long-distance pipelines, compounding network complexity [258]. Additionally, fire-retardant coatings (FRC) might be applied in high-temperature zones to limit heat transfer to the inner part of the pipe. FRCs inhibit heat spread through chemical releases or heat barrier formation [259–261]. Various FRCs are utilized to meet fire safety standards, such as those set by *NFPA* and the *American Wood Protection Association (AWPA)* [262,263].

CHAPTER 3

METHODOLOGY

The approach that will be taken to fulfill the objectives is divided into two parts: simulation and experimental. In the simulation part, PIPESIM software will be utilized to simulate a gas transmission network from the Western Australia network system with different H_2 fractions. The experimental part is subdivided into two parts as well. Firstly, a PU-based coating will be synthesized and tested for protection properties and fire resistance. Secondly, the developed coating will be applied to steel and liner substrates and stored in a hydrogen-rich environment at high pressure (1480 psi) for 30 days. Then, the coated substrates will be evaluated to check their degradation levels and suitability for implementation inside the high-pressure pipelines that contain elevated hydrogen concentrations. In the closed system, H_2 will be mixed with CH_4 (representing natural gas). Multiple H_2 - CH_4 concentrations will be prepared, and the samples will be soaked and tested afterwards. Figure 23 provides a summary of the methodology in this research.

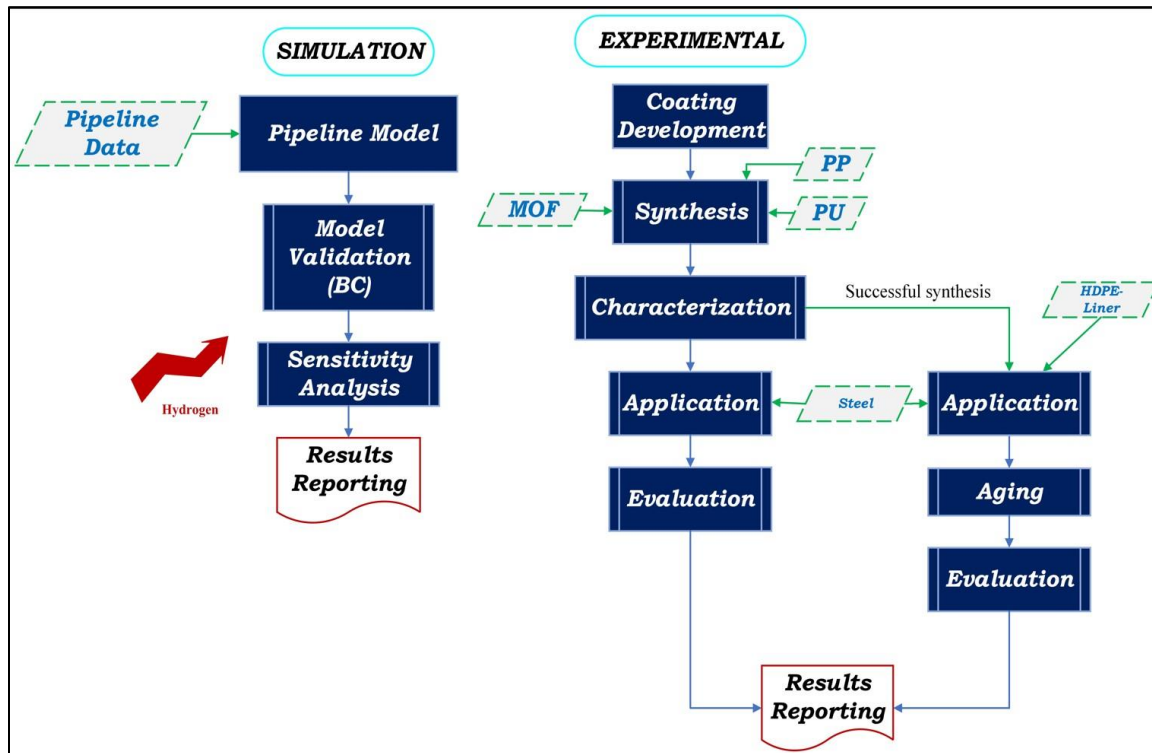


Figure 23: Methodology schematic to fulfill research goals.

3.1 Gas Network Simulation

3.1.1 PIPESIM Software

Over the last 30 years, the PIPESIM simulator has been refined by including not just the most recent scientific findings in the three fundamental areas of flow modeling (multiphase flow, heat transfer, and fluid behavior), but also the most recent advancements in computing, and oil and gas industry technology [264]. The simulator is equipped with state-of-the-art mechanistic models, such as those for three-phase processes, heat transfer, and PVT. The geographical information system (GIS) map canvas, powered by ESRI, aids in providing an accurate geographic depiction of wells, machinery, and networks. Both manual network construction on the GIS canvas and automated network generation from a GIS shapefile are supported. Fast modeling and analysis are made possible by the graphical wellbore's involvement and other features available in the software [265]. PIPESIM has been used to optimize production and improve the efficiency of the production system, including the pipeline networks [266–270].

To ensure the optimal functioning of the PIPESIM pipeline model, it is essential to accurately input the following components:

- Flowline with specifications such as diameter, length, and elevation profile.
- Nodes (sink/source) with appropriate boundary conditions (BCs).
- Fluid model (e.g., gas composition).
- Equipment's specifications (e.g., compressors).

The software version used to perform this study is PIPESIM 19.4 steady-state multiphase simulator. The GIS capabilities of PIPESIM are utilized to construct the network model. The necessary data for the model's execution were obtained from accessible online sources.

3.1.2 Pipeline Description

GGP is a 1,380-kilometer transmission pipeline built in 1996. GGP links Yarraloola in the Pilbara region to Kalgoorlie in the Goldfields-Esperance region. The GGP includes the 47-kilometer Newman lateral as well [276–280]. The GGP system transports between 180 and 200 TJ/D from Northern to Southern WA. APA Group owns and operates the GGP. Additionally, Alinta Energy maintains an 11.8% share in the pipeline [277]. The GGP interconnects with several APA Group-owned laterals. The connections, nodes, and features of GGP are outlined in a simple schematic diagram in [Figure 24](#). There are 13 terminals (or sinks) connected to the GGP mainline, including the Murrin Murrin lateral, which delivers the gas to Eastern Goldfields Pipeline (EGP).

Pipeline information was collected from official Australian government websites, online portals of operating companies, and the published reports [276–280], and summarized in Table 5. The specifications pertain to the main GGP line and do not encompass the attached distribution lines (i.e., laterals). Due to the limited information about these laterals, the Newman lateral’s diameter is presumed to be applicable to all other laterals connected to GGP’s main line.

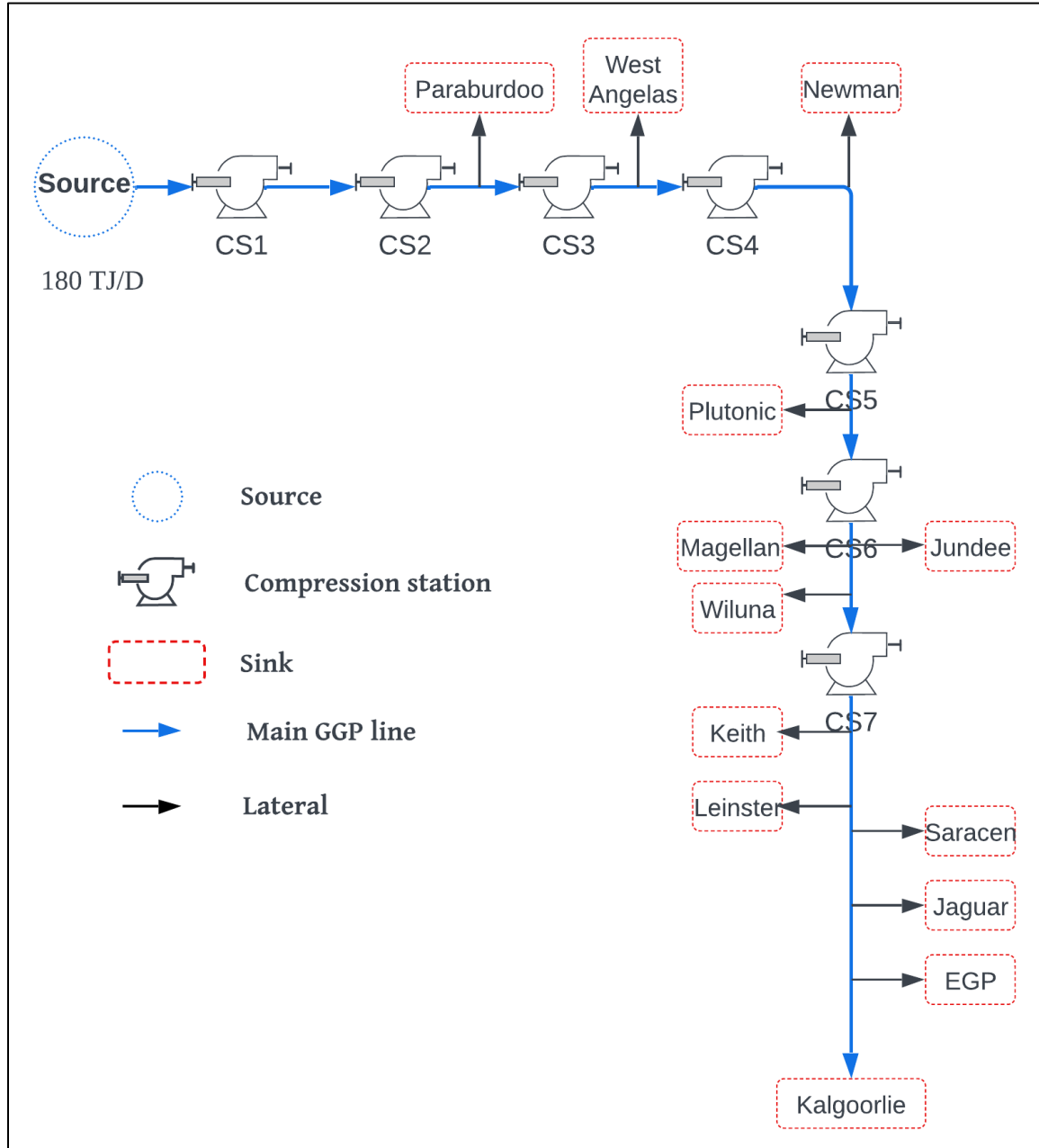


Figure 24: GGP pipeline features and nodes schematic.

Table 5: GGP general information.

Property	Value
Length, Km	1380
Diameter, mm (before Newman)	406
Diameter, mm (after Newman)	356
Newman lateral diameter, mm	219
Thickness, mm	5.3 – 6.8
Capacity, TJ/day	180 – 200
Number of compression stations	7
Maximum allowable operating pressure (MAOP), psia	1480

The pipeline's terrain data were retrieved from eAtlas [281], a platform that serves as both a mapping tool and a repository for environmental research data. These values were imported to PIPESIM's model, while the elevation profile of the network was automatically obtained through GIS plug-in. Pipeline's layout and elevation profile captured by GIS is represented in [Figure 25](#) [Figure 26](#), respectively.

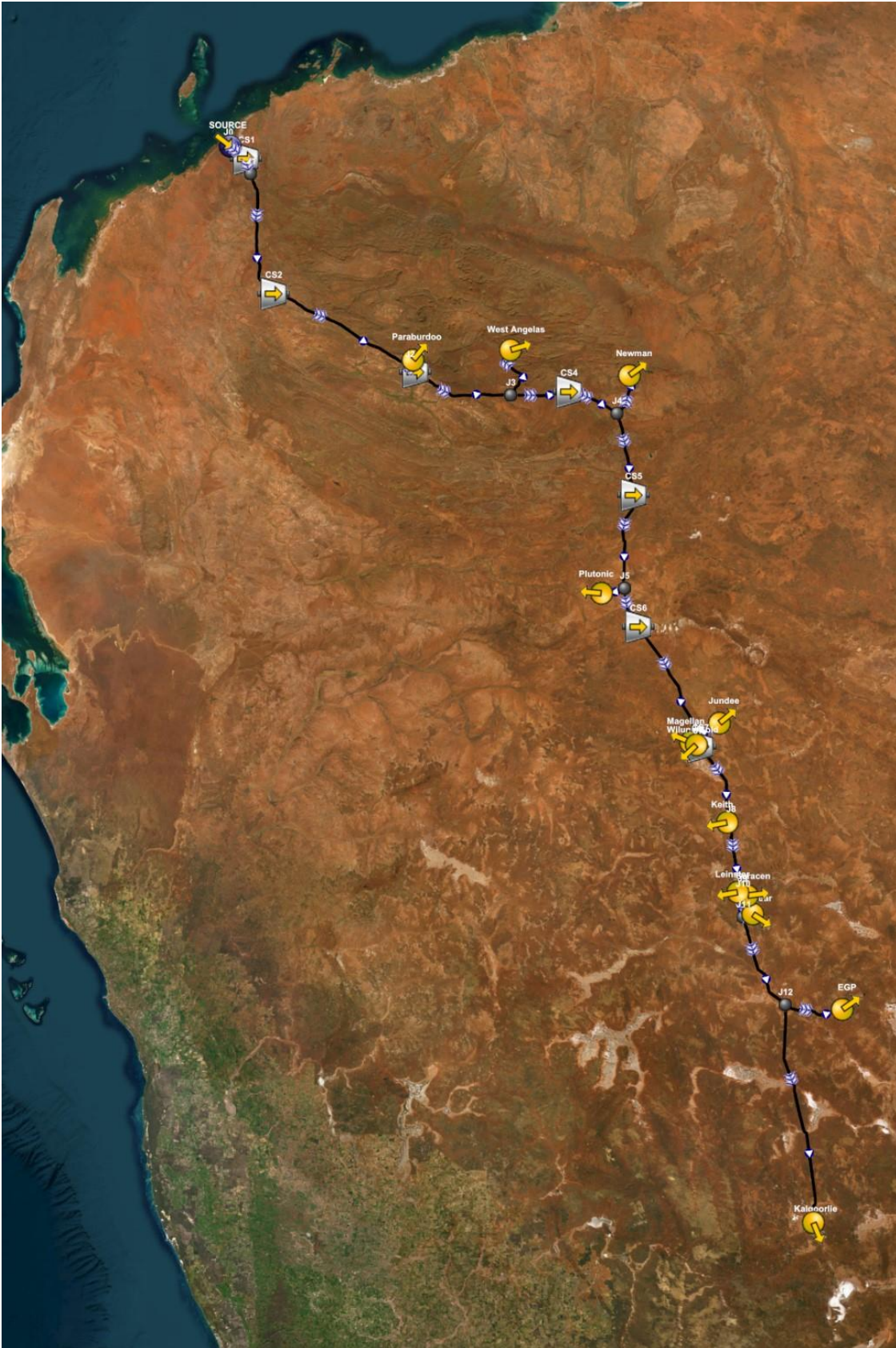


Figure 25: Snapshot from PIPESIM software for the developed GGP Model.

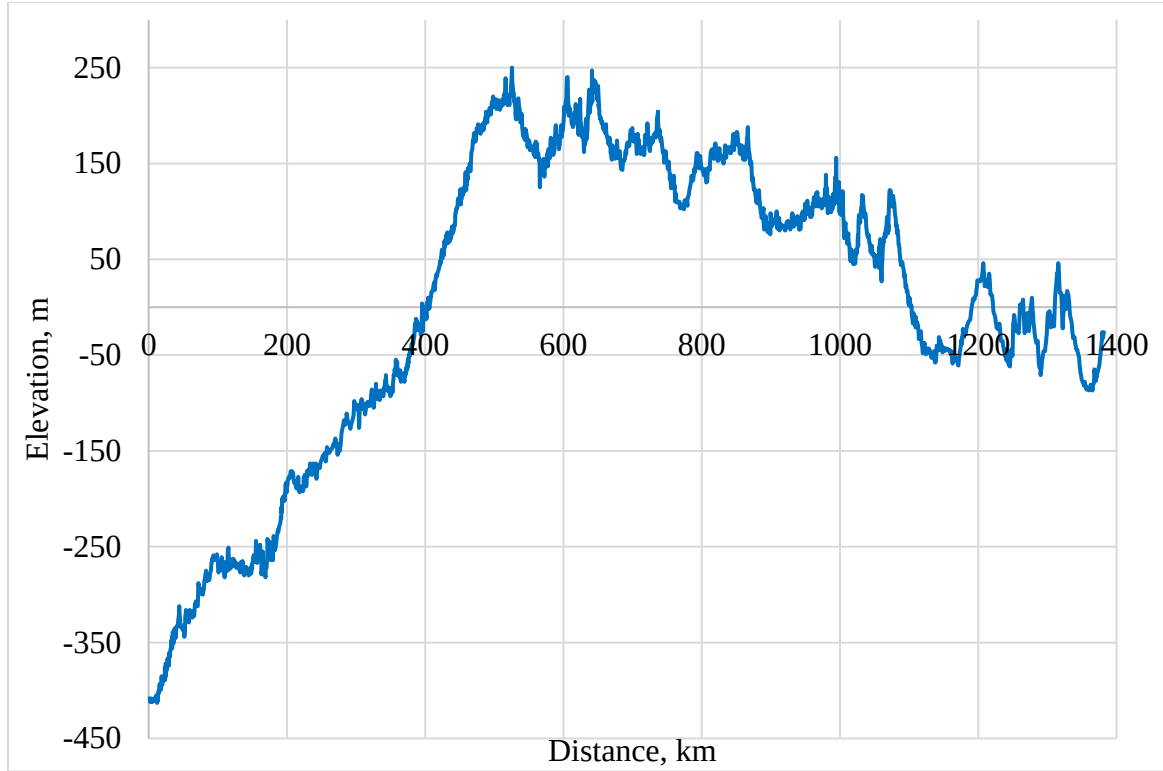


Figure 26: Elevation profile changes along GGP mainline.

The locations of the 7 compression stations (CS) are outlined in Table 6. The power used for each compressor was set to ensure an output pressure less than the maximum operating pressure of the GGP (i.e., 1480 psi). Also, the adiabatic efficiency of all compressors was kept at 70% [264].

Table 6: Compression stations data.

Compressor Number	Latitude, Deg	Longitude, Deg	Elevation, m	Distance, km
CS1	-21.4432	115.9573	41	24
CS2	-22.6535	116.2251	142	168
CS3	-23.3503	117.5959	328	330
CS4	-23.5255	119.0827	619	492
CS5	-24.4388	119.7066	602	628
CS6	-25.5943	119.7523	527	764
CS7	-26.6346	120.3523	503	896

Due to the unavailability of the precise gas composition of GGP, the reference gas composition from the Mondarra Gas storage and processing plant in WA has been used to represent the gaseous stream [282]. Mondarra plant's gas composition was cross-referenced with the Gas Supply Act 2009, considering the allowable maximum molar fractions of non-hydrocarbon components such as CO₂, H₂O, inert gases, and H₂S

[283,284]. A comparison between Mondarra and GGP gas specifications is presented in Table 7.

Table 7: Gas specifications and characteristics for Mondarra and GGP.

Component	Mondarra	GGP
Maximum Carbon Dioxide, mol%	4	4
Maximum total inert gasses, mol%	7	7
Maximum higher heating value, MJ/m ³	42.3	42
Minimum higher heating value, MJ/m ³	37	35.1
Minimum Wobbe Index	46.5	46
Maximum Wobbe Index	51	52
Maximum total Sulphur, mg/m ³	10-20	10
Maximum Hydrogen Sulfide, mg/m ³	2	5
Maximum oxygen, mol%	0.2	0.2
Maximum water, mg/m ³	48	48
Hydrocarbon dewpoint over the pressure range 2.50 to 8.72 MPa (absolute), °C	< 0	< 0

3.1.3 Model Description

Utilizing the inputs detailed earlier, the PIPESIM 19.4 software was employed to construct a simulation model for gas transmission within the GGP. The initial model configuration employed a gas composition outlined in Table 8, serving as the baseline for the GGP model.

Table 8: Gas composition used in simulation (base case).

Component	Mole %
Water	1
Methane	87.43
Ethane	5.78
Propane	1.71
Isobutane	0.18
Butane	0.27
Isopentane	0.05
Pentane	0.01
Hexane	0.03
Hydrogen	0
Nitrogen	2.51
Carbon Dioxide	1
C7+	0.03

In PIPESIM, it is necessary to provide either pressure (P) or flow rate (Q) values at each node for solving the entire network system. These designated values are known as BCs. The BCs established for gas transmission simulation are summarized in Table 9. The flow rates and pressures are sourced from a diverse range of references, including the APA reports [276,285].

Table 9: BCs of GGP nodes used in the model.

Node	Rate, MMSCFD	Pressure, psia
Source	-	1400
EGP	-	500
Jaguar	1.28	-
Jundee	2.93	-
Kalgoorlie	20.4	-
Keith	13.74	-
Leinster	18.14	-
Magellan	2	-
Newman	-	925
Paraburdoo	9.16	-
Plutonic	3.76	-
Saracen	2.2	-
West Angelas	18.6	-
Wiluna	2.75	-

It's important to highlight that an average heating value was employed to convert the flow rates from TJ/D to MMSCF/D [70]. The limits of Higher Heating Value (HHV) have been acquired from the established gas quality specification for gas transmission pipelines as specified in the Gas Supply (Gas Quality Specifications) Act 2009 [283]. These values are summarized in Table 10.

Table 10: Higher Heating Value limits of WA gas transmission networks.

Min HHV, MJ/m ³	35.1
Max HHV, MJ/m ³	42
Average HHV, MJ/m ³	38.55

3.1.3.1 Equations

The flow correlations integrated into PIPESIM cover various flow orientations, such as horizontal, vertical, and inclined scenarios [271]. PIPESIM automatically selects the appropriate correlation based on the phase behavior of the fluid at the particular section in the pipeline. The single-phase correlation utilized in this study is Cullender and Smith correlation [272]. The steady-state single phase pressure gradient is given by Eq. 19.

$$-\left(\frac{dP}{dL}\right) = \left(\frac{dP}{dL}\right)_{elevation} + \left(\frac{dP}{dL}\right)_{acceleration} + \left(\frac{dP}{dL}\right)_{friction} \quad (19)$$

Where the elevation, acceleration, and friction pressure gradients are given by:

$$\left(\frac{dP}{dL}\right)_{elevation} = -\rho g \sin\theta \quad (20)$$

$$\left(\frac{dP}{dL}\right)_{acceleration} = -\rho v \frac{dv}{dL} \quad (21)$$

$$\left(\frac{dP}{dL}\right)_{friction} = -\frac{f\rho v^2}{2D} \quad (22)$$

Where f is friction factor (dimensionless), ρ is density (lbm/ft³), v is velocity (ft/s), g is gravitational acceleration (ft/s²), θ is angle of the pipe to the horizontal (degrees), D is pipe diameter (ft), and L is pipe length (ft).

The total pressure drop along the pipe is calculated by Cullender and Smith correlation summarized by Eqs. 23-26.

$$\frac{dp}{dL} = \frac{P_{down} - P_{up}}{L} \quad (23)$$

$$P_{up}^2 = \frac{P_{down}^2 - a^2}{b} \quad (24)$$

$$a^2 = \frac{25f q_{vG}^2 \bar{T}^2 Z_G^2 (b-1)}{0.0375(12D)^5} \quad (25)$$

$$b = \exp\left(\frac{0.0375\gamma_G L}{\bar{T} Z_G}\right) \quad (26)$$

Where P_{down} is downstream pressure (psi), P_{up} is upstream pressure (psi), q_{vG} is stock tank volume flow rate (SCF/d), $\bar{T}$ is average temperature (°R), Z_G is gas compressibility factor (dimensionless), and γ_G is gas specific gravity (dimensionless).

Viscosity was estimated using the Pedersen correlation, originally developed for oil and gas systems. The correlation is derived from precise estimations of the density and viscosity of methane gas [273,274]. The correlation predicts gas mixtures' viscosity (μ_{mix}) using the formula in Eq. 27.

$$\frac{\mu_{mix}}{\mu_0} = \left(\frac{T_{cmix}}{T_{c0}}\right)^{-1/6} \left(\frac{P_{cmix}}{P_{c0}}\right)^{2/3} \left(\frac{MW_{mix}}{MW_0}\right)^{1/2} \left(\frac{\alpha_{mix}}{\alpha_0}\right) \quad (27)$$

Where μ_0 is reference gas (methane) viscosity (cP), T_c is the critical temperature (°R), P_c is the critical pressure (psia), MW is molecular weight (lbm.mol), and α is a parameter to account for molecular size and density which is calculated by the following equations:

$$\alpha_{mix} = 1 + 7.378 * 10^{-3} \rho_r^{1.847} MW_{mix}^{0.5173} \quad (28)$$

$$\alpha_0 = 1 + 0.031 \rho_r^{1.847} \quad (29)$$

Where ρ_r is the reduced density.

The phase behavior and thermodynamic properties of the gas are estimated by the equations of state (EoS). The Soave-Redlich-Kwong (SRK-EoS) was utilized in this model to predict these parameters. SRK-EoS is summarized by Eqs. 30 - 34 [275].

$$P = \frac{RT}{v - b} - \frac{a(T)}{v(v + b)} \quad (30)$$

$$a(T) = a_0 [1 + m(1 - \sqrt{T_r})]^2 \quad (31)$$

$$a_0 = \frac{0.4275 R^2 T_c^2}{P_c} \quad (32)$$

$$b = \frac{0.08664 R T_c}{P_c} \quad (33)$$

$$m = 0.48 + 1.574 \omega - 0.175 \omega^2 \quad (34)$$

Where P is pressure (psia), T is temperature ($^{\circ}\text{R}$), v is specific volume (ft^3), R is gas constant ($\text{psia}\cdot\text{ft}^3/{}^{\circ}\text{R lbm}\cdot\text{mol}$), $a(T)$ and b are correction factors depend on the critical properties of the gas. m is a parameter calculated by the acentric factor value (ω).

3.1.3.2 Sensitivity Analysis

A sensitivity analysis was conducted to appraise network performance under diverse gas compositions. This assessment aids in evaluating the feasibility of integrating hydrogen into the natural gas network.

The H_2 percentage was systematically raised to examine its impact on pressure profiles and fluid properties. Hydrogen concentration in the gas mixture was increased from the baseline of 0% up to 80%, progressing in 10% increments. Hydrogen concentration was increased by reducing methane (CH_4) content from the initial base case composition outlined in Table 8. This incremental adjustment in hydrogen concentration effectively offset the decrease in CH_4 concentration. With the exception of H_2 and CH_4 , the remaining gas components were maintained at a consistent level across all hydrogen scenarios. Similar methodology has been adopted by other scholars [29,286]. The pressure profile of GGP and delivery points (sinks) has been recorded and thoroughly analyzed in all simulation cases. Furthermore, the alterations in the properties of the H_2 -NG blend have been recorded and analyzed.

3.2 Coating Development

Polyurethane and phosphol polyol (PU-PP) dispersions were prepared to obtain a long shelf-life coating with protective properties. Then, the fire retardancy protection

properties against gas/water diffusion were improved by metal organic framework (MOF). The pristine PU dispersions were prepared with defined monomer fixed contents of polyether polyol, whereas the chain extender and diisocyanate contents were increased to have a stiff character of the coating. Several PU formulations were prepared, and the formulation exhibiting the highest stability was chosen for the addition of PP (i.e., PU4/PP4). Subsequently, the most stable PU/PP dispersion was selected for the inclusion of MOF.

All PU/PP-MOF dispersions underwent a comprehensive assessment to evaluate their protection properties and fire-retardancy characteristics. The formulation with the best performance has been further evaluated in harsh environments, including corrosive, UV-exposed, and hydrogen-rich environments. The possible changes in structure and properties of prepared coating in a hydrogen environment have been evaluated.

3.2.1 Materials

Sigma Aldrich provided all the chemicals. The used chemicals were 4,4-dicyclohexylmethane diisocyanate (H_{12} MDI), triethylamine (TEA), ethylene diamine (EDA), poly(tetramethyleneoxide glycol) (PTMG Mn = 2000) dimethylolpropionic acid (DMPA), methyl ethyl ketone (MEK) and dibutyltindilaurate (DBTDL). The PTMG was vacuum dried at 90 °C for three hours prior to use.

3.2.2 Polyurethane (PU) dispersion preparation

Pre-polymer process, in which an NCO-terminated pre-polymer was prepared at the first stage, was followed during PU dispersions. A nitrogen atmosphere was maintained during the reactions. As mentioned, the prepolymers were prepared by charging the H_{12} MDI, DMPA, and PTMG. To accelerate the reaction, the catalyst DBTDL (0.01 wt%) was added to the reaction mixture. To avoid the high viscosity of the reaction mixture the MEK (5.0 wt%) was added during the reaction. The reaction was carried out for 3 h at 85 °C. Later the neutralization (added TEA), dispersion (H_2O), and chain extension (EDA mixed with H_2O) were carried out at 65 °C (30 min), 25 °C (30 min), and 40 °C (2 h), respectively. The best PU dispersion was found when 25.63 mol% DMPA was used (i.e., PU4 as shown in Table 11), and it was considered for PP addition.

Table 11: Formulation of pristine PU coating.

Coating	Composition (Mol)					DMPA (mol %)
	PTMG	DMPA	TEA	EDA	H_{12} MDI	
PU4	1.25	2.05	2.05	0.70	4.00	25.63

3.2.3 Polyurethane Phosphol (PU/PP) dispersion preparation

All the steps were similar to pristine PU dispersion preparation. Only the phosphol monomer was added with PTMG before addition of DMPA. The most stable dispersion was found when 0.4 mol% PP was used, referred to as PU4/PP4 in Table 12.

Table 12: Formulation of coating with defined Phosphol content.

Coating	Composition (Mol)						
	Polyol		DMPA	TEA	EDA	H ₁₂ MDI	Phosphol (mol%)
	PTMG	Phosphol					
PU4/PP4	0.85	0.40	2.05	2.05	0.70	4.00	5.00

3.2.4 MOF prepartation and addition to PU/PP dispersion

The synthesis of the Zirconium metal-organic framework (Zr-MOF) followed the procedures outlined in a prior article [287]. In a 30 mL vial, Zirconium tetrachloride (Zr-Cl₄ - 125 mg, 0.54 mmol), 5 mL dimethyl formamide (DMF), and 1 mL concentrated hydrochloric acid (HCl) were combined and sonicated for 10 minutes until complete dissolution. Subsequently, 2-hydroxyterephthalic acid (135 mg, 0.75 mmol) and 10 mL DMF were added, followed by an additional 20 minutes of sonication. The resulting mixture underwent heating at 80 °C for 12 hours in an oven. After cooling to room temperature, the solid product was filtered, washed repeatedly with DMF, and then with ethanol. The final step involved drying the product at 120 °C under vacuum to obtain the MOF.

A defined MOF content (0.25, 0.50, 0.75, 1.00 and 1.25 wt%) was mixed with PU4/PP4 dispersion and subsequently stirred mechanically and ultrasonically. At first, a defined amount of PU dispersion was weighed in a vial, and MOF was added to that dispersion. Then, the mixture was positioned under mechanical stirring for 1 hour at room temperature. Most of the MOF particles mixed with dispersion. However, this dispersion was not quite satisfactory for a homogenous mixture. Thus, the dispersion was ultrasonicated (60 sonics/min, room temperature) for 1 hour and continued mechanically stirring for the next 24 hours. Finally, a homogenous dispersion was obtained. The conditions were kept similar with different MOF contents. A homogeneous and stable dispersion was obtained with a maximum 1.0 wt% MOF content. Figure 27 shows some pictures of PU/PP-MOF before and after mixing. The evaluated MOF-containing formulations are listed in Table 13.

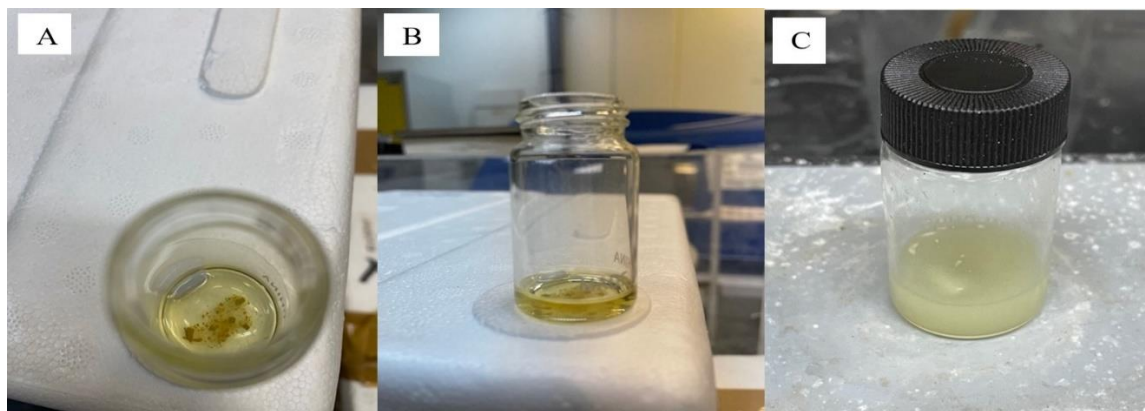


Figure 27: Mixing PU/PP dispersion with MOF. A&B: Before mixing, C: After mixing.

Table 13: Formulation of coating with defined MOF content.

Coating	Composition (Mol)						
	Polyol		DMPA	TEA	EDA	H ₁₂ MDI	MOF (wt.%)
	PTMG	Phosphol					
PU4/PP4-MOF1	0.85	0.40	2.05	2.05	0.70	4.00	0.25
PU4/PP4-MOF2	0.85	0.40	2.05	2.05	0.70	4.00	0.50
PU4/PP4-MOF3	0.85	0.40	2.05	2.05	0.70	4.00	0.75
PU4/PP4-MOF4	0.85	0.40	2.05	2.05	0.70	4.00	1.00

3.2.5 Preparation of Polymer Film

A certain amount of dispersion was transferred into a Teflon disk, shown in Figure 28. The dispersion was dried completely within 50 hours. The film was further dried at 60°C for 12 hours, under vacuum to remove the solvent completely.



Figure 28: PU/PP-MOF films preparation.

3.2.6 Coating application on metal sheets

An applicator was used to coat onto a metal sheet (S-36 mild steel Q-panels, 3 × 6×0.032-inch dimension; chemical composition: 0.60% max Manganese, 0.15% max Carbon, 0.030% max Phosphorus, 0.035% max Sulfur). A defined 50, 100, 150, and 200 μm wet

coatings were prepared shown in Figure 29. The coatings were properly dried before testing.



Figure 29: PU/PP-MOF coating after being applied in Metal sheets.

3.2.7 Exposure to hydrogen

Mild steel and high-density polyethylene (HDPE) liner were used as substrates (around 1.5x1.5 cm²) for coatings during hydrogen exposure of coatings (see Figure 30). The notches appearing on the steel specimen were made to facilitate hanging them inside the aging cell. Defined different concentrations of methane and hydrogen blended gases were used in an artificial gas exposure condition.

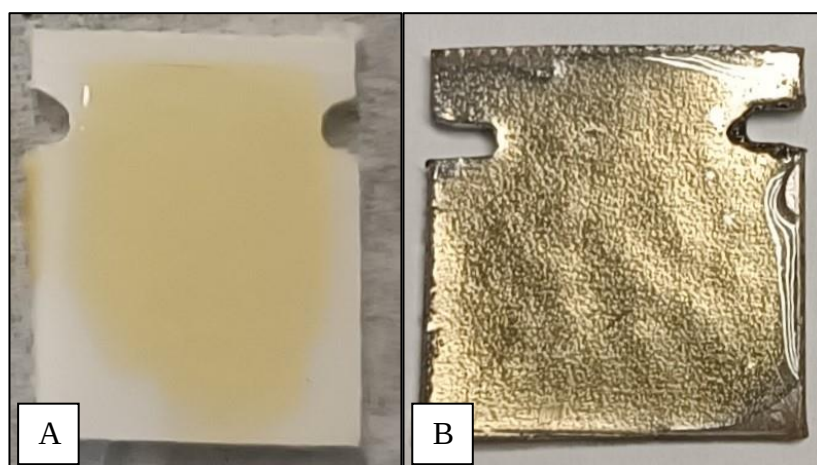


Figure 30: Coated specimen for hydrogen environment aging. (A) HDPE liner (B) Mild steel.

The PU4/PP4-MOF4 coated steel and liner substrates have undergone a one-month aging process within a closed cell environment. Given that the aging process will occur under

elevated pressure conditions, a 30-day duration is considered sufficient for the assessment of the coatings. It's worth noting that previous researchers subjected polymeric samples to a 6-week aging period, although they conducted their experiments under lower pressure conditions (2 bar) [25]. This aging process involved exposure to varying hydrogen fractions (up to 100%) to simulate H₂-NG blends, with methane gas representing the natural gas (NG) stream. The system's pressure was maintained at approximately 1480 psia, a typical range for transmission pipelines. To ensure uniform exposure, these samples were suspended using adjustable wire holders, ensuring their separation and equal exposure to H₂-CH₄ blends. Figure 31 shows the high-pressure cell used in aging the coated samples. After samples were mounted as per the illustrative configuration in Figure 31-B, H₂ and CH₄ gases were injected through the valve with predefined pressure until reaching up to 1480 psia. Following the one-month aging period, the samples were evacuated and subjected to thorough characterization to assess any potential physical or chemical degradation in the coating material.

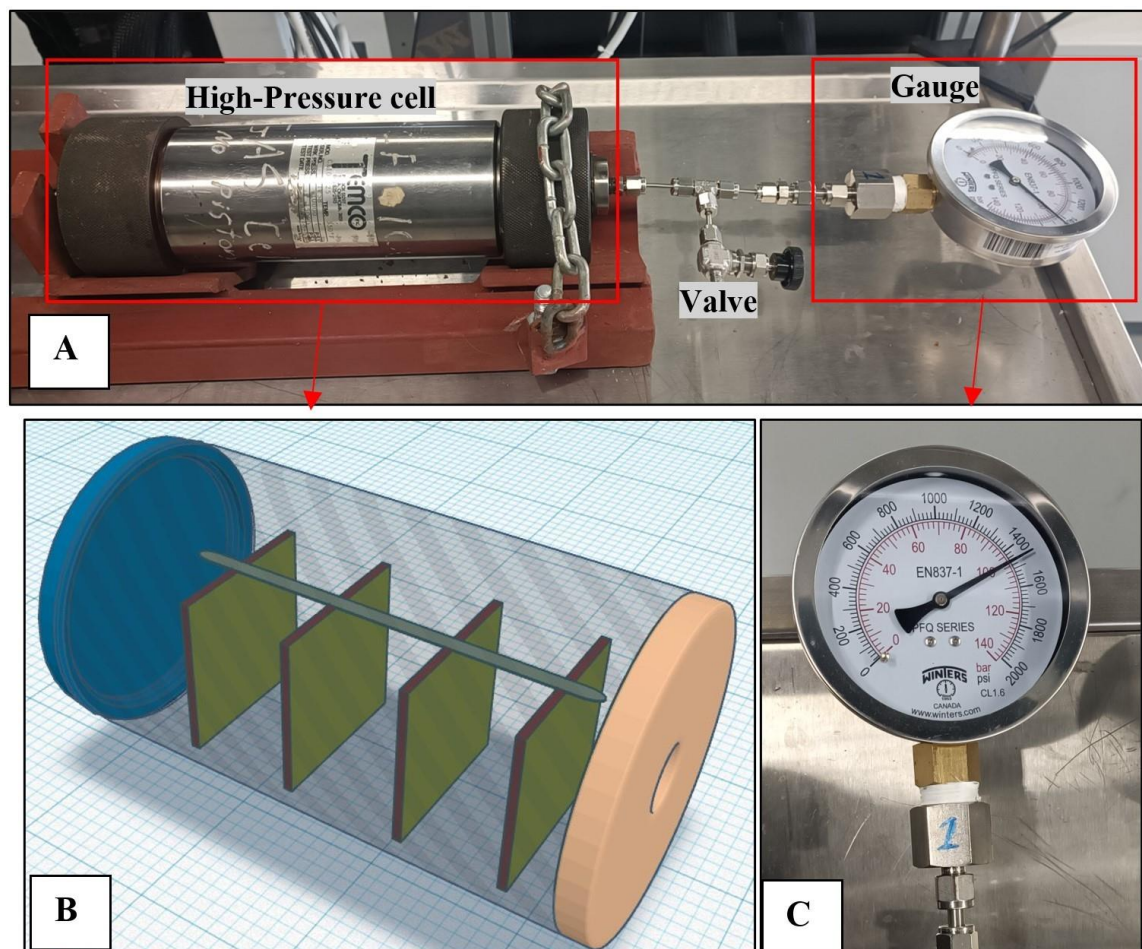


Figure 31: System set up for H₂-CH₄ aging.

3.2.8 Characterization

The typical functional groups of PU were identified by FT-IR (Impact 400D, Nicolet, 32 scans at a resolution of 4 cm⁻¹) analysis. The hydrogen bond of films was also analyzed by FT-IR analysis.

The swelling (%) test was conducted by immersing the coating films in water for a defined time and temperature (i.e., 48 hours and 30 °C). The swelling of the respective film was determined by Eqn. 35.

$$Swelling (\%) = \frac{W - W_0}{W_0} * 100 \quad (35)$$

W is the weight of the film at equilibrium swelling, and W_0 is the weight of the dried film. The water contact angle (WCA) test was conducted to evaluate the wettability of the coating.

The film hardness was measured by the Shore A hardness test according to ASTM D2240-75 specification. The LX-A Rubber Hardness Tester (Shanghai Liuling Instrument Company, Shanghai, China) was used during the testing. Other mechanical properties such as tensile strength, young modulus, and elongation at break were evaluated using Instron SSTM-1 tension meter (UDS, Japan). The tests were conducted at room temperature with a cross-head speed of 50 mm/min. The results provided are an average of five measurements.

The thermal gravimetry analysis (TGA) was performed on a Pyris 6 TGA (Perkim Elmer, USA). The heating was from 30 to 500°C at a heating rate of 10°C/min. Also, the limited oxygen index (LOI) test was conducted to further evaluate the fire-retardancy of the synthesized coating.

The corrosion resistance of the dispersion was conducted for PU4, PU4/PP4, and PU4/PP4-MOF4 dispersions. Potentiodynamic polarization (PDP) test was performed to measure the corrosion rate (i_{corr}) with the different dispersions (Gamry 3000 Potentiostat).

The surface properties of the coating before and after H₂-CH₄ aging were evaluated through scanning electron microscopy (SEM) (Joel 7000 desktop SEM). Additionally, the crystallinity was assessed with X-ray diffraction (XRD) spectra (Panalytical Empyrean diffractometer).

CHAPTER 4

RESULTS AND DISCUSSION

4.1 Gas Network Simulation

4.1.1 Model Validation

Utilizing the information presented in [Table 5 -Table 8](#), the model was executed to undergo validation against provided data from multiple sources [276,280,288]. For model validation, 3 nodes were maintained as P-specified nodes (i.e., Source, EGP, and Newman).

According to the data available on the Gas Bulletin Board - WA [288], the average GGP capacity for the past 12 months, as of August 2023, is approximately 182 TJ/D. This data portal divides GGP into three zones: Pilbara, Goldfields, and Kalgoorlie. [Table 14](#) displays the reported one-year capacity. The equivalent flow rate in MMSCF/D was calculated using the average HHV in [Table 10](#).

Table 14: GGP capacities reported between AUG 2022 - 2023.

GGP Zone	Average capacity, TJ/D	Equivalent flow rate, MMSCF/D
Pilbara	58	53.1
Goldfields	104	95.3
Kalgoorlie	20	18.3
TOTAL	182	166.7

Furthermore, a study undertaken by the University of Queensland revealed that the overall capacity of GGP falls within the spectrum of 180-200 TJ/D [280]. This translates to a range of 164.9 – 183.2 MMSCFD. According to these reports, the flow rate from the Source needs to be approximately 166.7 MMSCFD and should remain within the established range of 164.9 – 183.2 MMSCFD.

On the other hand, Newman has a capacity of 40 TJ/D, which is equivalent to 36.6 MMSCF/D [276]. Additionally, the capacity threshold for EGP is restricted to a maximum of 45 TJ/D, which is equivalent to 41.2 MMSCF/D [280]. The reported capacities of the P-specified nodes from reports and PIPESIM model are summarized in [Table 15](#).

Table 15: Comparison between real capacity data and model results for P-specified nodes.

Node	Real rate, MMSCF/D	Model rate, MMSCF/D
Source	166.7	168.9
Newman	36.6	36.2
EGP	< 41.2*	36.6

* This represents the nameplate capacity, a limit that should not be surpassed, and not necessarily the precise current flow rate.

As evident from [Table 15](#), the outcomes of the developed model align within the spectrum of pipeline data for the P-specified nodes used during validation. The remaining nodes have been configured to maintain specified flow rates (Q-specified), ensuring that the exact flow rates provided in the BCs are reflected in the results. [Figure 32](#) shows a comparison between the real and model flow rate at P-specified nodes.

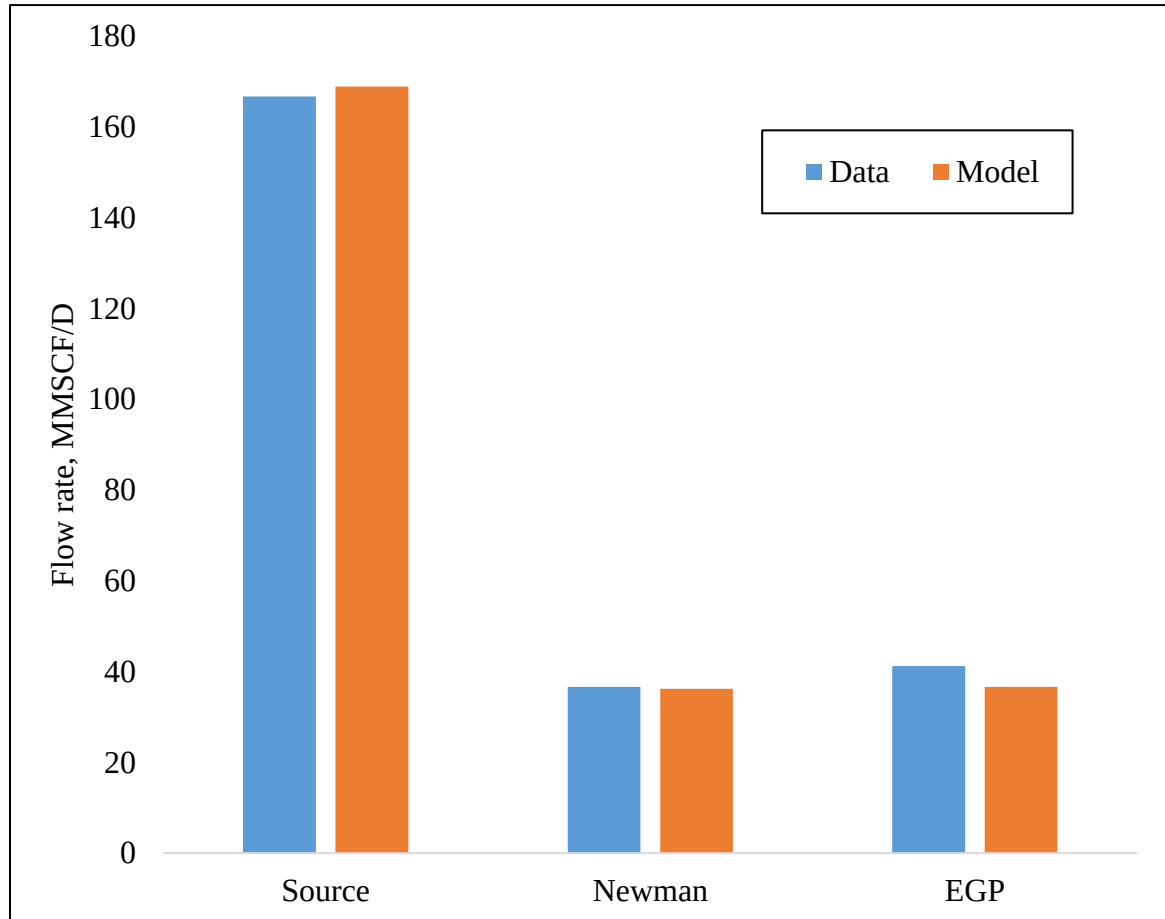


Figure 32: Flow rates of real data and model results at P-specified nodes.

The resulting flow rates and pressures for the entire GGP nodes are compiled in [Table 16](#). This validated model is considered as a base case for the subsequent sensitivity analysis.

Table 16: Flow rates and pressures at system nodes of the base case (validated case).

Node	Flow rate, MMSCFD	Pressure, psia
Source	168.9	1400
EGP	36.6	500
Jaguar	1.3	1122
Jundee	2.9	908
Kalgoorlie	20.4	985
Keith	13.7	1268
Leinster	18.1	1139
Magellan	2.0	914
Newman	36.2	925
Paraburdoo	9.2	487
Plutonic	3.8	1014
Saracen	2.2	1149
West Angelas	18.6	640
Wiluna	2.8	909

Figure 33 illustrates the pressure profile along GGP's mainline for the validated model using the previously stated BCs. The graph also highlights the locations of compressors. The presented data demonstrates that the pipeline pressure remains within the operational limit of 1,480 psia. The highest recorded pressure, 1477 psia, was noted downstream of the second compressor (CS2).

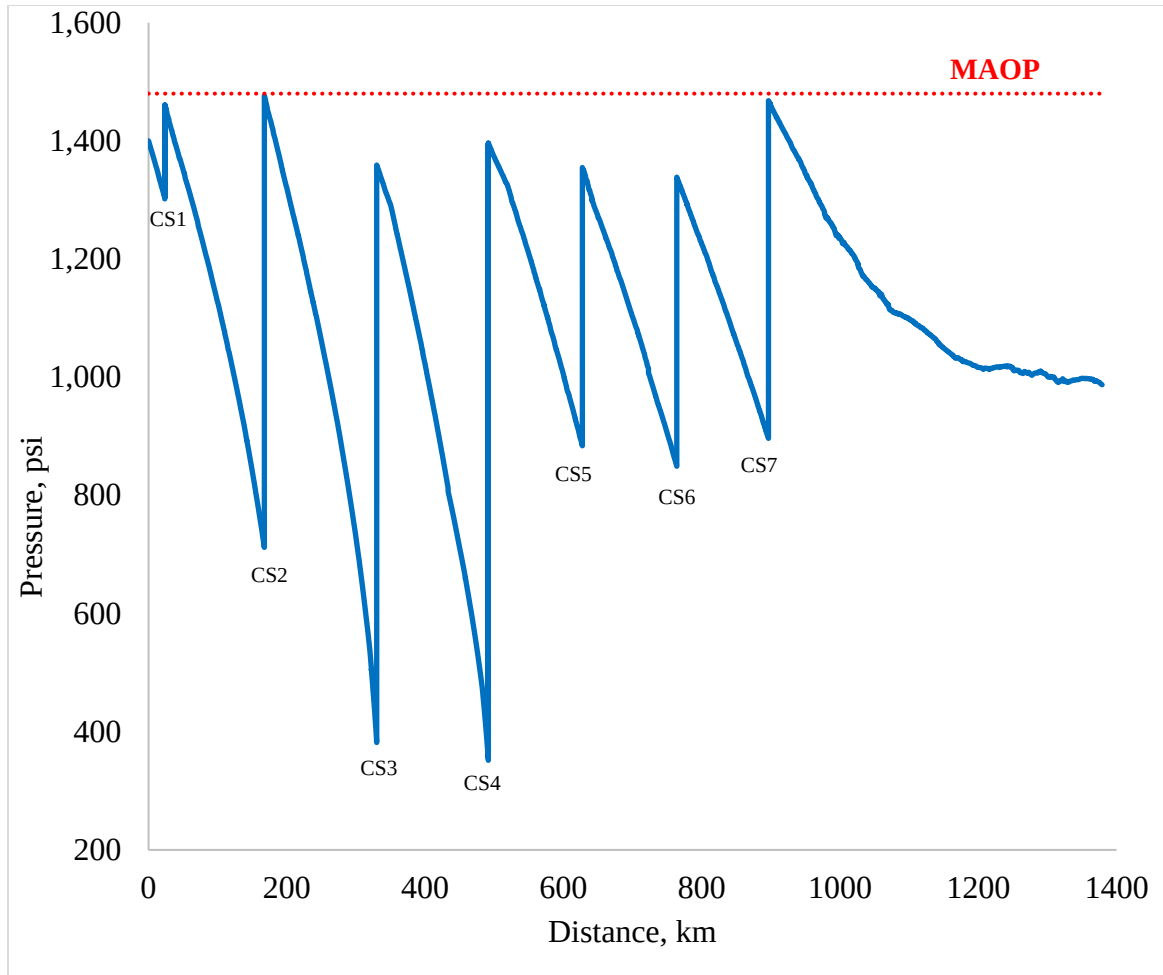


Figure 33: Pressure profile along GGP for the basic case (without hydrogen).

4.1.2 H₂ Sensitivity analysis

Hydrogen was incrementally introduced from its initial concentration of 0%, as explained in [Section 3.1.3.2](#). The model was executed for each H₂ scenario, maintaining uniform model parameters including BCs. The attained pressures at Q-specified nodes along the pipeline system were documented and displayed in [Figure 34](#). Adding 10% H₂ to the gas mixture has slightly affected the pressure of these nodes. It resulted in minor increase in some cases (i.e., Jundee, Magellan, Paraburdoo, West Angelas, and Wiluna Gold), while others has shown a slight decrease in pressure (i.e., Jaguar, Kalgoorlie, Keith, Plutonic, and Saracen). Notably, the Plutonic node exhibited lower pressure at 10% H₂ compared to 0% H₂, followed by a consistent pressure increase for higher H₂ fractions. However, these minimal changes were all less than 14 psia. Inclusion of H₂ with 20% fraction and higher resulted in a continues increase in the Q-specified nodes' pressure. Comparing 80% H₂ content with basic case (0% H₂), some nodes experienced a 25% increase in their pressure due to the elevated H₂ content. The increment in pressure at these points

indicated elevated pressure in the pipeline since a constant flow rate has been specified for these nodes.

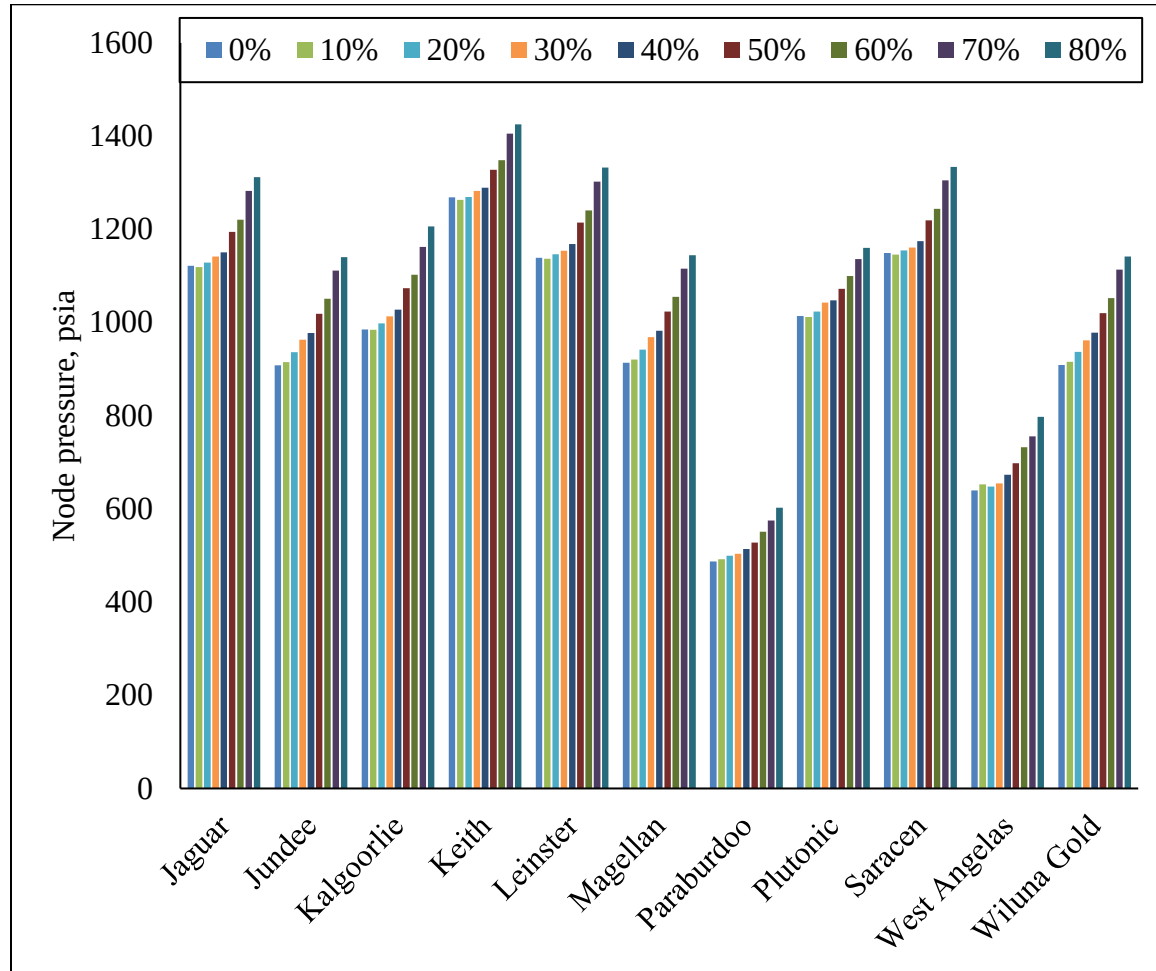


Figure 34: Variation in the pressure of Q-specified nodes with multiple H₂ fractions.

The rise in pressure values indicates a reduction in pressure drop along the pipeline, attributable to the alteration in mixture characteristics. Figure 35 depicts the effect of changing hydrogen concentration on mixture's density and viscosity at fixed pressure and temperature (1480 psia, 86 °F). Both density and viscosity showed a reduction as the H₂ concentration increased. Comparable patterns in properties have been documented in prior research studies [29,49,289,290]. The reduction in density significantly exceeds that of viscosity, as can be observed from Table 17. Reduced density and viscosity thresholds have a combined effect on hydrostatic (elevation), acceleration, and frictional pressure gradients. Although a decrease in density tends to increase the velocity of the mixture inside the pipeline, potentially resulting in increased acceleration and frictional losses, it has been suggested that the reduction in hydrostatic losses is greater than the increased losses caused by velocity [290]. On the other hand, reduction of viscosity reduced the pressure losses caused by friction. In general, pressure losses decrease with an increase in

hydrogen content, leading to higher pressures along the pipeline and consequently raising the pressure at the Q-specified nodes.

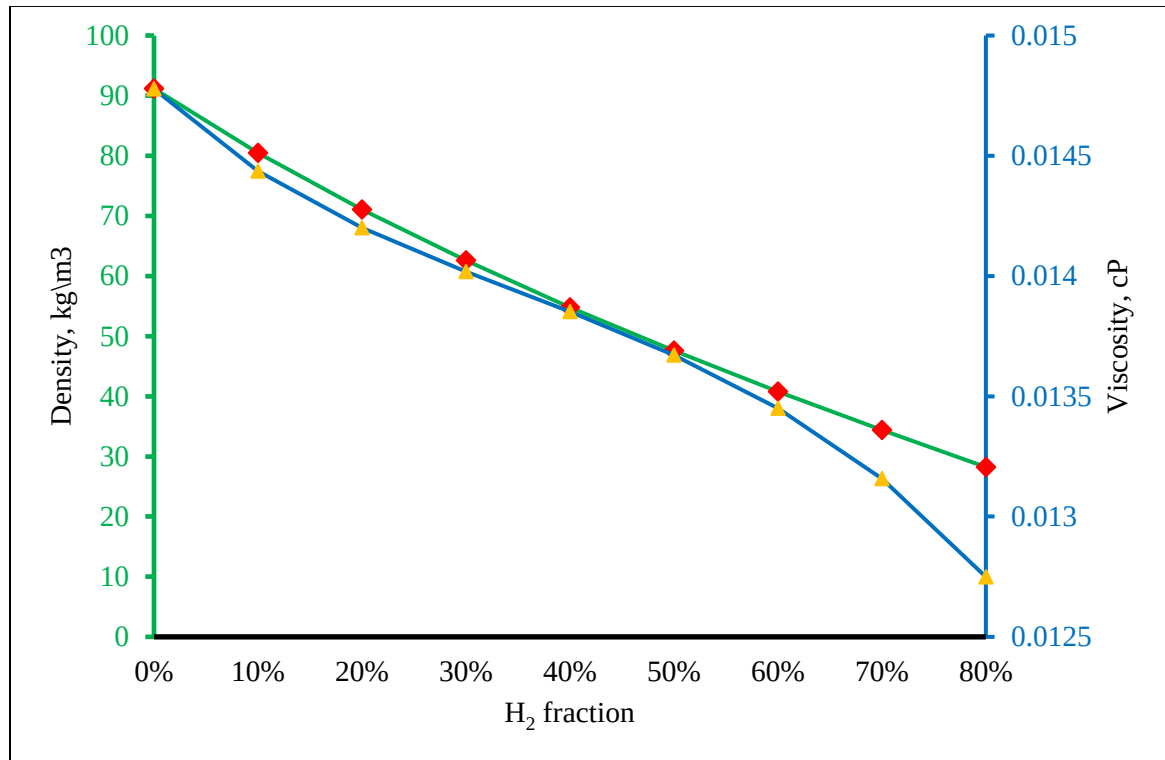


Figure 35: The effect of changing H₂ content in gas density and viscosity.

Table 17: Relative change in gas properties with multiple H₂ fractions compared to base case.

H ₂ %	Density	Viscosity
0% (base case)	-	-
10%	-12%	-2%
20%	-22%	-4%
30%	-31%	-5%
40%	-40%	-6%
50%	-48%	-7%
60%	-55%	-9%
70%	-62%	-11%
80%	-69%	-14%

The compression ratio variation with H₂ concentrations is illustrated in Figure 36-A. CS1 experienced a negligible reduction in compression ratio, while slight reductions were observed for CS5, CS6, and CS7. A significant drop in the compression ratio was reported in the remaining compressors, with CS2, CS3, and CS4 showing a reduction of 22%, 33%, and 36%, respectively. The compression ratio is determined by dividing the outlet pressure by the inlet pressure of the compressor (P_{out}/P_{in}). This reduction in

compression ratio is attributed to the elevated inlet pressure, which originated from the reduced pressure drop. Figure 36-B shows the pressure drop between the CS. The pressure drop in Figure 36-B is calculated by:

$$\Delta P_{i,i+1} = (P_{out})_i - (P_{in})_{i+1} \quad (36)$$

Where $\Delta P_{i,i+1}$ is pressure difference between compressor (i) and the subsequent compressor ($i + 1$). Table 18 summarizes the variations in pressure drop (ΔP), represented in Figure 36-B, with different H₂ concentrations.

Hence, the reduction in pressure losses resulted in a lower compression ratio. This necessitates reducing the power of compressors to meet the specified BCs at the terminals (Sinks). The decrease in the mixture's density and viscosity is the primary factor responsible for the alterations in pressure profile. Similar declining trends in compression ratios have been documented in another study [291].

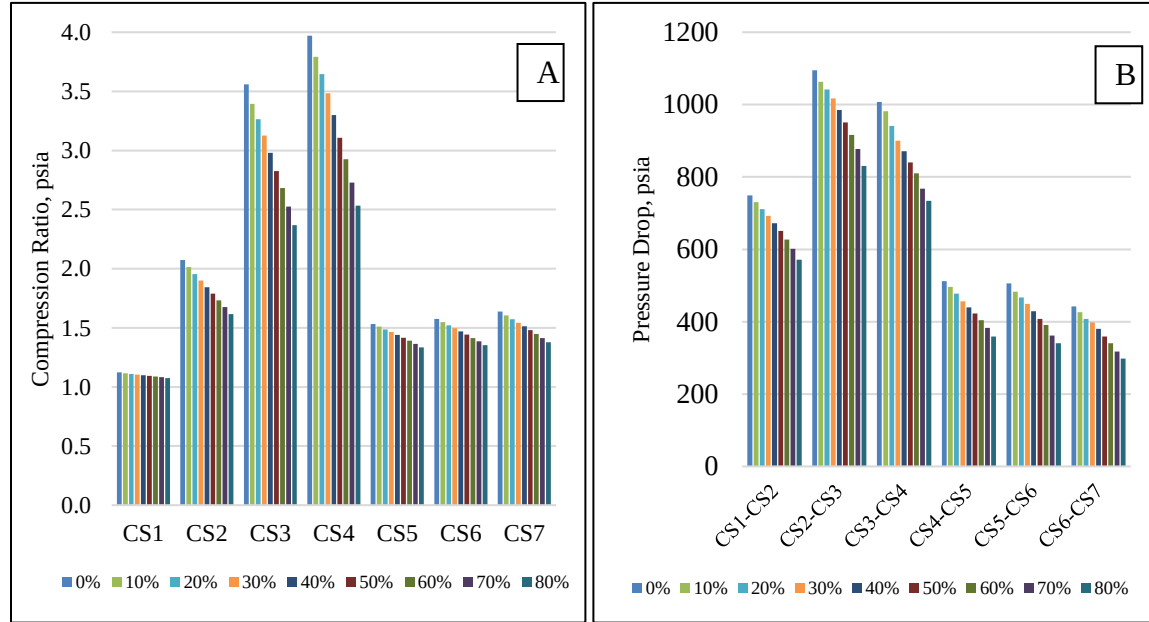


Figure 36: Effect of H₂ concentration in compression ratio (A), and pressure drop (B).

Table 18: Pressure losses between compressors with different H₂ fractions.

H ₂ (%)	Pressure Losses CS1-CS2			Pressure Losses CS2-CS3			Pressure Losses CS3-CS4		
	Pout (CS1)	Pin (CS2)	ΔP	Pout (CS2)	Pin (CS3)	ΔP	Pout (CS3)	Pin (CS4)	ΔP
0	1461	712	749	1477	382	1095	1359	352	1007
10	1456	726	730	1461	397	1063	1348	366	982
20	1451	740	711	1446	404	1042	1320	379	941
30	1446	754	692	1431	415	1017	1296	396	900
40	1441	769	672	1418	432	986	1288	416	871
50	1436	786	651	1405	454	951	1284	445	840
60	1432	805	627	1395	479	916	1285	475	810
70	1427	826	601	1384	507	877	1281	513	768
80	1422	851	571	1375	544	831	1289	555	734
H ₂ (%)	Pressure Losses CS4-CS5			Pressure Losses CS5-CS6			Pressure Losses CS6-CS7		
	Pout (CS4)	Pin (CS5)	ΔP	Pout (CS5)	Pin (CS6)	ΔP	Pout (CS6)	Pin (CS7)	ΔP
0	1396	884	512	1355	849	506	1339	896	442
10	1387	891	496	1344	862	483	1334	908	426
20	1382	904	478	1344	876	467	1334	926	408
30	1378	921	457	1349	900	450	1346	948	398
40	1374	934	440	1346	918	428	1348	968	380
50	1381	959	422	1357	950	407	1369	1010	359
60	1389	985	404	1370	979	391	1384	1043	341
70	1401	1018	383	1389	1027	362	1423	1105	318
80	1407	1048	359	1399	1058	340	1432	1134	298

Figure 37 depicts alterations in pipeline pressure across its length. Notably, pressure exceeded MAOP limit at CS7 when higher hydrogen fractions were introduced (above 40%). The outlet pressure of CS7 exceeded 1500 psia for hydrogen concentrations of 50% and higher. This poses numerous risk considerations and impacts the integrity of the pipeline's system components. Therefore, the compressor's outlet pressure must be reduced to avoid extreme pressure threshold downstream CSs.

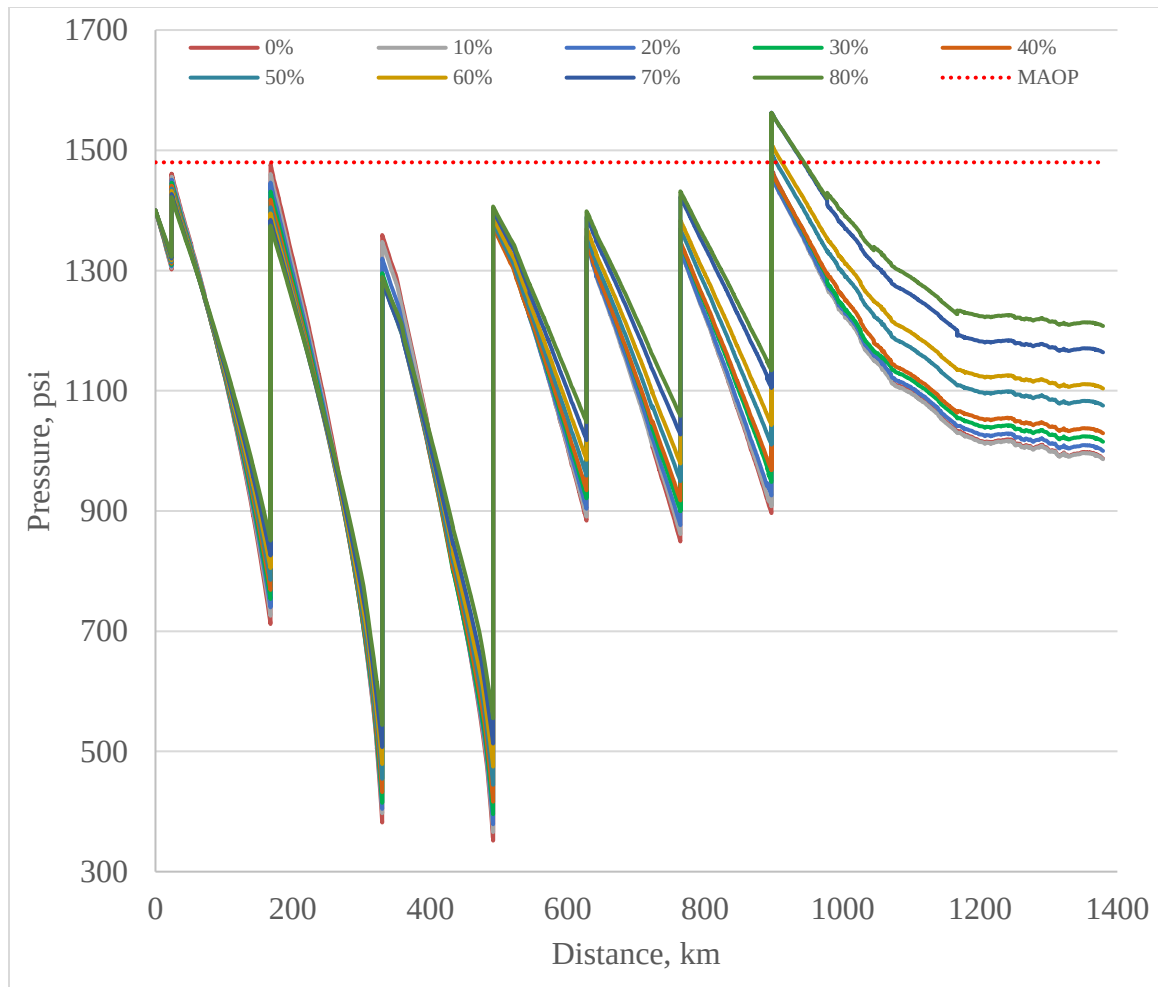


Figure 37: Pressure profile of GGP with multiple H₂ fractions.

The phase envelope of natural gas plays a vital role in the design of natural gas processing and transportation. The phase envelope consists of bubble point and dew point lines, with their intersection at the critical point. This diagram can be constructed using various equations of state (EoS) such as Peng-Robinson (PR), Soave-Redlich-Kwong (SRK), and GERG-2008. PIPESIM provides a fluid package that incorporates multiple EoS options. Figure 38 shows the phase envelope of natural gas with varying hydrogen fractions constructed by SRK-EoS model. SRK-EoS has been used by other scholars to evaluate NG and H₂-NG mixtures' phase behavior [292–294]. It is evident that the phase envelope shifts upward towards infinity at lower temperatures, with the upward shift commencing earlier as the H₂ concentration in the fluid increases. Similar upward shifting trends have been documented in previous research articles [290,295]. Remarkably, the bubble point curve disappeared when H₂ content reached 60% or higher. Additionally, the critical temperature of the blended gas was reduced from -79 °F to -139 °F for base case (0% H₂) and 40% H₂ gas compositions, respectively. At 60% H₂ content, a substantial reduction in the critical temperature was reported, reaching -207 °F. This is

attributed to the difference in critical properties between methane and hydrogen. Also, the increment in compressibility factor is the primary reason for phase envelope's upward shifting. Figure 39 shows the changes in Z-factor with multiple hydrogen fractions.

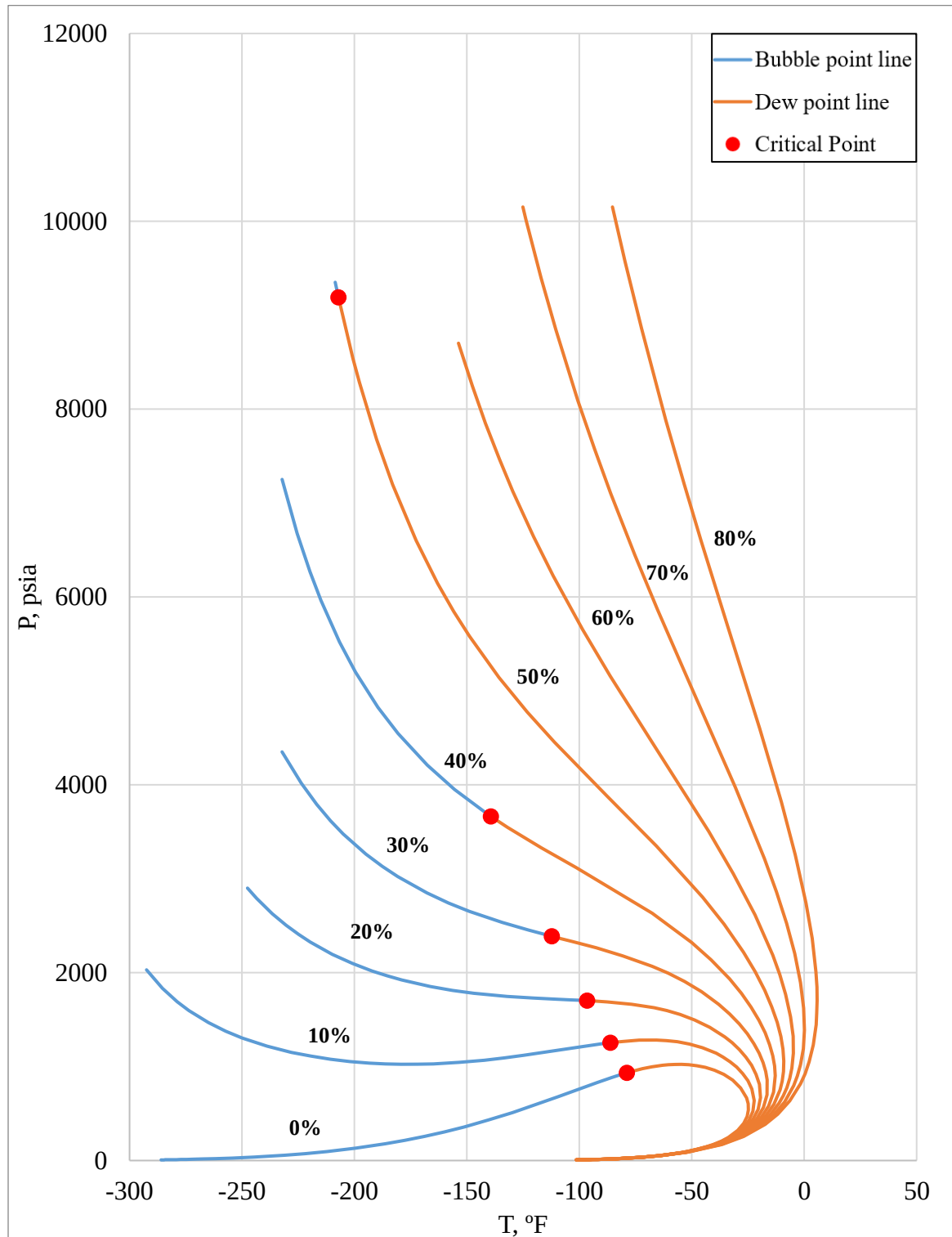


Figure 38: The effect of changing H₂ fraction in the phase envelope.

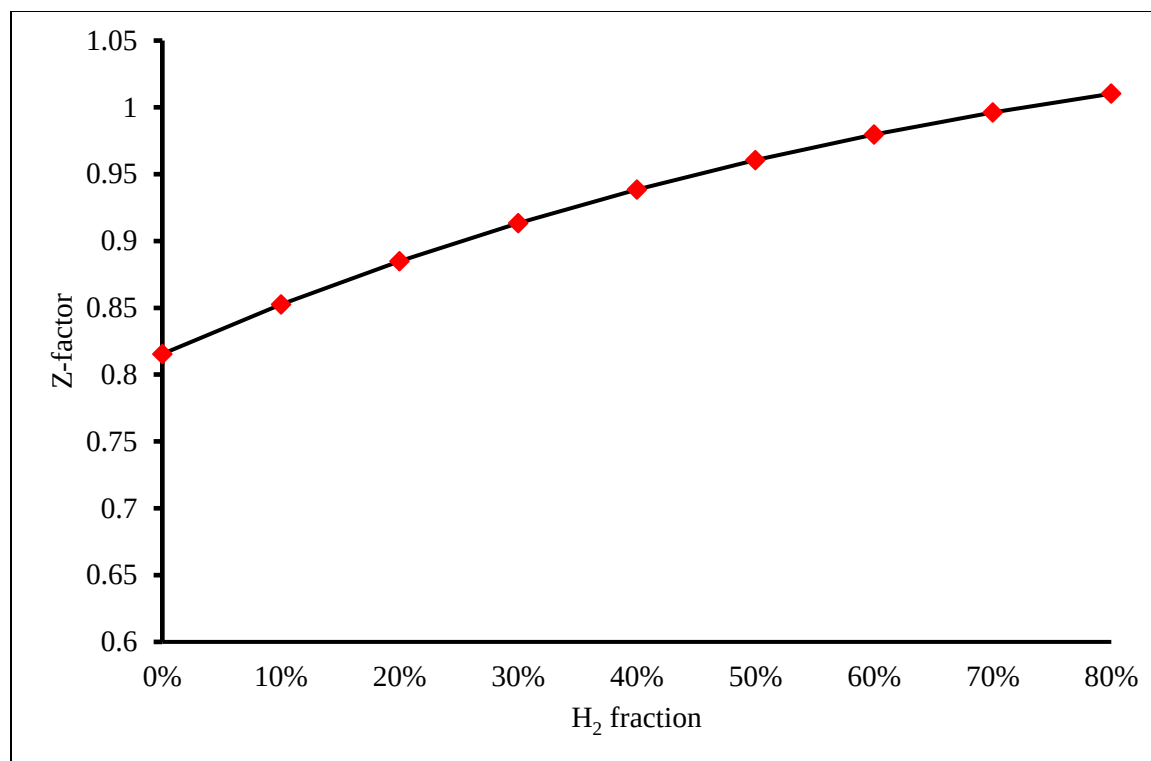


Figure 39: Changes in Z-factor with different H₂ content.

The aforementioned results emphasize the necessity of closely tracking pipeline pressure levels when integrating hydrogen into the system to avert high-pressure incidents and pipeline failure. Moreover, hydrogen's attack on metal structures (i.e., HE) [178] is induced at high-pressure levels [181,183]. Consequently, CSs power must be adjusted to balance delivering sufficient supply to endpoints while keeping mainline pressures within safe operating levels, as suggested in a comparable investigation [29].

4.2 Coating Development

4.2.1 Stability of dispersion

The PU dispersion stability and shelf life depend mainly on the DMPA/TEA content, which is always maintained at the same ratio. Above 12.0 mol% DMPA/TEA content usually makes a stable dispersion, although the shelf-life increases with higher DMPA/TEA content. In the first series of PU dispersion, different DMPA/TEA content was used, and the maximum shelf life was recorded with 25.63 mol% DMPA content (namely PU4). This dispersion was stable for more than 1 year. Based on the PU4 formulation, the phosphol was added to the PU dispersion (see Table 12). With fixed other monomer contents, the phosphol content was tuned. Fortunately, the stability of dispersions was almost unaffected. All the dispersions were also stable for one year. The PU4/PP4 dispersion was considered for MOF addition. Different MOF contents were added without sacrificing the stability and shelf life of PU dispersion (see Table 13).

Although the MOF-based polymer nanocomposite showed promising results, the use of these nanocomposites is still not considered practically. The main barrier to MOF-based polymer nanocomposite is making a homogeneous dispersion. It is common for unstable dispersion in different solvent media and polymer matrices. The MOF nanoparticles agglomerate both in dispersions and films very easily. The performance also deteriorated in agglomerate conditions. Thus, it is very important to avoid such agglomeration in both the dispersion and solid stages. It is well known that the stability of dispersions is based on phase separation. The unstable dispersions either changed to gels, showed some segmentation (precipitation) just after preparation, or phase separated within a few days of preparation. It is generally accepted that a minimum DMPA content is required for the formation of stable conventional PU dispersions. The stability and storing shelf life of dispersion increased with higher DMPA content. It was proved that positive and negative ion particles that create an electrostatic force can make a double layer, which ultimately makes PU dispersion stable. The MOF used in this study contains a hydroxyl group, which may contribute to keeping this layer almost unaffected; hence, the dispersion stability and shelf life of dispersion were almost the same for all dispersions. The MOF surface structure is particularly important to ensure stable dispersion.

4.2.2 Polymer Identification

The FT-IR spectra were used to identify the respective functional groups of polymers. The typical spectra are shown in [Figure 40](#). The peaks at certain wavelengths for certain functional groups confirmed the successful PU preparation of all three series. The bands were recorded at 2919, 1624, 1247, 1144, and 1001 cm^{-1} for $-\text{C}-\text{H}$, $-\text{C}=\text{C}$, $-\text{C}-\text{N}$, $-\text{C}-\text{O}-\text{C}$, $-\text{C}=\text{C}$ groups, respectively. These peaks mainly appeared due to the urethane and urea groups. Most importantly, the peaks were almost at the same intensity, although, the peak was slightly shifted for CO at 1704 and NH at 3340 cm^{-1} , respectively, at 1.0 wt.% MOF content. The slightly shifted to lower value confirmed a hydrogen bond formation. The free OH group of MOFs is involved in this hydrogen bond formation.

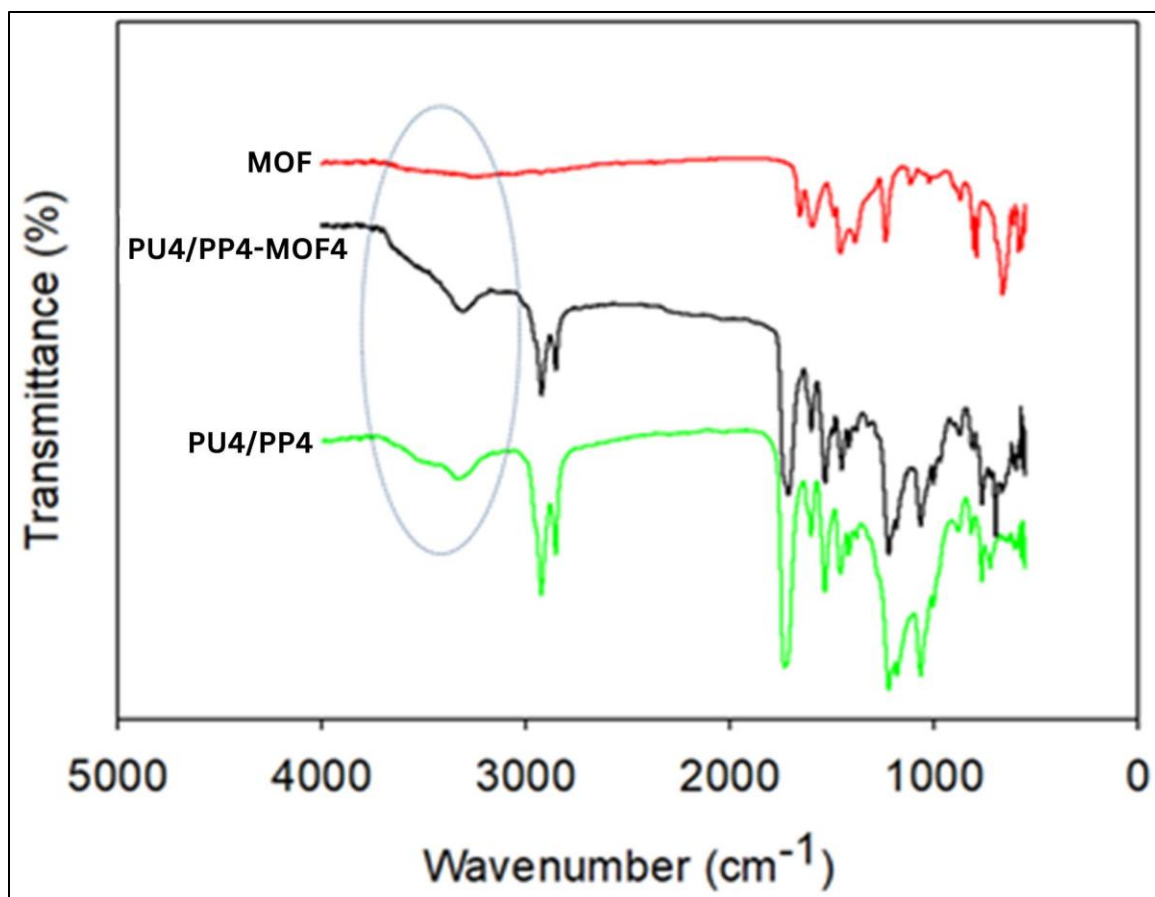


Figure 40: FTIR spectra of PU4/PP4, MOF, and PU4/PP4-MOF dispersions.

4.2.3 Coating dispersions properties

Coating characteristics were evaluated with the previously mentioned tests. The results are summarized in [Table 19](#). All values reported are the average of 5 measurements.

Table 19: Properties of coating dispersions.

Coating	Water swelling (%)	Water contact angle (°)	Hardness (Shore A)	Tensile Strength (MPa)	Young's Modulus (MPa)	Elongation Reduction (%)	LOI (%)	Residue Char (wt.%)
PU4/PP-4	8.2	74	70	24	5	0.00%	24.3	8.4
PU4/PP4-MOF1	8.0	75	72	24	5	-0.20%	24.6	8.6
PU4/PP4-MOF2	7.4	79	75	25	6	-1.01%	25.8	9.2
PU4/PP4-MOF3	6.8	85	79	26	7	-1.82%	27.2	10.8
PU4/PP4-MOF4	5.1	91	83	27	8	-3.24%	30.1	13.7

4.2.3.1 Coating Diffusion Protection

Water swelling (%) was considered to evaluate the coating diffusion property. Since polyurethane (PU) is a widely used engineering polymer, PU is used in a wide variety of industrial applications, including but not limited to coatings, adhesives, leather, and composites. However, due to the lingering polar groups, such as secondary amine, carbonyl, and urethanes, on the crosslinked structure, PU has poor moisture barrier qualities. These functional groups enable the connection with water molecules and enable the water to permeate the matrix, resulting in the eventual degradation of its characteristics. A water swelling (%) test was performed in order to estimate the swelling degree, which can provide information about the barrier and diffusion extent. The respective values are summarized in [Table 19](#). The pristine PU4/PP4 coatings are mostly hydrophilic in nature, which means fluids can diffuse easily. [Figure 41](#) visualizes the variations in water swelling with the prepared dispersions. Addition of MOF reduced the water swelling dramatically. The lowest recorded swelling percentage is 5.1%, which is linked to the maximum MOF content used (1.0 wt.%). The MOF made a strong barrier, and thus the coating performed slower diffusion. With PU4/PP4-MOF4, the water swelling decreased to 5.1%.

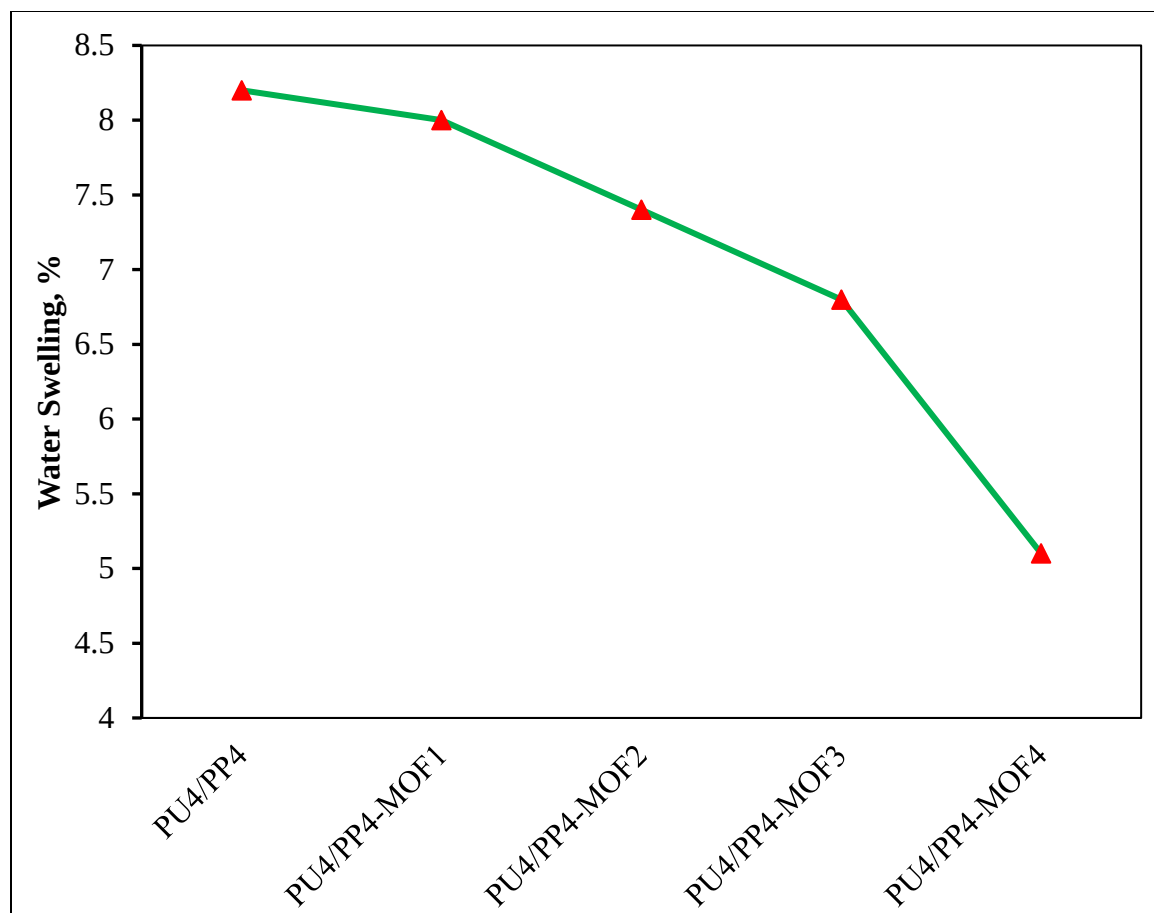


Figure 41: Changes in water swelling with multiple coating dispersions.

4.2.3.2 Water Contact Angle

The quantitative evaluation of wettability was done by Water Contact Angle measurement (WCA). Approximately 3 μL of distilled water was dropped onto each sample by an optical sessile drop system, and a sophisticated digital camera was applied to capture the water image on coatings. The respective values are summarized in [Table 19](#) and visually represented in [Figure 42](#). Notably, when higher percentages of MOF are mixed, the WCA has increased significantly from 74° to 91° . This indicates a very positive correlation between MOF contents and WCA values. Notably, using 0.25 wt.% MOF (i.e., PU4/PP4-MOF1) did not make a considerable change compared to the previous PU4/PP4 case. This is related to the small content of MOF particles added. Moreover, the increase of WCA for PU4/PP4-MOF2 up to PU4/PP4-MOF-4 is correlated to the change in polarity as a result of the modification of adding higher contents of MOF. Because of that, the hydrophobicity increased, and the highest value was recorded for PU4/PP4-MOF4, which has the highest MOF contents. Even though fully hydrophobic behavior was not achieved, the results were promising. In general, the wettability of the samples decreases as MOF contents increase.

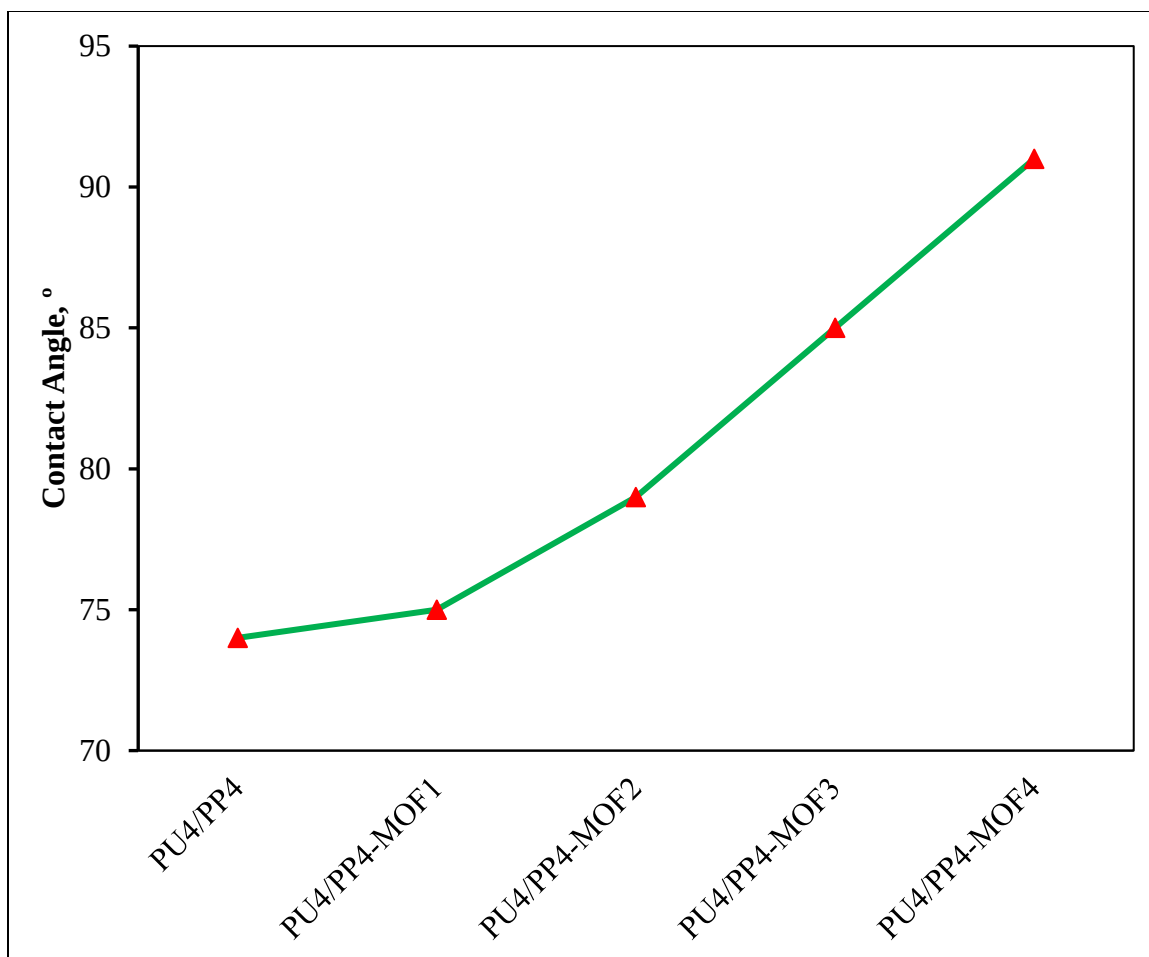


Figure 42: Changes in water contact angle with multiple dispersions.

4.2.3.3 Mechanical Properties

The newest and possibly one of the largest polymer families, polyurethanes (PU), are employed in the coatings industry and are renowned for their exceptional outdoor resilience and quick cure. They require certain changes because their thermal and mechanical characteristics have constrained their usage. Coatings with high hardness can be created using polyurethanes that have undergone MOF modification. The mechanical properties are tested and summarized in Table 19, including hardness, tensile strength, young modulus, and elongation at break. Shore A durometer test was performed to measure the hardness of the prepared materials. From Figure 43, the addition of MOF positively reflected in the hardness records, resulting in a significant increase. MOF increased the hardness from 70 to 83 MPa. According to Shore A scale, the inclusion of MOFs has changed the hardness scale of the coating from medium hard to hard material. The tensile test was also conducted to evaluate the film's mechanical performance. The values of tensile strength are illustrated in Figure 43. With the introduction of MOF to the dispersion, the tensile strength was significantly increased. Notably, 0.25 wt.% MOF did not change the tensile strength. However, higher MOF contents caused a remarkable

increase in tensile strength. The highest value was recorded with PU4/PP4-MOF4 dispersion, 27 MPa.

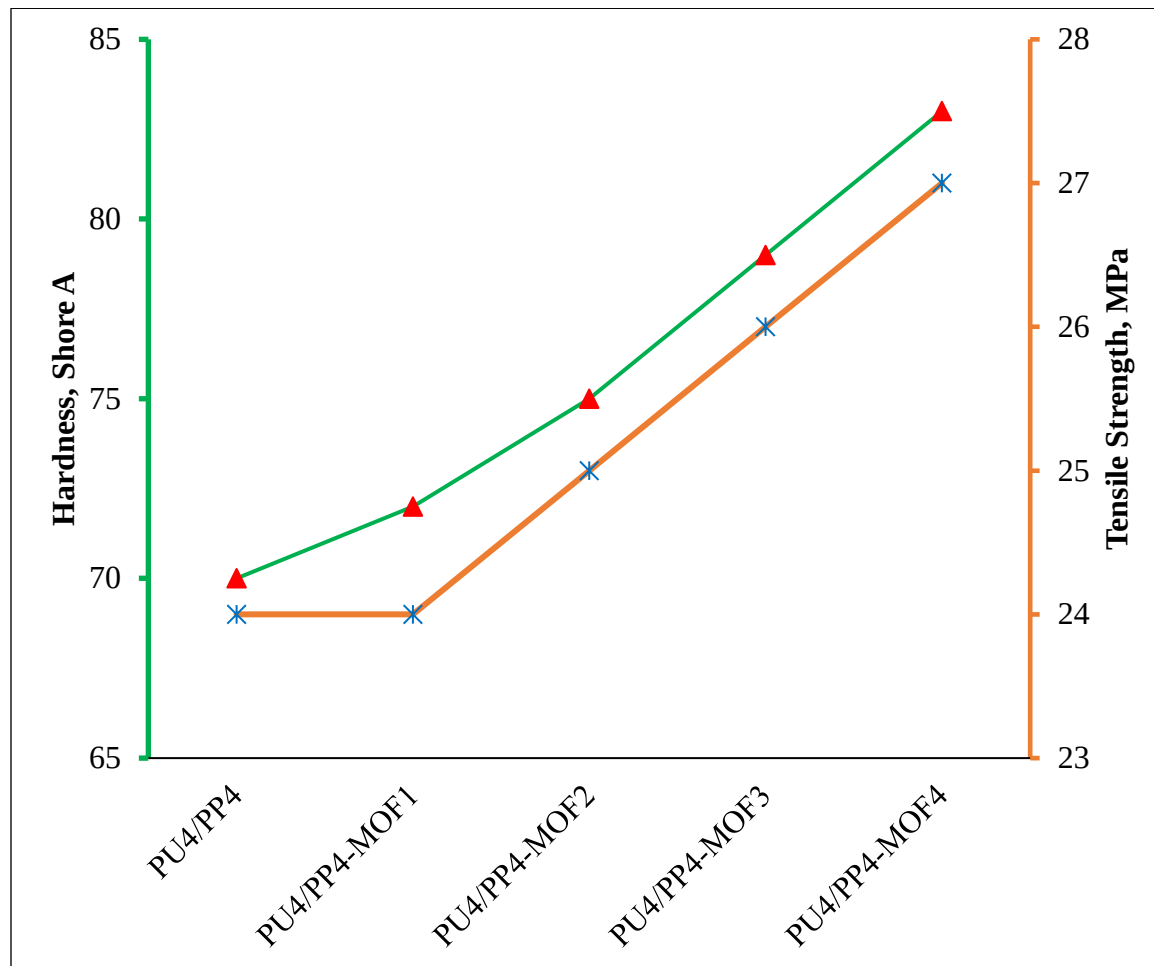


Figure 43: Changes in hardness and tensile strength with multiple dispersions.

Young modulus, as shown in Figure 44, has similar trends of tensile strength. That is because they are directly correlated. Young modulus reached up to 8 when 1.0 wt.% MOF was used. Remarkably, elongation at break has quite a reverse trend compared to Young Modulus and tensile strength. A minor reduction in elongation was observed with higher MOF content. The elongation decreased by 3.2% with addition of 1.0 wt.% MOF compared to the pristine PU4/PP4 dispersion.

All mechanical properties, except elongation at break, increased with increasing MOF content. The elongation at break was slightly sacrificed with higher MOF content. The MOF acted as a reinforcement and increased the mechanical strength. The MOF cages oppose the deformation of base polymer chains, resulting in higher tensile strength and Young Modulus.

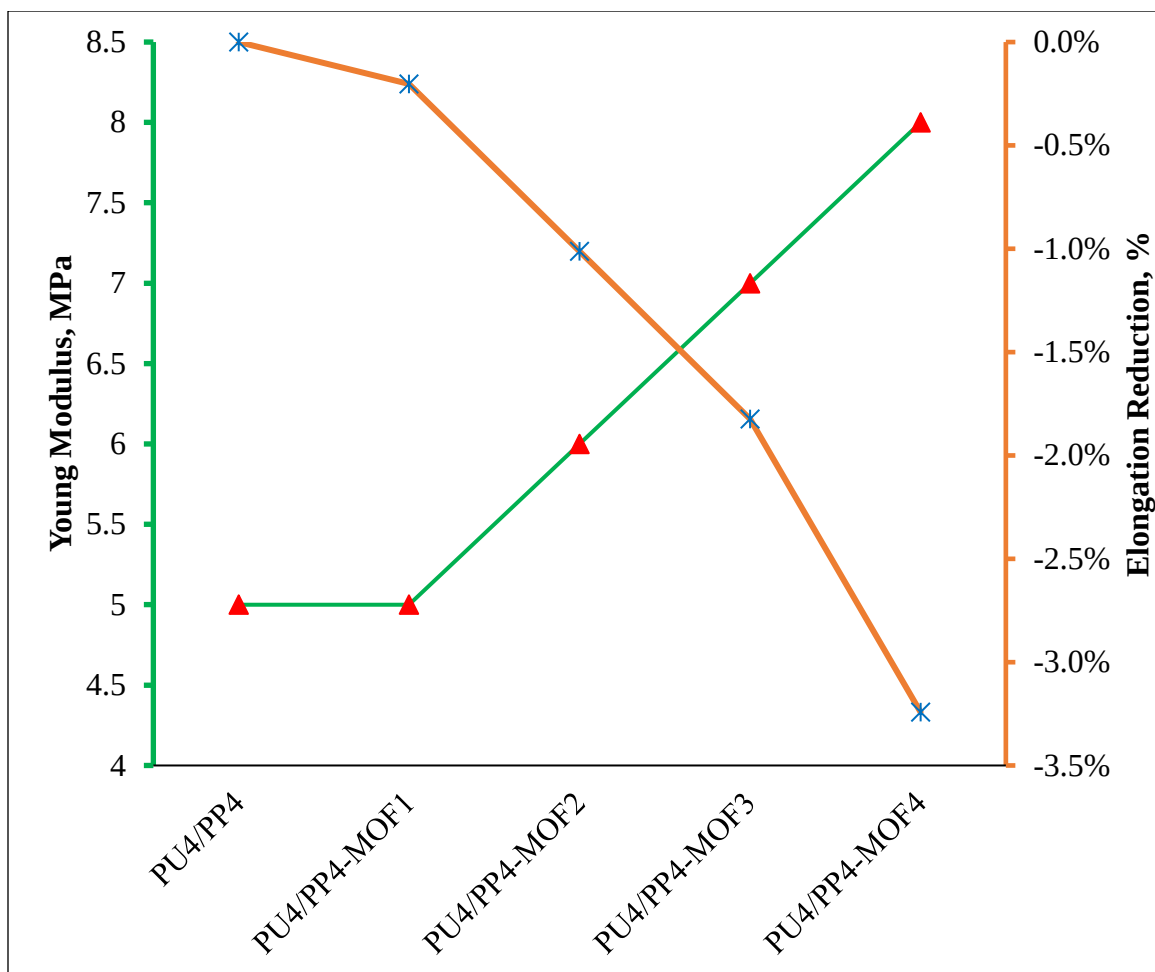


Figure 44: Changes in Young Modulus and Elongation at break with multiple dispersions.

4.2.3.4 Thermal Stability

Thermogravimetric Analysis (TGA) was used to evaluate the polymer thermal resistance property. The typical thermographs of PU4, PU4/PP4, and PU4/PP4-MOF4 are shown in Figure 45. All the films showed similar trends of degradation, implying that the inclusion of PP and MOF didn't alter the degradation phenomenon. PU4/PP4 showed almost identical degradation profile as PU4. The thermal stability and char residue increased significantly with the inclusion/increase of the MOF. A significant level of improvement was recorded with 1.0 wt.% MOF content. The degradation was mainly in two steps. The first degradation was at 250 °C for urethane groups. The second degradation was for urea groups at 312 °C. The degradation resistance increased in both groups. The improvement of thermal stability can be ascribed to MOF structure. The MOF interacted directly with the polymer chain as well as made a barrier to pass the gases which ultimately increased thermal stability with the presence of MOF.

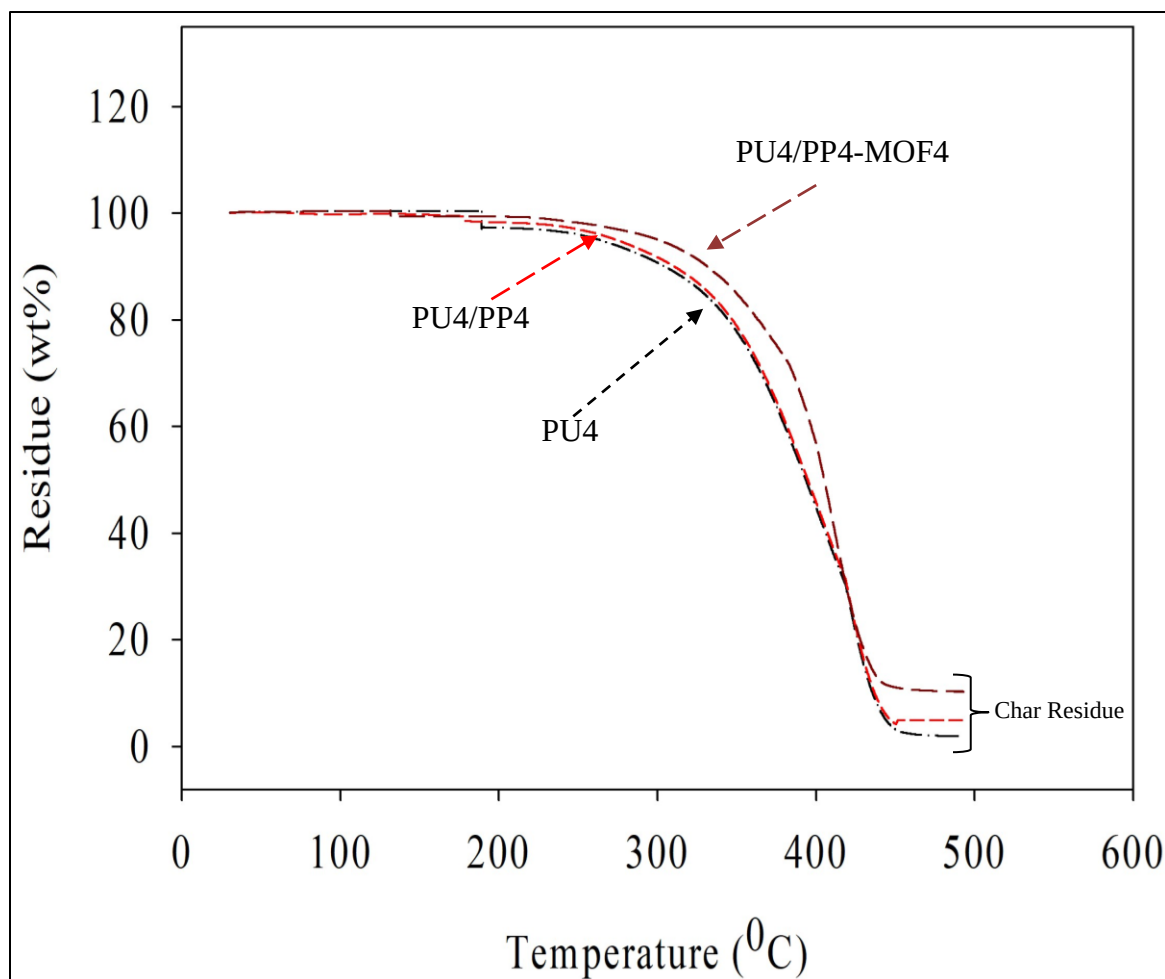


Figure 45: TGA results of multiple coating dispersions.

4.2.4 Fire Retardancy

The char residue (wt.%) from TGA analysis can predict the flame retardance of polymer materials. The respective values of char residues of the developed dispersions are summarized in Table 19, and plotted in Figure 46. The char content increased significantly with increasing MOF content. The value difference was minor with lower MOF content. However, the value difference was remarkable with higher MOF contents (0.75 and 1.0 wt.%). Char residue increased from 8.4 to 13.7 wt.% with gradual addition of MOF, which indicates improvements in flame retardance properties. The produced char can oppose the passes of produced volatile gases, it ultimately makes a cover to reduce the heat in the surroundings.

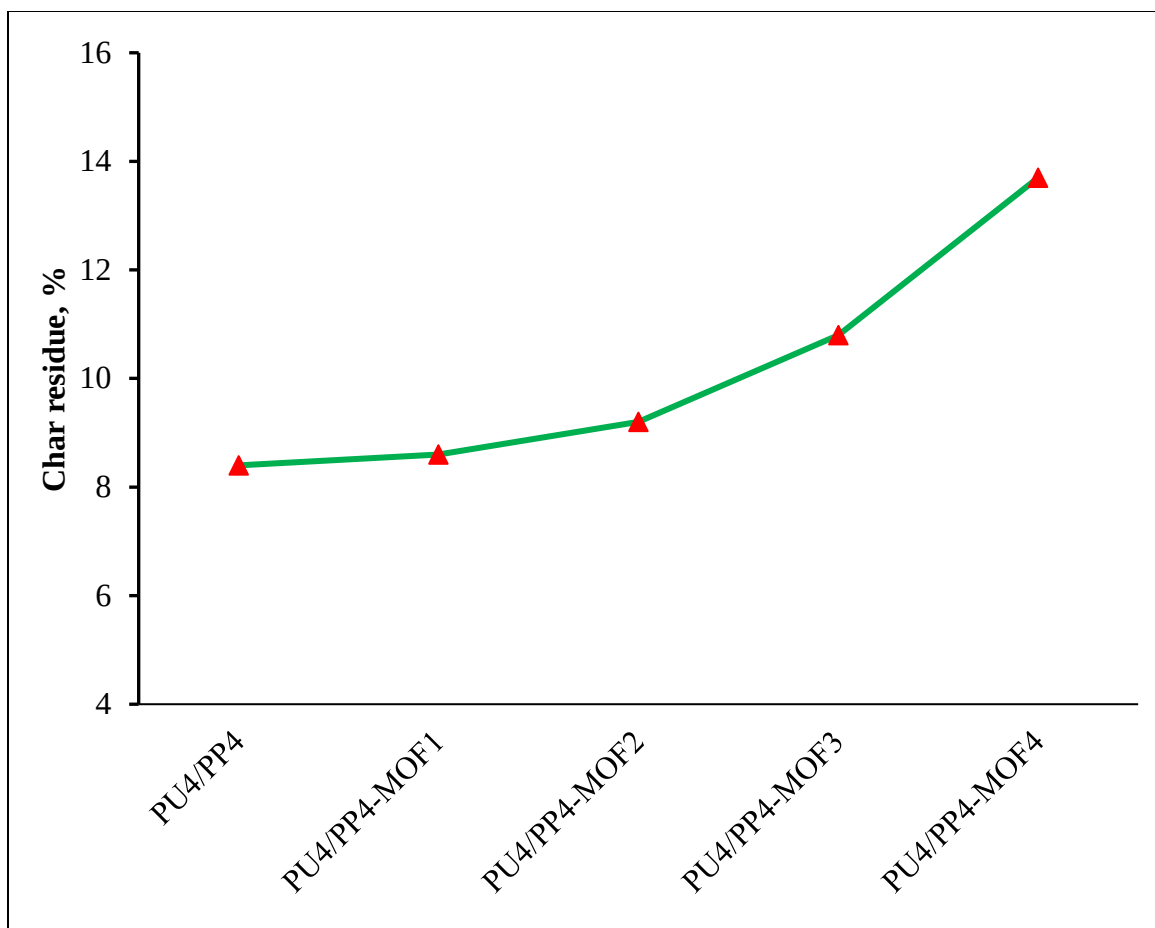


Figure 46: Char residues of coating dispersions from TGA analysis.

The fire resistance of coatings is also determined by Limited Oxygen Index (LOI) analysis (see Table 19). A higher LOI value is an indication of a higher level of fire resistance of materials. In Figure 47, LOI values significantly increased with increasing the MOF content. The LOI value reached up to 30.1% for PU4/PP4-MOF4 dispersion implying promising fire-retardant characteristics.

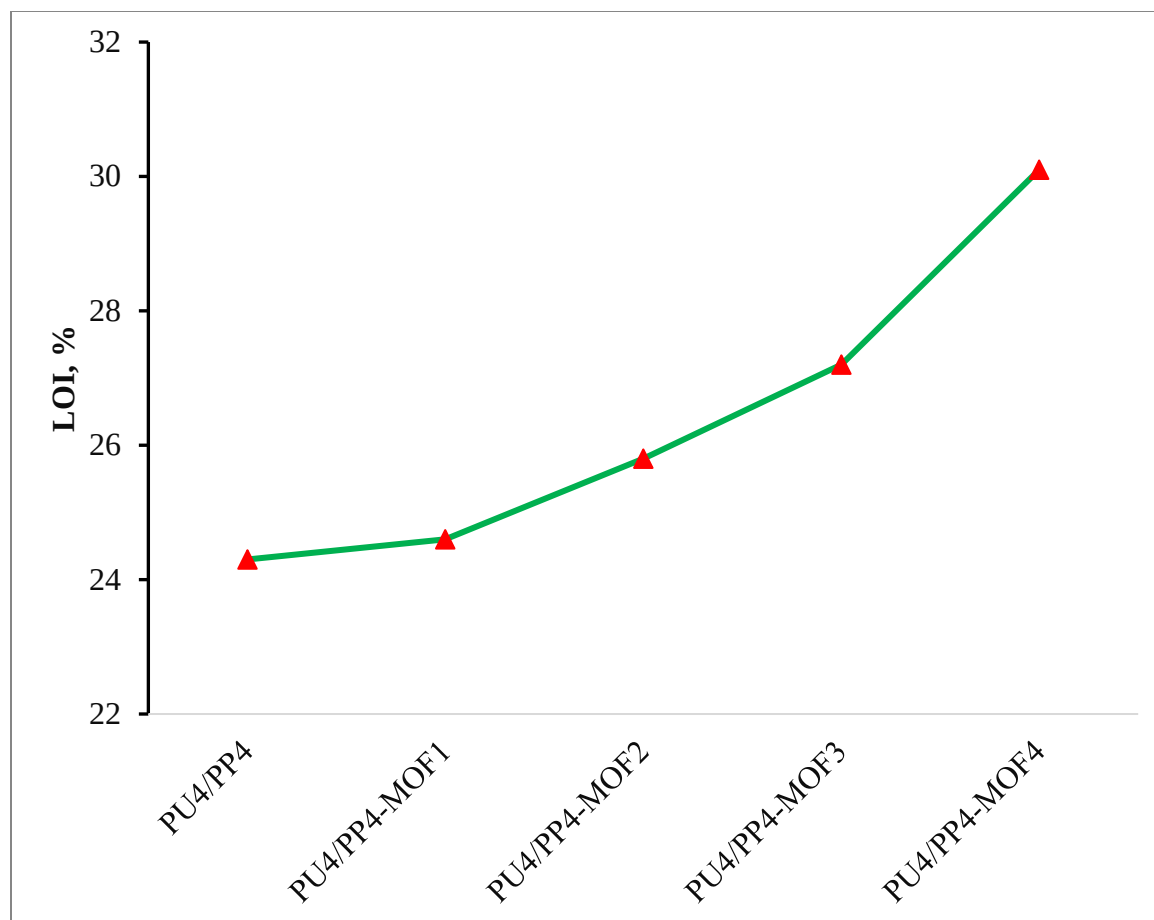


Figure 47: Changes in LOI with multiple polymeric dispersions.

4.2.5 UV Resistance

It is common that the external coating faces different natural weather conditions. As the PU4/PP4-MOF4 coating showed excellent fire retardance, this coating was also assessed for fire retardance after outdoor UV exposure conditions. The coatings were exposed near the seaside for 12 months. The coating was also assessed for UV-degradation as we believe the UV-degraded coating may lose its fire retardance property. Visually this coating was without any cracking or delamination as can be seen in [Figure 48](#). The exposed coating was analyzed by X-ray photoelectron spectroscopy (XPS). Usually, a peak for the CO group in XPS analysis indicates coating degradation. As the PU coating has a CO group, the band for the CO group is usually in higher intensity if there is a degradation of the PU coating. As expected, the intensity was slightly higher for the CO group in the exposed coating. It implies that there was a slight degradation, but the degradation was not intense enough to damage the coating at a risky level. The coating was very slightly affected in this exposure duration. Both the char residue (from TGA analysis) and LOI value were almost similar before and after exposure. Accordingly, the

formulated PU4/PP4-MOF4 coating didn't sacrifice the fire retardance property after exposure.

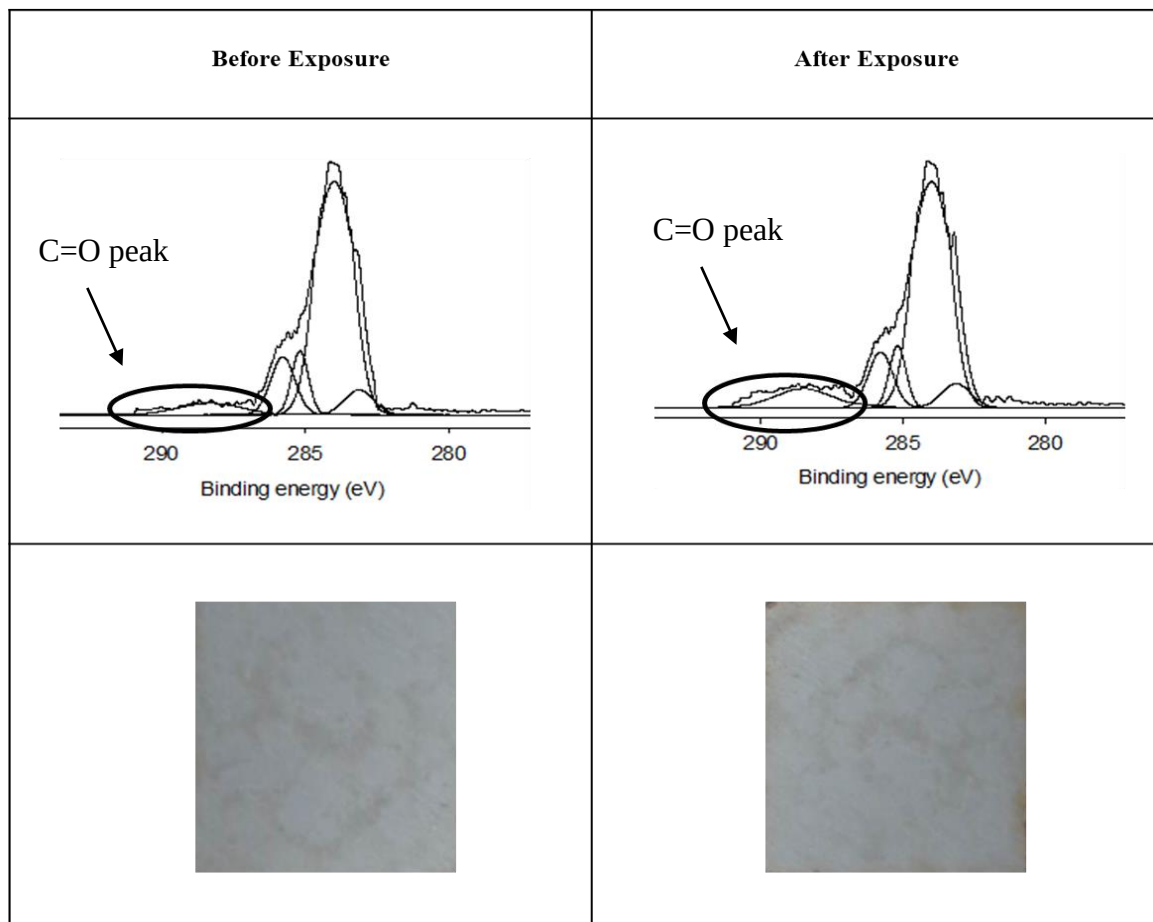


Figure 48: XPS spectra and photographs of PU4/PP4-MOF4 coating before and after UV exposure.

The fire retardancy properties were evaluated after one year of exposure. [Figure 49](#) shows the differences in the char residue and LOI before and after exposure for different dispersions. Notably, all coating dispersions containing less than 1.0 wt.% MOF experienced a significant degradation in their fire retardancy properties. Both char residue and LOI decreased dramatically after the exposure. Surprisingly, the 1.0 wt.% MOF dispersion maintained these characteristics after the long exposure. However, a slight reduction was observed in the char residue and LOI, with a decrease of 5.8 and 1.7, respectively, compared to the unexposed samples.

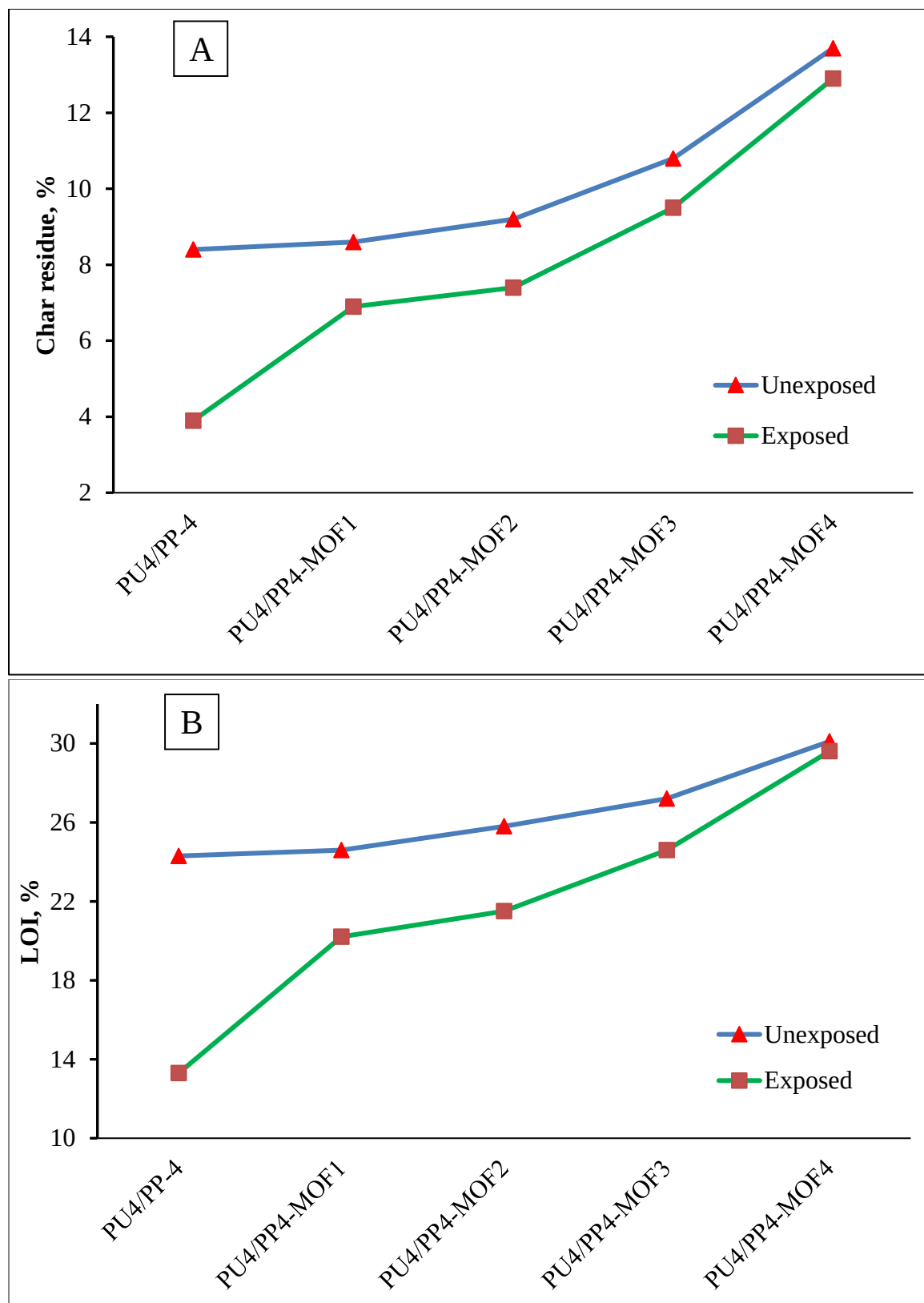


Figure 49: Changes in fire-retardancy characteristics after one-year exposure in atmospheric conditions. (A) Char residue. (B) Limited Oxygen Index.

4.2.6 Corrosion Resistance

Corrosion resistance was evaluated through Potentiodynamic Polarization (PDP) test using Gamry 3000 Potentiostat/Galvanostat instrument. The electrochemical measurements were executed within a traditional three-electrode cell setup [296,297], with coated steel substrates serving as the working electrode, a saturated calomel electrode (SCE) as the reference electrode, and a graphite rod acting as the counter electrode (See Figure 50-A). PU4 and PU4/PP4-MOF4 dispersions were applied to the steel substrate to evaluate their corrosion resistance. A defined 12.57 cm² of the coated sample was immersed in a 3.5% NaCl solution for 24 hours before conducting the test. The Tafel plot represented in Figure 50-B indicates a reduction in corrosion rate (i_{corr}) when PU4/PP4-MOF4 coating was used. The effect of PP addition is minor compared to MOF as a smaller curve shift was recorded in the case of PU4/PP4. The i_{corr} curve shifting to a lower value confirmed the higher protection of the coating. Since the maximum shift was recorded with the maximum MOF content, this content provided the maximum protection. This was expected since the minimum water diffusion value was reported for this dispersion. Accordingly, the corrosion protection was enhanced by adding MOF to the dispersion.

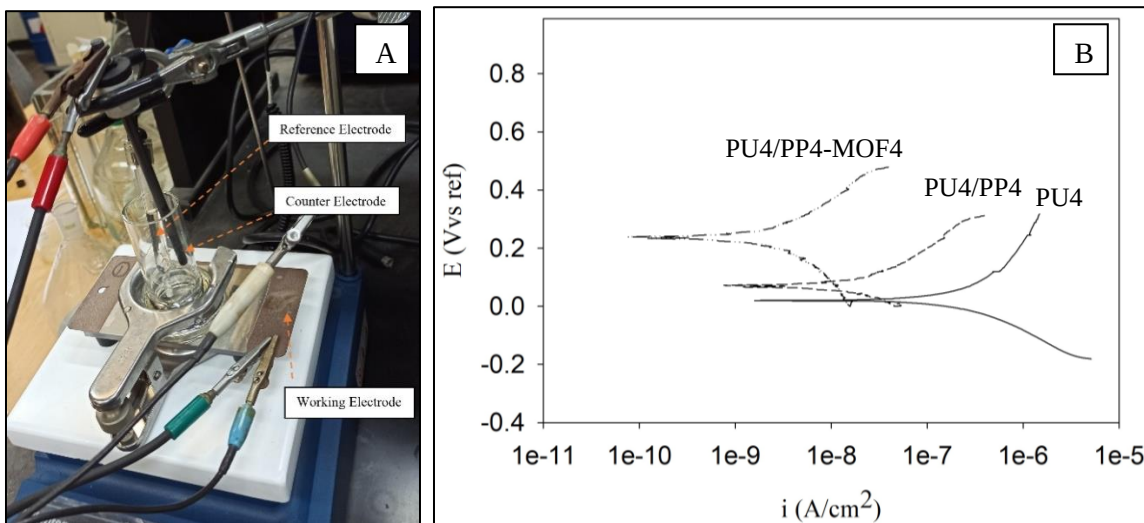


Figure 50: PDP test set up (A), and Tafel plot result (B).

4.2.7 Coating Exposure to H₂-CH₄ blends

Multiple H₂ concentrations were used in the process ranging from 10% up to 100%. In necked eyes, there were no changes after the aging of coatings, although few coatings experienced delamination. FT-IR, XRD, and SEM analysis were conducted to evaluate the changes in coating chemical composition and microstructure after the aging in a H₂-CH₄ gases environment. The FT-IR spectra are almost the same, as the peaks appeared at the same position for liners and coatings (see Figure 51). It's confirmed that the chemical

composition of the coating and liner was not affected in the hydrogen environment. The hydrogen concentration is also not influential in changing the chemical structure/functional groups.

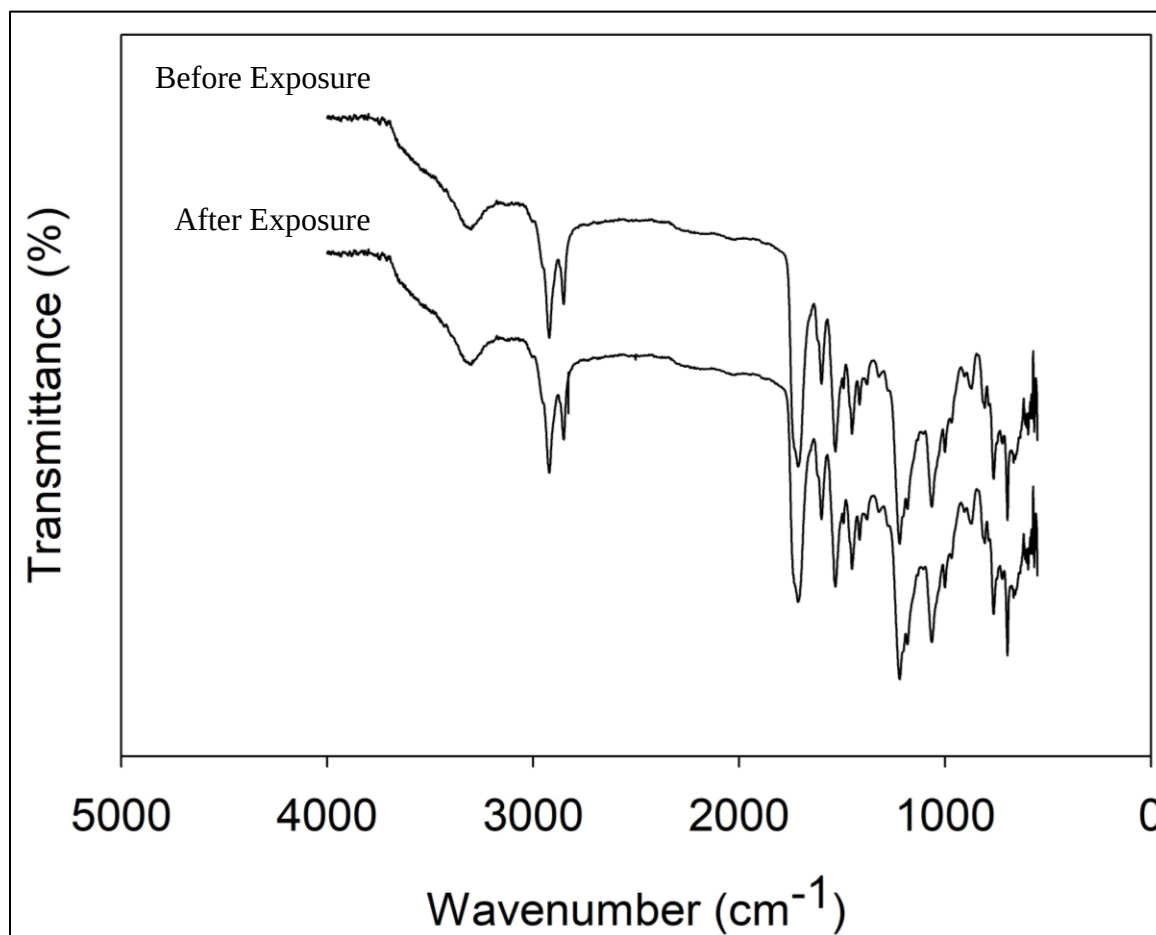


Figure 51: FTIR spectra before and after H₂-CH₄ aging for PU4/PP4-MOF4 dispersion.

Notably, a different XRD pattern was found for aged samples compared to untreated coatings as can be seen from Figure 52. The appearing lines in the graph has been smoothed using Gaussian fitting tool in FitYk software. Only a typical PU hollow peak appeared for both aged (10-100 %) and non-aged (0 %) coatings. It's confirmed an amorphous coating, which maintains the same structure with different blended gases. However, the intensity was slightly changed with different ratios of gases. Although, the peak intensity changes are not maintained in a systematic way; the changes are clearly seen. It implies that the microstructure of PU materials might be slightly changed in the hydrogen environment.

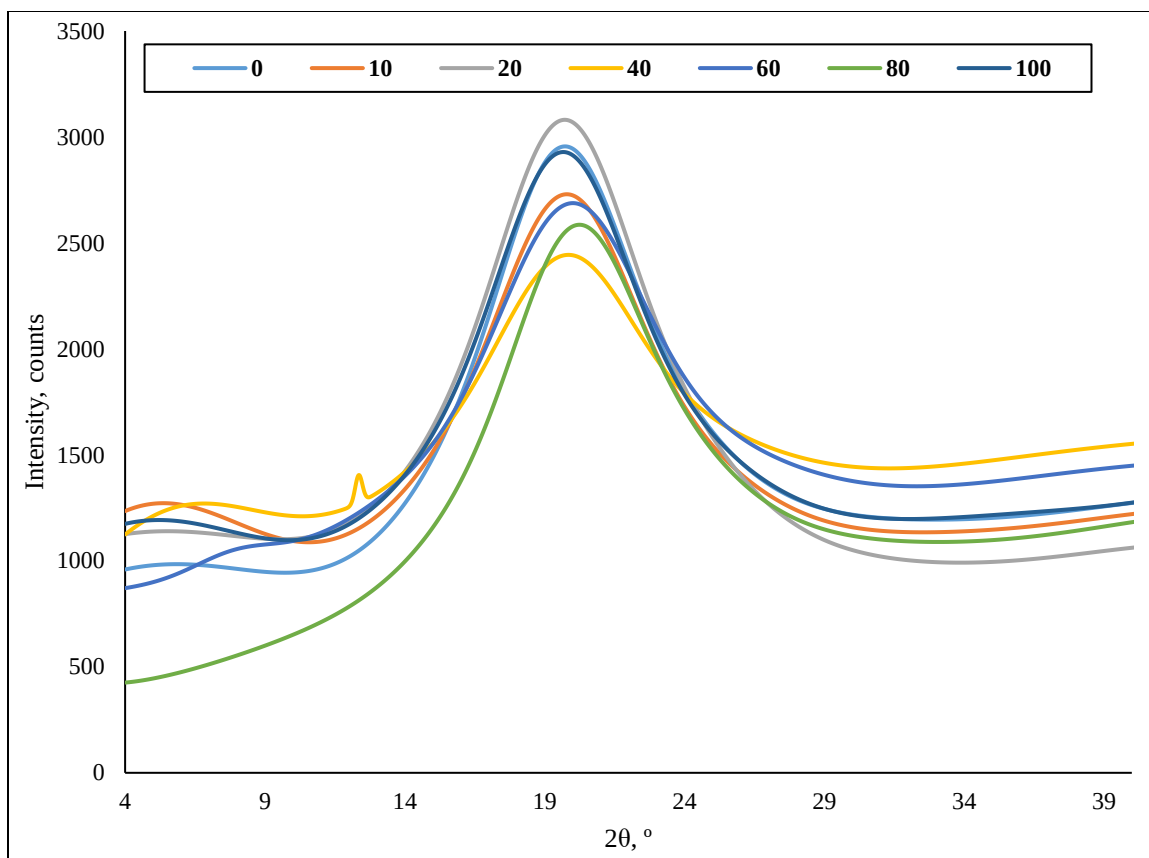


Figure 52: XRD spectra for PU4/PP4-MOF4 dispersion before and after aging under H₂-CH₄ conditions.

Figure 53 shows the surface morphologies of the coating before and after exposure to hydrogen conditions. The consistently smooth surface of the samples suggests a fair distribution of hard segment domains (isocyanates) within the soft segment (Polyols) [298]. Notably, this surface morphology remained unaffected even after aging in pressurized H₂-CH₄ conditions. Despite slight variations in microphotographs, no cracking was observed, indicating the coatings' resilience against microdamage at different gas concentrations. The microphotographic differences also suggest microstructure changes corresponding to various blended gas concentrations, aligning with the observations from XRD analysis.

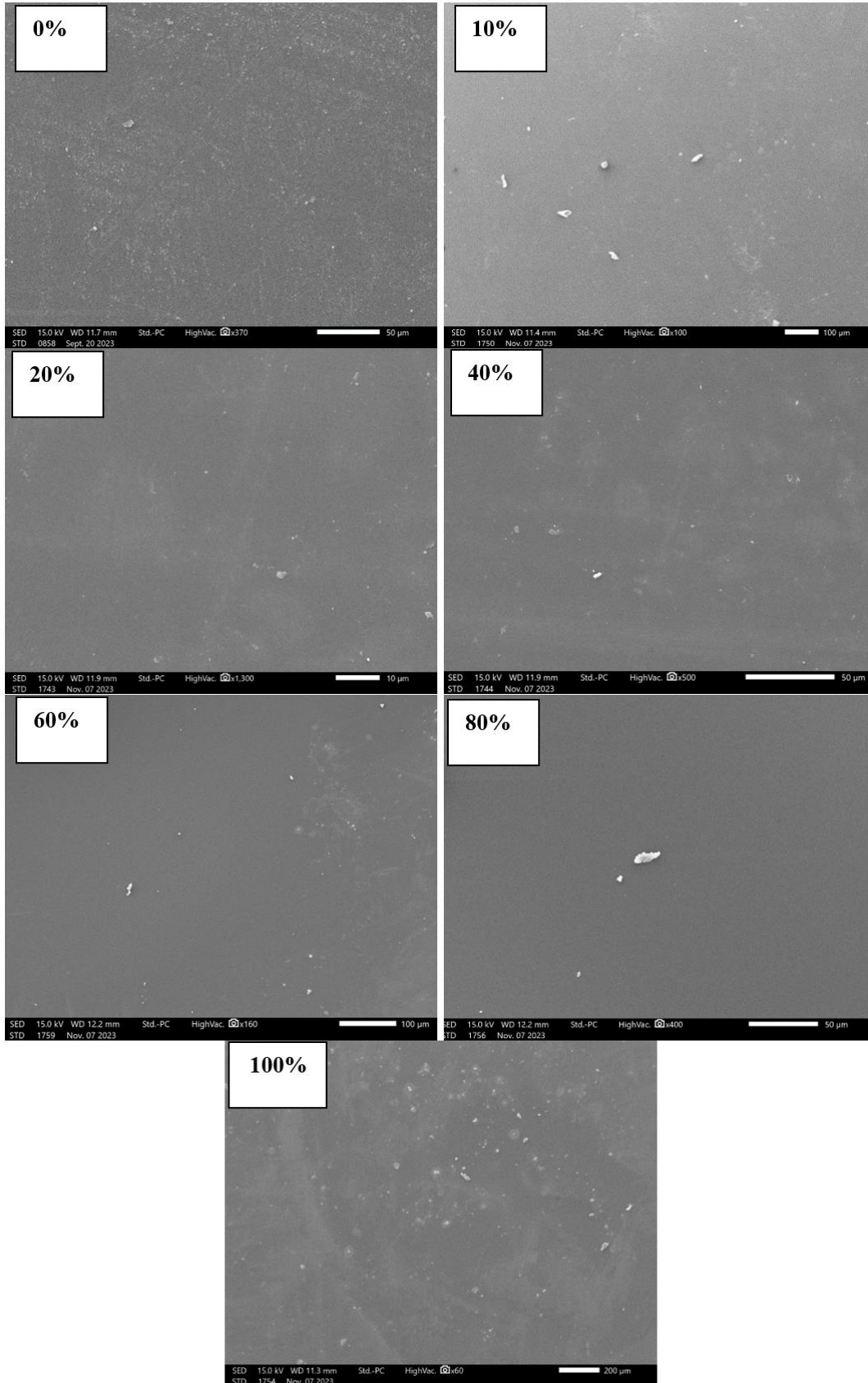


Figure 53: SEM images of unaged coating (0%), and aged coatings in H_2 - CH_4 environment (10-100 %).

CHAPTER 5

CONCLUSIONS and RECOMMENDATIONS

The incorporation of hydrogen into natural gas networks (H₂-NG) represents a promising avenue for decarbonizing the natural gas industry and mitigating carbon emissions. This study aimed to assess gas pipeline performance under multiple H₂-NG blends through simulation. Additionally, the development of an organic coating was considered to mitigate the threats arising from harsh environments around the pipelines, including high hydrogen fractions.

5.1 Conclusions

5.1.1 Gas Network Simulation

Much of the current research has concentrated on integrating relatively low hydrogen ratios into distribution networks characterized by lower operating pressures. In this work, a case study from the Western Australia (WA) gas transmission network has been simulated using PIPESIM software. A pipeline model representing the Goldfield Gas Pipeline (GGP) was constructed and validated. Real gas composition, that aligns with WA gas regulations, has been employed in the model, with hydrogen content being increased gradually. The pipeline's pressure profile and fluid characteristics were evaluated thoroughly with these H₂-NG blends. The main findings of this simulation section are as follows:

- The introduction of hydrogen into the GGP resulted in a reduction of pressure drop along the pipeline, leading to an elevation in delivery point pressures. Notably, instances were observed where the pressure increase reached up to 233 psia when higher hydrogen fractions were employed (i.e., 80 mol%).
- The allowable operating pressure was surpassed at the final compression station (CS7) when hydrogen fraction reached 50 mol% and above. In this station, the highest recorded pressures were 1563 psia and 1562 psia, corresponding to 70 and 80 mol% hydrogen, respectively. Nevertheless, the remaining compression stations remained within the prescribed pressure limits (i.e., <1480 psia).
- The main factor influencing the pressure profile was the change in gas mixture properties due to blended hydrogen. Hydrogen decreased mixture's density, reducing hydrostatic pressure losses, and concurrently lowered the viscosity, which impacted the frictional losses. The combined effects of density and viscosity reductions caused a significant decrease in total pressure losses.
- An 80% hydrogen fraction resulted in a 69% reduction in density from the original value of the basic gas, while viscosity decreased by approximately 14%. The

reduction in density surpassed that of viscosity, indicating the dominance of hydrostatic pressure losses gradient (psia/ft) in the pressure profile.

- An elevation in hydrogen content resulted in a notable shift in the phase envelope parameters. The critical temperature within the phase envelope exhibited a decrease from -78°F in the baseline scenario to -207°F when the hydrogen content reached 50%. A corresponding escalation was observed in the critical pressure, transitioning from 944 psia to 9189 psia for the aforementioned scenarios, respectively.

5.1.2 Coating Development

To enhance pipeline's protection, a polyurethane (PU)-based coating was developed and tested in multiple environments to evaluate its protective characteristics. PU coating was synthesized by mixing PTMG (polyol) and H₁₂DMI (isocyanate) as the main components. The protective properties of the coating were enhanced by adding MOF. The PU4/PP4-MOF dispersions were prepared with defined MOF contents. The dispersion stability was not altered with additional MOF content up to 1.0 wt.%. The best performance was found when 1.0 wt.% MOF was used in the dispersion (i.e., PU4/PP4-MOF4). The main findings of coating preparation and testing are summarized below:

- The most stable coating dispersion with the maximum protective properties was PU4/PP4-MOF4. This dispersion contains 25.63 mol%, 3.75 mol%, and 1.0 wt.% of DMPA, PP, and MOF, respectively.
- The contact angle was increased from 74° in PU4/PP4 up to 91° in PU4/PP4-MOF4 dispersion, implying an increase in the hydrophobic behaviour of this coating. Consequently, water diffusion has been reduced in PU4/PP4-MOF4 by 23% compared to PU4/PP4 dispersion.
- The mechanical properties also improved in PU4/PP4-MOF4 dispersion, including hardness and tensile strength. On the other hand, the elongation at break was reduced by 3.2% with 1.0 wt.% MOF.
- The thermal stability was slightly enhanced with the inclusion of MOF. The thermal degradation was slower in PU4/PP4-MOF4 dispersion.
- Fire-retardancy improved considerably with MOF inclusion. The char residue increased by 63%, while the limited oxygen index was 24% higher compared to pristine PU dispersions.
- The coating has shown minor degradation after exposure to real atmospheric conditions for one year. The coating did not show any cracking or detachment from the steel substrate. Noticeably, the 1.0 wt.% MOF dispersion maintained almost similar fire-retardancy characteristics after the exposure.
- The corrosion resistance was remarkably improved with a 1.0 wt.% MOF content. PU4/PP4-MOF4 dispersion provided enhanced protection from corrosive environments.

- When aged in H₂-CH₄ high-pressure conditions, the coating did not show any chemical degradation. However, slight changes in XRD spectra were observed.
- The minor changes in microstructure are the main reason for these variations in XRD peak intensity. Notably, the amorphous characteristics of these coatings were maintained after one-month aging.
- The surface morphology remained unchanged after aging in H₂-CH₄ conditions, implying that the coating can withstand these high-pressure hydrogen-rich conditions.

5.2 Recommendations

5.2.1 Gas Network Simulation

- Transporting H₂-NG blends through transmission lines provides an effective means to incorporate substantial hydrogen volumes into the gas stream. Repurposing GGP for hydrogen transportation is feasible but necessitates multiple adjustments to ensure safe transportation and enhance pipeline's integrity. The elevated pressure level of the pipeline increases its susceptibility to hydrogen embrittlement (HE), necessitating proper protection for the pipeline to prevent potential system failures.
- It is recommended to evaluate pipeline materials at various hydrogen fractions to address the optimum hydrogen mixing ratio.

5.2.2 Coating Development

- The developed coating can be considered for industrial applications due to its combination of UV-shielding, corrosion resistance, fire retardance, and resilience in harsh hydrogen-rich environments. The protective properties were sustained following one-month exposure to hydrogen.
- Conducting gas permeation/diffusion tests could provide additional evidence for these observations.
- It is recommended to explore longer aging time for hydrogen exposure.

References

- [1] Nyadjro E, Wang Z, Boyer T, Cross S, Cebrian J. NOAA NCEI Global Marine Microplastics Database Initiative 2020. <https://doi.org/10.1002/essoar.10504768.1>.
- [2] Ritchie Hannah, Rosado Pablo, Roser Max. CO2 emissions by fuel 2020. <https://ourworldindata.org/emissions-by-fuel> (accessed October 10, 2023).
- [3] Papadis E, Tsatsaronis G. Challenges in the decarbonization of the energy sector. *Energy* 2020;205:118025. <https://doi.org/10.1016/j.energy.2020.118025>.
- [4] Schwedes O. Grundlagen der Verkehrspolitik und die Verkehrswende. *Energiewende*, Springer Fachmedien Wiesbaden; 2019, p. 193–220. https://doi.org/10.1007/978-3-658-26327-0_7.
- [5] Neacsu A, Eparu CN, Stoica DB. HydrogenNatural Gas Blending in Distribution SystemsAn Energy, Economic, and Environmental Assessment. *Energies (Basel)* 2022;15:6143. <https://doi.org/10.3390/en15176143>.
- [6] Haeseldonckx D, D’haeseleer W. The use of the natural-gas pipeline infrastructure for hydrogen transport in a changing market structure. *Int J Hydrogen Energy* 2007;32:1381–6. <https://doi.org/10.1016/j.ijhydene.2006.10.018>.
- [7] Kong M, Feng S, Xia Q, Chen C, Pan Z, Gao Z. Investigation of Mixing Behavior of Hydrogen Blended to Natural Gas in Gas Network. *Sustainability* 2021;13:4255. <https://doi.org/10.3390/su13084255>.
- [8] Chae MJ, Kim JH, Moon B, Park S, Lee YS. The present condition and outlook for hydrogen-natural gas blending technology. *Korean Journal of Chemical Engineering* 2022;39:251 – 262. <https://doi.org/10.1007/s11814-021-0960-8>.
- [9] Najjar YSH. Hydrogen safety: The road toward green technology. *Int J Hydrogen Energy* 2013;38:10716–28. <https://doi.org/10.1016/j.ijhydene.2013.05.126>.
- [10] West M, Al-Douri A, Hartmann K, Buttner W, Groth KM. Critical review and analysis of hydrogen safety data collection tools. *Int J Hydrogen Energy* 2022;47:17845–58. <https://doi.org/10.1016/j.ijhydene.2022.03.244>.
- [11] Weiner SC, Fassbender LL, Quick KA. Using hydrogen safety best practices and learning from safety events. *Int J Hydrogen Energy* 2011;36:2729–35. <https://doi.org/10.1016/j.ijhydene.2010.03.037>.
- [12] Briottet L, Batisse R, Bernard P, Duret-Thual C, Heuzé JL, Martin F, et al. Industrial consequences of hydrogen embrittlement. *Mechanics - Microstructure -*

Corrosion Coupling: Concepts, Experiments, Modeling and Cases 2019:223–44.
<https://doi.org/10.1016/B978-1-78548-309-7.50010-7>.

- [13] Askar E, Schröder V, Schütz S, Seemann A. Power-to-Gas: Safety Characteristics of Hydrogen/Natural Gas Mixtures. The Italian Association of Chemical Engineering 2016.
- [14] Gerboni R. Introduction to hydrogen transportation. *Compendium of Hydrogen Energy*, Elsevier; 2016, p. 283–99. <https://doi.org/10.1016/B978-1-78242-362-1.00011-0>.
- [15] Xu K. Hydrogen embrittlement of carbon steels and their welds. *Gaseous Hydrogen Embrittlement of Materials in Energy Technologies: The Problem, Its Characterisation and Effects on Particular Alloy Classes* 2012:526–61. <https://doi.org/10.1533/9780857093899.3.526>.
- [16] Matsumoto Y, Yukawa H, Nambu T. In situ quantitative evaluation of hydrogen embrittlement in group 5 metals used for hydrogen separation and purification. *Advances in Hydrogen Production, Storage and Distribution* 2014:368–409. <https://doi.org/10.1533/9780857097736.3.317>.
- [17] Abubakirov R, Yang M, Khakzad N. A risk-based approach to determination of optimal inspection intervals for buried oil pipelines. *Process Safety and Environmental Protection* 2020;134:95–107. <https://doi.org/10.1016/J.PSEP.2019.11.031>.
- [18] Palmer-Jones R, Paisley D. Repairing Internal Corrosion Defects in Pipelines - A Case Study. 4th International Pipeline Rehabilitation and Maintenance Conference, 2000.
- [19] Zhou C, He Y, Jiang J, Zhang K, Tang D, Zhu H, et al. Hydrogen uptake induced by CO₂ enhances hydrogen embrittlement of iron in hydrogen blended natural gas. *Corros Sci* 2022;207:110594. <https://doi.org/10.1016/j.corsci.2022.110594>.
- [20] Mason J. *Thermoplastic Liners For Oilfield Pipelines*. Oil and Gas Pipelines, Wiley; 2015, p. 447–56. <https://doi.org/10.1002/9781119019213.ch31>.
- [21] Szklarz KE, Baron JJ. Learnings from thermoplastic liner failures in sour gas pipeline service and replacement liner design and installation. *NACE Meeting Papers*, 2004.
- [22] Bouledroua O, Hafsi Z, Djukic MB, Elaoud S. The synergistic effects of hydrogen embrittlement and transient gas flow conditions on integrity assessment of a

- precracked steel pipeline. *Int J Hydrogen Energy* 2020;45:18010–20. <https://doi.org/10.1016/j.ijhydene.2020.04.262>.
- [23] Martin ML, Connolly M, Buck ZN, Bradley PE, Lauria D, Slifka AJ. Evaluating a natural gas pipeline steel for blended hydrogen service. *J Nat Gas Sci Eng* 2022;101:104529. <https://doi.org/10.1016/j.jngse.2022.104529>.
- [24] Zhou D, Li T, Huang D, Wu Y, Huang Z, Xiao W, et al. The experiment study to assess the impact of hydrogen blended natural gas on the tensile properties and damage mechanism of X80 pipeline steel. *Int J Hydrogen Energy* 2021;46:7402–14. <https://doi.org/10.1016/j.ijhydene.2020.11.267>.
- [25] Birkitt K, Loo-Morrey M, Sanchez C, OSullivan L. Materials aspects associated with the addition of up to 20~mol% hydrogen into an existing natural gas distribution network. *Int J Hydrogen Energy* 2021;46:12290–9. <https://doi.org/10.1016/j.ijhydene.2020.09.061>.
- [26] El-Ghafour SAA, El-dein AHE, Aref AAR. Combustion characteristics of natural gas–hydrogen hybrid fuel turbulent diffusion flame. *Int J Hydrogen Energy* 2010;35:2556–65. <https://doi.org/10.1016/J.IJHYDENE.2009.12.049>.
- [27] Jones DR, Al-Masry WA, Dunnill CW. Hydrogen-enriched natural gas as a domestic fuel: an analysis based on flash-back and blow-off limits for domestic natural gas appliances within the UK. *Sustain Energy Fuels* 2018;2:710–23. <https://doi.org/10.1039/C7SE00598A>.
- [28] Topolski K, Reznicek EP, Erdener BC, San Marchi CW, Ronevich JA, Fring L, et al. Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology. 2022.
- [29] Liu J, Teng L, Liu B, Han P, Li W. Analysis of Hydrogen Gas Injection at Various Compositions in an Existing Natural Gas Pipeline. *Front Energy Res* 2021;9. <https://doi.org/10.3389/fenrg.2021.685079>.
- [30] Ekhtiari A, Flynn D, Syron E. Investigation of the Multi-Point Injection of Green Hydrogen from Curtailed Renewable Power into a Gas Network. *Energies (Basel)* 2020;13:6047. <https://doi.org/10.3390/en13226047>.
- [31] Zhou D, Wang C, Yan S, Yan Y, Guo Y, Shao T, et al. Dynamic modeling and characteristic analysis of natural gas network with hydrogen injections. *Int J Hydrogen Energy* 2022;47:33209–23. <https://doi.org/10.1016/j.ijhydene.2022.07.246>.

- [32] Guandalini G, Colbertaldo P, Campanari S. Dynamic modeling of natural gas quality within transport pipelines in presence of hydrogen injections. *Appl Energy* 2017;185:1712–23. <https://doi.org/10.1016/j.apenergy.2016.03.006>.
- [33] Clees T, Baldin A, Klaassen B, Nikitina L, Nikitin I, Spelten P. Efficient method for simulation of long-distance gas transport networks with large amounts of hydrogen injection. *Energy Convers Manag* 2021;234:113984. <https://doi.org/10.1016/j.enconman.2021.113984>.
- [34] Pellegrino S, Lanzini A, Leone P. Greening the gas network The need for modelling the distributed injection of alternative fuels. *Renewable and Sustainable Energy Reviews* 2017;70:266–86. <https://doi.org/10.1016/j.rser.2016.11.243>.
- [35] Zhou D, Yan S, Huang D, Shao T, Xiao W, Hao J, et al. Modeling and simulation of the hydrogen blended gas-electricity integrated energy system and influence analysis of hydrogen blending modes. *Energy* 2022;239:121629. <https://doi.org/10.1016/J.ENERGY.2021.121629>.
- [36] Sorgulu F, Dincer I. Analysis and techno-economic assessment of renewable hydrogen production and blending into natural gas for better sustainability. *Int J Hydrogen Energy* 2022;47:19977–88. <https://doi.org/10.1016/j.ijhydene.2022.04.133>.
- [37] Liu B, Liu S, Guo S, Zhang S. Economic study of a large-scale renewable hydrogen application utilizing surplus renewable energy and natural gas pipeline transportation in China. *Int J Hydrogen Energy* 2020;45:1385–98. <https://doi.org/10.1016/j.ijhydene.2019.11.056>.
- [38] Ozturk M, Dincer I. Development of renewable energy system integrated with hydrogen and natural gas subsystems for cleaner combustion. *J Nat Gas Sci Eng* 2020;83:103583. <https://doi.org/10.1016/j.jngse.2020.103583>.
- [39] Ozturk M, Dincer I. System development and assessment for green hydrogen generation and blending with natural gas. *Energy* 2022;261:125233. <https://doi.org/10.1016/j.energy.2022.125233>.
- [40] Gurieff N, Moghtaderi B, Daiyan R, Amal R. Gas Transition: Renewable Hydrogen's Future in Eastern Australia's Energy Networks. *Energies (Basel)* 2021;14:3968. <https://doi.org/10.3390/en14133968>.
- [41] Pellegrini M, Guzzini A, Sacconi C. A Preliminary Assessment of the Potential of Low Percentage Green Hydrogen Blending in the Italian Natural Gas Network. *Energies (Basel)* 2020;13:5570. <https://doi.org/10.3390/en13215570>.

- [42] Tabkhi F, Azzaro-Pantel C, Pibouleau L, Domenech S. A mathematical framework for modelling and evaluating natural gas pipeline networks under hydrogen injection. *Int J Hydrogen Energy* 2008;33:6222–31. <https://doi.org/10.1016/j.ijhydene.2008.07.103>.
- [43] Hafsi Z, Elaoud S, Mishra M. A computational modelling of natural gas flow in looped network: Effect of upstream hydrogen injection on the structural integrity of gas pipelines. *J Nat Gas Sci Eng* 2019;64:107–17. <https://doi.org/10.1016/j.jngse.2019.01.021>.
- [44] GOVERNMENT OF WESTERN AUSTRALIA. WA Renewable Hydrogen Strategy. 2021.
- [45] Dincer I. Green methods for hydrogen production. *Int J Hydrogen Energy* 2012;37:1954–71. <https://doi.org/10.1016/j.ijhydene.2011.03.173>.
- [46] Gondal IA. Hydrogen integration in power-to-gas networks. *Int J Hydrogen Energy* 2019;44:1803–15. <https://doi.org/10.1016/j.ijhydene.2018.11.164>.
- [47] Eames I, Austin M, Wojcik A. Injection of gaseous hydrogen into a natural gas pipeline. *Int J Hydrogen Energy* 2022;47:25745–54. <https://doi.org/10.1016/j.ijhydene.2022.05.300>.
- [48] Abd AA, Naji SZ, Thian TC, Othman MR. Evaluation of hydrogen concentration effect on the natural gas properties and flow performance. *Int J Hydrogen Energy* 2021;46:974–83. <https://doi.org/10.1016/j.ijhydene.2020.09.141>.
- [49] Deymi-Dashtebayaz M, Ebrahimi-Moghadam A, Pishbin SI, Pourramezan M. Investigating the effect of hydrogen injection on natural gas thermo-physical properties with various compositions. *Energy* 2019;167:235–45. <https://doi.org/10.1016/j.energy.2018.10.186>.
- [50] Durbin DJ, Malardier-Jugroot C. Review of hydrogen storage techniques for on board vehicle applications. *Int J Hydrogen Energy* 2013;38:14595–617. <https://doi.org/10.1016/j.ijhydene.2013.07.058>.
- [51] Lullo G Di, Oni AO, Kumar A. Blending blue hydrogen with natural gas for direct consumption: Examining the effect of hydrogen concentration on transportation and well-to-combustion greenhouse gas emissions. *Int J Hydrogen Energy* 2021;46:19202–16. <https://doi.org/10.1016/j.ijhydene.2021.03.062>.
- [52] Nowotny J, Veziroglu TN. Impact of hydrogen on the environment. *Int J Hydrogen Energy* 2011;36:13218–24. <https://doi.org/10.1016/j.ijhydene.2011.07.071>.

- [53] Wang C, Zhang J, Liu C, Hu Q, Zhang R, Xu X, et al. Study on hydrogen embrittlement susceptibility of X80 steel through in-situ gaseous hydrogen permeation and slow strain rate tensile tests. *Int J Hydrogen Energy* 2023;48:243–56. <https://doi.org/10.1016/J.IJHYDENE.2022.09.228>.
- [54] Cerniauskas S, Jose Chavez Junco A, Grube T, Robinius M, Stolten D. Options of natural gas pipeline reassignment for hydrogen: Cost assessment for a Germany case study. *Int J Hydrogen Energy* 2020;45:12095–107. <https://doi.org/10.1016/j.ijhydene.2020.02.121>.
- [55] Hoschke J, Chowdhury MFW, Venezuela J, Atrens A. A review of hydrogen embrittlement in gas transmission pipeline steels. *Corrosion Reviews* 2023;41:277 – 317. <https://doi.org/10.1515/corrrev-2022-0052>.
- [56] Kappes MA, Perez T. Hydrogen blending in existing natural gas transmission pipelines: A review of hydrogen embrittlement, governing codes, and life prediction methods. *Corrosion Reviews* 2023;41:319–47. <https://doi.org/10.1515/corrrev-2022-0083>.
- [57] Arrhenius K, Francini L, Büker O. Sampling methods for renewable gases and related gases: challenges and current limitations. *Anal Bioanal Chem* 2022;414:6285–94. <https://doi.org/10.1007/s00216-022-03949-0>.
- [58] Wang H, Tong Z, Zhou G, Zhang C, Zhou H, Wang Y, et al. Research and demonstration on hydrogen compatibility of pipelines: a review of current status and challenges. *Int J Hydrogen Energy* 2022;47:28585–604. <https://doi.org/10.1016/j.ijhydene.2022.06.158>.
- [59] Mahajan D, Tan K, Venkatesh T, Kileti P, Clayton CR. Hydrogen Blending in Gas Pipeline Networks - A Review. *Energies* 2022, Vol 15, Page 3582 2022;15:3582. <https://doi.org/10.3390/EN15103582>.
- [60] Vidas L, Castro R, Pires A. A Review of the Impact of Hydrogen Integration in Natural Gas Distribution Networks and Electric Smart Grids. *Energies (Basel)* 2022;15. <https://doi.org/10.3390/en15093160>.
- [61] Wu X, Zhang H, Yang M, Jia W, Qiu Y, Lan L. From the perspective of new technology of blending hydrogen into natural gas pipelines transmission: Mechanism, experimental study, and suggestions for further work of hydrogen embrittlement in high-strength pipeline steels. *Int J Hydrogen Energy* 2022;47:8071–90. <https://doi.org/10.1016/j.ijhydene.2021.12.108>.

- [62] Melaina MW, Antonia O, Penev M. Blending Hydrogen into Natural Gas Pipeline Networks. A Review of Key Issues. Office of Scientific and Technical Information (OSTI); 2013. <https://doi.org/10.2172/1219920>.
- [63] Erdener BC, Sergi B, Guerra OJ, Lazaro Chueca A, Pambour K, Brancucci C, et al. A review of technical and regulatory limits for hydrogen blending in natural gas pipelines. *Int J Hydrogen Energy* 2023;48:5595–617. <https://doi.org/10.1016/j.ijhydene.2022.10.254>.
- [64] Su Y, Li J, Yu B, Zhao Y, Han D, Sun D. Modeling of Hydrogen Blending on the Leakage and Diffusion of Urban Buried Hydrogen-Enriched Natural Gas Pipeline. *Computer Modeling in Engineering & Sciences* 2023;136:1315–37. <https://doi.org/10.32604/cmes.2023.026035>.
- [65] IGT Process Research Division. HYGAS: 1964 to 1972. Pipeline gas from coal--hydrogenation (IGT hydrogasification process) 1975;4. <https://doi.org/10.2172/5074193>.
- [66] Staniford A. Hydrogen: South Australia surges ahead in renewable leadership. *Ecogeneration* 2018:44.
- [67] Pearman D. Australian Gas Infrastructure Group 2021.
- [68] ARENA. Hydrogen Park Murray Valley Facility. ARENA Media Release 2023.
- [69] HyResource. Western Sydney Green Gas Project 2022. <https://research.csiro.au/hyresource/western-sydney-green-gas-project/> (accessed November 21, 2023).
- [70] Cristello JB, Yang JM, Hugo R, Lee Y, Park SS. Feasibility analysis of blending hydrogen into natural gas networks. *Int J Hydrogen Energy* 2023;48:17605–29. <https://doi.org/10.1016/j.ijhydene.2023.01.156>.
- [71] Donthu N, Kumar S, Mukherjee D, Pandey N, Lim WM. How to conduct a bibliometric analysis: An overview and guidelines. *J Bus Res* 2021;133:285–96. <https://doi.org/10.1016/J.JBUSRES.2021.04.070>.
- [72] Ji B, Zhao Y, Vymazal J, Mander Ü, Lust R, Tang C. Mapping the field of constructed wetland-microbial fuel cell: A review and bibliometric analysis. *Chemosphere* 2021;262:128366. <https://doi.org/10.1016/J.CHEMOSPHERE.2020.128366>.
- [73] He M, Zhang Y, Gong L, Zhou Y, Song X, Zhu W, et al. Bibliometrical analysis of hydrogen storage. *Int J Hydrogen Energy* 2019;44:28206–26. <https://doi.org/10.1016/J.IJHYDENE.2019.07.014>.

- [74] Verma S, Gustafsson A. Investigating the emerging COVID-19 research trends in the field of business and management: A bibliometric analysis approach. *J Bus Res* 2020;118:253–61. <https://doi.org/10.1016/J.JBUSRES.2020.06.057>.
- [75] Ghalambaz M, Sheremet M, Fauzi MA, Fteiti M, Younis O. A scientometrics review of solar thermal energy storage (STES) during the past forty years. *J Energy Storage* 2023;66. <https://doi.org/10.1016/J.EST.2023.107266>.
- [76] Yuan J, Mao W, Hu C, Zheng J, Zheng D, Yang Y. Leak detection and localization techniques in oil and gas pipeline: A bibliometric and systematic review. *Eng Fail Anal* 2023;146. <https://doi.org/10.1016/J.ENGFAILANAL.2023.107060>.
- [77] Chen C, Li C, Reniers G, Yang F. Safety and security of oil and gas pipeline transportation: A systematic analysis of research trends and future needs using WoS. *J Clean Prod* 2021;279. <https://doi.org/10.1016/J.JCLEPRO.2020.123583>.
- [78] Bello IT, Zhai S, He Q, Xu Q, Ni M. Scientometric review of advancements in the development of high-performance cathode for low and intermediate temperature solid oxide fuel cells: Three decades in retrospect. *Int J Hydrogen Energy* 2021;46:26518–36. <https://doi.org/10.1016/J.IJHYDENE.2021.05.134>.
- [79] Cobo MJ, López-Herrera AG, Herrera-Viedma E, Herrera F. Science mapping software tools: Review, analysis, and cooperative study among tools. *Journal of the American Society for Information Science and Technology* 2011;62:1382–402. <https://doi.org/10.1002/ASI.21525>.
- [80] Jan van Eck N, Waltman L. *VOSviewer Manual* 2023.
- [81] van Eck NJ, Waltman L. Software survey: VOSviewer, a computer program for bibliometric mapping. *Scientometrics* 2010;84:523–38. <https://doi.org/10.1007/S11192-009-0146-3/FIGURES/7>.
- [82] O’Connell HB. *IN-SPIRE: Creating a Visualization from a Google Search* 2011. <https://doi.org/10.2172/799007>.
- [83] Md Khudzari J, Kurian J, Tartakovsky B, Raghavan GSV. Bibliometric analysis of global research trends on microbial fuel cells using Scopus database. *Biochem Eng J* 2018;136:51–60. <https://doi.org/10.1016/J.BEJ.2018.05.002>.
- [84] Bello IT, Zhai S, Zhao S, Li Z, Yu N, Ni M. Scientometric review of proton-conducting solid oxide fuel cells. *Int J Hydrogen Energy* 2021;46:37406–28. <https://doi.org/10.1016/J.IJHYDENE.2021.09.061>.

- [85] Scopus tutorials - Scopus: Access and use Support Center n.d. https://service.elsevier.com/app/answers/detail/a_id/14799/supporthub/scopus/ (accessed May 28, 2023).
- [86] Butler L, Visser MS. Extending citation analysis to non-source items. *Scientometrics* 2006;66:327–43. <https://doi.org/10.1007/S11192-006-0024-1/METRICS>.
- [87] Öney F, Vezirolu TN, Dülger Z. Evaluation of pipeline transportation of hydrogen and natural gas mixtures. *Int J Hydrogen Energy* 1994;19:813–22. [https://doi.org/10.1016/0360-3199\(94\)90198-8](https://doi.org/10.1016/0360-3199(94)90198-8).
- [88] Isaac T. HyDeploy: The UK’s First Hydrogen Blending Deployment Project. *Clean Energy* 2019;3:114–25. <https://doi.org/10.1093/CE/ZKZ006>.
- [89] Abdel-Aal HK, Sadik M, Bassyouni M, Shalabi M. A new approach to utilize Hydrogen as a safe fuel. *Int J Hydrogen Energy* 2005;30:1511–4. <https://doi.org/10.1016/j.ijhydene.2005.07.007>.
- [90] NFPA 2-2020 - NFPA 2 Hydrogen Technologies Code, 2020 edition n.d. <https://webstore.ansi.org/standards/nfpa/nfpa2020> (accessed January 21, 2023).
- [91] CSA/ANSI HGV 4.9-2020 - Hydrogen fueling stations n.d. <https://webstore.ansi.org/standards/csa/csaansihgv2020-2407065> (accessed January 21, 2023).
- [92] Hydrogen Safety Panel. Hydrogen Equipment Certification Guide. Listing, Labeling, and Approval Considerations. 2017.
- [93] Verfondern K. Hydrogen fundamentals. Elsevier; 2022. <https://doi.org/10.1016/B978-0-12-820492-4.00001-4>.
- [94] Hord J. Is hydrogen safe? vol. 13. Department of Commerce, National Bureau, Institute for Basic Standards ...; 1976.
- [95] Messaoudani Z labidine, Rigas F, Binti Hamid MD, Che Hassan CR. Hazards, safety and knowledge gaps on hydrogen transmission via natural gas grid: A critical review. *Int J Hydrogen Energy* 2016;41:17511–25. <https://doi.org/10.1016/j.ijhydene.2016.07.171>.
- [96] Li H, Niu R, Li W, Lu H, Cairney J, Chen Y-S. Hydrogen in pipeline steels: Recent advances in characterization and embrittlement mitigation. *J Nat Gas Sci Eng* 2022;105:104709. <https://doi.org/10.1016/j.jngse.2022.104709>.

- [97] Lee KJ, Kim YR, Byun CH, Lee JT. Feasibility of compression ignition for hydrogen fueled engine with neat hydrogen-air pre-mixture by using high compression. *Int J Hydrogen Energy* 2013;38:255–64. <https://doi.org/10.1016/j.ijhydene.2012.10.021>.
- [98] EIA. Production of hydrogen - U.S. Energy Information Administration (EIA). Hydrogen Explained, Production of Hydrogen (EIA) 2021. <https://www.eia.gov/energyexplained/hydrogen/production-of-hydrogen.php> (accessed December 24, 2022).
- [99] IEA. Global hydrogen production by technology in the Net Zero Scenario, 2019-2030 – Charts – Data & Statistics n.d. <https://www.iea.org/data-and-statistics/charts/global-hydrogen-production-by-technology-in-the-net-zero-scenario-2019-2030> (accessed December 24, 2022).
- [100] Dincer I, Acar C. Review and evaluation of hydrogen production methods for better sustainability. *Int J Hydrogen Energy* 2015;40:11094–111. <https://doi.org/10.1016/j.ijhydene.2014.12.035>.
- [101] Chau K, Djire A, Khan F. Review and analysis of the hydrogen production technologies from a safety perspective. *Int J Hydrogen Energy* 2022;47:13990–4007. <https://doi.org/10.1016/j.ijhydene.2022.02.127>.
- [102] Guandalini G, Campanari S, Valenti G. Comparative assessment and safety issues in state-of-the-art hydrogen production technologies. *Int J Hydrogen Energy* 2016;41:18901–20. <https://doi.org/10.1016/j.ijhydene.2016.08.015>.
- [103] Piera M, Martinez-Val JM, Montes MJ. Safety issues of nuclear production of hydrogen. *Energy Convers Manag* 2006;47:2732–9. <https://doi.org/10.1016/j.enconman.2006.02.002>.
- [104] Bassani A, Previtali D, Pirola C, Bozzano G, Colombo S, Manenti F. Mitigating Carbon Dioxide Impact of Industrial Steam Methane Reformers by Acid Gas to Syngas Technology: Technical and Environmental Feasibility. *Journal of Sustainable Development of Energy, Water and Environment Systems* 2020;8:71–87. <https://doi.org/10.13044/j.sdewes.d7.0258>.
- [105] Sharma S, Ghoshal SK. Hydrogen the future transportation fuel: From production to applications. *Renewable and Sustainable Energy Reviews* 2015;43:1151–8. <https://doi.org/10.1016/J.RSER.2014.11.093>.
- [106] Markert F, Nielsen S, Paulsen J, Andersen V. Safety aspects of future infrastructure scenarios with hydrogen refuelling stations. *Int J Hydrogen Energy* 2007;32:2227–34. <https://doi.org/10.1016/j.ijhydene.2007.04.011>.

- [107] Witkowski A, Rusin A, Majkut M, Stolecka K. Comprehensive analysis of hydrogen compression and pipeline transportation from thermodynamics and safety aspects. *Energy* 2017;141:2508–18. <https://doi.org/10.1016/j.energy.2017.05.141>.
- [108] Li H, Cao X, Liu Y, Shao Y, Nan Z, Teng L, et al. Safety of hydrogen storage and transportation: An overview on mechanisms, techniques, and challenges. *Energy Reports* 2022;8:6258–69. <https://doi.org/10.1016/J.EGYR.2022.04.067>.
- [109] Aziz M. Liquid Hydrogen: A Review on Liquefaction, Storage, Transportation, and Safety. *Energies (Basel)* 2021;14:5917. <https://doi.org/10.3390/en14185917>.
- [110] Lowesmith BJ, Hankinson G, Chynoweth S. Safety issues of the liquefaction, storage and transportation of liquid hydrogen: An analysis of incidents and HAZIDS. *Int J Hydrogen Energy* 2014;39:20516–21. <https://doi.org/10.1016/j.ijhydene.2014.08.002>.
- [111] Mair GW, Thomas S, Schalaus B, Wang B. Safety criteria for the transport of hydrogen in permanently mounted composite pressure vessels. *Int J Hydrogen Energy* 2021;46:12577–93. <https://doi.org/10.1016/J.IJHYDENE.2020.07.268>.
- [112] Ma K, Deng J, Wang G, Zhou Q, Xu J. Utilization and impacts of hydrogen in the ironmaking processes: A review from lab-scale basics to industrial practices. *Int J Hydrogen Energy* 2021;46:26646–64. <https://doi.org/10.1016/J.IJHYDENE.2021.05.095>.
- [113] Griffiths S, Sovacool BK, Kim J, Bazilian M, Uratani JM. Industrial decarbonization via hydrogen: A critical and systematic review of developments, socio-technical systems and policy options. *Energy Res Soc Sci* 2021;80:102208. <https://doi.org/10.1016/J.ERSS.2021.102208>.
- [114] IEA. Hydrogen – Analysis. 2022.
- [115] Wang D, Chen S, Xu C, Xiang W. Energy and exergy analysis of a new hydrogen-fueled power plant based on calcium looping process. *Int J Hydrogen Energy* 2013;38:5389–400. <https://doi.org/10.1016/j.ijhydene.2013.02.060>.
- [116] Lim G, Lee S, Park C, Choi Y, Kim C. Effects of compression ratio on performance and emission characteristics of heavy-duty SI engine fuelled with HCNG. *Int J Hydrogen Energy* 2013;38:4831–8. <https://doi.org/10.1016/j.ijhydene.2013.01.188>.

- [117] Yu M, Muy S, Quader F, Bonifacio A, Varghese R, Clerigo E, et al. Combined Hydrogen, Heat and Power (CHHP) pilot plant design. *Int J Hydrogen Energy* 2013;38:4881–8. <https://doi.org/10.1016/j.ijhydene.2013.02.006>.
- [118] Rigas F, Amyotte P. *Hydrogen Safety*. CRC Press; 2012. <https://doi.org/10.1201/b12267>.
- [119] Landucci G, Tugnoli A, Cozzani V. Inherent safety key performance indicators for hydrogen storage systems. *J Hazard Mater* 2008;159:554–66. <https://doi.org/10.1016/j.jhazmat.2008.02.080>.
- [120] Casamirra M, Castiglia F, Giardina M, Lombardo C. Safety studies of a hydrogen refuelling station: Determination of the occurrence frequency of the accidental scenarios. *Int J Hydrogen Energy* 2009;34:5846–54. <https://doi.org/10.1016/j.ijhydene.2009.01.096>.
- [121] Kim E, Park J, Cho JH, Moon I. Simulation of hydrogen leak and explosion for the safety design of hydrogen fueling station in Korea. *Int J Hydrogen Energy* 2013;38:1737–43. <https://doi.org/10.1016/j.ijhydene.2012.08.079>.
- [122] Abohamzeh E, Salehi F, Sheikholeslami M, Abbassi R, Khan F. Review of hydrogen safety during storage, transmission, and applications processes. *J Loss Prev Process Ind* 2021;72:104569. <https://doi.org/10.1016/j.jlp.2021.104569>.
- [123] Wang T, Yang F, Hu Q, Hu S, Li Y, Ouyang M. Experimental and simulation research on hydrogen leakage of double ferrule joints. *Process Safety and Environmental Protection* 2022;160:839–46. <https://doi.org/10.1016/j.psep.2022.02.056>.
- [124] Royle M, Willoughby D. The safety of the future hydrogen economy. *Process Safety and Environmental Protection* 2011;89:452–62. <https://doi.org/10.1016/j.psep.2011.09.003>.
- [125] Yang F, Wang T, Deng X, Dang J, Huang Z, Hu S, et al. Review on hydrogen safety issues: Incident statistics, hydrogen diffusion, and detonation process. *Int J Hydrogen Energy* 2021;46:31467–88. <https://doi.org/10.1016/j.ijhydene.2021.07.005>.
- [126] Ubong EU. Safety issues in hydrogen transportation. *Proceedings: Electrical Insulation Conference and Electrical Manufacturing and Coil Winding Technology Conference* (Cat. No.03CH37480), IEEE; n.d. <https://doi.org/10.1109/eicemc.2003.1247916>.

- [127] Khalil YF. Science-based framework for ensuring safe use of hydrogen as an energy carrier and an emission-free transportation fuel. *Process Safety and Environmental Protection* 2018;117:326–40. <https://doi.org/10.1016/J.PSEP.2018.05.011>.
- [128] Papavinasam S. *Corrosion control in the oil and gas industry*. Elsevier; 2013.
- [129] CC Technologies Inc. *Corrosion Cost and Preventive Strategies in the United States*. United States. Federal Highway Administration; 2002. <https://doi.org/10.21949/1503647>.
- [130] Trench CJ, Kiefner JF. Oil Pipeline Characteristics and Risk Factors: Illustrations from the Decade of Construction 2001:721–9028.
- [131] Holloway MD, Nwaoha C, Onyewuenyi OA. *Process Plant Equipment: Operation, Control, and Reliability*. John Wiley and Sons; 2012. <https://doi.org/10.1002/9781118162569>.
- [132] Shirazi SA, Mclaury BS, Shadley JR, Roberts KP, Rybicki EF, Rincon HE, et al. *Erosion-Corrosion in Oil and Gas Pipelines*. Oil and Gas Pipelines, John Wiley & Sons, Inc.; 2015, p. 399–422. <https://doi.org/10.1002/9781119019213.ch28>.
- [133] Wasim M, Djukic MB. External corrosion of oil and gas pipelines: A review of failure mechanisms and predictive preventions. *J Nat Gas Sci Eng* 2022;100. <https://doi.org/10.1016/J.JNGSE.2022.104467>.
- [134] Liu X, Gong C, Zhang L, Jin H, Wang C. Numerical study of the hydrodynamic parameters influencing internal corrosion in pipelines for different elbow flow configurations. *Engineering Applications of Computational Fluid Mechanics* 2020;14:122–35.
- [135] Askari M, Aliofkhazraei M, Afroukhteh S. A comprehensive review on internal corrosion and cracking of oil and gas pipelines. *J Nat Gas Sci Eng* 2019;71:102971. <https://doi.org/10.1016/j.jngse.2019.102971>.
- [136] Al-Janabi YT. *An Overview of Corrosion in Oil and Gas Industry*. *Corrosion Inhibitors in the Oil and Gas Industry*, Wiley; 2020, p. 1–39. <https://doi.org/10.1002/9783527822140.ch1>.
- [137] Obot IB, Sorour AA, Verma C, Al-Khaldi TA, Rushaid AS. Key parameters affecting sweet and sour corrosion: Impact on corrosion risk assessment and inhibition. *Eng Fail Anal* 2023;145:107008. <https://doi.org/10.1016/j.engfailanal.2022.107008>.

- [138] Dugstad A. Fundamental Aspects of CO₂ Metal Loss Corrosion, Part I: Mechanism 2015.
- [139] Ossai CI. Advances in Asset Management Techniques: An Overview of Corrosion Mechanisms and Mitigation Strategies for Oil and Gas Pipelines. Article ID 2012;2012. <https://doi.org/10.5402/2012/570143>.
- [140] Koteeswaran M. CO₂ and H₂S Corrosion in Oil Pipelines. University of Stavanger, 2010.
- [141] Aegis Tech Line Aegis Chemical Solutions Technical Newsletter 2019.
- [142] Kvarekvål J, Moloney J. Sour corrosion. Trends in Oil and Gas Corrosion Research and Technologies: Production and Transmission 2017;113–47. <https://doi.org/10.1016/B978-0-08-101105-8.00006-1>.
- [143] Zheng Y, Brown B, Nešić S. Electrochemical study and modeling of H₂S corrosion of mild steel. Corrosion 2014;70:351–65. <https://doi.org/10.5006/0937>.
- [144] Esmaeely SN, Brown B, Nešić S. Verification of an Electrochemical Model for Aqueous Corrosion of Mild Steel for H₂S Partial Pressures up to 0.1 MPa. Corrosion 2017;73:144–54. <https://doi.org/10.5006/2172>.
- [145] Kahyarian A, Brown B, Nesic S. Fundamental Mechanisms of Mild Steel Corrosion in H₂S Containing Environments 2019.
- [146] Berkowitz BJ, Heubaum FH. The Role of Hydrogen in Sulfide Stress Cracking of Low Alloy Steels. Corrosion 1984;40:240–5. <https://doi.org/10.5006/1.3581948>.
- [147] Liu M, Wang CH, Dai YC, Li X, Cao GH, Russell AM, et al. Effect of quenching and tempering process on sulfide stress cracking susceptibility in API-5CT-C110 casing steel. Materials Science and Engineering: A 2017;688:378–87. <https://doi.org/10.1016/J.MSEA.2017.01.067>.
- [148] Mendibide C, Sourmail T. Composition optimization of high-strength steels for sulfide stress cracking resistance improvement. Corros Sci 2009;51:2878–84. <https://doi.org/10.1016/J.CORSCI.2009.08.013>.
- [149] Thebault F, Delattre L, Bernard J, ORLANS Jean-Jacques SERVIER Vallourec B, Hörstemeier M, BOSCH Salzgitter Mannesmann Forschung GmbH C, et al. Sulfide Stress Cracking Resistance of High Strength Low Alloy Steels for High H₂S Pressure Wells: Improvements of the H₂S Gas Loading Procedure of the Autoclave and Results for T95 and C110 Steel Grades 2012.

- [150] John RC, Fort WC. Petroleum Industry: Corrosion. Encyclopedia of Materials: Science and Technology 2001:6840–2. <https://doi.org/10.1016/B0-08-043152-6/01213-4>.
- [151] Iannuzzi M. Environmentally assisted cracking (EAC) in oil and gas production. Stress Corrosion Cracking: Theory and Practice 2011:570–607. <https://doi.org/10.1533/9780857093769.4.570>.
- [152] El-Sherik AM. Trends in Oil and Gas Corrosion Research and Technologies. Trends in Oil and Gas Corrosion Research and Technologies 2017:663–88.
- [153] Bonab MAM. Mechanism of failure by hydrogen-induced cracking in pipeline steels. University of Saskatchewan, 2015.
- [154] Tetelman AS, Robertson WD. Direct observation and analysis of crack propagation in iron-3% silicon single crystals. Acta Metallurgica 1963;11:415–26. [https://doi.org/10.1016/0001-6160\(63\)90166-4](https://doi.org/10.1016/0001-6160(63)90166-4).
- [155] Dadfarnia M, Sofronis P, Somerday BP, Liu JB, Johnson DD, Robertson IM. Modeling issues on hydrogen-induced intergranular cracking under sustained load 2009:613–21.
- [156] Lynch SP. Failures of structures and components by metal-induced embrittlement. Stress Corrosion Cracking: Theory and Practice 2011:714–48. <https://doi.org/10.1533/9780857093769.4.714>.
- [157] Kim WK, Koh SU, Yang BY, Kim KY. Effect of environmental and metallurgical factors on hydrogen induced cracking of HSLA steels. Corros Sci 2008;50:3336–42. <https://doi.org/10.1016/J.CORSCI.2008.09.030>.
- [158] Park YD, Maroef IS, Landau A, Olson DL. Retained Austenite as a Hydrogen Trap in Steel Welds Hydrogen trapping is investigated as a means of improving resistance to hydrogen-assisted cracking in HSLA steels. Welding Journal - New York 2002.
- [159] Qin W, Szpunar JA. A general model for hydrogen trapping at the inclusion-matrix interface and its relation to crack initiation. [Http://DxDoiOrg/101080/1478643520171378451](http://DxDoiOrg/101080/1478643520171378451) 2017;97:3296–316. <https://doi.org/10.1080/14786435.2017.1378451>.
- [160] Michler T, Naumann J. Microstructural aspects upon hydrogen environment embrittlement of various bcc steels. Int J Hydrogen Energy 2010;35:821–32. <https://doi.org/10.1016/J.IJHYDENE.2009.10.092>.

- [161] Mohtadi-Bonab MA, Ghesmati-Kucheki H. Important Factors on the Failure of Pipeline Steels with Focus on Hydrogen Induced Cracks and Improvement of Their Resistance: Review Paper. *Metals and Materials International* 2019;25:1109–34. <https://doi.org/10.1007/S12540-019-00266-7>.
- [162] Shi X, Yan W, Wang W, Shan Y, Yang K. Novel Cu-bearing high-strength pipeline steels with excellent resistance to hydrogen-induced cracking. *Mater Des* 2016;92:300–5. <https://doi.org/10.1016/J.MATDES.2015.12.029>.
- [163] Dayal RK, Grabke HJ. Hydrogen induced stress corrosion cracking in low and high strength ferritic steels of different phosphorus content in acid media. *Materials and Corrosion* 1987;38:409–16. <https://doi.org/10.1002/MACO.19870380803>.
- [164] Traidia A, Alfano M, Lubineau G, Duval S, Sherik A. An effective finite element model for the prediction of hydrogen induced cracking in steel pipelines. *Int J Hydrogen Energy* 2012;37:16214–30.
- [165] Jafari S, Harandi SE, Singh Raman RK. A review of stress-corrosion cracking and corrosion fatigue of magnesium alloys for biodegradable implant applications. *JOM* 2015;67:1143–53. <https://doi.org/10.1007/S11837-015-1366-Z/TABLES/1>.
- [166] Winzer N, Atrens A, Song G, Ghali E, Dietzel W, Kainer KU, et al. A Critical Review of the Stress Corrosion Cracking (SCC) of Magnesium Alloys 2005. <https://doi.org/10.1002/adem.200500071>.
- [167] B. Mainier F, Almeida PCF, Nani B, Fernandes LH, Reis MF. Corrosion Caused by Sulfur Dioxide in Reinforced Concrete. *Open Journal of Civil Engineering* 2015;05:379–89. <https://doi.org/10.4236/ojce.2015.54038>.
- [168] Little BJ, Wagner PA, Mansfeld F, SECTION NRLABSSCMSMICO. Microbiologically Influenced Corrosion, Volume 5. NTIS(USA), 1997:130.
- [169] Muhlbauer WK. Pipeline Risk Management Manual: Ideas, Techniques, and Resources. *Pipeline Risk Management Manual: Ideas, Techniques, and Resources* 2003:1–395. <https://doi.org/10.1016/B978-0-7506-7579-6.X5000-6>.
- [170] Bonis M, Crolet JL. Practical aspects of the influence of in situ pH on H₂S-induced cracking. *Corros Sci* 1987;27:1059–70. [https://doi.org/10.1016/0010-938X\(87\)90098-9](https://doi.org/10.1016/0010-938X(87)90098-9).
- [171] Beavers JA, Thompson NG. ASM handbook. Volume 13C ASM International 2006:1015–26.

- [172] John Houghton C, Petroleum Co Norway Robert Victor Westermarck P, Petroleum Co Norway P. North Sea Downhole Corrosion: Identifying the Problem; Implementing the Solutions. *Journal of Petroleum Technology* 1983;35:239–46. <https://doi.org/10.2118/11669-PA>.
- [173] Kim C, Chen L, Wang H, Castaneda H. Global and local parameters for characterizing and modeling external corrosion in underground coated steel pipelines: A review of critical factors. *Journal of Pipeline Science and Engineering* 2021;1:17–35. <https://doi.org/10.1016/J.JPSE.2021.01.010>.
- [174] Hawkins S, Joffe D. Technological Characterisation of Hydrogen Storage and Distribution Technologies. UKSHEC Social Science Working Paper No 21 Policy Studies Institute, London UK 2006.
- [175] Moradi R, Groth KM. Hydrogen storage and delivery: Review of the state of the art technologies and risk and reliability analysis. *Int J Hydrogen Energy* 2019;44:12254–69. <https://doi.org/10.1016/j.ijhydene.2019.03.041>.
- [176] Yang C, Ogden J. Determining the lowest-cost hydrogen delivery mode. *Int J Hydrogen Energy* 2007;32:268–86. <https://doi.org/10.1016/J.IJHYDENE.2006.05.009>.
- [177] Folga SM. Natural gas pipeline technology overview. Office of Scientific and Technical Information (OSTI); 2007. <https://doi.org/10.2172/925391>.
- [178] Popov BN, Lee J-W, Djukic MB. Hydrogen Permeation and Hydrogen-Induced Cracking. *Handbook of Environmental Degradation of Materials*, Elsevier; 2018, p. 133–62. <https://doi.org/10.1016/b978-0-323-52472-8.00007-1>.
- [179] Johnson WH. On some remarkable changes produced in iron and steel by the action of hydrogen and acids. *Proceedings of the Royal Society of London* 1875;23:168–79. <https://doi.org/10.1098/rspl.1874.0024>.
- [180] Woodtli J, Kieselbach R. Damage due to hydrogen embrittlement and stress corrosion cracking. *Eng Fail Anal* 2000;7:427–50. [https://doi.org/10.1016/s1350-6307\(99\)00033-3](https://doi.org/10.1016/s1350-6307(99)00033-3).
- [181] Symons DM. A comparison of internal hydrogen embrittlement and hydrogen environment embrittlement of X-750. *Eng Fract Mech* 2001;68:751–71. [https://doi.org/10.1016/s0013-7944\(00\)00123-5](https://doi.org/10.1016/s0013-7944(00)00123-5).
- [182] Gerberich WW, Birat JP, Zackay VF. A SUPERPOSITION MODEL FOR ENVIROMMENTALLY-ASSISTED FATIGUE-CRACK PROPAGATION. 1971.

- [183] Li X, Ma X, Zhang J, Akiyama E, Wang Y, Song X. Review of Hydrogen Embrittlement in Metals: Hydrogen Diffusion, Hydrogen Characterization, Hydrogen Embrittlement Mechanism and Prevention. *Acta Metallurgica Sinica (English Letters)* 2020;33:759–73. <https://doi.org/10.1007/s40195-020-01039-7>.
- [184] Liu Q, Atrens A. A critical review of the influence of hydrogen on the mechanical properties of medium-strength steels. *Corrosion Reviews* 2013;31:85–103. <https://doi.org/10.1515/corrrev-2013-0023>.
- [185] Sezgin J-G, Bosch C, Montouchet A, Perrin G, Wolski K. Modelling of hydrogen induced pressurization of internal cavities. *Int J Hydrogen Energy* 2017;42:15403–14. <https://doi.org/10.1016/j.ijhydene.2017.04.106>.
- [186] Hardie D, Charles EA, Lopez AH. Hydrogen embrittlement of high strength pipeline steels. *Corros Sci* 2006;48:4378–85. <https://doi.org/10.1016/j.corsci.2006.02.011>.
- [187] Lynch S. Hydrogen embrittlement phenomena and mechanisms. *Corrosion Reviews* 2012;30. <https://doi.org/10.1515/corrrev-2012-0502>.
- [188] Lynch SP. Metallographic and fractographic techniques for characterising and understanding hydrogen-assisted cracking of metals. *Gaseous Hydrogen Embrittlement of Materials in Energy Technologies*, Elsevier; 2012, p. 274–346. <https://doi.org/10.1533/9780857093899.2.274>.
- [189] Song J, Curtin WA. Atomic mechanism and prediction of hydrogen embrittlement in iron. *Nat Mater* 2013;12:145–51. <https://doi.org/10.1038/nmat3479>.
- [190] Dwivedi SK, Vishwakarma M. Hydrogen embrittlement in different materials: A review. *Int J Hydrogen Energy* 2018;43:21603–16. <https://doi.org/10.1016/j.ijhydene.2018.09.201>.
- [191] Rogers HC. Hydrogen Embrittlement of Metals. *Science* (1979) 1968;159:1057–64. <https://doi.org/10.1126/science.159.3819.1057>.
- [192] Dayal RK, Parvathavarthini N. Hydrogen embrittlement in power plant steels. *Sadhana* 2003;28:431–51. <https://doi.org/10.1007/BF02706442>.
- [193] Sznajder M, Geppert U, Dudek MR. Hydrogen blistering under extreme radiation conditions. *Npj Mater Degrad* 2018;2:3. <https://doi.org/10.1038/s41529-017-0024-z>.
- [194] Brandolt C de S, Noronha LC, Hidalgo GEN, Takimi AS, Schroeder RM, Malfatti C de F. Niobium coating applied by HVOF as protection against hydrogen

- embrittlement of API 5CT P110 steel. *Surf Coat Technol* 2017;322:10–8. <https://doi.org/10.1016/J.SURFCOAT.2017.05.017>.
- [195] Nam TH, Lee JH, Choi SR, Yoo JB, Kim JG. Graphene coating as a protective barrier against hydrogen embrittlement. *Int J Hydrogen Energy* 2014;39:11810–7. <https://doi.org/10.1016/J.IJHYDENE.2014.05.132>.
- [196] Zhang T, Zhao W, Li T, Zhao Y, Deng Q, Wang Y, et al. Comparison of hydrogen embrittlement susceptibility of three cathodic protected subsea pipeline steels from a point of view of hydrogen permeation. *Corros Sci* 2018;131:104–15. <https://doi.org/10.1016/J.CORSCI.2017.11.013>.
- [197] Kim YS, Kim JG. Electroplating of reduced-graphene oxide on austenitic stainless steel to prevent hydrogen embrittlement. *Int J Hydrogen Energy* 2017;42:27428–37. <https://doi.org/10.1016/J.IJHYDENE.2017.09.033>.
- [198] Rönnebro ECE, Oelrich RL, Gates RO. Recent Advances and Prospects in Design of Hydrogen Permeation Barrier Materials for Energy Applications—A Review. *Molecules* 2022;27. <https://doi.org/10.3390/MOLECULES27196528>.
- [199] Lee JA, Woods S. *Hydrogen Embrittlement*. 2016.
- [200] Khwaja SA, Paul S. Inspection of Coated Hydrogen Transportation Pipelines. *Applied Sciences* 2022;12:9503. <https://doi.org/10.3390/app12199503>.
- [201] Gangloff RP, Somerday BP. Gaseous hydrogen embrittlement of materials in energy technologies: the problem, its characterisation and effects on particular alloy classes. Elsevier; 2012.
- [202] Ilyushechkin A, Schoeman L, Carter L, Hla SS. Material Challenges and Hydrogen Embrittlement Assessment for Hydrogen Utilisation in Industrial Scale. *Hydrogen* 2023;4:599–619. <https://doi.org/10.3390/hydrogen4030039>.
- [203] Kain V, Gupta V, De PK. Embrittlement cracking of a stabilized stainless steel wire mesh in an ammonia converter. *Environment-Induced Cracking of Materials*, Elsevier; 2008, p. 411–20. <https://doi.org/10.1016/B978-008044635-6.50077-7>.
- [204] Cui H, Wang W, Li A, Li M, Xu S, Liu H. Failure analysis of the brittle fracture of a thick-walled 20 steel pipe in an ammonia synthesis unit. *Eng Fail Anal* 2010;17:1359–76. <https://doi.org/10.1016/j.engfailanal.2010.04.002>.
- [205] Jia G, Lei M, Li M, Xu W, Li R, Lu Y, et al. Hydrogen embrittlement in hydrogen-blended natural gas transportation systems: A review. *Int J Hydrogen Energy* 2023;48:32137–57. <https://doi.org/10.1016/j.ijhydene.2023.04.266>.

- [206] Meda US, Bhat N, Pandey A, Subramanya KN, Lourdu Antony Raj MA. Challenges associated with hydrogen storage systems due to the hydrogen embrittlement of high strength steels. *Int J Hydrogen Energy* 2023;48:17894–913. <https://doi.org/10.1016/j.ijhydene.2023.01.292>.
- [207] Chen Y, Zhao S, Ma H, Wang H, Hua L, Fu S. Analysis of Hydrogen Embrittlement on Aluminum Alloys for Vehicle-Mounted Hydrogen Storage Tanks: A Review. *Metals* (Basel) 2021;11:1303. <https://doi.org/10.3390/met11081303>.
- [208] Irani RS. Hydrogen Storage: High-Pressure Gas Containment. *MRS Bull* 2002;27:680–2. <https://doi.org/10.1557/mrs2002.221>.
- [209] Groysman A. Corrosion problems and solutions in oil, gas, refining and petrochemical industry. *Koroze a Ochrana Materialu* 2017;61:100–17. <https://doi.org/10.1515/KOM-2017-0013>.
- [210] Groysman A. Corrosion for everybody. *Corrosion for Everybody* 2010;1–368. <https://doi.org/10.1007/978-90-481-3477-9>.
- [211] Groysman A. Corrosion in systems for storage and transportation of petroleum products and biofuels: Identification, monitoring and solutions. *Corrosion in Systems for Storage and Transportation of Petroleum Products and Biofuels: Identification, Monitoring and Solutions* 2014:1–297. <https://doi.org/10.1007/978-94-007-7884-9>.
- [212] Guidetti GP, Rigosi GL, Marzola R. The use of polypropylene in pipeline coatings. *Prog Org Coat* 1996;27:79–85. [https://doi.org/10.1016/0300-9440\(95\)00523-4](https://doi.org/10.1016/0300-9440(95)00523-4).
- [213] Thompson I, Saithala JR. Review of pipeline coating systems from an operator's perspective. *Corrosion Engineering Science and Technology* 2016;51:118–35. <https://doi.org/10.1179/1743278215Y.0000000038>.
- [214] Wood LJ. The Protection of Steel Pipes With Coal Tar Enamel Systems: Importance of Specification and Design. *Anti-Corrosion Methods and Materials* 1984;31:4–7. <https://doi.org/10.1108/EB007250>.
- [215] Yin K, Yang Y, Frank Cheng Y. Permeability of coal tar enamel coating to cathodic protection current on pipelines. *Constr Build Mater* 2018;192:20–7. <https://doi.org/10.1016/J.CONBUILDMAT.2018.10.123>.
- [216] Niu L, Cheng YF. Development of innovative coating technology for pipeline operation crossing the permafrost terrain. *Constr Build Mater* 2008;22:417–22. <https://doi.org/10.1016/J.CONBUILDMAT.2007.06.001>.

- [217] Kehr JA, Enos DG. FBE, a Foundation for Pipeline Corrosion Coatings 2000.
- [218] Cheng YF. Stress corrosion cracking of pipelines. John Wiley & Sons; 2013.
- [219] Bigdeli F, Javidi M, Pakshir M. A comparative study of mechanical properties and corrosion behavior of fusion-bonded epoxy and liquid epoxy coatings and their service life in drill pipe applications. *Mater Res Express* 2021;8:25506. <https://doi.org/10.1088/2053-1591/abe313>.
- [220] Liu B, Fang ZG, Wang H Bin, Wang T. Effect of cross linking degree and adhesion force on the anti-corrosion performance of epoxy coatings under simulated deep sea environment. *Prog Org Coat* 2013;76:1814–8. <https://doi.org/10.1016/J.PORGCOAT.2013.05.022>.
- [221] Zargar H, Deen KM, Wong D, Lam CNC, Asselin E. CO2 Permeation Through Fusion-Bonded Epoxy Coating in Humid Environments n.d. <https://doi.org/10.2139/SSRN.4441476>.
- [222] Md Sauri AS, Zakaria M. Assessment of Internal Tubular Coating System for High CO2 Application. *Lecture Notes in Mechanical Engineering* 2023:919–25. https://doi.org/10.1007/978-981-19-1939-8_68/COVER.
- [223] Kirkpatrick D, Aguirre F, Jacob G. Review Of Epoxy Polymer Thermal Aging Behavior Relevant To Fusion Bonded Epoxy Coatings 2008.
- [224] Malik AU, Andijani I, Ahmed S, Al-Muaili F. Corrosion and mechanical behavior of fusion bonded epoxy (FBE) in aqueous media. *Desalination* 2002;150:247–54. [https://doi.org/10.1016/S0011-9164\(02\)00980-3](https://doi.org/10.1016/S0011-9164(02)00980-3).
- [225] Crosby T, Wolodko J, Tsaprailis H. Gap Analysis of Canadian Pipeline Coatings: A Review Study 2016.
- [226] Yang X, Gao Z, Wang X, Hu W. Influence of fusion bonded epoxy powder on Corrosion, wear performance of galvanized composite coating and hydrogen permeation behavior to based carbon steel. *Mater Lett* 2021;296:129922. <https://doi.org/10.1016/J.MATLET.2021.129922>.
- [227] Norsworthy R. Fusion Bonded Epoxy - A Field Proven Fail Safe Coating System 2006.
- [228] Legghe E, Aragon E, Bélec L, Margaillan A, Melot D. Correlation between water diffusion and adhesion loss: Study of an epoxy primer on steel. *Prog Org Coat* 2009;66:276–80. <https://doi.org/10.1016/J.PORGCOAT.2009.08.001>.

- [229] Moosavi AN, Al-Mutawa S, Balboul S, Saady M. Hidden problems with three layer polypropylene pipeline coatings. NACE - International Corrosion Conference Series 2006:060571–0605716.
- [230] Voloshkin AF, Firsov VA, Borovikov A V., Repkin NB, Skovpen TP, Deineka AYa. Polymeric Coatings for Large-Diameter Pipes. <https://doi.org/10.1177/0307174X0503200307> 2005;32:43–8. <https://doi.org/10.1177/0307174X0503200307>.
- [231] Argent C, Norman D. Fitness For Purpose Issues Relating To Fbe And Three Layer Pe Coatings 2005.
- [232] ISO 21809-1:2018(en), Petroleum and natural gas industries — External coatings for buried or submerged pipelines used in pipeline transportation systems — Part 1: Polyolefin coatings (3-layer PE and 3-layer PP) n.d. <https://www.iso.org/obp/ui/#iso:std:iso:21809:-1:ed-2:v1:en> (accessed March 12, 2023).
- [233] Howell GR, Cheng YF. Characterization of high performance composite coating for the northern pipeline application. *Prog Org Coat* 2007;60:148–52. <https://doi.org/10.1016/J.PORGCOAT.2007.07.013>.
- [234] Khanna AS. High-performance organic coatings. Elsevier; 2008.
- [235] Rippon IJ, Finnegan JE. Polyethylene Coating Damage on an Underwater Pipeline in the Southern North Sea. *Proceedings of the Annual Offshore Technology Conference* 1984;1984-May:179–88. <https://doi.org/10.4043/4668-MS>.
- [236] Heck CA, Dos Santos JHZ, Wolf CR. Waterborne polyurethane: the effect of the addition or in situ formation of silica on mechanical properties and adhesion. *Int J Adhes Adhes* 2015;58:13–20. <https://doi.org/10.1016/J.IJADHADH.2014.12.006>.
- [237] Akindoyo JO, Beg MDH, Ghazali S, Islam MR, Jeyaratnam N, Yuvaraj AR. Polyurethane types, synthesis and applications – a review. *RSC Adv* 2016;6:114453–82. <https://doi.org/10.1039/C6RA14525F>.
- [238] Noreen A, Zia KM, Zuber M, Tabasum S, Saif MJ. Recent trends in environmentally friendly water-borne polyurethane coatings: A review. *Korean Journal of Chemical Engineering* 2016 33:2 2015;33:388–400. <https://doi.org/10.1007/S11814-015-0241-5>.
- [239] Noreen A, Zia KM, Zuber M, Tabasum S, Zahoor AF. Bio-based polyurethane: An efficient and environment friendly coating systems: A review. *Prog Org Coat* 2016;91:25–32. <https://doi.org/10.1016/J.PORGCOAT.2015.11.018>.

- [240] Golling FE, Pires R, Hecking A, Weikard J, Richter F, Danielmeier K, et al. Polyurethanes for coatings and adhesives – chemistry and applications. *Polym Int* 2019;68:848–55. <https://doi.org/10.1002/PI.5665>.
- [241] Xiang H, Wang X, Lin G, Xi L, Yang Y, Lei D, et al. Preparation, Characterization and Application of UV-Curable Flexible Hyperbranched Polyurethane Acrylate. *Polymers* 2017, Vol 9, Page 552 2017;9:552. <https://doi.org/10.3390/POLYM9110552>.
- [242] Lee HS, Hsu SL. An Analysis of Phase Separation Kinetics of Model Polyurethanes. *Macromolecules* 1989;22:1100–5. <https://doi.org/10.1021/ma00193a017>.
- [243] He Y, Xie D, Zhang X. The structure, microphase-separated morphology, and property of polyurethanes and polyureas. *J Mater Sci* 2014;49:7339–52. <https://doi.org/10.1007/S10853-014-8458-Y>.
- [244] Zubielewicz M, Królikowska A. The influence of ageing of epoxy coatings on adhesion of polyurethane topcoats and protective properties of coating systems. *Prog Org Coat* 2009;66:129–36. <https://doi.org/10.1016/J.PORGCOAT.2009.06.014>.
- [245] Yang XF, Vang C, Tallman DE, Bierwagen GP, Croll SG, Rohlik S. Weathering degradation of a polyurethane coating. *Polym Degrad Stab* 2001;74:341–51. [https://doi.org/10.1016/S0141-3910\(01\)00166-5](https://doi.org/10.1016/S0141-3910(01)00166-5).
- [246] Hang TTX, Dung NT, Truc TA, Duong NT, Van Truoc B, Vu PG, et al. Effect of silane modified nano ZnO on UV degradation of polyurethane coatings. *Prog Org Coat* 2015;79:68–74. <https://doi.org/10.1016/J.PORGCOAT.2014.11.008>.
- [247] Noble KL. Waterborne polyurethanes. *Prog Org Coat* 1997;32:131–6. [https://doi.org/10.1016/S0300-9440\(97\)00071-4](https://doi.org/10.1016/S0300-9440(97)00071-4).
- [248] Singh RP, Tomer NS, Bhadraiah SV. Photo-oxidation studies on polyurethane coating: effect of additives on yellowing of polyurethane. *Polym Degrad Stab* 2001;73:443–6. [https://doi.org/10.1016/S0141-3910\(01\)00127-6](https://doi.org/10.1016/S0141-3910(01)00127-6).
- [249] Melchior M, Sonntag M, Kobusch C, Jürgens E. Recent developments in aqueous two-component polyurethane (2K-PUR) coatings. *Prog Org Coat* 2000;40:99–109. [https://doi.org/10.1016/S0300-9440\(00\)00123-5](https://doi.org/10.1016/S0300-9440(00)00123-5).
- [250] Chattopadhyay DK, Raju KVS. Structural engineering of polyurethane coatings for high performance applications. *Progress in Polymer Science (Oxford)* 2007;32:352–418. <https://doi.org/10.1016/J.PROGPOLYMSCI.2006.05.003>.

- [251] Samimi A, Zarinabadi S. Application Polyurethane as Coating in Oil and Gas Pipelines. *International Journal of Science and Engineering Investigations* 2012;1.
- [252] Rahman MM, Zahir MdH, Haq MdB, Madhan Kumar A, Arafat MdE, Rabbani MM. Silicone-enriched surface of immersed polyurethane-POSS antifouling coating. *International Journal of Polymer Analysis and Characterization* 2020;25:385–95. <https://doi.org/10.1080/1023666X.2020.1796106>.
- [253] Wang Y, Chen R, Li T, Ma P, Zhang H, Du M, et al. Antimicrobial Waterborne Polyurethanes Based on Quaternary Ammonium Compounds. *Ind Eng Chem Res* 2020;59:458–63. <https://doi.org/10.1021/acs.iecr.9b04828>.
- [254] Khalid HU, Ismail MC, Nosbi N. Permeation Damage of Polymer Liner in Oil and Gas Pipelines: A Review. *Polymers (Basel)* 2020;12:2307. <https://doi.org/10.3390/polym12102307>.
- [255] Ali MM, Magee JC, Hsieh PY. Corrosion protection of steel pipelines with metal-polymer composite barrier liners. *J Nat Gas Sci Eng* 2020;81:103407. <https://doi.org/10.1016/j.jngse.2020.103407>.
- [256] Davis R, Snider B. Economically Mitigating Downhole Corrosion and Wear Failures with Thermoplastic Liners. *CORROSION 2017, NACE International*; 2017.
- [257] TREMBLAY P, SAVARD M, VERMETTE J, PAQUIN R. Gas permeability, diffusivity and solubility of nitrogen, helium, methane, carbon dioxide and formaldehyde in dense polymeric membranes using a new on-line permeation apparatus. *J Memb Sci* 2006;282:245–56. <https://doi.org/10.1016/j.memsci.2006.05.030>.
- [258] Ahmed MR, Barua T, Das BK. A comprehensive review on techno-environmental analysis of state-of-the-art production and storage of hydrogen energy: challenges and way forward. *Energy Sources, Part A: Recovery, Utilization, and Environmental Effects* 2023;45:5905–37. <https://doi.org/10.1080/15567036.2023.2211029>.
- [259] Clark ES. FIRE RETARDANT COATINGS. *Construction Specifier* 1975;28. <https://doi.org/10.5772/67675>.
- [260] Saxena NK, Gupta DR. Development and evaluation of fire retardant coatings. *Fire Technol* 1990;26:329–41. <https://doi.org/10.1007/BF01293077/METRICS>.
- [261] Hao J, Chow WK. A Brief Review of Intumescent Fire Retardant Coatings. *Archit Sci Rev* 2011;46:89–95. <https://doi.org/10.1080/00038628.2003.9696967>.

- [262] National Fire Protection Association. NFPA 703: Standard for Fire-Retardant-Treated Wood and Fire-Retardant Coatings for Building Materials. 2022.
- [263] American Wood Protection Association. 2022 AWPB Book of Standards. 2022.
- [264] Mandal PC. Analysis of gas transmission network of Bangladesh, 2002.
- [265] Pipesim steady-state Multiphase flow simulator n.d. <https://www.software.slb.com/products/pipesim> (accessed August 10, 2023).
- [266] Iranzi J, Son H, Lee Y, Wang J. A Nodal Analysis Based Monitoring of an Electric Submersible Pump Operation in Multiphase Flow. *Applied Sciences* 2022;12:2825. <https://doi.org/10.3390/app12062825>.
- [267] Kondrat R, Matiishyn L. Improving the efficiency of production wells at the final stage of gas field development. *Mining of Mineral Deposits* 2022;16:1–6. <https://doi.org/10.33271/mining16.02.001>.
- [268] Nguyen DD, Atiku FA, Pirouzfard V, Su CH. Technical, economic and thermodynamic analysis for loading, storing, unloading and transporting of Ethane fluid. *J Taiwan Inst Chem Eng* 2021;120:218–28. <https://doi.org/10.1016/J.JTICE.2021.03.035>.
- [269] Noumo PG, Njomo D, Nana KZ, Chuisseu Nguewo LR. Numerical simulation of the minimum insulation thickness to thermally design a subsea pipeline carrying an oil and gas flow. *International Journal of Heat and Technology* 2021;39:763–74. <https://doi.org/10.18280/IJHT.390310>.
- [270] Dmitriy E, Uspenskaya M V., Kunakova AM, Usmanova FG. Simulate flow and select a pressure reduction method using pipesim software in an oil recovery system. *International Multidisciplinary Scientific GeoConference Surveying Geology and Mining Ecology Management, SGEM* 2019;19:73–8. <https://doi.org/10.5593/SGEM2019V1.4/S01.010>.
- [271] Rammay MH, Alnuaim S. Flow regime prediction using fuzzy logic and modification in Beggs and Brill multiphase correlation. *International Petroleum Technology Conference, IPTC*; 2015, p. D021S013R003.
- [272] Cullender MH, Smith RV. Practical Solution of Gas-Flow Equations for Wells and Pipelines with Large Temperature Gradients. *Transactions of the AIME* 1956;207:281–7. <https://doi.org/10.2118/696-G>.
- [273] Pedersen KS, Fredenslund A. An improved corresponding states model for the prediction of oil and gas viscosities and thermal conductivities. *Chem Eng Sci* 1987;42:182–6. [https://doi.org/10.1016/0009-2509\(87\)80225-7](https://doi.org/10.1016/0009-2509(87)80225-7).

- [274] Pedersen KS, Christensen PL, Shaikh JA. Phase Behavior of Petroleum Reservoir Fluids. CRC Press; 2014. <https://doi.org/10.1201/b17887>.
- [275] Janeček J, Paricaud P, Dicko M, Coquelet C. A generalized Kiselev crossover approach applied to Soave–Redlich–Kwong equation of state. *Fluid Phase Equilib* 2015;401:16–26. <https://doi.org/10.1016/j.fluid.2015.04.024>.
- [276] goldfields gas pipeline | APA Group n.d. <https://www.apa.com.au/our-services/gas-transmission/west-coast-grid/goldfields-gas-pipeline/> (accessed August 10, 2023).
- [277] Goldfields Gas Pipeline - Australian Pipelines and Gas Association n.d. <https://www.apga.org.au/goldfields-gas-pipeline> (accessed August 10, 2023).
- [278] WA: Goldfields Gas Pipeline | AEMC n.d. <https://www.aemc.gov.au/energy-rules/national-gas-rules/gas-scheme-register/wa-goldfields-gas-pipeline> (accessed August 10, 2023).
- [279] Pearson J. Western Australia: A Highly Competitive Destination For Private Sector Investment In The Offshore Petroleum Industry. *All Days, OTC*; 1998. <https://doi.org/10.4043/8633-MS>.
- [280] PIENAAR A. OPERATIONAL IMPLEMENTATION OF CURTAILMENT WITHIN NATURAL GAS TRANSMISSION PIPELINES. THE UNIVERSITY OF QUEENSLAND, 2019.
- [281] eAtlas. Oil and Gas Pipelines of Australia 2004 (GA) 2004. <https://eatlas.org.au/data/uuid/9793add6-c663-4bff-a2af-4f0d0f2a062b> (accessed August 13, 2023).
- [282] Serfaty J, Pogson M, Haq B. A study of subsurface integrity issues for the Mondarra underground gas storage field. *The APPEA Journal* 2011;51:215. <https://doi.org/10.1071/AJ10015>.
- [283] WA Legislation. Gas Supply (Gas Quality Specifications). 2016.
- [284] apa group mondarra gas storage facility | APA Group n.d. <https://www.apa.com.au/our-services/gas-transmission/gas-storage/mondarra-gas-storage-facility/> (accessed August 10, 2023).
- [285] eastern goldfields pipeline | APA Group n.d. <https://www.apa.com.au/our-services/gas-transmission/west-coast-grid/eastern-goldfields-pipeline/> (accessed August 15, 2023).

- [286] Witek M, Uilhoorn F. Impact of hydrogen blended natural gas on linepack energy for existing high pressure pipelines. *Archives of Thermodynamics* 2022;111–24.
- [287] Moghaddam ZS, Kaykhahi M, Khajeh M, Oveisi AR. Synthesis of UiO-66-OH zirconium metal-organic framework and its application for selective extraction and trace determination of thorium in water samples by spectrophotometry. *Spectrochim Acta A Mol Biomol Spectrosc* 2018;194:76–82. <https://doi.org/10.1016/j.saa.2018.01.010>.
- [288] Gas Bulletin Board (WA) n.d. <https://gbbwa.aemo.com.au/#flows> (accessed August 15, 2023).
- [289] Włodek T, Łaciak M, Kurowska K, Węgrzyn Ł. Thermodynamic analysis of hydrogen pipeline transportation – selected aspects. *AGH Drilling, Oil, Gas* 2016;33:379. <https://doi.org/10.7494/drill.2016.33.2.379>.
- [290] Abd AA, Naji SZ, Thian TC, Othman MR. Evaluation of hydrogen concentration effect on the natural gas properties and flow performance. *Int J Hydrogen Energy* 2021;46:974–83. <https://doi.org/10.1016/j.ijhydene.2020.09.141>.
- [291] Zhang H, Li J, Su Y, Wang P, Yu B. Effects of hydrogen blending on hydraulic and thermal characteristics of natural gas pipeline and pipe network. *Oil & Gas Science and Technology – Revue d'IFP Energies Nouvelles* 2021;76:70. <https://doi.org/10.2516/ogst/2021052>.
- [292] Justo-García DN, García-Sánchez F, Díaz-Ramírez NL, Díaz-Herrera E. Modeling of three-phase vapor–liquid–liquid equilibria for a natural-gas system rich in nitrogen with the SRK and PC-SAFT EoS. *Fluid Phase Equilib* 2010;298:92–6. <https://doi.org/10.1016/j.fluid.2010.07.012>.
- [293] Hafsi Z, Elaoud S, Akrouit M, Hadj-Taïeb E. Numerical Approach for Steady State Analysis of Hydrogen–Natural Gas Mixtures Flows in Looped Network. *Arab J Sci Eng* 2017;42:1941–50. <https://doi.org/10.1007/s13369-016-2393-y>.
- [294] Reshadi P, Nasrifar Kh, Moshfeghian M. Evaluating the phase equilibria of liquid water+natural gas mixtures using cubic equations of state with asymmetric mixing rules. *Fluid Phase Equilib* 2011;302:179–89. <https://doi.org/10.1016/j.fluid.2010.08.007>.
- [295] Arcangeletti G, Aloigi E, Baldoni A, Branduardi L, Castiglioni F, Filippi A, et al. Advancing Technologies for H₂ and CO₂ Offshore Transportation Enabling the Energy Transition: Design Challenges and Opportunities for Long Distance Pipeline Systems. OMC Med Energy Conference and Exhibition, Ravenna, Italy: OnePetro; 2021.

- [296] Jothi V, Adesina AY, Madhan Kumar A, Nirmal Ram JS. Influence of Organic Acids on the Surface and Corrosion Resistant Behavior of Anodized Films on AA2024 Aerospace Alloys in Artificial Seawater. *Metals and Materials International* 2020;26:1611–20. <https://doi.org/10.1007/s12540-019-00379-z>.
- [297] Suleiman RK, Adesina AY, Kumar AM, Rahman MM, Al-Badour FA, El Ali B. Anticorrosion Properties of a Novel Hybrid Sol–Gel Coating on Aluminum 3003 Alloy. *Polymers (Basel)* 2022;14:1798. <https://doi.org/10.3390/polym14091798>.
- [298] Panda SS, Panda BP, Mohanty S, Nayak SK. The castor oil based water borne polyurethane dispersion; effect of -NCO/OH content: synthesis, characterization and properties. *Green Processing and Synthesis* 2017;6:341–51. <https://doi.org/10.1515/gps-2016-0144>.

Vitae

Mohammed Sofian Ali Khalid is a full-time master's student at KFUPM, College of Petroleum Engineering and Geosciences, Department of Petroleum Engineering. He Awarded his BSc (Honors) from University of Khartoum, Sudan, in November 2017. Following his studies, Mr. Khalid worked for the Ministry of Oil and Energy, Sudan, in Conventional and Special Core Analysis Laboratories for one year. Later, Mr. Khalid joined Dal Group Company as a Supply Chain Graduate Trainee through their Graduates Development Program. During his time at Dal Group, he was oriented in different supply chain-related departments, including logistics operations, procurement, and supply chain planning. Eventually, Mr. Khalid started his graduate studies by joining KFUPM in August 2021. During his MSc studies, Mr. Khalid was engaged in multiple research activities in his coursework where he managed to co-author three articles (2 journals and 1 conference). The journal papers are in the Australian Petroleum Production & Exploration Association (APPEA) journal, and the Journal of Petroleum Exploration and Production Technology (JPEPT), respectively. The third paper was presented at the International Petroleum Technology Conference (IPTC), Riyadh 2022.

Name	:Mohammed Sofian Ali Khalid
Nationality	:Sudan
Date of Birth	:1/16/1996
Email	:mohammedkhalid16196@gmail.com
Address	:Building 42, Block 2, Maouna St., Alkadroo, , Khartoum, Sudan
Academic Background	:Petroleum Engineering

Publications

1. M. Sofian, B. Haq, D. Alshehri, M.M. Rahman, and Ehsan Zaman. “*Hydrogen and Natural Gas Blending in Gas Network – A Case Study of Kalgoorlie-Kambalda-Esperance Gas Pipelines in Western Australia*”. (**Accepted – OTC– Malaysia, February 2024**).
2. M. Sofian, B. Haq, D. Alshehri, M.M. Rahman, and Ehsan Zaman. “*Repurposing Western Australian Gas Network for Hydrogen Transportation - A Case Study of Goldfields Gas Pipeline*”. (**Accepted – OTC– USA, May 2024**).
3. M. Sofian, B. Haq, D. Alshehri, M.M. Rahman, and N. S. Muhammed. “*A Review on Hydrogen Blending in Gas Network: Insight into Safety, Corrosion, Embrittlement, Coatings and Liners, and Bibliometric Analysis*”. (**Under Review - IJHE**).
4. M. Sofian, B. Haq, D. Alshehri, and M.M. Rahman. “*Hydrogen-Natural Gas Blending in Western Australian Gas Network*”. (**Prepared**).