THE ROLE OF GAS INFRASTRUCTURE IN AUSTRALIA'S ENERGY TRANSITION

JUNE 2023

Context

This is a summary article on the role of Australia's domestic gas infrastructure in the energy transition. It has been commissioned by APA Group, Australian Gas Infrastructure Group, and Jemena. These are the three largest investors in Australia's gas pipeline transport infrastructure, and each has a publicly stated commitment to achieving net zero emissions.

This article considers the potential role of gas infrastructure - in Australia - in the transition to and in a net zero future, with a focus on transport infrastructure: pipelines, transmission and distribution. It describes the role over three loosely defined timeframes:

- The current state
- The 'transition phase' through which the energy system moves towards net zero
- The net zero future

This article should be read as a description of the potential role gas infrastructure could play in Australia, with a focus on supporting the transition of the Australian energy system as a whole in a least cost and most robust manner. The article does not address specific state-based emissions targets.

The article should not be read as a forecast of the role gas infrastructure will play, which is subject to a broader range of drivers, including policy decisions at all government levels. The article highlights broad actions required to realise the potential role but does not prescribe specific corporate or government policy actions.

This article includes a desktop review of several other papers written on the role of gas in the energy transition by a broad range of contributors, including industry, government bodies and advocacy groups. Reference to those papers should not be read as endorsement of their findings.

While the three commissioning organisations have been able to provide feedback on drafts of this article, the BCG team assigned to the project retained full control over the content. The conclusions presented in this article are the views of that BCG project team.

Disclaimer

Summary

Natural gas – and the gas infrastructure that stores and transports it – is a cornerstone of Australia's energy system today, representing 27% of primary energy. It is used by nearly all types of energy customers: ~71% by industry; ~15% by grid-connected electricity generation; and ~14% by homes, businesses, and other small user groups (e.g. agriculture, forestry, fishing). However, natural gas production, transport, and combustion accounts for 22% of Australia's energy-related emissions, and its use will need to be reduced to meet net zero ambitions, either by replacing natural gas with low-carbon gases or displacing gas by electrifying end uses supported by renewable electricity.

Natural gas will continue to play an important, but reducing (by volume), role during the energy transition phase. Various reports across a range of scenarios estimate that domestic consumption of natural gas will reduce to between 40% and 90% of current levels by 2040. The nature and extent of its use will be determined by how rapidly Australia develops renewable energy sources and how quickly customers electrify their use of energy. **Some customers have an economic case to electrify their usage – e.g. industrial low-grade heating, some light vehicles and new-build homes. For existing gas-using homes, the economic choice appears to be highly dependent on individual circumstances.** Customer choice may also be influenced by practicality, individual preference and amenity.

Renewable electricity is the primary technology to provide low emissions energy, along with other renewable energy sources. It can be deployed to displace fossil-generation or to electrify various end-uses, yielding different emissions reduction and system cost outcomes. **Beyond those customers who choose to electrify, a 'renewify first, maintain customer choice' sequence (prioritising the displacement of fossil primary energy sources – in particular coal for electricity generation – with renewable sources and electrification of transport), ahead of an electrification sequence (changing the end-use energy vector from gas to electricity) will reduce emissions sooner and with lower total system cost.**

During the 'transition phase', natural gas can support the 'renewify first' sequence by serving applications that are hard or expensive (peaking applications in particular) for the system to electrify. These applications include high-grade industrial heat, industrial feedstock, peak power generation and space heating in households – especially those in cold climates. Retaining natural gas for these applications will make the transition more robust and help manage the impact of potential disorderly exit of coal-fired generation, or unexpected delays to development of renewable electricity, transmission and storage projects.

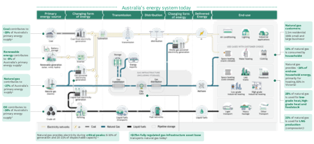
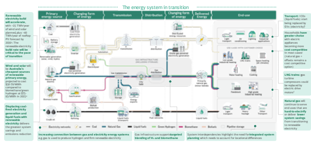
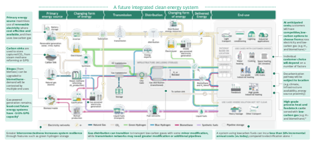
During the 'transition phase', existing gas infrastructure could be used to continue the development of low-carbon gases. Low-carbon gases are likely to be needed in a net zero future, for industrial use at a minimum. Preserving the gas infrastructure preserves an option for their wider use.

In a net zero future, low-carbon gases could provide competitive solutions at a total-cost level for customers – including some existing gas-using households – if supply costs reduce as anticipated, network charges are managed, and sufficient supply becomes available.

Some reports indicate that **an integrated clean energy system, combining low-carbon gas networks and expanded electric networks, could be the least cost approach to net zero. However, the specific least cost approach is likely to differ by location based on regional- and network-level considerations**.

The potential role of gas infrastructure in the transition and net zero timeframes will not happen automatically. Stakeholders in the energy sector would need to avoid near-term natural gas supply shortfalls, minimise fugitive methane emissions, define adequate and equitable cost recovery for regulated assets, integrate energy system planning at a granular level (across electricity and gas), and move low-carbon gas supply down the cost curve.

Exhibit 1: The role of gas and gas infrastructure in the energy transition (infographics in appendix)

	1. TODAY	2. TRANSITION	3. NET ZERO
THE ROLE OF GASEOUS FUELS	**Natural gas is a pillar of the energy system** 27% of primary domestic energy 34% of household energy 5-10% grid-connected electricity generation (NEM+SWIS)	**Natural gas has a reducing but critical role** Serves hard/expensive to electrify applications Maintains peaking applications, such as gas-powered generation (critical to an orderly electricity system transition) Provides low-carbon gas as sources start to build	**Low-carbon gas could be competitive for some existing gas customers, at anticipated prices** Essential for some hard-to-electrify industrial applications Competitive option for some households and available for potential new customers (e.g. fuel cell heavy transport)
THE ROLE OF GAS TRANSPORT INFRASTRUCTURE	**Gas infrastructure plays a critical role supplying energy to over 5m industrial, commercial, and residential customers** Transmission network supports distribution and industrial customers Distribution network supports homes, businesses and industrial customers	**Gas infrastructure continues to serve customers, while demonstrating low-carbon gases** Develops and demonstrates physical and economic feasibility of low-carbon gas (blending and 100% streams)	**Low-carbon gas networks form part of an integrated clean energy system** Transports low-carbon gas to end users domestically, and potentially for export Role likely to differ by region and network, based on a range of factors
	 **View Appendix 1**	 **View Appendix 2**	 **View Appendix 3**

1 Natural gas and its infrastructure form a pillar of today's energy system, but the role of natural gas needs to change for a net zero future

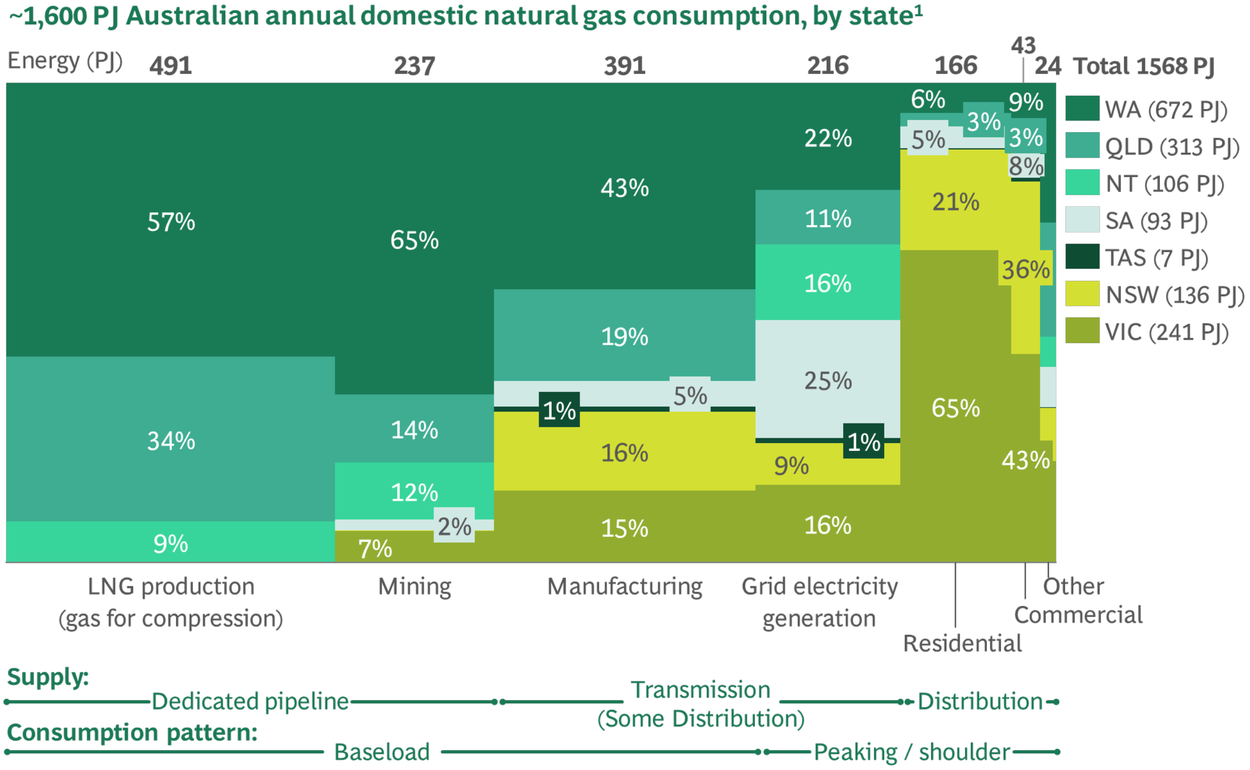
Natural gas is one of 3 pillars of Australia's energy system It provides 27% (1600PJ) of domestic primary energy and is used by nearly all customer groups, both directly and via its contribution to electricity generation. While residential and commercial users are the smallest group by energy use, over 5 million households and business are connected to the gas distribution network. Notwithstanding its importance, natural gas is a fossil fuel that contributes 22% of Australia's energy-related emissions (18% of total emissions), and its use must be decarbonised if Australia is to meet its net zero ambitions.

→ See Appendix 1

Natural gas is one of three pillars of Australia's energy system and contributes 27% of total domestic energy use (1600PJ of 5600PJ). The other two pillars are liquid fuels and coal, which contribute 37% and 28% of domestic energy respectively. Renewable electricity provides around 4% of domestic primary energy today and is playing an increasingly prominent role.

Natural gas plays a material role in the stability and resilience of the energy system. It is used by nearly all energy customer groups: ~71% of natural gas is used by industry; ~15% for grid-connected electricity generation; and ~13% for residential and commercial heating. While residential and commercial is the smallest group by energy use, over 5 million households and businesses are connected to the gas distribution network. 65% of residential natural gas is used in Victoria.

Exhibit 2: Natural gas is used by a range of customers for electricity generation, mining, industrial, commercial, residential use, and for export



1. Natural gas exports and imports excluded

Source: Australian Energy Statistics, Table F, Table J (2022); APPEA Key Statistics (2022); AEMO GSOO 2021; AEMO WA GSOO 2020; BCG analysis

Natural gas has particularly useful characteristics for the range of energy end-uses it currently serves. It is reliable and responsive, has a lower cost per unit energy and lower capital cost than its historical alternatives, and is the only available technology for some end uses.

However, natural gas represents ~22% of Australia's domestic energy-related emissions.[1] Alternatives to natural gas are becoming available:

- Electric technologies are becoming more widely available, such as heat pumps, battery storage, induction cooking, more efficient (e.g. heat pumps are in the order of 4x more efficient than natural gas appliances) and increasingly cost-competitive[2]
- Low-carbon gases could displace natural gas to decarbonise some end uses (see BOX 1)

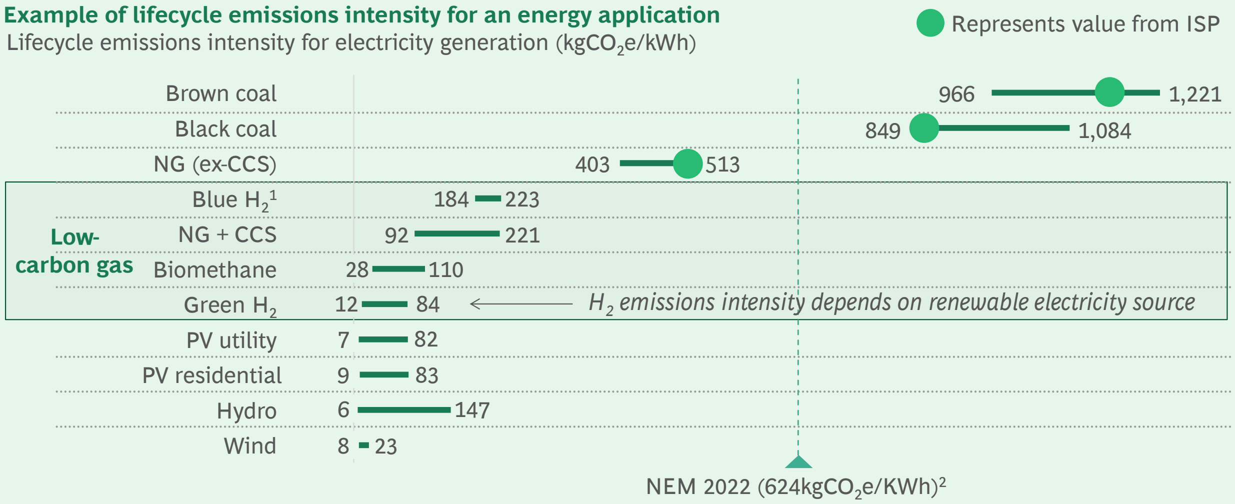
BOX 1: WHAT IS LOW-CARBON GAS?

The combustion of natural gas creates emissions (predominantly CO_2), and additional methane fugitive emissions (losses or leaks) are released along the supply chain. Emissions from natural gas are greater than from renewable energy, but lower than from combusting coal or liquid fuels.

Alternative gases can transport energy with fewer lifecycle carbon emissions (e.g. from raw materials, manufacturing, energy production, conversion, transport and use) than natural gas. Low-carbon gases include:

- Biomethane, derived from biomass feedstock
- Natural gas with carbon capture and storage (CCS)
- Green hydrogen, derived from electrolysis using renewable electricity
- Blue hydrogen, derived from steam methane reforming (SMR) with CCS
- Synthetic methane, synthesised from green hydrogen and direct-capture carbon dioxide

Exhibit 3: Combusting low-carbon gases results in similar emissions levels as electricity production



1. Blue hydrogen emissions intensity range determined by applying a 0.4% factor of fugitive losses of methane consumption in emissions calculation by Howarth & Jacobson 2. Based on AEMO ISP
Source: National Renewable Energy Laboratory; IPCC; UN Economic Commission for Europe; Howarth & Jacobson: How Green is Blue Hydrogen?; AEMO ISP; OpenNEM; BCG analysis

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[1] DCCEEW, Australian Energy Statistics, IEA methane tracker, IPCC, BCG analysis

[2] IRENA, Australian Equipment Energy Efficiency Committee

2 Natural gas will continue to play an important, but reducing, role during the transition phase

During the transition phase, natural gas and its existing infrastructure will play a reducing but critical role and support hard- and expensive-to-electrify applications. These applications lack alternatives (chemical feedstock and high-grade heat) or are peaking in nature (gas-powered generation and household space heating - especially in cold climates). The nature and extent of the role of natural gas will be determined by how fast renewable energy (including low-carbon gases) is built and customers electrify. The choice to electrify is highly individual for each customer. Beyond customer choice, emissions will be reduced sooner and at lower cost in a ‘renewify first, maintain customer choice’ sequence, in which renewable electricity is prioritised to decarbonise the grid and electrify light transport. This approach will also be more robust to risks in the electricity transition and preserves optionality. In the transition phase, gas infrastructure could be used to demonstrate low-carbon gases, such as hydrogen and biomethane, as blends of these gases require little change to existing gas infrastructure.

Natural gas will play a role in the energy transition, with varying views on the nature and extent of that role. Across a number of studies, 2040 domestic consumption of natural gas ranges from 40-90% of 2020 levels.[3]

The pace at which Australia develops renewable energy sources (**including low-carbon gases**)**, and the rate at which customers electrify, will influence the nature and extent of the role that natural gas and gas infrastructure play in the transition.** Exhibit 4 illustrates three potential sequences.

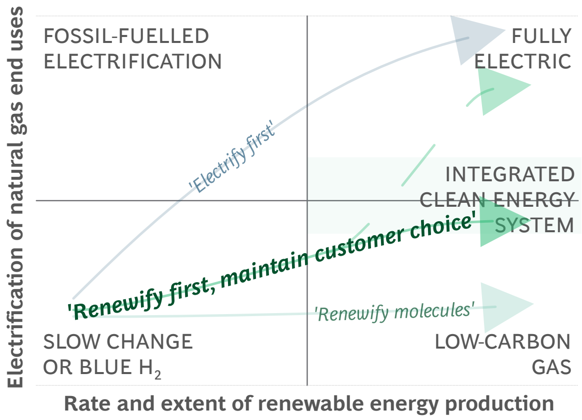
In ‘**electrify first’**, natural gas end-use is rapidly replaced with electricity. The higher demand for grid electricity would today be met with largely fossil-based electricity and in the future renewable electricity.

In **‘renewify first, maintain customer choice’,** fossil-based energy sources are replaced by renewable energy first to decarbonise the grid. Some customers choose to electrify their usage, in part driven by the economics. Depending on the emergence of low-carbon gases as a competitive solution, remaining customers might either draw low-carbon gases from the gas grid or electrify.

The **‘renewify molecules’** represents a pathway in which illustrate a pathway in which rapid development of renewable gases allows customers to choose to use low-carbon gases in the same way they do today.

A critical difference between the ‘electrify first’ and ‘renewify first’ pathways is how they respond to delays to the development of renewable electricity and storage, or a disorderly transition. **‘Renewify first’ mitigates these risks** because existing electricity supply shifts to firmed renewables as demand for electricity increases, and low-carbon gases are developed to decarbonise applications that are not electrified.

Exhibit 4: The rate of renewable deployment and extent of electrification will determine the role of gas and gas infrastructure in the energy transition



Source: BCG analysis

[3] BCG analysed scenarios from Net Zero Australia (2023), AEMO GSOO (2023), Frontier Economics (2020), and Investor Group on Climate Change (2022)

The economics of electrification for customers is highly individual

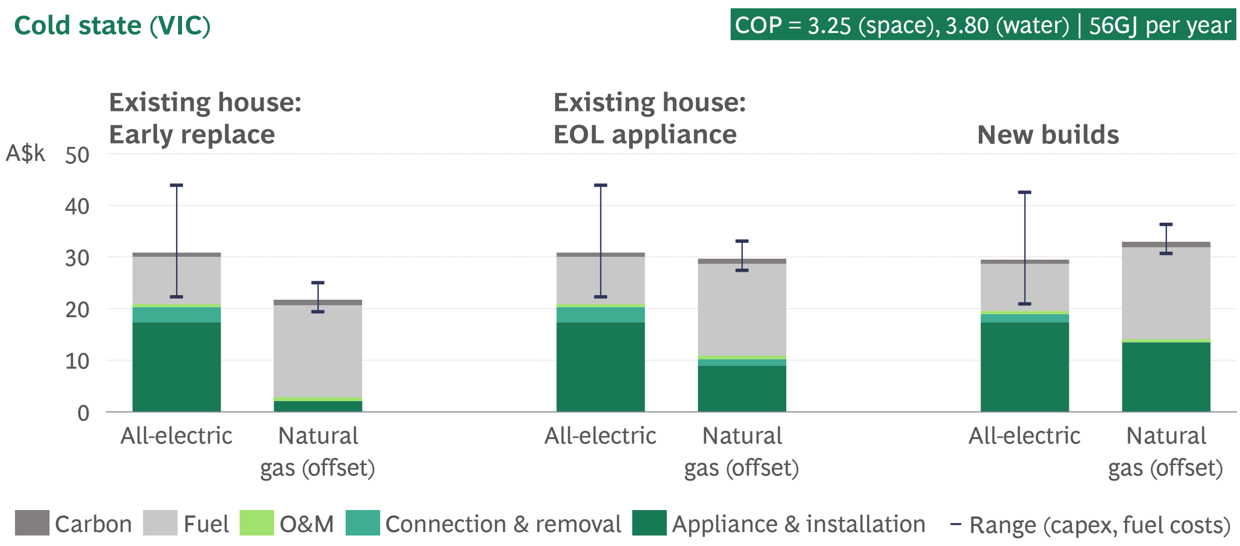
From a customer perspective, it could be economical for some end uses (e.g. low-grade industrial heating, some light vehicles) to switch to renewable electricity. For other customers, electrification is not technically feasible or economical for their end-uses, such as high-grade (>150C) industrial heat and chemical production (e.g. using natural gas for ammonia feedstock).

The economics of electrification for residential customers is contested in existing literature and the choice for households is highly individual. Location, appliance configuration, preference and other factors influence the most cost-effective solution, and customers may make decisions based on practicality, individual preference and amenity. Households will generally save energy and reduce bills because of the efficiency of heat pumps (also known as reverse-cycle air conditioners), though these energy savings are partially offset by the higher unit (per kWh) cost of electricity. However, the higher cost of new electric appliances and their installation, costs to upgrade power connections (if needed), and the cost of remediating gas connections, can mean it is cheaper to remain on natural gas if fuel savings do not recoup the capital cost over time.

For residential customers, Exhibit 5a shows an estimate of the relative costs (before subsidies) today of switching to electric appliances in the home compared to staying on natural gas appliances in Victoria for an average household consumption. It compares existing houses (where appliances are replaced early, or where they are at the end of life) with new builds (with new appliances).

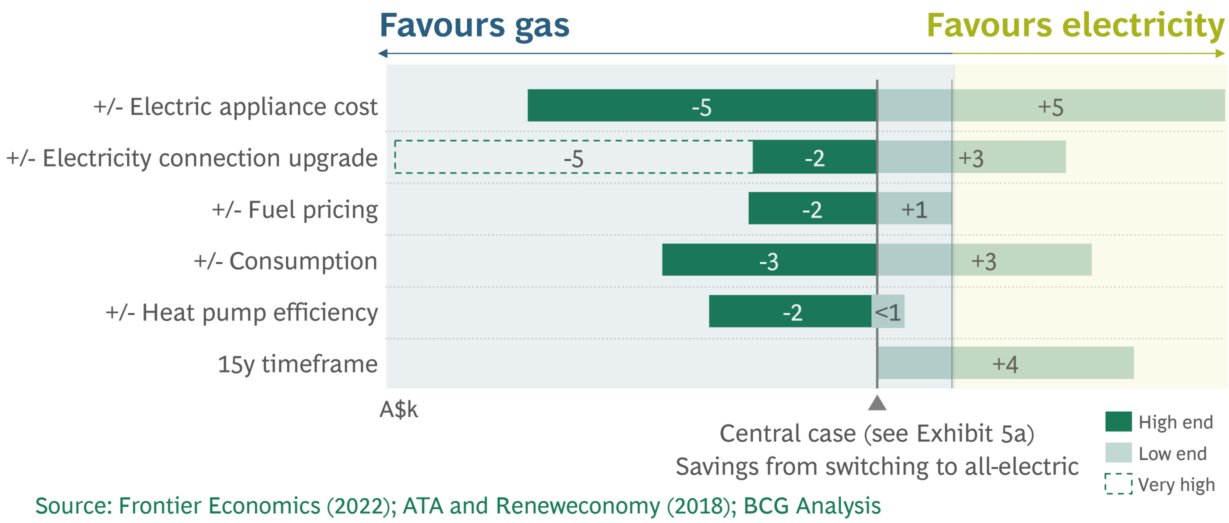
- **For existing homes with assets at end of life**, in the central case it would be marginally lower cost over 10 years to remain on natural gas than to switch to electric appliances, even if emissions are offset. The higher appliance costs, costs of removing existing appliances, upgrading the electricity connection (if needed), and disconnecting and abolishing the existing natural gas connection outweigh the accumulated savings. The conclusion depends directly on the extent and value of appliance purchase, installation, and remediation costs, which are specific to each household (Exhibit 5b).
- **For new builds**, in the central case it would be lower cost to electrify as gas appliance removal and disconnection costs are not applicable.

Exhibit 5a: Natural gas and electricity cost comparison (excl. subsidies) for residential users today



Note: Inclusive of space heating, water heating and cooking. Costs reflect NPV over 10Y period using real discount rate of 3%. All-electric homes are grid-connected and no subsidies are considered.
Source: Frontier Economics (2022); ATA and Reneweconomy (2018); BCG Analysis

Exhibit 5b: Relative total cost of ownership and savings from switching to all-electric (VIC)



Source: Frontier Economics (2022); ATA and Reneweconomy (2018); BCG Analysis

Beyond customer choice, a 'renewify first' sequence will reduce emissions sooner and at a lower system cost

Renewable electricity is a key technology to provide low emissions energy. It can be deployed in a number of ways: renewifying the primary energy source for grid electricity (i.e. displacing coal and gas-powered generation) or supporting electrification of direct uses of fossil fuels. Each application yields different emission reductions and imposes different costs on the system.

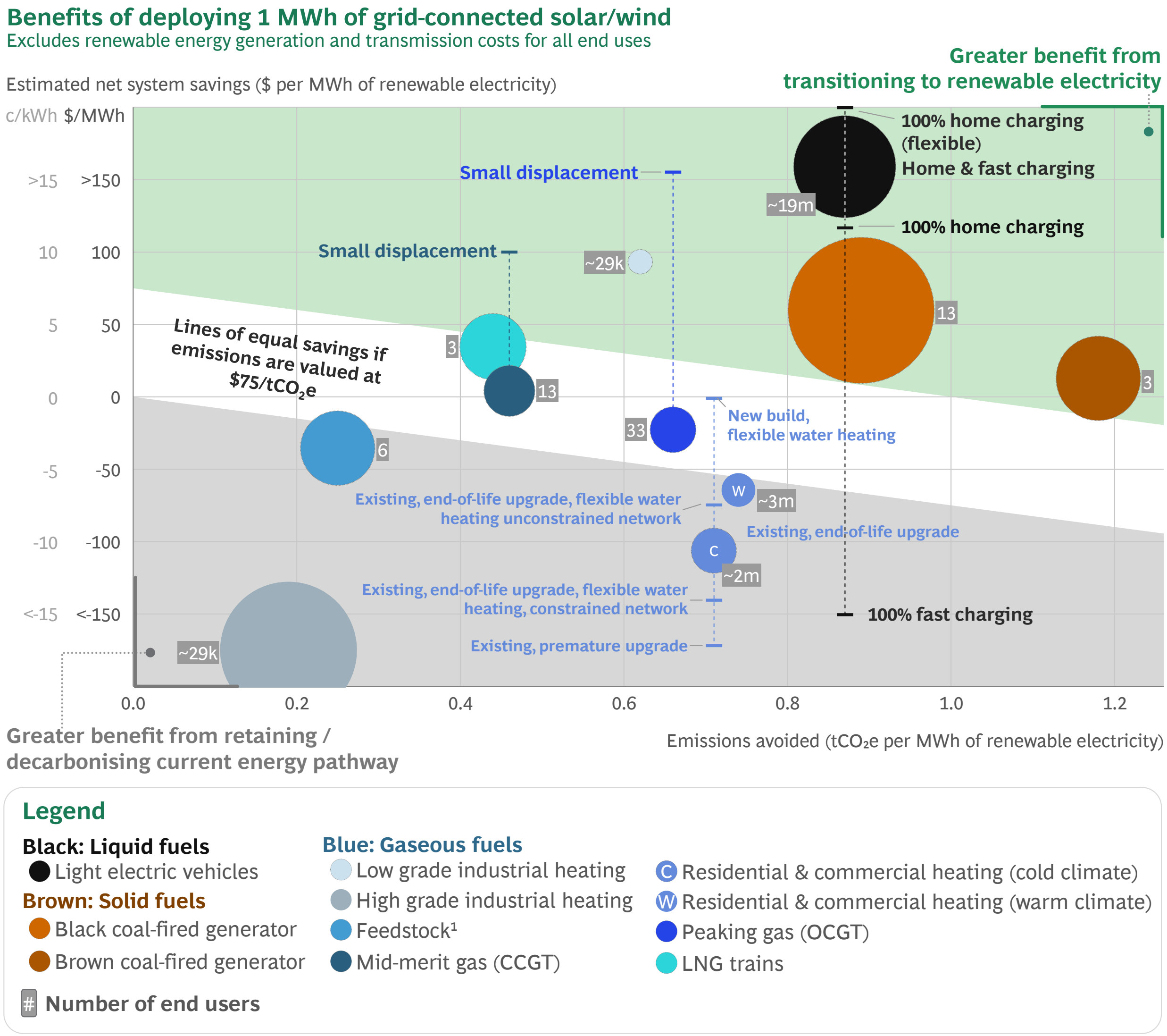
Exhibit 6 and Box 2 describe the emissions and cost impact of deploying 1 MWh of grid-connected renewable electricity for different applications. To avoid the most emissions and minimise system costs, renewable electricity could be prioritised (starting from the green area at top right and moving diagonally down through the white area in the middle of Exhibit 6). The priority applications for renewable electricity are to displace coal generation and liquid fuels used in light vehicles and low-grade industrial heating.

Electrification of residential gas applications is prioritised lower due to their impact on system cost, in particular where they coincide with electricity demand peaks

Electrifying end uses such as high-grade industrial heating, industrial feedstock (via green hydrogen produced from renewable electricity), residential and commercial heating (in particular in cold climates) and peaking gas-powered generation (in the grey and white areas of Exhibit 6) would have a higher cost for the system and avoid fewer emissions.

In the case of residential and commercial use, this is driven in part by the shape of demand: natural gas demand spikes in cold weather and in the evenings. In cold climates this would lead to an increase of peak electricity demand: system investment in network expansion could be needed and profile shaping would be needed (Box 2).

Exhibit 6: Grid-connected renewable electricity will have the greatest impact if first used to displace coal generation and liquid fuels

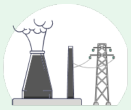
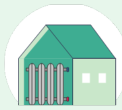


Note: Bubble size represents total annual volume of renewable electricity required to meet demand

1. Analysis based on methane gas substituted with green hydrogen produced from grid-connected electricity

Source: AEMO ISP (2022); OpenNEM; CSIRO; ABS; AIP; Frontier Economics (2022); Advisian, CEFC (2021); BCG analysis

BOX 2: WHAT DOES IT TAKE TO GET VALUE FROM 1 MWH OF RENEWABLE ELECTRICITY?

	Displace coal-fired generation	Electrify light vehicles	Electrify residential usage
Emissions reduction	0.8 – 1.2 tCO_2e/MWh	0.9 tCO_2e/MWh	0.7 tCO_2e/MWh
Cost savings	Coal supply Coal plant variable opex	Fuel Fuel distribution Lower vehicle opex	Gas supply Gas transmission and distribution variable opex Gas transmission infra-structure from new sources Lower appliance opex
Additional costs		Consumption profile matching Electricity distribution network upgrades Incremental capital cost of electric vehicle Public EV charging infrastructure	Consumption profile matching (hot water treated as controllable) Electricity distribution network upgrades Incremental capital cost of equipment
For all applications, the cost of supplying the MWh is excluded for comparison			

Compared to displacing coal-fired generation with 1 MWh of renewable electricity, electrifying a house's appliances and bringing 1 MWh to the home includes additional costs to:

- Match the profile of variable renewable electricity generation (when it is sunny and windy) to the profile of consumption (when people are heating their homes)
- Transport the electricity (with potential upgrades to the electricity distribution network)
- Buy new electric equipment (e.g. a heat pump), currently at higher capital cost [4]

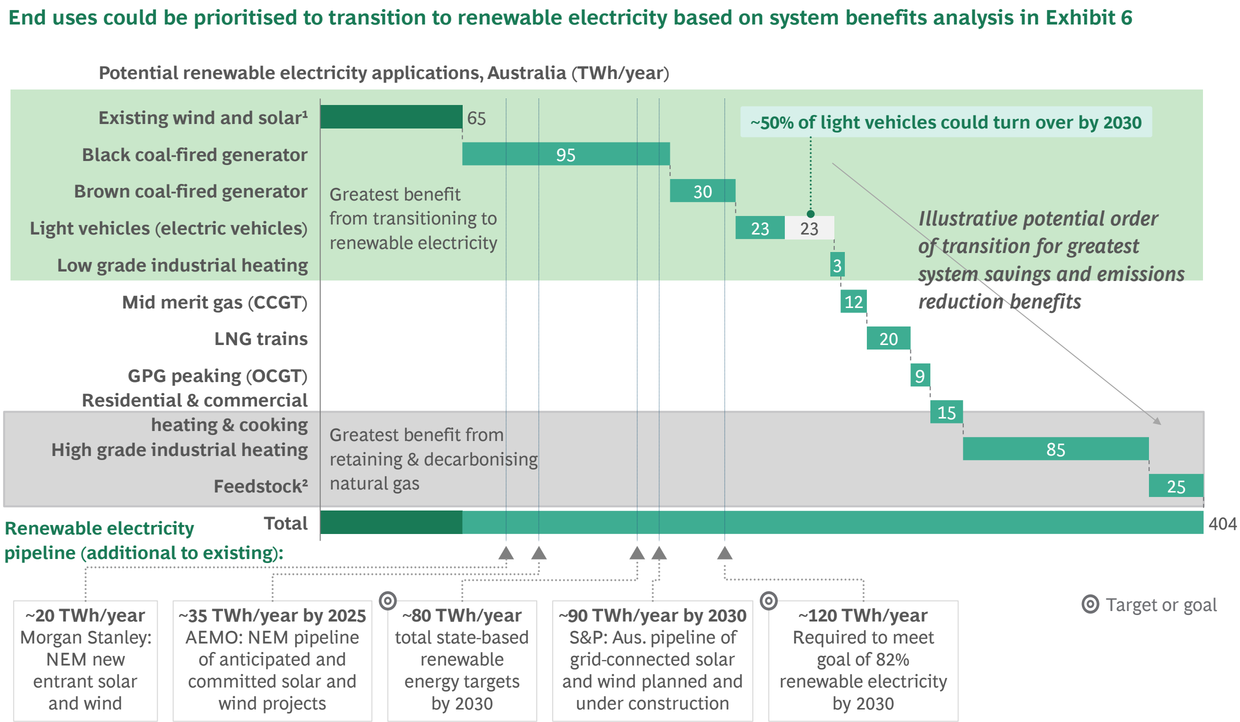
These additional costs are why bubbles are in the grey area of Exhibit 6. While electrifying light vehicles does incur additional costs, charging could be more flexible – if the vehicle is charged when overall (or local) electricity demand is low, it provides a benefit by balancing the system.

[4] This system analysis and total cost of ownership analysis is based on electrification with the use of heat pumps. Customers may choose to electrify with lower efficiency appliances

The renewable electricity pipeline does not yet have capacity to renewify all potential applications

Exhibit 7 shows the expected pipeline of renewable generation compared to the renewable generation required to transition a range of potential applications to renewable electricity. If the 82% renewable electricity ambition by 2030 were met, and if new renewable generation is prioritised in the sequence described in Exhibit 7, only coal generation would be displaced.

Exhibit 7: In the transition, natural gas can serve critical end uses that are hard and expensive to electrify



1. Includes onshore wind, utility scale solar, rooftop solar 2. Methane gas substituted with green hydrogen from grid-connected electricity
Source: Morgan Stanley Research, NEM new entrant plant estimate; AEMO, NEM Generation Information (Feb 2023); S&P Capital IQ, World Electric Power Plants Data Base; DCCEEW, Annual Climate Change Statement 2022; BCG analysis

In this prioritisation, natural gas plays a complementary role to renewable electricity

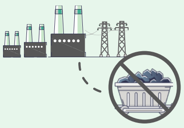
While renewable electricity is prioritised to end uses in the top right of Exhibit 6, natural gas can continue to support the end uses that are lower priority to electrify because they are hard or expensive to electrify. These are the end uses in the bottom left corner of Exhibit 6.

By doing this, natural gas will make the transition more robust

By avoiding additional strain on the electricity system at peak times and providing peak electricity generation, these applications of natural gas make the transition of the electricity system more robust. In other words, if the transition does not proceed as planned (e.g. renewable electricity and storage is delayed, or through the disorderly exit of coal), gas would pick up the slack. Gas-powered generation is a good backstop because it is dispatchable (unlike variable renewable electricity), can ramp up quickly (unlike legacy coal plants), and has access to storage in the gas infrastructure system.

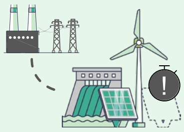
BOX 3: A CRITICAL ROLE FOR GAS IN AN ORDERLY TRANSITION

While renewables will eventually dominate electricity generation, gas-powered generation has a critical role to play. Analysis in AEMO's GSOO shows that:



+100PJ

Gas for gas-powered generation is required if there is a **disorderly coal exit**



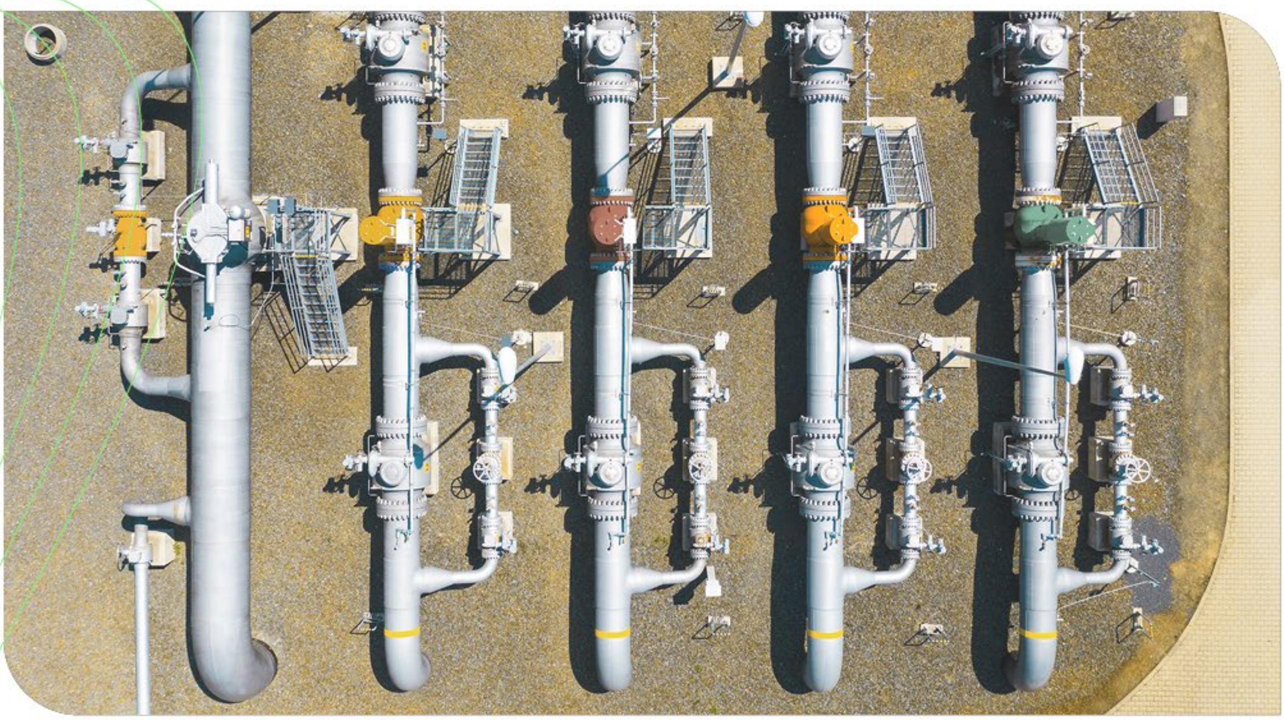
+30-40 PJ

Gas for gas-powered generation is required 2023-2025, if there are **delayed VRE projects**.[5]

In the transition phase, gas infrastructure could be used to demonstrate low-carbon gases, such as hydrogen and biomethane, as blends of these gases require little change to existing gas infrastructure.

While renewable electricity is prioritised towards displacing coal-fired generation, natural gas and gas infrastructure can play a significant part in the transition. However, natural gas will also need to decarbonise during the transition.

With minimal modifications, existing gas infrastructure could be used to demonstrate the physical and economic feasibility of low-carbon gases and support their development by blending low-carbon gas into the distribution network. These low-carbon gases could be developed progressively, initially supporting distribution-connected residential or industrial customers with applications that are hard or expensive to electrify.



[5] AEMO, Gas Statement of Opportunities (2023)

3 Gas infrastructure could transport low-carbon gases in a lower-cost, integrated clean energy system in a net zero future

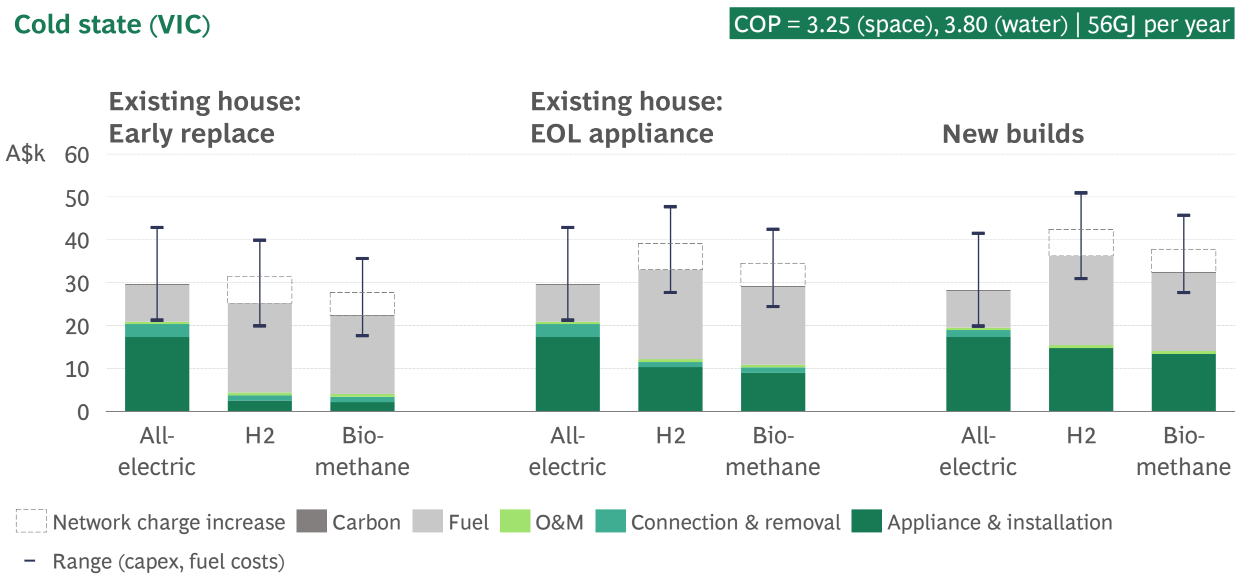
In a net zero future, all applications that use natural gas today will need to be decarbonised. There are two broad approaches: converting all applications to electric appliances only and using renewable electricity; or repurposing or upgrading existing infrastructure to carry low-carbon gases as part of an integrated clean energy system alongside electrification. Low-carbon gas in an integrated clean energy system could provide competitive offers at a total-cost level for some customers if low-carbon gas prices fall as anticipated and if network tariffs are managed. An integrated clean energy system could be equivalent or least-cost at a whole-of-system level in a net zero future, with reduced investment on the customer side, and offsetting higher running costs in the electricity system. The optimal solution for an integrated clean energy system likely differs by location and would require detailed regional-level planning (see Box 4).

→ See Appendix 3

Low-carbon gases could be competitive options for some customers in an integrated clean energy system, if costs fall to anticipated levels

If the price of low-carbon gas falls as forecast, green hydrogen and biomethane could be cost-competitive options for some existing gas households. At around $2-3kg wholesale ($40-51/GJ retail), green hydrogen could be total-cost-competitive for electric appliances in some existing houses with gas appliances, particularly those where it is expensive to electrify. Biomethane below around $15/GJ wholesale ($37-48/GJ retail) is also total-cost competitive (see Exhibit 8), though estimates of level of the available economic supply vary greatly.

Exhibit 8: Cost comparison for electricity, green hydrogen and biomethane for residential users in 2040



Note: Inclusive of space heating, water heating and cooking. Costs reflect NPV over 10Y period using real discount rate of 3%. All-electric homes are grid-connected and no subsidies are considered. Network charge increase (dotted box) reflects 50% distribution-connected customers, per GSOO OSC scenario in 2040 for biomethane and hydrogen.
Source: Frontier Economics (2022); ATA and Reneweconomy (2018); Advisian, CEFC (2021), IEA and Deloitte; BCG Analysis

Low-carbon gas is also anticipated to be the least cost (or most competitive) decarbonisation pathway for other uses, such as feedstock, high-grade process heat, and marginal peak electricity generation. There is the possibility for low-carbon gas to serve other new use cases, such as hydrogen fuel cell vehicles, green steel and sustainable aviation fuel.

BOX 4: WHAT IS AN INTEGRATED CLEAN ENERGY SYSTEM?

An integrated clean energy system (ICES) would integrate energy vectors.

Renewable electricity serving a large proportion of primary energy demand

Low-carbon gas serving a portion of existing natural gas customers, and potentially new types of customers like hydrogen fuelling

The potential benefits of an ICES include:

- Optimised balance of customer and system costs of transition
- Interconnected sources and networks of energy to increase efficiency and reliability

Appendix 3 shows an illustrative example of such an integrated clean energy system

Gas infrastructure can be used to transport low-carbon gases

For existing gas infrastructure to shift to 100% biomethane, no significant modifications are required. For hydrogen with a >10-20% blend, or higher, the feasibility of adapting gas infrastructure depends on many factors, including age, material type, operating conditions (pressure and capacity) and region. Many of Australia's distribution networks and some transmission pipelines have been investigated in detail and are compatible with transporting a 10-20% hydrogen blend, and some distribution networks are compatible with 100% hydrogen – requiring only little modification. This places several networks in Australia well to adopt hydrogen as it becomes available for further trials or use at scale and costs reduce.

While the extent of infrastructure modifications is understood in some distribution and transmission networks, further study is needed – particularly for transmission pipelines. Compared to distribution networks, transmission networks may require more modification or new infrastructure.

Gas infrastructure could support a lower-cost and higher-resilience integrated system

It is possible that an integrated clean energy system could be lower cost than a fully electric system. A study by Frontier Economics (2020)[6] showed the lowest annual system cost in the Zero-carbon/Renewable Fuels scenarios. Net Zero Australia (2023)[7] charts rapid (E+) and slower (E-) electrification scenarios across buildings and transport. It estimates similar total domestic system costs across the two scenarios, with lower customer side costs in the E- scenario balancing higher supply costs. Both Frontier Economics Renewable Fuels and the Net Zero Australia E- scenario achieve net zero with a combination of renewable electricity and low-carbon gas.

[6] Frontier Economics, The Benefits of Gas Infrastructure to Decarbonise Australia (2020)

[7] Net Zero Australia, Final Modelling Results (2023)

Leveraging existing gas infrastructure could reduce costs for several reasons:

- Lower peak electricity demand reduces the need for electricity network and storage investment
- Repurposing gas distribution networks for low-carbon gases utilises an existing asset and network decommissioning costs can be avoided
- Less investment is needed in customer-side equipment.

Retaining gas infrastructure could increase energy system reliability, resilience and synergies through interconnections (e.g. through hydrogen storage) and redundancy from multiple energy networks (i.e. fewer single points of failure).

The least-cost integrated clean energy system will likely differ by location
The relative attractiveness of repurposing gas infrastructure to deliver low-carbon gases will differ along a number of location-based factors, including:

- **Climate** – the coincidence of gas and electricity peaks is greatest in cold climates, whereas in warmer climates electrification might not add to peak demand
- **Network capacity** – a constrained local electricity network would need to build additional peak capacity for newly electrified demand
- **Marginal supply** – while the marginal supply of electricity is fossil-fuelled, there is less emissions benefit to electrification
- **Customer profile** – demand for low-carbon gases from industrial customers will support the ability for other customers to use low-carbon gas
- **Availability of low-carbon gases** – abundant and nearby biomethane or hydrogen allow the low-carbon gas system to deliver more competitive customer offers.

Therefore, granular planning at regional and network level will be needed to design the optimal integrated clean energy system or fully electric system.

4 Action is needed to make it possible for gas infrastructure to play this role

Without action, a number of risks could prevent gas infrastructure from fulfilling the potential role described in this article. Active choices would need to be made to ensure that there is sufficient supply in the near-term, that relevant and valuable infrastructure is preserved in the medium-term, and that new low-carbon gas is economically available in the long-term.

Avoid natural gas supply shortages in the near term

AEMO has forecast the risk of supply shortfalls in southeast Australia between 2023-2027 and called for near-term investment to ensure solutions from 2027.[8] Reliable and affordable natural gas supply will help to continue to meet power generation and customers' energy needs, particularly for customers who cannot afford to switch. This risk will not be completely avoided by switching away from gas appliances. For Victorian households in particular, gas consumption is correlated with electricity demand and electrification would likely lead to an increase in natural gas consumption for gas-powered generation.

Minimise the emissions from natural gas

Fugitive and operational emissions must be abated to reduce emissions from natural gas production and transport if natural gas use continues during the transition. The Safeguard Mechanism will encourage progress and a number of technical levers exist to reduce these emissions; however, concerted action will be needed as methane emissions cannot be offset in the same way as carbon dioxide.

Align planning, regulatory and pricing mechanisms for a more integrated energy system

System planning will need to reflect the increasing integration of the energy system. This includes across energy sources (gas and electricity) and along the value chain (generation, transmission, distribution and customers). System planning will also have to account for different requirements and outcomes by location. Some European countries (e.g. Netherlands, Germany) are increasingly conducting energy system planning at a regional level to make location-specific decisions during the transition.

Cost recovery and pricing mechanisms will need to account for true whole-of-system trade-offs. For instance, declining gas volumes could challenge the cost recovery and maintenance of regulated gas infrastructure and high tariffs, creating equity challenges through the transition.

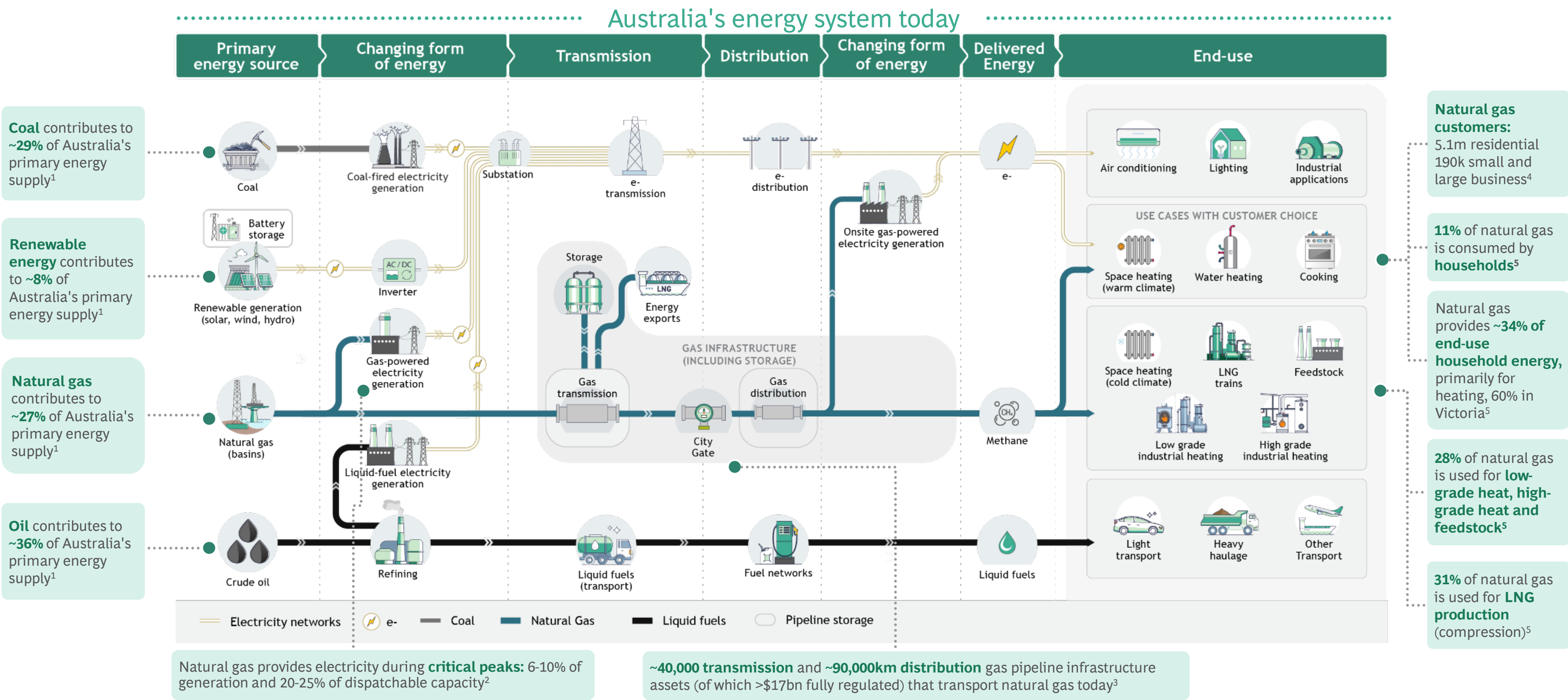
Advance low-carbon gas technology to reduce costs

If the cost of low-carbon gases declines as forecast, they could be competitive with electricity for some customers (see section 3). Hydrogen and biomethane technology are advancing, and their feasibility is being demonstrated in Australia, for example by the Malabar Biomethane Injection Project (NSW) or Hydrogen Park Murray Valley (Victoria). More action will be needed to scale green hydrogen production to reduce costs, increase feedstock availability for biomethane, and to plan for and demonstrate how gas infrastructure can adapt for low-carbon gases.

[8] AEMO, Gas Statement of Opportunities (GSOO) (2023)

Appendices: How the energy system can evolve

Appendix 1: Natural gas and gas infrastructure form one of three pillars of today's energy system



1. Australian Energy Statistics 2. OpenNEM 3. AER, Regulated Gas Pipelines; Access arrangements used for WA. Does not include value of assets under light regulation or unregulated assets. 4. Totals do not include NT and TAS customers; AER; Economic Regulation Authority; Essential Services Commission 5. Australian Energy Statistics; APPEA, Key Statistics 2022; AEMO GSOO 2021; AEMO WA GSOO 2020; Australia Institute, On the make (2020); Energy Consult, Residential Energy Baseline Study Australia (2015)
Source: BCG analysis

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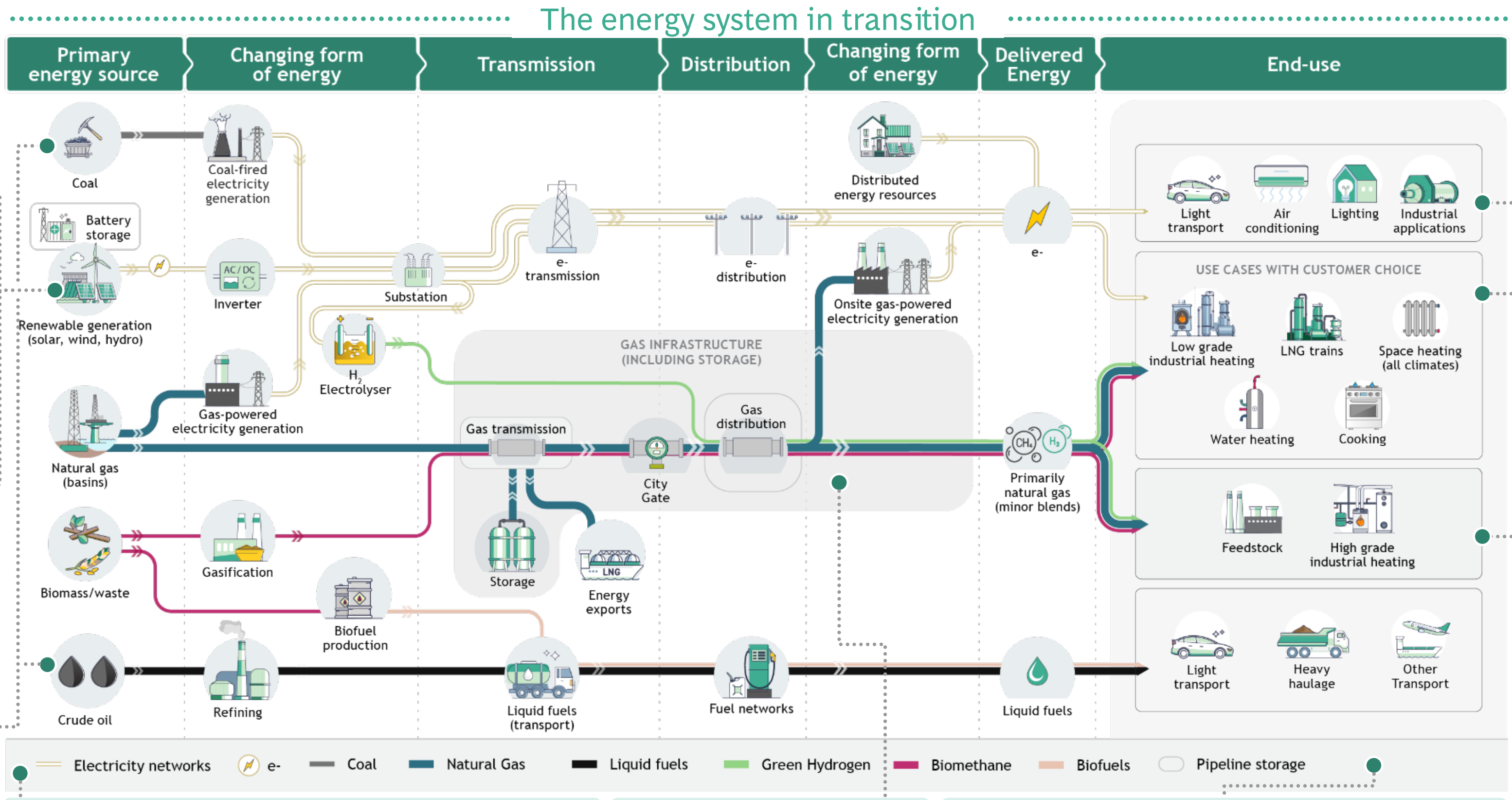
Appendix 2: In the transition to a clean energy system, the growth of renewable primary energy sources will drive a realignment of the energy system architecture

Renewable electricity build will accelerate, with ~25 TWh/year of wind and solar planned, plus ~40 TWh/year of rooftop PV forecast by 2030[1]. The renewable electricity **build rate will be critical to the pace of transition**

Wind and solar will be **Australia's cheapest sources of renewable primary energy,** projected to cost $50-70/MWh compared to biomethane/green hydrogen at $75-95/MWh in 2025[2]

Displacing coal-fired electricity generation and liquid fuels with renewable electricity delivers the greatest system savings and emissions reduction



Increasing connection between gas and electricity energy systems e.g. gas is used to produce hydrogen and firm renewable electricity

Gas infrastructure supports **targeted blending of H_2 and biomethane**

System interdependencies highlight the need for **integrated system planning which needs to account for locational differences**

Transport: ICEs (liquid fuels) start being replaced by EVs (electricity)[3]

Households **have greater choice** with electric appliances becoming more **cost competitive** in most cases[5] (natural gas + offsets remains a cost competitive option)

LNG trains: gas turbine compressors could be replaced by electric drive motors[4]

Natural gas will continue to serve end uses that are **hard-to-electrify** or deliver **lower system savings** from transitioning to renewable electricity

1. AEMO NEM Generation Information; AEMO NEM ISP Generation Outlook 2022 (Step Change scenario) 2. Wind and solar LCOEs from CSIRO, GenCost 2022-23 with blended average LCOE calculated based on 60% wind and 40% solar mix; green hydrogen cost is from Advisian and CEFC, Australian Hydrogen Market Study; biomethane cost is from IEA, Outlook for biogas and biomethane, and from Deloitte, Decarbonising Australia's gas network 3. CSIRO, Electric Vehicle Projections 2021; Advisian, Australian hydrogen market study 2021 4. IEA; ABB; company data; RFF; OIES 5. Grattan, Flame out (2020); Frontier, Cost of switching from gas to electric appliances in the home (2022); ATA/Reneweconomy, Household fuel choice in the NEM
Source: BCG analysis

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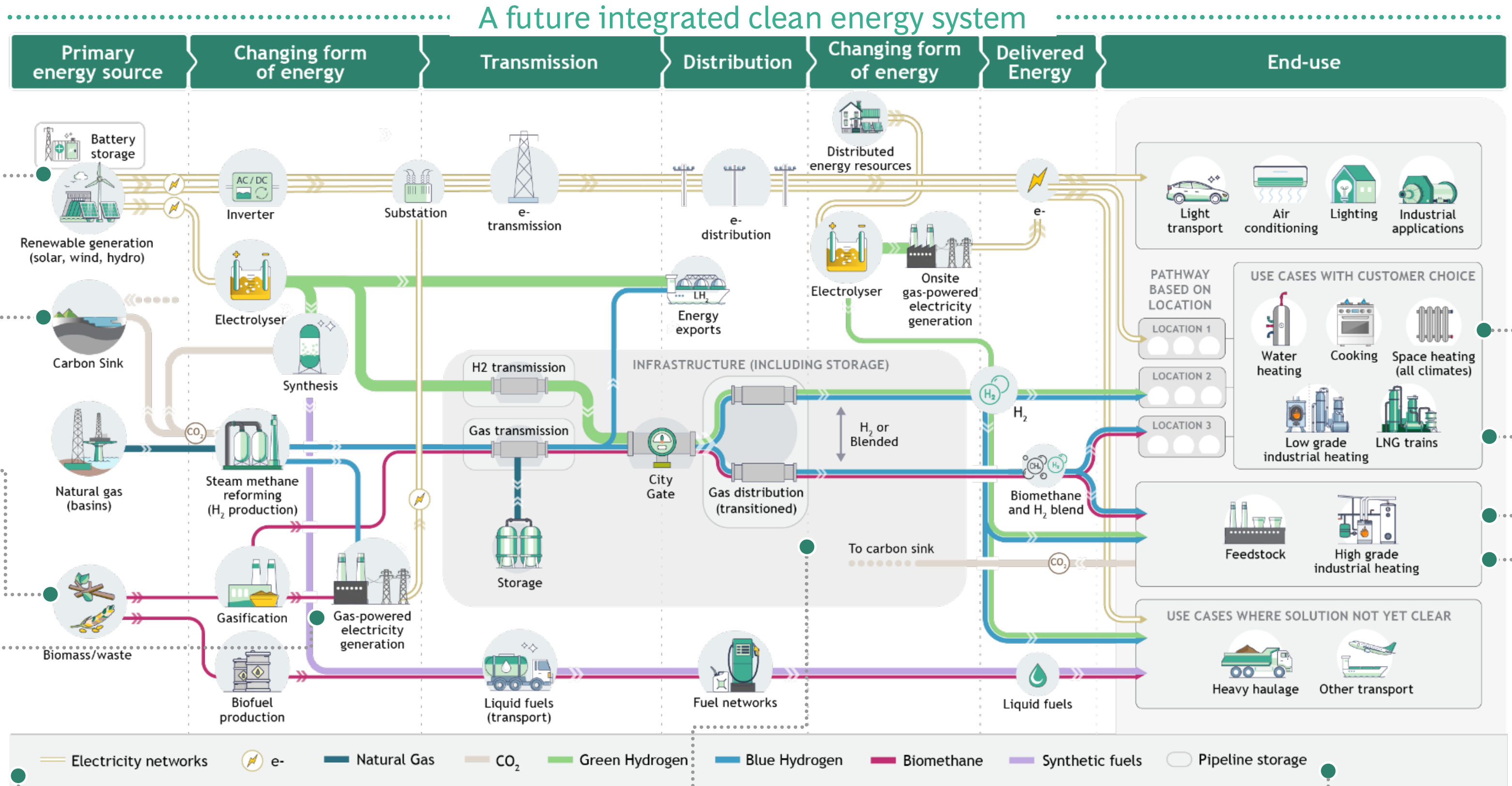
Appendix 3: In a clean energy system, low-carbon gas pathways could provide alternatives to natural gas and increase network resilience

Primary energy source maximises use of **renewable electricity** where **cost effective and available**, and then uses low-carbon gas

Carbon sinks are used to store captured CO_2 from steam methane reforming or GPG

Biogas (from biomass) can be upgraded to **biomethane** – demand will be contested by multiple end uses

Gas-powered generation remains; **least-cost future energy systems have ~5-11% GPG capacity**[1]



At anticipated costs, customers will have **competitive, low-carbon options to choose from** across electricity and low-carbon gas (e.g. H_2 and biomethane)[3]

Individual **customer choice will depend** on a number of factors

Decarbonisation pathway will be **subject to location** (e.g. climate, infrastructure availability, energy source proximity)

High-grade process heat and feedstock can be served with **low-carbon gas** (e.g. H_2 and biomethane)[4]

Greater **interconnectedness increases system resilience** through features such as green hydrogen storage

Gas distribution can transition to transport low-carbon gases with some **minor modification,** while **transmission networks may need greater modification or additional pipelines**

A system using low-carbon fuels can incur **less than 50% incremental annual costs (vs. today)**, compared to electrification alone[2]

1. Gilmore, Nelson and Nolan, Firming technologies to reach 100% renewable energy production in Australia's National Electricity Market; based on lowest average energy cost for a 100% VRE system. 2. Frontier Economics, The benefits of gas infrastructure to decarbonise Australia; 3. Advisian and CEFC, Australian hydrogen market study (2021); 4. ETI, Pathways to industrial decarbonisation (2023); ARENA, Renewable energy options for industrial process heat (2019)
Source: BCG analysis

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