21 January 2022

Renewables, Climate & Future Industries Tasmania
GPO Box 147
HOBART TAS 7001

Via: renewableenergy@stategrowth.tas.gov.au

Dear Minister,

TASMANIAN GAS FUTURE STRATEGY – DISCUSSION PAPER

Tas Gas welcomes the opportunity to provide input and recommendations on Tasmania's Future Gas Strategy Discussion Paper (the Paper) during the consultation period.

Tas Gas is an Australian energy company that works 24 hours a day to provide heat for families and businesses across Tasmania and regional Victoria. We own and operate the 839km distribution pipeline in Tasmania which is one of the most modern in Australia. It provides heat for cooking, home heating, hot water, and gas for commercial businesses and large industry every day. Tas Gas is also Tasmania's leading gas retailer. Tas Gas is privately owned by Infrastructure Capital Group.

Tas Gas supports initiatives to achieve a net zero carbon (NZC) gas supply. It sees this goal as not only consistent with Government policies and community expectations, but also one that presents business opportunities to Tasmanian industry in a low carbon energy world.

In this submission, Tas Gas offers five key recommendations for the future Tasmanian Gas Strategy that together we believe are integral to delivering greater energy security for the State while also aligning with a pathway to net zero. Appendix B to this submission provides detailed responses to the questions raised in the Discussion Paper.

Recommendation 1: Gas must be recognised as an essential part of Tasmania's future net zero carbon energy mix

Gas is essential to the provision of a reliable energy system in which businesses and the community can thrive. As such, it is recommended that the Tasmanian Future Gas Strategy be an integrated part of Tasmania's decarbonisation objectives. It must recognise that the gas industry is an important part of the energy mix, and that the role it plays is consistent with Tasmania's sustainability, economic and social objectives.

Gas is important in Tasmania today, playing an essential role in the supply of energy to meet annual demand. Currently natural gas makes up 15% of Tasmania's energy (electricity and gas) supply. Additionally, gas also plays a critical role for power generation and will also be needed for the production of hydrogen. Gas provides short term (daily or even hourly) peak energy support and back up to electricity which can swing as much as 50% from one day to the next.

In 2015/16 Tasmania saw how a stressed energy network behaves with the outage of the Basslink connector, compounded by low rainfall conditions which required the use of natural gas and diesel generation to maintain electricity supply. A NZC gas network would provide back up for future possible shortages and electricity generation and network issues. Tasmania's energy mix must ensure that it can respond to these changing circumstances and to the types of 1 in 10 and 1 in 20 year events to ensure energy security is maintained for the people of Tasmania. An energy strategy that fails to consider and plan for these risks, puts at risk the economic viability of industry in the State.

Despite the predicted demise of Gas, modelling demonstrates that this fuel is certain to remain an important part of the global energy mix in the future. The IEA in its 'Net Zero by 2050' scenario shows that globally natural gas made up 16% of the demand for energy in 2020. However, in 2050 the natural gas share falls to 6%, and renewable gas increases to 9%, for a total gas demand down just 1% to a 15% share. Maintaining gas industry assets and capabilities are clearly important, even with NZC targets.

Gas is essential for many businesses throughout Tasmania underpinning economic activity and growth. Currently, gas is estimated to directly support $1 billion in economic output and 4,000 direct jobs in Tasmania. Across Tasmania, 14,000 residential connections, 1,000 small to medium businesses and close to 70 industrial customers rely on gas to provide heat for their homes and businesses. Many of these businesses, including bakeries, hospitals, dry cleaners, restaurants, dairies, smelters and more, do not have a low cost and low-carbon energy alternative to provide their heating needs. Alternatives would be the reintroduction of coal, fuel oil, or burning huge amounts of biomass and this would be at the detriment to any transition to net zero. At the very least, the loss of Tasmania's gas system would put these jobs and economic contribution at risk or in need of redeployment. However, by developing the NZC gas sector, there exists the real opportunity to grow these businesses and attract new ones to Tasmania.

Recommendation 2: A hybrid fuel mix is important given the future is uncertain

We know that gas is essential, however what we do not know is what the optimal future NZC gas mix will be and the Tasmanian Gas Strategy and energy supply mix needs to be designed with reliability and affordability at the core of the decision. Tas Gas recommends minimising risk in pursuit of NZC by supporting a hybrid fuel mix. Whilst there is significant future uncertainty, what we do know is:

- It's too early to pick winners;
- Aggressive gas-out carries real risk to energy security and emissions reduction and may also have the effect of driving up energy prices; and
- Natural gas security of supply is robust.

It's too early to pick winners

NZC gases can be green hydrogen, bio-gas (including bio-methane) generated from organic sources, or NZC natural gas with carbon capture utilisation and storage (CCUS – where the carbon is captured and either used in industrial processes or stored underground) or carbon offsets.

A mix of these gases in a hybrid case is most likely to deliver the lowest cost and fastest path to NZC. Hydrogen produces a clean burning gaseous fuel, however the technology is not mature, is currently expensive, and end-user appliances will need to be upgraded for high hydrogen blends. Bio-gas can be directly substituted for natural gas, however volumes may be limited by availability of suitable feedstock. NZC natural gas infrastructure already exists, however there could be challenges to secure carbon capture and storage or offsets at scale in the long term. Therefore, a mix of gases will be required to navigate the energy transition and enable the NZC future.

Aggressive gas-out carries risk to energy security and emissions reduction

Any plan that focuses solely on limiting or eliminating supply and fails to address demand for gas will drive up energy prices, resulting in greater polarization around climate change and eroding progress. The pursuit of 100% electrification with an aggressive nil gas approach, creates real risks to energy security and emissions. It would remove a complete energy (gas) system which shares the energy load and backs up the electricity network. It also risks stranding industries, all of which must have mature economic energy options to compete.

New Zealand has demonstrated the consequences when this approach is not followed. The New Zealand government's plan to close down the petroleum industry is falling into place at a much greater speed than anticipated, with dramatic consequences for energy prices and national greenhouse gas emissions. Electricity price spikes due to low lake levels and gas supply issues have led to the restart of coal-fired generators. The resultant increase in greenhouse gas emissions would have been halved if natural gas remained as an option.

Natural gas security of supply is robust

The outlook for long term natural gas supply is robust, but the supply sources are likely to change. The expected decline of the Bass Strait gas fields will need to be replaced with further exploration, the use of long distance pipelines from gas fields in Queensland or the Northern Territory (NT), and/or LNG imports from Western Australia, NT, Queensland or internationally through import terminals being planned for Melbourne and Port Kembla.

Confidence in supply ensures that policy makers can plan on the basis that natural gas is able play its role as one component of the long term NZC gas mix (with CCUS or carbon offsets) or, at a minimum, as a transition fuel to NZC technologies that are still under development today.

Recommendation 3: Gas pipeline infrastructure and expertise is essential under any future scenario

The Tasmanian gas distribution pipeline system was completed in 2007, for an estimated capital cost of $230 million[1], excluding the Tasmanian Gas Pipeline which connects Tasmania to the Victorian gas system.

Today, 65% of energy across the National Electricity Market continues to come from coal fired power generation. The decarbonisation journey for electricity has provided the opportunity for electricity infrastructure to transition from "black" electrons to "green" electrons, and this transition is ongoing. Pipelines and gas distribution pipeline systems provide an existing delivery network to provide energy into people's homes, businesses and industry. Gas networks are on their own decarbonisation journey from "blue" molecules to "green" molecules and should be considered a valuable asset to continue to provide energy to consumers in Tasmania as this transition continues.

The Tas Gas distribution pipelines offer an efficient and effective way to move energy in the form of gas. In the future, it would be critical for the distribution of NZC gases such as hydrogen, bio-gas and NZC natural gas. Without pipelines, the only option would be to transport NZC gas by truck, with volume limits, safety concerns and higher unit costs.

Apart from the physical pipeline assets, the gas engineering and technical expertise of pipelines would be a critical skill for the development of hydrogen or other NZC gases at the manufacturing, transportation or utilisation stages. These skills need to be retained. For

[1] Electricity Supply Industry Expert Panel, 'Tasmania's Energy Sector – an Overview', April 2011; https://www.dpac.tas.gov.au/__data/assets/pdf_file/0017/141803/Tasmania_s_Energy_Sector_-_an_Overview.PDF

example, hydrogen as the lightest of gases is often stored at very high pressures – typically 3,500 to 7,000 kPa (5,000–10,000 psi), which requires the application of specialised gas storage engineers and operators.

Recommendation 4: Tasmania should begin transitioning to a NZC gas network now

Tasmania is uniquely placed to be a global leader in a NZC world. The opportunity for Tasmania is to attract new industry to Tasmania and increase global demand for NZC exports. The benefits from the resulting growth in Tasmanian businesses will flow to the community through new employment opportunities, new skills development and improved environmental outcomes. Tasmania's unique advantage include:

- Tasmania has the smallest state natural gas demand at approximately 7 PJ/a (12 months to end September 2021). This makes it easier to work with the gas industry and gas customers on NZC options and changes in fuel mix and appliance requirements;
- The gas distribution network owned and operated by Tas Gas is the most modern in Australia. The distribution pipelines were constructed in the last 15–18 years with HDPE pipe and several sections of high pressure steel pipe that are hydrogen-compatible, making the network more easily adapted to a wide range of gas mixes; and
- It is the only location in Australia currently capable of producing 100% renewable electricity all the time due to its large hydro power generation capacity. This is a strong starting point for manufacturing green hydrogen as a key element of the future gas strategy.

Capturing this opportunity means acting now to transition to a NZC gas network or Tasmania may lose the advantages to interstate or global competitors given global investment is occurring at a rapid rate and is set to continue. The International Energy Agency (IEA) in its NZC scenario puts the required global expenditure at US$5 trillion per year by 2030[2], and Deloitte estimates[3] the total figure is US$50 trillion to potentially up to hundreds of trillions of US dollars in total.

Recommendation 5: Government support is required to enable the transition

The Tasmanian Government has a key role in setting long term consistent policies, coordinating across industries and providing financial support to overcome development bottlenecks. To enable this transition, the Tasmanian Government must;

i. *Establish clear and consistent policy* that builds the confidence of industry to innovate and invest in the energy transition, and

ii. *Provide funding support* to bridge the affordability gap to net zero carbon gases whilst technology develops and costs come down.

Tas Gas is excited by the opportunity to support Tasmania's net zero carbon future. We note the essential role gas has to play in the energy transition and look forward to working with the

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[2] IEA, Pathway to critical and formidable goal of net-zero carbon emissions by 2050', 18 May 2021; https://www.iea.org/news/pathway-to-critical-and-formidable-goal-of-net-zero-emissions-by-2050-is-narrow-but-brings-huge-benefits

[3] Deloittes website, 'Will COP26 incentivize the scale of investment needed and deliver an equitable transition?', accessed 14 Jan 2022; https://www2.deloitte.com/global/en/pages/public-sector/articles/will-cop26-incentivize-the-scale-of-investment-needed.html

Tasmanian Government, businesses and broader community to capture the opportunities ahead.

The attached Appendix B provides more detailed data and analysis in response to the specific consultation questions.

We would welcome further discussions with RECFIT as this consultation process continues. For any questions please contact me on [redacted] or [redacted] (GM Commercial & Business Development) on [redacted].

Yours sincerely

Phaedra Deckart
Chief Executive Officer

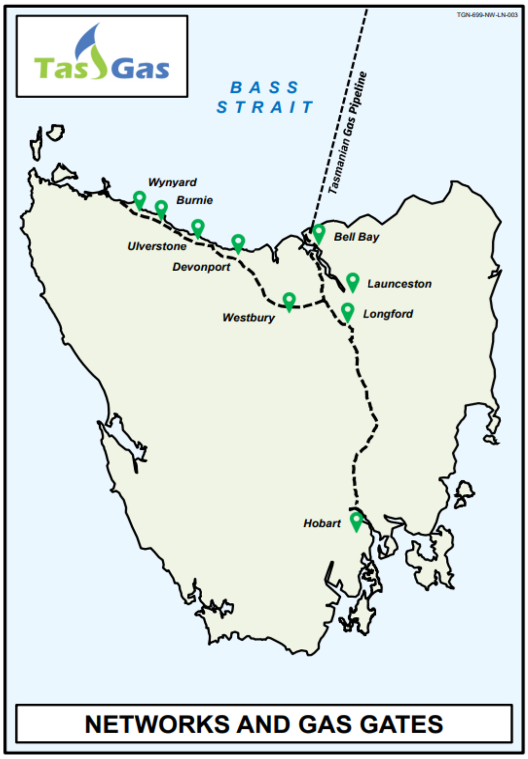
APPENDIX A: Tas Gas Background

Distributed natural gas first became available to Tasmanian homes and businesses in August, 2004, and has expanded across the state to towns including Hobart, Launceston, Devonport, Burnie, Wynyard, Longford, Bell Bay/George Town and Ulverstone.

Tas Gas is Tasmania's largest gas retailer and also operates the state's 839km natural gas distribution system (Figure 1), delivering natural gas to 14,700 homes and businesses in Tasmania.

The networks range in pressures and pipe diameters. It includes four steel high-pressure pipelines (up to 10,200 kPa) as well as high density poly ethylene (HDPE) plastic networks operating at 1,000 kPa and 500 kPa in sizes up to 250mm in diameter. The pipe infrastructure is compatible with renewable gases such as hydrogen and biomethane.

Figure 1. Tas Gas distribution networks and offtakes



Beyond Tasmania, Tas Gas also operates 182km of gas transmission pipeline in Western Victoria. It is also an innovative gas supplier using a 'virtual pipeline' to service 10 regional Victorian towns. The concept of the Virtual Pipeline sees gas supplied from a high pressure Natural Gas Transmission Pipeline to a "Mother Station" where it is further compressed and held in storage. Upon demand it is transferred into transportable high pressure cylinders, then delivered to a "Daughter Station" situated on the network at each town. Natural Gas is then supplied on demand into the network. In turn, the network then distributes Natural Gas and operates as per other conventional networks in Victoria. In its simplest explanation, the Virtual Pipeline (trucks) replace transmission pipelines. The Victorian network comprises, over 200km of HDPE gas networks, fronting over 12,000 premises and retailing to over 1,000 customers.

APPENDIX B: Detailed response to Discussion Paper

Drivers influencing the Tasmanian gas industry

Question 1: What factors do you think need to be considered in developing a strategy for the future of gas in Tasmania?

An effective Tasmanian gas strategy will:

A. Recognise gas as an essential part of the energy mix

Gas is a critical energy source for many industrial and commercial businesses. They must have confidence that they have a viable path to the NZC world.

Currently, natural gas is 15% of Tasmania's energy (electricity and gas) supply. Not only does gas supply energy to meet annual demand, it also supports short term (daily or even hourly) peak energy support and provides back up to electricity which can swing as much as 50% from one day to the next.

The IEA in its 'Net Zero by 2050' scenario[4] shows that globally natural gas made up 16% of the demand for energy in 2020. However, in 2050 the natural gas share falls to 6%, and renewable gas increases to 9%, for a total gas demand down just 1% to a 15% share. Maintaining gas industry assets and capabilities are clearly important, even with NZC targets.

The gas strategy must be an integrated part of Tasmania's decarbonisation objectives. It must unambiguously recognise that the gas industry is an important part of the energy mix, and that its support is consistent with Tasmania's sustainability, economic and social objectives.

The considerations of the strategy must not be too narrow and need to consider the use of carbon offsets as part of the decarbonisation path. For example, natural gas may be an attractive NZC energy option with properly certified carbon offsets.

B. Support existing customers and industries that rely on gas

Approximately three quarters of Tasmanian natural gas annual demand is from 16 large industrials (defined as those industrials with a load of more than 0.1 PJ/a) and gas-fired power generation (Table 1).

[4] IEA, 'Net Zero by 2050', Table A.2, May 2021; https://www.iea.org/reports/net-zero-by-2050

Table 1. Tasmanian gas demand by sector (indicative)

Sector	PJ/a	Annual Gas Consumption	Cumm %
Mining, smelting and minerals processing	2.7	38%	38%
Hot water/steam generation and cogeneration	2.8	40%	78%
Industrial feedstock	0.1	1%	78%
Total large industrial (greater than 0.1 PJ/a)	5.5	78%	
Other (Residential and small I&C)	1.1	16%	94%
Total non-GPG	6.6	94%	
Gas-fired power generation[1]	0.4	6%	100%
TOTAL	7.0	100%	

1. Historically, gas for power generation been variable year-on-year and may still be required for energy insurance purposes in the event of a wind or rain drought. For example, in 2019 GPG consumed 4.4PJ

Total annual consumption based on 12 months to 30 September 2021

The large industrials' use of gas falls loosely into three categories – hot water/steam generation, mining/smelting processes and industrial feedstock.

Hot water/steam generation and cogeneration is approximately 40% of the gas demand. It is a well-known industrial process, with multiple alternative fuel sources available for industrial grade heat. Options include moving to hydrogen or other NZC gas sources including bio-methane or bio-gas which currently are not cost-competitive, or LPG, fuel oil or coal which are higher carbon-emitting fuels. Electrification is not a viable alternative as it has limited capability to produce heat above 200 degrees Celsius. The critical factor is the impact of the gas strategy on costs to each of the industrials. It is conceivable that some industrials may be forced back to high carbon fuel oil or coal if the transition and option developments are not carefully managed.

Four large industrials who use gas in mining, smelting and ore roasting processes account for 40% of the gas demand. Typically these operations can use various fuel sources such as fuel oil and coal, and did so before the arrival of gas in Tasmania.

Natural gas is also used as an industrial feedstock (of methane) for the manufacture of fertiliser and other chemicals. This means there are higher constraints on what alternatives are feasible. These might include importing intermediate or semi-processed products, the use of LPG if the processing allows this, or the introduction of new NZC technologies under development.

There are of course many other smaller businesses in Tasmania with products and services reliant on gas such as bakeries, hotels, coffee roasters, dry cleaners, hospitals, and more as well as large industrials with large workforces. A few examples demonstrating the importance of gas for local businesses and the community who rely on their services include:

- Cripps Bakery who use gas to heat their ovens. Cripps explored electrification and determined that no other option than gas exists that is cost effective to provide the heading they need for their bakery ovens. Cripps is the number one supplier of baked goods across Tasmania
- The Royal Hobart Hospital has recently had a major redevelopment. As part of the redevelopment, gas has been installed to be used for cooking, hot water and to provide high grade heat for sterilisation
- The Marriott International's new hotel development in Hobart has installed gas for heating and cooking demonstrating the continued focus on gas as a fuel of choice for the hospitality industry. We have also seen similar consumer choices being made by

other newly established accommodation options for Tasmania's growing tourism sector including the Macq 01 Hotel, the Henry Jones Hotel and the Movenpick Hotel to name a few.

The gas strategy needs to work with individual large industrials, and more generally with the multitude of smaller businesses, to ensure that an energy source (or feedstock supply) is available which meets their business cost and low carbon requirements.

C. Achieve the lowest cost path to meet net zero carbon objectives for consumers and businesses

The cost to consumers and businesses is a critical consideration. The strategy must support maintaining the lowest possible cost of energy consistent with the decarbonisation pathway.

Research shows that while consumers are generally positive towards sustainable products, their willingness to pay is less so. The Harvard Business Review notes[5] 'a frustrating paradox remains at the heart of green business: Few consumers who report positive attitudes toward eco-friendly products and services follow through with their wallets. In one recent survey 65% said they want to buy purpose-driven brands that advocate sustainability, yet only about 26% actually do so'.

The strategy must ensure that people continue to have access to reliable and affordable energy sources and that consumers continue to have choice. This is the only way we can ensure that a green economy is fair and just and available to all. We must ensure that on the pathway to NZC we do not make decisions that drive up energy prices for those who can least afford it. The risk is that a material escalation in costs for consumers and businesses may erode support for NZC businesses and products.

The gas strategy must use cost analysis to consider the capital investment for new (or conversion of existing) equipment and appliances, as well as the lifetime operating costs of the fuel, against the alternatives. These can be substantial and need to be optimised for the Tasmanian situation. Government financial support will be required.

> **Case study: Leeds, UK H21 project**[6]. This project looked at converting the city of Leeds in the UK to hydrogen. The study considered converting an existing gas network with 264,000 meter points (99% domestic, 1% non-domestic) for a population of circa 660,000 people.
>
> The engineering study concluded that a conversion was feasible. The total capital cost estimate was GPB2.1 billion (A$4 billion, or A$14,782/meter point), with conversion of residential, commercial and industrial appliances at GBP1.1 billion (A$2.1 billion, or A$7,578/meter point). The balance was for hydrogen generation, storage and transmission. Ongoing annual costs were estimated at GBP0.139 billion (A$0.26 billion, or $A1,000/meter point) per annum.

These cost estimates highlight that the conversion to hydrogen is costly, and that using lower cost natural gas, at least as a transition fuel, must be a part of the NZC strategy. The lowest cost option for customers must be a consideration in any Tasmanian Government strategy.

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[5] Harvard Business Review, 'The Elusive Green Consumer', July-August 2019; https://hbr.org/2019/07/the-elusive-green-consumer

[6] H21 Leeds Project website, 'H21 Lees City Gate', p24 and p230, accessed 19 January 2022; https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Report-Interactive-PDF-July-2016.compressed.pdf

D. Optimise the transition to NZC and lower the risk to the Tasmanian economy

In progressing to a NZC future, not only is the path uncertain, but even when it is clear, for say a few years, then the risk to execution needs to be properly managed. The Government and gas strategy must build stability and confidence for industry and investors to innovate and commit capital to support the energy transition. New Zealand has demonstrated the consequences when this is not achieved.

> **Case Study:** The New Zealand (NZ) government is committed to reaching net zero emissions of long-lived greenhouse gas (such as methane and nitrous oxide) by 2050 and to reducing biogenic methane emissions by between 24% and 47% by 2050. However, the transition is already causing issues for energy security.
>
> The challenges are exacerbated by the NZ government's decision to end frontier natural gas exploration. In 2018, the NZ government announced it would no longer issue permits for offshore oil and gas exploration beyond Taranaki Basin. The NZ government expected exploration to continue in existing permits however this decision dented industry confidence in its future and the frontier explorers left leading to no further exploration whatsoever. Royal Dutch Shell plc left New Zealand in 2018 after more than 100 years of operation and they have been followed by a number of major explorers such as Equinor ASA (formerly Statoil) and Chevron Corporation also leaving.
>
> New Zealand's Gas Industry Company (GIC), established by the government in 2004 as a gas industry body and co-regulator with the sector, has noted the electricity sector and major gas users need certainty and transparency about gas supply as the country moves on the path towards a target of net zero. The report finds that a lack of predictability in policy settings is hampering investment.
>
> The impacts of this are being felt already. Methanol-producer Methanex, which consumes 40% of the total gas supply, has announced it will mothball part of its production and the GIC has started to investigate imports of LNG (likely from Australia) to manage the shortfall in supply and to get the country through the transition.
>
> The New Zealand government's plan to close down the petroleum industry is falling into place at a much greater speed than anticipated, with dramatic consequences for energy prices and national greenhouse gas emissions.
>
> New Zealand's wholesale electricity prices have soared over the past year from about NZ$80/MWh to NZ$300/MWh, leading to a temporary closure of the Norske Skog Tasman paper mill and production cuts by NZ Steel and Rio Tinto's Tiwai Point aluminium smelter, which is New Zealand's largest electricity user.
>
> The government has established an inter-agency team to monitor the electricity sector amid concerns over price and supply issues. Energy and Resources Minister, Megan Woods, said there is 'no need to panic' but acknowledges low lake levels and gas supply issues are causing serious issues.
>
> The immediate fix for New Zealand has been to restart coal-fired generators, which drove a 41% rise in coal imports in Q4 2020 compared to the same period in 2019. Coal generation for electricity in 2021 was at the highest level in nearly nine years.
>
> For the 12 months to 30 September 2021, coal generated 3.4 TWh in New Zealand, up 79% from the ten year average (2011–2020) of 1.9 TWh. Generating 3.4 TWh from coal is estimated to have emitted 3.3 Mt[7] of CO2 and the additional 1.9 TWh emitted 1.8 Mt

[7] For an emission factor of 0.974 t/MWh for Huntly, NZ power station. Source: Waikato Regional Council https://www.waikatoregion.govt.nz/assets/WRC/WRC-2019/TR201218.pdf

of CO_2, which would be half that if natural gas was used instead. The rushed New Zealand policy led to unintended consequences and a much higher and unexpected environmental cost without a gas option.

Moving to a new technology or infrastructure can be a high risk operation, and this is more so if the existing energy supply is abandoned prematurely leaving no fall back in the case of unexpected transition issues. In addition, it fails to provide the additional insurance required to manage for those 1 in 10 year and 1 in 20 year events, such as water or wind droughts, simultaneous heatwaves across multiple States and/or multiple generation units across the National Electricity Market experiencing outages, all of which have happened in Australia in the past 10 years.

The path to NZC needs to consider the risk of execution. It is recommended the strategy must optimise a low risk path which gives confidence to consumers and businesses.

E. Grow existing and new manufacturing industries in Tasmania

Beyond maintenance of existing industries, there is also the opportunity of growing these businesses and attracting new ones to the NZC future of Tasmania.

There are a number of factors which will support industrial growth in a NZC world:

- Consistent and long term policies;
- Robust and flexible infrastructure (e.g. pipelines, power, water, available NZC energy) which can support new industries and encourages growth in existing ones; and
- Openness to, and encouragement of, new proposals and concepts which may still be in the innovation or development phase.

The gas strategy must be flexible and agile in its support of new business and be careful to maintain infrastructure (including gas pipelines) and expertise which can be utilised to attract opportunities.

F. Develop skills and intellectual property for Tasmania

Tasmania is in a unique position to take advantage of the move to NZC with its gas strategy:

- Tasmanian has the smallest state natural gas demand at approximately 7 PJ/a (12 months to end September 2021), making it easier to convert the gas industry to meet new gas strategies and changes in the fuel mix;
- The gas distribution network is the most modern in Australia, and more easily adapted to fuel mix and other operational changes; and
- Tasmania has a large hydro power generation capacity to back green renewable gas options. It is the only location in Australia currently capable of producing 100% renewable electricity all the time. This is a strong point for manufacturing green hydrogen – an option for the gas strategy.

This combination enables Tasmania to be a leader in low carbon gas strategy and implementation. The expertise and experience gained from implementing the gas strategy can be exportable to other states and internationally.

G. Preserve options for uncertain energy pathways

While the objective of a NZC future is clear, the path to achieving that is still a work in progress.

Significant further technology development is necessary

The implementation of new technologies is a critical factor. The International Energy Agency (IEA) has noted[8] that for its 'net zero by 2050' (NZE) scenario, 'almost half of the emissions reductions needed in 2050 in the NZE come from technologies that are today at the prototype or demonstration state, i.e. they are not yet readily available on the market'.

McKinsey suggests[9] a similar estimate, 'that climate technologies that are already mature could, if deployed widely, deliver about 60 percent of the emissions abatement that will be needed to stabilise the climate by 2050. The challenge is that further abatement must come from climate technologies that aren't quite ready, including 25 to 30 percent from technologies that are demonstrated but not yet mature and another 10 to 15 percent from those still in research and development'.

This means it is impossible to reliably predict which exact mix of technologies will prevail, and the pace at which they will be commercialised to achieve the net zero carbon target.

Hydrogen and other NZC gas scenarios have a high degree of uncertainty

It is possible to develop gas scenarios which are consistent with longer term NZC objectives. However, the technologies are often still immature, or at least have not reached commercially competitive costs. This leaves long term forecasting with a high degree of uncertainty.

By way of example, the Australian Energy Market Operator (AEMO) estimated natural gas demand in the Gas Statement of Opportunities (GSOO) 2021 for three scenarios – Central, Slow Change and Hydrogen (Table 2).

Table 2. AEMO GSOO 2021 natural gas demand scenarios

Demand	Central			Slow Change			Hydrogen		
PJ/a	2020	2030	2040	2020	2030	2040	2020	2030	2040
Queensland	157	138	155	157	64	93	157	166	81
NSW/ACT	110	116	126	110	95	110	110	114	92
Victoria	214	191	210	214	167	183	214	182	184
South Australia	89	64	42	89	50	36	89	59	30
Tasmania	8	7	8	8	6	4	8	7	7
Total	578	516	541	578	381	426	578	528	394
% Change Tasmania		-13%	5%		-28%	-29%		-9%	3%
% Change Total		-11%	5%		-34%	12%		-9%	-25%
% Change to Central					-26%	-17%		2%	-24%

Source: AEMO

For 2030, natural gas demand varies from 528 PJ for the Hydrogen scenario (an increase of +2%, compared to the Central case) to 381 PJ for Slow Change (a decrease of -26%). The highest natural gas demand on 2030 is for the Hydrogen case.

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[8] IEA, 'World Energy Outlook 2021' p104, October 2021; https://www.iea.org/reports/world-energy-outlook-2021

[9] McKinsey, 'Innovating to net zero: An executives guide to climate technology', 28 Oct 2021; https://www.mckinsey.com/business-functions/sustainability/our-insights/innovating-to-net-zero-an-executives-guide-to-climate-technology

AEMO also estimated future hydrogen demand in its '2021 Inputs, Assumptions and Scenarios Report' [10] (Table 3).

Table 3. Hydrogen demand scenarios - AEMO 2021

	PJ/a	2019-2020	2029-2030	2039-2040	2049-2050
Progressive Change	NSW	0	6	17	49
	QLD	0	2	9	48
	SA	0	2	5	15
	TAS	0	0	1	3
	VIC	0	13	26	67
	NEM Domestic	0	22	58	182
Step Change	NSW	0	4	16	32
	QLD	0	2	24	90
	SA	0	1	4	26
	TAS	0	0	2	4
	VIC	0	8	14	28
	NEM Domestic	0	14	59	181
Hydrogen Superpower	NSW	0	13	56	117
	QLD	0	5	80	113
	SA	0	5	28	40
	TAS	0	0	3	5
	VIC	0	33	89	165
	NEM Domestic	0	57	256	440
Strong electrification	NSW	0	1	3	6
	QLD	0	0	2	3
	SA	0	0	1	1
	TAS	0	0	0	0
	VIC	0	1	2	4
	NEM Domestic	0	2	8	14

Source: AEMO '2021 Inputs, Assumptions and Scenarios Report', EnergyQuest analysis

Within these scenarios, hydrogen demand in 2049–50 varies from 14 PJ to 440 PJ, from zero today - indicating the high degree of forecasting uncertainty.

Beyond green hydrogen, NZC gases can include bio-gas (including bio-methane) generated from organic sources, or NZC natural gas with carbon capture utilisation and storage (CCUS) or carbon offsets. It is also possible to mix these gases in a hybrid case to take advantage of lower costs and available volumes. The optimal future mix of energy is highly uncertain with varying pros and cons (Table 4).

[10] AEMO '2021 Inputs, Assumptions and Scenarios Report', July 2021; https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf?la=en

Table 4. NZC gas scenarios with pro's and con's

Gas scenario	Description	Pro's	Con's
100% hydrogen	Convert the gas system to 100% hydrogen	Clean burning gaseous fuel.	Technology not mature. Still expensive. Needs very low electricity prices. Electricity must be zero carbon. Distribution system and end user appliances need to be adapted to hydrogen.
Bio-gas (including bio-methane)	Generate NZC methane gas from organic sources e.g. agricultural waste, sewerage	NZC methane. No need to change distribution systems or user appliances.	May be limited by volumes which can be produced. Potential conflicts with agricultural uses e.g. organic fertilisers.
NZC natural gas	Continue with natural gas, using either carbon capture and storage or carbon offsets	NZC methane. No need to change distribution systems or user appliances.	Potential challenge to secure carbon capture and storage or enough carbon offsets long term
Hybrid	Mix of hydrogen, bio-gas and NZC natural gas	Not picking a winner. Lowest cost wins.	Mix may be limited by gas quality requirements e.g. Wobbe index. Sourcing long term gas at a low cost may be uncertain.
Nil gas	Total electrification of the energy system	Simple conceptually, and utilises green hydro power with wind and solar.	Requires large expansion of electricity distribution system to accommodate additional load and peaks. All eggs in one basket for uncertain future. Lose options and expertise in gas technologies. Will not suit all industrial demand. All residential, commercial and industrial gas appliances will have to be replaced.

Source: Tas Gas analysis

This high degree of uncertainty highlights the need to maintain optionality and to not pick winners whilst technology continues to develop and transition costs are better understood.

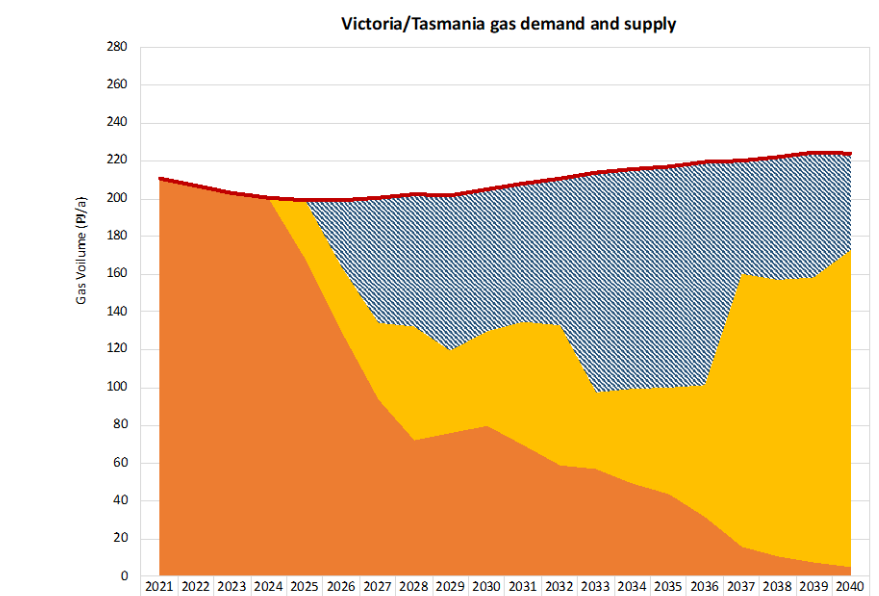
Question 2: What changes are you, or members of your industry, observing related to global and domestic market settings for fossil fuels that could potentially impact on the outlook for gas in Tasmania?

A. The east coast natural gas market is facing shortfalls, however declining Bass Strait natural gas production will be supported by long distance gas from Qld and NT and LNG imports

Tasmania has benefited from its close proximity to the Bass Strait gas fields which have historically met the gas demand of Victoria and Tasmania, and exported additional supply to NSW and South Australia. Bass Strait gas fields are now entering their decline phase[11], and supply is expected to be unable to meet 'business as usual' (BAU) demand for Victoria and Tasmania by around 2025. From then, additional long distance gas from Queensland and the Northern Territory will be required through the existing North to South pipeline network and supported by LNG imports (Figure 2). In this BAU scenario, LNG imports are expected to make up one third of gas supply to Victoria and Tasmania before the end of the 2020's, and more than half of gas supply by the mid-2030's.

This scenario has the (yet to be sanctioned) NSW Narrabri gas field being available by 2026 to meet NSW demand, which is not certain. If it is delayed, then gas supply for south-east Australia will face a more challenging period.

Figure 2. Victoria/Tasmania gas demand and supply



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LNG imports	0	0	0	0	0	35	67	70	82	75	73	78	116	116	117	118	60	65	66	51
Northern gas supply	0	0	0	0	31	34	40	60	44	50	65	74	41	50	56	70	144	147	151	168
Victorian gas supply	211	207	203	200	168	130	94	72	76	80	70	59	57	49	44	31	16	10	7	5
Vic/Tas Demand	211	207	203	200	199	199	201	202	202	205	208	211	214	215	217	219	220	222	224	224

Source: EnergyQuest analysis

[11] AEMO, 'Gas Statement of Opportunities – 2021', March 2021; https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo

B. Supply shortages will increase volatility in domestic gas prices which will trend to LNG import pricing

How Tasmania gets its gas?

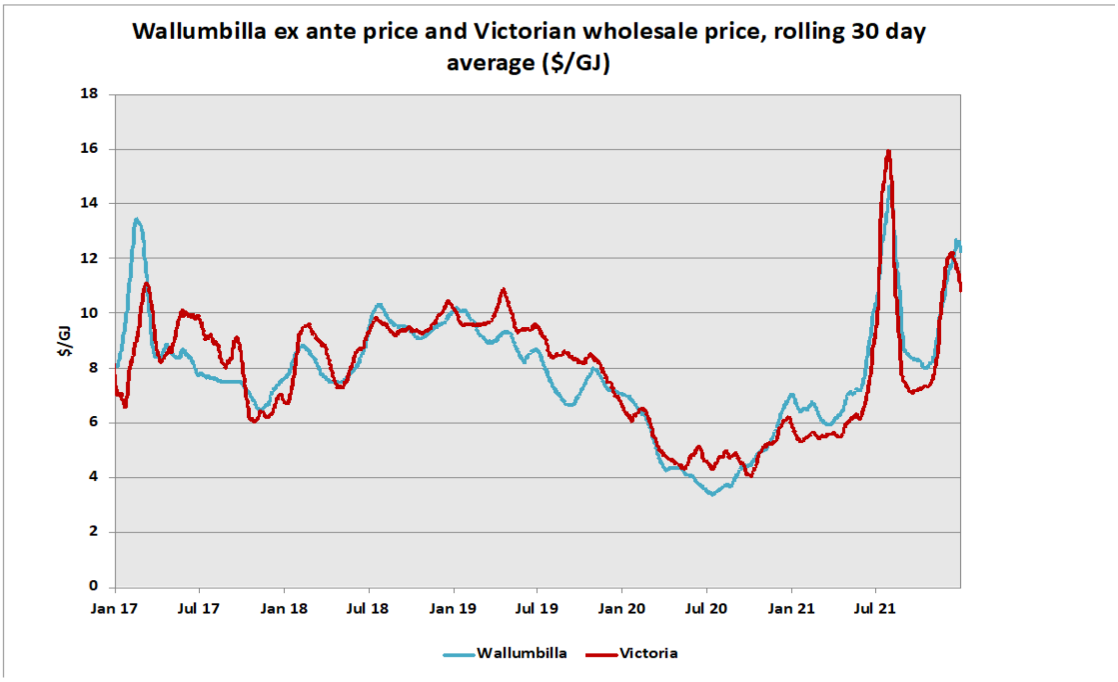
There are two designated gas supply hubs on the east coast of Australia. One in Queensland at Wallumbilla in the heart of the coal seam gas (CSG) resources, and the other is the Victorian Designated Wholesale Gas Market (DWGM), which is the closest trading hub to Tasmania. Short term trading markets also operate in Adelaide, Sydney and Brisbane.

Shipping from Longford across Bass Strait in the Tasmanian Gas Pipeline (TGP) to Bell Bay adds costs for both Jemena compression into the pipeline and the TGP tariff. TGP transmission pipeline costs from Bell Bay to reticulated network areas in Tasmania add additional costs for delivered gas. The Victorian gas market is approximately 214 PJ/a compared to Tasmania's 7 PJ/a. Gas prices in Tasmania are expected to follow trends in the larger Victorian DWGM, although individual Tasmanian contracts with specific contracted prices and time frames may cause some differences from the DWGM spot prices.

Historical gas prices

In 2021, the DWGM averaged $8.22/GJ ranging from a daily minimum of $4.90/GJ to a maximum of 34.98/GJ. The northern Wallumbilla gas supply hub averaged a higher $8.90/GJ, but was within a smaller range from a daily minimum of $5.70/GJ to a high of $19.50/GJ (Figure 3). The higher volatility in gas prices was driven by a number of factors including coal-fired power generator issues (e.g. Callide turbine failure mid-2021), renewables volatility, declining gas reserves and record setting global LNG prices. Tas Gas expects this type of gas price volatility to be a feature of future markets.

Figure 3. Gas supply hub prices - rolling 30 day average



Source: AEMO

A scenario for future gas prices

As more gas is shipped longer distances and LNG imports become a bigger part of the gas supply mix, then inevitably gas prices in the DWGM and Tasmania will rise.

Viva Energy is developing an LNG import facility at Geelong which would be the closest such facility to Tasmania. Long term Asian LNG contracts are mostly linked to an oil index such as Brent or the Japanese Customs-cleared Crude (JCC) oil price. Tas Gas estimates the delivered gas price from the Geelong facility to Bell Bay would be in the range of approximately $12.28/GJ to $17.85/GJ for oil in the range of US$50/bbl to US$90/bbl (Table 5).

Table 5. Estimated cost of imported LNG to Bell Bay

Brent or JCC US$/bbl	**US$/bbl**		**50**	**60**	**70**	**80**	**90**
Slope/Beta	**%**	**11%**					
Sale Price FOB Singapore	US$/MMBtu		5.50	6.60	7.70	8.80	9.90
Shipping to Geelong	US$/MMBtu	1.22					
LNG at Geelong	**A$/GJ**		**8.49**	**9.88**	**11.27**	**12.66**	**14.05**
Regas cost	A$/GJ	1.09					
Ex-plant	**A$/GJ**		**9.58**	**10.97**	**12.36**	**13.75**	**15.14**
Pipeline to Melbourne Metro	A$/GJ	0.36					
Delivered Melbourne Metro	**A$/GJ**		**9.93**	**11.32**	**12.71**	**14.10**	**15.50**
Pipeline to Bell Bay	A$/GJ	2.35					
Delivered Bell Bay	**A$/GJ**		**12.28**	**13.67**	**15.06**	**16.45**	**17.85**
Exchange rate	**US$/A$**	**0.75**					
Conversion	**GJ/MMBtu**	**1.055**					

Source: EnergyQuest analysis

It may seem strange that Australia, as the world's largest LNG exporter, would need to import LNG to the south-eastern states, but LNG is considered as a virtual pipeline from Western Australia (or any other LNG exporting area). With this point of view, Viva Energy announced[12] that it had signed a memorandum of understanding with Woodside, to look into the supply and regasification of LNG for the east coast Australian market.

Pipeline costs for long distance gas from QLD's CSG fields add approximately $2.63/GJ. NT gas at current pipeline tariffs would add between $5.53/GJ to $6.06/GJ to the NT ex-plant gas costs which is estimated to be in the range from around $6/GJ to $12/GJ, for a delivered NT gas cost of $11/GJ to $18/GJ to Melbourne — comparable to LNG imports. This may be lower if new pipelines are built and higher volumes are developed. Commercially this northern (NT and QLD) gas would also have LNG export feedstock markets in Darwin or Gladstone as an alternative to selling to southern markets.

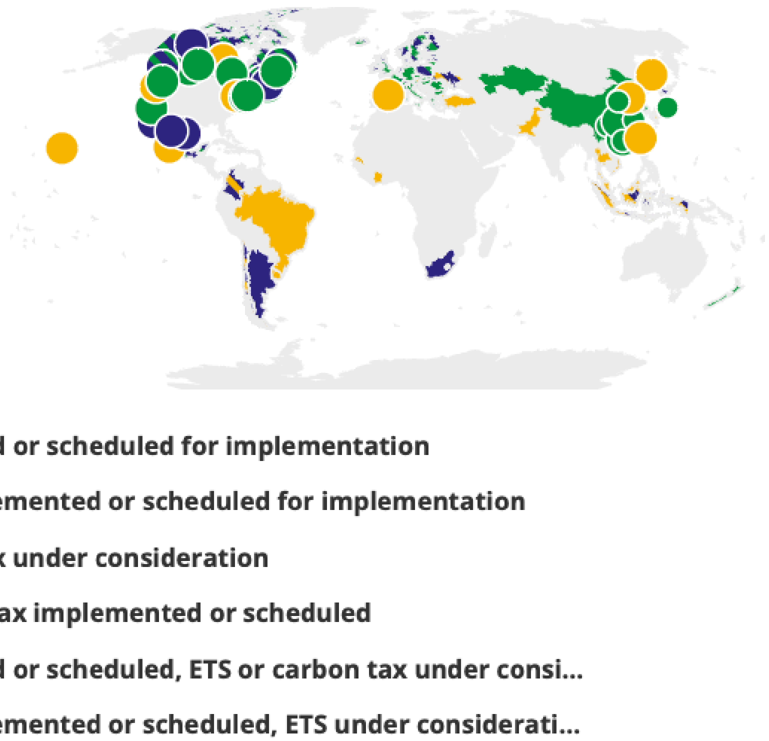
This suggests that by the 2030's, LNG import prices will be a key determinant of gas prices for Victoria and Tasmania in the BAU scenario. Tas Gas expects Tasmanian gas prices to be then in the range of $12/GJ to $18/GJ (real $2021).

[12] Viva Energy, 'MoU agreed with Woodside to progress LNG regasification agreement...', 9 Dec 2021; https://www.vivaenergy.com.au/media/news/2021/mou-agreed-with-woodside-to-progress-lng-regasification-agreement-viva-energy-signs-heads-of-agreement-for-fsru

C. Global market demand is moving to net zero carbon regimes and foreshadows where Australia will head

Globally there are growing initiatives to implement Emissions Trading Schemes (ETS) or Carbon Tax regimes (Figure 4).

Figure 4. Summary map of regional, national and subnational carbon pricing initiatives

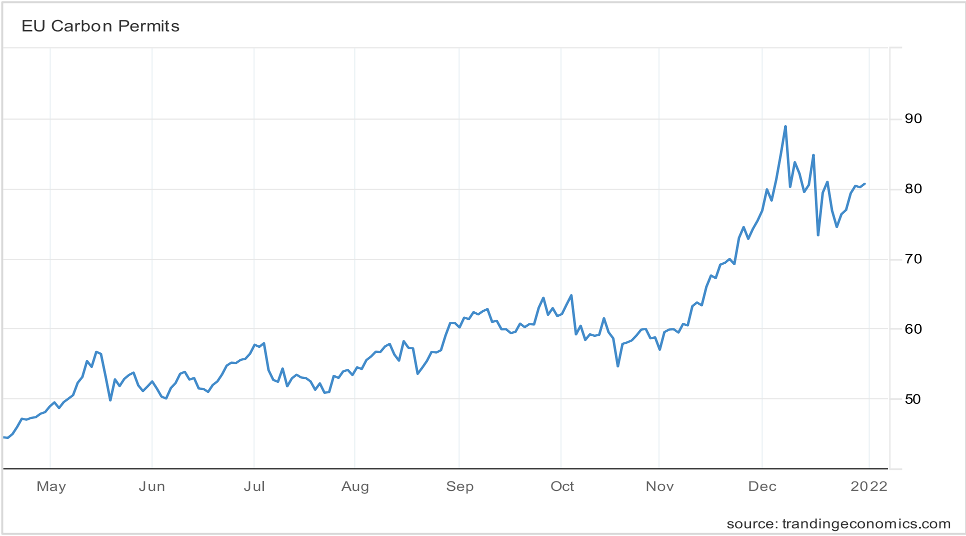


Source: World Bank, April 2021[13]

The European Union (EU) operates the most advanced ETS in the world. Prices for the European Emission Allowance (EEA) have increased from around EUR 44/tCO2e (A$69/tCO2e) in April 21 to EUR 81/tCO2e (A$128/tCO2e) at the end of December 2021.

[13] The World Bank, 'Carbon Price Dashboard', 1 April 2021; https://carbonpricingdashboard.worldbank.org/map_data

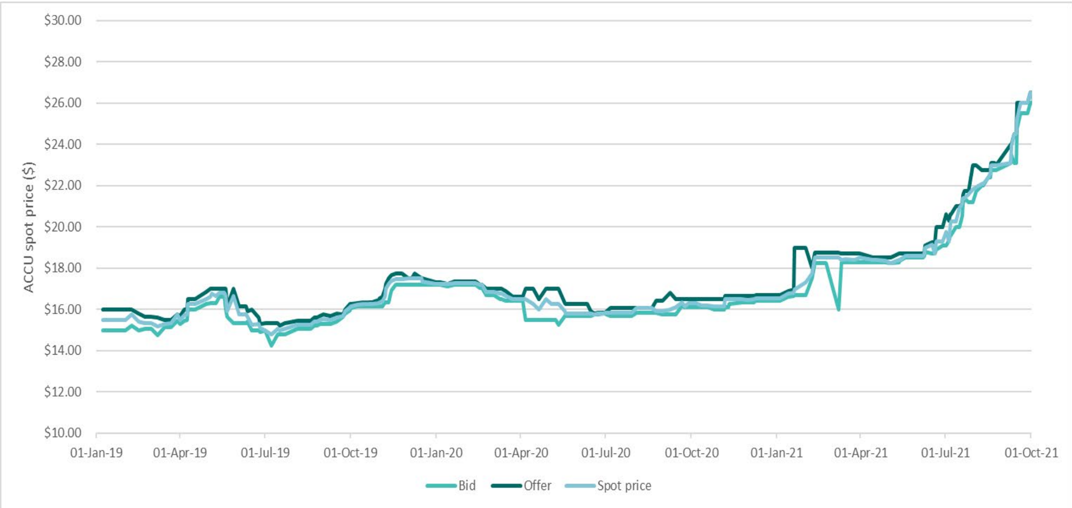
Figure 5. EU Carbon Permits (EUR/tCO2e)



Note: 1 EUR = A$1.58

Compared to the EEA, the Australian Carbon Credit Unit (ACCU) was around A$49/tCO2e — only 38% of the EEA. This record December pricing was already double the price seen in earlier 2021 of around $16 to $18/tCO2e, and previous years (Figure 6).

Figure 6. Historical ACCU spot prices (A$/tCO2e),January 2019 to September 2021



Source: Clean Energy Regulator, Sept 2021 Quarter Report[14]

This volatility in carbon pricing is a challenge to business both within Australia, and in accessing export markets. For export markets, there is already consideration of applying carbon border tariffs to imported products.

[14] Clean Energy Regulator, 'Quarterly Carbon Market report – September Quarter 2021', 26 Nov 2021; http://www.cleanenergyregulator.gov.au/Infohub/Markets/quarterly-carbon-market-reports/quarterly-carbon-market-report-—-september-quarter-2021

The EU has tabled a 'Carbon Border Adjustment Mechanism' [15] (CABM) which is designed to reduce 'carbon leakage'. Carbon leakage occurs when either production is transferred from the EU to other countries with lower ambitions for emission reduction, or that EU products are replaced by more carbon-intensive imports. If this risk materialises, there will be no reduction in global emissions, and this will frustrate the efforts of the EU and its industries to meet the global climate objectives of the Paris Agreement. The CABM will be phased in gradually and will initially apply only to a selected number of goods at high risk of carbon leakage: iron and steel, cement, fertiliser, aluminium and electricity generation. The EU plans to start reporting in 2023, and have the CABM fully operational by 2026[16].

A CABM is in effect a tax on the carbon content of imported products. For these markets, any potential advantage imports from a high carbon economy has in cost, is taxed away with the CABM.

Tasmanian products from a zero carbon economy need to be able to avoid the application of the CABM or similar tariffs into export markets. The gas strategy will support access by Tasmanian products to zero carbon markets.

D. Capital funds are supporting leading, credible low carbon initiatives

Capital funds are supporting sustainable initiatives.

It was reported[17] that at 30 September 2021, 'sustainable funds' around the world had a total of $US3.9 trillion ($5.3 trillion) in assets under management. In Australia, these green investment products are worth a collective $38 billion, up 11 per cent over the September quarter'.

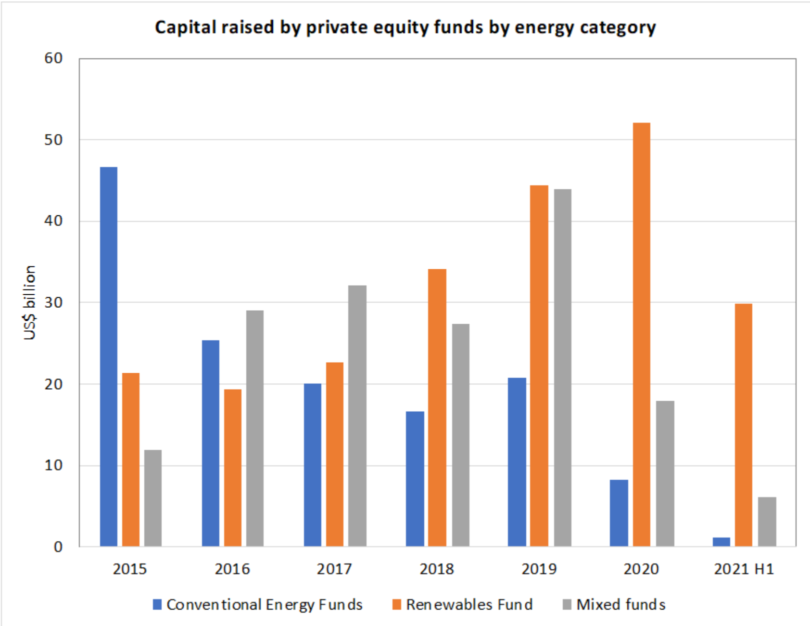
The mix of funding is moving from conventional energy to renewables (Figure 7).

[15] European Commission, 'EU Green Deal (carbon border adjustment mechanism), 2020; https://ec.europa.eu/info/law/better-regulation/have-your-say/initiatives/12228-Carbon-Border-Adjustment-Mechanism/public-consultation_en

[16] European Commission website, 'Carbon Bord Adjustment Mechanism', accessed 15 January 2022; https://ec.europa.eu/taxation_customs/green-taxation-0/carbon-border-adjustment-mechanism_en

[17] Australian Financial Review article, '$5 trillion powering the green investment market', 17 November 2021; https://www.afr.com/companies/financial-services/5-trillion-powering-the-green-investment-market-20211110-p597nv

Figure 7. Capital raised by private equity funds by energy category



Source: Bloomberg[18]

The gas strategy needs to be able to build on Tasmania's record of sustainable development, and set the ground work for attracting capital funding for the full range of NZC energy options — including gas technologies and infrastructure.

Who uses gas and for what?

Question 3: If you use gas in the home, what do you use it for? Are you connected to the natural gas network or do you have LPG delivered?

Tas Gas Retail household customers use gas in the home for gas cooking, instantaneous gas hot water, gas heating (ducted heating, hydronic heating, flame-effect fires) and gas barbecues.

Question 4: If you are a business that uses gas, what industry are you in? What do you use gas for?

Discussed in Question 1 (B).

Question 5: Are your gas appliances coming up for replacement? Are you considering switching to electricity or another alternative?

Residential gas appliances generally fall into the three categories of heating, cooking or hot water heating. Gas cooking appliances have a long working life (gas cook top 15–17 years, gas

[18] Bloomberg, 'Private equity follows the money – and the money is ditching fossil fuels', 6 July 2021; https://www.bloomberg.com/news/articles/2021-07-06/private-equity-is-ditching-fossil-fuels-over-climate-change-concerns

oven 10–18 years[19]), and generally last until the next kitchen renovation which is around 10–15 years. Gas heaters are similar at 13 –18 years[20]. Industry experience for gas hot water heaters is 7–10 years for storage hot water, and up to 20 years for instant hot water[21], and consumers generally run hot water heaters until failure. Individual gas appliances life time may vary around these indicative averages.

Given natural gas became available in Tasmania from 2004, the oldest natural gas appliance would be 18 years old. Compared to other areas such as Victoria, natural gas appliances in Tasmania are a younger stock. LPG hot water heaters may be older as it has been available in Tasmania for longer.

The decision by Tasmanian residential and business gas users to convert to gas or install gas appliances is a comparatively recent decision, and the conversion to electricity or alternative fuels is not only one of economics, but also involves individual preferences. For hot water heaters, the urgency of the replacement after failure means it is more likely that the fuel type (based on existing connections) would be unchanged. Room heaters may be upgraded to central heating or when a refurbishment occurs. The decision to move from a gas to electric cook top relates strongly to consumer preferences and the nature of the kitchen refurbishment.

Outlook for gas

Question 6: What do you see as the key opportunities and concerns as a gas user in Tasmania?

Tas Gas customers are concerned about:

A. Cost of energy

Business customers need low cost energy to support their competitive positions in Tasmanian, Australian and export markets. This is especially important for products which are price-takers i.e. the price is set by competitive global markets.

Residential customers are sensitive to increases in costs which they perceive they have little control over.

B. Location of network and ability to connect today and in the future

Business customers need to be able to connect to low cost and reliable energy at their sites. They also need to be able to grow their energy supply with the growth in the business. Infrastructure constraints and delays in expansion are detrimental to business growth.

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[19] International Association of Certified Home Inspectors, 'InterNACHI's estimated life expectancy chart' ; https://www.nachi.org/florida-life-expectancy.htm

[20] ASHRAE, 'Equipment Life Expectancy Chart'; https://www.info.com.au/serp?q=gas+furnace+life+expectancy&page=2&sc=4ffarHPnhTAo00

[21] Ryan Old Plumbing, 'How long do hot water systems last'' 14 June 21; https://www.ryanoldplumbing.com.au/plumbing-blog/how-long-do-hot-water-systems-last/

C. Reliability of supply

All consumers value reliability of supply. It is still difficult for many consumers to properly price this reliability, and make economic decisions to interrupt energy supply. This may be an opportunity to be developed.

D. Impact on environment

Most consumers see the value of being environmentally responsible. Policy settings must also respond to evolving market demand, as well as alternative supply options. However, the ability to fully pay for this responsibility is limited, as discussed in Section 2.2.

Question 7: What is your view on the outlook for the pricing of gas in Tasmania?

Discussed in Question 2 (B)

Question 8: Given the forecast supply shortfalls and reliance on importing gas, do you think there is any risk of supply of gas from mainland Australia?

Long term gas supply to the east coast is available as discussed in Question 2 (A). This supply is based on a combination of ongoing south-east gas production, long distance gas from QLD and the NT, and LNG imports. While this represents a new combination of supply options for the Victorian and Tasmanian markets, it is not new in the global market and is similar to the existing gas supply for the EU (Figure 8) which uses declining North Sea, Dutch and other domestic gas production, long distance gas pipelines from Russia, Libya and Algeria, and numerous LNG import terminals across the EU.

Figure 8. European gas network, and supply connections

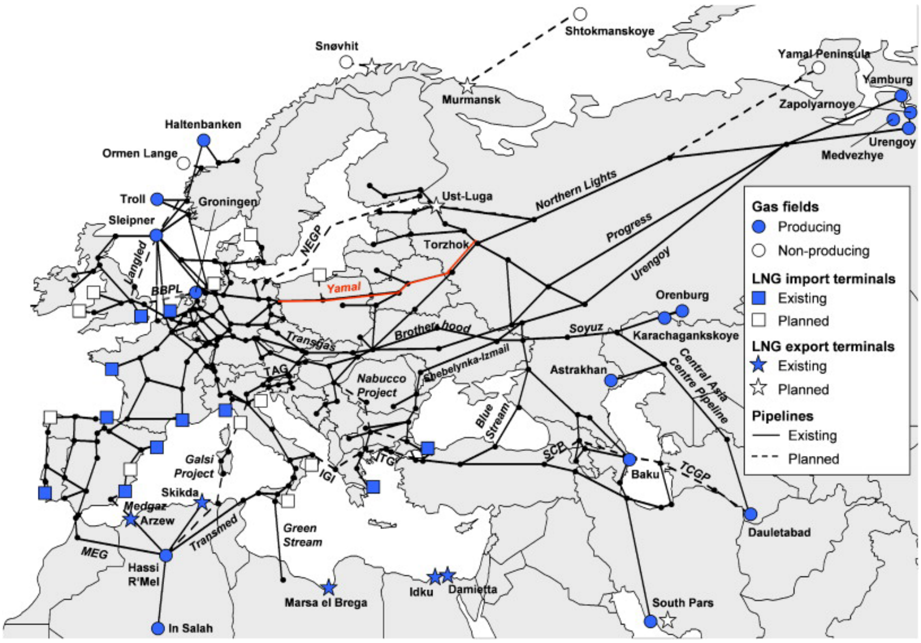


Image source: Sciencedirect.com

Question 9: If natural gas was unavailable in Tasmania, what would you do? Would you be considering moving to LPG, or to another alternative?

Discussed in Question 1 (B)

Decarbonisation pathway

Question 10: Should Tasmania be transitioning to a decarbonised gas network?

A. Tasmania should be transitioning to a net zero carbon gas network

Tas Gas uses a broader definition of 'net zero carbon' which would include natural gas with carbon offsets. Technically carbon would remain as part of that gas mix (i.e. not strictly decarbonised), however the net contribution to carbon in the environment is zero, i.e. has been offset through carbon abatement or carbon offset options.

A NZC gas network is consistent with community expectations and the stated Tasmanian Government policy of net zero emissions by 2030[22]. It is also builds on the clean, green Tasmanian brand. The transition must take account of the full costs and economic impacts, as well as all gas supply options including hydrogen, bio-gas and NZC natural gas.

Tasmania's modern gas distribution network has an advantage of being more easily adapted to a fuel mix and other operational changes to support a transition to a decarbonised gas network. A decarbonised gas network would build capabilities and expertise in a technology which could be exported to other markets.

It leverages off Tasmania's strengths as a leading renewable economy. A decarbonised gas network would support emerging industries such as hydrogen production by connecting supply with demand.

B. A decarbonised gas network would be a key part of Tasmania's future energy system

A decarbonised gas network would be an important part of the zero carbon energy system in Tasmania.

Gas is already a material part of energy supply to businesses and households.

In Tasmania, 6.9 PJ/a (1.9 TWh/a) of natural gas is used in energy supply (less gas chemical feedstock volumes). This is 15% of the total energy (electricity at 10.7 TWh/a, and gas) consumed in Tasmania.

The importance of gas to businesses was discussed in Question 1 (B).

For households with natural gas connected, gas is around two thirds of the household's energy supply (Table 6). Note this does not include LPG.'

[22] Premier P Gutwein media release, 'Securing Tasmania's status as a climate leader', 13 October 2021; https://www.premier.tas.gov.au/site_resources_2015/additional_releases/securing_tasmanias_status_as_a_climate_leader

Table 2. Tasmanian household energy consumption

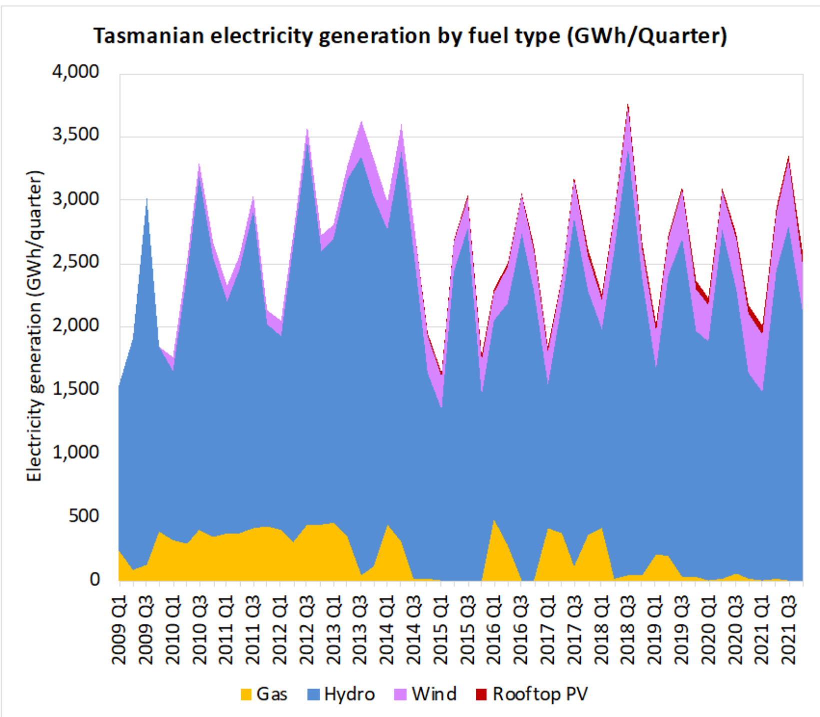
Energy Consumption	Unit	Energy	%
Electricity only households	KWh/a	9,060	
Dual fuel households			
Electricity	KWh/a	6,400	37%
Gas	GJ/a	40	
	KWh/a	11,112	63%
Total	KWh/a	17,512	100%

Source: St Vincent de Paul, 'Tasmanian Energy Prices' [23]

A NZC gas distribution network would also support the electricity distribution system on peak days

Tasmanian electricity generation is dominated by hydro (Figure 9), but this has historically been backed up by natural gas power generation which has been as high as 20% of the generation mix (Figure 10).

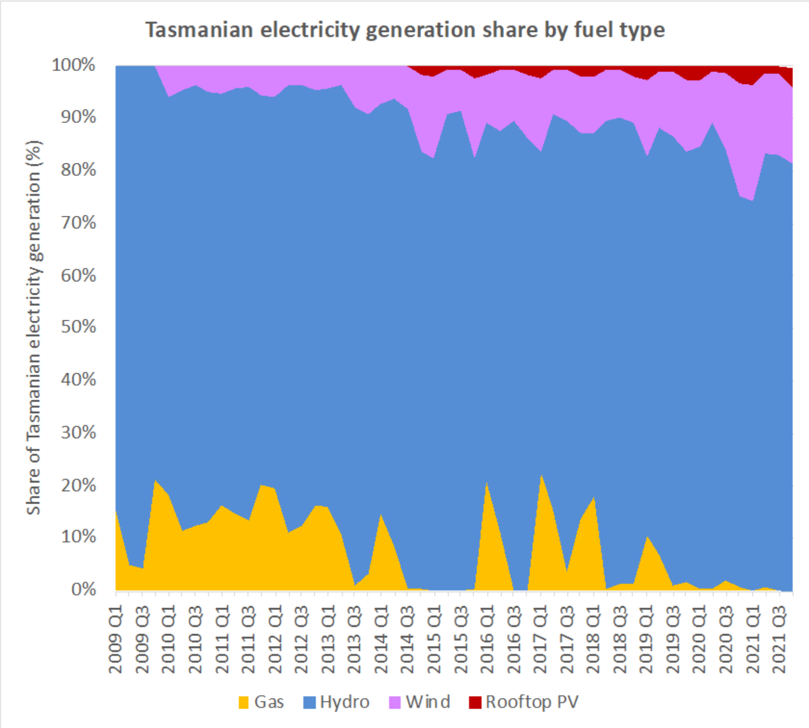
Figure 9. Tasmanian electricity generation by fuel type



Source: AEMO

[23] St Vincent de Paul, 'Tasmanian Energy Prices', July 2021; https://www.vinnies.org.au/icms_docs/329193_Tasmanian_Energy_Prices_July_2021.pdf

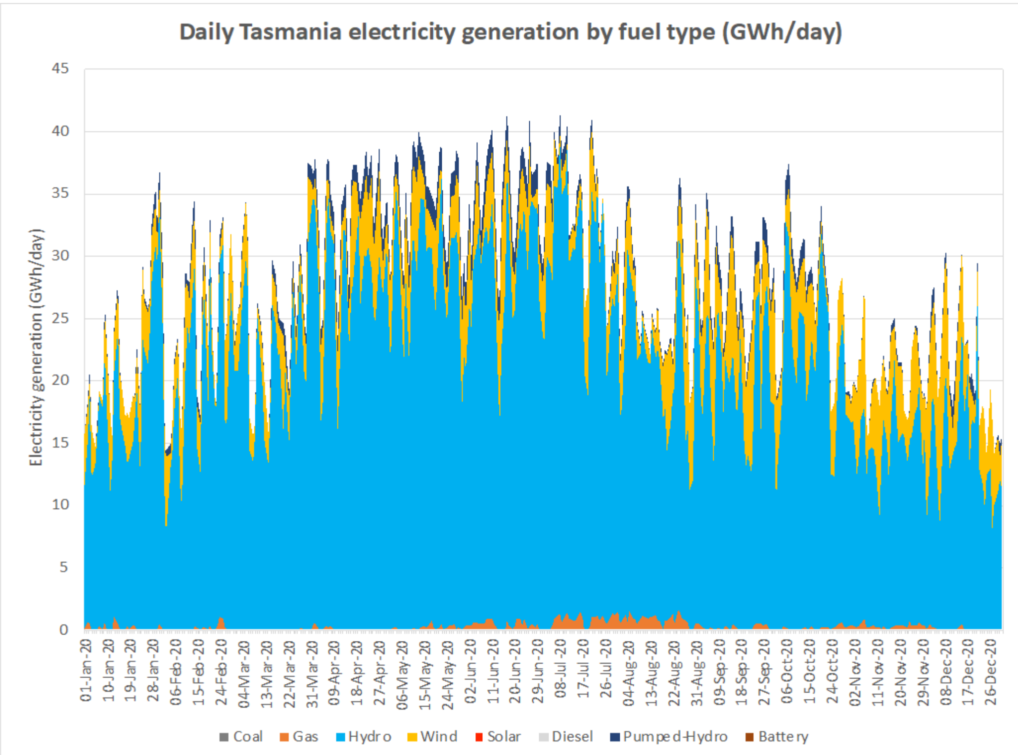
Figure 10. Tasmanian electricity generation share by fuel type



Source: AEMO

Tasmania's electricity demand can be quite volatile, with swings of more than 50% from one day to the next (Figure 11).

Figure 11. Daily Tasmania electricity generation by fuel type (2020)



Source: AEMO

This volatility means that the electricity network must have the capacity to meet these peaks – a costly proposition for only a few days use. A decarbonised gas network built around existing pipelines would offer a low cost option to support meeting peak energy day demand.

It is noted that the detailed economic analysis by Oakley Greenwood concluded[24] that 'once the impact on the electricity network is incorporated, the economics of retaining the existing gas network appear sound'.

Question 11: If Tasmania is to transition to a decarbonised gas network what should the transition pathway look like?

As stated in Question 1(G), there is great uncertainty as to how the pathway to NZC will unfold. The prudent and lower risk strategy is to preserve options and build expertise for different scenarios until the pathway is clear.

A transition pathway can be developed using the following steps:

a) *Appoint a working team representative of the energy industry to coordinate the transition*. The team should be accountable for planning, regular reporting against progress and critical recommendations or decisions being made.

b) *Develop long term NZC gas scenarios for analysis*. These scenarios might include hydrogen only, bio-methane or bio-gas, natural gas with carbon offsets, mixtures of these gases, aggressive and slower implementations, and electrification i.e. no gas. The impact on existing large industrials must be examined at an individual level.

c) *Identify decision points and scenario signposts for the transition pathway*. For each scenario, build a transition pathway with explicit decision points, review dates and scenario signposts to be used to identify the direction unfolding for a NZC future.

d) *Allocate resources and build critical skills*

    i. Identify and set aspirations for industry leadership positions.
    ii. Plan resource and infrastructure allocation and build critical skills which support the scenarios. This must maximise use of existing assets such as the pipeline network to minimise cost and risk. Tas Gas can be a critical coordinator and contributor to this stage.
    iii. Reallocate resources and skill priorities once scenario decision points have been reached.

e) *Use risk assessment and mitigation strategies to smooth the transition*. With so much uncertainty, including rapidly changing technology, businesses and markets, it is important to be explicit about the risks faced, and if and how they can be managed or mitigated.

[24] Oakley Greenwood, 'Tasmanian Gas Strategy', October 2021; https://recfit.tas.gov.au/__data/assets/pdf_file/0006/317445/Oakley_Greenwood_Final_Report_Oct_2021_Final.PDF . The conclusion was subject to other caveats outlined in this report.

Question 12: Would a switch to a renewable fuel need to be cost-equivalent or would you be willing to pay more for a carbon free fuel?

As discussed in Question 1(C), generally consumers are positive about sustainability but less inclined to pay a material premium for sustainable products. This means that any significant increase in fuel costs may be met with resistance or, worse, may trigger a negative view on sustainable objectives in general.

Businesses are now working in global markets, competing against businesses with different cost bases. Fuel costs must be competitive, and if not, then the NZC fuel needs to enable access to premium markets such as the EU if it implements the CABM.

> **Case Study:** As a demonstration of the cost challenge of hydrogen as a replacement for natural gas, Table 7 shows the cost of hydrogen against natural gas delivered to Bell Bay.
>
> The analysis shows that at today's natural gas price, hydrogen would only be cost competitive if electrolyser costs dropped to $500/kW (down from assumed $2,000kW) and electricity could be sourced at $15/MWh (down from average Tasmanian wholesale price of $45/MWh in 2020/21).
>
> However, if natural gas prices trend upwards towards an LNG import price, then hydrogen becomes cost competitive across a range of electrolyser capex and electricity price scenarios.

Table 3. Indicative comparison of hydrogen and natural gas commodity costs

Scenario 1: Natural gas (today's pricing) less hydrogen cost (A$/GJ)

A$/GJ	Capex (A$/kW)		
Electricity (A$/MWh)	2000	1000	500
15	9.36	2.39	-1.13
30	15.35	8.30	4.85
45	21.26	14.29	10.77

Scenario 2: Natural gas (LNG import pricing) less hydrogen cost (A$/GJ)

A$/GJ	Capex (A$/kW)		
Electricity (A$/MWh)	2000	1000	500
15	-5.70	-12.67	-16.19
30	0.29	-6.76	-10.21
45	6.20	-0.77	-4.29

Green = Hydrogen cost competitive against natural gas

Source: EnergyQuest analysis

References: Capital (Capex) cost estimates for electrolysers from IEA[25], IRENA[26] and ANU[27]

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[25] IEA, 'The future of hydrogen', June 2019; https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf

[26] IRENA, 'Hydrogen: A renewable energy perspective', September 2019; https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Hydrogen_2019.pdf

[27] ANU, 'Green hydrogen production costs in Australia: implications of renewable energy and electrolyser costs', August 2020; http://iceds.anu.edu.au/files/2020%2009%2001%20-%20ZCEAP%20-%20CCEP%20Working%20Paper%20-%20Green%20hydrogen%20production%20costs.pdf

Question 13: What risks do you see with decarbonising the Tasmanian gas network (technical, economic, social)?

Possible risks to the implementation of a zero carbon gas network to be considered and planned for include:

- Supply of zero carbon gas does not meet cost and volume expectations
- Demand falls short – customers are unable or unwilling to convert to zero carbon gas
- Lower utilisation of pipes causes large increases in tariffs for remaining users
- Schedule risk with implementation delays:
    - Loss of first mover advantages including brand position on world stage and technology leadership
- Stranded suppliers and users of zero carbon gas when other parts of the implementation are delayed
- Loss of community support if costs and schedule do not meet expectations
- Government policy and leadership appear inconsistent with the objectives

Question 14: If you are a commercial gas user in Tasmania that would not be able to switch to renewable alternatives, what are the key barriers?

Key barriers to a commercial gas user converting to renewable alternatives may include:

- Cost to convert and operate with renewable fuels
- Availability of appliances which use renewable fuels
- Time to mature technologies which are applicable to the business
- Uncertainty of policies, costs and market pricing for renewable fuels and products

Question 15: What is the role for the Tasmanian Government in a decarbonisation transition for the gas sector? What should the Government's priority measures be?

Measures the Government can take in the decarbonisation transition include:

- Maintain long term clear and consistent policies, and priorities
- Establish leadership departments, groups and forums to oversee and coordinate cross industry implementation
- Build stability and confidence for industry and investors to innovate and commit capital to support the energy transition.
- Keep options open with multiple pathways for longer (do not pick winners too early)
- Value reliability and lower risk options
- Identify constraints and bottlenecks, and be prepared to fund identified conversion costs, technology development and regulatory oversight to address them
- Facilitate cheaper power prices at the point of hydrogen production
- Provide support to bridge the gap between natural gas costs and renewable gas costs such that consumers are indifferent, enabling transition and renewable gas costs to reduce through electricity pricing and higher utilisation rates

ABBREVIATIONS

2P	proved and probable reserves
2C	best estimate contingent resources
ACCC	Australian Competition and Consumer Commission
ACCU	Australian Carbon Credit Unit
AEMO	Australian Energy Market Operator
AGIG	Australian Gas Infrastructure Group
ANU	Australian National University
BAU	business as usual
bbl	barrel (159 litres or 35 imperial gallons)
bbl/d	barrels per day
Bscf	billion cubic feet (109 or a thousand million)
Bcf/d	billion cubic feet per day
Bcm	billion cubic metres
boe	barrels of oil-equivalent
bopd	barrels of oil per day
Btu	British thermal unit (1.055 kilojoules)
CABM	Carbon Border Adjustment Mechanism
CCGT	combined cycle gas turbine
CCUS	carbon capture utilisation and storage
cf/d	cubic feet per day
CO2	carbon dioxide
CSG	coal seam gas
DWGM	Designated wholesale gas market (Victoria)
EEA	European Emission Allowance
EGP	Eastern gas pipeline
EIA	Energy Information Administration
EPC	engineering, procurement and construction
ETS	Emission Trading Scheme
EU	European Union
FID	final investment decision
FOB	free on board
FSRU	floating storage and regasification unit
FY	financial year
GIC	Gas Industry Company
GPG	gas-fired power generation
GJ	gigajoule (1 billion joules or 109)

GL	gigalitre (1 billion litres or 109)
GSOO	Gas Statement of Opportunities
GW	gigawatt
GWh	gigawatt hour
HDPE	high density poly ethylene
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
JCC	Japanese customs-cleared crude (Japanese crude cocktail)
JKM	Platt’s Japan Korea Marker
JV	joint venture
Kboe	thousand barrels of oil-equivalent
KJ	kilojoule (one thousand joules)
km	kilometre
kt	thousand tonnes
LNG	liquefied natural gas
LPG	liquefied petroleum gas (propane and butane)
kbbl	thousand barrels
kbbl/d	thousand barrels per day
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MJ	million (106) joules
ML	million litres (6,290 barrels or 796 tonnes)
mm	millimetre
MMbbl	million barrels
MMbbl/d	million barrels per day
MMboe	million barrels of oil-equivalent
MMboe/d	million barrels of oil-equivalent per day
MMBtu	million British thermal units
MMBtu/d	million British thermal units per day
MMscf	million cubic feet
MMscf/d	million cubic feet per day
MMcm	million cubic metres (35.31 million cubic feet)
MMscf/d	million standard cubic feet per day
MOU	memorandum of understanding
MPa	megapascal
Mt	million tonnes
Mtpa	million tonnes a year

MW	megawatt
MWh	megawatt hour
NEM	National Electricity Market
NZE	net zero by 2050 IEA scenario
NT	Northern Territory
OPEC	Organization of the Petroleum Exporting Countries
Pa	pascal
PJ	petajoule (one thousand terajoules)
PJ/a	petajoules a year
PL	Production licence
psi	pounds pressure per square inch
qoq	quarter on quarter
STTM	Short Term Trading Market
T	metric tonne
Tcf	trillion cubic feet (1012 or one thousand billion)
TGP	Tasmanian Gas Pipeline
therm	100,000 Btu
TJ	terajoule (one thousand gigajoules)
TJ/d	terajoules per day
TWh	tera watt hours (1,000,000 megawatt hours)
WGSH	Wallumbilla gas supply hub
yoy	year on year

CONVERSION FACTORS

crude oil 1 barrel (bbl) = 1 barrel oil-equivalent (boe)

sales gas 1 petajoule (PJ) = 171,937 boe

sales gas 1 billion cubic feet (Bcf) = 1.06 PJ

LPG 1 tonne (t) = 8.458 boe

LNG 1 million tonnes (Mt) = 55.43 PJ

LNG 1 million tonnes (Mt) = 9531 Kboe

LNG 1 cubic meter = 0.4157 tonnes

condensate 1 barrel = 0.935 boe

ethane 1000 tonnes = 0.05181 PJ

ethane 1 PJ = 15.1 MMcm

oil/condensate 1000 barrels = 158.97 kilolitres

LPG 1000 tonnes = 1.88 ML

sales gas 1 petajoule (PJ) = 26.71 MMcm

British thermal units 1 million (MMBtu) = 1.055 GJ = 1Mcf = 10 therms

British thermal units 1 billion Btu = 1.055 TJ = 1 MMcf

British thermal units 1 trillion Btu = 1.055 PJ = 1 Bcf

Electricity 1 PJ = 277.8 GWh