Executive Summary

This submission is a response to the “Towards 2050: Gas infrastructure in a zero emissions economy“ Interim Report. This submission herein largely sets out the merit of providing low level heat by electrification wherever possible. These applications would include residential, commercial and most industrial uses of gas. Power generation currently makes up 17% of the use of gas, which in the long term is unlikely going to continue from gas. The use of hydrogen, as a replacement for natural gas, can and should be limited for industrial processes requiring high temperature heat and hydrogen as a feedstock.

The policy setting of: “*To assist 250,000 low-income households to install reverse cycle air conditioners*“ , as described in “Victoria’s Gas Substitution Roadmap” shows commendable vision and prudence as further explained later.

Furthermore given the inefficiencies of producing storing and transporting hydrogen and the safety concerns about hydrogen transport and storage in areas close to the public, hydrogen is best produced near or where it is needed from (renewable) electricity supplies.

Much of this review focusses on the option of hydrogen. In Victoria’s Gas Substitution Roadmap hydrogen, blending with hydrogen and Biogas are mentioned. However this roadmap does not contain the same level of detail as the National Hydrogen Roadmap and therefore it was decided to use the National Road map as the scope for review in relation to the use of hydrogen as a replacement for natural gas.

The use of hydrogen as a purported “zero carbon” fuel has attracted a great deal of attention in recent years and is promoted enthusiastically by politicians, bureaucrats, persons in industry and climate change advocacy groups. The author of this submission fully accepts the reality of climate change and the need to address it urgently. While the author certainly sees a role for “green” hydrogen, concerns exist that some of the claims made relating to the suitability of hydrogen are highly exaggerated and unrealistic when considered against fundamental scientific and engineering principles. Rather than being beneficial to the cause of addressing climate change, the promotion of scientifically unsustainable views has the potential to ultimately prove counterproductive.

Jules Verne was a science fiction writer with truly remarkable visions. At that time his visions could not be calibrated for practicality, effectiveness or efficiencies to the same extent as they can be reviewed now. Therefore the author of this submission does not believe there is much benefit to reflect on Mr Verne’s visions in the current debate and one should concentrate solely on the merit, or otherwise, of specific hydrogen applications.

Slowing and eventually reversing climate change will be the largest and most daunting challenge engineers have faced. Around the world literally Trillions of dollars of engineering infrastructure will have to be abandoned before the end of its economic life. Since these changes require regulatory changes, it may be anticipated that significant compensation would be payable to owners of infrastructure and facilities that provided indispensable services to the community but which are no longer needed. Furthermore, many more trillions of dollars of entirely new engineering infrastructure will have to be designed and built.

Climate change affects all engineering fields: from cement manufacture to transport, from mining to chemicals, and from civil engineering to the energy industries and many more areas.

In terms of efficient use of renewable energy, engineers involved with new road transport vehicles (automobiles in particular) seem to have settled on the most optimal technology, which is batteries. This choice may be the result of the very large amount of scientific and engineering resources concentrated in, and available to that industry.

In certain industries hydrogen can indeed be an agent that may be used to reduce carbon dioxide emissions, where at this point no other technology would seem to be able to achieve this objective. Examples of effective hydrogen utilisation may include using it to make ammonia as a diesel/bunker oil substitute, in making Green Steel, Green Fertilisers, and processes requiring high temperature heat etc. These are not examined in this submission in further detail, which is consistent with the settings of "Towards 2050: Gas infrastructure in a zero emissions economy" interim Report. Likewise export of renewable energy has also not been explored.

Therefore most of our concerns are related to promoting hydrogen technologies in the two largest onshore segments of fossil fuel uses: power generation and low temperature heat applications. In these instances hydrogen is also promoted to become an energy carrier for producing electricity or provide low energy heat in other locations. In keeping within the boundaries of the consultation this review will further only focus on alternatives to Natural Gas. In such hydrogen applications the efficiency achieved from the use of renewable energy resources is in fact very low, often only about one third of that achievable by other technologies. The inefficiencies are such that hydrogen would, in many instances, seem unsuitable as an energy carrier, further reinforced by significant safety and environmental concerns. It is the view of the author these far-reaching changes in infrastructure should not be attempted before careful and thoroughly reviewed analyses have been carried out to unambiguously demonstrate the (purported) suitability of "hydrogen solutions" in these cases. It has been correctly pointed out by others that energy carriers other than hydrogen can be far more suitable in many cases. Once a suitable energy carrier has been developed, hydrogen, can be made "on demand and uninterrupted" and more efficiently on the location where it is needed. That would also overcome the significant inefficiencies of storing, handling, and transporting of hydrogen as well as leading to better environmental and safety outcomes.

Addressing climate change need not be centred on hydrogen solutions. There are several other options and, as discussed subsequently, these would to offer many advantages in terms of energy efficiency, environmental outcomes, safety and are ultimately more economical.

Front and centre in this debate is the efficient use of Renewable Energy. The choice of energy carrier determines the success or failure in tackling climate change. Therefore selection of the most suitable carrier(s) is the most important decision we, as a society, must make. In Appendix A, the efficiencies obtained with a water heater using different carriers are calculated. It demonstrates that both hydrogen and ammonia are significantly less efficient than other energy carriers.

There are various hydrogen lobby groups, some of which have very strong commercial interest and therefore may not always be a source of independent expert advice. Even universities and various research organisations also cannot necessarily be seen to be entirely independent because, at least in some cases, they offer and market their consultancy services and carry out research for income. For instance, it might be asked if it is appropriate for the CSIRO National Hydrogen Roadmap [1] to be sponsored by organisations which have clear commercial interests in promoting hydrogen and are listed as sponsors of the report. This does not seem like an ideal way to develop national policy. Hydrogen seems to be advanced as the default national solution for using and exporting renewable energy. There are two apparent matters that need to be addressed here:-

- Ultimately hydrogen would have to compete in the market place and that mechanism forces practicality of solutions, and;
- Decisions made by the market may not always be in the best interest of the community, and or the environment.

I argue, in particular, that hydrogen has not been shown to be an efficient "carrier" for electrical energy (or thermal energy to replace natural gas) and its utility in this area is limited by the fundamental physics and chemistry involved in the relevant processes. For instance, regardless of the technologies employed, it cannot become as efficient as the direct supply of electricity or electricity supplied from batteries or pumped hydro.

Dr Ulf Bossel [2-4], a fuel cell expert based in Switzerland, wrote several influential and convincing papers on the "hydrogen economy" in the early 2000's. He adeptly applied the laws of physics to demonstrate its limitations and, in many instances, its impracticality. More recently, in a radio discussion panel, Dr Fiona Beck [5] of the ANU Engineering and Computer Science Department, expressed similar views on some aspects of hydrogen's utility. Dr Beck cautioned against the widespread use of hydrogen and very justifiably recommends limiting it to industrial processes where heat is required that cannot be provided directly by electricity.

Governments are strong proponents of the "hydrogen economy" and some see it as a virtual panacea that, almost miraculously, overcomes the climate change problem. Unfortunately, in our view, any realistic analysis does not support this view. We are strongly of the opinion that the questions surrounding the utility of hydrogen are, in each instance, in need of first principle analysis of the kind applied by Dr Bossel.

In determining the efficiency of the hydrogen cycles the author has been principally generous towards hydrogen by accounting for liquefaction as an energy input instead it coming from the product stream. The same logic was applied to the production of ammonia from green hydrogen. Many others like Dr Bossel do not account for this parasitic loss in such manner. Despite that generous treatment, the use of heat pumps requires **1/12** the amount of renewable energy inputs compared with any of the hydrogen alternative cycles that power the base case of the respective hot water units, see also Section 1.3 and

Appendix A. If however the conventional methodology of energy efficiency calculations was used this would make the ratio even worse, and would translate the energy use and infrastructure needed to drive the hydrogen cycles to be **16 times** greater than the heat pumps powered directly from renewable with batteries or pumped hydro.

In that context the policy setting of: "*To assist 250,000 low-income households to install reverse cycle air conditioners*" as described in "Victoria's Gas Substitution Roadmap" is reinforced and confirmed as commendable vision and prudence.

Apart from all safety and hydrogen embrittlement concerns, hydrogen in gas distribution and transmission infrastructure has a fundamental disadvantage: low volumetric energy density. Natural gas contains approximately 36 MJ/m^3 and hydrogen 11.9 MJ/m^3 at atmospheric conditions and this relative difference remains practically the same, also at higher pressure.

Victoria's Gas Substitution Roadmap also refers to BioGas as a possible source of energy. In general the specifications of BioGas do not match does for natural gas and after some treatment it could generally be injected into natural gas networks in small quantities with no ill effect. However this also requires compression and metering based control of the injection flows. Injection into hydrogen networks could not be done, as much higher degrees of purity are required. For these reasons the use of BioGas should be restricted at the premises and used to provide low level heating or power generation. Power of course could be more readily exported to the grid.

Cornelis de Groot

[redacted]

[redacted]

16 August 2021

1) Introduction

This section introduces the author and discusses the need for action to reduce the effect of climate change. It make a further point of the vital importance such actions are carried out in the best interest of the environment and the world community and not be driven by commercial interest of individual proponents. Unfortunately, due to his personal circumstances, one of the co-authors declared he had to decline further involvement just days before this submission was due. As time was running out Cornelis de Groot could not involve an alternative co-author for this submission.

1.1 The author(s)

Cornelis de Groot, MEA, CPEng 600049, possesses 40-years of Mechanical Engineering experience. He has recently retired from his position of Principal Engineer Gas Supply in a WA government agency, after having been in that role for just under 16-years. Particularly during this time, he had exposure to new developments in the energy industry. Cornelis is certainly convinced of the need for urgent action on climate change and the necessity to reduce carbon dioxide emissions; the recently released IPCC AR6 report makes this very clear. He assesses matters always on first principles and only uses standards as possible sources for validation of his decisions and, of course, for compliance checks. He specifically does not rely on standards to make engineering decisions. That is driven by his awareness that standards are compiled by mostly industry stakeholders, who may be influenced by commercial as well as community and environmental interests. Cornelis does not propose a vastly different concept for formulating standards but only makes the point that *the quality of a standard is largely dependent of the competence of the committee members*. Therefore a standard cannot and should never be seen as the ultimate tool for design and construction of infrastructure or for determining an achievable safety outcome. Standards often are lagging developments and not leading them, furthermore improvements in standards are often driven by incidents. Cornelis has seen several instances where standards contain seriously large errors and has endured years of difficulty attempting (sometimes unsuccessfully) to have them rectified.

Cornelis was of the opinion that a so called “hydrogen economy” could have certain benefits. However, that was prior to June 2020 when, upon checking some efficiency and safety related matters and analysing the claims made by proponents, he began to look at these questions in a more skeptical and circumspect manner and began applying fundamental physics and chemistry to the proposition(s). He is concerned that insights (and guidance these insights offer) from experts such as Dr Bossel, and many others, have not been followed.

The author(s) are not connected to any stakeholder and have independently provided their advice in their own time and without compensation or reward of any kind.

1.2 Taking action in the best interest of the Environment and World community

An overall perspective is required that is, as much as possible, independent of political influence and financial interest. Somewhat mysteriously, market forces often go some way in resolving these issues, certainly in the second or third iterations when these matters arise in Western democracies. However the reliance on this alone would:-

- Lead to unacceptable delays, and;
- The process should be guided through the application of sound first principles and have the absolute minimal environmental impact and most efficient production of energy and not adversely affect the safety of the community. That framework needs to be established first so to avoid being misled by interest groups promoting suboptimal technical outcomes of whatever types and for whatever reasons.

1.3 The most important decision, choose an efficient Energy Carrier first

The choice of energy carrier is the single most important decision to be made and this needs to be done first before attempting to transport large quantities of renewable energy.

Australia is well placed to become a world leading exporter of renewable energy. We have access to vast land areas, a pattern of seasons that produce most renewable energy when the need overseas is highest, a politically stable environment, etc. Such endeavour would put Australia in a central position in the world economy.

To illustrate the efficiency of hydrogen against direct electricity utilisation, the base case of an electrical storage hot water system with an immersed resistive heating element is considered. This type of water heater is universally useable in all climates, from hot to very cold, climates such as the North American winters. It can be fitted inside, anywhere within a domestic dwelling. It may be supplied with electrical energy from renewables, batteries, pumped hydro or, from long distance electrical transmission lines, or a combination thereof.

As explained elsewhere, installing gas appliances inside modern houses when fuelled with hydrogen becomes a possible safety concern. Whilst in the Australian context a gas fired water heater could be installed outside, in cold climates that is often not a viable option.

Against the base case are pitched:

1. The same water heater but supplied with electricity generated by hydrogen.
2. As in the above case, but supplied with electricity generated by ammonia.
3. A further comparison is made using a gas fuelled 5-Star efficiency version, modified to burn hydrogen.
4. Finally the heat pump version is reviewed that would be a viable option for Victoria and other parts of Australia. This version is again supplied from energy imported via long distance electrical transmission cables, pumped hydro and or batteries.

The table shows the multiplier in input capacity of Renewable Energy for the various options in relation to the base case.

Case	**Renewable Energy Input multiplier**
Base case, Electric Appliance, Resistive, electricity from utility based networks. Electricity transmitted by high voltage from remote areas with renewable energy, batteries or pumped hydro back up.	**1**
Case 1, Electric Appliance, Resistive, electricity from utility based hydrogen fuel cells, liquefied storage of hydrogen.	**2.6**
Case 2, Electric appliance, Resistive, electricity from utility based Ammonia fuel cells or combined cycle systems, liquefied storage of ammonia.	**2.8**
Case 3, Gas fired Appliance, gas supplied from hydrogen gas distributed in networks which are supplied by gas transmission systems, liquefied storage of hydrogen to feed transmission networks.	**2.8**
Case 3, Electric water heating Appliance heat pump, electricity from utility based networks. Electricity transmitted by high voltage from remote areas with renewable energy, batteries or pumped hydro back up.	**0.24**

The results in the right column show that hydrogen and ammonia are both far less efficient than the base case and that using hydrogen in a gas-fired appliance gives an equally poor result.

It should be noted that extensive use of heat pumps will mean a reduction of renewable energy supplies (solar panels power transmission etc) typically of **2.8/0.24=11.7** times compared to hydrogen applications! Please refer to appendix A.

2) Independent verification

There are various hydrogen lobby groups which cannot be seen to be disinterested and independent as they have strong commercial interests. In addition research organisations and universities may be swayed by the opportunity to offer consultancy services and carry out research for income. This is, of course, not to suggest that such bodies should not be involved in hydrogen research, on the contrary, I believe that high quality research in this area is a fundamental requirement.

There are two apparent matters that need to be addressed:

- The various techniques would need to compete in the market place and that mechanism forces practicality of solutions, and;
- Decisions made by the market may not always be in the best interest of the community and or the environment.

The following points need to be recalled and taken into consideration:

- There are a number of hydrogen applications and suggested technologies that are unproven and require significant investments, Hydrogen applications and opportunities are often reported and promoted in the absence of scientific rigour, such reports often only concentrate on the virtues of hydrogen as an all-encompassing solution while neglecting its disadvantages, including that it is, in effect, an indirect greenhouse gas with a GWP estimated to be between 4 and 5 times that of CO_2 [6].
- While the wide flammability range and low ignition energy of hydrogen are well recognised [7], the very high deflagration index (explosion severity) [8-10] appears to be less so. This carries various possibilities of accidents occurring that are likely to be more severe than the comparably case with natural gas. Explosion relief calculations that apply to other fuel gases are inapplicable to hydrogen [11]. The deflagration venting standard NFPA 68 [12] includes the warning "*The susceptibility of a turbulent system to detonation increases with increasing values of the fundamental burning velocity. In particular, compounds that have values close to that of hydrogen are highly susceptible to detonation when ignited under turbulent conditions*."
- Following the above point, whereas with a natural gas fueled appliance, a delayed ignition often produces a "whoosh" and flame rollout, with hydrogen there might well be a violent explosion.
- The pursuit of hydrogen applications instead of other more efficient energy transfer and storage solutions may involve environmental penalties which are not experienced with other techniques, including even the continued managed use of fossil fuels.
- Engineers who promote supposed techniques for use of hydrogen that are claimed to be far more efficient than alternative means (i.e. batteries or pumped hydro) need to justify these on the basis of solid scientific principles if they are to be seen as acting in the best interest of society. Although, up to the present, this has been largely resolved by the market, with one of the clearest examples being the automotive industries

which, by and large, embraced battery technology in preference to hydrogen fuel cells, the disadvantage of markets making decisions is time delays due to re-iterations.

- Engineers and others who seek to promote the use of hydrogen and, in so doing, in effect, attempt to refute the work of experts such as Dr Bossel [2-4] and Dr Fiona Beck [5], who point out its limitations, need to produce solid fundamentally based evidence to support their claims.
- The production of “green hydrogen" requires copious amounts of high quality water that in Australia, in all likelihood, would have to be produced in desalination plants and this itself also becomes an environmental issue.

3) Discussion of hydrogen applications

This section aims to categorise a number of hydrogen applications and comments on their efficiencies and environmental benefits. They are not in any particular order.

The reader is also encouraged to refer to Appendix A where a set of calculations are provided to produce a certain quantity of hot water with different renewable energy carriers and appliances. The results are further discussed in Section 1.3.

3.1 Blending hydrogen in Natural Gas Networks

These comments are made in the context of Western Australia; however most of these comments also apply to Victoria, except for comment b) which is unique to WA.

It would appear that the Victorian gas usage in the distribution networks is around 200 PJ/year or 550 TJ/day that is 5.5 times higher than that of Western Australia. Although most of the comments apply to Victoria as well.

In WA the proportion of gas used in the Gas Distribution Networks is small compared to the industrial use. Furthermore, as shown below, even where a 10% hydrogen/natural gas is used the "CO_2 savings" are quite small and, in any case a more beneficial result can be achieved by instead using the electricity (needed to generate the hydrogen) through substituting electrons directly.

a) The positive effect of blending in the Gas Distribution Network would seem to be grossly overstated in some cases; by as much as a factor of 50. Firstly, at the proposed level of 10% by volume in natural gas this would give a 3.4% reduction in CO_2 emissions if all of the associated penalties are discounted (which, of course, they should not be in a full trajectory analysis, as considered later). However, the next point is even more relevant.

b) The State's total gas burn is about 1100 TJ/day (DBP+GGT) plus a further 500 TJ/day in energy spent for liquefying natural gas for export and other gas uses (fertiliser production for example). The networks where blending is proposed only use a nominal 100 TJ/day. That means 10% of blending will only lead to about 3.3/16 = 0.2% of CO_2 reduction from the natural gas burn and NOT the sometimes quoted 10%, or even more. And, this discounts such factors as energy expended in transporting the hydrogen and the required compression energy.

c) In the 80's, in WA as in Victoria, power was generated mainly by coal fired, simple cycle steam turbines with three stages at best. They produced electricity with about 33% efficiency before transmission and distribution. People used resistive space and water heating thus making the overall cycle roughly 30-32% efficient. With natural gas the heating efficiency to 60-70% and, furthermore, the more favourable C:H ratio of gas compared to coal, meant that the CO_2 emission per unit of energy produced was lower. However, the combined result of improved efficiency from modern generating plant more renewable energy, the uptake of heat pump space heating and the expanding use of solar hot water systems, is a reduction in the gas consumption per customer. Therefore the gas distribution network now carries a diminished fraction of the energy delivery mix. This also means the opportunity for the expansion of gas in the domestic and small commercial sector would appear to be limited. Currently gas consumption per customer in WA is lower than it has been for many years. Sadly despite switching to gas in the 80's, those reductions in CO_2 emissions will not be adequate to address the challenges to avoid climate change.

d) The above point does not necessarily apply in cold climates, where gas distribution networks are expected to continue to provide a large proportion of the delivered energy, till later and after those electricity networks are further upgraded. It is notable that in the CSRIO Report [1] the case for hydrogen networks was made on the basis of UK figures, while it was stated that electrification would be more feasible in Australia, viz "*While electrification is likely to be more feasible in Australia than the UK due to differences in heat demand, a 2016 report by KPMG analysing UK energy scenarios calculated that electrification could cost up to £170-196bn (AU$300-350bn) more than upgrading and facilitating a hydrogen gas network for heat*" The reference cited in the CSIRO report (*114*) was entitled "*KPMG 2016, 2050 Energy Scenarios; The UK Gas Networks role in a 2050 energy system*". The clear take away is that even in the context of only replacing the energy delivery from gas networks, upgrading of the electricity networks was feasible. However the feasibility of upgrading electricity networks in Victoria, and elsewhere in Australia, is further established, please refer to Sections 5.1 and 5.2.

e) Green hydrogen is produced from electrolysis and then needs to be compressed and transported. Older alkaline electrolysers are rarely more than 64% efficient, though newer PEM units may approach 70% [13], which means that over 30% of the input energy is lost in this first stage. Compression and transport each impose further losses, the severity of which are dependent on the particular circumstances, and may typically be in the order of 10% each. Some (PEM) electrolysers deliver the product hydrogen at moderately elevated (3 to 3.5 MPa) pressures [1]. However, while the compression process may be more efficient than could be achieved with a mechanical compressor, it is not "free" as it must be provided by the input electrical energy.

   Furthermore, depending on the installations and nature of the hydrogen injection facilities there may be the need for further compression and/or cooling of the gas to protect the receiving vessels [14, 15]. It follows that the efficiency, before combustion, is in the order of: 0.65*0.9*0.9 = 52.7%. When hydrogen is then burnt with 60-70% efficiency, the overall efficiency is 30-37-% efficiency. That is no better than the 1980's turbine technologies as summarised in point c) above. It follows that the electrical energy used to produce and handle hydrogen could be used far more efficiently to charge batteries, direct storage to pumped hydro or even drive resistive loads, without all of the disproportionately high infrastructure cost, as well as having a far more positive effect in the reduction of CO_2

f) Where transport of hydrogen is by pipeline, the compression energy is greatly increased compared to that of natural gas. According to Figure 12 in Kurz *et al* [16], the increased power is about 28% for even a 10% blend and 70% for a 20% blend. Other calculations, such as Bossel's [2] indicate lower but still highly significant increases. Calculations based on first principles tend to be closer to Bossel's predictions of a 13% increase in the power required with the 10% blend. Following Bossel [2], for neat hydrogen to achieve the same energy flow as with typical natural gas requires about 3.5 times the compression energy.

g) The blending operation (10%) to achieve 3.4% CO_2 reduction would require multiple sites that would each need to be able to accommodate large delivery vehicles two B-doubles. Roughly 18 B-double loads per day are needed to deliver that 10%/3.4% blending. That alone is 30 B-doubles and 4-5 prime movers operating 24/7. In the production facility a further 30 or so B-doubles would be needed that take the product as it is produced; because it is paramount only green hydrogen is used. Taken over the full trajectory, even the above 3.4% CO_2 reduction, may be illusory when transport, compression, infrastructure issues and the CO_2 produced in these activities and the production of the solar panels and wind turbines is taken into account.

h) Many, (18-20) truck movements per day would be needed (each way) from the production source to the injection point and would require permission from authorities, which would inevitably present an elevated road safety hazard as well as increase the need for road maintenance. Hydrogen pipelines to feed city gate injection sites are not viable for this purpose. For Victoria these truck movements may have to be multiplied by a factor of 5.5.

i) It seems reasonable to conclude that the cost of this endeavour is disproportionally high to remove 0.2% of the CO_2 from the WA daily gas burn. The same would most certainly apply to Victoria.

j) The wholesale cost of natural gas is in the order of $10 per GJ and hydrogen (when the cost to transport and inject etc is also accounted for) is expected to cost approximately $100 per GJ. On these figures, the 10/3.4% blending would increase the wholesale gas price for distribution by 20-30%.

k) It is understood that the cost of the blended gas cannot be passed onto consumers and may be incompatible with the Economic Regulations and the principles of the Tariff structure.

l) Partial blending of the network may mean commingling, if that were to occur, would further complicate billing very significantly (HHV management issues).

m) It is understood there are proposals to inject hydrogen into high pressure gas transmission lines. There is considerable literature to support the position that that even low concentrations of hydrogen may affect the metallurgical properties of the steel [7], causing embrittlement and limiting the future operational flexibility (in terms of allowable maximum pressure and pressure excursions). It is notable that the CSIRO report [1] mentions the "*line packing*" (of hydrogen) in gas pipelines. By its nature line packing involves major pressure excursions that do not seem consistent with acceptable operation of hydrogen in steel pipelines. Furthermore the line packing in the case of blended gases is predominantly natural gas (because of the blending) and the low volumetric energy density of hydrogen. That concludes that the storage of energy that can be apportioned to hydrogen is in fact negligible.

n) Starting initially with blending is not a natural/logical pathway to full hydrogen gas distribution because even if issues of appliances are resolved for 10-15%, and that is yet to be proven, higher blending ratios, and most certainly neat hydrogen, will require specifically designed appliances.

o) Even at 20% blending, the impact of CO_2 reduction still only reflects a 6.8% CO_2 reduction in the blended gas (if the penalties described above are discounted, which they should not be in any realistic evaluation, and a 0.4% overall improvement(and would require a great many (72-80) truck movements on a 24/7 basis. For Victoria these truck movements may have to be multiplied by a factor of 5.5.

p) It follows that hydrogen (made from electrolysis) is too "precious" to be burnt in "ordinary" gas appliances, especially when the functionality of such gas appliance can be fulfilled with greater efficiency using the electricity directly and even more so by using heat pumps.

q) There appears to be confusion in industry about the previous town gas experiences, with the claim that it was in some respects similar to hydrogen. Firstly, velocities and pressures in mains were much lower, secondly the gas was "wet" (often close to water saturated); the high humidity assisted in getting a good seal at pipe joints. The humidity combined with the metallic pipes used meant static electricity was not an issue. Also as a blended gas it (town gas) had a lower flammability range and, more importantly, only about one tenth of the deflagration Index of neat hydrogen, as noted above. Further, it is to be recalled that town gas was distributed in an era where there was a much lesser focus on safety than is the case today – it is doubtful that delivering into people's homes a gas containing perhaps 20% carbon monoxide (and numerous other toxins, including benzene) would be considered acceptable by today's standards.

r) If the 10% blending goes ahead (without appliance replacements) then all appliances approvals are no longer legally valid; as the safety margin for light back (flash back) is practically entirely taken up by routine blending. Verification over the past 45-years was with Nb test gas, which comprised 13% hydrogen/methane blend during type testing. It is notable that the GPA Report "Hydrogen in the gas distribution networks" [7] acknowledges that a test gas of at least 21.7% hydrogen would be needed to maintain consistency in light back testing if blended gases contained up to 10% hydrogen This could be highly problematic if someone gets injured, or worse, killed due to light back of an appliance burner. Under the Regulations the network operator has the responsibility that the consumer installation is safe. This concern about lack of validation of light back is overarching and in addition to concerns with specific appliances such as flueless space heaters and reciprocating engines, which are expected to be highly sensitive to any blending.

s) Following the above point, there is a surprising tendency in reports, including the CSIRO report [1] to cite European experience with blended gas. This overlooks the fact that European appliances are type tested with Test Gas G222, which contains 23% hydrogen in methane compared to 13% for Test Gas Nb, as noted earlier. Operating a 10% blend in the Australian situation would represent a far greater degradation of the safety margin than would be the corresponding case in Europe. As in the preceding point, this is acknowledged in Reference 7. It is also the case that gas appliance operating pressures are higher for example in the UK than in Australia; the respective minimum inlet pressures being 2.0 and 1.13 kPa. Finally flueless gas space heaters are not commonly used overseas and are prohibited in Victoria.

t) The Western Australian renewable Hydrogen Strategy [17] on page 26 states: *"Western Australia has a vast gas reticulation network and a unique customer base. Blending up to 10% renewable hydrogen into the natural gas network could reduce the emissions intensity of gas combustion by up to 13%. This offers an opportunity to partially decarbonise gas consumption and a step towards deeper decarbonisation in the longer term."* This statement is a grossly inaccurate at best and incorrect on numerous grounds. It could imply that all domestic gas will be blended, which as explained above is not the case. Furthermore, blending at 10% would only reduce the carbon emissions by 3.4% if all of the CO_2 penalties in so doing were discounted, which they cannot be in any credible analysis. We are not aware of the calculation method employed to reach the 13% figure, but it is clearly incorrect.

3.1 Conclusions:

- New infrastructure is required for producing, transporting and injecting hydrogen into gas distribution networks.
- Appliances may require full replacement, even at relatively low blending rates. This applies to Victoria too.
- No proper testing or research could be found that validates hydrogen blending on appliances including, in general, susceptibility to flash back, flueless space heaters and reciprocating engines, such as used in shopping centres and hospitals. It is expected this applies to Victoria as well.

- Use of “green hydrogen” in Gas Distribution Networks represents a very low efficiency use of renewable energy, that contributes only minimally at reducing CO_2 emissions, if at all on the full trajectory basis. It is expected this applies to Victoria as well.
- The CO_2 reduction achieved is very insignificant (maybe even non-existent) and disproportionate to the cost. It is expected this applies to Victoria as well.
- The potential CO_2 reduction is greatly increased if that renewable energy is stored in batteries and supplied when renewable sources are not at adequate output. It is expected this applies to Victoria as well.
- There are significant logistical issues in accommodating blending and transporting the hydrogen needed to the blending sites. It is expected this applies to Victoria as well.
- The use of neat hydrogen raised a number of safety and other issues that would need to be addressed. It is expected this applies to Victoria as well.
- The above more detailed analysis is mostly in line with the analysis presented by Mr Forcey [17], Dr Fiona Beck [5] and Dr Ulf Bossel [2-4]. It is expected this applies to Victoria as well.
- A Western Australian Government publication that proclaims the purported advantages of the hydrogen economy [16] contains a serious error that greatly overstates the CO_2 reduction benefit of blending. Publicising such erroneous information supposedly in support of action to reduce CO_2 emissions does not assist in promoting action on climate change; in fact it does the opposite.

3.1 Recommendations:

Before further promoting hydrogen for use, either blended or neat, into gas distribution networks, the safety and efficiency both need to be demonstrated unequivocally and issues raised above be addressed adequately.

3.2 Neat hydrogen in Gas Distribution Networks

This question has been dealt with briefly above and is considered further here. In Western Australia the proportion of gas used in the Distribution Networks is very small compared to the industrial use, however if networks are to operate on neat hydrogen, transportation by trucking hydrogen is not viable. The existing Gas Transmission infrastructure is not suited to deliver neat hydrogen to the City Gate Stations. The newer pipelines are made of high tensile steels that often do not tolerate hydrogen without adversely affecting the operational flexibility and safety of these pipelines. The older pipelines are understood to be constructed of a material more tolerant to hydrogen, but are approaching 50-years of age and the end of their operational life. It is likely that the older pipelines will not have the required capacity. This means an entirely new transmission infrastructure is required to deliver that gas to the networks thus nullifying the arguments in favour of conversion for the continued use of the existing transmission infrastructure.

It is of significant concern that by promoting blending (see section 3.1) more often than not an expectation is communicated which could be interpreted that blending is a stepping stone towards neat hydrogen Gas Distribution. Furthermore suggestions are made that such transitions are seamless and following established practices from the past, in particular the "conversion" (of appliances) when town gas was replaced by natural gas. Entirely new appliances are needed, the existing network capacity would be reduced almost threefold (unless velocities are increased to impractically high velocities; up to 80 m/s has been indicated [19]. Further reductions in network capacity may be required because of the de-rating by equipment and pipe suppliers (due to the low density and potentially higher leakage rates). Such change could scarcely be called seamless. Again this situation largely nullifies the argument of using existing gas distribution infrastructure. Some further considerations:

a) It has never before been attempted to replace gas in existing distribution and transmission infrastructure that has an ignition range of 4 to 75% in air combined with a minimum ignition energy of less than 0.02 mJ.
b) Likewise it is unprecedented to reticulate a gas with a deflagration Index reported at up to 14 times higher than natural gas and 10 times that of a 50/50 methane/hydrogen mixture.
c) Current intrinsically safe gas detection equipment would not necessarily be intrinsically safe in hydrogen use.
d) Hydrogen/air mixtures in pipelines, if ignited, have a far greater likelihood of transitioning to a (highly destructive) detonation than is the case with a natural gas/air mixture.
e) The low volumetric energy density means that to maintain capacity pipeline velocities need to be much greater, which also increases the risks associated with static electricity.
f) In the case of distributing natural gas, not every third party pipeline strike will result in a gas escape that catches fire. That is unlikely the case with hydrogen where, from this desktop analysis, every strike is expected to generate a fire. If air has entered the line, the risk of a flash back is greatly increased due to hydrogen's high burning velocity.
g) Hydrogen flames are almost invisible unless contamination from foreign materials (sodium in particular) is present. This is an added hazard. Reference 20 warns "*Hydrogen flames have low radiant heat. Unlike a hydrocarbon fire, you may not feel any heat until you are very close to the flame*" and "*Because of these properties, use a portable flame detector, such as a thermal imaging camera, when possible. If flame detection equipment is not available, listen for venting hydrogen and watch for thermal waves*." Reference 21 also describes some of the flame detection measures that are unique to hydrogen.
h) The electrostatic charge required to ignite hydrogen is reported [22] to be one sixth that of methane (10 nC vs 60 nC). It is also reported to be sensitive to frictional and spontaneous ignition [22]. These properties greatly increase the potential hazards of handing hydrogen. It is also notable that according to Reference 22 that "*Methane is far less susceptible to this phenomenon. Recent work (27) shows that the addition of small quantities of methane (5 – 10%) to hydrogen significantly desensitises the gas mixture*". This again illustrates that the properties of town gas (containing typically 50% hydrogen) cannot reasonably be compared with those of neat hydrogen.
i) Only complete displacement purging would seem viable, and even there the great density difference between hydrogen and the other gas (i.e. nitrogen) can be expected to result in stratification issues, requiring much higher purge velocities. The necessity to use completed displacement purging is unprecedented in gas distribution operations and would be significantly expensive. With indirect purging (as practised in gas distribution and transmission), the slug of inert gas used to separate the hydrogen and air is likely to rapidly degrade unless very high, perhaps impractically so, velocities are maintained, which apart from any other consideration increase the static electricity hazard. Furthermore, while it has been shown that deflagrations of methane air mixtures in pipelines do not readily

transition to detonations, this is unlikely to be the case with hydrogen/air mixtures where they more than likely will escalate in more severe explosions.

j) Green hydrogen is produced from electrolysis and then needs to be compressed and transported. In producing hydrogen alone 30-40% of the input energy is lost, compression loses a further 10% and transport takes another 10%. It follows that the efficiency before combustion is in the order of: 0.6*0.9*0.9= 48.6%. When hydrogen is then combusted with 60-70% efficiency, the overall efficiency is 29-34%, which is very low. These matters are further explored in Section 1.3 and Appendix A.

k) If in Victoria 550 TJ/day of natural gas was replaced by hydrogen, the equivalent capacity would need to be 583 TJ/day to account for the reduced LHV/HHV ratio. On the basis of the CSIRO figures [1] of 54 kWh of electrical energy being required per kilogram of hydrogen produced, and adding to that a further 12 kW/kg for liquefaction, desalination and other losses an average electricity supply of 11.3 GW would be required. This does not include further losses in decanting and compression of the gas supplies. In order to provide this quantity of electrical power, at 100 MW/km^2 (200 W/m^2 plus 100% space for pathways and avoidance of shading) and an utilisation factor of 25%; 451 km^2 of solar collectors would need to be installed. This should be rounded of to 480 km^2 (or 480,000,000 m^2) to account for further losses for the supply of hydrogen (but without other energy losses for export to other countries). The CO_2 penalty in such an operation would be far from negligible and there may be other unforeseen environmental consequences. To this must also be added the CO_2 penalty incurred in the provision and installation of new pipelines and other infrastructure noted above.

In contrast if 67% of that gas load was replaced with heat pumps powered by direct renewable electricity and backed up by pumped hydro and batteries; it follows that 320 km^2 can be reduced to 320/12*=26.7 km^2. If the remainder is equally split between resistive and hydrogen then 80 km^2 in the form of resistive becomes 80/2.6*= 30.7 km^2 and of course the remaining hydrogen need can be reduced to about 80*0.75=60 km^2 (No need for liquefaction of hydrogen, hence 0.75). That brings the total down from 480 km^2 to 26.7+30.7+60=117.4 km^2. Furthermore consideration should be given to the opportunities offered by thermal Solar for electricity production, thermal storage as well as supplying process heat.

*See table in Section 1.3.

3.2 Conclusions:

- New infrastructure would be required for transmitting and distributing hydrogen, making redundant much of the existing infrastructure.
- All appliances require full replacement at least once.
- Neat hydrogen gas is expected to be entirely unsuitable (for safety reasons) in gas distribution. For example every third party break would most likely result in a fire. Furthermore such fire may flash back if air has entered the line. Also each repair would require complete displacement purging (both directions) as hydrogen's low density causes stratification and this, combined with its exceptionally wide ignition range, low ignition energy and tendency to flame acceleration, makes direct, and even slug, purging too dangerous. Furthermore, hydrogen flames may be almost invisible.
- Due to the ignition range and the explosive nature of combustion hydrogen should not be used indoors.

- No proper testing or research could be found that validates hydrogen as a viable and safe distribution gas (third party damage or purging for example).
- Use of green hydrogen represents a very low efficiency use of renewable energy.

3.2 Recommendations:
Before further promoting neat hydrogen for use in gas distribution the safety and efficiency both need to be demonstrated to a standard acceptable to the community. Otherwise any pursuit of this application would be a waste of resources, time and energy.

Furthermore any such schemes need to be assessed on merit because even operating resistive heating on batteries or pumped hydro is almost three times more efficient than the combined effect of the hydrogen cycle. Since hydrogen needs to be produced from those same renewable energy sources, it is already demonstrated that the use of hydrogen is not environmentally friendly because it needs three times the generating infrastructure and an entirely new gas transmission and distribution infrastructure along with the replacement of all appliances. If heat pumps can be used this factor for those loads becomes 12 times instead of three times.

For all of these reasons neat hydrogen does not improve the financial viability of the gas distribution network either, notably this was the main driver for considering this activity.

3.3 Hydrogen for road transport

The authors would observe that first principle analysis has most likely been carried out in the automotive industry, as with few exceptions, they arrive at similar conclusions to Dr Bossel; that battery technology is a superior choice than the hydrogen/fuel cell alternative. The authors would also observe that the combined engineering and science resources of the automotive industry are very large and there would no doubt have been extensive and thorough investigations undertaken before arriving at the decisions that have led to the chosen pathway (BEVs).

The hydrogen projects, it has continued with, are small scale. Furthermore nothing to date has led to mass produced fuel cell vehicles, while the number of BEVs is growing rapidly. If there are concerns about rolling out re-charge points for BEVs, then it should be recognised that a hydrogen bowser would probably cost 10-times more than a fast recharge point. Added to that; are the logistic and safety issues of supplying hydrogen to these hydrogen refueling sites. Decanting of the hydrogen from the delivery will require the use of compressors and cooling of the gas to -20 to -40˚C to protect the receiving vessel from the compression generated heat [14,24]. Finally, vehicles fitted with cylinders containing hydrogen at 70 to 90 MPa (700 to 900 times the atmospheric pressure) [24] is surely a discomforting factor. For comparison, this is about ten times the maximum pressure in a typical natural gas transmission pipeline! These are also laid in controlled environments and pipeline corridors.

3.3 Conclusions

This is an area where the market has made wide ranging decisions that are heavily in favour of BEV's rather than the hydrogen/fuel cell alternative.

The use of batteries is approximately 3 times more efficient than that of hydrogen in terms of utilisation of the originally produced renewable energy. The use of ammonia as a fuel for internal combustion engines in vehicular transport, apart from other considerations, similarly cannot match batteries in terms of efficiency.

The electricity networks would likely need various kinds of upgrading to accommodate the transportation load.

3.3 Recommendations

The current evidence indicates that the use of hydrogen in motor vehicle applications is unlikely to be successful and gain wide acceptance compared to BEVs.

Wide spread use of BEVs means the upgrades for the transportation and gas substitution could and should run simultaneously. This is particular applicable to Victoria.

4) Exaggerated techniques and unsubstantiated statements

There have been a number of claims and proposals that have been put forward and also in the media reports of intended projects that require significant evaluation at desk top level before consideration of is given to proceeding to physical trials and demonstration projects.

In this context the production of a quantity of hot water has been calculated and comparisons are made between gas and electricity and how the electricity has been derived. Please refer to Section 1.3 and Appendix A.

4.1 Questionable claims of high efficiencies and hydrogen applications that have merit

The proponents of the hydrogen economy often argue that new technologies will substantially improve efficiencies. In fact, in many cases, the efficiencies of current technologies in the **individual** process steps (that combined provide the entire energy cycle) are already quite mature and it follows there would be limited room for improvement. In any case there are no foreseeable technological breakthroughs that would sufficiently change the overall very low efficiencies of the various hydrogen processes. These matters are dictated by the laws of physics and cannot be changed by legislation, investment or wishful thinking. The problem (as Dr Bossel correctly pointed out) is the inefficiencies are cumulative and therefore the fractions for each of the individual steps in the "hydrogen chain" have to be multiplied together. The reality for fuel cell generated electricity, when accounting for all process steps (electrolyser, compression and transport, storage of hydrogen and finally fuel cell efficiency, becomes something like: 0.6*0.8*0.5=0.24 or 24%. Proponents may argue that **each** individual step in the hydrogen economy is highly or at least reasonably efficient and there is some truth in that. **Each** of these (electrolyser and fuel cell) processes are indeed generally more efficient than their practical heat engine equivalent.

However, the main issue with the hydrogen economy, as Dr Bossel pointed out, is that all of these losses are cumulative and that is where "hydrogen solutions" suffer from inefficiency compared to battery or pumped hydro alternatives.

Dr Fiona Beck articulated similar observations during a recent podcast [5]. She pointed out that where industrial processes require heat, which traditionally has been provided by the use of fossil fuels (in applications such as glass making, steel production etc), that hydrogen can and should generally be used. However domestic and commercial applications require only low levels of heat and therefore do not fall into this category. It is her views that applications which cannot be electrified are the areas where hydrogen can be used advantageously, which the author fully agrees with.

4.1 conclusions

- Hydrogen combustion is unable to match the efficiency of using the electricity even with resistive heating and should be limited to industrial processes requiring high levels of heat. It will also continue to find application as a feedstock. While it might seem counterintuitive, if hydrogen is needed in particular applications, it is better produced from imported renewable energy at location where it is to be used, rather than transported from a remote production site in liquid or compressed forms.
- Despite proponents setting out the supposed advantages of hydrogen in many applications, the robustness and viability remains far from proven.
- Desktop analysis can prove the efficiency of the hydrogen cycle to be substantially lower than direct electricity used in the same application.

4.1 Recommendations

- In cases where hydrogen is required, it should, if practical, be produced on-site. From renewable electricity. Electrical energy storage by alternative means such as hydro, pumped hydro, or batteries is a preferred option to hydrogen.
- Industrial processes that require ammonia, or where ammonia can be used for such processes, trigger different considerations. As ammonia presents fewer issues with storage in liquid form than hydrogen, there is more scope for remote production. Therefore it can be more readily shipped from countries that have an abundance of renewable energy.

4.2 Use of underground caverns for storing hydrogen gas

Cornelis de Groot recently noticed an article in the engineering magazine: “De Ingenieur” from June 2021 (engineering magazine in the Netherlands). It promotes the use of salt caverns and or depleted gas field (such as Slochteren) to store hydrogen under high pressure. Hydrogen produced from renewables through electrolysis is generally considered very pure and suitable for use in fuel cells. If hydrogen were to be stored in such an environment it predictably becomes contaminated (typically substantially with hydrogen sulphide, bacteria and methane) and would need significant (and costly) processing before it could be used in fuel cells. In addition the type of contamination would vary greatly from location to location and, furthermore, the risk of an escape resulting in a vapour cloud explosions cannot be discounted. A link of a paper that discusses these issues in more detail is included in Section 6 [25]:

Another concern is seepage/leakage of hydrogen. The gas fields in Slochteren are mostly onshore. The province of Groningen has suffered significant subsidence in some locations 0.3 metres. Hydrogen escapes confinement much more readily than other gases, and in addition the recoverability of hydrogen stored may be low, detracting from the already low overall efficiency of the process.

4.2 conclusions

- As per section 4.1 the use of hydrogen should be limited to industrial processes only. In combination with producing hydrogen from imported electrical energy and so avoid the need large scale hydrogen storage.
- Hydrogen storage in underground caverns and depleted gas fields is not likely to be viable.
- Such underground storage is potentially unsafe; a major escape could result in a large vapour cloud explosion, which may be unprecedented in magnitude and strength for this kind of explosion.
- The hydrogen recovered is likely to be highly contaminated and would need extensive processing before it can be used in industrial processes and fuel cells. Seepage of hydrogen from such storage systems is environmentally unacceptable both as an (indirect) greenhouse gas and in that it further detracts from an already very inefficient process.
- Despite proponents setting out the advantages of such applications the robustness and viability remains far from proven.

4.2 Recommendations

- Unless safety and practicality of hydrogen storage at high pressure in underground caverns can be demonstrated at a small scale, a large scale trial should not be attempted.

4.3 Reusing existing gas transmission and distribution networks and transitioning

Owners of gas infrastructure will face a decline in the value of their assets. They would seem to advocate that hydrogen allows them to extend the life of their assets. As has been pointed out in section 3.1, blending with hydrogen is a very inefficient use of renewable energy and introduces potential issues with appliances.

If the blending ratio is increased these issues and cost only increase. When blending beyond 30-50% hydrogen; the capacity of the networks becomes much reduced. At higher rates approaching neat hydrogen a great many (apparently unforeseen) safety and other disadvantageous issues begin to emerge.

For gas transmission networks the issues are generally even starker because these pipelines are generally not tolerant of any free hydrogen, much less towards blends of 10% and higher. Also the required compression power increases greatly, requiring major upgrades to compressor stations and more renewable energy to drive the compressors harder.

In light of these impediments it is **un**reasonable to suggest that existing hydrocarbon based infrastructure can be seamlessly converted to deliver energy at a comparable rate with hydrogen. This applies to blended and neat hydrogen networks. In addition there are numerous safety issues described above in Section 3.2

The best use of the existing gas infrastructure may be to continue the supply (a slowly declining volume of) undiluted natural gas until the renewable energy and electrical infrastructure is built. This may take many years.

4.3 conclusions

- The bulk of the existing gas transmission infrastructure would be unsuitable for a conversion to hydrogen because of a three-fold reduction of energy flow capacity at design velocities (due to hydrogen's uniquely low volumetric energy density), and the possible de-rating of MAOP would reduce the capacity even further. In addition, existing gas transmission pipelines are mostly subject to metallurgical impediments, and as a consequence of those, limitations in fluctuating operating pressures also apply. Finally the compression equipment typically is based on centrifugal machines that require re-wheeling and hydrogen requires significantly more compression energy at equal energy flows. A major upgrade of the compressors and their drivers may be required.
- The bulk of existing gas distribution facilities would also suffer from significantly reduced capacity to distribute the required energy flow. Also there is a significant possibility that MAOPs may have to be reduced. This is in addition to the numerous safety issues noted earlier.
- From the above, it appears likely that the use of hydrogen as a replacement for natural gas is unlikely to be viable.

4.3 Recommendations

- Transition to an as much as possible an all-electric society fueled by renewable energy sources seems inevitable if greenhouse gas targets are to be met. A hydrogen supply infrastructure will be required only where hydrogen is required for unique processes and it be made at locations where needed.

4.4 Use of line pack as storage

Some major documents such as CSRIO's National Hydrogen Roadmap [1] advocate the use of line pack in existing gas transmission pipelines as a means of hydrogen storage. In certain specific pipelines that may be possible. However it would seem in most cases that metallurgical issues would be incompatible with the required pressure excursions. Furthermore, even if the pipeline was capable of storing hydrogen at the same, high pressure as the natural gas, the energy stored would be approximately only 33% of that achievable with natural gas.

Despite numerous experts and reports state that metallurgical issues limit the use of existing gas transmission pipelines, these pipelines still seem to be considered in the dispatchable infrastructure as if they were suitable for use with hydrogen blends or even neat hydrogen also for line packing. The author is puzzled by this apparent perseverance; it raises concerns about possible future major incidents that may come from sudden pipeline containment failures. Another very important consideration is that a pipeline made of a material susceptible to hydrogen embrittlement, is not only going to be affected at the point of failure, but also the entire pipeline may have to be abandoned. This could be extremely disruptive to an economy.

4.4 conclusions

- If hydrogen is blended then any line pack is still **predominantly** in the form of natural gas and as pointed out before means that the actual stored hydrogen is **insignificant**.
- Pipelines that are unsuitable for use of hydrogen blends or neat hydrogen should not be used for that purpose as it may lead to very significant safety issues. It was noted that one suggestion to slowdown the deterioration of the pipeline (from hydrogen embrittlement) could be achieved by keeping the pressure steady, that of course would mean line pack cannot be materialised as access to that storage cannot be materialised due to the requirement of keeping pressures constant.
- Claims of line pack hydrogen storage opportunities in existing pipelines are exaggerated and given the pipeline properties and resulting safety considerations are not considered viable.
- It is expected that the vast majority of existing transmission pipelines are unsuitable for hydrogen blending and or neat hydrogen.
- Even pipelines that are suitable for hydrogen can notionally only store 1/3 of the energy of natural gas, due to the low volumetric energy density of hydrogen.

4.4 Recommendations

- Claims of line pack hydrogen storage opportunities in existing pipelines would seem exaggerated and given the pipeline properties and resulting safety considerations considered not viable.
- Despite the above, a stock take should be made which pipelines may be suitable for use of hydrogen blends and neat hydrogen. This allows some quantification of the potential

for storage and adequacy in the new energy economy. This may present some scope in transporting hydrogen for a subset of process heat applications.

4.5 Morphing natural gas or blended networks into neat hydrogen networks and conversion issues.

Apart from the energy efficiency issues (that seriously affect the viability of producing hydrogen and then burning it in gas appliances, as opposed to using electricity directly in electrical appliances, see also Section 1.3 and 4.1), the use of a gas like neat hydrogen in gas distribution networks is unprecedented and brings many unfavourable issues (as reported before in section 3.2).

Some people further seem to suggest that blending ratios of gas in networks can by steadily increased to a point they become neat hydrogen networks. Such is entirely incorrect and moving from a blend of, say, 10% to neat hydrogen requires a major conversion and involves new appliances, often new consumer installations and additional infrastructure.

CSRIO's National Hydrogen Roadmap [1-] on page 48 advocates the use legislation and government support to achieve a conversion to hydrogen. In the longer term such move is expected to be more expensive than compensating the loss of value of the infrastructure to its owners.

Recommending the force of legislation changes, as advocated in CSRIO's paper, does not seem consistent with allowing market forces to prevail, which is the frequently expressed position of political leaders and industry expert.

4.5 conclusions

- Converting existing networks into neat hydrogen networks is unprecedented and involves many potentially dangerous scenarios and does not contribute efficiently (if at all) to meeting reduced greenhouse gas emission targets.

4.5 Recommendations

Conversion of existing gas distribution networks to neat hydrogen, or the construction of new hydrogen gas distribution networks does not appear viable or in the interests of achieving the best environmental outcome. It should be assessed by a panel of highly qualified and disinterested engineers and scientists before proceeding.

4.6 Various pieces of mis-information

Proponents of the “hydrogen economy” state that hydrogen is a natural fuel and is the most abundant element in the universe. While it is indeed the most abundant element in the universe (and is the fuel that powers the sun), that fact is irrelevant to the current question. It does not occur in a free state on earth, other than at low concentrations in the atmosphere and in some natural gases etc. On this planet it is a man-made “energy carrier”. Free hydrogen in any significant concentrations in an oxygen rich atmosphere is generally incompatible with the principles of chemical equilibrium. In the upper atmosphere free hydrogen does exist at low levels where it reacts with hydroxyl free radicals (OH). These OH radicals are then unavailable to “clean up” methane and other greenhouse gases and hence hydrogen acts as an indirect greenhouse gas [6]. It follows that hydrogen in the context of the current debate is an energy “carrier”.

5) Various considerations of replacing natural gas for low temperature heat applications

This section collates various observations and reflects on relevant conclusions made in Section 3 in the context of this submission to Infrastructure Victoria. In relation to the gas sector the Victorian Gas Substitution Roadmap does not contain the same level of discussion points as the National Hydrogen Roadmap. For that reason significant references are made to the latter. The author has formed the opinion that the National Hydrogen Roadmap overstates the benefits of hydrogen as a replacement of natural gas for low temperature heat applications (residential, commercial and possibly significant parts of industrial applications).

5.1 Electrification to be considered in a wider context; i.e. along with electric vehicles

In the National Hydrogen Roadmap [1] page 49 the CSIRO flags that, despite bringing up numerous arguments in favour of maintaining the gas networks, conversion to an "all electric" society may be more feasible in Australia than in the UK. That would seem to have been concluded in the context the electricity networks needed to be solely upgraded for accommodating the residential and commercial gas loads. However those electricity networks would be expected in need for upgrading to accommodate charging of electric vehicles, and when such upgrade is considered the incremental cost (to also upgrade the electricity networks for electrification of the gas loads) may become much less significant, if not insignificant.

5.2 Electrification to be considered in a wider context, to address the limited suitability of existing networks to transport hydrogen

The National Hydrogen Roadmap would seem to base its conclusion on the fact that the current gas network infrastructure can in fact be converted to hydrogen and supply the same heating load. At desktop level as pointed out in Sections 4.2, 4.3 and 4.4 that is unlikely the case, unless credible and practical findings convincingly dispute these multiple findings that run counter to these desktop generated findings derived from first principles. Section 3 points out that blending of hydrogen is also quite impractical and such activity does not materially reduce the CO_2 discharge from the energy supplied through natural gas networks. If anything, the renewable energy, allocated for the purpose of blending, instead be fed directly into the electricity network would reduce that CO_2 output by a significantly greater amount.

5.3 Extra renewable Energy Infrastructure

Section 1.3 shows the multipliers of extra renewable energy infrastructure needed if the energy currently supplied by natural gas networks was supplied through hydrogen networks in comparison to an electricity solution even when using a resistive heating element. These multipliers typically translate to a factor of close to three times more than the supplies needed for supplying such loads through electrification. Evidence if this issue was indeed considered could not be found in CSIRIO's National Hydrogen Roadmap. Likewise it did not elaborate which party would pay for that extra renewable energy plant needed to sustain the various hydrogen solutions.

5.4 Energy storage with hydrogen

Since the volumetric energy density of hydrogen is uniquely low, it would not be adequate to rely on line pack in transmission lines (even not after all transmission lines were replaced with materials tolerant to hydrogen). Therefore hydrogen would need to be stored in liquid form to overcome the cyclic nature of supplies from renewables; this has been factored into the efficiency calculations of Section 1.3. It should be noted that storing of such vast quantities of liquid hydrogen is also unprecedented.

5.5 Cyclic nature of renewable energy sources, impact on hydrogen production?

It is a well-established fact that outputs from renewable energy sources are highly cyclic and therefore output fluctuations must be accommodated. It is understood that, with specific battery technologies, charging does not have to be continuous and therefore can accommodate such fluctuations. Likewise with pumped hydro, pump operations can be arranged to follow the fluctuating output and still fill the storage reservoirs at optimised rates.

The National Hydrogen Roadmap [1] does not comment and the author of this submission does not know if electrolysers and or liquefaction processes can tolerate these power fluctuations. If hydrogen plant designers would opt to smooth out such fluctuations of renewable input power with batteries, or pumped hydro then it brings up an interesting consideration. Such “electricity” storage mechanism if sufficient for such need (with a three times higher energy transfer needed than that for direct electrification) it would therefore be more than adequate for direct electrification, thus removing the entire purposefulness of the hydrogen cycles for residential and commercials gas uses. This aspect would need to be reviewed and the outcome disclosed for further consideration.

5.6 Cyclic nature of renewable energy sources, no impact on hydrogen production extra equipment?

If hydrogen production with electrolysers and liquefaction are not affected by such output cycles, then it is expected that (like the renewable energy supplies) the installed capacity of electrolysers and liquefaction equipment to be also three times larger than had this gas load been supplied from electricity (that was backed up by batteries and or pumped hydro).

The National Hydrogen Roadmap [1] does not comment and the author of this submission does not know if electrolysers and or liquefaction processes have been scaled up for to accommodate such typical input power fluctuations. Likewise the author questions the capital costings for these installations and how they have been factored into the various models. This aspect would need to be reviewed and the outcome disclosed for further consideration.

5.7 Further questions about the viability of gas networks

If the issues brought up in Sections 5.5 and 5.6 are further considered and costed such costs should be considered in reviewing the long-term viability of gas networks. This is along with the author's anticipation that the entire gas infrastructure (gas distribution and gas transmission) would need to be replaced if it were to transport hydrogen. When such costs are viewed in the context with the lower incremental cost to upgrade the electricity networks (expected to be upgraded to accommodate electric vehicles in any case); the author further questions the viability and merit of hydrogen gas network infrastructure.

5.8 Hydrogen around the house and subsidy on certain gas appliance replacements only

If hydrogen is introduced by first blending upwards of 10%, and later in neat form; then it is likely that in the first instance the appliances need to replaced and in the second phase both the consumer installations and appliances need to be changed. Dual fuel appliances are not expected to be viable, neither the use of appliances indoors (for safety reasons). Hydrogen appliances would likely require significantly more expensive safety features than current natural gas appliances. In comparison resistive heating appliances are already cheaper than their natural gas counter parts. Electric heat pump appliances are already extensively used for space heating and their cost for water heating is also expected to come down to become on par with the current pricing for natural gas appliances.

In that context it is of concern that on page 48 (in the National Hydrogen Roadmap) for subsidising new (hydrogen) a suggestion is made that the replacement of gas appliances be funded by government. Whether a hydrogen pathway is selected (which may require changing the appliances twice) or an electrification pathway instead is opted for; such subsidies should be across the board and not favour a specific commercial interest. Such move would have a tendency to skew the overall economics. One sided subsidies could also be seen as another form of subsidy to the gas industry aiming to convert to hydrogen.

5.9 Reduced gas loads and applications

It would not be expected that hydrogen gas would be used to make electricity in the context of electricity network power generation. It is understood that current gas use for power generation represents 17% (refer interim report) in Victoria. That load is expected to disappear as this would be supplied directly from renewables, and perhaps by for example by pumped hydro for management of peaking and fluctuations.

The remaining, industrial loads that are currently supplied by natural gas could then be provided by hydrogen produced from electricity supplies at the locations where these hydrogen supplies are needed. That would also alleviate the practical difficulties of transporting and storing hydrogen safely, economically and efficiently. There are major environmental benefits in this approach because this method provides the lowest environmental impact of producing and delivering hydrogen.

5.10 Gradual transfer away from natural gas and compensating current industry participants

Regardless which option is pursued, the current natural gas infrastructure will need to be abandoned (100% if an electrical solution is used and more than likely in most part if a hydrogen solution is applied refer Section 5.7). The natural gas infrastructure is expected to be conforming to current Regulations. Any transfer will require amended Regulations (and or Acts). As has occurred elsewhere, business owners disadvantaged by changes in legislation may receive a level of compensation for their losses, in this case the reduced life of gas infrastructure assets.

As that compensation would be required regardless the direction of transfer, it would greatly advance the case for electrification from an economic stand point, even more so when the upgrade of the electricity networks (to accommodate the gas load) is only incremental and this increment can be further reduced by factors elaborated in Section 5.11. Furthermore the efficiency gains made by not using hydrogen cycles also reduce the otherwise required renewable energy capacity by a very significant magnitude.

5.11 Further reduction of the gas load when transferred to the electricity networks

As explained elsewhere the efficiency of gas appliances is in the order of 70%. Therefore if these applications would be supplied by electricity using resistive heating (which has a nearly 100% efficiency) the electrical load increase would only be 70% of the gas load. However as most space heating would be replaced by heat pumps and consumers would most likely also replace their hotwater gas appliances with Solar or heat pumps further reductions are more than likely. Some of the following data has been obtained from the Victorian Gas Substitution Roadmap [23]. If 74% of the residential gas load is space heating [23] then it would be expected to be reduced to an electrical load of (heat pump COP of 3) by 0.74*0.7*0.33=0.17 or 17%. Likewise if 24% of the gas load is some form of low temperature level water heating that too would lead to the same result or 5.5%. That means 98% of the residential gas load may only lead to 22.5% of the gas energy load onto the electricity network and with the remainder staying resistive it follows that the increase is 22.5%+2%=24.5% of that load onto the electricity network. Given the expected higher capacity of the electricity networks this then becomes an incremental load only especially in the context of the increased loads on the electricity networks from vehicle charging. In large parts these increases would be also offset by consumers' own PV systems more commonly backed up by batteries.

5.12 Staged transfer during which natural gas is continued to be supplied

It will take considerable time to build the additional renewable energy supplies and pumped hydro, storage batteries and possibly thermal solar plants. Furthermore the electricity networks need to be reinforced (also to accommodate electric vehicles). When areas are completed the customers need to be switched across to "all electric" homes and businesses. That process would lead to a gradual reduction and eventual abandoning of the current gas network infrastructure. Industrial customers requiring high temperature heat would need to be equipped with facilities to produce their own hydrogen and electricity supplies for the electrolysis.

This entire process is considered to be far less disruptive than multiple conversions of appliances and gas network replacements. Along with the considerably lower renewable electricity supplies entirely due to the vastly higher efficiencies gained with electrical appliances (especially heat pumps) such transfer is also considered far more economical, better for the environment and much safer for all concerned.

Meanwhile new residential and commercial customers should not be added to the networks anymore, in particular for Greenfield developments.

References

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Appendix A

Comparisons between different energy carriers

	200 litres per day, rise from 15 to 60 degrees C as per energy labelling				
Base case, electric water heater, battery or long power line transmission					
Model	4A1250				
Electric heater thermal efficiency		eff=		1	
200 litre per day of a rise of 45 degrees C using 4.2 (kJ/kg.K)		E is		37800000	J
3.6 kW 0r	12.96 MJ/hr	T =		2.9166667	hr
Modified $E_{electrical}$ =	100% efficiency and minimal standing losses			37800000	J
				37.8	MJ
Battery charge and discharge or pumped hydro eff			85%	0.85	
Nil losses shipping intercontinental			100%	1	
Conventional Transmission and distribution			97%	0.97	
Overall efficiency				0.8245	
Renewable energy input	Base Case			**45845967**	J
				45.84	MJ
desal	3.0 kw/m^3	energy needed 0.027	kw/kg h_2		

Electric water heater hydrogen fuel source for electricity generation

Model	4A1250						
Electric heater thermal efficiency		eff=		1			
200 litre per day of a rise of 45 degrees C		E is		37800000	J		
3.6 kW 0r	12.96 MJ/hr	T =		2.916667	hr		

Modified $E_{electrical}$ = 100% efficiency and minimal standing losses 37800000 J

		kw input based on 1 kg @54 kw/kg				
Electroliser efficiency		60%	0.75	40.5	54	kWh
Penalty to produce clean water from desal 5%		3.0 kw/m^3	for 9 kg water		0.27	kWh
Liquefaction		70%	0.7		12.15	kWh
Gross input					66.42	kWh
Nil losses shipping		100%	1	40.5		
decanting and pressurisation	6%	90%	0.9	36.45		
Producing electricity at location in power station		60%	0.6	21.87		
Conventional Transmission and distribution		97%	0.97	21.2139		
Overall efficiency				**0.32**		
Renewable input energy required				118350515	118	MJ

Multiplier from Base Case **2.6**

Electric water heater ammonia fuel source for electricity generation

Model 4A1250						
Electric heater thermal efficiency		eff=	1			
200 litre per day of a rise of 45 degrees C		E is	37800000	J		
3.6 kW 0r 12.96 MJ/hr		T =	2.916667	hr		
Modified $E_{electrical}$ =		100% efficiency and minimal standing losses		37800000	J	
		kw input based on 1 kg @54 kw/kg				
Electroliser efficiency		75%	0.75	40.5	54	kWh
Penalty to produce clean water from desal 5%		3.0 kw/m^3	for 9 kg water		0.27	kWh
Producing ammonia		10 kwh/kgh2			10	kWh
Nil losses shipping		100%	1	40.5	64.27	kWh
decanting and pressurisation	3%	87%	0.87	35.235		
Producing electricity at location in power station		60%	0.6	21.141		
Conventional Transmission and distribution		95%	0.95	19.0269		
Overall efficiency			**0.30**			
Renewable input energy required			1.28E+08		128	MJ
Multiplier from Base Case				**2.8**		

Gas HWS, running on hydrogen gas

model 850265

Gas heater thermal efficiency for 5 star is 70%		eff=		0.7			
200 litre per day of a rise of 45 degrees C		E is		37800000	J		
At 30 MJ/h	model 850265	T =		1.482353	hr		

Add 10% standing losses due to partial insulation in comparison to full insulation for electric per 24 hour

Modified E_{gas} =	effect of 70 % and 10% standing losses			60000000	J		
		kw input based on 1 kg @54 kw/kg					
Electrolyser efficiency		75%	0.75		40.5	54	kWh
Penalty to produce clean water from desal 5%		3.0 kw/m^3	for 9 kg water			0.27	kWh
Liquefaction		70%	0.7			12.15	kWh
Nil losses shipping		100%	1		40.5	66.42	kWh
Gas transmission		90%	0.9		36.45		
decanting and pressurisation	10%	90%	0.9		32.805		
extra loss due to higher latent heat compared to NG		94%	0.94		30.8367		
Overall efficiency					**0.46**		
Renewable input energy required					129235619	129	MJ
Multiplier from Base Case					**2.8**		

Electric heat pump water heater, battery or long power line transmission

Model	HDc-270				
Electric heater thermal efficiency		eff=	1		
200 litre per day of a rise of 45 degrees C		E is	37800000	J	
3.6 kW 0r	12.96 MJ/hr	T =	2.916667	hr	

Modified $E_{lectrical}$ =	5% standing losses			39789474	J	
COP				4.5		
Battery charge and discharge eff			85%	0.85		
Nil losses shipping			100%	1		
Conventional Transmission and distribution			95%	0.95		
Overall efficiency				0.8075		
COP				4.5		
Renewable energy input		Actual input into motor		**10949976**	10.9	MJ
Multiplier from Base Case				**0.24**		