Oakley Greenwood

Tasmanian Gas Strategy:

Background research, analysis and suggested next steps

Final Report

October 2021

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Structure of Report

- Background and objective of report.
- Key macro factors affecting the existing Tasmanian Gas sector.
- Key factors affecting mainland gas supply.
- Key macro factors likely to affect the Tasmanian Gas sector in the future.
- High-level options reflecting Tasmania's Strengths, Weaknesses, Opportunities and Threats.
- High-level assessment of efficacy of each option.
- Deep-dive into how Tasmania might transition to renewable gases, including high-level modelling of different options.
- Recommended strategy.
- Next steps.
- Appendices:
  - How we estimated the cost of renewable synthetic methane (RM).

Background and objective of report

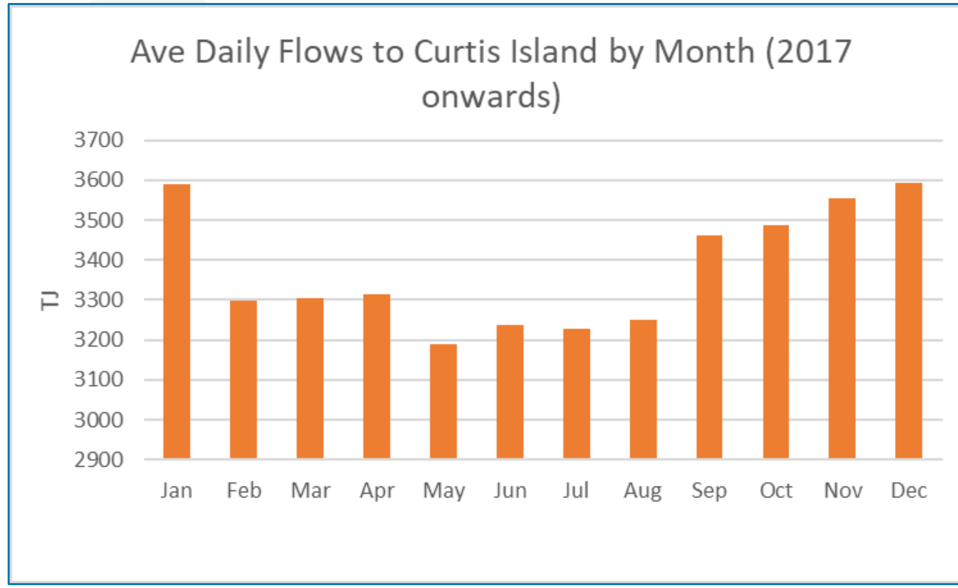
- Background
  - The Department is developing a 'Future Gas Strategy for Tasmania 2020-2040'.
  - A Working Group was established to advise and inform the development of the strategy.
- The Department engaged Oakley Greenwood (OGW) to:
  - Undertake initial research into, and provide advice on, the Tasmanian and Australian gas market – to assist in the development of the longer-term Tasmanian gas strategy; and
  - Focus on the following key aspects:
    - a) Research to understand the Tasmanian context. For example the gas users, the current uses of gas, the gas supply chain, renewable energy/zero emissions targets, renewable energy initiatives, hydrogen and other renewable gas developments, etc.
    - b) Attend and facilitate discussion at the 2nd Working Group meeting, which was held on Wednesday 9th December 2020; and
    - c) Provide a Preliminary Report on the current Tasmanian gas market. For example challenges, opportunities, risks, alignment/synergies with broader national gas markets – to help guide the next steps of the project. This was presented and discussed at the 11th of February Gas Working Group meeting.
- This Report constitutes the final draft of the Report referred to above.

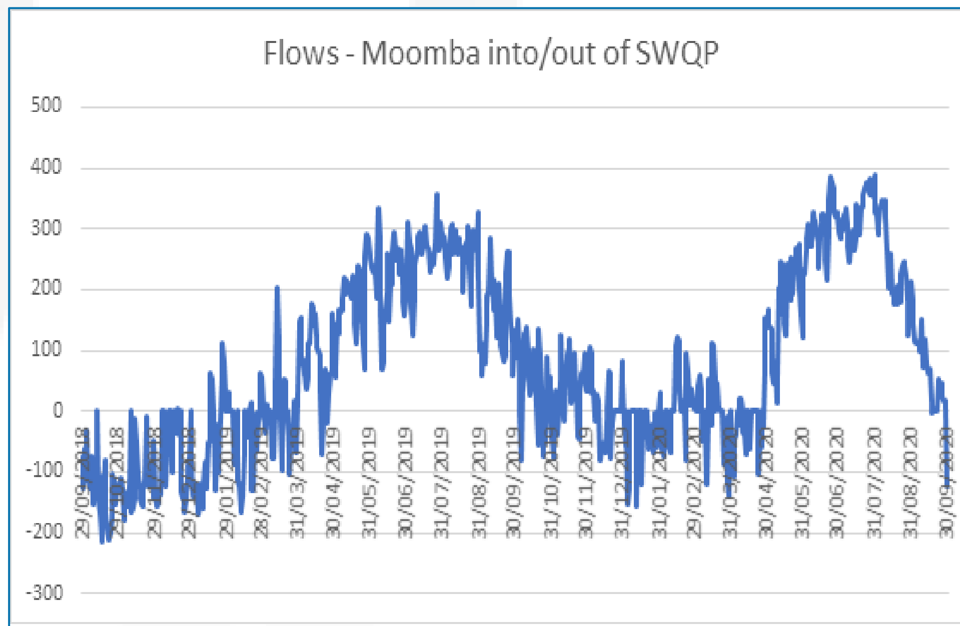
There are a number of key macro factors affecting the *existing* Tasmanian Gas sector, which should be explicitly had regard for when developing Tasmania's future gas strategy.

Macro Factor	Comment [TGP = Tasmanian Gas Pipeline]
Gas Costs and Utilisation	• Hydro Tasmania's contract with TGP (used to support supply to the Tamar Valley Power Station) underpins haulage costs incurred by Tasmania's other gas customers. • The TGP has relatively low utilisation, but has contributed to energy security. • Gas costs are highly variable – oil linked pricing, supply tightness.
Low penetration of gas customer connections	• ~13,000 residential customers and 1,050 business customers. • Potential customer base (@100% penetration) is ~45,000 customers – capped by access to gas distribution – circa 285,000 electricity customers in Tasmania. • Annual gas sales are very low to these customers – circa 7 PJ/year.
Low growth in gas connections	• <1% per annum in residential gas customer growth in recent times. • Similar for business customers. • Prima facie, indicates gas has made some but limited in-roads as a fuel of choice.
Relatively new gas distribution network	• The distribution network is relatively young, at ~20 years. • The materials likely to have been used (polyethylene pipes) are conducive to distributing H_2…the network's age means that it could also accommodate a conversion to renewable (bio or synthetic) methane in the medium term, *without having to incur* substantive (sunk) costs to replace assets.
High value gas users in Tasmania	• A number of Tasmania's largest industrial customers rely heavily on natural gas, and initial feedback is that some are unable to convert to other fuel sources readily while some may be able to utilise Hydrogen.
Limited indigenous fossil-fuel CH_4	• The limitations on indigenous (fossil) gas exacerbate the reliance on gas supply from the mainland, and the TGP.

Key factors affecting the supply and demand for gas on the mainland…

- LNG flows are large and fluctuate by season:
  - LNG industry worth ~$50b per annum.
  - Our three key LNG markets have all recently made Net Zero commitments:
    - 1. Japan $21,224B (2050).
    - 2. China $17,499B (2060).
    - 3. South Korea $5,268B (2050).
    - **Total $43,991 (88% of total).**
  - More gas is exported in our spring/summer - in the northern hemisphere winter.
  - Less gas is exported in our autumn/winter.
- Flows to/from southern states and QLD align with this per attached charts (Sept 18 – Sept 20):
  - Gas flows north into the South West Qld Pipeline (-ve) from Moomba in Spring/ Summer.
  - Gas flows south out of SWQP (+ve) into Moomba in Autumn and Winter.

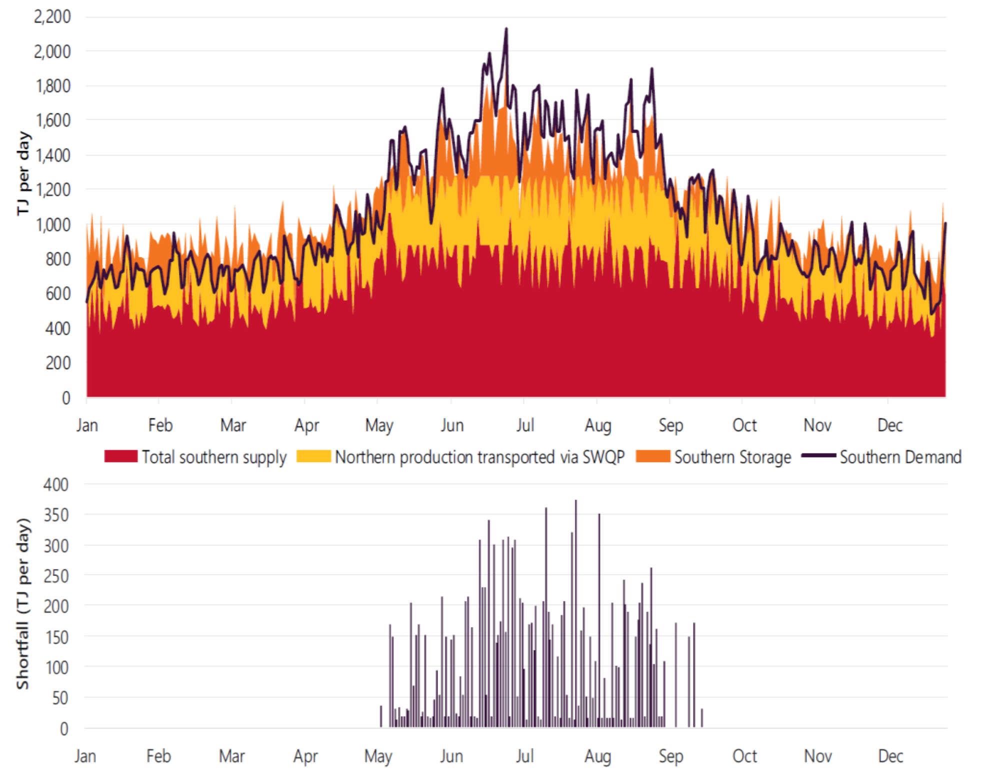




Key factors affecting the supply and demand for gas on the mainland…

- AEMO is forecasting a supply/demand imbalance on peak demand days in southern states from 2024, despite forecasting large flows from the northern states (Qld mainly):
  - *"Some supply gaps of between 13 TJ and 374 TJ are observed across winter 2024 as peak day production within southern states is insufficient to meet forecast daily demand, even with the South West Queensland Pipeline (SWQP) transporting northern gas at full capacity"*
  - *"Peak day field production in Victoria and other Victorian and South Australian pipeline infrastructure will limit the amount of further gas that could contribute to meeting southern domestic demand. The planned WORM augmentation of the Victorian DTS helps address these shortfalls…."*

Figure 4 Example evolution of daily supply-demand balance in southern states in 2024 including existing and committed projects (top) and forecast shortfalls in southern states (bottom), Central scenario



"Total southern supply" in Figure 4 includes all gas processed through Moomba processing facility, whether it comes from Moomba storage or Moomba production. This figure does not include the gas produced to refill Moomba storage.

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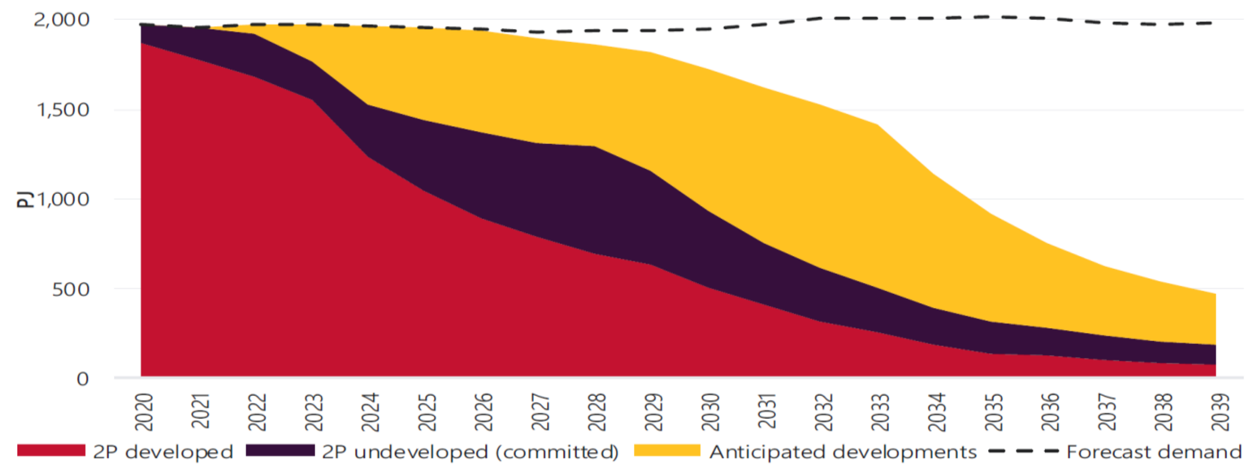
Key factors affecting the supply and demand for gas on the mainland…

AEMO is also forecasting a large imbalance in overall gas supply/demand from late 2020's onwards - as Bass Strait gas reserves deplete - needs new gas from Qld or LNG imports - or onshore Victoria - or Bass Strait - or NT.

Figure 3 Projected eastern and south-eastern Australia gas production (export LNG and domestic) – existing projects, and committed and anticipated developments; Central scenario, 2020-39



Overall, these factors are likely to have implications for:

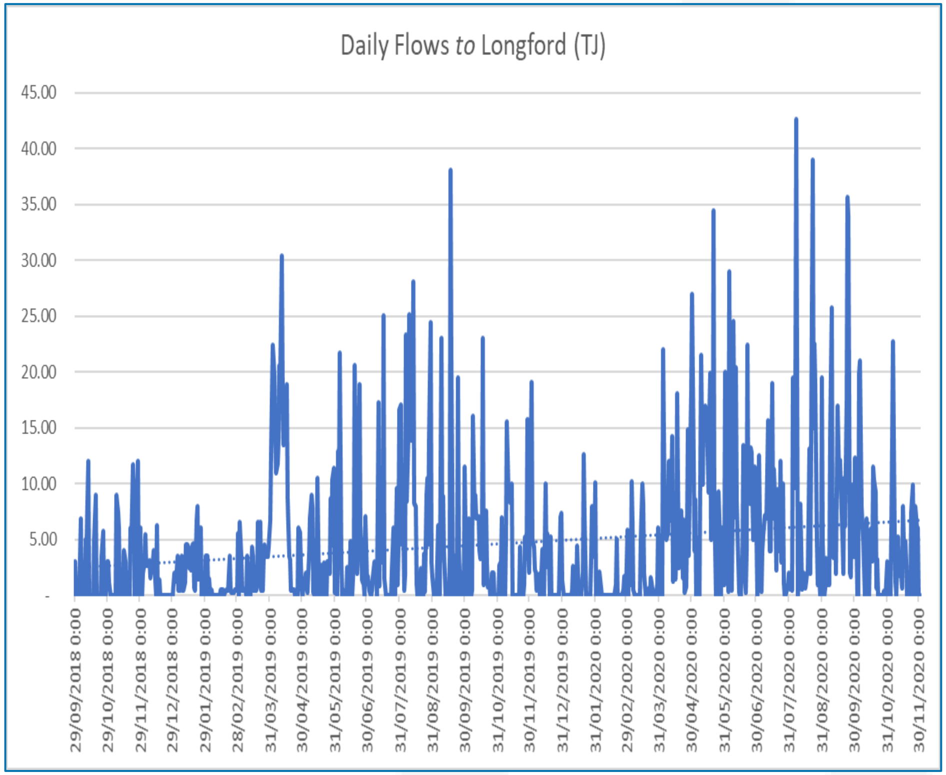
- The demand for the services TGP offers to the markets it serves (east coast mainland, Tasmania) - gas transport and storage.
- Ability for Tasmanian gas customers to access gas (commodity) on reasonable prices and terms - oil and LNG price links, fixed prices; and
- The value placed on alternative sources of gas - preferably very low emission (green gas).

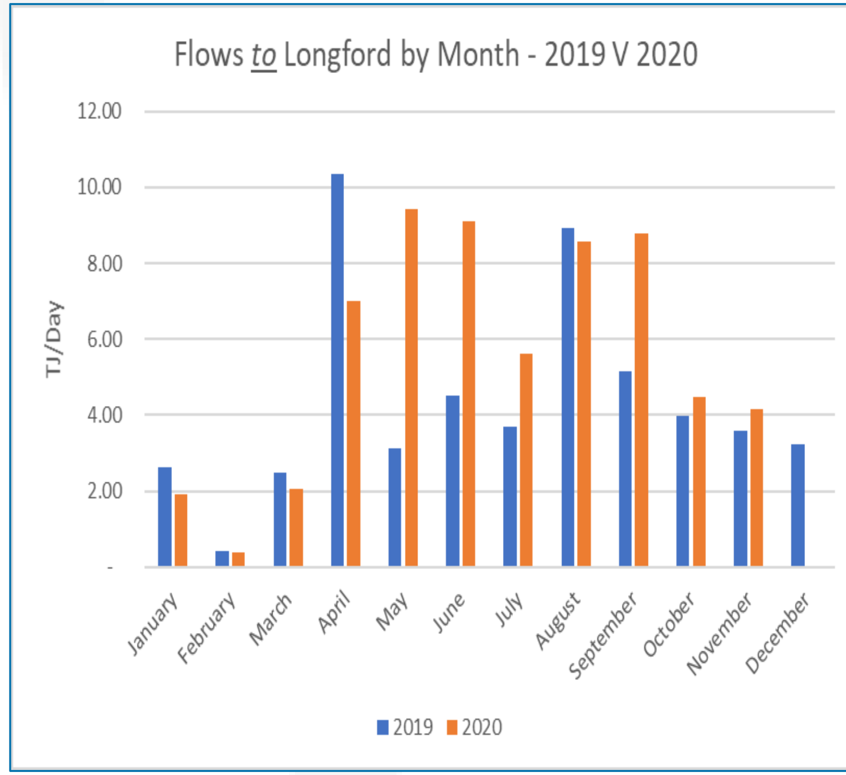
Key macro factors that will affect *the* Tasmanian gas sector in the future

Macro Factor	Comment

Changes to the East Coast and Tasmanian wholesale delivered gas markets	• Transmission pipelines (TGP) are likely to continue to evolve service offerings.
	• For example - since 2017 TGP has been offering a High Security Storage Service to East Coast gas participants.
	• It generated $5.2m from "Firm park/loan services", on total revenue of $32m, in 2020 (Source: TGP – Financial Information required to be reported under Part 23 of the NGRs)
	    • 21.5% of gas (1,876 TJ) flowed *to "Longford TGP – Transfer Station*" in 2020 YTD.
	    • 13.4% in 2019 (1,590 TJ).
	    • 8.7% in 2018 (188 TJ).
	    • ~0 in 2017, as service only commenced in 2017.
	
	Raises questions as to:
	• The commercial priority TGP will be able to place on supply to Tasmania once existing contracts are up at the start of 2022, critically if the key Hydro Tasmania Gas Transport Agreement (GTA) lapses?
	• For example, will storage become the major revenue generating service, or at least, be expected to evolve into the major revenue generating service – recognising this is a growing, competitive service?
	• Will there be the commercial pressure to seek to ramp up the tariffs for the remaining gas customers – significantly increasing the chances of those revenues also lapsing as customers move to alternatives?

How the TGP is being used (2019/2020)…





- An increasing amount of gas is flowing *to* Longford on the TGP over the last few years, with it predominately being used during the peak winter periods (May through Sept) – how storage is used.
- However, the maximum daily flow to Longford is still only 43TJ (NB: the total flow on that day was 71.22 TJ – the largest in our records going back to 2018).
  - Indicates that the Storage Service may still be under-contracted, given the advertised capacity is "*firm injection from TasHub into the VTS comprises 120TJ/day, at a rate of 5TJ//hr*".

Key macro factors that will affect *the* Tasmanian Gas sector in the future

Macro Factor	Comment
Tasmania's Net Zero emissions commitment (and those of key exporting nations)	Everything else being equal, Net Zero commitments will negatively impact upon the long-term use of fossil-fuel based methane in Tasmania and in fact the east coast (and LNG by key nations with similar policies). It is a massive issue to decarbonise gas on the east coast. For example Victoria consumers more energy as gas then as electricity (60:40) – the gas load is the size of the Qld electricity load. The $50b LNG industry is also at risk. The 20,000km plus of transmission pipelines are at very high risk of stranding if this is implemented (technical issues with taking hydrogen for example) – serious studies being undertaken by Government., legislation in place in 5 States. Renewable hydrogen can potentially play a key role in some areas in Tasmania and on the east coast – very active development programs – major cost hurdles. It will also provide additional support to the development and use of other renewable natural gases such as renewable synthetic methane and bio-methane. The task to decarbonise gas in Tasmania is for relatively small quantities, which may assist.
Tasmania's Renewable Energy Target	The significant increase in renewable energy generated (+10,500 GWh pa - ~100% increase - by 2040), supported by an additional electrical linkage to the mainland (Project Marinus), is likely to: • Provide additional security of supply to Tasmania, which, everything else being equal, would reduce Hydro Tasmania's dependence on the gas fired TVPS to maintain security of supply (NB: this is not to say that the TVPS should not / could not be retained for other reasons e.g. as syncons for grid stabilisation). • Improve the economics of electrifying existing gas loads where this is feasible to support Tasmania's overall decarbonisation efforts.

Key macro factors that will affect *the* Tasmanian Gas sector in the future

Macro Factor	Comment
Tasmania's Renewable Energy Action Plan (REAP - Dec 2020)	Under Action item 1.8, "*Development of a Bioenergy Vision for Tasmania*", the Tasmanian Government is committing Renewables Tasmania to "*explore options to use bioenergy to decarbonise by displacing fossil fuels used in heat generation and the production of transport fuels*". Under Action item 1.12, "*Gas Decarbonisation Pathway Study*", Renewables Tasmania is to leverage two key workstreams – being Tasmania's Bioenergy Vision and Tasmanian Renewable Hydrogen Action Plan (see below) - and "*conduct additional analysis as part of its work on the future of the gas industry in Tasmania, to understand what a gas decarbonisation pathway would look like. This study will identify the key opportunities, barriers, network infrastructure and regulatory issues to set out a potential pathway to decarbonise Tasmania's gas sector*".
Tasmania's Renewable Hydrogen Action Plan (TRHAP)	The TRHAP proposes to "*work with the incumbent natural gas distribution network infrastructure owner to explore opportunities for hydrogen blending at 10 per cent and to investigate potential trials of higher hydrogen blends in Tasmania's hydrogen compatible gas distribution networks*". This is part of a broader strategy that would see, from 2030, Tasmania becoming "*a significant global supplier of renewable hydrogen for export and domestic use*". Large scale hydrogen (export) production may bring scale costs advantages that could assist the local supply.

Strawman options underpinning Tasmania's future gas strategy

Strawman Options	Strengths, Weaknesses, Opportunities and Threats
'Do nothing' (status quo) - take the risks - not have a Tasmanian Gas Strategy that is pro-active?	• Will the Tasmanian gas supply industry be financially sustainable in the medium to long-term, if no change in strategy is made - delivered gas prices may escalate? • Specifically, if Hydro Tasmania chooses not to renew its contract with the TGP and this sees haulage prices escalate does Tasmania allow the market to decide the outcomes via private decisions and investments - prices absorbed, conversions to alternatives, shut downs, etc.? • Is a 'do nothing' strategy aligned to Tasmania's Net Zero policy and/or its REAP? • Would this impact on Tasmania's ability to export existing products produced by its gas consumers to Net Zero nations (e.g., Japan, South Korea)?

Focus on the evolving services role for the TGP limiting potential price shocks for Tasmanian gas customers.	• Ensuring the TGP prices to gas customers in Tasmania reflect:
	    • The increased revenue TGP generates (and will continue to generate) from its High Security Storage products; &
	    • Hydro's reduced reliance on the TVPS and hence TGP (if this is in fact correct?)
	    • The true marginal costs for existing customers - recognising the sunk nature of the investment.
	• May rely on Government supporting the effective use of some form of equitable arbitration procedure to ensure a reasonable negotiated outcome for all parties. For example Part 23 of the National Gas Rules, or other agreed options - the Tasmanian Government may need to advocate for changes to the framework at a National level if this is not clearly available to the parties.
	• Does not address the risks of continuing to rely on mainland gas (via the TGP) - e.g., poor negotiating position, unfavourable supply/demand balance for gas commodity in the medium term, decarbonisation of the east coast gas supply, etc.

Strawman options underpinning Tasmania's future gas strategy

Strawman Options	Strengths, Weaknesses, Opportunities and Threats
Grow fossil-fuel CH_4 use to spread sunk / fixed costs across more customers	• How would this option be perceived in light of Tasmania's Net Zero targets? • Places continued reliance on the use of the TGP - costs will be spread more but it is also likely to increase the commercial risks and delivered prices new gas users face if locating in Tasmania (as compared to locating on the mainland). • Low likelihood of success, given Net Zero/decarbonisation policies locally and internationally, and the delivered gas price issues?
Electrify existing gas loads	• Use the increased renewable electricity generated to decarbonise existing gas loads (via conversion to electricity). • Small number of existing gas customers …. everything else being equal, reduces the total cost of conversion. • Conversion though could be timely, if a large stock of gas appliances are coming up to the end of their useful life (~20 years). • However, there are some gas loads that are unable to be electrified - a blanket approach is likely to have material negative consequences for some industries/customers. • It would negatively impact TasGas' business (sovereign risk?). • May increase electricity peak demands, hence increasing electricity cost - but most likely costs relate to the impacts on industries and the costs to households of converting away from gas.

Strawman options underpinning Tasmania's future gas strategy

Options	Strengths, Weaknesses, Opportunities and Threats

Convert the distribution network to Hydrogen (H_2)	• TasGas' network is (a) relatively young; (b) currently underutilised, and (c) is likely to face relatively low growth under a 'do nothing' scenario – all of which means the opportunity cost of converting to H_2 is likely to be much lower than in many other jurisdictions.
	• Conversion to renewable H_2 would align with Tasmania's Renewable Hydrogen Strategy - there are already risks that the gas users could convert to renewable electricity to decarbonise.
	• Conversion would also reduce the on-going risk of relying on access to and the costs of east coast gas and TGP's infrastructure for its delivery.
	• Hence it may also offer scope to grow renewable gas usage in Tasmania, without these commercial risks – a renewable gas source may well appeal to more customers.
	• There may be a role for the TGP infrastructure to support hydrogen development but it is unlikely (due to technical constraints).
	• More likely the hydrogen would be made and consumed at the distribution level. This will require transitional financial support as it requires building a number of small hydrogen production units or the development of storage, transport and injection systems (e.g. trucking) – and these costs are not trivial.
	• It will also require transitional support for the costs of appliance replacements (and maybe conversions in some cases).
	• Create additional value by providing Tasmania with the option of being able to:
	    • Respond to decarbonising efforts at the national and international level (noting however that the transportation of H_2, even via transmission pipelines, is difficult).
	    • To support the development of new products (e.g., if electrolysers located at existing wastewater treatment plants, the Oxygen can potentially be used to reduce wastewater treatment costs – energy/future capex, and other options in such plants to increase green gas outputs).

Options reflecting strengths, weaknesses, opportunities & threats

Options	Comment

Renewable synthetic methane (RM)	• Could start by blending hydrogen into the natural gas network (to ~10% by volume), and then over time (once blending limits reached), increase the conversion of hydrogen to renewable synthetic methane using a methanation process (via a marginal addition to hydrogen production and carbon dioxide direct air capture), or dedicated renewable methane plants.
	• Enables continued use of TasGas' existing infrastructure (e.g., limits de-rating of network) and reduces on-site conversion costs – lower transitional costs likely.
	• Depending on the location of RM production, the flows on the TGP pipeline could be reversed, with delivery of RM *to* the mainland thus:
	    • Providing ready access to a market that is forecast to face a significant supply/demand imbalance (for fossil-fuel based methane) in the short to medium term); and
	    • Providing access (e.g., via gas swaps) to the LNG export industry which itself will be facing pressure to decarbonise given its key customers' Net Zero commitments.
	    • Potential "at scale" for LNG direct exports from Tasmania - the key resources are there – water, and low cost renewable electricity, ports, etc. - there is also huge demand for a green LNG product (especially in Japan).

Bio-methane	• Development of a larger scale bio-methane industry - thus creating an indigenous, distributed, source of (renewable) bio-methane as a priority.
	• If coupled with hydrogen/renewable methane, it could contribute to:
	    • Decarbonising the entire gas network; and
	    • De-linking the Tasmanian gas supply industry from the mainland (unless of course renewable gas is exported *from* Tasmania *to* the mainland).
	• Aligns with Net Zero policies of Tasmania and key exporting nations.
	• May well tie in with waste water as a bio-gas resource – a lot of work being done in this area to enhance the production of renewable methane from waste water (COD).

High-level assessment of efficacy of options…

- The ‘do nothing’ option is not likely to be palatable, as it:
  - Continues to expose the Tasmanian gas supply industry (and it customers) to material pricing (and therefore financial) risk and uncertainty, particularly if Hydro Tasmania chooses not to renew its contract with the TGP in 2022 and if gas prices materially escalate with looming Victorian gas shortages.
  - Is likely to be perceived as being misaligned with Tasmania’s Net Zero policy.
  - Is misaligned with Tasmania’s REAP, given that Tasmania is pursuing renewable energy generation - for export - and is tasking ‘Renewables Tasmania’ with developing a potential pathway to decarbonise Tasmania’s gas sector; and
  - In the longer-term, is misaligned to key export markets that have announced net zero commitments (e.g., Japan, South Korea).
  - It does not recognise the opportunity for green gas development in Tasmania that will potentially become a major industry locally and internationally, and the optimal use of existing gas infrastructure.
- For similar reasons to the above, we see the option of growing fossil-fuel methane use to spread sunk / fixed costs across more customers (and hence improve the financial viability of the industry and its end-customers) as unpalatable.

Our high-level assessment of efficacy of options…

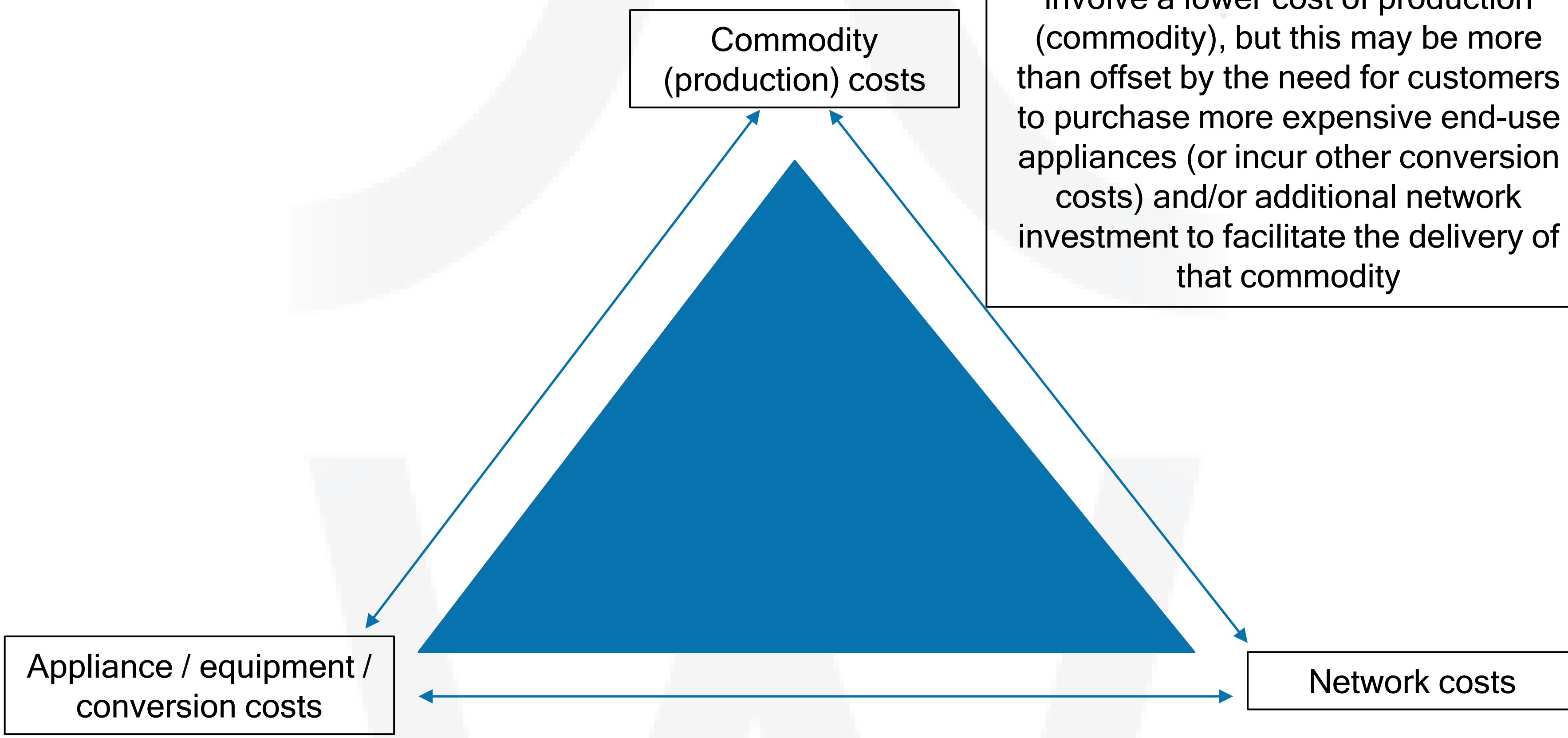
- The macro-factors appear supportive of re-purposing the existing gas distribution (and potentially gas transmission) networks in Tasmania to facilitate the distribution of renewable gases – over time – as it:
  - Is aligned with Tasmania's Net Zero policy, its REAP, and key export markets that have (and those that will in the future) announce net zero commitments (as well as major customers seeking to reach net zero emission outcomes).
  - Would align with, and potentially positively contribute to the ambitions underpinning Tasmania's Renewable Hydrogen Action Plan (assuming hydrogen and/or renewable methane contribute materially to the renewable gases that are utilised).
  - Could be a catalyst for the creation of a new export product (both to the mainland, and internationally), if renewable methane forms part of the mix of renewable gases.
  - Reduces Tasmania's gas customers' exposure to the mainland gas market, which AEMO is currently forecasting will be affected by a significant supply/demand imbalance in the medium to long-term; and
  - Contributes to reducing Tasmania's gas customers' exposure to the uncertain pricing of the services provided by the TGP, if underpinned by 'on island' production/sourcing of renewable gases. Similarly, it might make a contribution to Tasmania's electricity customers, if there is a flow-on effect to Hydro Tasmania's contractual arrangements with TGP.
- Notwithstanding the above, Tasmania's renewable electricity ambitions also suggest that a program of electrification could also be a feasible option for much of the gas demand.

Deep-dive into how Tasmania might transition to renewable gases and/or electrification …

- To inform the development of the future strategy, we undertook a high level assessment of the costs of the different renewable gas and electrification options*:
  - Hydrogen.
  - Renewable synthetic methane and bio-methane.
  - Electrification.
- To simplify the quantitative analysis we:
  - Only focused on residential and commercial/small industrial customers, with large customers i.e., the two gas transmission connected customers and the Hydro Tasmania Gas Power Generation (GPG) addressed qualitatively.
  - Estimated long-term (end-point) commodity costs, with these based on our broad estimate as to the likely long-run cost of supplying the different forms of energy; and
  - We have based our assessment of the relative costs of different energy sources purely on the relative energy contents of the different options (i.e., we have not had any regard to the efficiency of performance – e.g., air conditioning COPs).

**Due to a lack of publicly available information on both costs and availability, we have not at this stage assessed the cost or feasibility of moving to bio-methane in the following analysis. That said, one industry player indicated that bio-methane could be produced, cleaned and injected into the gas network at around $18/GJ – but we haven't seen any detail to support this and it is unclear whether this would translate into a Tasmanian context. However, Tasmania's roots in agricultural production, amongst other things, is likely to mean that using bio-methane as an energy source could be a very cost-effective renewable gas.*

The objective of the modelling is to highlight the trade-off between the commodity, appliance and network costs of electrification Vs H_2 Vs renewable methane options.



For example, a strategy pathway may involve a lower cost of production (commodity), but this may be more than offset by the need for customers to purchase more expensive end-use appliances (or incur other conversion costs) and/or additional network investment to facilitate the delivery of that commodity

Modelling how Tasmania might transition to renewable gases and/or electrification …

- More specifically, our analysis involved:

1. Estimating the 'commodity' costs related to using each alternative energy source (listed earlier) to provide the equivalent amount of energy to that of the natural gas that it displaces (so we made no allowance for growth, nor the efficiency of different appliances - e.g., coefficient of performance). This commodity cost therefore reflects:
   - The production cost of the alternative source of energy (e.g., \$/kg of H_2); and
   - The energy created from that commodity unit (e.g., 1kg of H_2 creates 142MJ of energy (HHV), or 0.039MWh based on GJ to MWh conversion of 0.2777).
2. Assessing the differences in the production cost outcomes between: (a) H_2 and electricity; (b) H_2 and renewable methane; and (c) renewable methane and electricity, at a:
   - Annual (total) cost level,
   - Annual per customer level, and
   - Per customer level over an assumed appliance life (20yr Present Value – 20yr PV).
3. In addition:
   - For all comparisons to electricity, we present cost savings on a "per kW of estimated additional peak demand" basis, so as to allow comparison with TasNetworks' published Long Run Marginal Cost (LRMC); and
   - For the H_2 to renewable methane comparison, we present the total cost savings over 20yr PV.

Caveats to the modelling…

- **Long-run production costs:** The modelling 'assumes' a long-run production cost for hydrogen, renewable methane and electricity, as alternatives to natural gas. These costs estimates are obviously fundamentally important to the derivation of the strategy. Everything else being equal, the lower an energy source's production cost is, the more economic it is as a fuel source, when compared to the other options. These costs assumptions would need to be tested and explicitly considered by the Department when formulating its final strategy - in particular, our $40/MWh electricity production cost - which we assume the Department/Hydro Tasmania will have more insight into (including via detailed modelling).

- **We didn't model final retail prices:** The modelling does not model final retail prices, but rather, as outlined above, it models production (economic) costs. Whilst these have been presented as a "cost saving" to certain customer types, they are also the underlying economic benefit associated with using one commodity relative to another. Whilst a customer's final retail bill will be greater than just the production costs, as it reflects the costs of other parts of the value chain, commodity (economic) costs are assumed to flow through to retail bills in a reasonably cost reflective manner (e.g., lower/higher commodity costs flow through to lower/higher retail bills), hence why we present them as 'cost savings'.

- **Other costs and benefits:** We have not attempted to quantify the broader economic costs or benefits to Tasmania of different strategies (e.g., to future value of resource development; ability to aid the decarbonisation of other sectors).

Table of results of high-level analysis

Parameter	Residential customers	Commercial customers	Key Assumptions
Customer Numbers	13275	1059	Energy in Tasmania 2019-20 data
Average usage per day (GJ)	1455	10000	Residential average consumption of 40GJ pa; Commercial based on reconciling to data out of NEO (from GBB)
Conversion to kg / H2	10245	70423	GJ per KG (0.142 based on HHV*)
Conversion to electricity (MWh)	404	2778	GJ to MWh Conversion (0.27777)
Conversion to renewable methane	1455	10000	1GJ Natural Gas (NG) = 1GJ Renewable Methane (RM)
Gas Cost per day	$ 17,458	$ 120,000	$12 per GJ
H2 Cost per Day	$ 30,735	$ 211,268	$3 per kg
Electricity Cost per Day	$ 16,164	$ 111,111	$40 per MWh
Renewable Methane Cost per Day	$ 35,031	$ 240,800	$24.08 per GJ
Gas Cost per Year	$ 6,372,000	$ 43,800,000	Excludes fixed charges incurred by Hydro Tas
H2 Cost per Year	$ 11,218,310	$ 77,112,676	Assumes this recovers capital cost
Electricity Cost per Year	$ 5,900,005	$ 40,555,588	Assumes this recovers capital cost
Renewable Methane Cost per Year	$ 12,786,480	$ 87,892,000	H2 cost *plus* the cost of methanation

*All hydrogen conversions are based on the HHV of 1kg = 0.142GJ. If the LHV of 1kg = 0.120GJ were used, this would increase the relative cost of hydrogen in the order of 15% over the figures presented in this report.

Table of results of high-level analysis

Parameter	Residential customers	Commercial customers	Key Assumptions
PER annum differences - H2 to Elec			
Diff Hydrogen to electrification - TOTAL pa	$ 5,318,305	$ 36,557,088	Difference in total cost of production
Diff Hydrogen to electrification - per Customer	$ 401	$ 34,520	Total cost / customer numbers
Commodity Cost savings over 20 year per customer - H2 Vs Elec	$ 4,993	$ 430,200	PV over 20yrs, based on WACC of 5%
Assumed impact per customer on coincident peak demand (kW)	1.5	182	1.5kW coincident peak demand for residential customers based on VIC data; OGW est. load factor for commercial (0.6)
Backsolved LRMC to make it economic to go to H2 if no gas network upgrages/difference in appliances	267	190	C.f TasNetworks of $100-150kVA
Amount that could be spent on elec appliance upgrades over H2 appliance upgrades and still breakeven, even if no upgrade to NG network is required cater for H2	$ 3,123	$ 203,196	Based on an LRMC of $100/kVA
	Residential customers	Commercial customers	Key Assumptions
Per annum differences - H2 to Renewable Methane			
Diff Hydrogen to Renewable Methane - TOTAL pa	-$ 1,568,170	-$ 10,779,324	Difference in total cost of production
Diff Hydrogen to Renewable Methane - per Customer (Commodity)	-$ 118	-$ 10,179	Total cost / customer numbers
Commodity Cost savings over 20 year per customer - H2 Vs RE	$ 1,472	$ 126,850	PV over 20yrs, based on WACC of 5%
Breakeven amount that could be spent on network and appliance upgrades (TOTAL)	$ 19,542,866	$ 134,334,202	
Parameter	Residential customers	Commercial customers	Key Assumptions
PER annum differences - RM to Elec			
Diff Renewable Methane to electrification - TOTAL pa	$ 6,886,475	$ 47,336,412	Difference in total cost of production
Diff Renewable Methane to electrification - per Customer	$ 519	$ 44,699	Total cost / customer numbers
Commodity Cost savings over 20 year per customer - RM Vs Elec	$ 6,465	$ 557,050	PV over 20yrs, based on WACC of 5%
Assumed impact per customer on coincident peak demand (kW)	1.5	182	1.5kW coincident peak demand for res based on VIC; OGW est. load factor for commercial (0.6)
Backsolved LRMC to make it economic to go to RM if no gas network upgrages/	346	245	C.f TasNetworks of $100-150kVA
Amount that could be spent on elec appliance upgrades over NG appliance upgrades and still breakeven	$ 4,596	$ 330,046	Based on an LRMC of $100/kVA
Parameter	Residential customers	Commercial customers	Key Assumptions
PER annum differences - Natural Gas (NG) to Elec			
Diff NG to electrification - TOTAL pa	$ 471,995	$ 3,244,412	Difference in total cost of production
Diff NG to electrification - per Customer	$ 36	$ 3,064	Total cost / customer numbers
Commodity Cost savings over 20 year per customer - NG Vs Elec	$ 443	$ 38,180	PV over 20yrs, based on WACC of 5%
Assumed impact per customer on coincident peak demand (kW)	1.5	182.2	1.5kW coincident peak demand for res based on VIC; OGW est. load factor for commercial (0.6)
Backsolved LRMC to make it economic to go to NG if no gas network upgrages/	24	17	C.f TasNetworks of $100-150kVA
Amount that could be spent on elec appliance upgrades over NG appliance upgrades and still breakeven	-$ 1,426	-$ 188,825	Based on an LRMC of $100/kVA

Explanation of results of high-level analysis - H_2 c.f Electrification

Parameter	Residential customers	Commercial customers	Key Assumptions
PER annum differences - H2 to Elec			
Diff Hydrogen to electrification - TOTAL pa	$ 5,318,305	$ 36,557,088	Difference in total cost of production
Diff Hydrogen to electrification - per Customer	$ 401	$ 34,520	Total cost / customer numbers
Commodity Cost savings over 20 year per customer - H2 Vs Elec	$ 4,993	$ 430,200	PV over 20yrs, based on WACC of 5%
Assumed impact per customer on coincident peak demand (kW)	1.5	182	1.5kW coincident peak demand for residential customers based on VIC data; OGW est. load factor for commercial (0.6)
Backsolved LRMC to make it economic to go to H2 if no gas network upgrages/difference in appliances	267	190	C.f TasNetworks of $100-150kVA
Amount that could be spent on elec appliance upgrades over H2 appliance upgrades and still breakeven, even if no upgrade to NG network is required cater for H2	$ 3,123	$ 203,196	Based on an LRMC of $100/kVA

- Comparing hydrogen to electrification assuming a commodity cost of:
  - $3/kg for H_2 ($21/GJ);
  - $40/MWh for (green) electricity ($11.11/GJ)
- Even excluding the comparative efficiency benefits of some electric appliances (e.g., COPs of up to ~5 for heat pumps), the results indicate the following commodity cost (and therefore economic) savings:
  - Ave residential customer saves $401 pa ($4,993 over 20yrs) from electrification over H_2.
  - Ave commercial/industrial customer saves $34,520 ($690,408 over 20yrs) from electrification over H_2 .
  - TasNetworks' current published (Annual Pricing Submission) LRMC is well below the above breakeven values, in the order $80 (HV Customers) - $140 (LV Customers).

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Explanation of results of high-level analysis – H2 c.f Electrification

- To offset the commodity (economic) cost saving, and hence for H_2 to breakeven with electrification, an LRMC related to the additional peak demands placed on the electricity network would need to be as high as:
  - Residential customer = $267/kVA (based on a per customer *average coincident* peak demand of 1.5kVA).
  - Commercial/small industrial = $190/kVA (based on a load factor of 0.6).
- Looking at the analysis slightly differently, if we assumed a $100/kVA LRMC for TasNetworks' network, the residual amount that this would leave to spend on electricity appliance upgrades / conversions OVER and ABOVE what would need to be spent on H_2 appliance upgrades / conversions whilst still leading to electrification breaking even with H_2, is:
  - Per Residential customer = $3,123
  - Per Commercial/industrial customer = $203,196
  - And this assumes that NO upgrade to the gas distribution network to accommodate H_2 is required (which, to the extent it is required, would mean the breakeven amounts shown above increase).

Explanation of results of high-level analysis – H2 c.f Electrification

Conclusion

- Assuming a \$3/kg and \$40/MWh commodity cost, on face value, full hydrogen conversion is unlikely to compete economically with the electrification of existing gas loads (in fact, electrification shows savings over natural gas on an energy-on-energy basis).
- For the avoidance of doubt, the analysis has no regard for customers' willingness to pay (WTP) for different types of gas appliances, or any technical issues at the customer end from conversion (although if the majority of residential and commercial/small industrial end uses are for cooking, water heating and heating, there are likely to be few). Moreover, and importantly, this does not take into account the relative efficiency of the appliances (e.g., a heat pump has a COP of in the order of 5). This will further favour electrification.
- The point where H_2 breaks even with electrification (for residential customers) is around \$2.10kg for H_2, assuming a \$40/MWh electricity cost (and assuming a LRMC of \$100/kVA for network). At this point there would be no additional amount of money that could be spent on appliance upgrades/conversions OVER and ABOVE what would need to be spent on H_2 appliance upgrades.
- Alternatively, if H_2 was assumed to remain at \$3/kg, on a purely commodity cost basis, the breakeven point for electricity production is ~\$75/MWh.

Explanation of results of high-level analysis – H2 c.f Electrification

- However, this analysis still excludes investments required to facilitate the distribution of hydrogen through the natural gas network (e.g., additional/changed compression facilities; investments to counteract the de-rating of the natural gas network), although given the age and likely utilisation of TasGas' network, this may not be as much of an issue as for some other networks - but would need to be understood.

- Moreover, a move to full hydrogen conversion is likely to require:

  - All gas end-use appliances in the affected area to be converted or replaced at the time when the 10% by volume blend is to be exceeded, inevitably leading to additional appliance costs and in some cases the bringing forward of appliance replacements relative to the electrification case, which could occur at the end of their life (hence the economic effect of a H_2 conversion strategy must include these costs and the bring-forward of some appliance replacement where it may otherwise have not have been at the end of its useful life when the blending limit was reached); OR

  - Blending to be limited to 10% by volume in an area until all appliances that can not be converted have been replaced over time with what might be more expensive, hydrogen-conversion-ready, appliances.

- In summary, even with particularly aggressive assumptions regarding the cost of hydrogen, if electrification (commodity costs) settle at around $40/MWh, electrification is likely to be a more economic outcome relative to hydrogen where it is technically feasible and appliance costs (including conversion costs) are reasonable (noting that given many properties have converted from electric to natural gas, conversion back may not be as overly onerous).

Explanation of results of high-level analysis - H_2 c.f renewable methane

	Residential customers		Commercial customers		Key Assumptions
Per annum differences - H2 to Renewable Methane					
Diff Hydrogen to Renewable Methane - TOTAL pa	-$	1,568,170	-$	10,779,324	Difference in total cost of production
Diff Hydrogen to Renewable Methane - per Customer (Commodity)	-$	118	-$	10,179	Total cost / customer numbers
Commodity Cost savings over 20 year per customer - H2 Vs RE	$	1,472	$	126,850	PV over 20yrs, based on WACC of 5%
Breakeven amount that could be spent on network and appliance upgrades (TOTAL)	$	19,542,866	$	134,334,202	

- Comparing H_2 to renewable methane ($3/kg for H_2, which equates to ~$21/GJ (HHV), vs an estimated $24/GJ commodity cost for renewable methane*), the results indicate the following commodity cost (and therefore economic) savings:
  - Ave residential customer saves $118pa ($1,472 over 20 years) on their commodity costs by using H_2 instead of renewable methane based on current estimates (first generation for RM).
  - Ave commercial/small industrial customer saves $10,179 ($126,850 over 20 years) by using H_2.
- Disregarding the impact on network costs, this represents the maximum amount customers could spend on H_2 appliances over NG appliances (including the cost of appliance conversions or bringing forward appliance replacement to cater for H_2), before it is more economic to adopt renewable methane.
- Looking at this another way, if we assumed that appliance unit costs (and conversion costs) and the timing of appliance replacement were exactly the same under a H_2 and renewable methane rollout, then the amount that could be spent on upgrading the network to accommodate H_2 is:
  - Residential customers = $19.5m in TOTAL
  - Commercial/small industrial customers = $134.3m in TOTAL

*The assumptions underpinning this figure are discussed in an Appendix to this report - but note they are first generation technology - unlike the H2 and Electric.

Explanation of results of high-level analysis – H_2 c.f renewable methane

<u>Conclusion</u>

- To be economic, the commodity cost savings resulting from the use of H_2 relative to renewable methane (e.g., $1,472 over 20 years for a residential customers), need to offset the:
  - The timing issue that we mentioned earlier, that is, if you move beyond a 10% blend by volume (over a short period), all gas end-use appliances in the affected area need to be converted or replaced at the time when the 10% by volume is to be exceeded, inevitably leading to the bringing forward of appliance conversion and replacement costs relative to the renewable methane option;
  - Incremental difference in H_2 appliance costs versus existing NG appliances; and
  - Cost of repurposing the network (including compression facilities) to deliver H_2.
- To illustrate the impact of the first one, bringing forward $10,000 worth of appliance purchases by 5 years, assuming a WACC of 5%, equates to $453 (~30% of the overall commodity savings of $1472 for a residential customer over 20 years)
- If the cost of H_2 appliances/conversion were $1,000 more in total, then the entire commodity savings would be wiped out; and
- In terms of impact on the network, whilst the age and likely existing (under) utilisation of TasGas' network is likely to mitigate some of the incremental network costs, it would not limit all of them (i.e., there will be some cost of conversion related to system controls and other technology issues as well as metering, etc.). There may also be constraints in some areas due to the volume derate – 66% derating takes place at the same pressures in terms of energy carried.

Explanation of results of high-level analysis – H_2 c.f renewable methane

Conclusion (cont'd)

- Finally, renewable methane has the added advantage of enabling the utilisation of existing transmission pipelines (noting that H_2 may cause embrittlement in transmission gas pipelines, precluding their use in transporting H_2). This generates a number of additional benefits for renewable methane, over and above what we have reflected in our quantification, including:
  - **Scale efficiency of production:** Everything else being equal, if H_2 can't be transported via transmission pipelines, then its production needs to be at a localised level (e.g., at a point where it can be injected at the distribution network), OR new H_2 transmission gas pipelines must be built. The former leads to a loss in scale efficiency, relative to if you could build larger, centralised, plants that transport their production via an existing network of pipelines. The latter solution (a network of H_2 transmission gas pipelines) has obvious issues from a cost perspective. Central plants will need new transmission gas pipelines or storage and trucking facilities with the associated problems and costs.
  - **Ability to use the TGP connected to the mainland:** Renewable methane means that the existing TGP pipeline can continue to be used, whether for: (a) the export of renewable methane to the mainland; or (b) for security of supply (e.g., ability to import gas - whether fossil or renewable - from the mainland to Tasmania to support Tasmania's security of supply, noting that without this, some buffer/storage is likely to be required, whether H_2 or renewable methane is adopted); or (c) as storage to even out renewable methane production.

Explanation of results of high-level analysis – H_2 c.f renewable methane

Conclusion (cont'd)

- **Easier to export on the world market:** Renewable methane is easier and cheaper to liquify than H_2, enabling easier access to export markets; mitigates the need for purchasing parties to have to change over appliances / end use equipment to cater for H_2 (if that was their next best alternative).

- Overall, we believe that conceptually, there are likely to be significant economic benefits from adopting renewable methane as compared to H_2 for this purpose – it is also incrementally consistent with hydrogen production and development – the perfect add-on to existing plans for hydrogen developments, or development of specific renewable methane reactors.

- The costs of bio-methane that have been proffered are also much lower than the current modelled costs for hydrogen and renewable methane (e.g. $18/GJ) and if this is the case and sufficient economic resource is available then bio-methane would be a clear preference for decarbonisation of the natural gas than either hydrogen or renewable methane production.

Explanation of results of high-level analysis – renewable methane to electric

Parameter	Residential customers		Commercial customers		Key Assumptions
PER annum differences - RM to Elec					
Diff Renewable Methane to electrification - TOTAL pa	$	6,886,475	$	47,336,412	Difference in total cost of production
Diff Renewable Methane to electrification - per Customer	$	519	$	44,699	Total cost / customer numbers
Commodity Cost savings over 20 year per customer - RM Vs Elec	$	6,465	$	557,050	PV over 20yrs, based on WACC of 5%
Assumed impact per customer on coincident peak demand (kW)		1.5		182	1.5kW coincident peak demand for res based on VIC; OGW est. load factor for commercial (0.6)
Backsolved LRMC to make it economic to go to RM if no gas network upgrages/		346		245	C.f TasNetworks of $100-150kVA
Amount that could be spent on elec appliance upgrades over NG appliance upgrades and still breakeven	$	4,596	$	330,046	Based on an LRMC of $100/kVA

- Comparing renewable methane to electricity ($24/GJ Vs $40/MWh commodity cost) the results indicate the following commodity cost (and therefore economic) savings:
  - Ave residential customer's bill increases by $519pa ($6465 over 20 years) if renewable methane is adopted instead of electrification.
  - Ave commercial/small industrial customer increases by $44,699 ($557,050 over 20 years) if renewable methane is adopted.
- Everything else being equal, this is the maximum additional amount that the customers could spend on electricity appliances over NG appliances (including bring forward appliance replacement) before it is more economic to adopt renewable methane.

Explanation of results of high-level analysis – renewable methane to electric

- To offset commodity cost savings, and hence for renewable methane to breakeven with electrification (assuming away appliance cost differences), an LRMC related to the additional peak demands placed on the electricity network would need to be as high as:
  - Residential customer = $346/kVA (based on a per customer average coincident peak demand of 1.5kVA).
  - Commercial/small industrial = $245/kVA (based on a load factor of 0.6).
  - As stated earlier, TasNetworks' current published (Annual Pricing Submission) LRMC is well below the above breakeven values, in the order $80 (HV Customers) - $140 (LV Customers).
- Looking at the analysis slightly differently, if we assumed a $100/kVA LRMC for TasNetworks' network, the residual amount that this would leave to spend on electricity appliance upgrades/conversions OVER and ABOVE what would need to be spent on renewable methane appliance upgrades, whilst still leading to electrification breaking even with renewable methane, is:
  - Per Residential customer = $4,596.
  - Per Commercial/industrial customer = $330,046.

Explanation of results of high-level analysis – renewable methane to electric

- On face value, based on our commodity cost assumptions, electrification looks appealing from an economic sense <u>where it is readily able to be done</u>, as is it difficult to envisage that residential customers would have to spend in the order of $4,500 extra to get electric appliances (and associated conversion costs) relative to natural gas appliances <u>in the future</u> (and again, this disregards the relative efficiency of some electric appliances relative to NG appliances); for commercial customers, the assessment is more difficult, as the customer segment is not homogenous, however:
  - For small commercial customers, gas usage appliances and volumes are likely to be relatively similar to residential customers, hence the same observation applies; and
  - For larger commercial customers, it is likely to be more bespoke, however the figures we have presented above highlight that on average, there is likely to be a substantial residual amount ($666,762) that is available to spend on electric appliances relative to gas appliances.
- If we assumed a higher cost of electrification, at say $60/MWh, whilst still assuming a $100/kVA LRMC for TasNetworks' network, the residual amount that this would leave to spend on electricity appliance upgrades/conversions OVER and ABOVE what would need to be spent on renewable methane appliance upgrades, whilst still leading to electrification breaking even with renewable methane, is:
  - Per Residential customer = $2,050.
  - Per Commercial/industrial customer = $110,747.
- At this level, renewable methane starts to look more appealing, from an economic perspective, as ~$2,000 per residential customer conversion (including appliance and other conversion costs), is not unrealistic.

Explanation of results of high-level analysis – renewable methane to electric

- Notwithstanding the previous analysis:
  - It is inevitable that not every commercial/small industrial customer can readily electrify their load; renewable methane or bio-methane are likely to be much more feasible options in those circumstances, as compared to the other gaseous fuel we have considered in this analysis (H_2);
  - Renewable methane and bio-methane have additional benefits over H_2, as outlined earlier; and
  - Renewable methane provides the means of attracting new customers' who may be 'shut out' of other markets that have adopted a blanket electrification/hydrogen solution.

Explanation of results of high-level analysis – natural gas to electric

Parameter	Residential customers	Commercial customers	Key Assumptions
PER annum differences - Natural Gas (NG) to Elec			
Diff NG to electrification - TOTAL pa	$ 471,995	$ 3,244,412	Difference in total cost of production
Diff NG to electrification - per Customer	$ 36	$ 3,064	Total cost / customer numbers
Commodity Cost savings over 20 year per customer - NG Vs Elec	$ 443	$ 38,180	PV over 20yrs, based on WACC of 5%
Assumed impact per customer on coincident peak demand (kW)	1.5	182.2	1.5kW coincident peak demand for res based on VIC; OGW est. load factor for commercial (0.6)
Backsolved LRMC to make it economic to go to NG if no gas network upgrages/	24	17	C.f TasNetworks of $100-150kVA
Amount that could be spent on elec appliance upgrades over NG appliance upgrades and still breakeven	-$ 1,426	-$ 188,825	Based on an LRMC of $100/kVA

- Whilst we stated earlier that a move away from natural gas (NG) appears to align with the broader macro factors and policies affecting Tasmania, it is still worthwhile understanding the relative costs of NG as compared to electrification.
- Comparing NG to electricity ($12/GJ Vs $40/MWh commodity cost) the results indicate the following commodity cost (and therefore economic) savings
  - Ave residential customer's bill increases by $36pa ($443 over 20 years) if NG is adopted instead of electrification.
  - Ave commercial/small industrial customer increases by $3,064 ($38,180 over 20 years) if NG adopted.
- Everything else being equal, this relatively small amount is the maximum additional amount that the customers could spend on electricity appliances over NG appliances.
- Once the impact on the electricity network is incorporated, the economics of retaining the existing gas network appear sound (however, this should be read, subject to all other caveats outlined in this report).

What about the two large transmission connected customers, and Hydro Tasmania?

Customer	Impact of strategy on end customers
Hydro Tasmania (HT)	• An electrification strategy increases electricity loads on island, which, if everything else were equal, would marginally increase the likelihood of HT having to rely on the GPG for 'on island' security of supply reasons. *However in the future,* this risk would be likely be mitigated by: (a) increased on island electricity generation in support of Tasmania's Renewable Energy targets; and (b) Project Marinus (assuming it is undertaken). • Therefore, even with electrification strategy, HT's reliance on TGP for gas delivery from the mainland may reduce, which in turn places downward pressure on the price it would be prepared to pay for access to the TGP e.g. could use day ahead auction platform. • However, the counterbalance to this is that if Tasmania's gas customers face higher costs to access the TGP due to reduced gas loads flowing to Tasmania over time, pressure may be placed on HT to provide financial 'support' to those customers via a continuing form GTA contract with TGP or other means.

What about the two large transmission connected customers, and Hydro Tasmania?

Customer	Impact of strategy on end customers
Hydro Tasmania	• A H_2 and/or renewable methane strategy reduces the electricity loads (hence reducing the impact on security of supply requirements from an electricity perspective). A renewable methane scenario also provides an alterative on-island source of feedstock gas for the power station, which lessens again the need for delivery of gas from the mainland to run the GPG off of natural gas. • For example, if HT were paying in the order of $20m per annum for transmission services, in addition to a cost of gas of ~$10/GJ, for in the order of 1.5 PJ per annum, the overall cost of gas is around $23.5/GJ – similar to our long-term estimate of the cost of renewable methane if H_2 costs decline to $3/kg. Overall comment: • In the long-run, an option that reduces natural gas demand is likely to be to the advantage of HT. Electrification, if combined with Project Marinus (to provide additional on Island security of supply), puts HT in a strong position to consider not supplying TVPS with gas from the mainland. The adoption of alternative gas options on-island, particularly renewable methane, are also likely to materially assist in this consideration.

What about the two large transmission connected customers, and Hydro Tasmania?

Customer	Impact of strategy on end customers
For Example: Grange Resources	• It is our understanding that there are some processes that are unable to be electrified, therefore, if continued reliance on NG is required even under a broader electrification strategy, the cost of NG is likely to go up, as electrification reduces the gas loads of other customers, hence forcing TasGas (and TGP) to try and recover some of the sunk costs from a smaller customer base – or cause them right-downs. • An alternative would be for these large customers to adopt on-site hydrogen, renewable methane or bio-methane production. The size of the loads would enable significant scale efficiency to be achieved, hence there may not be much difference to them of adopting a co-located electrolyser/methanation/bio-methane plant versus relying on a centralised plant(s) under a broader H_2 or renewable methane strategy (although a renewable methane strategy may assist negotiations for mainland delivered gas, TGP). • For example, our estimate is that collectively, these customers consume ~4.3PJ per annum, which equates to an electrolyser of around 220MW (based on a 1MW electrolyser producing around 140 tonnes per annum at around an 85% capacity factor (and a conversion factor of 1kg = 0.142 GJ)). Even at half this size (i.e., to reflect two electrolysers, at the two-different sites), the scale is significant.

What about the two large transmission connected customers, and Hydro Tasmania?

Customer	Impact of strategy on end customers
For Example: Grange Resources.	• Notwithstanding the above, even at a production cost of \$3/kg for H_2 (whether from centralised facilities, or on-site), the cost per GJ is around \$21 (more if renewable methane is adopted, although as stated elsewhere, this may negate the need to change out certain equipment - potentially less if bio-methane). At \$2/kg for H_2, the cost per GJ is around \$14, which may be starting to approach existing prices for natural gas (after transportation is taken into account). Whilst we can't be sure what each customers' marginal willingness to pay for gas is, on the presumption that is somewhere above \$14/GJ and below \$21/GJ, if a renewable methane strategy is adopted for example, it may be appropriate for Government to step in with a capital subsidy if these customers' are unable to access gas from the mainland at a competitive price - gas plus TGP charges. Overall comment: • Any move away from NG - whether via electrification, H_2 or renewable methane - will almost certainly negatively impact on the large connected customers. • The only proviso would be a methane mix - renewable and from the mainland - if a large renewable methane program were adopted for the broader gas industry, yet these customers continued to utilise NG (so the renewable methane limits the loss of load on NG networks, whilst these customer continue to purchase NG (potentially with offsets)). • Again bio-methane is also a potential option but needs more confirmation as to resource capability and costs.

What about the impact on remaining NG customers, if widescale electrification occurs?

- It is difficult to quantify the impact on any remaining NG customers, without undertaking detailed modelling and applying a significant number of assumptions (e.g., the timing of customer transfers; what contribution were those customers making to TasGas' overall revenue recovery; how might TasGas rebalance its tariffs overtime in response, including by reducing its overall revenue recovery over time).
- Notwithstanding the above, in assessing both Aurora Energy Retail and TasGas Retail's gas retail tariffs, the usage rates appear to be quite similar across both the companies, as well as both customer types (residential vs commercial) – at around $40/GJ.
- Based on OGW's Gas Price Trends Review 2017, in 2017, the average gas price delivered to Tasmanian households was 3.91 ¢/MJ, of which 1.91 ¢/MJ (49%) was the distribution component, 0.47 ¢/MJ (12%) was the retailer component, 1.00 ¢/MJ (26%) was the wholesale gas component and 0.53 ¢/MJ (14%) was the transmission component.
- Taking this information, if TasGas' network charges are broadly similar across both residential and commercial customer segments, and distribution charges make up around 50% of overall retail charges for residential and commercial customers, and assuming that the majority of TasGas' revenue is generated from variable charges, then broadly, a halving of gas volumes delivered (throughput) would broadly lead to a doubling in network charges (in order to allow TasGas to recover a similar amount of revenue) which would flow through to a ~25% increase in retail charges (this excludes any change in transmission costs).

Strawman strategy?

2022 → **Project Marinus** → **2040**

Electrification where economic; commence H2 blending; and technical analysis of renewable methane and bio-methane

Pivot from H_2 blending to renewable and/or bio-methane methane if technically and commercially feasible

As production of renewable methane increases, pivot volumes to other markets

2022

Appropriate information provision to support residential and commercial / small industrial loads switching where feasible, upon appliance replacement.

Commence blending small volumes of H_2 into gas network up to 10% by volume (s.t technical assessments).

Determine technical and commercial feasibility of renewable methane as an add on to the hydrogen strategy.

Cost complete hydrogen case for gas supply at the distribution level.

More detailed modelling of pathways, including bio-methane, as well as cross-sectoral benefits of different pathways (e.g., H_2 distribution for use in transport/mobility).

Project Marinus

Evolve from blending H_2 to primarily injecting renewable methane and bio-methane into the network (if technical and commercial feasibility stacks up).

No conversion of gas network to H_2, but continuation of small amount of blending if it supports mobility decarbonisation pathway.

TGP storage utilised to smooth out renewable methane production and potentially bio-methane production (if economic).

2040

Pivot supply of renewable methane towards other markets - e.g., VIC - as production grows and other markets ramp up demand for renewable gases.

TGP used to supply those markets.

Key enabling steps

Step	Discussion
Feasibility study into a 5 PJ/year renewable methane production module for Tasmania.	• This likely to be of the order of less than $5m to look at marginal additions to the existing hydrogen strategy and to look at a more integrated stand alone plant option (which is expected to provide much lower renewable methane prices). • Best undertaken with a key partner or two. • Would be a staged program - scope the studies first as this is a natural follow on from this work and consideration for a green gas strategy for Tasmania. • Scope out the other stages in this work.
Detailed cost-benefit analysis of transition pathways	• To be undertaken but will need pre-work such as Stage 1 above and more detailed modelling. • In particular work to be done on appliance issues - conversion to hydrogen focus - as this is the main option that requires appliance conversions or replacements (as a lot of the existing stock will not be convertible). • Finalise a short term strategy for natural gas supply at affordable levels (say 5 years holding strategy).
Develop policies to support the strategy	• Information for customers on costs and potential future pathways - what does it mean for them as they transition to low emissions? • Leading edge renewable methane development – support those that can develop high efficiency reactors and new plant (e.g. Universities, chemical plant developers). • Revise plan for hydrogen with proponents to see them examine adding on a 5 PJ/year renewable methane plant - what would be the real marginal cost?

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Appendix A: How we estimated the cost of Renewable Methane

- MAN, a large multinational company based in Germany that produces diesel engines and turbomachinery for marine and stationary applications such as marine propulsion systems, power plant applications and turbochargers, provided us with an estimated capital cost for a 5PJ/pa (13,700GJ/day) methanation plant. We thank them for that collaboration.

- We calculated a levelized capital cost based on the plant cost ($100m), production per annum (5PJ), a WACC of 5% and life of 20 years.

- In addition to the capital cost, we added an estimate of the levelized cost of operating the plant - which we assumed would be predominately driven by the costs of electricity. To inform this estimate, we applied the same wholesale electricity cost assumption that we have applied elsewhere in this report ($40/MWh), plus an allowance for transmission ($20/MWh), multiplied by an assumed electricity consumption of 400kWh per ton of CO2*, with this based on a published article outlining some of the characteristics of the Climeworks Direct Air Capture process ('The Role of Direct Air Capture in Mitigation of Antropogenic Greenhouse Gas Emissions', by Christoph Beuttler, Louise Charles and Jan Wurzbacher).

**Information from MAN indicated that 32t/h of pure CO2 would be required.*