KPMG

Hydrogen Communities

Assessment for suitability of communities for conversion to hydrogen

June 2019

KPMG.com.au

POWERED BY CSIRO ENERGY DATA

Contents

Disclaimer

Inherent Limitations

This report has been prepared by KPMG and CSIRO as outlined in the Scope Section. The services provided in connection with this engagement comprise an advisory engagement, which is not subject to assurance or other standards issued by the Australian Auditing and Assurance Standards Board, and consequently, no opinions or conclusions intended to convey assurance have been expressed.

No warranty of completeness, accuracy or reliability is given in relation to the statements and representations made by, and the information and documentation provided by, Australian Renewable Energy Agency ('ARENA') management, personnel and stakeholders consulted as part of the process.

KPMG have indicated within this report the sources of the information provided. We have not sought to independently verify those sources unless otherwise noted within the report.

We are under no obligation in any circumstance to update this report, in either oral or written form, for events occurring after the report has been issued in final form.

The findings in this report have been formed on the above basis.

Third Party Reliance

This report is solely for the purpose set out in the Scope Section and for ARENA's information and is not to be used for any other purpose or distributed to any other party without KPMG's and CSIRO's (collectively 'our') prior written consent.

This report has been prepared at the request of ARENA in accordance with the terms of KPMG's engagement letter dated 20/05/2019 Other than our responsibility to ARENA, neither we nor any of our employees undertakes responsibility arising in any way from reliance placed by a third party on this report. Any reliance placed is that party's sole responsibility.

We understand a complete and unaltered version of this report is to be published on ARENA's website, to be accompanied only by any such other materials as we may agree. Responsibility for the security of ARENA's website remains with ARENA. We accept no liability if the report is or has been altered in any way by any person.

We shall not be liable for any losses, claims, expenses, actions, demands, damages, liabilities or any other proceedings arising out of any reliance by any third party on this report.

01 Executive Summary

Hydrogen is emerging as an alternate carrier of energy. It has the potential to play a key role in the decarbonisation of the energy sector, if produced by zero or low emissions sources. Governments around the world and in Australia are signalling interest in moving the hydrogen economy forward. Current efforts are focused on developing hydrogen visions and strategies, supported by investments and partnerships with industry to progress technology and unlock the barriers across the hydrogen value chain.

Hydrogen technology is still maturing. For hydrogen to be cost competitive, key barriers in supply chain infrastructure and supply cost need to be overcome. Current investments are focused on research and trials to further develop the maturity of technology, educating and gaining acceptance of communities for hydrogen.

With Australia's extensive renewable energy resources of wind and solar, clean hydrogen can be produced for domestic use as a lower emissions source of energy. This would ensure security of the energy system and provide an opportunity for export to the global market.

Australia's government and private sectors have already progressed a number of initiatives and investments in the hydrogen economy. These have focused on research and trials to improve technology and cost competitiveness for hydrogen; developing technical and regulatory standards; and unlocking barriers across the hydrogen supply chain. Examples include:

- CSIRO's national hydrogen roadmap
- The hydrogen strategy group, led by Chief Scientist Alan Finkel, releasing a briefing paper outlining the opportunities of hydrogen for Australia
- ARENA's opportunities for Australia from hydrogen export report
- The establishment of the hydrogen working group, by COAG's energy council. Key priorities of the working group include:
  - The development of a national hydrogen strategy for 2020-2030
  - Undertaking a coordinated approach to hydrogen projects
  - Supporting the development of the hydrogen industry in Australia.

Purpose and scope

KPMG developed an assessment framework accompanied by an assessment tool (the H2City Tool) for early concept screening of potential communities suitable for converting their energy usage to hydrogen. The outputs of this project include:

This report which provides a brief review of selected global and Australian case studies, a description of the H2City assessment framework, and a description of the functionality and assumptions of the H2City Tool.

Spreadsheet-based H2City Tool, which encompasses a combination of qualitative and quantitative considerations for input. The H2City Tool comes pre-populated with time based assumptions containing relevant cost and performance data obtained from CSIRO as well as publically sourced data, set as default assumptions within the H2City Tool. The H2City Tool provides outputs that allows the user to compare the outcomes for different scenarios analysed.

Additionally, **KPMG has worked with the Commonwealth Scientific and Industrial Research Organisation (CSIRO)** to provide the following services:

Inputs into the MCA criteria selection

Data for the Tool

A review of the Tool in regards to data provided and its application within the Tool

Scope is further detailed in **Appendix 1.**

H2City Report and Tool context

This report has been prepared to:

- Provide an overview of observations and lessons learnt to-date from global and Australian hydrogen case studies
- Set out the factors for consideration to assess the suitability of converting a community's energy source to hydrogen
- Outline the approach and underlying assumptions and data for the H2City Tool

The report accompanies the H2City Tool. The H2City Tool has been developed to assist users with screening of communities that may be suitable for transitioning to a hydrogen-based energy future and provides two broad pathways - a hydrogen pathway and an electrification pathway, to allow relative comparison to be made between these options. The opportunities identified using the H2City Tool would then require further scoping and detailed analysis.

The H2City Tool has been developed to support energy industry participants, government, transport and infrastructure agencies, developers and policy makers in assessing suitable communities for conversion to hydrogen.

The H2City Tool has been preconfigured to operate in three different modes. The different modes affects the number and level of inputs required. The calculations in each mode remains the same.

Modes
Mode 1: Limited (5) number of inputs exposed to user with H2City Tool pre-populated
Mode 2: A hypothetical town with all inputs loaded for review (noting over 200 inputs)
Mode 3: A bottom up mode where users can choose to populate all inputs from scratch

The H2City Tool is a demand driven model, and calculations are based on a community's specified demand. Outputs are determined through upstream requirements of demand. The information and data provided in this report and the H2City Tool have been sourced from available research, supported by CSIRO, as well as public documentation and analysis of the industry. At this point in time, the hydrogen industry is rapidly evolving, therefore the information contained in this report is relevant at the time of authorship.

The outputs of the H2City Tool, allow the user to compare and test different scenarios and assumptions on multiple quantitative variables across the hydrogen value chain. A key quantitative metric produced by the model is the 'Levelised Supply Chain Cost' (LSCC).

Qualitatively, the outputs provide a high-level view of regulatory implications depending on location and participation. Potential policy impacts and social benefits can be included in the H2City Tool through various inputs.

Essentially the H2City Tool allows the user to compare outcomes from different scenarios. Different inputs and assumptions used in the model can generate varying outcomes. At a macro level, by assessing different scenarios, the user is able to better understand key factors that are potential constraints to conversion, and trade-offs required, provide the optimal balance of cost and ease of implementation.

Due to the complexity of factors required in undertaking an assessment using the H2City Tool, it is assumed users have:

- A basic knowledge of the energy sector and hydrogen industry
- Have a good understanding of the available infrastructure within the location of study
- Have an ability to interpret data assumptions
- Can select appropriate inputs within the relevant context and access suitable user-defined data and assumptions.

Structure and context of report

Case Studies and Lessons Learnt

This section outlines a summary of selected case studies and observations referenced in developing the H2City Tool

H2City Tool Approach

This section describes the approach of the H2City assessment H2City Tool and scenarios that can be analysed

H2City Tool Assessment Criteria

This section, details the criteria for the assessment of Hydrogen communities in the H2City Tool

Electrification Pathway

This section provides a description of the electrification pathway approach in the H2City Tool

Appendix

H2City Tool scope

H2City Tool key known simplifications and limitations

Regulatory issues considerations

Bibliography

List of references used in developing this report and analysis

Hydrogen

H_2 Fast Facts

1 kg of hydrogen is the equivalent of:

4 litres of petrol

120MJ of energy
compared to 50MJ per kilogram of methane

14L of volume
when liquefied at -253°C

Most abundant element in the universe

When burned, hydrogen produces little more than water vapour

Acts as an energy carrier and is not itself a source of energy

When produced with renewable electricity, the process is carbon neutral

Has the greatest energy density per unit mass of any fuel

H_2 Applications

Hydrogen has the potential to play an important role in decarbonisation

Gas network

Industrial feedstock

Export

Grid support & power generation

Transport & Mobility

H_2 Lesson Learnt

Complete lessons learnt can be found section 2 of the FULL REPORT

Liverpool-Manchester Hydrogen Cluster **UK**

- Low blending rates (5 – 20% volume) requires no domestic appliance conversion
- State objective is prompting hydrogen related initiatives

California Fuel Cell Partnership **USA**

- Strategically placed hydrogen refuelling stations located within 15-minute drive
- Early government program stimulated initial build-out of refuelling stations

H21 Leeds City Gate **UK**

- Refurbishment with hydrogen-suitable materials to minimise conversion costs
- Minimising customer disruption an important success factor

HyDeploy **UK**

- 20% blending limit imposed to negate customer disruption
- Onsite electrolyser eliminates the need for extensive pipeline infrastructure

H_2 Mobility **Germany**

- Refuelling stations along main arterial highways, provides convenience and community buy in
- Continued government support has been critical to meet targets

Hydrogen Energy Supply Chain **Australia**

- Partial decarbonisation pathway which requires CCS solutions as a stepping stone towards green hydrogen
- Local and International government support expedites project progress

Hydrogen Highway Partnership **Scandinavia**

- Collaboration between Nordic countries to increase project support and resources
- Triple helix arrangement fosters economic and social development opportunities

ENE-Farm **Japan**

- Distributed fuel cells are a pathway to partial decarbonisation
- Public-private partnerships stimulate installations of technologies

Clean Energy Innovation Hub **Australia**

- Excess renewable energy produced through solar PV
- Hydrogen for direct use testing and to power a fuel cell for back-up generation

Western Sydney Green Gas Project **Australia**

- Excess renewable energy purchased through PPA's for hydrogen production
- Low blending rates ensure customer appliances do not require replacement

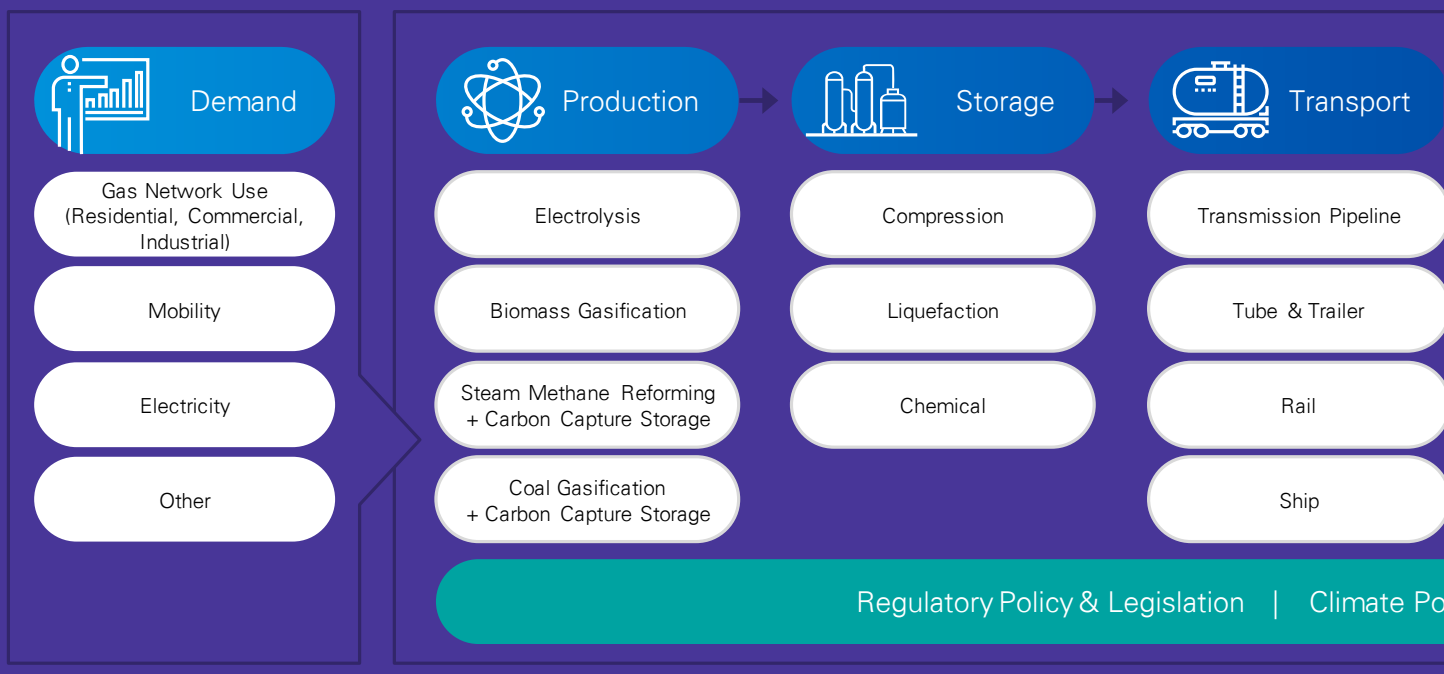
Hydrogen Park **Australia**

- Blending of up to 15% to minimise customer disruption
- Hydrogen supports the balance of electricity supply and demand and grid stability

Toyota Ecopark **Australia**

- Solar PV and battery storage to convert hydrogen via electrolysis, with onsite compression and storage
- Onsite commercial hydrogen refuelling station reduces the requirement of transport infrastructure

Hydrogen Value Chain



Demand

Defines the energy demand of the community to be met via the selected pathway, for each relevant demand category

Production

Defines the resource and technology to be used to produce the required hydrogen or renewable electricity to meet the defined demand

Storage & Transport

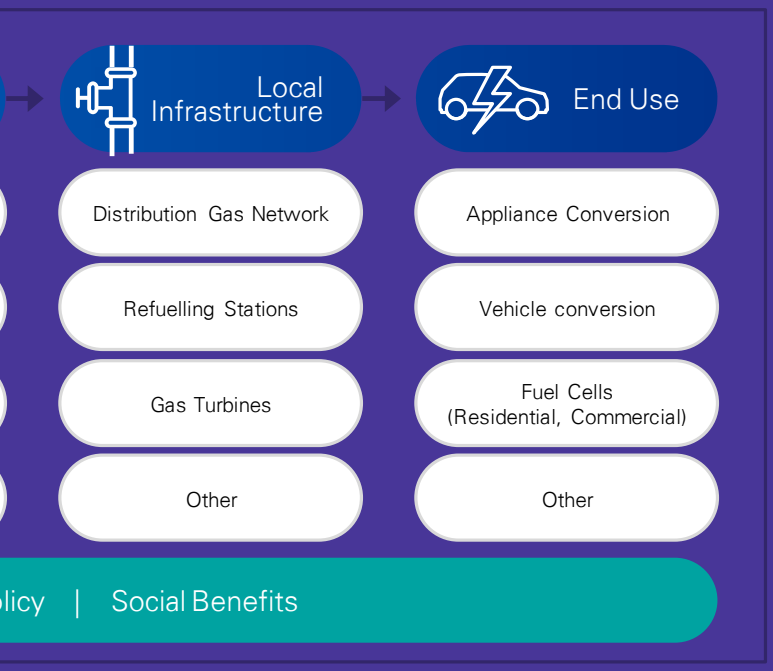
Defines the requirements for infrastructure to transport the energy produced via transmission pipeline, tube and trailer, rail or ship as well as storage requirements tailored to the applicable supply chain

Local Infrastructure

Defines the requirements for local infrastructure upgrades or new build required to distribute the produced hydrogen to the end user

End Use

Defines the costs to the end user – cost of converting domestic appliances switching to battery, electric vehicles, etc.



Regulatory Policy & Legislation

Economic regulatory factors for consideration, depending on the role that the user intend to undertake, and the State and Commonwealth regulations that may apply

Climate Policy

Includes the potential climate policy mechanisms aimed to accelerate decarbonisation

Social Benefits

Includes considerations of social benefits and community acceptance.

Key H2City Tool Assumptions

The H2City Tool has been developed based on a number of key assumptions. Additional assumptions and details are contained within the Full Report.

Hydrogen/Electricity Demand - is calculated on the basis of total demand forecast for each state/ community relative to the population

Gasification Pathway

Gas network use – hydrogen will replace natural gas in the gas network, either as a blend of up to 10% or at 100%.

Hydrogen Production - facilities are located at the resource site.

Storage and Transport – considers the gas network and mobility use to account for different means of hydrogen transport and storage

Local Infrastructure – the level of augmentation required is specified by the user and costs are calculated on pro rata basis

Electrification Pathway

Gas network use – electricity replaces natural gas as an energy source

Electricity Generation – intermittent electricity generators are located at the site of the resource

Storage and Transport – utility scale firming technologies are accounted as energy drainers and not generators

Local Infrastructure Upgrades – the level of augmentation required is specified by the user and costs are calculated on pro rata basis

02

Case Studies and Lessons Learnt

Global and Australian case studies of hydrogen community conversions and hydrogen initiatives were reviewed to support the development of the H2City tool. The review assessed the approach undertaken, observations and considerations applicable to development of the tool.

This section summarises selected key global and Australian case studies, described through the hydrogen value chain.

Introduction

In supporting the development of the H2City Tool, global case studies of communities undergoing hydrogen conversions were reviewed. In this section, a summary of selected case studies are outlined.

The hydrogen industry is currently in trial phase, with various projects in research, pilot or demonstration phase, to capture learnings and improve technology and cost competitiveness. As the hydrogen industry is continuing to evolve, the case study review was focused on where the research, study or trial is reasonably progressed, the information published is current and available from reliable sources.

Key findings

In reviewing the case studies, the following observations and considerations across the hydrogen supply chain and other factors were identified. Key highlights and a summary of those observations and considerations applicable, when assessing the suitability of a community for conversion are as follows:

Demand

- The production, transport and storage of hydrogen is optimised to meet the demand and location of a community
- Analysis of consumption and demand profile is required to determine production, transport and storage requirements

Production

- At current cost, production facilities are one of the largest costs across the supply chain. Production facilities to meet higher demand improve with economies of scale
- Electricity sources for the Hydrogen production facilities can be connected through the grid with renewable power purchase agreements in place
- All production methods require a significant amount of water. As Australia is one of the most water stressed regions in the world, the long term cost and availability of water requires careful assessment

Storage & Transport

- Existing gas network pipelines can be leveraged to store and transport Hydrogen to the end user. This reduces the overall supply chain costs
- To meet more localised, smaller demand, developing the production facility close to the demand point reduces transport costs

Local Infrastructure

- As with Storage and Transport, existing gas network pipelines can be leveraged to store and transport hydrogen. This reduces the overall supply chain costs
- To meet more localised, smaller demand, developing the production facility close to the demand point reduces transport cost

End Use

- The current cost of converting appliances in a 100% scenario is significant
- Blending of hydrogen greater than 10% into the gas network will require testing on a case-by-case basis to ensure safety and risk impacts are well understood
- For hydrogen use in mobility, coordination of fuel cell vehicle uptake and refuelling stations is required

Decarbonisation

- Hydrogen can be produced from clean or green energy sources providing an alternative fuel source. This will help decarbonise the energy sector and achieve emissions targets
- Decarbonisation targets encourage research into a potential adoption of Hydrogen as alternate zero emissions fuel source

Government Policy & Incentives

- Government policy and incentives help stimulate research and progress of the hydrogen industry
- Most projects and initiatives are supported with government incentives and/or policy direction
- Projects are being developed in partnerships consisting of a combination of industry participants, government and universities

Partnership & Coordination

- Developing the Hydrogen industry requires coordination of players across the supply chain
- Partnerships allow pooling of resources and expertise, as well as sharing of risks

2.1 H21 Leeds City Gate

The H21 Leeds City Gate (H21 LCG) project aimed to decarbonise the gas network through demonstrating feasibility of conversion of a community's gas network to hydrogen for supply of heating demand [1]. The key project partners are Northern Gas Networks, Wales and West Utilities, Kiwa and Amex Foster Wheeler. The H21 LCG project initially focused on conversion of natural gas to Hydrogen in the city of Leeds.

A detailed report was published in 2016, outlining the technical approach to conversion and the economic implications. The report proved the suitability of converting UK gas networks, for the following reasons [1]:

- The gas network pipelines are correctly sized to be converted to 100% hydrogen
- The gas network pipelines are currently being replaced with materials capable of carrying hydrogen through their asset replacement program, hence reducing incremental cost of conversion
- Large scale low carbon hydrogen can be produced
- Conversion of natural gas to hydrogen should be undertaken incrementally
- Ability to store hydrogen to manage intraday and inter-seasonal swings in demand
- Ability to capture and store carbon through sequestration.

In November 2018, H21 North of England (H21 NoE), a project partnership between Cadent, Equinor and Northern Gas Networks was launched, building upon the H21 LCG project. H21 NoE is 13 times larger than H21 LCG, by total energy. It aims to build on economies of scale of the H21 LCG to improve cost and create greater impact to UK's climate change obligations.

H21 NoE proposes to convert 3.7 million homes and businesses in Leeds, Bradford, Wakefield, York, Huddersfield, Hull, Liverpool, Manchester, Tesside and Newcastle from natural gas to Hydrogen, over 2028-34. To achieve this, it proposes a front-end engineering design (FEED) study be undertaken.

Key observations and considerations

Criteria	Observations and considerations
Demand	• Conversion of the Leeds area includes 264,000 gas supply points • Estimated total annual demand (in a peak year) is 6.4TWh; maximum hour demand is 3.18 GW
Production	• When considering the production technology, total demand is a key factor in the selection of viable options. Steam methane reforming (SMR) coupled with carbon capture storage (CCS) was selected as the most viable option. Electrolysis production powered by renewable electricity was considered difficult to achieve due to the amount of renewable electricity and corresponding land required • The proposed hydrogen production site is co-located alongside natural gas sources • SMR production facilities were designed to be positioned near carbon capture sites and hydrogen storage locations. This is to centralise and capture all carbon produced as well as allowing for a continuous hydrogen production throughput
Storage	• The project considered overall demand, inter-seasonal and intraday variations to establish the right mix of production and storage capacity requirements
Transport	• A hydrogen transmission pipeline is required to transport hydrogen from the production facility and storage (salt) caverns to Leeds • Feasibility of pipeline routes included consideration of planning laws, consultation with landowners and environmental impacts
Local infrastructure upgrade	• Leeds area gas pipelines are currently already being replaced with Hydrogen-suitable materials of construction (through its asset replacement program), hence will minimise the incremental cost of conversion
End use	• Appliance conversion cost is estimated to be up to 50% of the total conversion cost when converting a gas distribution network to 100% hydrogen • Converting home appliances will be a significant disruption to customers and therefore an important success criteria is to minimise the disruption to the end customer where practical
Regulatory policy and legislation	• Cost of conversion is proposed to be funded through an increase of regulated tariffs, distributed across all of Northern Gas Network's customer base, which will minimise impact on individual customers
Social benefits and acceptance	• Hydrogen production facilities are planned to be located within an already established chemical industry zone

2.2 Liverpool-Manchester Hydrogen Cluster

Liverpool–Manchester Hydrogen Cluster project (L-M Cluster Project) is a conceptual study to develop a practical and economic framework to introduce Hydrogen into the Liverpool–Manchester (L-M) gas network [2]. The project is being led by Cadent Gas, a gas distribution network in the UK, in partnership with Progressive Energy, a clean energy company focusing on project development and implementation.

In August 2017, a study documenting the outcomes of the study was published [2]. The report detailed the technical and economic considerations throughout the hydrogen value chain for the conversion of natural gas into hydrogen gas. It proposes blending of hydrogen (5 – 20%) with natural gas in the local distribution gas network.

SMR production coupled with CCS to capture carbon dioxide discharged from the production process was selected [2].

The project's incremental cost of conversion is reduced because:

- There are no appliance conversion costs for households. Blending of hydrogen is considered - not a 100% conversion from natural gas to hydrogen
- Existing and planned onshore salt caverns may be turned into hydrogen storage locations, reducing costs of developing new assets
- Existing CCS infrastructure is already in place reducing start-up costs. Only incremental operating usage costs would be required

The next steps of this project are to scope out the proposed design in more detail and engage with regional stakeholders.

Key observations and considerations

Criteria	Observations and considerations
Demand	• In the L-M area, the total gas consumption (2015 actuals) was 47,631 GWh with industrial and commercial making up 57% of the total consumption. This total area is considered for conversion
Production	• SMR coupled with CCS, was identified as the most suitable production method to produce the required hydrogen for L-M area • Gas is currently supplied by offshore fields directly to L-M. In the longer term, a diversified feedstock for hydrogen production will need to considered, as future low cost and available gas supply isn't guaranteed • There is existing CCS infrastructure that can be expanded to capture the carbon dioxide from the hydrogen production
Storage	• Available existing infrastructure reduces new asset investment required for storage • L-M area will be able to manage the fluctuations in demand within the four core industrial sites, facilitating line-pack and variable gas/hydrogen use
Transport	• New 90km of onshore Hydrogen pipeline from the SMR production site to the industrial cluster in the L-M area would be required. Points for injection of hydrogen into the network should be identified at detailed design phase
End Use	• No domestic appliance conversion is required, with blending of 5-20% of hydrogen with natural gas • Some modifications to the industrial boilers, engines and turbines is assumed to be required
Regulatory policy and legislation	• Funding for the conversion is proposed to be included within Ofgem's[1] network incentives framework
Social benefit and acceptance	• The Liverpool City Region Local Enterprise Partnership (LEP) has stated an objective in its strategic growth plan to develop a hydrogen gas grid to provide cheap, low carbon heating for the city region. It is also promoting hydrogen related initiatives in industry and transport

1 Ofgem (Office of Gas and Electricity Markets) is the government regulator for gas and electricity markets in Great Britain

2.3 HyDeploy

The HyDeploy project is a trial to test the blending of hydrogen concentrations up to 20%. The project is delivered through a consortium, comprising Cadent Gas, Northern Gas Networks, Keele University, The Health and Safety Laboratory, ITM Power and Progressive Energy, with specialist gas safety testing support from industry experts.

HyDeploy@Keele, is the first phase of the project to run a live trial within Keele University's closed, private gas network at the campus in Staffordshire, UK [3]. This project study commenced in 2017. Hydrogen will be produced via a 0.5MW electrolyser supplied by renewable power. Last year, approval was granted by the UK Health & Safety Executive to run a 12 month trial of blending up to 20% of Hydrogen with natural gas. The current limit of Hydrogen injection into the UK gas network is 0.1%. The trial is now proceeding to the design and build phase for the on-site production and other required local infrastructure.

HyDeploy$_2$ is the next phase of the project, which will plan similar trials at two licenced gas distribution networks; one in Cadent's North West region and second in Northern Gas Networks' North East region.

The decision to limit hydrogen blending to 20% is based upon earlier studies of risk comparisons to natural gas, impact to customers, and UK gas appliances manufactured after 1993, designed to operate with a hydrogen mix of up to 23%.

Key observations and considerations

Criteria	Observations and Considerations
Demand	• The location of conversion consists of 340 residential, teaching and business premises within a closed network. The standalone private gas network provides a good test environment for blending of up to 20%
Production	• A 0.5 MW electrolyser will be built onsite, eliminating the need for long pipeline infrastructure
End Use	• Approval of the hydrogen blending limit of 20% was granted by the safety regulator after an extensive safety research phase. At this stage, approval of blending limits are assessed on a case by case basis and extensive testing will be required to understand the safety and risk implications • Hydrogen will be blended with natural gas within a mixing unit to ensure consistent concentrations before injecting the blended gases into the network
Regulatory policy and legislation	• In 2016, Ofgem provided £6.8million as part of its network innovation competition funds for the trial at Keele University
Social benefits and acceptance	• Keele University is committed to a carbon neutral future through its Smart Energy Network Demonstrator Project • Blending of up to 20% does not have an impact to the end user, i.e. no appliance conversion is required and the risks are not greater than using natural gas. Therefore, there is no major barriers in gaining customer or social acceptance

2.4 ENE-Farm

The ENE-Farm project has installed over 230,000 residential fuel cells in Japanese homes to produce electricity and hot water from liquid petroleum gas (LPG) through the city gas network. The project is a public-private partnership between the Japanese government and residential fuel cell manufacturers [4].

Hydrogen is extracted through the LPG connection to the property via a fuel reformer and is processed through a fuel cell to generate electricity, heat and produce water. Electricity is fed via an inverter and the heat produced is captured by a recovery system for heating the water supply. The technology can deliver a combined 95% heat and electrical efficiency, compared to grid efficiencies of 35% to 40% [5]

The system's technology prioritises power generated from the LPG powered unit and only draws from the electric power grid when power is insufficient. Consumers are also able to manually select the source of power generation. Based on the generation capacity of ENE-Farm units, a theoretical 60% of household power demands can be supplied by the technology, ensuring power reliability during power outages and reducing CO_2 emissions by up to 50% [5].

Key observations and considerations

Criteria	Observations and considerations
Production	• ENE farm produces hydrogen from LPG at point of use for immediate use within fuel cells • Distributed energy is a pathway to decarbonisation by reducing the overall fuel demand rather than decarbonising the fuel source itself
Other	• Public-private partnerships are an effective way for governments to stimulate installations of technologies

2.5 California Fuel Cell Partnership

The California Fuel Cell Partnership is aimed at delivering zero-emissions fuel cell vehicles and domestically produced renewable hydrogen in California [6]. It targets, establishing a network of 1,000 hydrogen stations and creates a FCEV fleet of one million vehicles by 2030. Having zero-emissions vehicles will help reduce greenhouse gas emissions and criteria air pollutants generated from transportation, and consequently help meet California's air quality goals. The project focuses on three strategic priorities, which are to enable, establish and expand the market.

To enable the FCEV market, environmental and government policy is critical. Early government grant funding programs were provided to help finance capital investment and operational costs for hydrogen refuelling stations. As of 2018, 35 retail hydrogen stations have opened with the support of the California Energy Commission's first grant solicitation in 2010. To achieve the target of building 200 hydrogen stations by 2025, a transition from public funds to private capital investment is required. Long term policies are needed to provide confidence and certainty to private industry to invest. The economies of scale for hydrogen stations will reduce capital cost and provide certainty to suppliers on the expected demand for components and scaling of workforce to support construction, operation and maintenance of the refuelling stations. This will help attract more private investment.

The uptake and transition to FCEV is supported through California's regulators and policy. Recently, the California Air Resources Board has mandated a state-wide target to transition to 100% zero-emissions bus fleets by 2040 [7], through the Innovative Clean Transit regulation.

Key observations and considerations

Criteria	Observations and considerations
Local infrastructure	• To facilitate acceleration of uptake of FCEVs, a network of strategically located hydrogen refuelling stations is planned across the state. Refuelling stations are located within a 15-minute drive of 94% of the entire local population • For long-haul and short-haul transport trucks, the refuelling stations are strategically positioned along the state's freight corridors • Target economies of scale for development of infrastructure and refuelling stations to lower cost
Other	• Early government grant funding program stimulated initial build-out of hydrogen stations • State-based incentives are also provided to motivate uptake of FCEVs, raise awareness and familiarity with the new technology • Establish a market by encouraging uptake through incentives to enable transition by mainstream buyers

2.6 H_2 Mobility

The H_2 Mobility project is a joint venture between oil, gas and automotive industry partners which aims to deliver 400 Hydrogen refuelling stations (HRS) throughout Germany by 2023, with an interim goal of 100 HRS by 2019 [8]. As of November 2018, 68 HRSs have been commissioned.

Driven by the carbon dioxide emission reduction targets set by both the EU and Germany, the project accelerates the decarbonisation of road transport through promotion of FCEVs by providing refuelling infrastructure for vehicle owners [9]. H_2 Mobility is funded through the German Federal Ministry of Transport and Digital Infrastructure (BMVI) in connection with several European Union Associations and Commissions.

The first HRSs were constructed in high population metropolitan areas and along major arterial highways, focusing on convenience and customer experience. Installation of HRSs are integrated if possible, with existing petrol stations. Production methods of hydrogen vary from green (Carbon free production via wind to gas (i.e. power to gas) and electrolysis) and brown technologies (Produced from a national grid via upstream reformer of methane, propane and ethanol) [10].

Hydrogen gas is then delivered by tankers and stored at 45 bar, with further compression to 700 bar for automobile refuelling.

Key observations and considerations

Criteria	Observations and considerations
Transport	• Hydrogen is delivered to the refuelling stations via tankers
Local infrastructure and social acceptance	• The initial installations of HRSs were placed in large metro areas and along high traffic highways, ensuring convenience of access as well as secondary consumer marketing • Hydrogen refuelling componentry is similar in design to traditional fuel dispensers, the integration with current refuelling stations raises awareness and familiarity of the technology
Regulatory policy and legislation	• Continued government support has ensured roll-out targets are on schedule

2.7 Scandinavia Hydrogen Highway Partnership

The Scandinavia Hydrogen Highway Partnership is a triple helix innovation partnership between industry, academia and authorities across multiple levels of Nordic country governments with the primary objective of accelerating the deployment of FCEVs and delivering Hydrogen refuelling stations across the region [11].

The partnership has recognised opportunities and leveraged the policy mechanisms in each region to stimulate the attractiveness of renewable energy, promote adoption and attract investment (via tax benefits, investment options, funding, etc.) for the new technology [12].

Projects funded under the partnership include:

- H_2Moves – The Hydrogen pioneer project in 2006 aimed to increase awareness and acceptance of hydrogen as an energy carrier and its capability as a fuel source for cars. The first fuelling station was constructed in Oslo and hydrogen is produced via electrolysis. The success of the project fostered regional co-funding and reduced the administrative documentation for additional network ventures [13]
- Nordic Hydrogen Corridor - Co-financed by the EU, this project consists of eight refuelling stations, 100% of FCEV supplied by a central electrolysis production facility [14]
- Fuel Cells & Hydrogen Joint Undertaking Program (FCH-J) - The program aims to establish hydrogen as a primary energy carrier by 2020 through improving energy efficiency of electrolysis and development of storage, handling and distribution infrastructure [15]

Key observations and considerations

Criteria	Observations and considerations
Local infrastructure (Refuelling stations)	• Large HRSs are planned installations in metro areas and along high traffic highways, with smaller satellite stations located in rural areas to ensure greater accessibility to users
Other	• The program collaborated between Nordic countries to increase the support and resources available for the project • Government support is critical to ensure resolutions to project and program negotiations • The triple helix arrangement between academia, industry and governments fosters greater economic and social development opportunities and possibilities

2.8 Clean Energy Innovation Hub

ATCO, WA's gas distributor is constructing an AUD $3.6 million clean energy innovation hub (CEIH) to test the production, storage and end-use of green Hydrogen in a microgrid set-up [16]. The project is jointly funded by the Australian Renewable Energy Agency (ARENA). The facility is located at ATCO's Jandakot Operations Centre.

The CEIH will generate 300kW of power from approximately 1000 solar panels. The facility will include battery storage of 250kW, which can supply about 20 homes for a day in summer. The excess power of approximately 150kW will be used to produce Hydrogen through an electrolyser. Approximately four tons of hydrogen will be produced per annum from excess renewable energy produced by the solar PV system. The hydrogen produced will be injected into a microgrid system at the Jandakot facility, to test the use of hydrogen in a demonstration home for direct use on existing gas appliances such as gas powered air-conditioning as well as through a fuel cell for back-up power generation.

This initiative aims to study and test some of the safety and technical challenges, including optimising hydrogen storage solutions, blending hydrogen with natural gas, using hydrogen as a direct use fuel and using hydrogen for electricity balancing.

It is expected the project will be fully operational in mid-2019.

Key observations and considerations

Criteria	Observations and considerations
Production	• The CEIH will produce green hydrogen via electrolysis powered by excess solar energy • The project is grid connected and the excess renewable energy is produced from on an site solar PV system
Storage and transport	• Hydrogen is stored at site and piped into the microgrid. Hydrogen powers a fuel cell to provide backup power to the residential scale demonstration home
End Use	• Hydrogen produced will be injected into a microgrid system to test the use of hydrogen in a home.

2.9 Western Sydney Green Gas Project

The Western Sydney Green Gas Project is an AUD15 million trial, co-funded by Jemena and Australian Renewable Energy Agency (ARENA), to convert excess solar and wind power into hydrogen through electrolysis. The project involves the design and construction of a 500kW electrolysis facility which will be powered from renewable energy sources to produce hydrogen [17].

The majority of the hydrogen will be blended at a rate of 5 to 10 per cent in the gas mix and be injected into the gas network, supplying approximately 250 homes. A portion of the gas will be utilised for electricity generation with the remainder stored at a hydrogen refuelling station to support the automotive industry as clean fuel for hydrogen fuel-cell vehicles [18].

Key observations and considerations

Criteria	Observations and considerations
Production	• Excess renewable energy will be used to produce hydrogen. The production facility will be grid connected and the renewable energy is proposed to be purchased through Power Purchase Agreements
End Use	• Low blending rates to ensure that appliances do not require replacement, avoiding significant initial capital expenditure • Whilst initially established as a gas network trial, there is potential to investigate hydrogen's alternative uses of mobility and electricity production

2.10 Hydrogen Park South Australia

Australian Gas Infrastructure Group's (AGIG) Hydrogen Park of South Australia (HyP SA) proposes hydrogen production from renewable energy through a 1.25MW polymer electrolyte membrane (PEM) electrolyser [19]. The AUD11.4 million project is funded with support from the South Australian Government. The project partners are Siemens, KPMG and SA Power Networks.

Up to 15 per cent of hydrogen will be injected into Tonsley Innovation District's local gas distribution network. Following the pilot phase, the project may advance to supplying a residential development area.

This power-to-gas demonstration plant will produce up to 100kg of hydrogen per day via electrolysis.

It is expected production of hydrogen will commence mid-2020. The hydrogen centre of excellence will capture and report on the learnings across this project.

Key observations and considerations

Criteria	Observations and considerations
Production	• A 1.25 MW PEM electrolyser will be used to produce hydrogen • The project is grid connected and the renewable energy is proposed to be purchased through Power Purchase Agreements
Transport	• Initially hydrogen will be injected into the AGIG's gas distribution network at the Tonsley Innovation District, however will also have the ability to be expanded to supply a proposed residential area and transport hydrogen through tube and trailer to remote customers
End Use	• Hydrogen will be blended up to 15 per cent into the local gas distribution network to supply to homes and businesses • Potential for hydrogen to support balancing of electricity supply and demand and grid stability will be explored

2.11 Hydrogen Energy Supply Chain (HESC) Project*

The Hydrogen Energy Supply Chain (HESC) Project is a supply chain project which aims to convert Victorian brown coal into liquid hydrogen to be transported to Japan. This world-first project will deliver hydrogen to Japan in 2021 as part of a pilot phase, with full commercial operations targeted for 2030.

The HESC Project is being delivered by a consortium comprising a number of large Japanese corporations, including Kawasaki Heavy Industries, Electric Power Development Co. (J-POWER), Iwatani Corporation, Marubeni Corporation, Shell Japan, as well as AGL Energy.

The Japanese, Victorian and Commonwealth Governments are strong supporters of the project and are investing in the pilot phase. This includes funding of $50 million each from the Victorian and Commonwealth Governments.

The key elements of the HESC pilot phase supply chain include:

- A hydrogen production plant, located at AGL's Loy Yang Complex in the Latrobe Valley, will produce hydrogen gas using existing gasification and refining technologies adapted specifically for brown coal
- The hydrogen gas will be transported by road (pipeline for commercial phase) to a liquefaction and loading terminal at BlueScope's site at the Port of Hastings.
- Hydrogen gas will be liquefied at the Port of Hastings then shipped to Kobe, in Japan, by a marine carrier specifically developed for the task.

A key requirement for the commercial phase of the HESC Project is the need for a carbon capture and storage (CCS) solution to ensure that carbon emissions are minimal and to make the hydrogen produced virtually CO_2 free. The Victorian and Australian Governments' CarbonNet Project has the potential to deliver this CCS solution. The pilot phase will produce only a very small quantity of CO_2 – equivalent to the annual output of approximately 20 cars – and as such, will not include a CCS solution.

Key observations and considerations

Criteria	Observations and considerations
Production	• A CCS solution is critical to any future commercial scale operation. The Victorian and Australian Governments' CarbonNet Project has the potential to deliver this CCS solution
End Use	• The Japanese government released a basic hydrogen strategy to guide the development of a 'hydrogen society', including setting targets for establishment of hydrogen supply chains and development of hydrogen infrastructure by 2030 and beyond
Transport	• Hydrogen gas will be transported via road (for pilot phase). A pipeline will be used for the commercial phase

**Note: All information in relation to the commercial phase, including locations of all plant facilities is subject to ongoing consideration and is yet to be confirmed.*

2.12 Toyota Ecopark Hydrogen Demonstration

In March 2019, Toyota and ARENA announced the Toyota Ecopark Hydrogen Demonstration project. The project will convert part of the now decommissioned Toyota manufacturing plant in Altona (Victoria) into a renewable energy hub for production of renewable hydrogen [20]. The project will cost an estimated $AUD 7.4 million with ARENA providing $AUD 3.1 million of the funding.

The supply chain project is Australia's first in using renewable energy for hydrogen production and use on a single site, and aims to demonstrate the end-to-end process of hydrogen production through electrolysis, compression and storage and electricity generation via hydrogen fuel cells. The project will be supported via onsite solar PV and battery storage to provide electricity to support energy requirements

When completed, the facility will be capable of producing at least 60 kg of hydrogen daily and stored and fed into an onsite commercial scale hydrogen vehicle refuelling station.

Key observations and considerations

Criteria	Observations and considerations
Production	• The plant will produce green hydrogen via electrolysis powered by excess solar energy using solar PV systems and energy stored in onsite batteries
End Use	• Toyota aims to compress and store the produced green hydrogen for its onsite hydrogen vehicle refuelling station
Transport	• Green hydrogen is produced onsite for compression and storage and fed directly into hydrogen vehicle refuelling station reducing the need for increased transport requirement

03

H2City Tool Approach

This section describes the approach of the H2City Tool and scenarios which can be analysed.

3.1 Pathway scenarios

The underlying assumption used in the development of the H2City Tool and related scenarios is there is an intent to convert to zero carbon by 2050. Consequently, two pathways have been considered - a full hydrogen pathway and a full electrification pathway.

Whilst both scenarios have been modelled in similar amount of details, for the purpose of this document, the focus is around hydrogen.

The H2City Tool allows the user to **quantitatively** test **two pathways in** Step 2 of the assessment process**, namely a hydrogen pathway and an electrification pathway**. The user selects which proportion of each demand category in the community is to transition via either pathway. Therefore, the user is able to specify any proportion of any demand category to convert, and the H2City Tool calculates the supply chain costs associated with demand. The H2City Tool follows the following structure:

- A separate calculation is provided for each pathway, building up the total cost of the supply chain associated with the relevant requirements of each pathway
- This functionality allows the user to test a similar level of transition in the community, assuming the adoption of either pathway, in order to compare the relative incremental costs associated with opposite book-ends

More detailed assumptions associated with the hydrogen pathway are provided in **Section 4**; further information on the electrification pathway is provided in **Section 5**. Whilst KPMG has modelled both scenarios in similar amount of details, for the purpose of this document, the focus is around hydrogen.

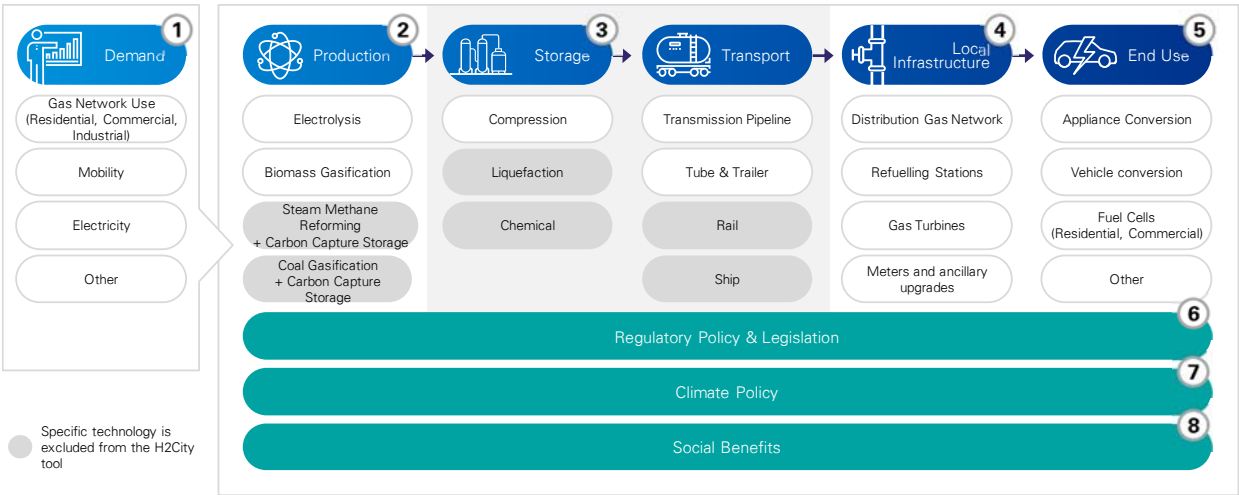
3.2 Hydrogen Pathway Value Chain

The main purpose of the H2City Tool is to provide a platform to screen potential communities for suitable conversion to hydrogen. The H2City Tool includes over 200 input drivers which can be grouped into eight broad categories for the user to consider in defining the scope of transition in the community.

1. **Demand** – defines the energy demand of the community to be met via hydrogen pathway, for each relevant demand category
2. **Production** – defines the resource and technology to be used to produce the required hydrogen to meet the defined demand
3. **Storage and transport** – defines the requirements for infrastructure to transport the energy produced via transmission pipeline, tube and trailer, rail or ship as well as storage requirements tailored to the applicable supply chain
4. **Local infrastructure** – defines the requirements for local infrastructure upgrades or new build required to distribute the produced hydrogen to the end user
5. **End use** – defines the costs to the end user related to the hydrogen demand, such as conversion of cooking appliances in the home or vehicles converted to hydrogen fuel cell electric vehicles (FCEVs)
6. **Regulatory policy and legislation** – economic regulatory factors for consideration, depending on the role that the user intend to undertake, and the State and Commonwealth regulations that may apply
7. **Climate policy** – includes the potential climate policy mechanisms aimed to accelerate decarbonisation
8. **Social benefits –** includes considerations of social benefits and community acceptance

Section 4 includes a detailed description of each of the elements above and how they apply in the H2City Tool.

Figure 1: H2City Tool assessment approach – the hydrogen value chain



3.3 Electrification Pathway Value Chain

1. **Demand** – defines the energy demand of the community to be met via electrification pathway, for each relevant demand category

2. **Production** – defines the resource and technology to be used to produce the required renewable electricity to meet the defined demand

3. **Storage and transport** – defines the requirements for infrastructure to transport the energy produced via transmission pipeline, tube and trailer, rail or ship as well as storage requirements tailored to the applicable supply chain

4. **Local infrastructure** – defines the requirements for local infrastructure upgrades or new build required to distribute the produced hydrogen to the end user

5. **End use** – defines the costs to the end user related to the renewable electricity demand, such as conversion of cooking appliances in the home or vehicles converted to battery electric vehicles (BEVs)

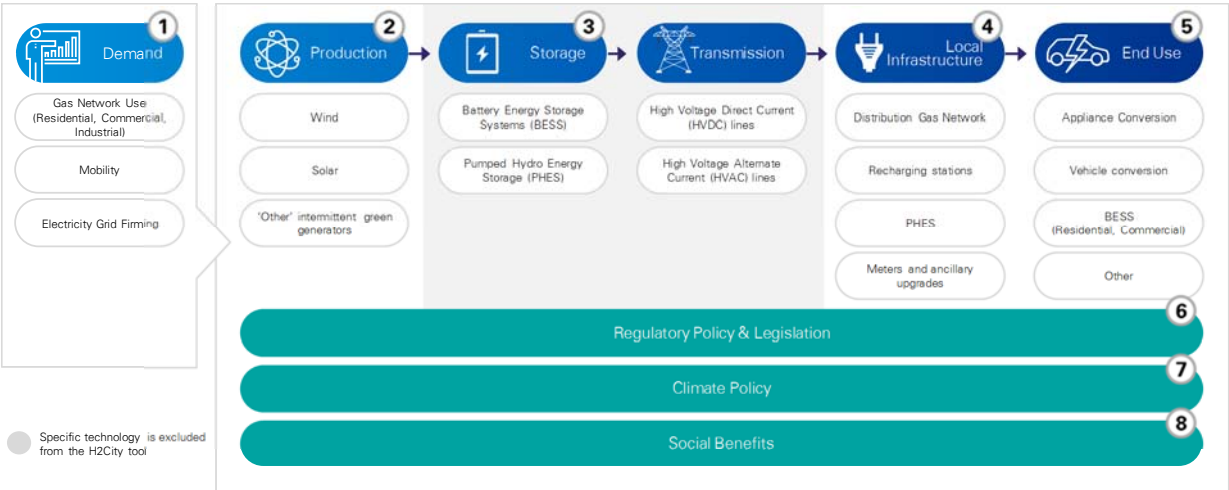
6. **Regulatory policy and legislation** – economic regulatory factors for consideration, depending on the role that the user intend to undertake, and the State and Commonwealth regulations that may apply

7. **Climate policy** – includes the potential climate policy mechanisms aimed to accelerate decarbonisation

8. **Social benefits –** includes considerations of social benefits and community acceptance.

Section 4 includes a detailed description of each of the elements above and how they apply in the H2City Tool.

Figure 2: H2City Tool assessment approach - the electrification value chain



3.4 Tool's approach to value chain

The assessment process follows four steps

Step 1 – Define demand and match source of production

The H2City Tool steps the user through some initial pre-screening questions to identify hydrogen demand for the community, assessing potential production technology options depending on feed sources available and prompts the user to identify available infrastructure within the proximity of the community for conversion. These are key factors that impact significantly on the cost of conversion and suitability of conversion. At this stage, demand is calculated based on the default "top-down" approach, which relies on State consumption and population to work out average demand. The H2City Tool then allows the user to cross-check the available potential production technologies to meet the demand.

Step 2 – Quantify the high level incremental cost of conversion

The quantitative part of the H2City Tool is a simplified supply chain cost calculator designed to assess the relative incremental costs associated with converting sections of a community's energy demand defined in Step 1. The user is able to test a range of options to develop a better understanding of the relative cost implications and screen potential options that may justify further investigation. At this stage, the user has the option to further refine the high level demand worked out by the default approach. Using the interface sheet, the user can select appliances at a household level to determine demand. Further assistance can be found in the User Guide in the H2City Tool.

Step 3 – Review qualitative aspects of options

Following the high level quantification exercise, the H2City Tool takes the user through considerations of other non-quantitative elements that will impact the viability of each option being considered. These include regulatory and policy considerations, climate policy and social licence.

Step 4 – Review qualitative and quantitative outputs

The outputs are a combination of tabular, graphical and numeric outputs which will help the user analyse the qualitative and quantitative outcomes of their proposed conversion.

A key metric produced by the model is the 'Levelised Supply Chain Cost' (LSCC). This output will allow the user to compare the quantitative outcomes from different scenarios. The LSCC is calculated by adding the levelised supply chain capital expenditure to the supply chain operating expenditure. The capital expenditure is levelised over the useful life of the assets with different weighted costs of capital applying to regulatory and privately funded capital expenditure. The H2City Tool will allow the user to classify assets as either regulatory or privately funded.

The user will be able to draw their own conclusions based on their motivations for using the H2City Tool. They will have the option to cycle through these four steps multiple times if required to test different scenarios. The results of all eight criteria can be reviewed and weighted by the user in a holistic manner when analysing different communities for conversion.

3.5 Tool's modes

The H2City Tool has been preconfigured to operate in three (3) different modes, the different modes affect the number and level of inputs required.

Mode 1: Simplified mode – Prepopulated with data for a hypothetical regional town, with a limited number of inputs available for review

Mode 2: Advanced mode – Prepopulated with data for a hypothetical regional town, with all inputs available for review (noting over 200 inputs)

Mode 3: Clean mode – Where the user populates inputs for their specific town

For the remainder of this report, the functionality in this report is described in reference to when the user opts to activate model Mode 3. Should the user choose to operate in the other two options, material in the report may not be fully applicable.

Modes 1 and 2 is provided for the user to gain familiarity with the functionality before accessing the detail available in Mode 3.

04

H2City Tool Assessment Criteria

From the review of global literature and case studies, the criteria for assessing suitability of a community for conversion were identified in the development of the H2City Tool.

This section describes each criteria considered and how it is incorporated in the tool.

4.1 Introduction

As outlined in **Section 3**, the H2City Tool considers eight criteria as part of assessment. A guide of considerations within each criteria is provided and for a number of elements, the user is able to use information from the pre-populated time based assumptions containing relevant cost and performance data or provide their own assumptions. Additionally a summary 'Getting started with the H2City Tool' guide has been provided in Appendix 4: Getting started with the H2City Tool.

Figure 4: Inclusions in H2City Tool shows the elements included in the H2City Tool. This chapter provides a brief description of the criteria, factors considered, approach and assumptions within the H2City Tool.

General approach to the H2City Tool

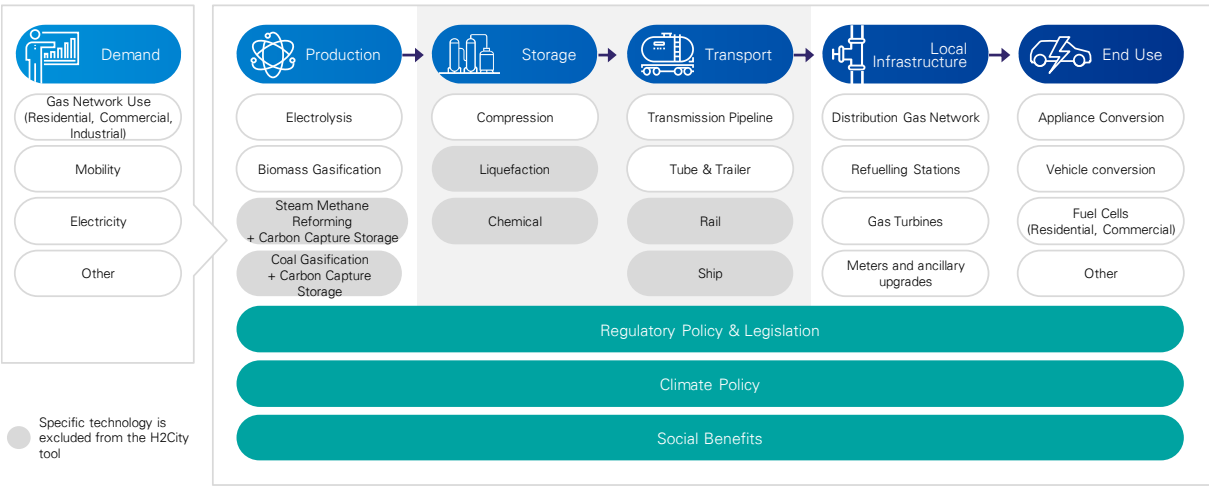
In order to develop a user friendly tool which covers a range of very complex issues at a high level, a range of simplifications have been made. These simplifications and inherent limitations are considered to be reasonable given the intended purpose of the H2City Tool. The user is cautioned to be mindful of this and read this section carefully to fully understand the approach to developing the H2City Tool and the underlying assumptions.

As the purpose of the H2City Tool is to facilitate pre-screening of concepts, it is recognised that the user may not have access to adequate levels of detailed data and inputs at such an early stage. Detailed data required has therefore been pre-populated as default assumptions based on a range of cost information and technical assumptions, industry benchmarks and rules of thumb that are commonly used in the industry for similar studies and based on current available public information and data obtained from CSIRO.

Points to consider in relation to the use of the H2City Tool:

- The H2City Tool is designed with a degree of flexibility enabling the user to select inputs from pre-populated time based assumptions containing relevant cost and performance data, or override with user specific data
- Where practical, flexibility has been constrained to an extent to prevent inputs that may be unreasonable
- The above-mentioned restrictions have mainly been applied through the use of adoption curves, relevant to the adoption of certain technologies or applications, or via dropdown lists
- The adoption curves were developed by CSIRO under the base assumption that **100% decarbonisation for the relevant energy demand of the community would be achieved by 2050**

Figure 4: Inclusions in H2City Tool



For example, the hydrogen fuel cell vehicle adoption curve assumes that 100% of the community's mobility demand would transition to Hydrogen vehicles by 2050 (within the vehicle categories covered by the H2City Tool). As a consequence, if the user selects to use default inputs from **pre-populated time based assumptions containing relevant cost and performance data***, the uptake of hydrogen vehicles will gradually increase each year up to 2050, when hydrogen vehicle share will reach 100%. The user may define an adoption rate below this curve to test an alternative rate of uptake for their community.*

- If the user opts to utilise Mode 3, the user has to consider key costs and assumptions that require customised user inputs include, but are not limited to:
  - Choice of pathway to be assessed
  - Date of community transition. This drives the calculation of the once off cost of converting all elements of the supply chain in the applicable year, followed by further incremental capital costs to meet growing demand and ongoing operating costs in subsequent years
  - Size of the community
  - Location of the community
  - Number of businesses and industrial users associated with the community
  - Number and type of appliances to convert for businesses and industrial users
  - Proximity to existing electricity and gas transmission infrastructure
  - Hydrogen blend level, with a limit of 10%. Beyond 10%, gas networks are assumed to convert to 100%. It is also assumed that no gas network or appliance augmentation is required up to 10% blends
  - Available sources of energy production, including hydrogen production sources and location of sources in relation to the community
  - Costs associated with feedstock, electricity or water to produce Hydrogen
  - Levels of augmentation in the transmission and distribution networks required to meet the incremental increase in demand
- The H2City Tool calculates the **incremental cost of the steps in the supply chain** associated with the infrastructure capital and operating costs to meet the specified demand in each year
- To the extent that existing infrastructure is used in the supply chain, e.g. in transmission and distribution networks, the cost of the existing infrastructure is accounted for via network charges to the end user. The level of augmentation that is to be specified by the user of the H2City Tool drives the calculation of the pro rata portion of energy supported by existing infrastructure
- The cost of delivering the balance of energy via new infrastructure is accounted for as part of the supply chain capital and operating cost. However, it is recognised that some of these costs may be recovered from the end user in a similar way, depending on the regulatory treatment, although this aspect has not been incorporated into the H2City Tool

4.2 Hydrogen demand

4.2.1 Overview

Hydrogen is a versatile energy carrier with various applications. It is currently used as a feedstock for industrial processes, however technology advancement is unlocking alternative uses.

Assessing the quantity of hydrogen required is the first step in defining a community's suitability for hydrogen conversion. The level of hydrogen demand will influence the hydrogen source (production), storage and transport requirements, and end use conversions or modifications.

4.2.2 Quantitative Assessment Criteria Considered in H2City Tool

For the H2City Tool, use of hydrogen across four main quantitative categories was considered. Each usage type has been analysed for inclusion or exclusion in assessing a local community's suitability for hydrogen conversion.

Gas Network Use

Hydrogen gas can be used as a substitute fuel for natural gas demand as a decarbonisation pathway for the natural gas network. Blending of hydrogen of up to 10% is generally accepted, without significant modifications to the network. However some recent testing and research indicate that enrichment of Hydrogen up to 20% concentration is also possible, without significant modifications to the network [21]. Suitability of gas networks to accept hydrogen concentrations greater than 10% will require a more detailed assessment on a case by case basis.

In determining forecast domestic natural gas usage, influences of climate change and sensitivity scenarios may be considered by the user [see **Box 1**].

Mobility

Hydrogen usage within the transport sector offers decarbonisation options for oil-derived fossil fuels. Hydrogen powered vehicles use fuel cells to convert the hydrogen fuel to electricity, powering an electric motor (FCEVs). Battery electric vehicles (BEVs) on the other hand can be powered by electricity generated from hydrogen, either through hydrogen gas turbines or fuel cells. FCEVs have advantages over BEVs with the ability to travel longer distances without refuelling or charging however, currently experience limitations of cost and lack of supporting infrastructure (refuelling stations) [22].

Hydrogen can power various transport modes, including but not limited to:

- Light passenger vehicles (Cars, utes, vans)
- Heavy passenger vehicles (Buses)
- Heavy freight vehicles (Trucks)
- Rail

The requirements for transport-related hydrogen demand is dependent on the uptake and usage of hydrogen fuelled vehicles. As the purpose of this assessment tool is comparing and determining a suitable community for conversion, only the transport modes within the boundaries of the community are considered.

Local vehicle usage of light and heavy passenger vehicles within a community are included. Long-haul freight vehicles and rail networks are not specifically identified, but can be included by the user if relevant. This is because determining the hydrogen demand for long-haul freight and rail would require estimating the demand of the entire freight network and the related inter-city refuelling infrastructure which is not the intended scope of this tool.

Electrical network

Hydrogen as an energy vector gives it the flexibility to couple energy demand of both the gas network (as a direct fuel) and the electricity network (via electricity generation source and storage capabilities from power-to-gas systems). Hydrogen produced can be used to generate electricity through either gas turbines or fuel cells. Additionally hydrogen systems coupled with an appropriate storage source may supply electricity grid reliability services for seasonal intermittency [22].

Industrial feedstock

Currently the greatest hydrogen demand globally is as an industrial feedstock for various chemical manufacturing processes (petroleum refining, fertiliser production) [22]. Incorporating industrial feedstock as a demand source within a community would be subject to the existing levels of industry activities and the local market for industrial hydrogen.

4.2.3 Qualitative Assessment Criteria Considered in H2City Tool

Export

As the H2City Tool aims to assess the viabilities of local communities for hydrogen conversion, export has not been included as a qualitative rather than quantitative criteria.

The current primary medium of international energy trade is fossil fuels. Hydrogen is attracting attention as an energy transport carrier due to its potential role in decarbonisation efforts.

Australia's abundance of natural resources positions it well in the emerging Hydrogen market, however it must overcome price challenges to become competitive against other countries. Some of the challenges include:

- Cost of production
- Transport costs
- Additional port costs to consider
- Etc. [23]

The hydrogen energy supply chain project in Victoria is demonstrating these factors. The pilot project proposes to co-locate hydrogen production nearby the coal feed source and then transport the hydrogen via truck to the nearby, existing port facilities[2]. Multiple industrial and government parties across Japan and Australia are supporting the project.

2 Approximately 150kms from Latrobe Valley to the Port of Hastings

Box 1: CSIRO Climate Futures Tool

There is consensus among the international scientific community, increased atmospheric greenhouse gas concentrations due to human activity is the major cause of observed global warming since the mid-20th century **[24]**. Long term climate changes will affect energy demand, for example lowering heating demand.

The Intergovernmental Panel on Climate Change's Fifth Assessment Report [52] is based on four potential climate scenarios:

- **RCP8.5 –** this scenario highlights the current, business-as-usual trajectory of global warming we are on
- **RCP6.0** – this scenario outlines the decarbonisation pathways that are on par with current policy commitments being implemented in full (e.g. all Nationally Determined Contributions are supported and implemented)
- **RCP4.5 –** this scenario outlines the decarbonisation pathways that are on par with current policy commitments being implemented in full (e.g. all Nationally Determined Contributions are supported and implemented) with peak emissions around 2040. It is considered the most credible low emissions option
- **RCP2.6** – The most aggressive decarbonisation scenario (RPC2.6) is considered extremely difficult to achieve in practise, albeit still technically possible **[25]**

CSIRO's Climate Futures is a detailed projection tool based on data from global and regional climate models, capable of providing projected changes in selected variables in different regions. The interface allows assessment and testing of changes of up to 16 climate variables.

Implication to gas demand

Climate change can influence natural gas demand forecasting as a rise in average temperatures may reduce heat demand. For example, inputs to AEMO's gas demand modelling for the NEM are weather standards of heating demand days (HDDs) and effective degree days (EDD). AEMO applies the climate scenario RCP4.5 to HDD and EDD days. This scenario results in an estimated increase in average temperatures by approximately 0.5 °C over the next 20 years across Australia compared to current temperatures. The outcome of this modelling is a demand reduction of approximately 25 PJ for every 1°C increase in average temperature **[26]**.

4.2.4 User Application of Criteria in H2City Tool

When used in Mode 3, the H2City Tool provides flexibility for the user to input their demand assumptions within their community of assessment against each demand category below:

- **Gas network**, which includes residential, commercial and industrial uses
- **Mobility**, which includes light passenger vehicles, buses, semi-rigid trucks and articulated vehicles used within the community
- **Electrical network**, including residential, commercial and industrial users
- **External** (demand external to the boundary of the selected community)
  - Industrial feedstock
  - Mobility (rail, long haul transportation)
  - Other

For hydrogen demand within a community, the H2City Tool considers the cost of developing and operating a supply chain to produce, store, transport and deliver the hydrogen required to meet the relevant energy demand of the community. These are described further in the coming sections.

Overall external hydrogen demand can be specified by the user within a single open field if relevant. External hydrogen demand may include industrial feedstock, mobility (rail, long haul transportation) or export.

Users should note that external hydrogen demand will likely be associated with additional infrastructure costs associated with the supply chain between production and delivery to the end user, as well as intermediate processing and export infrastructure. As the H2City Tool is focussed on conversion of local communities, and the functionality of the H2City Tool includes a relative comparison with the electrification pathway, these supply chain costs have not been incorporated as it would be unbalanced. However, the H2City Tool allows the user to provide a direct input for external demand to increase the hydrogen production rate and associated production infrastructure, enabling users to assess the potential impact of economies of scale on hydrogen production cost that may result from an external source of demand.

4.3 Hydrogen production

4.3.1 Overview

There are two well-developed pathways for producing hydrogen; the first is via electrochemical means and the second is via thermochemical.

4.3.2 Quantitative Assessment Criteria Considered in H2City Tool

Electrochemical hydrogen production

Electrochemical hydrogen production involves the use of an electrical current to split water into hydrogen and oxygen. This form of production requires the use of low or zero emissions electricity to produce clean hydrogen. Mature technologies include alkaline electrolysis (AE) and polymer electrolyte membrane (PEM). The comparative advantages and disadvantages of both technologies are described in Table 1 Advantages and disadvantages of AE and PEM electrolysis

Alkaline Electrolyser (AE)

- Electrochemical cell that uses a potassium hydroxide electrolyte to form H_2 at the negative electrode and O_2 at the positive electrode
- AE is currently the more established and cheaper technology and will therefore continue to play an important role in the development of the industry
- Its component parts are currently produced at scale given that they are similar to those used in the commercial manufacture of chlorine and sodium hydroxide (chlori-alkali industry)
- Despite its level of maturity, incremental improvements in AE can still be achieved through subtle gains in efficiency

This production process uses approximately 9L of water per kgH_2

Polymer Electrolyte Membrane (PEM)

- Also known as a proton exchange membrane. Water is catalytically split into protons which permeate through a membrane from the anode to the cathode to bond with neutral hydrogen atoms and create hydrogen gas
- There has been a recent emergence of the PEM electrolyser which has a number of distinct advantages over AE
- PEM has a smaller footprint and faster dynamic response time which is preferred for coupling with variable renewable energy than AE. Combined with anticipated cost reductions, PEM electrolysis is fast becoming a more competitive technology
- Recent studies involving a number of industry stakeholders showed that a majority believed PEM will be the dominant electrolyser technology by 2030 [27]. This, combined with the fact that AE is a relatively mature technology would suggest that PEM electrolysis is likely to continue to attract considerable investment for further research and development

Thermochemical hydrogen production

Thermochemical hydrogen production uses a feedstock to produce hydrogen, commonly fossil fuel but biomass is also an alternative as a feedstock. This involves the interaction of heat and chemicals with hydrocarbons, coal or biomass to first produce syngas, a combination of hydrogen and carbon monoxide/carbon dioxide gas. The syngas is then reacted with water through the 'water-gas shift reaction', which increases the concentration of carbon dioxide and hydrogen gas. This process must be paired with CCS to produce clean hydrogen (unless a biomass feedstock is used). Mature technologies include steam methane reforming (SMR) and coal gasification. Both methods of production require hydrogen purification. These technologies need to be built on a large scale due to large capital cost of plant and CCS. They are impacted by the cost of fuel, which can fluctuate, however, this is less of an issue for coal which tends to have more stable prices. Location is an issue for these technologies, as they require an appropriate carbon dioxide storage reservoir.

Steam Methane Reforming (SMR)

- Light hydrocarbons, such as natural gas or biomethane (upgraded biogas), are mixed with steam in the presence of a catalyst at high temperatures (~750°C) and moderate pressure to produce syngas. SMR uses approximately 37L of water per kgH_2 [27]
- Most widely used method of hydrogen production, currently comprising 48% globally [28]
- Currently cheapest form of hydrogen production but further expansion in Australia may be challenging due to the fluctuations in natural gas prices

Table 1 Advantages and disadvantages of AE and PEM electrolysis [22]

Electrolyser	Advantages	Disadvantages
AE	• Currently lower capital costs • Benefits from Chlori-alkali process improvements • Well established supply chain and manufacturing capacity	• Poor current density/larger footprint • Oxygen impurity in the hydrogen stream • Low pressure Hydrogen product
PEM	• Smaller, flexible and modular • Faster dynamic response and wider load ranges [29] • Lower temperature operation • Higher power cycling capability • Higher current density • Higher purity hydrogen	• Currently higher capital costs

Coal gasification

Gasification involves reacting dried and pulverised coal with oxygen and steam in a gasifier at high temperatures and pressure to produce syngas. To date, black rather than brown coal, has been the dominant fuel sourced globally. This technology currently comprises 18% of global hydrogen production. Coal gasification uses approximately 37L of water per kgH_2 [27].

Thermal black coal is the most common input, but more expensive than brown coal. Brown coal has less favourable characteristics; higher water content, volatility and reduced efficiency and increased operating and maintenance costs throughout time.

Biomass gasification

Biomass such as wood chips, agriculture and forestry residue, can be gasified at high temperatures (600-1000˚C) to produce syngas (TRL 6-8). To date this process has been primarily used for power generation. Individual technologies within this process are generally mature, however further research and development is required in connecting them for the primary purpose of producing hydrogen. This technology is similar but not as mature as coal gasification (it requires different feedstock preparation and has different impurities). Challenges remain in understanding the characteristics of different biomass feed stocks and in process handling due to the high temperatures required [30]. The process could allow for lower emissions hydrogen production without the need for CCS. Biomass plants would need to be large-scale in order to be economical.

Table 2 Advantages and disadvantages of SMR with CCS, coal gasification with CCS and biomass gasification [22]

Process	Advantages	Disadvantages
SMR	• Established technology	• Requires purification • High temps required • Need for CO_2 storage site
Coal gasification	• Abundant fuel	• Requires purification • High cost • Need for CO_2 storage site
Biomass gasification	• Zero emission	• Requires purification • High cost • Biomass availability • Lower TRL than other technologies

4.3.3 User Application of Criteria in H2City Tool

Hydrogen production technologies can be loosely classified as green or brown.

- **Green hydrogen** generates zero emissions and uses renewable energy sources. Electrolysers using renewable energy and biomass gasification production technologies are green hydrogen production methods included in the H2City Tool
- **Brown hydrogen** such as SMR and coal gasification are currently more mature and commercially viable. Combining those technologies with CCS would reduce carbon emissions. These technologies emit carbon of approximately 0.71 - 0.76kg CO_2 per kg H_2 produced [31]. These production methods have been identified as viable options in the Leeds H21 and L-M hydrogen cluster projects. Low emission hydrogen production is seen to be a pathway towards 100% decarbonisation, and is therefore available as a user defined input in the H2City Tool

All production methods require a significant amount of water. SMR and coal gasification require water for cooling, and electrolysis require water as the feedstock. The cost of water has been included as a consideration in the H2City Tool. The other aspect to consider is water risk. Australia is one of the most water stressed region in the world, the long term cost and availability of water requires careful assessment in mapping a community's transition path to hydrogen. **Box 2** provides more details on a water risk assessment that canbe undertaken.

Box 2: Water risk assessment

The Aqueduct Water Risk Atlas produced by the World Resources Institute is a tool that can be used to assess water scarcity and risk in a particular selected area. The Aqueduct Water Stress Projections Data include indicators of change in water supply, water demand, water stress, and seasonal variability projected for the coming decades under scenarios of climate and economic growth.

The water risk atlas can be used in conjunction with the CSIRO Climate Futures tool. Long-term changes in a number of climate variables in a region can impact future availability of water. The climate variables most relevant for a water risk assessment are:

- Rainfall (mean)
- Evapotranspiration (mean; Morton Wet Environment Areal Potential Evapotranspiration; CMIP5[3] Global Climate Models only)
- Evaporation (mean; Morton Areal Potential Evaporation; CMIP3[4] Global Climate Models only)
- Time in drought (SPI[5] based) **[32]**

3 CMIP5 is the model ensemble for the Intergovernmental Panel on Climate Change (IPCC)'s Fifth Assessment Report (AR5) and was released in 2013

4 CMIP3 is the model set for the Intergovernmental Panel on Climate Change (IPCC)'s Fourth Assessment Report (AR4) and was released in 2010. Both CMIP5 and CMIP3 Global Climate Models have been used to generate projections of future climate conditions globally. More information on CMIP5 and CMIP3 is detailed in: https://climatechange.environment.nsw.gov.au/Climate-projections-for-NSW/About-NARCliM/CMIP3-vs-CMIP5

5 Standardised precipitation index

4.4 Storage and transport (of hydrogen)

4.4.1 Overview

Hydrogen is a very light gas and has a lower energy density by volume compared to fossil fuel alternatives of natural gas and petroleum [33]. It can be stored in large amounts for a long period of time. To store and transport economically, hydrogen must be compressed, liquefied or chemically converted (material-based).

Key factors to consider when designing the most appropriate storage and transport methods are:

- Form of hydrogen required for end-use
- Hydrogen demand for the community
- Number of days storage required
- Distance from hydrogen production source to end-use
- Geographic location

This section discusses the hydrogen storage and transport methods from the hydrogen production source to the community.

4.4.2 Quantitative Assessment Criteria Considered in H2City Tool

There are various options to store and transport hydrogen from production to a community or location.

Storage of hydrogen

Broadly, hydrogen storage methods can be categorised as physical compression, liquefaction or chemical/material-based. Currently physical storage technologies are the most mature and commonly used.

Compression

Compressed hydrogen gas can be stored within tanks, underground geological caverns or line packing within gas networks. Choosing the level of compression and type of compression vessel is a trade-off between the quantity of Hydrogen required, volume to be stored and energy requirements to compress [22]. In addition to these requirements, underground geological storage requires specific geographic locations with geological conditions suitable to contain the hydrogen. This form of storage is considered to be most viable for stationary storage due to comparatively lower cost and availability of space.

Liquefaction

Liquefaction of Hydrogen gas is capital and energy intensive due to the low temperatures required to liquefy hydrogen (-253°C) [34]. Liquefaction significantly increases Hydrogen density and is suitable for storage situations where space is limited [22]. Storage facilities with liquefied hydrogen are specialised tanks made of advanced materials suitable for cryogenic storage.

Chemical or material-based

Hydrogen converted to ammonia can be considered as a storage carrier of hydrogen due to the high density of hydrogen compared to compression or liquefaction. Ammonia transport and storage exist today in various forms, however, there is an energy penalty and cost of converting the ammonia back to hydrogen for use.

Transportation of hydrogen

Once hydrogen is produced and stored, it will need to be transported to the community of use. Consideration needs to be given and balanced across a number of factors such as Hydrogen demand or amount to be transported, available infrastructure and distance from production to consumption point and end-use type.

Main transportation options available are via:

- **Compressed gaseous or liquid hydrogen** transported by truck
- **Compressed gaseous hydrogen** through pipelines
- For long distances, **liquid hydrogen or material-based storage**, with transportation via rail or ship are suitable options

Transport methods and storage technologies considered with indicative distance thresholds are summarised in the Table 3: Hydrogen storage and transport methods below

Table 3: Hydrogen storage and transport methods [22]

Vehicle	Storage type	Indicative distances	Description/Use
Truck (Virtual pipelines)	Compression, liquefaction, ammonia	<1000km [34]	Transport of liquefied and compressed hydrogen as well as ammonia is available commercially. Ammonia is less likely as a hydrogen carrier here given the scale requirements and need to convert back to hydrogen for use. Higher pressures/liquefaction are typically used for trucking distances greater than 300km
Rail	Compression, liquefaction, ammonia	>800-1100km [35]	As per trucks but for greater distances travelled
Pipeline	Compression	1000 - 4000km	More likely to be used for simultaneous distribution to multiple points or for intercity transmission
Ship	Ammonia, liquefaction	>4000km	Unlikely to use compression storage for shipping given cost of operation, distance and lower hydrogen density. Likely vehicle for export

Storage and transport of hydrogen are also influenced by the end use type. Each typical end use type consideration are outlined below:

Gas network use and electricity grid firming

Hydrogen uses of residential / commercial demand and electricity grid firming would typically be delivered through an integrated hydrogen pipeline network within the community. Transportation of hydrogen from production source to the community for these uses would be through a pipeline connecting to the community's gas network. Compression is the common storage option within pipelines. Factors to consider when designing a pipeline are the demand, distance required, pressure of the pipeline, and proximity to existing transmission infrastructure. A potential upside of transporting Hydrogen through the pipeline from production to the community is the additional storage created via line-packing within the pipeline.

4.4.3 Quantitative Assessment Criteria Not Considered in H2City Tool

Mobility

The H2City Tool does not incorporate the cost of transporting Hydrogen to refuelling stations however like petrol and diesel today, this is likely to be via trucks. Hydrogen as a fuel for mobility would likely be transported to refuelling stations via trucks, just as petroleum and diesel is transported to service stations today. All storage technologies can be implemented for trucking transport however ammonia is less likely due to the scale necessary.

Export

Transport options for Australian export are limited to shipping. Technology for shipping liquid hydrogen over long distances is currently still in development, an example is Kawasaki Heavy Industries' pilot project to develop a ship capable of carrying liquefied hydrogen [36].

4.4.4 User Application of Criteria in H2City Tool

Due to the complex factors to consider for storage and transport methods, each community will need to be assessed on a case by case basis, and inputs from other parties such as asset infrastructure owners may be required for greater accuracy of inputs to the H2City Tool.

4.5 Local infrastructure upgrades

4.5.1 Overview

Hydrogen gas has different properties to natural gas and this influences the design of the infrastructure and networks which will utilise Hydrogen.

4.5.2 Assessment Criteria Considered in H2City Tool

This section discusses the impact on a community from the conversion of the infrastructure of existing gas networks, mobility infrastructure (refuelling stations) and electricity generation (gas turbines and fuel cells).

Gas network use

To transport large volumes of hydrogen, a pipeline network would be the best option if an existing network is available. When considering converting a gas distribution network from natural gas to hydrogen there are three main considerations; (1) the extent of conversion, (2) existing pipeline materials, and (3) impact to network capacity.

Hydrogen enrichment (blending) or 100% hydrogen conversion

There is a direct correlation between the extent of gas network augmentation required and the level of hydrogen conversion; the higher the hydrogen blend, the greater the level of augmentation required:

- 0 – 10% blending: It is widely accepted that no network augmentation will be required
- 10 – 20% blending: Some network augmentation may be required
- >20% blending: Network augmentation will be required

In Australia, Jemena's Western Sydney Green Gas Project is proposing a trial of a hydrogen blend of 5-10% into their gas network [18]. More recently, HyDeploy, a hydrogen community conversion in the UK, was granted approval to inject 20% hydrogen mix into their trial network after extensive laboratory research and testing of each customer's gas appliances [21]. It is acknowledged that this needs to be tested and approved on a case by case basis. Concentrations greater than 20% will require specific pipeline materials capable of carrying hydrogen. In addition to limits for pipeline materials, limitations also apply to the gas appliances at end-use, these are discussed in Section 4.6.

Pipeline materials

Concentrations of hydrogen greater than 20% can cause issues within gas networks due to pipe embrittlement where the hydrogen attacks the pipeline materials [1]. Extent of the hydrogen embrittlement is dependent on the pipeline pressure and materials on construction. Risk of embrittlement is also higher in the transmission network due to higher operating pressures. However it has been indicated that use of steel and fibre reinforced plastic pipes with hydrogen at pressures at 70 – 105 bar is possible [22].

High density polyethylene (PE), used in gas distribution networks are capable of carrying hydrogen as maximum pressure of 20 bar. The different properties of hydrogen also influence ancillary infrastructure of meters and valves which may need upgrading for 100% hydrogen conversion of a network.

Network capacity

Hydrogen fuel has a lower energy density by volume compared to natural gas. For hydrogen to meet the same energy demand requirements of natural gas there is a greater volume required. Each gas network considered for hydrogen conversion will require analysis to determine if there are any upgrades required to manage the additional throughput of gas. Some areas may require reinforcement or redesign to accommodate for the greater volume of gas required.

Mobility infrastructure

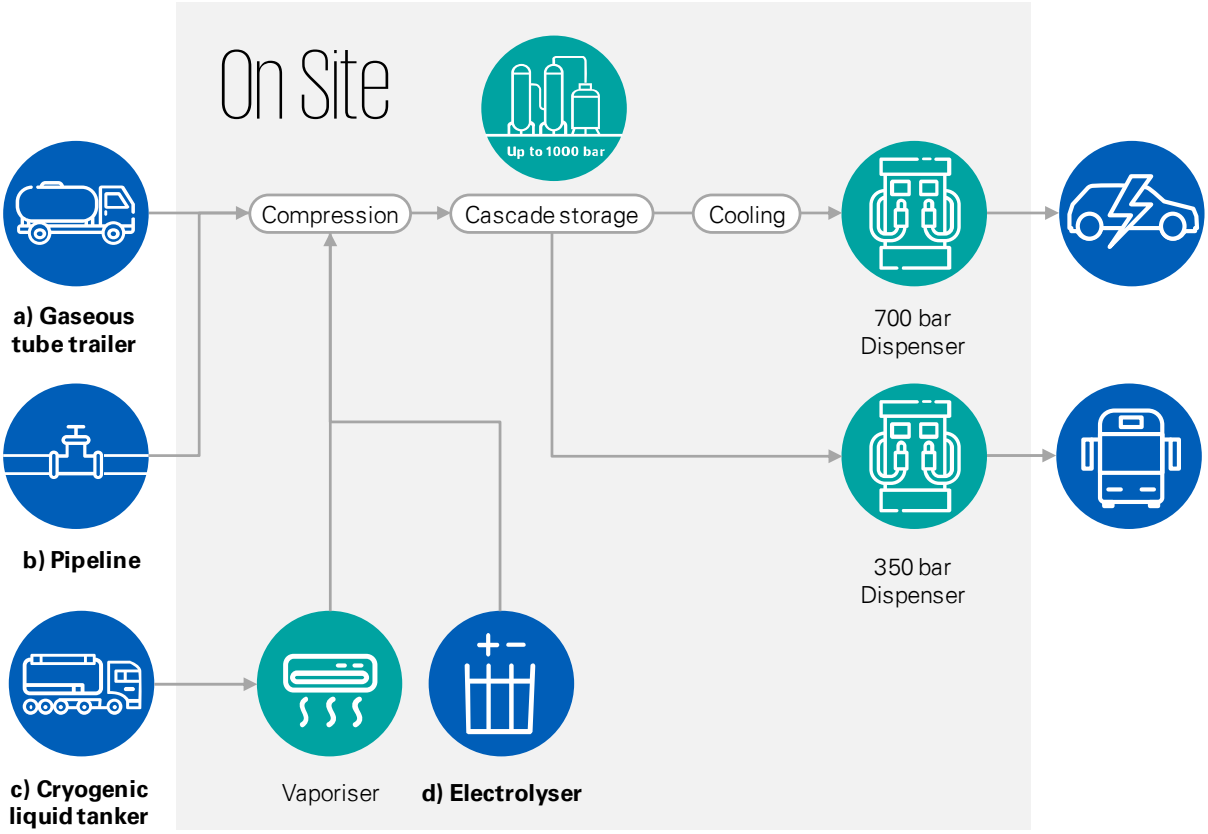
The use of hydrogen as fuel for vehicles relies on the successful roll out of refuelling stations. Hydrogen may be more suitable in certain applications than battery electric vehicles due to longer range and faster refuelling times but refuelling stations are critical infrastructure required for large scale uptake. Australia currently has only two hydrogen refuelling stations trialled [37].

The standard refuelling station configuration is shown in Figure 5: Standard refuelling station configuration

.

Expected hydrogen demand is a key design criteria for a hydrogen refuelling station. This enables the facility size and expected storage requirements. Hydrogen refuelling stations have onsite compressors and cooling modules to control the refuelling process.

Figure 5: Standard refuelling station configuration [22]



Electricity generation (Gas turbines and fuel cells)

There are two main options to produce electricity from hydrogen, thermodynamically through gas turbines and electrochemically through fuel cells. Both options require specific infrastructure which run on hydrogen.

Gas turbines

Gas turbines combust fuels to generate mechanical and heat energy for electricity generation. The flame properties and flammability of hydrogen create challenges in gas turbine design, however this has not prevented development. Example projects are: (1) Mitsubishi Hitachi Power Systems (MHPS) successfully firing a gas turbine on a 30% hydrogen mix [38] and (2) Obayashi Corporation and Kawasaki Heavy Industries successfully running a gas turbine on 100% Hydrogen to supply local facilities in Kobe, Japan [39].

Fuel cells

Hydrogen fuel cells are the reverse reaction of hydrogen production via electrolysis. There are various fuel cell types, with the majority involving the reaction of hydrogen and oxygen across a membrane, electrolyte and catalysts to produce water and electricity. Examples of fuel cell use are within Japan's ENE-Farm and as the electricity source for FCEVs.

4.5.3 User Application of Criteria in H2City Tool

Due to the different properties of hydrogen compared to natural gas, infrastructure to transport hydrogen from production to end use point may need to be upgraded or newly built.

The extent of upgrades required to existing infrastructure is dependent on the level of hydrogen demand required and/or the extent of hydrogen blending. Gas networks may be able to be upgraded to accept hydrogen; however, refuelling stations, gas turbines and fuel cells are require new infrastructure to fulfil hydrogen energy demands.

In the H2City Tool, consideration and cost for local infrastructure upgrades have been included for the user to consider and provide their input. Local infrastructure upgrades for hydrogen mainly includes refuelling stations for hydrogen vehicles, small scale fuel cells (constrained by fuel cell adoption curves), Hydrogen fired gas turbines and gas distribution network upgrades.

4.6 End use

4.6.1 Overview

This section considers the infrastructure and appliance conversion requirements. The impact and costs of the conversion will depend on the use of hydrogen and amount of hydrogen conversion.

4.6.2 Assessment Criteria Considered in H2City Tool

Appliance conversion

Depending on the amount of hydrogen blended in the existing gas network, switchover from natural gas to hydrogen compatible appliances may be required.

As indicated in a number of case studies described in the previous chapter, recent studies and testing in the HyDeploy project have allowed for blending of up to 20% of hydrogen into the Keele University Campus gas network without conversion of appliances. Other studies have shown for most industrial heat applications, 10-15% by volume of hydrogen blends are achievable with minimal changes to appliances [2]. Despite this, it is recognised that for each site or community and type of customers use, the safety requirements and blending limits will need to be assessed on a case by case basis.

Safety and technical standards

Low concentrations of Hydrogen blended into the existing gas network infrastructure is not prohibited by current regulations. However to blend higher levels of hydrogen or completely convert natural gas to hydrogen, changes in legislative and regulatory instruments will be required.

Australia currently has key gaps in safety standards for hydrogen appliances in the following areas:

- Device safety and design
- Device installation
- Gas composition (purity, odorant etc.)

Standards Australia convened the Hydrogen Standards Forum in October 2018 to identify gaps in standards and agree on level of participation for Australia in international committees. A discussion paper [40] was published and Standard Australia recognised the benefits of adopting or aligning the international standards, which will facilitate trade and help deliver alignment of technologies across the hydrogen value chain. By proactively contributing to the international standard forum allows Australian perspectives to be considered.

4.6.3 User Application of Criteria in H2City Tool

Within the H2City Tool, the cost for appliance conversion is considered and the user can estimate based on the number of appliances that require conversion.

The development of safety and technical standards are still in early stages and impacts on all conversion projects that are proposed. Therefore safety and technical standards have not been included as a differentiating criteria of one community to another in the assessment H2City Tool. The technical requirements required to meet safety for customers will need to be assessed and tested on a case by case basis.

4.7 Regulatory policy and legislation

4.7.1 Overview

The supply of energy to communities is subject to regulation at both State and Commonwealth level. The overarching objectives of regulation are to protect customers and promote economic efficiency[6]. As hydrogen is a relatively new energy source, there are still many questions on how the regulatory framework would need to adapt. The answers to these questions would initially be provided by regulators and policymakers on a case by case basis until the frameworks are updated to consider hydrogen more comprehensively.

4.7.2 Assessment Criteria Considered in H2City Tool

In assessing the appropriate regulatory arrangements for hydrogen supplied communities, the conditions would need to be assessed against the costs and benefits of applying regulatory obligations. This will depend on a number of factors including:

- whether it is considered hydrogen should be subject to the same regulatory framework as natural gas
- the extent of choice for customers to use alternative sources of fuel and hence the competitive pressures on hydrogen
- whether there are any market failures across the hydrogen supply chain which could lead to insufficient investment or poor outcomes for customers
- given the nascent nature of hydrogen supply and range of permutations for hydrogen production, it is hard to forecast how policy-makers will adapt the regulatory framework to hydrogen

The first question to consider is whether there is any reason why the current regulatory framework for natural gas should not also apply to hydrogen supply. This framework is set out in the National Gas Law (NGL) and supported by jurisdictional based licensing regimes. The scope of these legal instruments differs with the NGL primarily covering arrangements covering the transportation and trading of natural gas, while the other instruments govern the production and retail parts of the supply chain.

Currently the level of regulation for production, transportation and retail can differ significantly. Retailing of natural gas is subject to extensive regulation under national and jurisdictional arrangements, and in some cases this includes the regulation of retail gas prices in addition to price determination on network charges. While the transportation of natural gas depends on whether access to a pipeline has the ability to influence the level of competition in another market. Various tiers of regulation apply, based on competition and significance criteria. Currently economic regulation provisions apply only to transportation of gas via pipelines.[7] There are numerous ways that the gas sector could transition to Hydrogen, and it is not practical to attempt to address the regulatory issues relating to each of them individually. In our analysis we are considering the regulatory barriers for two scenarios; injection of up to ten percent hydrogen into natural gas pipelines and conversion to deliver 100 percent hydrogen to end users.

6 The scope of this chapter does not consider the impact of safety and technical regulations to hydrogen conversion.

7 A covered gas pipeline is a pipeline that is covered under the NGL and NGR. Such pipelines are subject to regulatory oversight by the Australian Energy Regulator or the Economic Regulatory Authority of Western Australia. There are two forms of regulation that may be applied: full and light regulation, to both transmission and distribution pipelines.

Issues to consider

Considering the existing regulatory frameworks, and their underlying principles, there are three major issues which encapsulate the regulatory challenges that would need to be overcome.

Proportion of hydrogen injected into the network

Current regulations would allow injecting hydrogen into natural gas pipelines to a concentration of ten per cent. This would still have implications for regulations covering metering and tariff design (At concentrations above ten per cent it is not possible to provide any certainty about the regulatory arrangements that would be put in place).

Co-ordination across the supply chain

Regulations could affect the roles that different parties can play across the supply chain and requires that proponents consult with the licensing body in their jurisdiction. The regulations that apply to natural gas may not be appropriate to provide effective co-ordination (i.e. sharing of risks and information) and ensure optimal supply for customers.

Cost recovery for upgrades and conversion costs

The significant expenditure for large scale hydrogen conversion will need to be recovered. Regulators and policy-makers will have a role in determining what can reasonably be passed on to consumers. The particular transition scenario will influence this. Additionally the relative cost competitiveness of hydrogen will determine the extent of any cost pass through.

Each of these challenges are further elaborated in Appendix 1.

Alternative approach of stand-alone networks

An alternative option from conversion of an existing gas network is to have a stand-alone network which is not connected to the main transportation grid and therefore not covered by the NGL.

'Uncovered' pipelines are those pipelines which are exempt from economic regulation, and they present fewer regulatory barriers to conversion. Investment can be made with less regulatory scrutiny in uncovered pipelines, although these networks generally serve small populations, and the pool of users to recover costs is small compared with a larger network. Cost recovery is a matter of commercial negotiation with the local community.

Proposed regulatory approaches for transition to hydrogen

Regulatory frameworks for gas were designed and fitted to existing infrastructure, to deal with existing issues in established technology. CSIRO suggests extending the definition of gas in the NGL to include hydrogen, and the creation of a dedicated agency to cut through the burden of gas regulation at several levels of government [41]. This would be one way to co-ordinate reforms needed to adapt the existing framework to the different incentives and hazards presented by hydrogen conversion.

Many of the barriers to conversion presented by regulation are the result of trying to fit the development of a new technology into a framework designed for a mature industry. There may need to be temporary arrangements to help proponents manage the additional risks and costs which arise during the transition phase.

The NGL is a suitable template for regulation of hydrogen, but it is not ideally suited to accommodate transition. Formation of a complete regulatory framework appropriate to hydrogen transition is not practical, and the most likely path forward will come from combining existing laws and exemptions to create fit-for-purpose solutions while a comprehensive policy position is determined.

Aside from the coverage status of the pipeline, the relative magnitude of the regulatory barriers to hydrogen conversion are not measured by attributes of the regulations themselves, but the ease with which exemptions and/or amendments can be made. Any conversion scenario will require consultation with national and jurisdictional regulators and policymakers to establish suitable arrangements.

4.7.3 Application in the H2City Tool

The regulatory issues for a transition scenario will depend on the details and structure of the proposed project, and will most likely require consultation with jurisdictional regulators and policy makers. The range of issues relating to the regulatory framework that would need to be evaluated in considering suitable communities for transition includes, but is not limited to, the following:

Production

- The production approach for hydrogen, ideal location and whether the use of gas transmission pipelines is needed
- Whether the producer of the hydrogen will have other roles in the project

Network

- Whether the existing gas network is covered under the NGL, and the form of regulation (i.e., light or full)
- Whether the transition will affect the gas network infrastructure
- Whether the conversion is a hydrogen blend or full 100% conversion to hydrogen

Retail

- The retail arrangements for the project
- Any existing retail price regulations for gas in that jurisdiction

Other

- The complexity and extent of obligations under the state based licensing regimes. There are differences between jurisdictions in terms of local legislation that are attached to the licence
- How the State based environmental policies and zero-emissions objective rewards and incentivises carbon reduction

4.8 Climate policy

4.8.1 Overview

In 2016, Australia ratified the Paris Agreement [42], committing to reduce in greenhouse gas emissions below 2005 levels (~26-28%) by 2030. The level of decarbonisation required to meet this target is a significant driver for the transition to renewable hydrogen. Looking globally, there are a number of successful examples of policy levers that have helped an economy decarbonise.

4.8.2 Carbon Price

The price of carbon in Australia and internationally will be a key driver in the transition to hydrogen, and in some cases could be the difference between hydrogen being cost-competitive with other energy options [27]. 45 national and 25 subnational jurisdictions are putting a price on carbon, as part of their commitment to the Paris Agreement [43]. This is in the form of emissions trading schemes (largely based on cap and trade mechanisms) or carbon taxes.

Examples of carbon price or tax applications are:

- $13.52 per tonne, based on the average price of carbon reduction in the seventh Emissions Reduction Fund auction held by Australia's Clean Energy Regulator in June 2018 [44]
- A high-range example from other countries, for example Sweden (US$139/tCO2-e) [45]
- The guidance of the Carbon Pricing Leadership Coalition (CPLC) recommends $40-80 per tonne CO2 by 2020 and $50-100 per tonne CO2 by 2030 [46]

4.8.3 Other Policy Mechanisms

There are various examples around the world of policies directly related to hydrogen or that would indirectly drive the transition, including:

- Japan's Basic Hydrogen Strategy, which seeks to reduce the cost of hydrogen and includes an action plan to 2030 and future vision to 2050 [47]
- The National Innovation Programme Hydrogen and Fuel Cell Technology (NIP) in Germany, initially focused on research and now facilitating market activation through incentives and large-scale commercial projects [48]
- Various incentives offered by the California state government, such as the Alternative Fuel and Vehicle Incentives, Advanced Transportation Tax Exclusion, and the State Agency Low Carbon Fuel Use Requirement [49]

4.8.4 Application in the H2City Tool

In the H2City Tool, the user is prompted to consider climate policies and incentives available or assumed, that may make the hydrogen conversion more economically viable.

4.9 Social benefits

4.9.1 Overview

Social license and common acceptance is an important factor in the consideration of 'target' communities. It is particularly important that community acceptance is sought through engagement, education and providing transparency of the process.

Present evidence would suggest that Australians are relatively agnostic to hydrogen and have little understanding of its potential and uses. This is based on a survey undertaken by the University of Queensland (funded by ARENA) to understand perceptions of the Australian public of hydrogen for energy, it found that 81% responded with a neutral response (associated with gas, energy, water), with 13% providing a negative association with hydrogen (bomb, explosion) and 3% positive (clean, future). The survey also found that the public has limited knowledge of hydrogen properties and its uses, and mostly have a neutral association with the word hydrogen. Majority of (52%) of participants were supportive of hydrogen as a possible solution for energy and environmental challenges. However safety is a top concern around hydrogen technologies [50]. Education will be a key aspect as part of any community conversion to gain community acceptance.

From a social benefits perspective, ARENA estimates that total employment (direct and indirect) in the production of Hydrogen for export would create between 3,500 and 16,000[8] Full time equivalent (FTE) by the year 2040 in a low or high hydrogen demand scenario, respectively. [51]. The proposed Moreland City Council project involving the replacement of existing rubbish collection fleet with fuel cell trucks in 2017 is estimated to create up to 15 ongoing full-time jobs and a potential 100 indirect jobs [52]. Estimates on employment and/or job creation may support the overall justification for conversion.

4.9.2 Application in the H2City Tool

Consideration of employment and/or job creation from the hydrogen economy can be included as a benefit for justification of converting a hydrogen community. Each community or area for conversion is unique and the social benefits and acceptance should be identified separately. A prompt for social benefit considerations is included in the H2City Tool for the user to include.

[8] Direct employment is estimated between 800 and 4,000 FTE and Indirect employment is estimated between 2,700 and 12,000 FTE. Information sourced through Acil Allen's "Opportunities for Hydrogen Exports", 2018

05 Electrification Pathway

This section provides a description of the electrification pathway approach in the H2City Tool

5.1 Introduction

Although this document and the H2City Tool focuses on conversion of a community to a hydrogen-based economy, it is recognised that a myriad of pathways are evolving that may also support the energy sector's aspirations for decarbonisation. Each of these pathways would have a different impact on the energy supply chain, of which the relative costs are currently not well understood.

The H2City Tool therefore includes two pathway scenarios, namely a hydrogen pathway and an electrification pathway, to allow for relative comparison to be made between these options.

This section provides a description of the approach and key assumptions for the electrification pathway included in the H2City Tool.

5.2 Approach and key assumptions

Since the purpose of the electrification pathway is to allow for a relative comparison with the hydrogen pathway, the general approach followed in developing each is largely the same. This section describes the relevant distinct differences applicable to the electrification pathway assumptions.

5.2.1 Demand

The approach to calculating community energy demand is identical to that described for the Hydrogen pathway. The key difference in the electrification pathway is that all demand categories are assumed to transition to electricity-based solutions, as follows:

- **Gas network** – it is assumed that the relevant gas network energy demand will convert to electricity demand, and hence instead of calculating the hydrogen demand for the gas network, the tool calculates the electricity demand for the equivalent gas network use to be converted.
- **Mobility** – battery electric vehicles are assumed to replace conventional vehicles up to the limit set by the applicable adoption curve. The supply of electricity to charging stations to meet the vehicle demand is assumed to be distribu*ted* via the electrical network, which may require significant augmentation to meet the incremental increase in electricity demand.
- **Electrical network** – the approach to defining the energy mix in the electrical network is similar to that of the hydrogen pathway. However, grid firming is assumed to be met by a combination of residential, commercial and utility scale batteries, as well as pumped hydro. All carbon-based capacity in the existing generation fleet will be assumed to retire by 2035.

5.2.2 Production

As opposed to calculating the cost of hydrogen production, with the associated renewable electricity build required to supplement grid firming hydrogen technologies, the electrification pathway calculates the cost of producing renewable electricity to meet the total shortfall in peak demand using batteries, pumped hydro and intermittent renewable energy.

- The approach to estimating the electricity generation mix is similar to the hydrogen pathway, with the distinct difference being the adoption of pumped hydro and batteries to provide grid firming.
- The uptake of residential and commercial batteries is constrained by the applicable adoption curve, in a similar manner as fuel cells applied to the hydrogen pathway.
- It is assumed that the generation shortfall is met by a combination of solar and wind energy.

5.2.3 Transmission and storage

The transmission of electricity is achieved via the electrical transmission network following a similar approach to that described for the hydrogen pathway. Due to the increased demand, the transmission network may require significant upgrades, particularly with regard to augmentation of existing transmission substations and lines, as well as new builds. The default source of energy storage is assumed to be provided by pumped hydro and batteries.

- The user should be mindful of the fact that a system that is fully reliant on **electricity storage may have an inherent lower redundancy** in the system compared to an energy system supplied via the gas network, due to the shorter durations of storage
- This assumption is considered to be sufficient for the purposes of high level screening; however, the user may adjust the storage capacity by increasing the duration of storage assumed for batteries and/or pumped hydro and providing the relevant direct user inputs for the cost and technical assumptions associated with these installations

5.2.4 Local infrastructure

Local infrastructure upgrades for electricity mainly includes utility scale batteries which are assumed to be located near the community, similar to the assumption made for hydrogen power plants, distribution substations and powerlines, charging stations for electric vehicles and small scale residential and commercial batteries.

- For **electrical distribution network upgrades**, the approach is similar to that described for transmission networks, where the user can specify the level of augmentation to be accounted for. Likewise, any requirement for distribution level upgrades to accommodate the utility scale batteries should be included, while transmission system upgrades should be accounted for in Section 4.5
- All **residential and commercial battery systems** are assumed to be accompanied by solar rooftop PV and hence the cost is combined for both systems. The demand associated with charging these systems are therefore also considered to be behind the meter
- The ratio of hydrogen fuel cars to refuelling stations assumed is adjusted by a factor below 100%, to be specified by the user, for **electric vehicle charging stations** to account for the fact that users can sometimes charge their vehicles at home or charge it at refuelling stations

5.2.5 End user

The end user cost comprises of the cost of appliances or vehicles to be transitioned, as well as the cost of the electricity attributed to the incremental shift in energy demand, similar to the approach described for the hydrogen pathway.

- The H2City Tool **calculates the cost** of switching out home appliances, based on the number of households to be converted, on the default assumption that an average household would convert one gas stove and one hot water system to electric, and the balance of other appliances will already be electric. The cost of a freestanding oven, which includes a cooktop as well as an oven and an electric hot water system with built-in storage is assumed as the default

- As this scenario assumes that the gas network ceases to exist**, all end users will have to switch appliances**, and the cost of this conversion is shown in two categories, namely voluntary and mandatory uptake, similar to the 100% hydrogen pathway. Voluntary uptake is associated with end users choosing to purchase electrical appliances for new homes or upgrade their appliances due to customer choice, and this rate is determined by the adoption curve. It is assumed that all other appliance conversions will be mandated and require some form of government intervention; hence these are reported as mandatory conversions

- The H2City Tool caters for the **user to specify additional appliances to convert**, similar to the hydrogen pathway. Should the user choose to specify this, it is advised that the household electricity demand is revisited taking the consumption of the relevant appliances in the average home into account

- **Electricity consumption of a range of appliances** have been pre-populated using time based assumptions containing relevant cost and performance data to support this assessment and assist the user in identifying potential gas and electricity network demand profiles

- Where existing transmission and distribution infrastructure is used to supply energy to the end user, **a state average of network and environmental charges are included** in the cost of energy sourced from hydrogen. Users are to note that these costs only apply to existing infrastructure, and the cost of all new build infrastructure is reported as a supply chain cost

06 Appendices

Appendix 1: H2City Tool scope

KPMG was contracted by the Australian Renewable Energy Association (ARENA) to complete a global literature review, develop a Multi-Criteria Assessment (MCA) Framework and Total Cost of Ownership (TCO) Model (the 'Tool') to support the screening of communities that may be suitable for transitioning to a hydrogen-based energy future. The Project was called H2City.

The scope of work included:

Global Literature Review

KPMG undertook a global scan to:

- Identify the most applicable case studies in hydrogen conversion
- Review and amalgamate findings
- Synthesise findings as an input into the MCA Framework

Develop an Multi-Criteria Assessment Framework

KPMG would develop a MCA Framework to:

- Document outputs from the Global Literature Reviews
- Define factors that need to be considered in screening for the selection of a community
- Develop a user guide in relation to the use of the Tool
- Document all of the above into a report that can be used in conjunction with the Tool
- Provide pre-populated using time based assumptions containing relevant cost and performance data for input data used in the Tool

Total Cost of Ownership (TCO) Model (the 'Tool')

Using factors and/or considerations defined within the MCA Framework, KPMG would create a Microsoft Excel model to:

- Enable the user to select and/ or enter inputs for each of the defined criteria
- Calculate the impact (or outputs) of selected scenarios
- Enable comparison between hydrogen and electrification pathways
- Display outputs in a visual format

In delivering the contracted scope, KPMG has subcontracted with the Commonwealth Scientific and Industrial Research Organisation (**CSIRO**) to provide the following services:

- Inputs into the MCA criteria selection
- Data for the Tool, including:
  - Capex and Opex projections for behind the meter technologies including rooftop photovoltaics (PV), battery storage, fuel cells, electrolysers, electric vehicles and fuel cell electric vehicles and household appliances that may be affected by conversion to Hydrogen (cooktops, heaters, air-conditioners)
  - Adoption curves for the given technologies in the case of:
    - 100% electrification
    - 100% hydrogen
  - Cost projections (Capex, Opex) and performance for centralised generation technologies including large scale PV, wind, gas peaking plant, gas combined cycle etc. (technologies relevant to the H2City Tool)
  - Vehicle demand projections in the relevant states
  - Uptake of these technologies in the relevant states
  - Cost of new electrical transmission and distribution infrastructure
  - Cost of new hydrogen pipelines
  - Cost of hydrogen storage
- A review of the Tool in regards to data provided and its application within the Tool

Appendix 2: H2City Tool key known simplifications and limitations

General

Key general assumptions and limitations of the model are:

- State specific figures have not been used for the number of gas and electricity connections. ABS data was used as a proxy for the number of households, commercial businesses and industrial businesses. This results in a **lower average energy consumption per premise.**
  The user is able to input more accurate data for their community using Mode 3 if required.
- **Phased conversion for gas network use (GNU)** with adoption curves utilised for appliances
- **Most curves are forced to 100% adoption by 2050, as a default**, users have the option to override with natural curves
- **National (average) gas capacity factors are used as a default**; additional data from CSIRO polygon is provided if the user chooses to override defaults
- **Model does not account for NUOS (or equivalents)** in both pathways. Inclusion would overstate the cost of conversion by including cost of the status quo
- Model **does not account for replacement costs for existing generators**. Incorporating overstates the cost of conversion by including costs of the status quo
- **A 'per household' cost for the end user cost**, but it should be noted that this cost also includes vehicle and appliance costs
- **Cost difference between EV and ICE** incorporated into the model as Opex. This is because modelling of the entire cost of EVs overstates the cost of electric vehicles, with the community then incurring costs for ICE vehicles regardless
- **Dynamic adoption curves to be adopted** for costs that require some intervention for conversion to start
- All costs entered and displayed should be **real terms**. I.e. the cost today is not adjusted for inflation

Hydrogen

Hydrogen demand

Within the H2City Tool, the community demand for hydrogen can be calculated on the basis of total demand forecasts for each state and the population size of the community relative to the population size of the state. This is the top-down approach to calculating demand and is referred to as 'Mode 1'. Conversely, the user can pick and choose appliances on a per household basis, based on observations of the typical household in their community. This is the bottom-up approach to calculating demand and is referred to as 'Mode 2'. Mode 1 is the default approach of calculation adopted by the model, should the user need to refine the inputs further, they have the option to override the default inputs with Mode 2 input.

The user is also required to specify the portion of this community demand that is to transition to hydrogen. The H2City Tool gives the user the option to define demand for their community.

The key categories for demand are:

- **Gas network use** – hydrogen will replace natural gas in the gas network, either as a blend of up to 10% hydrogen, or at 100% hydrogen. At 100% hydrogen, transmission and distribution pipelines and networks may require augmentation, in addition to conversion of natural gas appliances

- **Mobility** – the rate at which FCEV and BEVs will replace conventional vehicles is constrained by its adoption curve; i.e. warnings are provided should the user select a value above the ceiling. As a hydrogen conversion does not preclude the existence of electricity infrastructure, both electric vehicle types can be accommodated in this scenario. In addition, as hydrogen would be used to firm the electricity grid; either through hydrogen gas turbines or fuel cells, the additional electricity demands as a result of BEV use, will have a direct impact on hydrogen demand. For FCEVs, supply of hydrogen required to meet the vehicle demand is assumed to be distributed to refuelling stations within the community via truck and trailer or gas pipeline
- **Electrical network** – it is assumed hydrogen sourced power will replace all new build infrastructure required for firming of the electrical network applicable to the community. The existing installed generation capacity in the applicable network will therefore be augmented with a combination of hydrogen fuel cells and decentralised hydrogen gas turbines to meet any shortfall in peak demand. Intermittent renewable energy will make up any shortfall in generation capacity, along with the required transmission and distribution upgrades. In relation to the existing generation fleet in the network, it is assumed that all carbon-based capacity will retire by 2035 and be replaced with renewable energy sources

Hydrogen production

In the H2City Tool, it is assumed hydrogen production facilities will be located at the site of the resource, i.e. adjacent to a wind or solar farm, or in the vicinity of a biomass resource.

The following hydrogen production technologies are included in the H2City Tool:

- PEM Electrolysis
- AE Electrolysis
- Biomass gasification
- Other (user to provide direct input on cost of production in $/GJ of hydrogen)

The H2City Tool references an average economic scale for each hydrogen production technology, and adopts the capital cost of this reference scale for each new unit to be built.

Hence, depending on the hydrogen demand in each year, it is possible that the production capacity may be oversized in a given year. The H2City Tool assumes that the production unit will be built at the reference scale and as demand increases, the operational capacity factor will increase until the maximum production rate is reached before a new unit is built.

This approach is consistent with typical asset infrastructure investment, which generally occurs at the appropriate economic unit scale, and hence is oversized to meet future growth in demand.

The user is required to specify the cost of electricity and water delivered to electrolyser units and the cost of biomass delivered to biomass gasification facilities.

Storage and transport (of hydrogen)

The transport and storage of hydrogen is split between the gas network use and mobility use to account for different means of hydrogen transport and storage adopted. For each transport and storage method, the following assumptions apply in the H2City Tool:

- **Hydrogen for the gas network and electrical grid firming** is transported via the nearest transmission gas pipeline. The user is required to provide a distance to connect to the transmission pipeline as well as the level of augmentation required for the existing transmission pipeline to the community. User guidance is provided earlier in this document on the considerations for network augmentation. It is assumed that the gas network has sufficient storage capacity to store the hydrogen required for mobility, small scale fuel cells (residential and commercial) and grid firming gas turbine facilities
- **Hydrogen for mobility is transported via truck and trailer**, with 1 day storage assumed at the point of filling, or via the gas pipeline, which provides sufficient storage to absorb day to day fluctuations in demand. The cost of storage and compression at the refuelling station is built into the capital cost

Local infrastructure upgrades

Hydrogen technologies are assumed to meet the additional grid firming requirements instead of battery energy storage systems (applicable to the electrification pathway), and hence it is assumed that small-scale fuels cells will be adopted in commercial and residential applications, while a localised gas turbine power plant and utility scale fuel cells will be used to provide additional grid firming.

- For **gas distribution network upgrades**, the approach is similar to that described for transmission pipelines, whereby the user is required to specify the level of augmentation required and a cost is included on a pro rata basis compared to new hydrogen pipeline costs
- The number of **refuelling stations** are calculated using the number of existing fuel stations in the community as a proxy for the ratio between vehicles and fuel stations
- For **electricity grid firming**, it is assumed that the shortfall in capacity required to meet peak demand will be met via a combination of small scale fuel cells in homes and businesses, and the balance will be supplied via decentralised Hydrogen gas fired power plant(s) supplied via the gas network
- Location of plant - the hydrogen power plant is assumed to be located within the community in close proximity to the electrical network. Should additional transmission and distribution infrastructure be required to accommodate the gas turbine power plants, users should specify this as part of the network augmentation discussed in Section 4.4
- Peak demand - The peak demand to be met by dispatchable technologies is estimated using the approach outlined in AEMO's Integrated System Plan, which equals the peak demand for the applicable electrical network plus the installed capacity of the largest generator in the network. The contribution of peak demand factors for wind and solar have not been incorporated as a default, although users are able to provide an overriding assumption on the peak demand to be met
- Peak demand calculation - To calculate the default peak demand for the community, a pro rata of the applicable electricity network's existing fleet is calculated based on the size of the community in relation to the applicable network, i.e. the NEM, SWIS or NT network
- Electricity generation - It is assumed that the balance of electricity generation will be met by a combination of intermittent renewables, including wind and solar, and a category for other intermittent green energy is catered for as a direct user input
- Overrides - The H2City Tool caters for the user to override the default assumptions of the ratios for new build technologies for both dispatchable and intermittent renewable energy

End use

The end use cost comprises of the cost of appliances or vehicles to be transitioned, as well as the cost of the hydrogen-sourced energy to meet the incremental shift in energy demand.

- Appliances will not require switching/augmentation at or below 10% blending
- In a 100% hydrogen scenario, all end users will have to switch appliances, and the cost of this conversion is shown in two categories, namely voluntary and mandatory uptake. Voluntary uptake is associated with end users choosing to purchase hydrogen appliances for new homes or upgrade their appliances due to customer choice, and this rate is determined by the adoption curve. It is assumed that all other appliance conversions will be mandated and require some form of government intervention; hence these are reported as mandatory conversions
- The default assumption is that an average household will convert one combined gas stove and cooktop, and one hot water system, while the balance of appliances will be electric, hence no cost of switching other appliances is automatically included. For commercial and industrial users, the number and type of appliance conversions is left to the user to specify. It is important for the user to note that the costs for appliances in the model are those for the default appliances. Should they use Mode 2 to calculate demand, they will need to adjust appliance costs to account for their selected appliances
- The H2City Tool also caters for the user to specify additional appliances to convert in a household. If the user chooses to specify this, it is advised that the gas and electrical network demand specified at a household level is revisited taking the consumption of the relevant appliances in the average home into account
- Gas consumption of a range of appliances have been provided in the H2City Tool to support this assessment and assist the user in identifying potential gas and electrical demand profiles
- Where existing transmission and distribution infrastructure is used to supply energy to the end user, a state average of network and environmental charges are included in the cost of energy sourced from hydrogen. Users are to note that these costs only apply to existing infrastructure, and the cost of all new build infrastructure is reported as a supply chain cost
- The adoption curve for the uptake of each class of hydrogen vehicle is provided in the H2City Tool assuming that 100% conversion of conventional vehicles is converted to hydrogen vehicles by 2050. The user is able to provide an assumption on conversion for each vehicle type in each year below this curve

Electrification

Electricity demand

Within the H2City Tool, the community's electricity demand can be calculated on the basis of total demand forecasts for each state and the population size of the community relative to the population size of the state. This is the top-down approach to calculating demand and is referred to as 'Mode 1'. Conversely, the user can pick and choose appliances on a per household basis, based on observations of the typical household in their community. This is the bottom-up approach to calculating demand and is referred to as 'Mode 2'. Method 1 is the default approach of calculation adopted by the model, should the user need to refine the inputs further, they have the option to override the default inputs with Mode 2 input.

The user is also required to specify the portion of this community demand that is to be converted to electrification. The H2City Tool gives the user the option to define demand for their community.

The key categories for demand are:

- **Gas network use** – electricity will replace natural gas as an energy source. Transmission and distribution power lines and networks may require augmentation, in addition to conversion of natural gas appliances
- **Mobility** – BEVs will replace conventional vehicles at the rate selectable by the end user to be no faster than the applicable adoption curve set within the H2City Tool
- **Electrical network** – it is assumed that intermittent renewable electricity generators, supported by pumped hydro (PHES) and batteries (BESS) will replace all new build infrastructure required for firming of the electrical network applicable to the community. The existing installed generation capacity in the applicable network will therefore be augmented with a combination of PHES and BESS to meet any shortfall in peak demand. Intermittent renewable energy will make up any shortfall in generation capacity, along with the required transmission and distribution upgrades. In relation to the existing generation fleet in the network, it is assumed that all carbon-based capacity will retire by 2035 and be replaced with renewable energy sources

Electricity production

In the H2City Tool, it is assumed that intermittent electricity generators will be located at the site of the resource e.g. high solar or wind regions.

The following electricity generators technologies are included in the H2City Tool:

- Dispatchable – dam hydro, biomass and WTE, CSP, other
- Intermittent – solar, wind, other

Generation technology capacity factors are based on a national average; however, the H2City Tool provides additional data for specific regions that the user can input to override the national defaults.

Storage and Transmission

For electrification, because of efficiency limitations, the H2City Tool accounts for the utility scale firming (storage) technologies as energy drainers not generators. It is assumed that small-scale batteries will have PV solar panels attached to them, so no additional generation is required to support their adoption.

Storage technologies for the community will be:

- Small scale batteries
- Utility scale batteries
- PHES

For transmission power line connection and augmentation, the user will have the option to choose between high-voltage alternate current (HVAC) and high-voltage direct current (HVDC) power lines. Power line type will influence costs.

Local Infrastructure Upgrades

- For **electricity distribution network upgrades**, the user is required to specify the level of augmentation required and a cost is included on a pro rata basis compared to the cost of distributing all of the community's electricity

- The number of **recharge stations** are calculated using the ratio of number of stations per 1 BEV

End use

The end use cost comprises of the cost of appliances and/or vehicles to be converted.

- In a 100% electrification scenario, all end users will have to switch appliances, and the cost of this conversion will be calculated each period based on additional adoption
- The default assumption is that an average household will convert one gas stove and one hot water system and the balance of appliances will already be electric, hence no cost of switching other appliances is automatically included. Should the user decide to convert these appliances to hydrogen as well, the H2City Tool allows the user to input an overall cost of conversion for remaining appliances. For commercial and industrial users, the number and type of appliance conversions is left to the user to specify. It is important for the user to note that the costs for appliances in the model are those for the default appliances. Should they use Method 2 to calculate demand, they will need to adjust appliance costs to account for their selected appliances
- The H2City Tool also caters for the user to specify additional appliances to convert in a household. If the user chooses to specify this, it is advised that the gas and electrical network demand specified at a household level is revisited taking the consumption of the relevant appliances in the average home into account
- Gas consumption of a range of appliances have been provided in the H2City Tool to support this assessment and assist the user in identifying potential gas and electrical demand profiles
- Where existing transmission and distribution infrastructure is used to supply energy to the end user, a state average of network and environmental charges are included in the cost of energy sourced from hydrogen. Users are to note that these costs only apply to existing infrastructure, and the cost of all new build infrastructure is reported as a supply chain cost
- The adoption curve for the uptake of each class of BEVs is provided in the H2City Tool assuming that 100% conversion of conventional vehicles is converted to BEVs by 2050. The user is able to provide an assumption on conversion for each vehicle type in each year below this curve

Appendix 3: Regulatory issue considerations

Proportion of hydrogen injected into the network

A study of the national and state laws for the transport and sale of gas found that there are no explicit prohibitions on injecting hydrogen into natural gas pipelines up to a concentration of ten per cent[9]. For the purposes of transportation and retail obligation, a blended gas of this composition would be treated as natural gas, and the National Gas Law (NGL)[10] would continue to apply. Existing state based licences would also continue without any amendments.

In contrast, a pipeline or network transporting hydrogen at a concentration of more than 10 per cent would not be captured under the NGL, as this blend of hydrogen/natural gas does not meet the definition of natural gas under the legislation. Without any amendments to the current regulatory framework, this would leave a hydrogen network in a sense largely unregulated from an economic efficiency perspective[11].

It is unlikely hydrogen networks would be able to avoid regulation by skirting the definition of natural gas, since gas for fuel is an essential service, and government oversight is necessary to enforce technical and safety legislation. Equally, it would be impractical for a pipeline operator to operate without the rights and exemptions over land use that are provided through a state-issued licence.

A challenge for the ten per cent threshold is that this may not be the optimal blending proportion for the customer in terms of balancing the carbon reduction with the costs associated with hydrogen injection. The gas network and customer appliances may be able to cope with a higher percentage without materially greater costs.

The optimal percentage of blending could vary substantially across different communities. Consequently, the general consensus across a number of studies is that methane with hydrogen additions can be safely transported through distribution networks at levels up to 20 per cent hydrogen.

Another challenge with this legislative definition is how it will influence the production scenarios for hydrogen. These could range from a large scale centralised plant where hydrogen is transported to the community, to having multiple small scale hydrogen plants which are embedded within the community. Under the scenario of localised production there will be need to be sufficient blending and monitoring procedures to ensure that the ten per cent threshold is not breached. It may be easier to achieve the ten per cent blending under a centralised plant and centralised insertion but this could require the agreement of the transmission operator and incurred extra costs associated with gas transmission.

As discussed in this paper, hydrogen is a far less dense gas than natural gas and therefore requires substantially more volume to deliver the same energy value[12]. This could have implications for the regulatory rules governing metering and tariff design, even under the ten per cent blended supply situation.

9 JWS, A report on the injection of hydrogen and biogas into gas distribution networks, Prepared for Energy Networks Australia.

10 And also the National Energy Retail Law (NERL) will apply for jurisdictions except WA and NT.

11 AS 4564 sets out the limits of gas distributed as natural gas. Gas may contain variations on components which meet upper and lower criteria when used for combustion use. Heating value and residue limits apply, and contaminants are not allowed. It should be noted that the latest update of this Standard proposes to limit hydrogen in networks to 15%.

12 Hydrogen has a lower density than natural gas which means that it disperses relatively quickly from a safety perspective.

Coordination across the supply chain

A common issue for both the ten percent blending and 100 per cent hydrogen scenario is how to regulate effectively across production, transport and retail.

Vertical integration of the activities across the hydrogen supply chain may not permitted due to concerns about inefficient cost allocation and creating barriers to competition. If the regulatory framework results in multiple commercial participants being involved there are likely to be trade-offs and conflicts of interests which could impede effective co-ordination and optimal supply. If common ownership across the supply chain was not allowed, the key questions regarding co-ordination which would need to be resolved include:

- Who determines the percentage of hydrogen blended with natural gas? The network and retailer could have quite different motivations on this matter
- Who is responsible for engaging with and informing customers on the transition
- Who pays for the costs of any upgrades and conversion costs

Under the NGL, the operator of a covered pipeline is precluded from involvement in production or retailing of natural gas. Under the NGL, a pipeline operator could theoretically produce hydrogen (which is not natural gas), and then transport it through its network once it is blended with natural gas. This would require the producer (i.e., the network) to have an agreement with the retailer to sell blended fuel. While this is legally acceptable, it could raise issues if the network was able to use its market power to influence this arrangement.

In the case of uncovered pipelines and private networks, vertical integration is acceptable, but there may be barriers imposed by state regulators through their licensing framework. This might be exercised at the discretion of the licensing body.

The applicability of a ban on vertical integration would depend on the community and the network being considered for conversion.

It may be more efficient, during development of new technology to allow one party to manage the production, transport and supply, or it may be considered practical to ring-fence the operations to accommodate future separation. The decision would be on a case by case basis considering the structure of the network, the licensing arrangements in the state, and the proposed pricing and cost-sharing arrangements. As with any economic regulation decision, the major consideration would be the long term interests of consumers.

In the case of a pure hydrogen network, where the NGL framework does not apply, given the absence of any regulatory framework there is theoretically no constraint on a single entity producing, transporting and retailing hydrogen. Whether such a constraint is imposed, and if so, when, depends on how the regulator evaluates the need for effective co-ordination and low transaction costs across the supply chain versus the risk to market competition. Under this scenario it would be necessary for the hydrogen network to separate from the natural gas distribution network.

Under current regulations the quality of gas must be reliable. Injection of hydrogen by another party would require an agreement to ensure that the concentration was consistent and reliable. Similarly, the network operator would need to be guaranteed that the concentration of hydrogen was maintained at a safe level and did not risk the safety of the network.

Regulation is one way to accommodate this tension, while the alternative is private commercial agreements. Commercial arrangements are simpler and more flexible to establish, but regulations have stronger incentives for compliance. In the absence of vertical integration, there is likely to be need a need for regulations or government intervention to ensure that the supply chain works together to deliver efficient outcomes for customers.

Cost recovery for upgrades and conversion costs

Large scale hydrogen conversion will require significant expenditure on upgrades to infrastructure, metering equipment and household appliances. For existing pipelines which are covered, the question is whether these costs can be passed through to customers under the current regulatory framework[13]. For non-covered pipelines, the question is whether commercial participants are prepared to make such investments in the absence of any regulations regarding cost recovery.

Northern Gas Network's Leeds H21 project showed that upgrades, rather than replacement of appliances would suffice. We would also expect this to hold true in Australia. However further research should be undertaken to confirm the costs and effectiveness of an approach which minimises appliance replacement where upgrades of existing appliances are feasible.

Conversion to a hydrogen network in Australia will undoubtedly create disruption to customers, but technology upgrades are not unprecedented and can be managed to minimise customer inconvenience. However it is questionable whether existing consumers would pay for the costs of conversion to hydrogen given there is no corresponding improvement in the quality of service/product for the customer. Further, gas consumption per connection has been declining in recent years across Australia [53] which could impact on the commercial viability of conversion expenditure.

Covered pipelines would need to consider how such expenditure would pass the expenditure rules under the National Gas Rules (clause 79 and 91). In the absence of a price on carbon, or an explicit regulatory obligation for Hydrogen conversion, such justification could be very difficult under the current clauses. A case could be made that the risk of stranded assets under a zero emissions future justified some expenditure on new technology. However, the regulator's approach tends to focus on productive efficiency of providing existing services, as evidenced in the Australian Energy Regulator's (AER) draft decision on Australian Gas Networks' proposal for funding to trial alternative ways to manage peak demand [54].

The current regulatory framework for businesses under price controls is not conducive to innovation and for testing hydrogen insertion. General expenditure for innovation, or R&D could be approved under certain circumstances, but there is no certainty, and the AER is limited in its discretion. ATCO made a case for funding of R&D for innovation in its AA5 submission, stating that the regulatory framework for gas is "predicted on a stable technological change assumption with substantially unchanged energy supply and demand patterns". ATCO argues that meeting customers' future energy needs at lowest cost may require investment in services for a low emission energy source like hydrogen. Jemena's Western Sydney Green Gas Project is stated as a way to make renewable energy dispatchable, by converting excess solar and wind energy into storable hydrogen, but is not funded from regulated revenue.

The AEMC is addressing the incompatibility between innovation and regulation in the electricity sector through its *2019 Electricity Network economic regulatory framework review*, which encompasses consultation on the use of a 'regulatory sandbox'. This approach is based on relaxing regulation for small scale trials of new technologies and models. The AEMC is providing advice to COAG on the use of sandboxes in February 2019.

13 This will depend on whether the regulator accepts that the proposed expenditure satisfies the relevant criteria under part 9 of the National Gas Rules. Under clause 79(2) there a number of possible avenues for capital expenditure to be approved. Further under clauses 77(2)(b) and 78, the regulator must carry out an ex-post assessment of any capital expenditure. The proponent will have to consider this risk when making hydrogen related investments.

Appendix 4: Getting started with the H2City Tool

Purpose

The H2City Tool is spreadsheet-based and has been developed to assist users with screening of communities that may be suitable for transitioning to a hydrogen-based energy future and provides two broad pathways:

- a hydrogen pathway; and
- an electrification pathway

The H2City Tool allows a relative comparison to be made between these options. Opportunities identified using the H2City Tool would then require further scoping and detailed analysis.

The H2City Tool has been developed to support energy industry participants, government, transport and infrastructure agencies, developers and policy makers in assessing suitable communities for conversion to hydrogen.

Modes

The H2City Tool has been preconfigured to operate in three different modes. The different modes affects the number and level of inputs required. The calculations in each mode remains the same.

Modes
Mode 1: Limited (5) number of inputs exposed to user with H2City Tool pre-populated
Mode 2: A hypothetical town with all inputs loaded for review (noting over 200 inputs)
Mode 3: A bottom up mode where users can choose to populate all inputs

The H2City Tool is a demand driven model, and calculations are based on a community's specified demand. Outputs are determined through upstream requirements of demand. The information and data provided in this report and the H2City Tool have been sourced from available research, supported by CSIRO, as well as public documentation and analysis of the industry. At this point in time, the Hydrogen industry is rapidly evolving, therefore the information contained in this report is relevant at the time of authorship.

Pre-populated data

When operating in Modes 1 and 2, the H2City Tool is pre-populated with time based assumptions containing relevant cost and performance data obtained from CSIRO as well as publically sourced data and example data for a hypothetical regional town.

When Mode 3 is selected, the hypothetical regional town data is removed, and only CSIRO data will remain pre-populated. Within the User Guide tab in the H2City Tool, a checklist has been inbuilt to inform the user of required inputs (Figure 6 - Mode 3 required inputs example). The inputs required can be categorised under:

- **General** – The proportion of Hydrogen blending (by mass)
- **Demand** – Total number of premises within community, adoption curves, capacity factors, etc.
- **Production** – Electrolyser (PEM), other intermittent green, other dispatchable green
- **Transportation/ Transmission** – Onsite compression costs
- **Local infrastructure upgrades/ Augmentation** – Gas turbines and Distribution network upgrades

- **End user** – Appliance CAPEX

Outstanding inputs from user				
Bookend	**Input**	**Mandatory input**	**Input has been populated?**	**Link to input**
	General			
Hydrogen	Proportion of H2 blending	Yes	✗	Click here
Both	Proportion of community for GNU conversion	Yes	✓	Click here
	Demand			
	Total number of premises in the community			
Both	Number of commercial premises	Yes	✗	Click here
Both	Number of industrial premises	Yes	✗	Click here
	H2 required			
Hydrogen	Inter-community mobility	N/A		
Hydrogen	Industrial feedstock	N/A		
Hydrogen	Export	N/A		
	Adoption Curve			
Hydrogen	Proportions by vehicle engine type	Yes	✗	Click here
	Capacity factor			
Both	Other dispatchable green	Yes	✗	Click here
Both	Other dispatchable brown	Yes	✗	Click here
Both	Other intermittent brown	Yes	✗	Click here
Both	Other intermittent green	Yes	✗	Click here

Figure 6 - Mode 3 required inputs example

Should the user choose to override the CSIRO data, or any of the pre-populated data in Modes 1 and 2, they can do so by inserting self-sourced data into the coloured cells in Figure 7 - Overriding pre-populated data. Doing so will nullify pre-populated data adopted in the H2City Tool.

Biomass Gasification					
Installed capacity per unit			*CSIRO*		
Adopted in Model	GJ/h				3,123.79
Maximum value (user overrides cannot exceed)	GJ/h				-
Raw	GJ/h				3,123.79
Cases				Cells to override	
Databook	GJ/h	✓			
Bottom-up demand databook (currently INACTIVE)	GJ/h				
User base case input (optional)	GJ/h	⌧			
User scenario 1 (optional) (currently INACTIVE)	GJ/h				
User scenario 2 (optional) (currently INACTIVE)	GJ/h				
User scenario 3 (optional)	GJ/h	⌧			

Figure 7 - Overriding pre-populated data

In depth explanations of assessment criteria and user input requirements are detailed in Sections 3 and 4 of this report.

Appendix 5: H2City Tool illustrative examples for the hydrogen pathway

This guide offers a high level demonstration of how users can navigate the simple mode of the H2City Tool to change selected inputs so as to produce certain outcomes. Examples are provided below to guide users on using the H2City Tool effectively.

It should be highlighted that the figures provided within the worked examples are purely for illustrative purposes. The discussed changes to inputs are only applicable to the hydrogen pathway and are not be taken into account in the electrification pathway. Should users wish to modify and edit the electrification pathway, they will need to activate the advanced user mode by following the instructions contained within the tool.

Within the H2City Tool, there are three metrics in the simple mode and ten graphs included in the optional advanced user outputs section of the dashboard sheet. The advanced outputs are for the benefit of advanced users as they are linked to inputs that are only accessible in the advanced mode of the H2City Tool. In order to perform detailed analysis on these outputs, the model should be operated in the advanced mode so that the user can flex and form their own views on the detailed inputs.

Inputs sheet

This sheet contains a summary of key inputs in the simple mode, which users can populate and alter to understand the impact on outputs in the hydrogen pathway. This is a small subset of the overall suite of inputs available in the advanced mode.

Total number of converted households

Overview

The Tool currently computes the number of households in the community, which converts to using hydrogen each year, based on pre-populated adoption rates and the number of households per State. These inputs are accessible only in the advanced mode and are based on the population of a hypothetical regional town. Nonetheless, the user can override the tool's computed figures in the simple mode by providing inputs in the yellow cells in Figure 8: Number of Converted Households.

17	Key Inputs									
18										
19	Active pathway	Converting	Electrification							
20	Location	State	Western Australia		Click here to go to the Dashboard					
21	Year of conversion	Year	2030							
22	*Please go to the Dashboard to amend the above inputs*									
23										
24			Calendar year	2020	2021	2022	2023	2024	2025	2026
25	Total number of converted households	#								

Figure 8: Number of Converted Households

Worked Example: Setting the Number of Converted Households

- The user specifies the number of households in the community from 2020 to 2025 that switches to using hydrogen, as seen in Figure 9. These new figures will override the Tool's pre-populated data in the advanced mode to calculate a hydrogen demand that is based on the user's edits.
- Depending on the active pathway, these inputs will directly affect the community's demand for hydrogen or electricity per annum, the costs of appliance conversion, the costs of meter upgrades (in Hydrogen pathway only) and the number of new builds for small-scale batteries (in electrification pathway only).

17	**Key Inputs**									
18										
19	Active pathway	Converting	Electrification							
20	Location	State	Western Australia		Click here to go to the Dashboard					
21	Year of conversion	Year	2030							
22	*Please go to the Dashboard to amend the above inputs*									
23										
24			**Calendar year**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
25	Total number of converted households	#		25000	25750	26523	27318	28138	28982	29851

Figure 9: Worked Example for Number of Converted Households

- These inputs will impact all three metrics displayed in the Dashboard in the simple mode. Figure 10: Impact on Metric 1 for specifying the Number of Converted Households shows the differences in Metric 1 with hydrogen as the active pathway before and after the inputs.

After

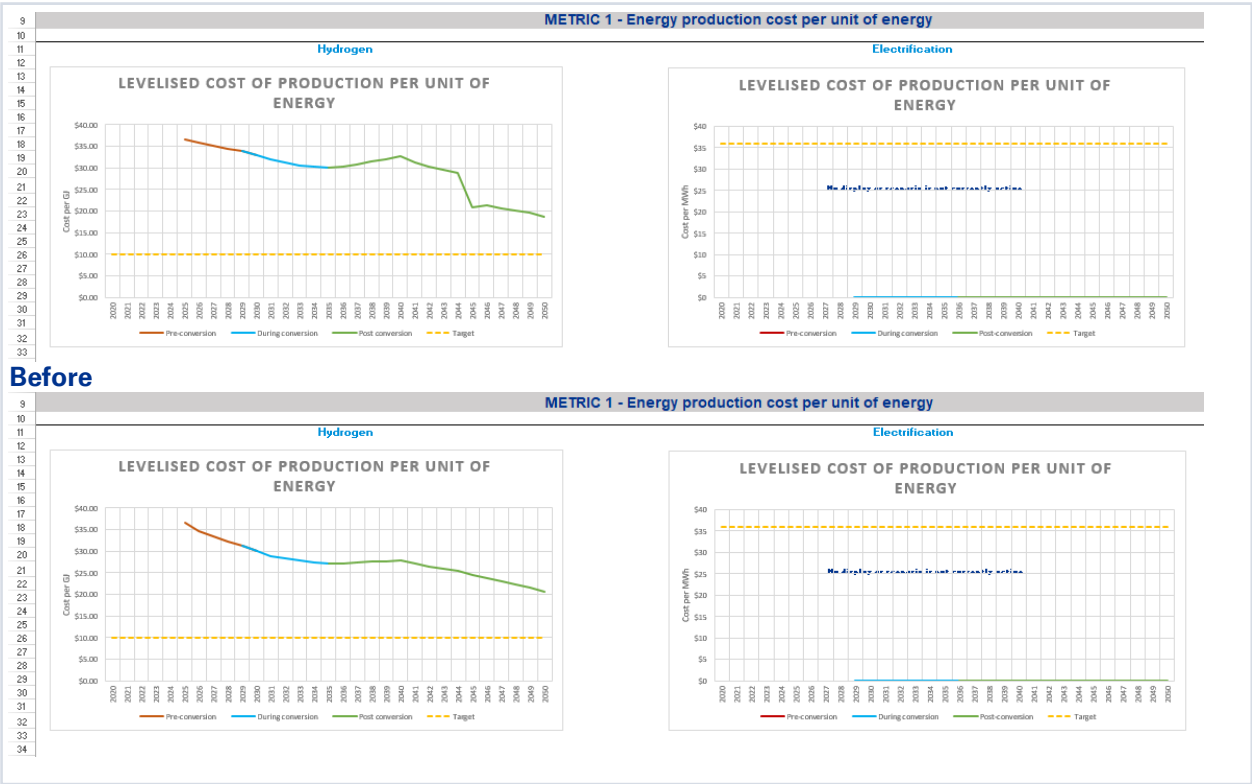


Figure 10: Impact on Metric 1 for specifying the Number of Converted Households

Impacted outputs

While the above example provides a snapshot of the changes to Metric 1, a change in the input for the number of converted households will directly impact all three metrics in the dashboard sheet, namely:

- **Metric 1 Energy production cost per unit of energy** – this shows the total cost of producing energy, divided by the community's projected total energy consumption in a particular period. The levelised cost of production comprises of three main components:
  - **Capital expenditure:** The spending on building new facilities required to generate the requisite amount of energy demand in that period. In the hydrogen pathway, this refers to the cost of building new PEM electrolysers as the Tool assumes hydrogen will be 100 per cent produced with PEM electrolysers.
  - **Operating expenditure:** The spending on operating the facilities that produce energy to meet demand in that period, including electricity and water costs of running the PEM electrolysers.
  - **Cost of capital:** The costs incurred in funding the capital expenditure on new facilities.

- **Metric 2 Supply chain cost per unit of energy and per km** – this shows the total cost of producing and delivering the energy to the end user, divided by the community's projected total energy consumption or distance travelled in that period. The main components of the supply chain cost will be discussed using another worked example in the ensuing sections.
- **Metric 3 Incremental Costs to the End User** – This metric outlines the total additional costs that the end users has to bear for converting to 100 per cent hydrogen or electricity, per premise (i.e. household, industrial, commercial premise) or per distance travelled basis. The main components of the costs to the end user will be discussed using another worked example in the ensuing sections.

Hydrogen demand, electrolyser capex and utilities cost

Overview

As these inputs do not impact the electrification pathway, the user should ensure the active pathway selected is 'hydrogen' in the dashboard sheet prior to inserting figures into any of the yellow cells in Figure 11.

28	Hydrogen		
29			
30	*Please only provide inputs for the following fields if you are intending to explore the pathway for Hydrogen. Note that these inputs do not impact the Electrification pathway.*		
31	H2 demand per household	GJ	
32	*Please note GJ demand does not change based on energy source.*		
33	Electrolyser capex per kW	$/kW	
34	Water cost	$/L	
35	Electricity cost	$/kWh	

Figure 11: Hydrogen Demand, Electrolyser and Utilities Cost

Worked Example: Setting Water Costs to $0.02 per litre and Electricity Costs to $0.03 per kWh

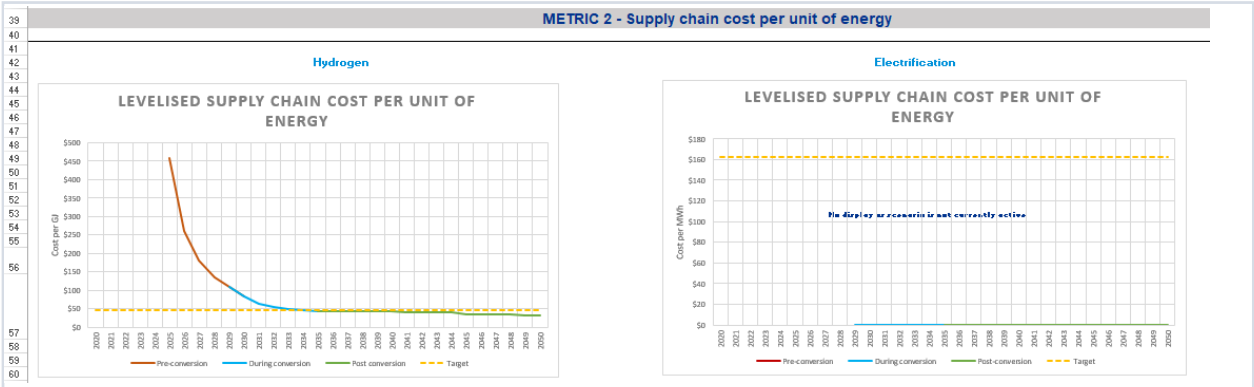
- The user fixes the cost of water and electricity at $0.02 per litre and $0.03 per kWh respectively from 2020 to 2050, as illustrated in Figure 12.

28	Hydrogen		
29			
30	*Please only provide inputs for the following fields if you are intending to explore the pathway for Hydrogen. Note that these inputs do not impact the Electrification pathway.*		
31	H2 demand per household	GJ	
32	*Please note GJ demand does not change based on energy source.*		
33	Electrolyser capex per kW	$/kW	
34	Water cost	$/L	0.02
35	Electricity cost	$/kWh	0.03

Figure 12: Worked Example for Water and Electricity Cost

- These inputs directly impact the operating costs of producing hydrogen and will therefore affect the graphs for all three metrics displayed in the dashboard in the simple mode shows the differences in Metric 2 with hydrogen as the active pathway before and after the inputs.
- Users will need to zoom in on the graphs in the dashboard sheet to observe the difference. The difference between the before and after graphs is very slight given that the change is not material.

After



Before

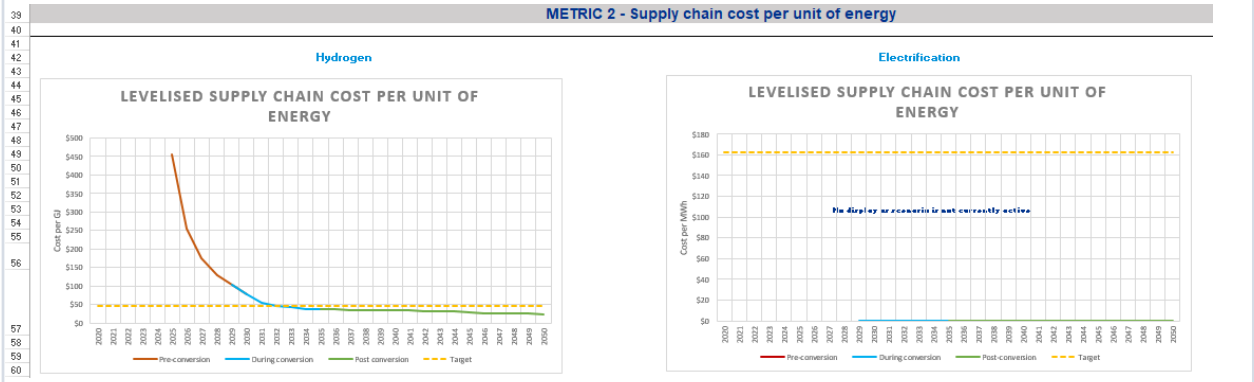


Figure 13: Impact on Metric 2 after Setting the Water and Electricity Cost

Impacted outputs

While the above example provides a snapshot of the changes to Metric 2, any changes in the input for the hydrogen demand per household, electrolyser capex, electricity and water costs will directly impact all three metrics in the dashboard sheet:

- **Metric 1 Energy production cost per unit of energy** – Refer to the earlier sections on the main components of the energy production costs.
- **Metric 2 Supply chain cost per unit of energy and per km** – The total cost of producing and delivering the energy to the end user, divided by the community's projected total energy consumption or distance travelled in that period. The levelised supply chain cost comprises of four main components:
  - **Levelised cost of production:** The capital and operating costs involved in building and running the electrolysers (or other energy generation facilities) to meet the demand for energy in a given period. This also includes the cost of capital for funding the capital expenditure.
  - **Levelised storage cost:** The operating costs of compressing and storing hydrogen.
  - **Levelised transportation/transmission cost:** The capital and operating costs of building new transmission pipelines to connect the new production source to the nearest transmission injection point. This also includes the cost of capital for funding the capital expenditure.
  - **Levelised local infrastructure cost:** The capital and operating costs of building new distribution pipelines to allow the distribution of hydrogen, meter and ancillary upgrades, building vehicle recharge stations, building and operating new facilities (e.g. gas turbines) and fuel cells (in the hydrogen pathway) or batteries (in the electrification pathway) for electricity grid firming purposes. This also includes the cost of capital for funding the capital expenditure.
- **Metric 3 Incremental Costs to the End User** – The main components of the costs to the end user will be discussed using another worked example in the ensuing sections.

Dashboard sheet

This sheet is intended to show key performance indicators and outcomes from either the Hydrogen or electrification pathways, noting that it incorporates the result of complex calculations derived from over 200 different input variables – most of which are only available for updating in the advanced mode.

Pathway, location and year of conversion

Overview

The yellow cells in Figure 14 contain drop-down menus for the user to select the active pathway, geographical location and year of conversion in the tool. The pre-populated tool has hydrogen as the active pathway, Western Australia as the location and 2030 as the year of conversion.

In the hydrogen pathway, the year that conversion starts indicates the year in which the gas network switches from a 10 per cent blend of hydrogen to beginning to convert to running completely on hydrogen. The pre-populated tool assumes that local communities across each State will progressively switch to running on 100 per cent of hydrogen over the next five years. The year that conversion is completed therefore indicates the year in which the population in the entire State has fully converted to using the gas network running on a 100 per cent hydrogen.

In the electrification pathway, the year that conversion starts is not applicable as the tool assumes that there is no ramp up period required for local communities to switch to renewable electricity. The user should refer to the year that conversion is completed as the year in which the entire State has fully converted to using electricity. There are no conversion costs incurred in the early years of the Tool under the electrification pathway.

Figure 14: Pathway, Location and Year of Conversion Inputs

Worked Example: Selecting Northern Territory as the Location

- The pre-populated tool does not contain demand inputs for Northern Territory due to limitations in publicly available data.
- Therefore, if the user chooses Northern Territory as the State, an error message will appear to remind users to provide demand inputs in the empty cells in the TB_Databook Sheet, as seen in Figure 15.
- In order to access the TB_Databook Sheet, the user will be required to change to the advanced mode. Instructions on how to activate the advanced mode are contained within the Tool.

The above is a worked example of how a user may wish to edit or fill in an input using the advanced mode. Other inputs that are only available in the advanced mode that may be of interest to users include (but are not limited to):

- Technology used to produce Hydrogen, Rows 131 to 135 of the DefineDemand Sheet;
- Retirement of existing fleet of carbon emitting generators, Row 26 of the InputsConstant Sheet;
- Consumer price index rate, Row 48 of the InputsConstant Sheet;
- Cost of building new HVAC/HVDC transmission pipeline connection, Row 109 and 110 of the InputsConstant Sheet;
- Proportion of Hydrogen blend in the gas network prior to mandatory conversion, Rows 34 to 37 of the InputsTimeBased Sheet;

- Proportion of the community that is on blended Hydrogen prior to mandatory conversion, Rows 56 to 59 of the InputsTimeBased Sheet;
- Electricity required per household, Rows 180 to 183 of the InputsTimeBased Sheet;
- Capital cost for building a wind farm, Rows 1813 to 1817 of the InputsTimeBased Sheet;
- Capital cost for building a solar farm, Rows 1854 to 1858 of the InputsTimeBased Sheet; and
- Cost of switching to a hydrogen appliance, Rows 2681 to 2685 of the InputsTimeBased Sheet.

Worked Example: Selecting 2032 as the Year of Conversion

- Should the user select a year of conversion that is earlier or later than the pre-populated year of conversion in the model (i.e. 2030), an error message will appear to remind users to change the demand adoption curve inputs in the InputsTimeBased Sheet, as seen in Figure 15.
- In order to 곎ss the InputsTimeBased Sheet, the user will be required to change to the advanced mode.

Figure 15: Worked Example for Location and Year of Conversion

Impacted Outputs

Any changes in the input for the pathway, location, year of conversion will directly impact all three metrics in the Dashboard sheet, namely:

- **Metric 1 Energy production cost per unit of energy** – Refer to the earlier sections on the main components of the energy production costs.
- **Metric 2 Supply chain cost per unit of energy and per km** – Refer to the earlier sections on the main components of the supply chain costs.
- **Metric 3 Incremental Costs to the End User** – The total additional costs that the end users has to bear for converting to 100 per cent Hydrogen or electricity, per premise (i.e. household, industrial, commercial premise) or per distance travelled basis.

In particular, the user may be interested in knowing how a change in the year of conversion affects the costs to end users. A snapshot of the impact to Metric 3 has not been provided in the above worked example as the Tool has been pre-populated with a hydrogen adoption curve that is tied to 2030 as the year of conversion. Therefore, the user will be required to access the detailed hydrogen demand inputs in the advanced mode to fully evaluate and understand the impact on end user costs.

Notwithstanding this, the main components of the end user cost are described below to help the user appreciate the relationship between the year of conversion and end user costs:

- **Electric vehicle costs** – this refers to the capital and operating costs involved in owning and driving a fuel cell electric vehicle (in the hydrogen pathway) or battery electric vehicle (in the electrification pathway).
- **Appliance conversion costs** – this refers to the capital costs incurred in purchasing appliances that are compatible with being powered by 100 per cent hydrogen or electricity.
- **Small scale fuel cell/batteries costs** – this refers to the capital and operating costs of installing and operating small scale fuel cells or household/commercial batteries in the community for electricity grid firming purposes.

Units of display

Overview

The user can select the units of display for the levelised cost of production, end user costs and hydrogen costs per unit of energy from the drop-down menus within the yellow cells in Figure 16.

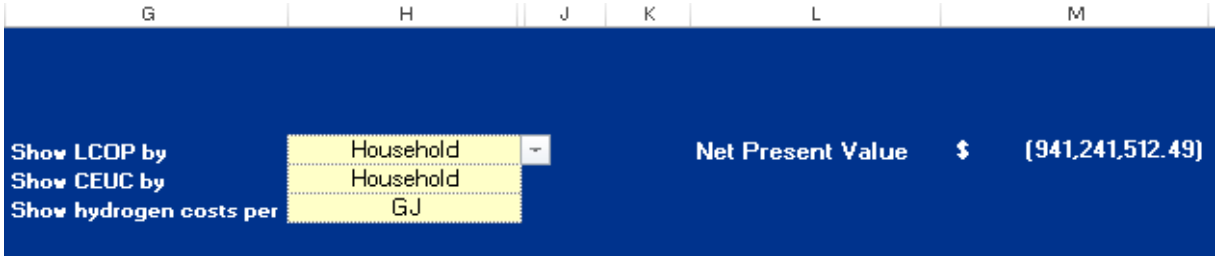


Figure 16: Units of Display

Worked Example: Show Hydrogen Costs per MWh

- For the avoidance of doubt, the switch between gigajoules to megawatt hours is on an equivalent energy basis. It is not intended to represent how much electricity can be generated by that amount of hydrogen.
- The user can choose to display the hydrogen costs per unit of energy in megawatt hours, as demonstrated in Figure 17.

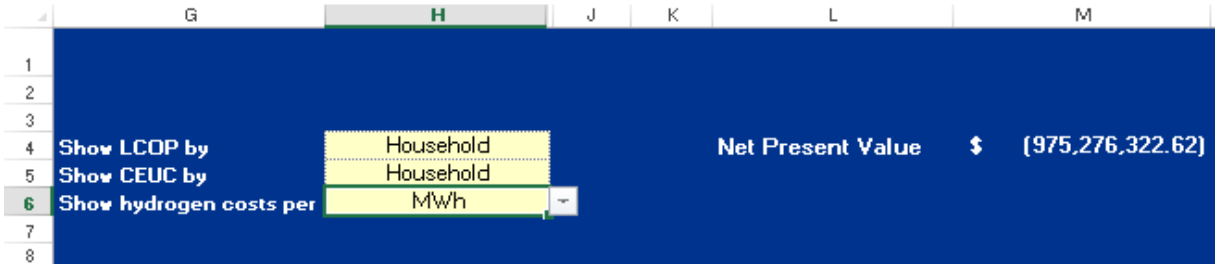


Figure 17: Worked Example for Changing Units of Display

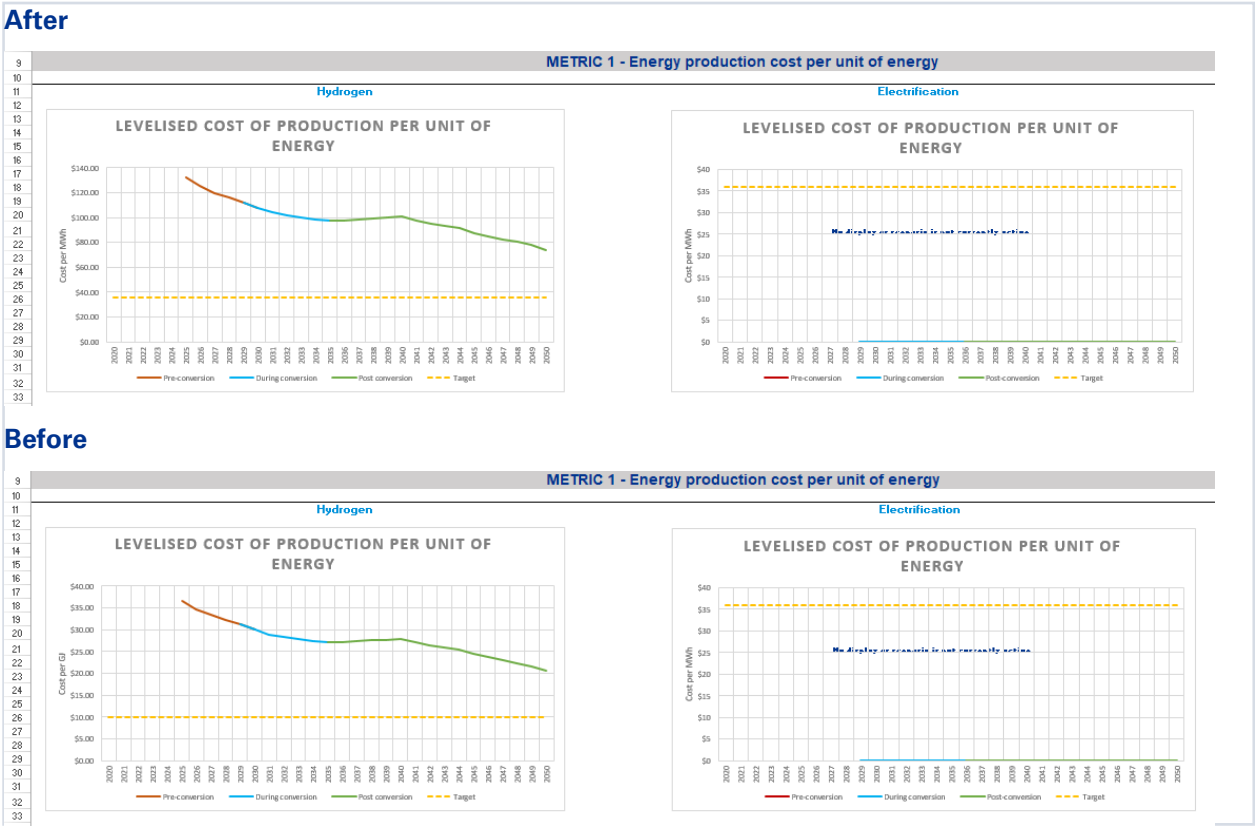


Figure 18: Impact on Metric 1 for Changing Units of Display

Impacted Outputs

Any changes in the units of display will directly impact two metrics in the Dashboard sheet, as they are both computed per unit of energy when the hydrogen pathway is active. These are:

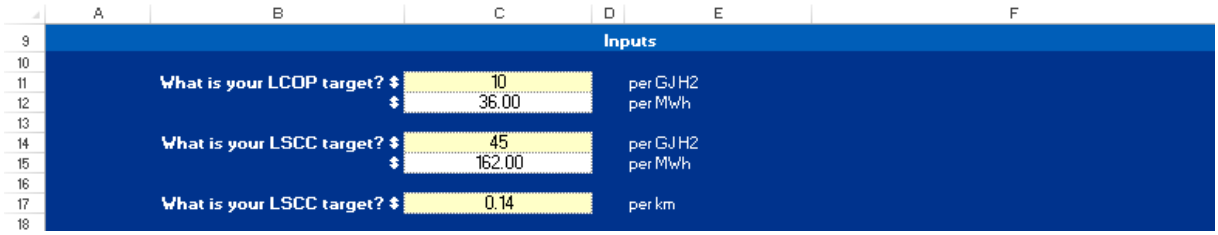
- **Metric 1 Energy production cost per unit of energy**; and
- **Metric 2 Supply chain cost per unit of energy and per km.**

Levelised Cost Targets

Overview

The user can change the inputs for the target levelised production and supply chain costs in the yellow cells in Figure 19.

Figure 19: Cost Target Inputs



Worked Example: Setting Levelised Supply Chain Cost Target to $0.3 per KM

- The user can change the target levelised supply chain cost from $0.14 per km to $0.30 per km, as demonstrated in Figure 20.
- Note that the levelised supply chain cost expressed on a per km basis is applicable to mobility costs only.

Figure 20: Worked Example of Changing LSCRR Target per KM

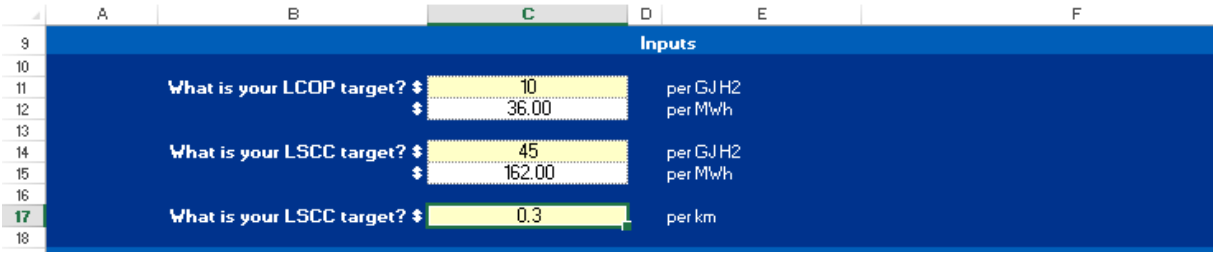
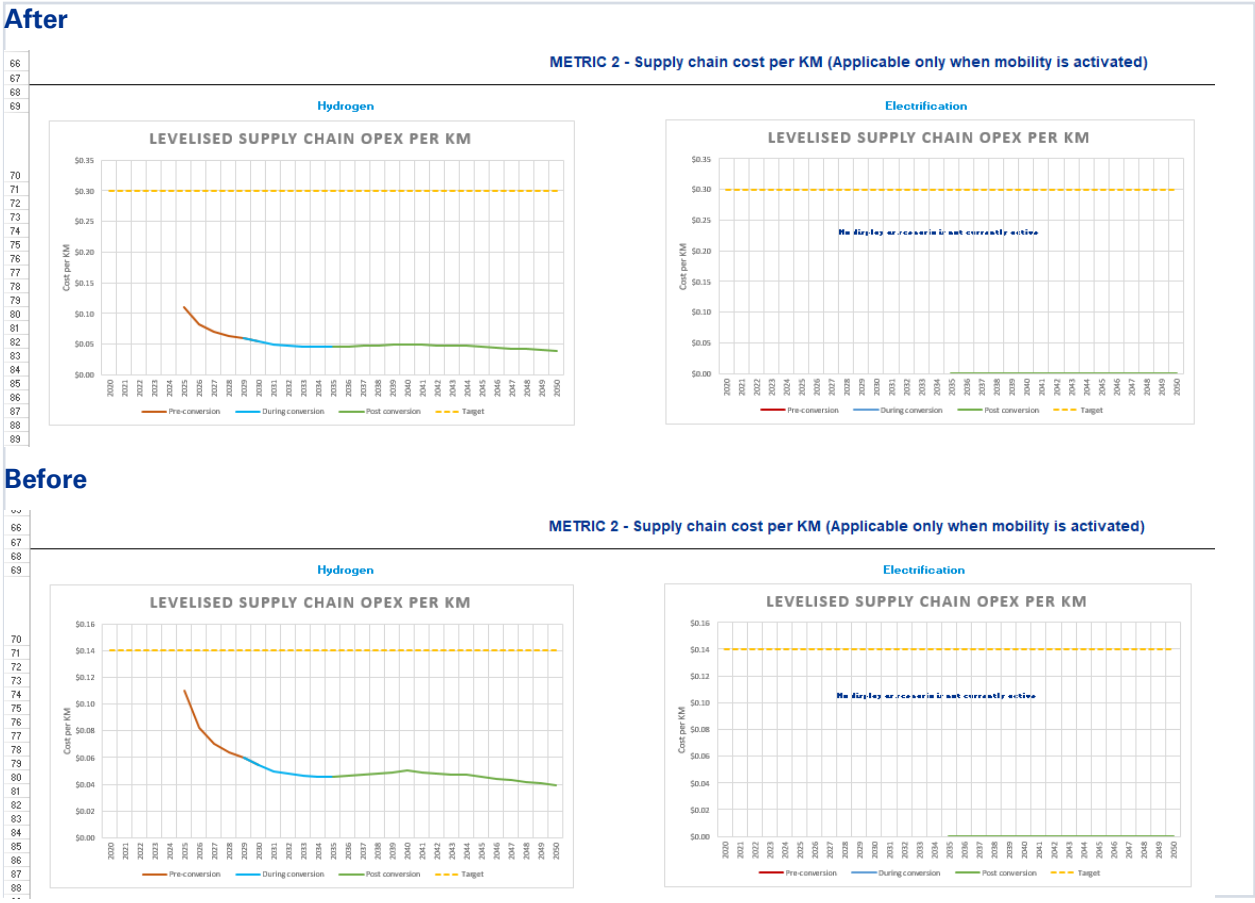


Figure 21: Impact on Metric 2 for Changing LSCC Target per KM



Impacted Outputs

Any changes in levelised cost targets will directly impact all three metrics in the Dashboard sheet, as they are both computed per unit of energy when the hydrogen pathway is active. These are:

- **Metric 1 Energy production cost per unit of energy**;
- **Metric 2 Supply chain cost per unit of energy and per km**; and
- **Metric 3 Metric 3 Incremental Costs to the End User.**

Energy Bill and Mobility Costs

Overview

The user can use the Tool to estimate his or her quarterly energy bill in the selected year post conversion by specifying inputs in the yellow cells in Figure 22.

19	Key metrics				
20					
21	**Your energy bill after converting**				
22		Hydrogen		Electricity	
23	Year	2030		2035	
24					
25	What is your quartely usage?		GJ		MWh
26					
27	What are your quartely network charges?				
28					
29	Estimated bill for quarter	$ -		#N/A	
30				Pathway not active	
31					
32	**Your mobility costs after converting**				
33		Hydrogen		Electricity	
34	Year	2030		2035	
35					
36	What is your annual distance travelled?		km		km
37					
38	Estimated mobility costs	$ -		#N/A	
39				Pathway not active	

Figure 22: Energy Bill and Mobility Costs

Worked Example: Compute Energy Bill and Mobility Costs in the First Year after Conversion

- In the Tool, the current year that conversion is completed is 2035.
- For example, the user inputs a quarterly usage of 2 GJ and quarterly network charges of $100. This will provide an estimated gas bill of $253 per quarter in 2030, as shown in Figure 23.
- The user also inputs an annual distance travelled of 9,500 km, which amounts to about $518 per year for driving a hydrogen-fuelled vehicle, as shown in Figure 23.
- Note that the model will not allow the user to select a year prior to conversion because the Tool does not model status quo. In the hydrogen pathway, during the years when hydrogen is blended into the natural gas network, the bill will only account for the portion of the cost that is Hydrogen (i.e. 10 per cent in the years prior to mandatory conversion) but not the remainder of the cost that is natural gas (i.e. 90 per cent).

19	Key metrics				
20					
21	**Your energy bill after converting**				
22		Hydrogen		Electricity	
23	Year	2030		2035	
24					
25	What is your quartely usage?	2	GJ		MWh
26					
27	What are your quartely network charges?	100			
28					
29	Estimated bill for quarter	$ 253.22		#N/A	
30				Pathway not active	
31					
32	**Your mobility costs after converting**				
33		Hydrogen		Electricity	
34	Year	2030		2035	
35					
36	What is your annual distance travelled?	9500	km		km
37					
38	Estimated mobility costs	$ 517.98		#N/A	
39				Pathway not active	

Figure 23: Worked Example for Energy Bill and Mobility Costs

07 Bibliography

[1] Leeds City Gate, "H21 Leeds City Gate - Northern Gas Networks," 2016. [Online]. Available: https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Report-Interactive-PDF-July-2016.compressed.pdf.

[2] Cadent Gas, "The Liverpool-Manchester Hydrogen Cluster: A Low Cost, Deliverable Project," 2017. [Online]. Available: : https://cadentgas.com/getattachment/About-us/Innovation/Projects/Liverpool-Manchester-Hydrogen-Cluster/Promo-LMHC-downloads/Technical-Report.pdf.

[3] HyDeploy, "Positive progress to reduce UK C02 emissions," 2017. [Online]. Available: https://hydeploy.co.uk/about/document-library/.

[4] R. ". Rose, "ENE-FARM installed 120,000 residential fuel cell units," Fuell Cell Works, 2015. [Online]. Available: https://fuelcellsworks.com/archives/2015/09/23/ene-farm-installed-120000-residential-fuel-cell-units/.

[5] Japan LP Gas Association, "House-use Fuell Cell (ENE-FARM)," [Online]. Available: http://www.j-lpgas.gr.jp/en/appliances/index.html. [Accessed 2018].

[6] B. Elrick, "The California Fuel Cell Revolution," 2018. [Online]. Available: https://cafcp.org/sites/default/files/CAFCR-Presentation-2030.pdf.

[7] K. Caeser, "California transitioning to all-electric public bus fleet by 2020," California Air Resources Board, Sacramento, CA, 2018.

[8] H2 Mobility, "H2 Mobility," [Online]. Available: https://h2.live/en/h2mobility. [Accessed 2018].

[9] Federal Ministry for the Environment, nature Conservation, Building and Nuclear Safety, "Climate Action in Figures: Emission Targets Germany and EU," [Online]. Available: https://www.bmu.de/fileadmin/Daten_BMU/Download_PDF/Klimaschutz/klimaschutz_in_zahlen_klimaziele_en_bf.pdf. [Accessed 2018].

[10] National Organisation Hydrogen and Fuel Cell Technology (NOW GmbH), "Hydrogen Mobility," [Online]. Available: https://www.now-gmbh.de/en/national-innovation-programme/mobil-mit-wasserstoff. [Accessed 2018].

[11] Scandinavian Hydrogen Highway Partnership (SHHP), "Hydrogen for transport in the Scandinavian region," [Online]. Available: http://www.scandinavianhydrogen.org/shhp/about-shhp/. [Accessed 2018].

[12] Generating Renewable Energy Business Enterprise (GREBE), "Policy and Funding Mechanisms," GREBE, [Online]. Available: http://grebeproject.eu/projects-activities/policy-funding-mechanisms/. [Accessed 2018].

[13] D. U. B. Ludwig-Bölkow-Systemtechnik, "H2moves Scandinavia," 2012. [Online]. Available: https://www.fch.europa.eu/sites/default/files/1.%20U.%20BUENGER%20-%20H2%20moves%20%28ID%20193324%29%20%28ID%20193796%29.pdf.

[14] FuelCellsWorks, "8 New Hydrogen Stations in Sweden by 2020," FuelCellsWorks, 2018. [Online]. Available: https://fuelcellsworks.com/news/8-new-hydrogen-stations-in-sweden-by-2020.

[15] Fuel Cells and Hydrogen (FCH), "About us; Who we are," FCH, [Online]. Available: https://www.fch.europa.eu/page/who-we-are. [Accessed 2018].

[16] ATCO, "Clean Energy Innovation Hub," [Online]. Available: https://yourgas.com.au/energy-future/clean-energy-innovation-hub/. [Accessed 2018].

[17] M. Davis, "Jemena Power to Gas Demonstration," Australian Renewable Energy Agency (ARENA), 2018. [Online]. Available: https://arena.gov.au/projects/jemena-power-to-gas-demonstration/.

[18] Jemena, "Renewable, Green gas, Trial Gets te Go Ahead," Jemena, [Online]. Available: https://jemena.com.au/about/newsroom/media-release/2018/renewable,-green-gas,-trial-gets-the-go-ahead. [Accessed 2018].

[19] Government of South Australia - Renewables SA, "Hydrogen Park of South Australia," [Online]. Available: http://www.renewablessa.sa.gov.au/topic/hydrogen/hydrogen-projects/hydrogen-park-south-australia. [Accessed 2018].

[20] Australian Renewable Energy Agency, "Toyota Ecopark Hydrogen Demonstration," March 2019. [Online]. Available: https://arena.gov.au/projects/toyota-ecopark-hydrogen-demonstration/.

[21] HyDeploy, "HyDeploy Project," 2017. [Online]. Available: HyDeploy 2017, HyDeploy Project Report.

[22] S. T. M. H. J. S. E. M. C. P. D. H. P. Bruce, "National Hydrogen Roadmap," CSIRO, Australia, 2018.

[23] A. Acil, "Nothern Australia Case Study," CSIRO, Australia, 2017.

[24] Climage Change in Australia, "Australian Climate Futures," Climate Change in Australia, 2018. [Online]. Available: https://www.climatechangeinaustralia.gov.au/en/climate-projections/climate-futures-tool/introduction-climate-futures/. [Accessed 2018].

[25] IPCC, [Core Writing Team, R.K. Pachauri and L.A. Meyer (eds.)], "Climate Change 2014: Synthesis Report.," *Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change,* p. 151, 2014.

[26] Australian Energy Market Operator (AEMO), "Demand Forecasting Methodology," 2018. [Online]. Available: http://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2018/2018-Gas-Statement-of-Opportunities-methodology--demand-forecast.pdf.

[27] A. Mehmeti, "Life cycle assessment and water footprint of hydrogen production methods: From conventional to emerging technologies, Italy," *Environments 2018,* vol. 5, no. 24, 2018.

[28] L. A. A. a. B. T. Weger, "Methane cracking as a bridge technology to the hydrogen economy," *International Journal of Hydrogen Energy,* vol. 42, no. 1, pp. 720 - 731, 2017.

[29] P. E. a. H. A. (. Dodds, "The role of hydrogen and fuel cells in providing affordable, secure low-carbon heat.," H2FC SUPERGEN, London, UK, 2014.

[30] A. C. H. L. F. L. K. a. C. C. Chang, "Biomass gasification for hydrogen production," *International Journal of Hydrogen Energy,* vol. 36, no. 21, pp. 14252 - 14260, 2011.

[31] The Engineering Toolbox, "Fuels - Higher and Lower Calorific Values," The Engineering Toolbox, 2003. [Online]. Available: https://www.engineeringtoolbox.com/fuels-higher-calorific-values-d_169.html.

[32] World Resources Institute, "Aqueduct Water Risk Atlas," World Resources Institute, 2013. [Online]. Available: https://www.wri.org/resources/maps/aqueduct-water-risk-atlas. [Accessed 2018].

[33] Hydrogen Strategy Group, "Hydrogen for Australia's Future," Commonwealth of Australia, Australia, 2018.

[34] U.S. DRIVE, "Hydrogen Delivery Technical Team Roadmap," U.S. DRIVE, 2017.

[35] D. O. T. B. C. a. H. R. Seedah, "Evaluating Truck and Rail Movements along Competitive Multimodal Corridors," Center for Transportation Research, Austin, TX, 2013.

[36] Kawasaki, "Kawasaki Hydrogen Road," Kawasaki, 2018. [Online]. Available: http://global.kawasaki.com/en/hydrogen/.

[37] N. C. N. Hoshua Dowling, "Hyundai Nexo Hydrogen Car," 2018. [Online]. Available: https://www.news.com.au/technology/innovation/motoring/hitech/hyundai-nexo-hydrogen-car-coming-to-australia-this-year/news-story/70718407b2b6a78020d054febd9a5f57.

[38] Mitsubishi Hitachi Power Systems, "The hydrogen gas turbine, successfully fired with a 30% fuel mix, is a major step towards a carbon-free society," 2018. [Online]. Available: https://www.mhps.com/special/hydrogen/article_1/index.html.

[39] New Energy and Industrial Technology Development Organization (NEDO), "World's First Heat and Electricity Supplied in an Urban Area Using 100% Hydrogen," 2018. [Online]. Available: http://www.nedo.go.jp/english/news/AA5en_100382.html.

[40] Standards Australia, "Hydrogen Technologies Standards - Discussion paper," Standards Australia, Australia, 2018.

[41] E. F. E. V. H. a. S. M. Karen Stenner, "Australian Consumers' Likely Response to Cost-Reflective Electricity Pricing," CSIRO, Australia, 2015.

[42] *United Nations Treaty Collection; 7. d Paris Agreement,* 2015.

[43] World Bank Group, "State and Trends of Carbon Pricing," World Bank Group, Washington DC, 2018.

[44] Australian Government - Clean Energy Regulator, "Clean Energy Regulator; Emissions Reduction Fund," 2018. [Online]. Available: http://www.cleanenergyregulator.gov.au/ERF/Auctions-results/june-2018.

[45] World Bank Group, "Carbon Pricing Dashboard," World Bank Group, 2018. [Online]. Available: https://carbonpricingdashboard.worldbank.org/.

[46] Carbon Pricing Leadership Coalition, "Report of the High-level Commission on Carbon Prices," Carbon Pricing Leadership Coalition, 2017.

[47] Ministri of Economy, Trade and Industry (METI), "Basig Hydrogen Strategy Determined," METI, 2017. [Online]. Available: http://www.meti.go.jp/english/press/2017/1226_003.html.

[48] ScienceDirect, "NIP seen as a success for Germany, as Phase 2 plans next 10 year," *Fuel Cells Bulletin,* vol. 2017, no. 1, ISSN 1464-2859, p. 12, 2017.

[49] U.S. Department of Energy; Energy Efficiency & Renewable Energy, "Hydrogen Laws and Incentives in California," U.S. Department of Energy, 2012. [Online]. Available: https://afdc.energy.gov/fuels/laws/HY?state=CA.

[50] The University of Queensland, "The Australian public's perception of hydrogen for energy," The University of Queensland, 2018.

[51] A. Allen, "Opportunities for Australia from Hydrogen Exports," ARENA, Australia, 2018.

[52] Victoria Minister for Energy, Environment & Climate Change, "Building Australia's First Hydrogen Refuelling Station," *Media release,* 5 August 2017.

[53] AEMO, "National Gas Forecasting Report," AEMO, 2016.

[54] AER, "Australian Gas Networks Victoria and Albury gas access arrangement 2018 - 2022, Attachment 14 - Other incentive schemes, Draft Decision," AER, 2017.

Contact us

James Arnott
Partner
+61 8 9263 7109
jamesarnott@kpmg.com.au

Sabine Schleicher
Partner
+61 7 3233 3233
sschleicher@kpmg.com.au

Cassandra Hogan
Partner
+61 2 9455 9642
cjhogan@kpmg.com.au