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Technical and Commercial Review of Infrastructure Victoria's Gas Infrastructure Interim Report

Energy Networks Australia

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1 Introduction

GPA Engineering (GPA) has been engaged by Energy Networks Australia (ENA) to provide a technical and commercial review of Infrastructure Victoria's interim report, *Toward 2050: Gas infrastructure in a zero emissions economy* ("the Report"). The review in this report compiles feedback from senior staff at GPA Engineering from a range of disciplines, who are listed in Appendix 1.

Achieving net-zero carbon emissions requires decarbonisation across the whole economy and primarily the energy sector, which is currently responsible for transferring large volumes of carbon from fossil fuel sources into the atmosphere. More than 70% of Victoria's energy demand is provided by coal and oil. Furthermore, most energy is not used in the form of electricity, but is directly consumed by the manufacturing and transport sectors. About 20% is provided by natural gas, which is primarily used for residential heating. Only 5% of Victoria's energy demand is currently met by renewable sources (2019 data from DISER).

As identified by the Report and the underlying modelling, multiple technologies may contribute to achieve a net-zero emissions economy. These include increasing the uptake of renewable energy, electrification, batteries, hydrogen as an energy store and carrier, bio-fuels as a carbon-neutral fuel source, and carbon capture and storage (CCS).

The last three of these require gas handling; hence, they can potentially utilise existing infrastructure and could even support new gas infrastructure in some scenarios (such as new parallel hydrogen infrastructure, or new gas-fired generation for firming). Though the Report identifies this potential, it is pessimistic about the ongoing utility of Victorian gas infrastructure, describing it as ageing and incompatible with hydrogen.

The main output from our technical review is that these conclusions are misleading and erroneous; additional and more detailed information would be necessary to achieve the stated goal of "identifying the infrastructure decisions that need to be made" (page 8). Specifically, a review that distinguishes different categories of infrastructure and takes a more accurate view of their utility and remaining life is needed to identify what role they could play in uptake of hydrogen, biogas, or CCS. A valuable outcome of this assessment could be recommendations for "future-proofing" of new infrastructure for potential decarbonisation pathways (e.g. making new suburbs hydrogen-ready, or new gas production CCS-ready). The Report also oversimplifies commercial and economic considerations, making significant assumptions about demand and supply projections, and not effectively assessing cost. A transition that compromises the economics of existing energy supply infrastructure could lead to a cascading withdrawal from the market, as has been seen with coal-fired power-plants that closed before their end of design life.

The Report does not address the commercial arrangements and markets that underpin the ongoing operation and investment in Victoria's existing gas infrastructure. In our opinion, understanding the long-term contracts, how gas is traded, how Victoria's gas markets work and their effects on operation, pricing and investment is of central importance to assessing the implications of the four scenarios listed. Also essential is defining the sources of renewable energy that are going to account for a more than 20-fold increase in renewable output for electrification. To achieve this, Victoria cannot be considered as an island; Victoria is most likely to be a net importer, and the Victorian energy market will remain part of an interconnected east coast energy market in a country that currently exports more than twice as much energy as it uses.

Some potential future decarbonisation pathways have not been addressed in the report, and yet may play a role in Victoria's energy future. From a policy perspective, potential establishment of a carbon price has not been considered. Additionally, a range of low TRL technologies exist and are being explored by researchers and industry; these include dense hydrogen-based synthetic fuels (such as ammonia, methane/syn-gas and methanol, MCH or LOHCs), carbon utilisation technologies and other biofuels (other than biogas). A consideration of these and their impact on existing infrastructure and markets would also benefit the study.

The following report summarises GPA's feedback on the interim Report, identifying areas that we consider will benefit from clarification or, in some instances, correction.

2 Technical Review

2.1 Victoria’s Gas Infrastructure

2.1.1 The various types of infrastructure are conflated

Most of the Report does not clearly distinguish between different categories of infrastructure, which limits the granularity of the recommendations and analysis. With the exception of Table 4 (refer Section 2.1.3) it is referred to as ‘gas infrastructure’ throughout the Report.

In reality the different categories of gas infrastructure will each be impacted differently by an energy transition. Broadly, these are:

- Production infrastructure—such as wells and flow-lines
- Processing infrastructure—such as gas treatment facilities
- Storage infrastructure—such as storage reservoirs, LNG tanks, and storage pipelines
- Transmission infrastructure—such as compressors and pipelines
- Distribution infrastructure—such as low-pressure pipelines and customer connections
- Customer infrastructure and appliances—which includes:
  - Residential,
  - Commercial,
  - Industrial, and
  - Gas-powered electricity generators.

A result of this generalisation is that sweeping conclusions are often made about the usability of Victoria’s gas infrastructure. For example, Section 4.1.5 (**IV Report pg. 16**) states that ‘further expansion of gas infrastructure may increase the risk of some infrastructure becoming underutilised or… stranded’. Such conclusions will not apply equally to the different gas infrastructure categories. GPA has used these distinctions in the feedback in this report.

2.1.2 Design life of assets can extend up to 100 years

The Report advises that Victorian infrastructure is approaching end-of-life, repeatedly stated as being 40 years (**IV Report pgs. 5, 11, 31**). In reality the achievable life for most categories of gas infrastructure exceeds the design life, and the Report consequently draws incorrect conclusions about the remaining utility of Victoria’s infrastructure.

Production infrastructure assets are diverse and include upstream and raw gas pipelines. As a result the service life for production assets is more varied. Assets upstream of gas processing can be vulnerable to a range of internal corrosion threats and consequently have a limited life. To combat this such assets commonly have a reduced design-life as they are only expected to be used over the gas reservoir’s lifetime. Even so, some upstream assets may have potential to be reversed and used for gas storage, or carbon capture and storage, in the future while still maintaining a reasonable service life suitable for that application.

Transmissions infrastructure assets are typically high pressure licensed (metal) pipelines. Most of these metal assets have a significant effective life as they are monitored and protected from deterioration. The Report highlights old infrastructure, citing specifically that it is 'over 40 years old' (**IV Report pg. 5**). A useful summary of Victorian pipeline licenses can be found in the Australian Pipelines and Gas Association (APGA) Members Directory[1], though that list also includes production and liquid fuel assets.

Unless the pipelines have an integrity problem that is causing un-preventable deterioration such that the cost of maintenance is becoming uneconomic, they may be subject to a life extension and continued use. If they do have integrity issues, they may also be re-rated rather than retired. It is common to expect pipelines to have a real service life in excess of 100 years. In particular any pipelines built since the early '90s (conservative estimate) are likely to have good coating properties that will permit their operation indefinitely into the future.

Distribution infrastructure assets are typically low pressure networks constructed out of plastic. Plastic assets degrade gradually under stress and are designed using a 'linear regression' approach. In practice, however, the lower operating pressures used in the distribution sector significantly extends their expected life time up to around 100 years.

Anecdotally, most plastic assets in the Victorian distribution sector are less than about 30 years old; recent renewal programmes in the distribution sector have replaced older metal assets with plastic. Most lines built in the 1930s, '40s and '50s have been replaced—some of the replaced lines were built in the 1800s, giving an indication of the real service life that is commonly achieved. It is therefore expected that significantly less than half of the distribution network would be more than 30 years old.

Some of the low pressure distribution networks are also constructed out of metal pipe. A small proportion of these assets have inadequate corrosion protection which will consequently deteriorate over time. These assets, however, have been prioritised for replacement in past and ongoing renewal programmes.

2.1.3 Decarbonisation impacts on Victorian infrastructure

Table 4 of the Report provides a summary of decarbonisation pathways and impacts on gas infrastructure. GPA considered this table to be considerably flawed and ambiguous, and it did not match the discussion in the rest of the document. Additional comments on Table 4 of the report (**IV Report Table 4, pg. 35**) are attached in Appendix 2.

2.2 Hydrogen

2.2.1 Hydrogen material incompatibility is overstated within the report

The material incompatibility of hydrogen is overstated within the Report, which claims that 'reuse of the existing natural gas network… will be limited beyond the initial transition' due to the 'the potential for hydrogen embrittlement' (**IV Report pg. 31**).

High pressure **transmission and production infrastructure** (i.e. above about 3 MPag[2]) will have varying degrees of hydrogen compatibility between assets. Many pipelines in good condition, made from modern steels, will be compatible in their current form, while some old assets with poor steels may have

[1] 30th edition APGA Member Directory 2021, published by Great Southern Press

[2] A pressure of 1.05 MPa is the cut-off for a pipeline being licenced and designed to AS 2885.1. However, most infrastructure below around 3 MPa is also designed with low design factors and hence similar low risk profiles.

issues due to low toughness. Most of the oldest lines in Australia are from the 1970s or a little earlier (aside from a handful of exceptions). At that time the international industry was still learning about fracture toughness in the wake of some fracture propagation incidents the USA. Some of those early generation pipelines consequently have inferior properties, however it is also true that many of these pipelines have a low design factor (i.e. excess wall thickness compared to modern requirements). APA Group for example are currently investigating the conversion of part of the Parmelia Gas Pipeline in WA. This pipeline was built in the 1970s, demonstrating that these pipelines cannot be written off for hydrogen application merely because of their age.

This highlights an important concept: *all assets will be hydrogen-incompatible within a determinable operating envelope*. That is, they can be de-rated, rather than demolished.

From a materials perspective, steel fatigue is also an important consideration. The most significant risk hydrogen poses to these pipelines is accelerated fatigue-crack-growth. Fatigue is not caused by the pressure (e.g. the maximum allowable operating pressure—MAOP), but rather the frequency with which the pressure cycles. Pipelines that have higher design factors are likely to have limited capacity for pressure cycling in hydrogen service. This means that they will be useful for hydrogen transport, but may have limited use for hydrogen *storage*[3]. Research is being undertaken to pursue other opportunities to increase the fatigue resistance of pipelines in hydrogen service.

Most **distribution infrastructure** will be hydrogen-compatible due to low application pressures. In fact, some of the low and medium-pressure infrastructure has operated in the past with 'Town gas', which contained hydrogen. Several programmes are being executed by private industry to map hydrogen compatibility across some Australian networks. The expected outcomes are that most distribution infrastructure can be safely converted to either blended or pure hydrogen. All pipe materials will be compatible due to the low pressures and design factors. Some jointing types *may* exhibit higher leak-rates, such as electrofusion joints (in polyethylene) and PVC pipe joints—although this is still an uncertainty. The implications for the distribution infrastructure are expected to be less significant/problematic than the implications for the downstream appliances.

The technical impact of hydrogen on **customer infrastructure and appliances**, otherwise referred to as end users, is also overstated within the Report. The Report implies that the limit for existing pipelines is a blend of 20% hydrogen, with a lower limit of 10% imposed on existing appliances (**IV Report pg. 21**). This statement, however, isn't necessarily true.

A large amount of research is available in this area, and more is still underway, with research currently being conducted by the Australian Hydrogen Centre, the Future Fuels Cooperative Research Centre, and other international organisations. Current research suggests that blending hydrogen up to 10% can be handled by most devices and networks without requiring significant modification or creating unacceptable risk. Pushing this up to 20% may be possible without modifications, although further work and more data is required to validate this claim. Completely transitioning to hydrogen would require most (if not all) appliances to be replaced. This constitutes the most significant barrier for use of pure hydrogen in existing networks.

An important factor that may limit transition pathways is the potential for end users to not support large variations in hydrogen concentration. Once a network is converted to 100% hydrogen it will not be able to operate again with natural gas—there will be a maximum permissible variance. For this reason it is

[3] Storing hydrogen requires cycling the inventory of the pipeline between a "full" pressure and an "empty" pressure. This cycling will contribute to fatigue.

less likely that there will be networks transitioned to intermediate compositions (between 20% and 100%).

The modification of residential appliances on such a scale would require a staged campaign, not an instantaneous conversion. It would require a similar type of activity as that required to achieve wide-spread electrification (modifying everyone's appliances) or improvement in energy efficiency (improving home design, changing appliance types), which are also anticipated in this report.

Most of the available data applies to residential uses and some commercial scale use. The requirements of industrial users are more specific and would require a case-by-case consideration of their potential to change fuel characteristics. Research is also underway in this area (for instance, by the Future Fuels CRC and the new Heavy Industry Low-Carbon Transition (HILT) CRC currently being established).

2.2.2 Conclusions about hydrogen odorising and safety are incorrect

The Report states that 'unlike natural gas, hydrogen cannot be odorised' (**IV Report pg. 21**). Though there is little published data and operational experience, this is incorrect. Hydrogen can be odorised using the same odorants that can be applied to natural gas. The main limitation is that they currently cannot be used in hydrogen fuel cells as the odorant will damage the cells. Other appliances that combust hydrogen (e.g. stove-tops, burners, engines, turbines, etc.) can use odorised hydrogen. A report on this topic was prepared by the National Physics Lab in the UK for the Hy4Heat program, which identified several potential odorants, with one potentially compatible for proton-exchange membrane (PEM) fuel cells.

Despite being able to be odorised, hydrogen still has a different risk profile to that of natural gas. Hydrogen is known to have a higher probability of ignition and a wider flammability range. When it burns its flame emission bands typically lie further in the ultraviolet and infrared regions, resulting in flames that are considerably less visible (often near-invisible in daylight) than those of hydrocarbon flames. Conversely, hydrogen is more buoyant and disperses more rapidly.

Whilst research is still underway on the topic of hydrogen safety, its risk can be managed in much the same way as those of natural gas with generally the same technology. This is particularly relevant for lean hydrogen/natural gas blends (below 20 mol% hydrogen) which are functionally equivalent to pure natural gas from a safety perspective.

2.2.3 Electrolysis requires purified water

The Report defines green hydrogen as 'hydrogen produced with renewable electricity and seawater' (**IV Report pg. 5**). Seawater is not a preferred water source for electrolysis as high purities are required. The use of seawater would limit electrolysis to coastal locations and impose a high necessity for upstream water-purification, increasing energy demands. Seawater use would additionally generate a very high salinity waste stream (from water purification) which would require a disposal solution. The purification required for a good quality water source, however, may instead result in a waste stream that is only marginally more mineral rich and suitable for a range of uses.

If drinking-water scarcity is a genuine problem then modelling ought to be done to identify the quantities of water involved. Further research should also be conducted on the impacts of hydroelectricity on drinking-water availability since the expansion of hydroelectricity, which includes hydro-electric storage, has the potential to lock up significant volumes of water.

2.3 Biogas

Biogas will require the same gas infrastructure as that used to transport natural gas. Importantly, it also uses the same *appliances* as natural gas, which means it is not vulnerable to the most significant barrier facing hydrogen.

The potential for biogas to directly connect to the distribution system at distribution pressures, thereby not requiring compression, is worthy of Infrastructure Victoria's consideration. If the estimate of 48 PJ for biogas production in Victoria is accurate (**IV Report pg. 24**), this could contribute a large proportion of domestic gas consumption—approximately 64 PJ and reducing, based on Deloitte & Access Economics report for ENA—despite only accounting for one quarter of total gas consumption. This would allow a large amount of existing infrastructure to be used without necessitating modification.

Biofuels, including biogas, also reduce emissions and can hence meaningfully contribute to Victoria's net-zero emissions target. It is difficult to conceive of any pathway to net-zero that would not use this resource given the barriers that apply to every other known technology option that can provide dispatchable energy (such as hydrogen, batteries, hydroelectricity, and geothermal). Scenarios that do not use biogas are dismissing that energy source—GPA therefore proposes that scenarios that do not use biomass to generate biogas should alternatively identify how this important feedstock is being used (e.g. liquid biofuels for the transport sector), or the barriers to its utilisation.

We endorse the comment from the Report's Executive Summary that to 'reach the state's interim emissions reduction targets, an immediate scaling up of proven, reliable and relatively low-cost solutions is likely to be required, including… biogas' (**IV Report pg. 5**).

The report correctly references suggestions for regulatory reform relating to the definition of natural gas in some state and national legislation (**IV Report pg. 39**). GPA is of the view that the definition of natural gas in the National Gas Law and elsewhere will generally need amendment for the inclusion of hydrogen in existing gas infrastructure, and is ambiguous in relation to biogas.

2.4 Electrification

2.4.1 Electricity storage is still a problem

The problem of energy storage is known to be a significant barrier to increased penetration of renewable energy sources. The magnitude of this problem in the electrification scenarios (A and B) does not seem to be acknowledged clearly in either the Report or the supporting DORIS report.

For scenario A, the full electrification case, Table 41 of the DORIS report predicts a required battery storage of about 69,503 GWh (250 PJ) and pumped hydro of 34,788 GWh (125 PJ) (**DORIS Report pg. 94**). The report does not make clear if this is the storage capacity or the total amount stored and withdrawn over the year. Given that it is most likely the latter the report then fails to clearly define the required instantaneous capacity; this value is expected to have significant implications on the required infrastructure. The modelling assumptions around electrical energy storage are also simplistic, with requirements set at 24 hours of solar generation for battery energy storage systems (BESS) and 168 hours of wind generation for pumped hydro energy storage (PHES) (**DORIS Report pg. 42**). From our experience, this is likely an overestimation of the storage requirements.

A Grattan Institute report from April 2021, *Go for net zero—A practical plan for reliable, affordable, low-*

emissions electricity[4], focuses primarily on the electricity sector, and makes the following statement:

> Third, the best information today indicates that achieving net zero emissions in the NEM will be most efficient if a small and declining quantity of emissions are offset. The alternative—achieving absolute zero emissions—looks more costly. As the proportion of renewables grows from 90 per cent to 100 per cent, the physical and economic challenge of balancing the system during rare, sustained periods of high demand, low wind, and cloudy skies becomes too big.

The Grattan report highlights that storage requirements increase disproportionately as an increasing fraction of demand is met by renewables. That is, the barriers to achieve 100% renewables penetration are significantly increased compared to achieving even 90% renewable. It provides useful insight to differentiate between the scenarios that have been considered by Infrastructure Victoria.

2.4.2 Hydrogen can be used to store electricity

Infrastructure Victoria's Report discusses the use of hydrogen as a fuel, but doesn't seem to distinctly explore the use of hydrogen as a form of energy storage. As a result the DORIS report almost counterintuitively requires a greater use of batteries in Scenario C than in Scenario A (**Table 78, pg. 167**). It also states that Scenarios A and B require 15% more renewables than Scenario C despite renewable energy being required for the production of green hydrogen (**DORIS Report pg. 167**). Though they may have considered this generation as off grid and consequently ignored it, in practice there will be more wind and solar farms for Scenario C; a portion of this will simply be producing green hydrogen.

Hydrogen made by electricity and returned to electricity is a round-trip electricity storage technology that competes with batteries. It may eventuate that hydrogen is the preferred solution for long-term 'inter-seasonal' storage or 'deep' storage (for several days with no sun/wind). Such an approach may also allow parts of the existing infrastructure to be re-used, most likely in the transmission sector, enabling hydrogen to be used for peaking and for backup generation during high demand or low wind/solar generation periods, though noting technical limitations relating to pipe material fatigue and gas density will limit the storage capacity.

We propose that electrification and green hydrogen should not be viewed as alternatives, but rather complementary solutions. For instance, the DORIS report highlights 'excluding Australia from the hydrogen economy' as a key risk for both electrification scenarios (**DORIS Report pg. 14**). However, green hydrogen will be made from electricity and a full electrification scenario may include excess 'curtailed' electricity that can support a green hydrogen industry.

2.4.3 Electrification does not necessarily lead to decarbonisation

The Report's Executive Summary states 'to reach the state's interim emissions reduction targets, an immediate scaling up of proven, reliable and relatively low-cost solutions is likely to be required, including energy efficiency, electrification and biogas' (**IV Report pg. 5**).

Currently, this is not true. Electrification only contributes to net-zero emissions if the electricity is made by zero- or low-emission energy sources and so electrification must be coupled with increased renewable generation. Victoria's current electricity supply profile is majority brown coal, as observable in the following figures, taken from <https://opennem.org.au> on 9 August 2021.

[4] Available online at <https://grattan.edu.au/report/go-for-net-zero/>

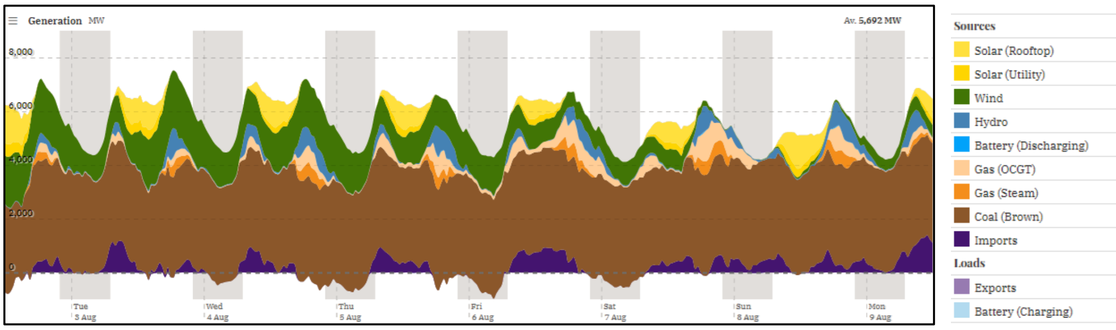

Figure 1—Energy Source Breakdown (daily) for Victoria

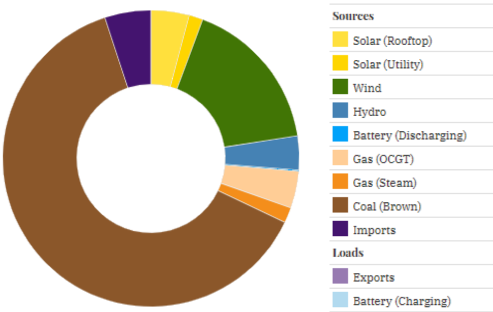

Figure 2—Energy Source Contributions (Victoria)

If immediate measures are taken to increase supply of renewables then it is quite possible, even likely, that a need would emerge in the medium-term for increased gas-powered generation, since gas is readily dispatchable and it can ramp well. Consider, for instance, South Australia's energy mix, which is largely dependent on both gas and renewable energy sources[5]. This is discussed in Table 4 of the report but is not reflected elsewhere.

Electrification is not a pathway to net-zero under the current energy generation mix in Victoria. The immediate scaling-up required is not electrification, but rather building more renewable generation.

2.4.4 Responsive demand has similar benefits to efficiency increases

In several locations the Report discusses increasing efficiency as a 'no regrets' measure to move towards net-zero (**IV Report pg. 3, 36, 40, 43**). Demand response is a similar opportunity that has significant potential to aid electrification, reducing demand at times when there is low supply and hence directly offsetting the needs for peaking and storage. An elastic hydrogen production market (production with significant turn-down) for export or domestic use is one technology that could be used for this purpose. Other demand response mechanisms, at the scale of smart domestic appliances up to industrial demand-response contracts should also be considered.

[5] Note that until electricity is more renewable, emissions from electrification of the gas sector could be increased rather than decreased.

2.5 Decarbonisation

2.5.1 Unproven technologies and technological hurdles

The Report states that 'hydrogen production and use is not yet proven at scale' (**IV Report pg. 5**)[6]. This is true, yet it is also true of multiple technologies. Battery use for long-term and large-scale storage applications is yet to be proven; a number of technical hurdles remain, including design life and rare material requirements. Potential solutions to these issues also have a low technology readiness level (TRL).

Pumped hydroelectricity is the most *proven* technology but is limited by its efficiency and up-take potential (given there are only so many prospective locations). The scenarios in the DORIS report appear to require a significant increase in hydroelectricity.

Hydrogen, on the other hand, has not been scaled, although it is true that the technology itself is demonstrably proven and that pathways for technology improvement—capable of achieving the necessary cost reductions—have been identified. The Report points out that other countries such as the UK, Netherlands and Japan are investing significantly in hydrogen (**IV Report pg. 21**). Despite the actions of other countries having been used elsewhere in the report to support the credibility of other scenarios, for some reason the same isn't done here.

Lastly, the Report also states that, in contrast to saline aquifers, carbon capture and storage (CCS) in depleted oil and gas fields 'has been limited to pilot demonstrations [to date]' (**IV Report pg. 24**). This statement is potentially misleading. GPA understands that the technology is established and well understood as it is effectively used for enhanced oil recovery (EOR) in various locations.

2.5.2 Methane leakage and its significance

The Report touches on fugitive emissions, stating that 'research has suggested the amount of fugitive emissions may be underestimated, meaning that natural gas's contribution to greenhouse gas emissions is potentially more significant' (**IV Report pg. 13**). The reference used to support this claim is a report that focuses on liquefied natural gas (LNG), which then references another two reports which specifically relate to Shale production from USA[7]. This cannot be applied in Australia.

Fugitive emissions are different for different parts of the gas sector. Methane releases from transmission pipelines are very low. There are very few release pathways and infrequent release event; most pipelines are never vented after commissioning.

Releases from upstream operations do occur and will relate to the number of release paths, frequency of venting, and type of processing that is carried out. In Victoria, however, the likelihood is very low where the upstream sector consists of offshore production, which has few leak paths (when compared

[6] Here "proven" is taken to mean an economical technology that has been implemented previously at scale. Most of these technologies are 'proven' in the sense that they already exist and are ready for deployment (TRL = 9).

[7] A more holistic view from the Global Carbon Project, which reports on the earth's atmospheric 'methane budget', indicates that bottom-up estimates of fossil fuel emissions generally exceed top-down estimates, contrary to the paper referenced. As a greenhouse gas, methane is more potent than carbon dioxide, though it also has a shorter half-life in the atmosphere and will be converted to carbon dioxide by natural processes such as lighting storms <https://www.eurekalert.org/news-releases/805414>. In 2007, the levels of methane in the atmosphere actually decreased from the previous year; though it should be made clear that the majority of anthropogenic methane releases are not by the methane industry but from agriculture, and that coal production also releases methane.

to an onshore region like the Cooper Basin with several hundreds of separate wells). Upstream fugitive emissions can be regulated and minimised. For example the EPA will typically manage such releases by regulating that they should be flared (burnt) instead of cold-vented. Australian gas producers also have to report methane emissions and typically have been actively reducing these releases.

Releases from the distribution sector, particularly residential lines and meters, can be more prominent though they release smaller volumes due to the low pressure. Residential gas is also odorised, so users are sensitive to releases. The more 'leaky' technologies also tend to be older and have been increasingly replaced, such as the replacement of ductile iron pipes, which leak at joints due to ground movement, with polymer pipes.

3 Commercial review

3.1 Scenario modelling

3.1.1 Cost assessments are not fit for purpose

Cost is a significant factor in differentiating between the scenarios considered in the report, but in GPA's view, the cost modelling undertaken is in general not adequate for this purpose.

For example, the DORIS report assumes that the 'cost to consumer of home and vehicle upgrades resulting from a switch to hydrogen or electrification is ignored' (**DORIS Report pg. 42**). However, home and appliance upgrades will be one of the single largest costs and most complex changes required due to the number and variety of appliances that will need to be switched over.

The DORIS report also assumes that '…industrial gas users will either retain their own source of natural gas on the transmission lines that exist, or that the cost of upgrading the networks to hydrogen will cover connections to their facilities' (**DORIS Report Table 27, pg. 42**). This assumption does not reflect the reality of gas transmission and its operational and commercial arrangements. Users are typically located near existing pipelines. It would therefore be expected that many industrial users would either shut down or move to where a reliable and cost effective form of energy can be accessed.

Table 4 of the report also takes a false perspective on cost. It refers to "required investment" as a benefit rather than a cost. However, *investment* is a cost and *return on investment* is a benefit. Costs need to be considered in terms of carrying value of the assets, profitability of the assets and net present value/cost (the time effect of money).

In general, neither the IV Report nor the DORIS report contain sufficient information to provide transparency behind the conclusions and findings being made. This was especially the case for the cost assessment work completed by DORIS Engineering (**DORIS Report §2.2.2, pgs. 48–57**), which lacked supporting information around its assumptions, referenced data, and calculation basis. This made it difficult to assess the accuracy and validity of its results and conclusions.

3.1.2 Commercial viability is not addressed

Section 4 of the Report focuses heavily on the feasibility of different technologies without considering their commercial viability. The commercial realities of investment, by the private sector, need to be addressed. More data should be developed on the business cases surrounding investment for all four scenarios. The business cases should also be brought back to the core levers: risk (commercial, regulatory, technical, etc.) versus reward (principally, NPR/IRR as driven by profitability and scale).

Analysis of the ongoing viability and use of existing gas infrastructure does not seem to account for unit cost analysis or operating and net profitability. Owners of gas assets are typically heavily indebted against their assets. As such, for each asset, there must be a minimum level of profitably that enables them to:

a. Exceed the unit cost of production / processing / transport to earn an operating profit, and
b. Service debt and corporate overheads to earn a net profit.

A net loss (b) could see assets sold, maintenance curtailed, or owners declare bankruptcy, while an operating loss (a) would likely see the immediate withdrawal of the asset from service with little notice.

Note that in Victoria the majority of costs associated with constructing gas infrastructure (being capital cost) has been depreciated, resulting in the transport and storage infrastructure carrying a relatively low unit cost. Hence, in Victoria, the majority of the delivered cost of gas is currently driven by upstream exploration and production costs.

3.1.3 Key parts of the gas value chain are neglected

Considering Victoria as 'an island [with] no access to external energy sources [from other states]' (**DORIS Report pg. 42**) is a major simplification for both electricity and gas markets. In reality there will be complex interplay between several jurisdictions in the National Electricity Market (NEM) and the East Coast Gas Market, particularly with regards to proposed gas import terminals interstate and the anticipated 'bi-directional' upgrades to the major gas pipelines between Victoria, NSW, and SA.

The DORIS report specifically excluded the following factors from its cost analysis and cost breakdown structure (**DORIS Report pg. 53**):

- Energy efficiency impacts
- Transport
- Residential and commercial use
- Industrial use
- Export

These exclusions result in an analysis that fails to capture how the integrated gas value chain operates.

Excluding significant parts of the gas value chain is likely to result in distorted results. For example, a key feature resulting from the integrated physical and commercial nature of Victoria's gas infrastructure is that the loss of even one key asset could lead to a cascade effect where all assets are rapidly shutdown before a suitable replacement is deployed (refer also Section 3.2.2 below). This is a major risk to the Victorian economy that does not seem to be adequately addressed in the Report.

3.1.4 Macro-economic impacts are not clearly stated

At 22% of total energy use (**IV Report pg. 11**), gas has a major impact on the competitiveness of the Victorian economy against other economies and the standard of living of Victorians. Given the current gas prices and usage, Victorians consume (directly and indirectly) several thousand dollars of natural gas per annum, per capita. Hence, natural gas represents a major component of their cost of living, playing a key role as an energy vector and feedstock for a large range of essential goods and services. Figure 5 and its accompanying comments distinguishes between different usage sectors and don't recognise this link (**IV Report §4.1.3, pg. 15**).

Consideration should therefore be given to the broader economic effects (positive and negative) of potentially major increases in gas prices during any transition. We recommend that IV estimate the average annual spend per household—or working age citizen—on gas in order to quantify the potential sensitivity of price changes to Victorians resulting from the four scenarios. A similar observation applies to the DORIS report, in which the jobs analysis fails to provide a 'net' job creation statistic (**DORIS Report pg. 12**). Given the disruptive nature of these changes it is important to account for loss of existing jobs when evaluating the new low-emissions jobs potentially created by the different scenarios.

Though briefly discussed in Section 5.3 of the Report (**IV Report pg. 5**), Infrastructure Victoria does little to outline the potential need and scale of government support to ensure major energy disruptions do not occur during any transition. This will be required both in terms of maintaining the commercial viability of key gas assets to avoid disruptive retirement and in assisting the workforce to transition to other industries and regions.

3.2 Policy and regulation

3.2.1 The role of government

Whilst the report considers different policy drivers and their impact on decarbonisation pathways, there is little consideration of broader policy drivers such as a carbon pricing mechanism, other than to incentivise CCS. The benefit of considering broader policy measures than those outlined would be to further model the industry response to more broad ranging market signals (**IV Report pgs.36, 40**).

The report highlights legislative, regulatory and policy considerations for gas sector decarbonisation, and the need for review of both state and federal laws and standards.

GPA concurs that some of the regulation affecting gas infrastructure decarbonisation is driven by federal legislation, such as the National Gas Law, and standards such as the National Building Code, requiring significant coordination and cooperation across jurisdictions. Similarly, significant regulatory reform at a state level will be required depending on the decarbonisation pathways identified, and early work is required to commence the lengthy process of effecting revisions to existing legislation.

The Report has limited focus on the role of government to support consumers, the community, workforce transition and other stakeholder issues, and on energy affordability/cost of living (see also 3.1.4) as a result of the transition. However, it is recognised that future work is needed in this area. These are important considerations for government policy, as energy transition is expected to have significant impacts in these areas.

3.2.2 Asset retirement will be disruptive

The two reports assume that assets will be gradually retired, with:

- The IV Report claiming that ‘a slow phase out of natural gas… enables some infrastructure to be retained’ (**IV Report pg. 30**), and
- The DORIS report assuming that, under each scenario, ‘plant underutilisation capacity is taken to be decommissioned at the end of the decade’ (**DORIS Report Table 27, pg. 43**).

The reality is that a slow or ordered phase out is unlikely to occur given that there are minimum technical and commercial (profitability) thresholds for continued operation. It is more likely that a disrupted phase out would occur as the economic and business cases for ongoing asset operation faces uncertainty. Underutilisation will force out asset owners as the unit cost of gas escalates. This could result in a major, sudden switch and/or loss of assets from the market as owners deem them to be uneconomic.

To ensure a smooth transition, government would need to provide assistance to legacy infrastructure operators to keep them profitable while also providing major incentives—or stepping into the market—to develop the required alternative infrastructure. If not, it is likely that there will be economic dislocations, disruptions, and energy value chain failures to both commercial users and consumers of gas. A small insight can be gained from the sudden closure of the Hazelwood Power Station which not only drove Victorian power prices up by 30% but also resulted in a number of power stations suddenly being withdrawn from the market.

3.3 Supply and Demand

3.3.1 Gas demand will not necessarily decline

The Report takes a simplistic approach to projection of total energy demand, predicting a decrease in total demand (despite an increase in population). Australia's per capita energy demand has been declining in recent years, while total use has been increasing modestly. These forecasts are a significant assumption; in our opinion their validity and the sensitivity of the modelling results should be explored in the next phase.

Regarding the gas sector, the Report claims that for 'each of the scenarios considered… Victoria's reliance on natural gas will decline' (**IV Report pg. 5**). However, the scenario modelling explicitly *assumes* that hydrocarbon demands will decline (**DORIS Report pg. 29**); it is not reasonable to express an assumption as a conclusion.

The DORIS report additionally states that natural gas use will 'drop off to a lower amount in 2040 after the closure of Longford and completely cease by 2050 when all Victorian gas plants are expected to reach their end of life' (**DORIS Report pg. 109**). Should an electrification scenario be adopted, in reality decommissioning of the gas distribution network will begin before 2030 as users begin to switch over to electricity. It is also highly likely that the plants and infrastructure would have a useful life beyond this design life, and that should be taken into account as an opportunity cost.

Finally, the IV Report also states that:

> Alongside declining supply, gas prices have risen significantly in eastern Australia in recent years, including in Victoria. By 2018, wholesale gas prices has risen from historic levels of between \$4–\$6 per GJ to \$8–\$10 per GJ for new gas contracts. This primarily reflects rising costs, but also an increase in Australian LNG exports which has put pressure on domestic supply. (**IV Report pg. 16**)

This statement is incorrect. LNG exports have increased *demand*, not reduced supply. Supply has reduced, particularly in Victoria, due to national declines in older gas fields and a lack of exploration and development of new resources in Victoria, corresponding to a government moratorium for onshore and unconventional gas exploration.

3.3.2 Why is gas demand so high?

The report concludes that there are significant efficiency gains to be made in Victorian gas use.

In part this is justified by Figure 4 of the Infrastructure Victoria Report, which compares gas usage in two other (colder) jurisdictions (**IV Report pg. 14**):

- Victoria—50 GJ per household
- United Kingdom—40 GJ per household
- Netherlands—34 GJ per household.

However, the Report does not identify the reason for the difference and it may not reflect potential efficiency gains. These are not equivalent jurisdictions; for instance, the figure does not take into account average dwelling and household size, which may account for some of the difference. We recommend that Infrastructure Victoria request this data from Accenture to ensure information is presented on an equivalency basis. Identifying these reasons would be beneficial as they could be used to identify pathways to improve efficiency, which may include more efficient building practices or alterative space-heating practices such as geothermal or electrical.

3.3.3 Where are Victoria's renewable energy feedstocks?

The Report does not identify the renewable resources that are capable of meeting or perhaps exceeding Victoria's energy demand. As is clear from the Doris report, electrification scenarios[8] require a significant increase in renewable generation. Hence the source of that energy is a significant concern for the proposed forecasts, and especially relevant from an infrastructure perspective since infrastructure is required to transport and store the energy.

We would expect Victoria to be a net importer of energy as its production of brown coal and gas declines, due to the size of its economy and limited renewable energy resources compared to elsewhere in Australia. The issue of inter-dependence on neighbouring states needs to be addressed. This report makes the major assumption that renewable power is available in sufficient quantities (i.e. it is not required elsewhere), is dispatchable, and at the correct frequency. It neglects the market and pricing impacts of energy shortfalls which would potentially be crippling (see Section 2.4.1 for details).

In contrast, Infrastructure Victoria's report identified Victoria as a potential 'exporter of low carbon goods, and potentially energy, given that several key trading partners have a carbon price or ambitious emissions reduction targets' (**IV Report pg. 5**). It is unclear where Victoria would find sufficient quantity of abundant, low cost, zero-carbon energy sources capable of supporting an export market.

The concern of renewables availability is noted in the report, but we do not think it is adequately addressed in the current modelling. For example, Scenario A is heavily reliant on hydro power as a dispatchable energy source, and the report states that (**IV Report pg. 31**):

> …there is a technical risk that there are not enough locations in Victoria with the topography required to support hydro power. However, hydro power can be sourced from other states to provide backup with the use of state interconnections.

This works against the modelling assumption of considering Victoria as an "island". Neighbouring states may require their own extensive hydroelectric reserves to take a similar pathway to net-zero.

The report also describes geothermal technology as accounting for 5 to 10% of the energy mix (**IV Report pg. 34**). Geothermal is well demonstrated for low-grade heat, but has not been successfully commercialised or demonstrated for electricity production in Australia—this is a conclusion of the DORIS report to which we concur (**DORIS Report Pg. 79**). It is difficult to conceive of geothermal accounting for such a large portion of the energy mix.

The Report would benefit from a summary of proposed energy sources to account for a more than 20-fold increase in renewable energy production.

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[8] The exception to this is Scenario 4, which utilises the extensive coal resources, but requires large-scale CCS to be a net-zero pathway.

APPENDIX 1 GPA Review Team

Table 1—GPA Review Team Overview

Employee	Bio
Nick Kastelein › Senior Mechanical Engineer	Nick Kastelein is a Senior Mechanical engineer at GPA Engineering with over 10 years' experience in the oil and gas sector, including production, transmission and distribution. Over the last two years he has worked in the emerging hydrogen sector, including lead mechanical design of the Western Sydney Green Gas Project, a hydrogen pilot plant owned by Jemena, and project coordination for the Future Fuels Cooperative Research Centre, where he chairs the Metal Assets Working Group.
Dean Williams › Commercial Consultant	Dean has 18 years' experience with top-tier international oil and gas companies like Shell and BG Group, as well as consulting and strategy experience with KPMG. He has worked on some of the world's most complex upstream energy projects, including leading large multi-disciplinary teams at APA Group accountable for $1.4 billion of revenue across 17 integrated gas assets worth $15 billion. Dean is also working extensively in the hydrogen sector assisting companies in developing hydrogen strategies and understanding the business cases of hydrogen investments.
Briony O'Shea › Hydrogen Industry Portfolio Manager	Briony is the Hydrogen Industry Portfolio Manager at GPA Engineering with 25 years of energy sector experience. Her current focus is on regulatory and policy aspects of the emerging hydrogen economy and she has led a number of research and advisory projects on the topic, including: investigation of regulatory barriers to introducing hydrogen into the gas distribution networks for COAG Energy Council; a net zero emissions scoping study for Evoenergy; and approvals management for Jemena's Western Sydney Green Gas Project.
Edward Higginson › Senior Electrical Engineer	Edward has over 9 years' experience as a project engineer and electrical design engineer across a broad range of industries. His experience includes power generation and distribution utilities, mining, minerals processing, water and waste water, and oil and gas. Recent works have focused on embedded generation and renewable energy projects including solar, green hydrogen, biogas, micro-grid, power supply option studies, and grid connection / utility negotiation.
Sam Hatwell › Process Engineer	Sam Hatwell is a process engineer at GPA Engineering with over 8 years' experience in the oil and gas sector, including production, transmission and distribution. Over the last two years he has worked in the emerging hydrogen sector, including lead process design of the Hydrogen Plant South Australia (HyP SA) project, a hydrogen pilot plant owned by AGIG which produces hydrogen and injects it into the natural gas distribution network for use as blended gas.
Elijah Rousseau › Graduate Process Engineer	Elijah is a graduate process engineer at GPA Engineering with just over 1 year of experience in the oil, gas, and renewable energy sectors. After graduating from the University of Queensland with first class honours and a university medal, Elijah joined GPA to follow his passion in the emerging renewables industry. This has allowed him to be involved in a number of hydrogen-related projects, including a feasibility study looking at renewable power generation in remote area power generation applications and how hydrogen can be used to support this transition.

APPENDIX 2 Review of Table 4

Reducing emissions from the whole energy sector, not just gas, otherwise comments on electrification "increasing demand for gas" doesn't make sense.

It is not clear in this table what "cost" means. Costs need to be considered in terms of carrying value of the assets, profitability of the assets, net present value/cost (the time effect of money).

Potential net cost to owner/user | Potential net benefit to owner/user | Neutral or ambiguous effect on owner/user

Lever for reducing emissions from gas	Expected impact on gas infrastructure			Expected impact on gas users		
	Exploration, production, imports, processing	Gas networks	Gas storage	Residential and commercial gas users	Industrial gas users	Gas-powered electricity generators
Energy efficiency (gas)	Lowers demand for natural gas, reducing upstream opportunities Note: lower upstream leakage reduces emissions	Lowers demand for natural gas, reducing required network investment; addressing leaks may increase network investment	Lowers demand for natural gas, reducing storage needs	Requires investment in upgrades for gas customers, with mix of long and short paybacks	Requires investment in equipment and process re-engineering	Lowers demand for natural gas, potentially reducing gas input costs; electrification could see higher electricity demand
Electrification	Increases electricity demand, potentially increasing demand for gas for power generation	Increases electricity demand, potentially increasing demand for gas transmission for power generation	May increase role for gas storage for flexible electricity generation or seasonal storage	Requires investment in upgrades for gas customers, with mix of long and short paybacks	Requires investment for electrification of process heat and process re-engineering	Supports higher electricity demand, potentially supporting demand for gas for power generation
Carbon capture and storage	Upstream firms could participate in carbon storage; CCS could support demand for natural gas	Supports network connections to CCS-equipped gas users; networks may play a role in carbon dioxide transport	No direct impact	No direct impact	Supports extended role for gas at facilities in CCS clusters; investment required in carbon capture and transport	Supports a longer-term role for gas-powered generation; investment required in carbon capture and transport
Hydrogen	Investment opportunities for upstream segment in hydrogen export	Requires significant network upgrades to transport and store hydrogen, extending network life	No direct impact	May require new meters and safety devices for blending; requires appliance upgrades at higher blending levels	Requires process and equipment upgrades; hydrogen may replace natural gas in some industrial processes	Opportunity to build or convert to hydrogen-powered generators
Biomethane	Biomethane blending lowers demand for natural gas, reducing required investment (minor effect)	Opportunity for biomethane production and blending trials	No direct impact	No direct impact	No direct impact	Opportunity for biomethane-powered generation (potentially with CCS)

Implied increased use of renewable electricity sources.

Reduction in Scope 1 emissions negligible compared to consumer emissions reduction, and true of anything that displaces production.

Logically, only CCS would be an emissions reduction technology that is beneficial to the upstream sector, it is questionable whether the other items in this column should be blue.

Converting to H2 and consequent capacity de-rating will at best be neutral.

Some gas storage, e.g. Dandenong LNG will not be compatible with Hydrogen. Similarly Iona cannot necessarily be used for storage of hydrogen – refer FFCRC's report on underground H2 storage.

How will addressing leaks increase network investment? Addressing leaks is an ongoing cost, not affected by gas efficiency measures. Note the amount of leaks is not commercially significant.

Victoria is unlikely to have renewable energy resources available to commercially underpin an export volume hydrogen project. Especially in a market where it is likely to be a net-importer of electricity. – How does this point represent benefit to upstream gas infrastructure?

Industrial gas users are likely already to be at maximum efficiency. Likely therefor to be a net cost rather than benefit.

Electrolysers may also provide responsive load

Currently, no private sector power generator will invest in gas-fired generation, as the risk and uncertainties are too high. For example, KurriKurri gas-fired powerplant in hunter Valley, which required Federal Government to fund due to no private sector tenders.