Jemena Gas Networks (NSW) Ltd

Revised 2020-25 Access Arrangement Proposal

Attachment 8.5

Response to the AER's draft decision - Hydrogen Future Study

Jemena NSW Gas Distribution Network

Hydrogen Future Study

Jemena Gas Networks (NSW) Ltd

GPA Document No: 19853-REP-001

Rev	Date	By	Checked	QA	Description
0	19/12/2019	DK	BOS	APW	Issued for use
1	24/12/2019	DK	BOS	APW	Re-issued for use

pp

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SUMMARY

Recognising the opportunities for hydrogen in Australia, in November 2019, the Council of Australian Government (COAG) Energy Council prepared and released the “National Hydrogen Strategy”. The strategy outlines an adaptive approach to scaling up Australia’s hydrogen industry as demand grows. The strategy includes a set of nationally coordinated actions involving governments, industry, and community and identified several strategic actions directly supporting hydrogen in the natural gas networks.

Jemena have acknowledged the likely energy transition by taking proactive steps to ensure their gas assets are prepared for the new future clean energy transition. Jemena’s *Western Sydney Green Gas Project* (WSGGP) will seek to demonstrate the ability to utilise existing gas pipeline infrastructure to store excess renewable energy as hydrogen.

GPA Engineering (GPA) were commissioned by Jemena to complete an independent study to identify the technical impacts of 10% and 100% hydrogen (by volume) blended in their NSW gas distribution network, and develop the high level actions to support the transition.

Jemena Gas Network (JGN) own and operate a number of natural gas assets across NSW that includes over 26,000 km of piping operating from 2 kPa to 6,895 kPa and is safely controlled by more than 1.5 million components including regulators, isolation valves and flow meters. Facilities within the network include pressure-regulating stations, custody transfer stations, and metering stations. The materials of construction for the trunk, primary and secondary mains are coated steel. As the network reduces in pressure to the medium and low pressure mains, the pipeline materials are commonly plastic (polyethylene and nylon). A cast iron replacement program in the 1990s reduced the amount of cast iron in the Jemena NSW Gas Distribution Network to less than 1%.

The network includes a large number of end users of natural gas for domestic, commercial and industrial applications. The different gas quality, combustion and materials characteristics of hydrogen compared with natural gas need to be considered when assessing the technical suitability of blending hydrogen with or replacing natural gas, including the impact on installations and appliances downstream of the network, however this was excluded from the scope of this study.

GPA reviewed the impacts of blending 10% and 100% hydrogen into the network and found that overall, based on current understanding, the network it is a good candidate for hydrogen blending. The low and medium pressure networks that make up a large percentage of the network, are all relatively new plastic piping systems, that are likely suitable for hydrogen. The steel primary mains are designed to operate at low stress, significantly reducing the risk of embrittlement.

Although well suited for conversion, there is still significant research and upgrades required before hydrogen can be safety blended in the network. Consequently, GPA developed a number of actions outlining further studies required to understand the technical impact of conversion of the network for a hydrogen future. These include a review of impacts to network capacity, materials compatibility assessments of existing piping and components, and review of existing safety, operating, and risk management systems. Following is a summary of the impacts of 10% and 100% hydrogen in the Jemena NSW Gas Distribution Network.

Area	Description	10% H2	100% H2
Network Performance	Network capacity	M	H
Materials Compatibility	High pressure steel pipelines (primary, trunk and pipeline)	M	H
	Low pressure steel pipelines	L	L

Area	Description	10% H2	100% H2
	Pipelines under integrity management	H	H
	Pipelines subject to cyclic loading	H	H
	Other steel equipment	M	M
	Polyethylene pipelines	L	U
	Cast iron pipeline	L	L
	Elastomers	M	U
Equipment	Flow meters	M	H
	Manual valves	L	M
	Control valves and regulators	M	H
	Heaters – gas fired	M	L
	Heaters – electrical	L	L
	Gas chromatographs	M	H
	Instrument gas systems	L	L
	Gas detectors	L	H
	Station/facility pipework	L	M
	Filters	L	M
Safety	SCADA system	M	M
	Hazardous areas	L	H
	Odorant	L	U
	Safety and Operating Plan	M	H
	Pipeline Safety Management Study	M	H
	Gas detectors (personal)	L	H
	Emergency response plan	L	M
Operation and maintenance	Prohibition of in-service welding	M	U
	Blowdown facilities	L	H

Key:

L	Low impact – Low probability of modifications required
M	Medium impact – Minor or partial modifications are expected
H	High impact – Major modifications are expected
U	Unknown, further information is required, by means of analysis or research

GPA completed a review of domestic and international network conversions to understand the potential magnitude of transition. This review highlighted that previous conversions from “town gas” to natural gas incurred a significant financial cost. A recent town gas conversion in Isle of Man (2016) was estimated at £3,500 per connection ($6,698 AUD). Similarly, 100% hydrogen conversion studies completed in the UK indicated that replacement and upgrades to the distribution network and gas appliances would be required, resulting in significant financial impacts. The H21 project in Leeds (UK) estimated that the average cost of conversion per connection, including gas network and appliance upgrades was £4,028 ($7,708 AUD).

Based on the results of this desktop study, in GPA's opinion, there will be significant investment required to transition to hydrogen in the gas network including potential accelerated and new capital investment. Given the potential for significant costs associated with transitioning the network to a hydrogen future, it is recommended that Jemena undertake further work to define the preferred transition pathway, in order to better quantify the capital investment required and prioritise transitional actions.

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1 INTRODUCTION

1.1 BACKGROUND

In 2016, Australia committed to the achieving the targets set out by the Paris Agreement. The Paris Agreement's central aim is to strengthen the global response to the threat of climate change by keeping a global temperature rise this century well below 2ºC above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5ºC.

To achieve this, a reduction of greenhouse gas emissions, or decarbonisation, is required. Decarbonisation is already underway in the electricity and transport sectors with broad uptake of renewable generation such as solar photovoltaic and wind energy and a steady increase in the use of electric vehicles.

Recently, a number of domestic and international reports have been released in support of Australia's energy transition. Of particular interest to the natural gas networks is the National Hydrogen Strategy.

1.1.1 National Hydrogen Strategy

In 2019, the Council of Australian Governments (COAG) Energy Council released the National Hydrogen Strategy. The strategy sets "*a vision for a clean, innovative, safe and competitive hydrogen industry that benefits all Australians and is a major global player by 2030*".[1] The strategy, which outlines an adaptive approach to scaling up Australia's efforts as the hydrogen market grows, includes a set of nationally coordinated actions involving governments, industry and the community.

The strategy recognises blending of hydrogen in the gas networks as a catalyst for stimulating early hydrogen demand growth. This is in part due to governments being able to directly influence when and by how much demand for hydrogen in gas distribution is increased, whereas other uses of hydrogen depend on market uptake of hydrogen end-use technologies or international demand growth.

Additionally, the strategy identified opportunities in New South Wales (NSW) for both domestic hydrogen use and export. It highlighted Jemena's *Western Sydney Green Gas Project* (WSGGP) as leading the way in seeking to demonstrate the ability to utilise existing gas pipeline infrastructure to store excess renewable energy in the form of hydrogen.[2]

Several strategic actions are identified in the National Hydrogen Strategy that directly support blending of hydrogen in the gas networks, and the eventual use of 100% hydrogen in the gas networks.

1.1.2 GPA Capabilities

GPA is a multidisciplinary, technical engineering consultancy that has an extensive knowledge of the project life cycle in the oil and gas, power generation, mining and water treatment industries.

Recently, GPA has completed the following projects that are relevant to this study, including two reports commissioned directly to support the development of the National Hydrogen Strategy:

- Technical and regulatory impacts of addition of hydrogen to gas distribution networks (COAG)
- Technical impacts of addition of hydrogen to downstream users (COAG)
- Detailed design of Western Sydney Green Gas Project (Jemena)
- Detailed design of HyPark South Australia (Australian Gas Infrastructure Group)

[1] Commonwealth of Australia, *Australia's National Hydrogen Strategy*, 2019
[2] Details of this project - https://jemena.com.au/about/innovation/power-to-gas-trial

- Zero emissions study for the Canberra Gas Network (Evoenergy)

Appendix 1 provides a full list of GPA's relevant experience in hydrogen, natural gas and distribution networks.

1.2 PURPOSE

This study broadly outlines the technical impacts of adding hydrogen to natural gas and the actions required to transition the Jemena NSW Gas Distribution Network to a 10% or 100% hydrogen future.

The purpose of this study is to:

1. Outline the technical impacts of addition of 10% and 100% hydrogen (by volume) to the Jemena NSW Gas Distribution Network,
2. Develop a set of high level actions to enable Jemena to commence transition of the Jemena NSW Gas Distribution Network to 10% or 100% hydrogen, and
3. Identify additional studies or further research required to understand the implications of adding hydrogen to the Jemena NSW Gas Distribution Network.

1.3 SCOPE OF THE STUDY

The scope of this study includes:

1. Desktop review of the:
    a. Jemena NSW Gas Distribution Network, including identification of key equipment, components and facilities
    b. Changes in gas properties when 10% and 100% hydrogen is blended with natural gas
    c. Technical impacts of 10% and 100% hydrogen blended with natural gas to the Jemena NSW Gas Distribution Network
2. Development of the high level requirements for transition to a hydrogen future including:
    a. Actions to transition
    b. Required research and development
    c. Financial implications
    d. Other considerations

1.4 LIMITS AND EXCLUSIONS

The following limitations are applicable to this study:

- The study was limited to a high-level desktop review only of the Jemena NSW Gas Distribution Network
- The hydrogen properties summary is for reference only and blend properties are calculated with pure methane
- This study was limited to the technical impacts of hydrogen and did not consider commercial, regulatory, environmental, social or economic impacts. Additional work to understand the non-technical implications of transition to a hydrogen future is also warranted
- The actions identified are intended for the purpose of providing a broad outline of the investment requirements to progress a transition to injecting hydrogen into the gas networks. Prior to commencing these actions, feasibility studies would first be necessary to identify the optimal transition path to introduction of hydrogen

For the purpose of this study, the Jemena NSW Gas Distribution Network (Herein known as "the Network") includes:

- NSW Distribution System

- Central West Distribution System
- Wilton-Newcastle trunk pipeline (Northern trunk) including:
    - Wilton to Horsley Park Natural Gas Pipeline (Pipeline Licence No. 1)
    - Horsley Park to Plumpton Natural Gas Pipeline (Pipeline Licence No. 3)
    - Plumpton to Killingworth Natural Gas Pipeline (Pipeline Licence No. 7)
    - Killingworth to Kooragang Island Natural Gas Pipeline (Pipeline Licence No. 8)
- Wilton-Wollongong trunk pipeline (Southern trunk) that included:
    - Wilton to Wollongong Natural Gas Pipeline (Pipeline Licence No. 2)

The physical boundaries of this study are:

- Downstream of the Custody Transfer Station (CTS) and Packaged Off-Take Stations (POTS)
- The connection to consumer piping off-takes (outlet of consumer billing meter)
- Piping, facilities, equipment and components in-between

This study excluded:

- The impacts of addition of hydrogen to downstream users or networks
- The impacts of addition of hydrogen to transmission networks (in a reverse flow scenario)

2 IMPACTS OF HYDROGEN TO THE NETWORK

Transporting either pure hydrogen or a hydrogen / natural gas blend would have technical implications for the operation of the Jemena gas network.

To understand the impacts of hydrogen to the Jemena NSW Gas Distribution network a review of the existing network and the different properties of hydrogen was completed. Appendix 2 summarises the key aspects of the Jemena NSW Gas Distribution network and Appendix 3 summarises the properties and changes thereof due to hydrogen at 0%, 10% and 100% when blended with methane.

2.1 NETWORK PERFORMANCE

2.1.1 Capacity

Hydrogen has a lower energy density than natural gas. That is, hydrogen carries less *energy* per unit volume than natural gas at the same conditions (the same pressure and temperature). Consequently, any addition of hydrogen to the network will reduce the maximum capacity of the network in terms of energy delivery[3]. In this respect, 100% hydrogen will have a significantly greater effect than lower proportion hydrogen blends.

The capacity of each element in a network (every pipeline, valve, regulator and any other in-line components) is primarily determined by pressure loss. Elements of the network that are not currently operating at their maximum capacity can accept a greater pressure loss than is currently occurring. For these, the reduction in energy density might be offset by an increase in the gas velocity without requiring an upgrade.

A secondary consideration in determining the capacity of a component is *acceptable* gas velocity. High gas velocity can cause noise or pipe erosion, and consequently limits are applied on velocity. In some situations, this consideration would take precedence over pressure in determining the network capacity.

Jemena will need to complete a hydraulics study to assess the capacity of the network and identify potential physical bottlenecks that limit flow-rate. Where the system is capacity-constrained, upgrades may be required. These could include modifying, supplementing or replacing equipment.

In stations, it is likely that regulators and control valves will require replacement for pure hydrogen service, and it is possible that some will require replacement for blended service also. Other equipment *may* require modification, such as heaters and filters.

If the pipe itself is a bottleneck, required upgrades could be in the form of looping the pipeline, replacing the pipeline, or installing new pipeline connections (e.g. converting to a ring main).

2.1.2 Product accounting

Jemena track the flow of gas through their network by means of distributed flow metering and gas chromatography. Transition to pure hydrogen or hydrogen blends in the network will have implications for the metering facilities that are provided.

Firstly, meter types will require modification in order to accommodate the properties of the gas. Some flow meter types do not depend on gas properties (such as Coriolis meters, which directly measure mass flow) but other meters will require review to confirm they are effective at metering hydrogen or hydrogen blends. Most gas chromatographs are also not equipped to measure hydrogen contents greater than 5% and will

[3] It is assumed that network capacity is only measured in terms of flow capacity. If *stored inventory* is also a relevant metric of the pipeline or network's performance, this will also be reduced in hydrogen service.

require upgrading.

Secondly, new metering facilities may be required. Natural gas is currently provided to the network from discrete upstream sources. In contrast, hydrogen injection is likely to be de-centralised, with multiple injection points distributed throughout the network. Additional metering and gas chromatography may be needed to accommodate the more complicated flow resulting from distributed injection.

Thirdly, corresponding to the above two changes, modifications to flow-computers and SCADA oversight will be required, to interpret the additional data and use correct flow equations for system-wide product accounting.

2.1.3 Unaccounted for gas (UAG)

Gas will leak through all materials and connections in a network. Gas diffusion through metals is slow enough to be neglected. Gas diffusion through plastics can be noticeable at a network level. Gas leaks at connections vary depending on the connection 'leak tightness' for which there are a range of different grades.

Hydrogen is a smaller molecule than methane, and one consequence of this is that it leaks and diffuses at a higher rate than natural gas. At a network level, this may be detectable as an increase in unaccounted for gas (UAG). Though the UAG may increase, it is not expected that physical modifications would be made in response to this issue.

2.2 MATERIAL COMPATIBILITY

2.2.1 Steel pipe

The main effect that hydrogen has on steel is hydrogen embrittlement. This causes a decrease in crack initiation toughness and also a reduction in fatigue life.

2.2.1.1 DEFECT TOLERANCE

The ability of pipelines to tolerate defects depends simultaneously on the stress in the material, the toughness of the material, and the size of the pipe. These together determine the critical defect length (CDL). If a crack exceeds the CDL then the pipe will burst, whereas below the CDL the pipe will not[4].

To guarantee that a new pipeline does not have any critical defects, it is hydrotested at a pressure 25% greater than the design pressure of the pipeline. This proves that any defects in the pipeline are less than the CDL, with a safety factor of approximately 150%.

Hydrogen embrittlement decreases the material toughness, which in turn decreases the CDL. If the reduction is significant enough, then this may invalidate the hydrotest results. The effect on the CDL will be more significant at higher design factors (e.g. 0.5 to 0.72), higher strength steels (e.g. >X52), for steels that have a low toughness to begin with (vintage steels), and for larger diameter pipe (e.g. >DN 150). *Note that the ranges provided in parentheses here are estimates only and should not be used to avoid assessment of any specific pipeline.*

Low design factor pipelines (<0.3) have low stress in the pipe wall. Despite material embrittlement, these pipelines will still be acceptable, because the design is not relying on material toughness for critical safety outcomes. It is likely that all the secondary, medium and low-pressure mains fall into this category.

[4] This problem also extends to surface cracks. The critical size of a cracks in the pipe wall is a function of the crack depth *and* length; when the depth reaches critical conditions, it will first grow through the pipe wall and then may rupture if its length exceeds the CDL.

For high design factor pipelines (>0.3) a review of the pipeline CDL would be required. This either requires an estimate of toughness reduction or it requires testing to be conducted to measure the reduction in toughness. Currently there are no laboratories in Australia that can do this testing, so the cost of testing is unknown. It is expected that this will change over the next decade.

After review, the pipeline *may* require either:

- a Maximum operating pressure (MOP) reduction, or
- re-hydrotesting.

Note that an MOP reduction would require replacement of regulator sets in the network and will reduce the pipeline's capacity.

2.2.1.2 INTEGRITY MANAGEMENT

During operation, new defects can form in a pipeline due to corrosion, fatigue or external interference. Some pipelines maintain good condition because they have a high quality coating. Other pipelines can have a population of defects that are managed under the direction of an integrity management plan. Typically these defects are ranked by size, and the longest defects are prioritised for repair before they can grow to the length of the CDL.

Hydrogen embrittlement will affect the integrity management of these pipelines in two ways. Firstly, a reduction in CDL will mean that a greater number of defects may have to be prioritised for repair. Secondly, defect growth rate may be accelerated for sharp defects.

Consequently, for pipelines under integrity management, a review of the integrity management plan is required. For pipelines that have a population of known defects, the IMP will require revision based on the reduced critical defect dimensions, and a modified crack growth rate model.

Outcomes may include:

- Acceleration of the defect repair programme. Based on the new modelling, it is possible that defect repairs will be required more frequently. This will increase the ongoing costs of integrity management. Note that this also is likely to be more significant for vintage and high design factor pipelines.
- Reduction of the remaining life. The end of life for a pipeline under integrity management generally occurs when there are too many near-critical defects and it is no longer cost effective to repair them. If the CDL of such a pipeline is reduced due to embrittlement, this horizon will be reached sooner.

2.2.1.3 FATIGUE LIFE

It is rare for gas pipelines to see cyclic service sufficient to cause pipe fatigue, especially in distribution networks which operate in relatively steady-state conditions.

However, there can be some pipelines within a network that operate with a pack-and-deplete "batch operation" philosophy and see large pressure swings These pipelines require fatigue modelling to predict their remaining life. Fatigue rate at the later stages of fatigue crack growth is significantly accelerated by the presence of hydrogen.

For **pipelines in cyclic service,** a review of fatigue modelling is required. Firstly, the network should be reviewed to identify any sections that are subject to cyclic loading. Secondly, the fatigue life should be calculated taking into account hydrogen-assisted fatigue crack growth (HA-FCG).

Possible outcomes include:

- The remaining life of the pipeline may have to be decreased, and

- the inspection frequency may have to be increased (it is common to base the inspection period on the time taken for the smallest detectable crack to become critical, which will reduce in hydrogen service).

2.2.2 Other steel components

Hydrogen embrittlement will affect any steel component, though carbon steels are affected more than stainless steels.

Almost all other steel components (valves, filter vessels, facility piping, etc.) operate at lower stress than line-pipe, with tighter defect tolerances, and consequently do not rely heavily on material toughness. A desktop review of steel components would be recommended, highlighting any locations of high stress or cyclic loading that may require further assessment and possible replacement. This activity is critical for due diligence, but it is not likely that there would be any facility piping or components that are susceptible to hydrogen embrittlement to the point of failure.

2.2.3 Ductile iron

Ductile iron is only used in low pressure service. Due to the low design factor of these pipes, it is not expected that there will be any deleterious effect of using hydrogen in ductile iron pipe.

2.2.4 Plastic

The design philosophy for plastic piping is different to steel because the pipe is expected to continuously accumulate damage throughout the life of the asset towards a failure point. Unlike steel, where the remaining life is unlimited provided the steel is protected, plastic pipe has a limited life that cannot repeatedly be rerated.

Research is already available indicating that methane blended with up to 20% of hydrogen can be used in plastic pipe without accelerating degradation. Investigations of 100% hydrogen are yielding promising results so far, but further confidence is required. Refer the COAG report *Hydrogen in the gas distribution networks* for more information.

2.2.5 Elastomers

Elastomeric materials are used for seals in a range of components, including some valves. Research shows that some elastomers which have been exposed to pure hydrogen have been affected with consequences including a change in elasticity and swelling. This is not expected at low hydrogen concentrations.

The COAG report suggests that **at low hydrogen concentrations (10%),** no replacement of sealing materials would be required.

However, for **high hydrogen concentrations (>10%),** elastomeric sealing performance should be confirmed. Currently research is underway through the FFCRC and other international research organisations to explore this further. A seal replacement campaign may be required at higher concentrations; it is unknown what the threshold concentration would be.

The uncertainty of conclusions regarding plastic and elastomeric materials should be stressed. The FFCRC has concluded the following from their initial literature reviews into the effect of hydrogen on these materials:

> *"This report highlighted the limited number of peer-reviewed literature concerning polymer and elastomer interactions with hydrogen. Limitations include large scatter within the data sets preventing any clear conclusions, limited experimental examination, a clear gap is the*

lack of fatigue based measurements to probe slow crack growth behaviour in hydrogen exposed pipe materials. While permeation and diffusion rates have been studied, potential plasticisation effects caused by hydrogen is yet to be investigated. In terms of elastomers, majority of the work has been conducted at high pressures and have shown failure when hydrogen gas is used, a further limitation is the lack of systematic investigations and clear identification of the exact grade and type of elastomer used in the study. Furthermore the performance of elastomeric materials with hydrogen: methane blends have not been investigated."[5]

2.3 EQUIPMENT

2.3.1 Heaters

Gases change temperature during decompression according to the Joule-Thompson effect. Where the temperature change at pressure reduction stations exceeds allowable temperature range for downstream systems, this is accommodated with gas pre-heating.

In contrast with natural gas, hydrogen has a small, negative Joule-Thompson coefficient. Consequently, the temperature change for hydrogen blends and for pure hydrogen will be different than the current design basis for any heating systems in Jemena's natural gas network.

In the case of pure hydrogen, heating systems will be decommissioned or disused. In the case of hydrogen blends, heating systems may see decreased use and may require a control-system modification to change temperature set-points or control philosophy.

Many heaters on the network are gas-fired Type B appliances. These are designed for a specific fuel composition. If a hydrogen-blend is introduced, then these systems will require re-certification to confirm that the new blend is appropriate for the device. It is unlikely that physical modifications will be required at low percentage blends.

2.3.2 Instrument gas systems

Instrument gas systems use natural gas to provide pneumatic force, usually to actuate valves. This is variably used for both isolation valves and gas regulators. The pneumatic systems operate at pressures of 700 kPag or less.

Instrument gas systems are most commonly constructed using stainless steel tubing with pressure capacity well in excess of the application. Because the use is pneumatics, the properties of the gas are not important to the function of the system (it is only the pressure that matters). It is expected that instrument gas systems will continue to be operable with hydrogen blends and with pure hydrogen.

Some pneumatic valves continuously vent a small amount of gas. It is recommended that instrument gas systems that continuously vent should be reviewed. Hydrogen releases have a greater probability of ignition than natural gas, and so there may be cause for increased control of release rate. Refer also Section 2.4.1.2 on "hazardous areas".

2.3.3 Control valves

Due to the impact of hydrogen on capacity (see Section 2.1.1) and elastomers (see Section 2.2.5), it is likely that most control valves (including pressure regulators) will need to be overhauled or replaced in pure hydrogen service. Some may also require replacement or modification in a 10% blend service.

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[5] Literature Review and Preliminary Update on Experiment Setup, Milestone report, RP3.1-03, FFCRC

2.4 SAFETY

2.4.1 Safety and operating plans

Jemena has a well-established approach to safety, due to the significant hazards that exist. This is managed under the overarching safety and operating plans (SAOPs) required by state legislation.

Natural gas poses heat and explosion hazards, due to the chemical energy (flammability) and compression energy (expansion after release from pressure vessels or pipework) of the gas. It can also pose an asphyxiation hazard to individuals, if it accumulates in an enclosed space. Due to the inherent risk, safety is a key consideration across all sectors of the gas industry.

In a 10% hydrogen blend, the change to the gas characteristics are marginal and so safety management process are substantially unchanged. A lean gas mixture is more buoyant, has a reduced heating value (energy density), a marginally reduced lower explosive limit (about 1% reduction), and different flow characteristics possibly leading to a faster leak rate – but none significant enough to invalidate typical controls.

Pure hydrogen, in contrast, has several properties that would require a change in approach to safety. These include:

- Hydrogen burns with a low-visibility flame (it can be difficult to see in the daytime)
- Hydrogen releases higher UV radiation and less infra-red radiation, meaning it feels less hot but can still cause extensive burning similar to sun-burn
- The likelihood of ignition is significantly higher with hydrogen, likely due to the greater flammability range of the gas
- Hydrogen is currently incompatible with odorants. This means that a pure hydrogen release will not be detectable by smelling it.
- Hydrogen does not trigger a respiratory response, meaning that a pure hydrogen release in a confined space poses an asphyxiation risk if it displaces air.

2.4.1.1 ODORISATION

Addition of a chemical substance is required in a natural gas distribution network to enable it to be detected by smell. Similar to that of natural gas, pure hydrogen is odourless and will require an odorant.

For 10% hydrogen blends, Jemena will need to review their odorant injection strategy and determine whether it is necessary to increase or decrease odorant injection rates to account for the dilution effect of blending but avoid overdosing in non-blended sections.

In 100% hydrogen, Jemena will need to review the suitability odorant that is used.

2.4.1.2 HAZARDOUS AREA

Electrical installations in Australia are required to meet the requirements of AS/NZS 60079, where they are installed in potentially explosive atmospheres.

A ‘hazardous area’ is a three-dimensional space defined around pressure equipment (particularly joints and vents) in which an explosive atmosphere may be present. Outside the hazardous area, the gas concentration is expected to be below 50% of the lower explosive limit (LEL). Special precautions are required to prevent ignition sources within the hazardous area, which affects any use of electrical equipment.

Hazardous areas are a function of leak rate and dispersion (driven by buoyancy and mixing) and the LEL, which varies for different compositions. Consequently, modification of the gas composition could have an impact on the size of a hazardous area.

For blends of up to 10% hydrogen in a natural gas distribution system it is likely that the existing hazardous area sizing guidelines presented in AS/NZS 60079.10 will remain applicable.

For pure hydrogen, review of hazardous area design is required, with two likely consequences:

- Hydrogen hazardous areas are typically larger than for natural gas. This means that some equipment that is currently outside hazardous areas might move inside one.
- Hazardous area rated equipment is required to meet Zone IIC or greater in hydrogen service. Natural gas only requires a IIA rating or higher, and IIB is most common in industry. This means that most existing hazardous area rated equipment in natural gas service would require replacement or modification to certify it to the more stringent rating applicable for hydrogen service.

2.4.1.3 *PERSONNEL PROTECTION SYSTEMS*

A significant contributor to safe operation are personnel protection systems, which include appropriate clothing, gas detection, hearing protection and similar. Most of these systems will remain suitable when working around hydrogen and hydrogen blends.

For up to 10% hydrogen it is expected that existing personal gas detection will be likely suitable because detection of the methane component will still provide safe advance warning.

For pure hydrogen, existing gas detection devices will not be suitable and modifications or replacements will be required. This is true of both personnel and fixed gas detectors.

In addition, personnel training about safe practices around hydrogen is required before working at any site where pure hydrogen is used. This training would highlight the unique safety concerns for hydrogen gas.

2.4.2 Emergency response plans

Gas distribution companies undertake emergency response planning, in accordance with the requirements of state legislation. The response plans involve coordination with emergency services and other state departments to manage the significant hazards that exist if there is a loss of containment event in the network.

The different flame combustion characteristics and gas properties mean that the current emergency response plans would need to be reviewed an updated. This could then also require training of emergency services to understand the different parameters of a hydrogen gas incident.

For natural gas blended with 10% hydrogen, the mixture acts similar to pure natural gas so minimal changes would be required.

For pure hydrogen, the existing emergency response plan would not be suitable due to the different threat profile from hydrogen, detailed above.

2.4.3 Pipeline safety management

Pipeline safety is managed according to the methodology set out in AS 2885.6. The pipeline safety management study (SMS) will require review. There are three specific types of impacts that may result – affecting the assessed failure mode, consequence and frequency of consequence, for a given threat.

2.4.3.1 *FAILURE MODE CHANGE*

The change in pipeline defect tolerance for high design-factor pipelines (see Section 2.2.1.1 above) may also affect the safety management of the pipeline. One of the most significant threats to a pipeline is 'external interference'—the possibility that the buried pipeline will be struck by mechanical digging equipment. Safety Management Studies take into account the failure mode and consequence of these threats. If the CDL of a pipeline is reduced, then the failure mode for some credible threats may escalate from 'leak' to 'rupture'.

In residential areas (which applies to most of the network), a pipeline is required by the standard to be "no rupture" pipe. That is, rupture is not a credible failure mode. In the worst case, hydrogen embrittlement could change this status.

An SMS review will be required (this is a mandatory requirement of the standard for a change in operating condition like this), especially revising the failure modelling from external interference threats. In the worst case, this may also lead to a detailed ALARP review, resulting in new controls installed on the pipeline and possibly an MOP reduction.

2.4.3.2 CONSEQUENCE MODELLING AND LOCATION CLASS CHANGE

Radiation contours are also used in the pipeline industry to determine the largest area in which infrastructure and people may be affected by an ignited gas leak. This informs consequence modelling and hence risk ranking for public safety. The radiation contours for full-bore rupture are used to define the "location class" of the pipeline.

For 10% hydrogen, it is expected that the radiation and dispersion distances for pure natural gas will remain appropriate.

For 100% hydrogen, radiation contours are expected to increase, though GPA have not completed specific modelling. If the radiation contours increase, then this means the consequence of an event may be greater, and the location class may change. It is common for a change in location class to incur a requirement for additional physical threat controls (such as concrete slabbing above the pipeline). However, this is a risk-based activity and any changes would be due to land use far from the pipeline, not close to it. Nevertheless, it should be expected that some costs would result if the radiation contours are expanded.

2.4.3.3 RISK ASSESSMENT FREQUENCY REVIEW

Risk assessments on a pipeline include firstly an assessment of consequence, and then an assessment of the frequency of that consequence. Such risk assessments commonly assume an ignition likelihood based on historical natural gas pipeline incident data. These risk assessments should be revised for the increased ignition likelihood of hydrogen releases.

2.4.4 Blending control

Uncontrolled changes to composition can have significant safety impacts to downstream users. If the network is converted to a hydrogen blend, then controls will be required at hydrogen injection points to prevent the formation of hydrogen-rich flow. (A pocket of pure hydrogen could cause flames to be extinguished in downstream devices, resulting in a hydrogen release, which in turn could accumulate and lead to explosion.)

Blend controls will be required at injection and blending points in the network. There are many different implementations of blending control that may be used. Generally it will involve additional metering and certified safety instrumented control systems.

2.5 NETWORK OPERATION AND MAINTENANCE

Two implications for the operation and maintenance of network pipelines have been identified.

2.5.1 In-service welding

To avoid supply disruption, pipeline repairs and modifications in the network are usually completed while the network is still ‘live’. This requires in-service welding—welding on the outside of the pipe while gas is flowing through the inside.

Minimising hydrogen exposure is critical to most welding methods, to avoid hydrogen-assisted cold cracking when the weld cools. It is possible that this will be unavoidable, for in-service welding, if the pipeline is transporting hydrogen.

Specific research on this topic has not been identified. The COAG report recommends that in-service welding on hydrogen pipelines should be avoided altogether until research has been conducted.

The implications of this are that future modification and expansion of the network, and also repairs, may not be possible on ‘live’ pipeline. This significantly adds to the cost of such activities.

2.5.2 Pipeline blowdown

Some significant works will require a pipeline to be depressurised or “blown down”. Pipeline blowdowns are also sometimes required as part of emergency response.

Natural gas pipeline blowdowns in remote areas are achieved by cold venting, which release the gas at a high rate in a large vertical stream—the risk of ignition is controlled in these blowdowns (and if ignition were to occur, the consequences would be major). In hydrogen service, however, the potential for ignition is higher than for natural gas, so this same method of depressurising the pipeline may not be acceptable. Consequently, the design of blowdown facilities may require modification, which could include:

- flow reduction using restriction orifices or control valves,
- piping modification to reduce outlet velocity, or
- use of burner trailers.

The isolation plan for these pipeline will require revision. If the blowdown duration is significantly affected, this may warrant the installation of new main-line valves (MLVs).

For natural gas pipeline blowdowns in residential areas, Jemena use gas burner trailers, to burn the gas in a controlled ignition during the blowdown. Though it is expected that the existing burner trailers would work with a 10% blend, the trailers are not likely to be suitable for pure hydrogen use, and will need to be modified or replaced.

2.6 DOWNSTREAM USERS

Any change in gas quality would need to consider the impacts to the downstream user. The suitability of downstream users of the network for 10% and 100% hydrogen blended with natural gas are.

- Domestic appliances (Type A) are likely suitable for up to 10% hydrogen, however, further investigation of the impact of hydrogen to flame stability and materials is required. For 100% it is unlikely that current appliances will be suitable.
- Commercial and industrial appliance (Type B) are likely suitable for up to 10% hydrogen, however, further investigation of the impact of hydrogen to the flame stability and materials is required. For these appliances, it is expected that any additional safety risks can be managed by tuning and minor modifications to the appliance. For 100% it is unlikely that current appliances will be suitable without major upgrades.
- Users of compressed natural gas (CNG) face an increased probably/likelihood of embrittlement in high-pressure, steel storage vessels, piping and components. The risk of failure increases significantly with pressure even at low concentrations. No hydrogen, at any concentration, should be blended to a network before confirmation that the piping, equipment and components at CNG

refuelling facilities are suitable.

- Feedstock users are likely suitable for up to 10% hydrogen, however, further investigation of the impact of hydrogen to the efficiency and safety of the applications is required. For feedstock applications, any additional safety and performance risks should be able to be managed by tuning and minor modifications. For 100% it is unlikely that current feedstock will be able to operate without major modifications.
- Piping installations, which connect the distribution network to the appliance, are likely suitable for up to 10% hydrogen, however, further detailed review of the materials found in the network are completed and assessed for suitability is required. For 100% it is unlikely that current piping installations will be suitable without significant modifications.

2.7 SUMMARY

Table 1 provides a summary of the potential impacts of hydrogen to the network for 10% and 100% hydrogen blended with natural gas. This summary represents current understanding of the technical impacts of hydrogen, however it should be noted that understanding is continually evolving, and a detailed, case specific assessment should be undertaken prior to the introduction of hydrogen.

Table 1 Hydrogen network impacts

Area	Description	10% H2	100% H2
Network Performance	Network capacity	M	H
Materials Compatibility	High pressure steel pipelines (primary, trunk and pipeline)	M	H
	Low pressure steel pipelines	L	L
	Pipelines under integrity management [1] [2]	H	H
	Pipelines subject to cyclic loading [2]	H	H
	Other steel equipment	M	M
	Polyethylene pipelines	L	U
	Cast iron pipelines[3]	L	L
	Elastomers	M	U
Equipment	Flow meters	M	H
	Manual valves	L	M
	Control valves and regulators	M	H
	Heaters – gas fired [4]	M	L
	Heaters – electrical [4]	L	L
	Gas chromatographs	M	H
	Instrument gas systems	L	L
	Gas detectors	L	H
	Station/facility pipework	L	M
	Filters	L	M
Safety	SCADA system	M	M
	Hazardous areas	L	H
	Odorant	L	U

Area	Description	10% H2	100% H2
	Safety and Operating Plan	M	H
	Pipeline Safety Management Study	M	H
	Gas detectors (personal)	L	H
	Emergency response plan	L	M
Operation and maintenance	Prohibition of in-service welding [5]	M	U
	Blowdown facilities	L	H

Table Notes:

1. Pipelines under integrity management means pipelines with a database of known defects for which there is a repair schedule in place.
2. The high impact for these items could be a reduction in remaining asset life.
3. Cast iron has been designated as low impact. Nevertheless, cast iron piping in the network typically has issues due to the asset age and condition, warranting the replacement campaign currently underway.
4. In the case of pure hydrogen, these items have been designated low impact because these systems can be mothballed, and hence no modifications will be required.
5. Prohibition of in-service welding has been assessed as medium impact on the hydrogen blend case, because it may be possible to purge the line of hydrogen and operate with natural gas only during the in-service welding.

Key:

L	Low impact – Low probability of modifications required
M	Medium impact – Minor or partial modifications are expected
H	High impact – Major modifications are expected
U	Unknown, further information is required, by means of analysis or research

3 TRANSITION REQUIREMENTS

To enable transition to a hydrogen network, a number of studies and additional actions are required. In many cases, studies and actions will be specific to the particular transition path.

3.1 JEMENA ACTIONS TO TRANSITION

Table 2 is an indicative action summary to enable Jemena to better understand the necessary steps for transitioning the network to a hydrogen future. They do not include preparatory actions such as feasibility studies to determine the best location for new hydrogen production infrastructure, but outline the high level actions that will need to be undertaken once a particular transition path is determined, and/or to assist with screening potential transition options.

The further study actions were then extrapolated to give an indication of potential further actions required to progress the transition. Whilst no specific cost analysis has been undertaken, an indication of the *type* of further investment required has been included to further inform potential transition requirements.

It should be noted that the potential further actions are not necessarily additive to give a worst-case cost scenario; some cost implications would negate or reduce others (such as trunk line replacement due to material incompatibility – which could also address any capacity constraints). The actions identified are applicable for transitioning to both a 10% and 100% hydrogen network, however, it is expected that the costs for 100% hydrogen network will be significantly higher. The cost implications listed are based on realisation of the worst-case potential outcomes listed in the third column.

Table 2 Network transition actions

		Potential future investment required	
Issue	**Further study action**	**Modification, replacement or upgrade**	**Notional cost implication**
Network capacity	Hydraulics study to identify physical bottlenecks causing system capacity constraint.	Where constraints are identified upgrade of limiting network sections. • Looping or replacement of trunk, primary or secondary mains • Unlikely to impact low or medium pressure mains, but impact would be significant if so due to the extent of these assets	New capital investment
Steel piping compatibility	Audit of the steel piping systems in the network. Steel pipe toughness review, testing of high design factor pipelines. Identification of piping subject to load cycling.	Where incompatible materials are found reduction of MOP (and resultant capacity) or replacement of piping. • Potential for trunk main or primary main replacement, particularly if reduction in MOP causes unacceptable capacity constraint • Potential addition of pigging facilities in order to assess and monitor pipeline integrity • Potential reduction in technical life of piping subject to load cycling For piping systems currently under integrity management – reduced technical life, accelerated defect repair and replacement, revised IMP. • Potential for reduction in remaining technical life of assets and accelerated investment in defect repairs	New capital investment Accelerated investment
Metering and measurement	Review metering and measurement types for materials compatibility and performance.	Where incompatibilities are identified upgrade of meters and flow-computers. • Potential replacement of over 1.5 million billing and custody transfer meters	New and/or accelerated capital investment

Issue	Further study action	Potential future investment required: Modification, replacement or upgrade	Potential future investment required: Notional cost implication
Injection and blending control	Review of injection and blending methodology to ensure adequate control of network gas blend.	Where technical and safety impacts are identified the current injection and blending philosophy will require revision. • Potential requirement for additional control hardware on the network	New capital investment System and procedural review
Plastic piping compatibility	Audit of plastic piping in the network and a materials compatibility assessment.	Where non-compatible piping sections are identified, the existing piping will need to be replaced. • Potential replacement of sections of low and medium pressure mains • Considered low likelihood but remains unknown for 100% hydrogen	New capital investment
Elastomer compatibility	Audit of elastomers in the network and a materials compatibility review.	Where non-compatible elastomers are identified, existing seals will need replacement. • Likelihood unknown but extensive replacement if required	New capital investment
Heating systems	Review heater systems (WBH and EIH) for materials compatibility and performance.	Where constraints are identified upgrade, replacement or decommissioning of heaters. • Potential upgrade, replacement or decommissioning of up to 17 heaters	New capital investment
Instrument gas systems and vent ignition risk	Review instrument gas systems for materials compatibility and performance.	Where constraints are identified upgrade of instrument gas systems would be required.	New capital investment
System control valve compatibility	Review system control valves and regulators for materials compatibility and performance.	Where constraints are identified upgrade of system control valve. • Potential replacement of up to 600 regulator sets	New capital investment
Odorant	Review odorant compatibility and injection requirements.	Where non-compatible odorants are identified, odorant and hardware will need replacement. • Highly likely to require replacement • Difficult to quantify modification requirement due to lack of understanding of 100% hydrogen odorant requirements	New capital investment Systems and/or procedural review
Hazardous area	Review and update hazardous area zoning and complete an audit of existing hazardous area rated equipment.	Where hazardous area equipment and zones are identified to be non-compliant replacement of equipment may be required. • Potential replacement of existing hazardous area rated equipment with zone IIC or greater in hydrogen service. • Potential need for additional hazardous area rated equipment due to larger zone	New capital investment
SAOP adequacy	Review adequacy of SAOP and implement operational, systems and procedural changes.	SAOP will require review and update of existing procedure and systems.	Systems and/or procedural review

		Potential future investment required	
Issue	**Further study action**	**Modification, replacement or upgrade**	**Notional cost implication**
Personal gas detector device compatibility	Complete an audit of personal gas detectors that are in operation across the network for ability to detect hydrogen.	Where gas detectors are unable to detect hydrogen units will likely need to be upgrading or replacement.	New capital investment Systems and/or procedural review
Emergency response	Review the current emergency response plans and philosophy.	Where the current plan is found to not be suitable an update would be required.	Systems and/or procedural review
Pipeline Safety Management Study (SMS) adequacy	Review the pipeline safety management study including review of failure mode, consequence modelling, location class review and risk assessment frequency review.	Where the inconsistencies are found these would need to be addressed, however, revisions are not expected to be significant.	Systems and/or procedural review
In-service welding	Assess impacts of incompatibility of hydrogen with in-service welding, and its impact on future modification, expansion and repair activities	• Potential for modification to planned maintenance, repair or replacement programmes • Potential need for pre-investment in repairs, modifications or replacements prior to transition to 100% hydrogen • Difficult to define likelihood due to unknown impacts	New capital investment Systems and/or procedural review
Pipeline blowdown	Review the current pipeline blown down methodology and existing equipment for suitable of use with hydrogen.	Where existing is found to not be suitable, modification to systems and hardware would be required.	Systems and/or procedural review New capital investment

3.2 RESEARCH AND DEVELOPMENT

There remains a lack of understanding around certain aspects of adding hydrogen to the natural gas distribution network. To determine the full extent of the technical impacts, the following research and development is required:

- Understanding of impacts to materials including:
  - Embrittlement in steels, operating at high pressures and high stress levels.
  - Permeation through materials in plastic piping.
  - Leakage through fittings, joints and seals.
  - Elastomer degradation.
- Compatibility and development of odorants with 100% hydrogen.
- Understanding of the impacts to downstream users (appliances and process users).

Much of this research is underway and should be leveraged. International research organisations such as Sandia (USA), NREL (USA) and HSE (UK) are well progressed in hydrogen research programmes. Domestically, organisations like the Future Fuel Cooperative Research Centre (FFCRC) are exploring topics related directly to Australian applications.

3.3 FINANCIAL IMPLICATIONS OF SIMILAR TRANSITION PROJECTS

In order to understand the financial implications for energy conversion a literature review of previous and current gas transitions was completed. This review identified the following relevant projects and studies:

- Town gas
  - British Town Gas Conversion
  - Isle of Man Town Gas Conversion
  - Victoria Town Gas Conversion
- Hydrogen
  - H21 Leeds hydrogen conversion
  - UK hydrogen conversion
  - Logistics of hydrogen changeover
  - Decarbonising Australia's gas networks

The review found that in all cases there were additional costs of upgrades, generally, in the form of appliance and network upgrades. Appendix 2 provides a summary of each of these projects or studies.

Conversion from town gas to natural gas was relatively technically simple. Existing appliances were modified (injectors drilled out) and minimal modifications to the gas networks were required. The previous town gas conversions that were reviewed ranged from $500 AUD - $3,500 AUD per connection.

Conversion from natural gas to 100% hydrogen will be technically, economically, socially and commercially more complex. These studies found that appliances will need significant modification or replacement. Existing gas distribution networks were found to require upgrade to handle the increased capacity and minimise the risk of materials impacts. Hydrogen network conversion has been estimated up to $7800 AUD per connection.

It is important to understand the assumptions that have been used as a basis in these reports. Gas networks globally vary in design and operation. Generally, international reports and case studies should be used for guidance only.

Based on the literature review of similar transitions and the cost of these transitions on a per connection basis, the notional cost of transitioning a network with 1.4 million connections the notional costs could be up to $11 billion AUD, however, extensive work would be required to further substantiate this cost.

3.4 OTHER CONSIDERATIONS

Whilst it is recommended that specific actions and audits be undertaken in order to better understand the capital investment required to progress a transition to hydrogen in the distribution networks, we note that there are numerous other factors and costs that will necessarily influence the investment decision for converting to hydrogen. These include but are not limited to the cost of customer appliance conversions, hydrogen production costs and commodity price, and the capital cost of hydrogen production facilities. It is recommended that decisions relating to further investment are made with consideration of these additional factors.

This study has reviewed the technical impacts of addition of hydrogen to the network. The following aspects need to be considered before progressing with the addition of hydrogen to the natural gas networks.

- Regulatory
- Environmental
- Commercial
- Social acceptance
- Impacts to downstream users

4 CONCLUSION

GPA were commissioned by Jemena to complete a study to identify the technical impacts of 10 and 100% hydrogen and develop high level actions to support the transition to a hydrogen future in the Jemena NSW Gas Distribution Network.

As part of this study, GPA reviewed the technical impacts of 10% and 100% hydrogen in the existing gas network. Overall, the network is a good candidate for initially blending up to 10% hydrogen, however further work is required to understand the feasibility of a 100% hydrogen network. The low and medium pressure networks, which make up a large percentage of the network, are all relatively new, plastic piping systems that are likely suitable for hydrogen. The steel primary mains are designed to operate at low stress, significantly reducing the risk of embrittlement. Finally, the network is operated safety and well maintained.

The majority of the network is suitable for hydrogen, however, a significant amount of further work and capital investment is required to make the network hydrogen compatible.

- A network capacity assessment is required to ensure gas supply to current and future users remains reliable. Where capacity constraints are identified, expansion of existing capacity will be required, which would involve significant capital investment.
- Integrity and durability reviews of existing piping, components and equipment is required to ensure they are compatible. For incompatible items, upgrading or replacement would be required, which would involve significant capital investment.
- Review of all existing Jemena safety systems and operating procedures including (but not limited to) SCADA, SAOPs, emergency response plans, blend and network control philosophy, and maintenance guidelines would be necessary. Where inadequacies are identified revision, change management, communication and re-training would be required.

Research is required in the following areas:

- There is uncertainty around the impact of embrittlement to the trunk and primary mains. Where they were identified not to be hydrogen compatible, it will need upgrading or replacement, which would involve significant capital investment.
- The impact of hydrogen to downstream users needs to be better understood before transitioning. Where downstream installations or appliances are identified not to be compatible upgrading or replacement would be required. Given the number of connections and downstream appliances in service, this would involve significant capital expenditure.

At this early development stage, it is difficult to quantify the financial implications of transition, however it is apparent that significant capital investment would be required. GPA completed a review of domestic and international network conversions to understand the potential magnitude. Previous conversions from “town gas” to natural gas incurred a significant financial cost. These conversions required upgrades to the distribution network itself as well as gas appliances. A recent town gas conversion in Isle of Man (2016) was estimated at £ 3,500 per connection ($6,698 AUD). Similarly, 100% hydrogen conversion studies completed in the UK indicated that replacement and upgrades to the distribution network and gas appliances would be required, resulting in significant financial impacts. The H21 project in Leeds (UK) estimated that the average cost of conversion per connection, including gas network and appliance upgrades, was £4,028 ($7,708 AUD).

Based on the results of this desktop study, in GPA’s opinion, there will be significant investment required to transition to hydrogen in the gas network. Given the potential for significant costs associated with transitioning the network to a hydrogen future, it is recommended that Jemena undertake further work to define the preferred transition pathway, in order to better quantify the capital investment required and prioritise transitional actions.

APPENDIX 1 GPA CAPABILITIES

Hydrogen production and utilisation is new in Australia with limited application. GPA has developed broad knowledge and specialist expertise through our extensive roles in the Future Fuels CRC, ME-093 standards committee membership, and execution of projects in the hydrogen sector for the Australian gas industry including the following:

- **AGIG HypSA Hydrogen Facility Detailed Design**
- **Jemena WSSGP Hydrogen Facility Detailed Design**
- **Ammonia Plant Hydrogen Supply and Storage Concept**
- **Neoen Hydrogen Gas Injection Feasibility Study**
- **COAG Energy Council Hydrogen in the Gas Networks Kickstart Projects**
- **Evoenergy Net Zero Emissions Project**
- **Epic Energy Hydrogen Compatibility Study**
- **Moranbah Hydrogen Storage and Supply Concept Study**

In addition, the following table scores the capability of GPA Engineering against criteria relevant to the project scope.

Key technical and commercial criteria:	**GPA Engineering**
Understanding of Australia's gas pipeline network	✓✓✓
Detailed understanding of distribution assets in NSW	✓✓✓
Undertaking technical analyses of gas projects in Australia	✓✓✓
Understanding of hydrogen embrittlement risks in transmission & distribution pipelines	✓✓✓
Detailed understanding of pipeline connection requirements, gas transportation and storage	✓✓✓
Understanding of gas characteristics for hydrogen / natural gas blended compositions	✓✓✓
Understanding of hydrogen safety impacts including hazardous areas, material selection, risks and limitations	✓✓✓
Understanding of impacts to consumer burner equipment / downstream gas devices	✓✓✓
Understanding of regulatory frameworks for gas distribution across Australia and general gas legislation	✓✓✓
Detailed knowledge of relevant technical standards (AS4645, AS2885, AS4564, AS60079, AS/NZS5601, AS3814, AS/NZS5263, AS4563)	✓✓✓
Detailed knowledge of current demonstration projects proposing to inject blended gas into distribution networks	✓✓✓

[Key: ✓✓✓= highly capable ✓✓ = some capability ✓ = working knowledge]

GPA engineers are active in both developing, contributing to leading edge research and technology in the pipeline and energy sector and have members on the following hydrogen and pipeline industry associations and standards committees:

- Future Fuels CRC
- ME-093 Hydrogen Technologies Committee
- AS2885 and AS4041 Standards Committees (ME-038)
- Australian Pipeline and Gas Association Research Council

RESEARCH & STANDARDS

The following provides an overview of GPA's relevant industry involvements including research and development.

Energy Pipelines Cooperative Research Centre (EPCRC)

GPA is involved in the Australian Pipeline & Gas Association Research & Standards Committee and was involved in the research program undertaken by the Energy Pipelines Cooperative Research Centre. The EPCRC was a cooperative research group who developed research and innovation for the Australian pipeline industry.

During the ten-year EPCRC program, GPA were involved as researchers, industry advisors and program coordinators.

Future Fuels Cooperative Research Centre (FFCRC)

Since the initiation of the FFCRC, GPA have been actively involved in research projects, industry advice and steering committee membership. Similar to the EPCRC, FFCRC are a consortium of academia, industry and government. GPA is involved in all three research programs.

Specifically, GPA is advising or contributing to research on the following projects:

- Techno-economic modelling of the hydrogen supply chain and production technology.
- Technical review of hydrogen production methodology and alternative energy carriers e.g. ammonia and MCH.
- Technical suitability of domestic appliances for hydrogen suitability.
- Technical suitability of industrial appliance for hydrogen suitability.
- Regulatory mapping of Australian state and commonwealth legislation impacted by the addition of future fuels to natural gas infrastructure.

Research partners of the FFCRC are the University of Wollongong, University of Adelaide, Deakin University, RMIT University, University of Queensland and University of Melbourne. GPA has access to research and development produced by these universities as part of the CRC. This includes access to researchers and subject matter experts.

Australian Standards

Recently, GPA has been involved in the working groups of the recently formed hydrogen standards committee "ME-093 Hydrogen Technologies".

GPA members are involved in the following working groups of the new Australian Standards including:

- Working Group 1 – Hydrogen production standards including electrolysis
- Working Group 2 – Hydrogen storage and transport including pressure vessels
- Working Group 4 – Gas networks and distribution pipelines

Previously, GPA has been involved in the development of Australian Standards for the oil and gas industry. We have been heavily involved in the development of AS 2885 and in 2018 were tasked with preparing the Fracture Control Code of Practice.

APPENDIX 2 JEMENA NSW GAS DISTRIBUTION NETWORK

This section outlines the key aspects of the Jemena NSW Gas Distribution Network.

OVERVIEW

The network supplies Sydney and its surrounding areas with natural gas transported from Central Australia via APA Group's Moomba-Sydney Pipeline and from Gippsland, Victoria via Jemena's Eastern Gas Pipeline (EGP). The network includes over 26,000km of pipelines of various materials and sizes, with operating pressures ranging from 2 kPag to 6,895 kPag. Figure 1 provides the geographical overview of network.

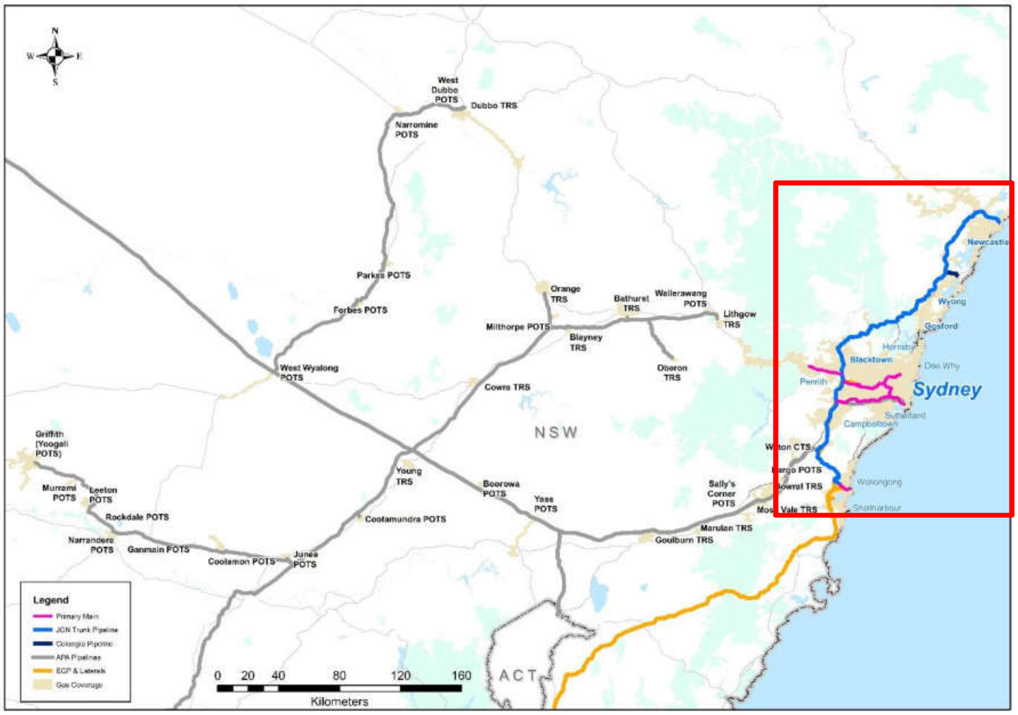

Figure 1 Configuration of Jemena NSW Gas Distribution Network

Legislation

Jemena gas assets are constructed, operated and maintained in accordance with the following legislation:

- Pipelines Act 1967 No 90 (NSW)
- Pipelines Regulation 2013 (NSW)
- Gas Supply Act 1996 (NSW);
- Gas Supply (Safety and Network Management) Regulation 2013.

Standards

The *Pipelines Regulation* 2013 mandates that the design, construction, operation and maintenance of pipelines are required to conform with the provisions of AS 2885 *Pipelines—Gas and liquid petroleum* series of standards. The scope of this standard excludes pipeline operating at pressures less than 1,050 kPag, and so it only applies to the high pressure pipelines and primary mains in the network.

For gas distribution networks operating at pressures less than 1,050 kPag, *AS 4645 – Gas Distribution Network Management* series of standards are applicable. Though they are not mandated by local legislation (since 2013 revision of the regulations), the series captures 'best practice' and Jemena generally apply it to their network. Consequently, the network is designed to AS 4645 where the maximum allowable operating pressure (MAOP) is less than 1,050 kPag.

PIPELINES AND PIPING

This section describes the piping and components that are found on the network. This includes piping systems, pipeline isolation valves, flow meters and regulator sets.

Figure 2 provides an overview of the network materials and configuration of the network.

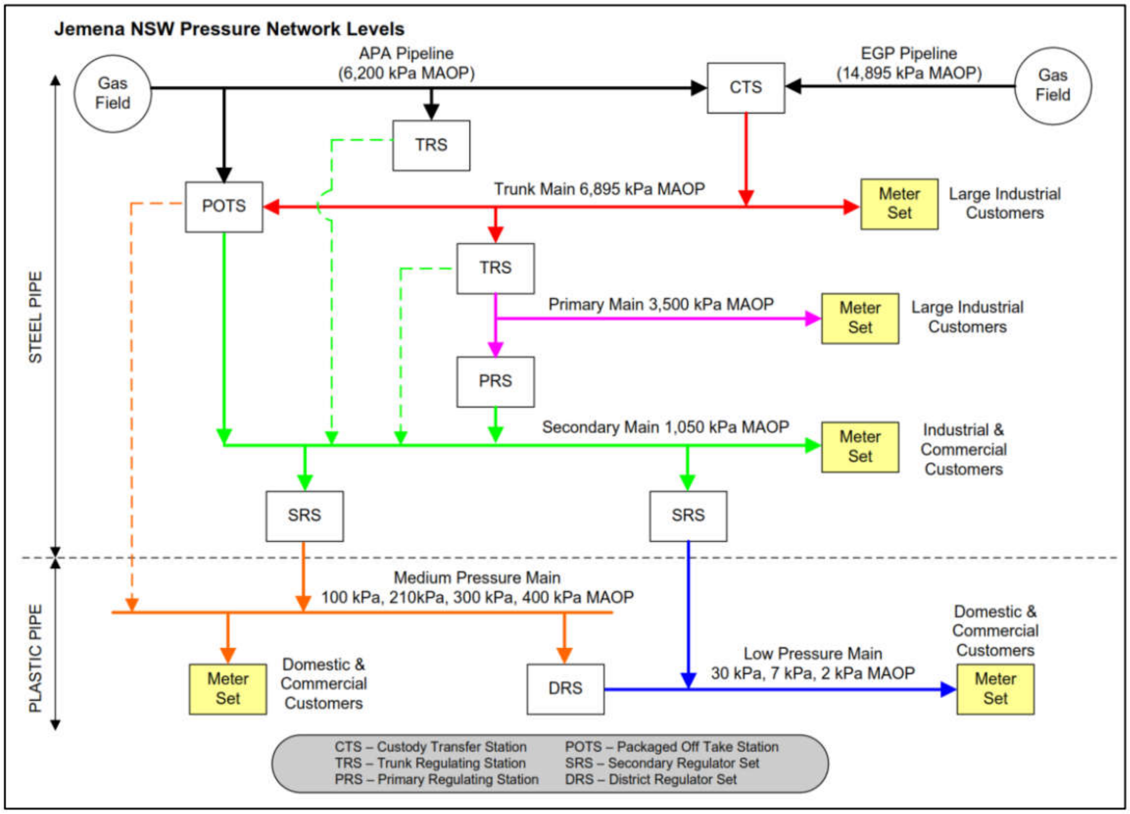

Figure 2 Network overview

Table 3 provides details of the network piping system operating pressures and materials.

Table 3 Jemena gas distribution network categories

	Operating Pressures	Material	Size (DN)	Total Length
Trunk Mains	>3,500 kPa and ≤6,895 kPa	• API 5L X65 (PL1) • API 5L X60 (PL1, 3, 7, 8)	250 - 850	284 km
Primary Mains	>1,050 kPa and ≤3,500 kPa	• API 5L X42 (~90%) • API 5L X42, X56, X60 (~10%)	150 - 550	147 km
Secondary Mains	>545 kPa and ≤1,050 kPa	• Carbon Steel, API 5L Grade B or Grade X42 • SDR9 PE100	80 - 350	1,450 km
Medium Pressure	>15 kPa and ≤ 400 kPa	• Polyethylene • Nylon • Cast Iron[6]	18 – 160	25,000 km
Low	>2 kPa and		50 – 350	

[6] Cast Iron is only found in low pressure applications (less than 1,050 kPa).

	Operating Pressures	Material	Size (DN)	Total Length
Pressure Mains	≤7 kPa	• Unprotected Steel • Protected Steel		

As can be seen in Table 3, three material groups are used in the network. The high pressure pipelines and secondary mains are exclusively manufactured from coated steel pipe. The low and medium pressure mains include plastics (nylon and polyethylene), cast iron, and steel lines, some of which is uncoated. Note that downstream of these distribution lines, it is also common for customers to use copper pipe for gas application.

Mains replacement program

The percentage of cast iron, PVC, older high density PE and some steel pipeline sections will reduce in the future due to distribution networks undergoing "end of life" mains replacement programs. These programs include identifying old cast iron, PVC and PE and replacing it with modern PE.

Cast iron and unprotected steel pipe already constitute a low percentage (approximately 0.6%) of the network mains, because AGL, the former asset owner, commenced a replacement program in the 1990's.

It is important to understand the distribution of older pipeline sections that are potentially in degraded condition when considering the viability of hydrogen injection into the network.

Pipeline isolation valves

In the event of a pipeline failure or required maintenance activity where gas flow must be stopped, the network has Main Line Valves (MLV) and Automatic Line Break Valves (ALBV) located along on the mains (trunk, primary or secondary) to lessen the consequence of a failure and provide safe isolation to the public and staff during an incident or maintenance activity.

For the medium and low pressure systems, valves are used to stop the flow of natural gas. This includes both standard isolation valves and high risk sector valves.

Table 4 provides the numbers of safety and isolation valves that are currently in-service throughout the network.

Table 4 Safety valves on the network

Main Type	Pipeline safety valves
Trunk Mains	15 MLV's and ALBV's
Primary Mains	27 MLV's and ALBV's
Secondary Mains	~1,200 MLV's
Medium and Low Pressure Mains	>2, 000

Flow meters

Measurement of flow-rate is required for gas pricing and commercial transaction. This is relevant for custody transfers between gas shippers or industrial customers, as well as for billing of smaller gas users such as households and businesses. Table 5 provides a list of the meters installed on the network

Table 5 Meters on the network

Type	Meter fleet	Manufacturer and model	Installed amount
Residential	Domestic	Landis&Gyr E-750 Kromshroder BK1.6 EDMI U8 Davies Shepherd DS5 Rochwell MR8	1,492,000

Industrial and commercial	I&C Diaphragm	AL425 AL1000	54,000
	Rotary meters	M3C35 M3A36	2,150
	Turbine gas meters	M4A13 M4A23 M4A33	94

Regulator sets

Secondary Regulator Sets (SRS) are the regulators that supply the medium pressure networks. The SRSs reduce the pressure from the secondary network to supply the medium pressure networks. Most SRSs are located on public land and are installed in underground boxes, with a small number installed above ground.

District Regulator Sets (DRS) are regulators that supply the low pressure networks. The DRSs reduce the pressure from the medium pressure network to supply the low pressure networks. Most DRSs are located on public land and are installed in underground boxes.

Table 6 Number of regulators on the network

Type	Number of regulator sets
Secondary Regulator Sets	520
District Regulator Sets	50

FACILITIES

There are a number of facilities located on the network, which perform a variety of functions:

- Metering – equipment is provided throughout the network to measure flow-rate and gas composition for product accounting and billing purposes, and pressure and temperature for system management purposes.
- Isolation - isolation facilities are distributed through the piping network as appropriate to enable isolation of sections of the network for maintenance and upgrades or for emergency response.
- Regulation - pressure 'regulation' facilities reduce the pressure of the gas where it flows from higher to lower pressure parts of the network or at customer boundaries.
- Inspection – 'receiving' stations include launching and receiving equipment for pipeline inspection tools, and are installed on the pipelines, trunk lines and some primary mains.

The facility components within these stations include above and below ground pipework, isolation valves, insulating joints, control valves / regulators, filters, SCADA and other related components to promote the safe delivery of gas to the network.

Table 7 provides a list of facilities in the network that operate at pressures higher than 1,050 kPag. In total, there are 78 facilities plus 17 heaters.

Table 7 Facilities on the network

Type	No.	Description
Custody Transfer Stations (CTS)	6	Custody Transfer Stations (CTS) are equipped with metering facilities to accurately measure gas transfer and gas quality through the CTS. These meters are used for billing purposes and are calibrated in accordance with appropriate measurement standards. These CTS's are not included in the network but play an integral part in securing the natural gas supply.
Trunk Regulating Stations (TRS)	29	Gas pressure reduction and filtration facilities that are supplied at trunk pressure and deliver gas at the appropriate pressure to the downstream network.

Packaged Off-Take Stations (POTS)	25	Smaller capacity installations combining or 'packaging' the functions of measurement, filtration and pressure reduction. They are supplied at trunk pressure and deliver gas at the appropriate pressure to the downstream network.
Primary Regulating Stations (PRS)	15	Gas pressure reduction and filtration facilities located at each off-take on the primary mains. They reduce the pressure from 3,500kPa to 1,050kPa to supply the secondary network or lower metering pressures to a specified customer.
Bulk Metering Stations (BMS)	2	Stations used to deliver gas to a single user who is generally a large industrial customer. The only two BMS's located within the Jemena NSW Distribution Network are Botany STA Buses BMS and Incitec BMS.
Munmorah Delivery Station (MDS)	1	Gas regulating station which receives gas from the Munmorah Gas Pipeline (MGP) and regulates the gas pressure into the Munmorah Delivery Pipeline (MDP), in turn, supplying the Colongra Power Station

The facility components within these stations include above and below ground pipework, isolation valves, insulating joints, control valves / regulators, filters, SCADA and other related components to promote the safe delivery of gas to the network.

Water bath heaters & electrically insulated heaters

Large pressure drops can occur across the gas regulating stations. This can cause low temperature in the pipework due to the Joule-Thompson effect. To mitigate this, the gas is preheated via Water Bath Heaters (WBH) or Electrically Insulated Heaters (EIH) to protect downstream equipment and materials. There are fifteen WBHs and two EIHs located on the network.

Gas chromatographs

Gas Chromatographs (GCs) are instruments which analyse the individual components of gas. In the network, GCs have been installed are located in strategic locations to accurately measure the resulting mixture of gases. Accurate measurement of composition and flow-rate are required for gas pricing and commercial transaction. This is relevant for custody transfers between gas shippers or industrial customers, as well as for billing of smaller gas users such as households and businesses.

Currently, these locations are at West Hoxton, Horsley Park, Plumpton, Wyong and Hexham.

Instrument gas systems

In some facilities, a small portion of the gas is used to provide pneumatic force to drive equipment, such as valves. These systems are used at multiple facilities throughout the network and are designed to work with a range of possible gas compositions.

Stationary gas detectors

Accurate gas detection is a fundamental requirement for the safe operation of a gas distribution network. Facilities have gas detection instrumentation designed to shut down and/or isolate sections of plant when the concentration of an explosive gas mixture in air reaches a fraction of the lower explosive limit (LEL).

Generally, Jemena uses Honeywell Sieger System 57 gas detectors.

SAFETY AND ASSET MANAGEMENT

Jemena has an overall Asset Management System (AMS), of which safety management is a key element. The AMS provides the principle framework for the organization to direct, coordinate and control asset management activities, and provides assurance that Jemena's operational, societal and environmental objectives are achieved on a consistent basis. It brings together the external influences, asset management drivers, business values and selected strategies to deliver sustained performance for the benefit of all stakeholders

The following safety and asset management documentation is used by Jemena to safety operate and manage the network.

Table 8 Reference Documents

Item	Title	Document Number	Date
1	Jemena Gas Networks – Asset Management Plan 2019-2025	GAS-999-PA-IN-001	31 May 2019
2	Safety Case (SAOP) of Jemena Gas Assets (NSW)	GAS-999-PA-HSE-002	1 May 2018
3	Safety Management Manual	GAS-999-OM-HSE-001	10 May 2019
3	Formal Safety Assessment (FSA) AS 4645	GAS-999-PR-RM-001	12 August 2019
4	Asset Management System Manual	JEM-AM-MA-001	15 October 2019

Operations and maintenance of Jemena's gas assets in NSW are guided by these documents.

Jemena facilities are generally unmanned and technicians will visit depending on the criticality. For example, Horsley Park PRS is visited every day while Appin POTS is attended once every 2-3 months.

DOWNSTREAM USERS

The uses of natural gas supplied by the network include:

- Space heating with both radiant and convective heaters
- Water heating including boilers (for space heating systems and domestic hot water production and dedicated water heaters)
- Cooking heat using stoves (hobs) and ovens
- Process heating including process burners of a wide range of designs for many different industrial processes, high pressure and high temperature hot water boilers, steam boilers, and steam generators
- Power generation using gas turbines and gas engines
- As a process feedstock e.g. for ammonia or ethylene production
- Compressed Natural Gas (CNG) for refuelling and storage

Categorisation of gas appliances to Type A and Type B is based on the energy consumed, in megajoules per hour (MJ/h), the application and the certification type. Categorisation of end-user type is by the gas retailers and is based on the total gas consumption of the user rather than on the consumption of individual equipment and appliances.

The physical limits of the distribution network are upstream of and including the consumer billing meter, which is typically located at the edge of a property. Consumer piping is downstream of the consumer billing meter and includes the pipework, fittings and components that are required to complete the installation between the meter and the appliance.

SUMMARY

Table 9 provides a summary of the network.

Table 9 Network summary

Element	Summary
Pipelines and piping	Piping systems The high include pressure pipelines and secondary mains are manufactured from

<table>
<tr><td></td><td>coated steel pipe. The low and medium pressure mains include plastics (nylon and polyethylene), cast iron, and steel lines, some of which is uncoated.
Cast iron and unprotected steel pipe already constitute a low percentage (approximately 0.6%) of the network mains.

Across the network, a number of valves, regulators and flow meters are currently in operation. These include:
15 MLV's and ALBV's installed on the trunk mains
27 MLV's and ALBV's installed on the primary mains
1,200 MLV's installed on the secondary mains
More than 2,000 isolation valves installed on the MP and LP mains
520 Secondary regulator sets
50 District regulator sets
More than 1.4 million domestic flow meters
More than 55,000 commercial and industrial flow meters</td></tr>
<tr><td>Facilities</td><td><u>Facilities</u>
The facility components within these stations include above and below ground pipework, isolation valves, insulating joints, control valves / regulators, filters and SCADA systems.
79 facilities located on the network. These include facilities for metering, isolation, regulation, and inspection.
17 heaters (15 WBH and 2 EIH)
6 Gas Chromatographs</td></tr>
<tr><td>Safety and asset management</td><td>Jemena has an overall Asset Management System (AMS), in of which safety management is a key element. This system provides the framework to ensure safety operation of the network. It consists of a number of documents and systems including:
Jemena asset management plan
Safety Case
Safety management manual
Formal safety assessment
Asset management system manuals</td></tr>
<tr><td>Downstream users (Outside the scope of this study)</td><td><u>Domestic</u>
The uses of natural gas by domestic users on the network include:
Space heating, water heating including boilers, cooking heat using stoves (hobs) and ovens
<u>Commercial and industrial</u>
The uses of natural gas by commercial and industrial users on the network include:
Space heating, water heating including boilers, cooking heat using stoves (hobs) and ovens
Process heating including process burners of a wide range of designs for many different industrial processes, high pressure and high temperature hot water boilers, steam boilers, and steam generators
Power generation using gas turbines and gas engines
As a process feedstock e.g. for ammonia or ethylene production
Compressed Natural Gas (CNG) for refuelling and storage</td></tr>
</table>

APPENDIX 3 HYDROGEN PROPERTIES SUMMARY

Table 10 summarises the properties and changes thereof due to hydrogen at 0%, 10% and 100% when blended with methane. It highlights some of the different gas quality and materials characteristics of different hydrogen/methane blends.

Table 10 Hydrogen properties[7] [8]

Parameter	Description	100% methane (vol%)	10% hydrogen / 90% methane (vol%)	100% hydrogen (vol%)
Wobbe Index (MJ/Sm^3)	Indicator of energy throughput and ability to change between gases.	50.67	49.44	45.87
Relative Density (kg/kg)	The density of a gas mixture relative to density of air at standard conditions.	0.55	0.51	0.07
Methane Number	Describes the knock characteristics for internal combustion engines.	100	90	0
Higher Heating Value (MJ/m^3)	Amount of energy contained in a volume of gas that is released when combusted.	37.71	36.61	12.11
Minimum Ignition Energy (mJ)	The minimum energy required to bring the gas to a combustible state.	0.29	Not calculated	0.019
Flammability Limits (Vol %)	Describes the limits where a flammable or explosive atmosphere is present.	LFL: 4.4 UFL: 17	LFL: 4.36 UFL: 18.44	LFL: 4 UFL: 77
Auto Ignition Temperature (ºC)	The temperature which the gas combusts without a spark or flame present.	600	Not calculated	560
JT Coefficient	Describes the temperature change that results from a pressure change	During pressure reduction the temperature decreases	Not calculated	During pressure reduction the temperature increases
Flame Speed (m/s)	The speed that a flame will move through unburned gas.	0.37 – 0.45	Not calculated	2.65 – 3.25
Moisture Production (g/kg H_2O)	The mass of water produced per mass of fuel gas consumed.	2.47	2.54	9.3

[7] Natural also includes other constituents such including heavier hydrogen carbons and inerts. The purpose of this table is understand the general property changes that are experienced when hydrogen is added to methane.
[8] (GPA Engineering, 2019)

Stoichiometric Composition (Vol %)	The air to fuel ratio during combustion.	9.5	10.19	29.58
Adiabatic Flame Temperature (ºC)	The temperature of flame produced from combustion of the fuel.	1875	1880	2045
Gas Stratification	The separation of gases due to differences in densities.	As turbulence is always present in the pipe then it is not likely to occur after injection.		
Embrittlement	The reduction in mechanical properties of steel caused by hydrogen.	Likelihood of embrittlement occurring increases with increase to hydrogen content, pressure or internal stress level.		
Fatigue due to pressure cycling	A failure mode that occurs over time due to cyclic loading.	Likelihood of fatigue due to pressure cycling increased with increase in pressure and pressure fluctuations of the pipeline.		
High Temperature Hydrogen Attack	Fissure formation in steel at high temperature due to hydrogen dissolution.	Likelihood increases with hydrogen content and increases to temperature but depends on the material. Only application in temperatures over 205ºC.		
Leakage	Losses of gas through existing seals and joints of permeation through the material.	Increase to hydrogen content increases the loss but the rate is dependent on material, condition and operating pressure.		

APPENDIX 4 REVIEW OF ENERGY TRANSITION

INTRODUCTION

In order to understand the financial implications for energy conversion a literature review of previous and current gas transitions was completed. This review identified the following relevant projects and studies:

- Town gas
    - British Town Gas Conversion
    - Isle of Man Town Gas Conversion
    - Victoria Town Gas Conversion
- Hydrogen
    - H21 Leeds hydrogen conversion
    - UK hydrogen conversion
    - Logistics of hydrogen changeover
    - Decarbonising Australia's gas networks

A short summary of the financial highlights of each of these projects is given below.

BRITISH TOWN GAS CONVERSION

In the conversion from town gas to natural gas, the national program to convert or replace every gas appliance in 12 million homes cost £600m ($1148bn AUD) in 1977, which is equivalent to £2.9bn ($5.5bn AUD) in 2010 prices.[9]

Only minor work was required to existing gas pipes, for example to installation of new valves to assist the purging of town gas or to fix faults that were identified during the appliance conversion program.

In this conversion, new high-pressure transmission and distribution networks were constructed to deliver natural gas.

ISLE OF MAN TOWN GAS CONVERSION

In 2016, a town gas conversion programme was completed on the Isle of Man. This cost on average approximately £3,500 per property, including all work both within the property (reported at about £1,200) and in the street (reported at about £2,300/property).

VICTORIA TOWN GAS CONVERSION

The Gas and Fuel Corporation of Victoria spent close to $350 million in present-day terms on its conversion of 435,000 households and 1.25 million appliances. This amounts to about $800 per household, or $280 per appliance.[10] The relative expenditure by the Colonial Gas Association is likely to have been similar. It is important to note that rather than replacement these appliances were modified, which would be expected to be significantly cheaper.

H21 LEEDS HYDROGEN CONVERSION

Leeds is currently undertaking network conversion of their gas networks to 100% hydrogen.[11] This project was commenced in 2016 and is in the final stages of research and development before the physical modifications will commence.

The final conversion area under the project will encompass approximately 660,000 people across 264,000 connections. Full conversion of the city of Leeds is anticipated to be feasible by 2025 (at the earliest).

The studies to date have concluded there are no significant technical obstacles regarding network

[9] Williams TI. A history of the British gas industry. Oxford, UK: Oxford University Press; 1981
[10] The household numbers are in https://www.newspapers.com/image/121952172
[11] H21 Report

capacity to converting the distribution system, i.e. medium and low pressure, to hydrogen. The network is of sufficient size for the conversion to take place.

The total costs associated with undertaking any remedial measures are estimated to be less than £5m for the LP network.

If there is a national decision to move towards a hydrogen conversion programme, many of these projects could be incorporated into the existing IMRP with minimal cost impact.

The vast majority of the low and medium pressure networks are being replaced as part of the IMRP. However there will be an element of retained iron mains under the current strategy. These are generally above 8 inch in diameter and/or have a zero risk score or will not be replaced under a cost-benefit analysis assessment, (i.e. minimal leakage history). The relative risks of transporting hydrogen, and any associated leakage, through these mains needs to be assessed identifies a requirement to quantify the relative risk of hydrogen in these retained metallic mains against the current risk of natural gas.

A full network conversion cost estimate is to be completed but it is expected that, for the 264,000 connections an average costs of $7708.33 AUD is expected. This included the costs of getting the network “hydrogen ready” and appliance change over.

UK HYDROGEN CONVERSION

A research project completed was completed by Dodds, which summarised the costs of converting households in the UK to 100% hydrogen.

The appliance conversion costs were dominated by labour costs. Dodds identified these could be mostly avoided if the government legislated to make appliances hydrogen-ready in advance of the switchover.

Consequently, two household conversion scenarios were investigated. In the first scenario, there would be government legislation for conversion in advance and the principal cost of conversion to fit new meters and sensors would be £230 per house.

In the second scenario, there is little forward planning prior to conversion and cost is £490 per household.

In 2016, there were around 22.6 million households that use natural gas in the UK. The total cost of conversion would be £5bn for the first scenario and £11bn for the second scenario if all households were converted.

LOGISTICS OF HYDROGEN CHANGEOVER

The predicted timescales and associated costs of the various stages of a conversion in the UK were reviewed by Fraser Nash Consultancy.[12]

The timescales associated with the different appliance options were discussed – noting that Hydrogen-Ready appliances would be installed in advance of the conversion, whilst the adaption of existing natural gas appliances and the installation of new hydrogen appliances would be undertaken at the point of conversion.

There is no significant difference in the total amount of time required within each property between these appliance options and so for simplicity in this section a single timescale is assumed to apply to all three options. The labour costs were been determined at between £750 – 1000 + parts and appliance costs per household. These labour costs include modification of piping and equipment up to (and including) the consumer billing meter.

[12] Logistics of Domestic Hydrogen Conversion

DECARBONISING AUSTRALIA'S GAS DISTRIBUTION NETWORKS

Deloitte recently published a report entitled "Decarbonising Australia's gas distribution networks".

The report identified that the injection of decarbonised gas into the distribution network is not expected to add substantially to existing costs. The additional costs may arise with the requirement to pressurise hydrogen in order to inject it into the existing distribution network and subsequently depressurise the gas before injecting into low pressure pipes to users (households and businesses). A more complex pressure system may incur higher maintenance costs than the existing system.

The main network costs associated with decarbonised gas relate to the transition and may include:

- Management costs incurred in managing the transition from a natural gas network to a decarbonised alternative, including:
    - Identifying the types of appliances that currently exist in the network and whether these will require upgrade or replacement
    - The nature of industrial gas connections and whether users use natural gas as a feedstock or energy source.
- Operational costs associated with running a dual gas network during the transition. By 2035, the majority of the distribution network is expected to consist largely of polyethylene (PE) pipes that will be capable of carrying hydrogen. As such, the distribution costs are likely to largely resemble current costs for distributing natural gas, assumed to be $0.02/kwh or ($5.55/GJ).

SUMMARY

A number of town gas conversion have previous been completed both domestically and internationally. A review found that in all cases there were additional costs of upgrades, generally, in the form of appliance upgrades.

Conversion from town gas to natural gas was relatively technical simple. Existing appliances were modified (injectors drilled out) and minimal modifications to the gas networks were required. The previous town gas conversions that were reviewed ranged from $500 AUD -$3,500 AUD per connection.

Conversion from hydrogen to natural gas will be technical, economical, socially and commercially more complex. Appliances will need to be significantly modified or replaced and existing gas networks will need to be upgrade to handle the increased capacity and minimise the risk of materials impacts. Hydrogen network conversion has been estimated at $500 AUD - $7800 AUD.

It is important to understand the assumptions that have been used as a basis in these reports. Gas networks globally vary in design and operation. Generally, international reports and case studies should be used for guidance only.