Government of South Australia

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South Australian Green Hydrogen Study

A report for the Government of South Australia

Level 13, 333 Collins Street, Melbourne VIC 3000 Australia

Synopsis

A techno-economic assessment of the potential for a Green Hydrogen industry in South Australia found that two pathways, that produce niche fertiliser products and hydrogen for local buses, are attractive now. Five or ten years in the future hydrogen export and value add products may also be viable projects.

Demand for hydrogen from Japan and South Korea could drive a significant new industry in South Australia, leveraging existing manufacturing, engineering and project delivery capabilities.

Disclaimer

Project No: A32334. - Document No.1 – South Australian Green Hydrogen Study:

Rev	Description	Author	Review	Advisian Approval	Date
Rev1	Draft	PO/EQ	PE/JS		25/5/17
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Rev3	Issued for use	PO/EQ	PO/RS		07/09/17

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Proudly prepared for the Government of South Australia
Department of Premier and Cabinet

Government of South Australia

Executive Summary

The South Australian government Department of Premier and Cabinet (DPC) has engaged Advisian, supported by Siemens and ACIL Allen, to examine three questions in relation to 'Green Hydrogen' in the State. This examination was undertaken through a study, resulting in this report.

Here, Green Hydrogen is defined as hydrogen that has been produced using energy from renewable sources or is net carbon zero energy through carbon capture and/or emissions offsets. The three questions under examination are:

1. What role can hydrogen play in decarbonising the SA economy, including the transport sector?
2. Can SA competitively produce and export Green Hydrogen?
3. Is there scope for SA to participate in a hydrogen industry supply chain, exporting manufactured products and/or services?

Advisian also acknowledges the inputs from a range of government, equipment provider and project developer stakeholders who have generously provided feedback and information for this assessment.

Technology assessment

To explore these questions, the Advisian team worked closely with DPC and a project steering group to develop plausible hydrogen production and value-add product pathways – from energy resource through hydrogen production to end markets – that could be implemented in South Australia over the next 10 years. The selection of the technologies and pathways involved a technology and commercial readiness assessment followed by a location selection. The result of the readiness assessment is shown in the table below.

Study No	Case description	Stage	TRL	CRI
Technologies				
1	Hydrogen by water electrolysis	Production	9	4
2	Hydrogen by natural gas SMR with CCS	Production	5	1
3	Hydrogen by coal gasification with CCS	Production	5	1
4	Hydrogen by biomethane SMR	Production	4	1
5	Cryogenic liquefaction of hydrogen	Carrier	8	2
6	Ammonia production from hydrogen	Carrier	9	4
7	Hydrogen production from ammonia cracking	Production	5	1
8	Compressed gaseous hydrogen	Carrier	8	2
9	Methane / methanol production from hydrogen	Carrier	9	2
10	Toluene as carrier	Carrier	8	1
11	Metal hydrides	Carrier	9	3
12	Power generation fuel cell	End use	9	3
13	Power generation combustion pure or H_2 mix	End Use	9	2
14	Nitrogen based products, fertilisers, explosives, urea, refrigerants	End Use	9	4
15	Transport - heavy vehicles primarily	End use	9	2
16	Hydrogen blending with natural gas	End use	9	2
17	Industrial utilisation of hydrogen/oxygen e.g steel, refineries, glass	End use	9	4

Of the 17 technologies considered, 9 were considered ready for inclusion in the assessment for 2017 and were developed into the pathways described in the following section. For the 2022 and 2027 assessment, a hydrogen carrier was added to allow consideration of an export hydrogen pathway.

To select an appropriate location for each pathway, a range of criteria were reviewed for each pathway and site location. These were:

- Electricity network - availability and capacity
- Water – fresh water availability
- Natural gas network – availability and capacity
- Port facilities – distance and type of facility
- Land – availability of suitable industrial land
- Hydrogen demand – existing or anticipated industries that could require hydrogen
- Oxygen demand – existing or anticipated industries that could require oxygen

The final location selections are included in the table in the following section.

Pathway selection

The pathways selected utilise South Australian generated renewable electricity to produce hydrogen from water in an electrolysis process for use in industry, transport and peaking power generation in South Australia. The hydrogen can be further transformed into products such as ammonia, fertilisers and explosives for local use and export. The study has also considered the production of a hydrogen carrier to allow export to Asia Pacific countries for transport use.

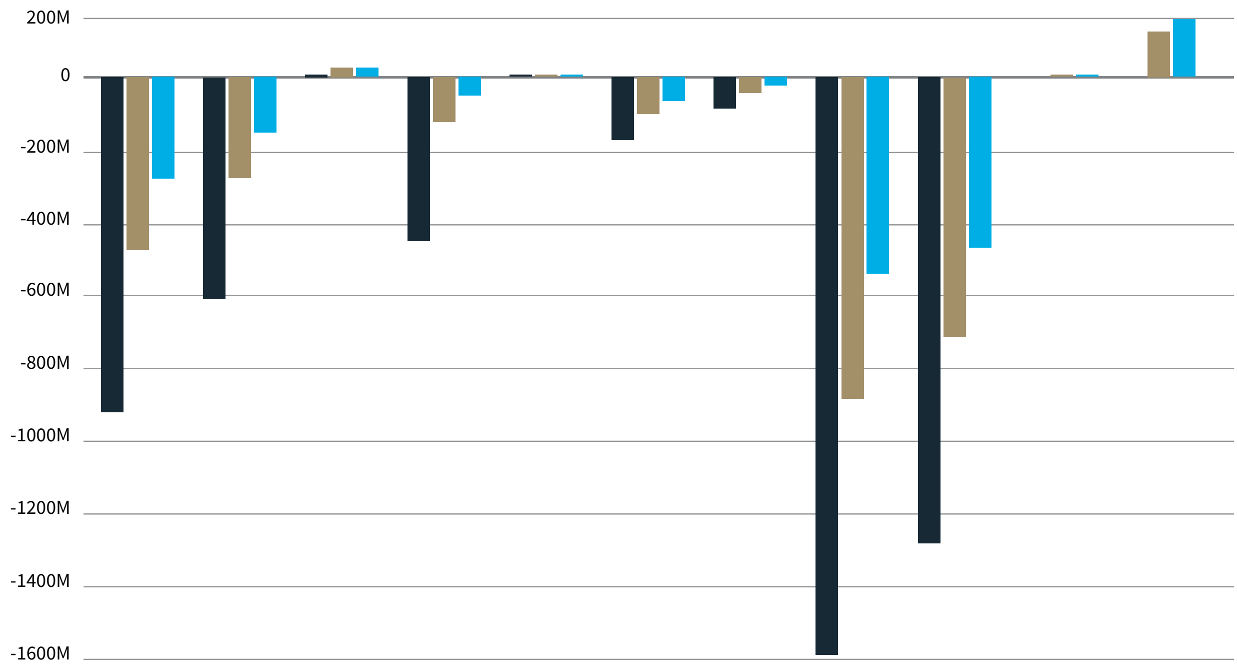
The pathways assessed are tabulated below.

Pathway		Selected location	Comments
A1.	Large ammonia for export	Upper Spencer Gulf	Ammonia export
A2.	Large hydrogen for export	Upper Spencer Gulf	Production of hydrogen and conversion to carrier for export. Liberation of hydrogen at destination.
B.	Large ammonia mono ammonium phosphate (MAP) / diammonium phosphate (DAP)	Upper Spencer Gulf	For local and export markets
C.	Mod. ammonia crystal fertilisers	Upper Spencer Gulf	For local markets
D.	Large ammonia explosives	Upper Spencer Gulf	For local and export markets
E.	H_2 Vehicle Station	Metropolitan Adelaide	Local consumption
F.	Hydrogen fuel cell	Upper Spencer Gulf	Peaking power generation
G.	Hydrogen engine	Upper Spencer Gulf	Peaking power generation
H.	Blending into natural gas network	Metropolitan Adelaide	Green Gas
I.	Industrial utilisation	Upper Spencer Gulf	Food, glass, hydrocarbons manufacturing
J.	Modular hydrogen for export	Metropolitan Adelaide	Production of hydrogen and conversion to carrier for export. Liberation of hydrogen at destination.

Financial analyses

A financial analysis was carried out considering three implementation dates for projects; 2017, 2022 and 2027, where data for future projects has been developed by applying learning rates to capital and operational costs and projecting input costs over the lifetime of each project. The NPV of each pathway is shown below using base values for all variables.

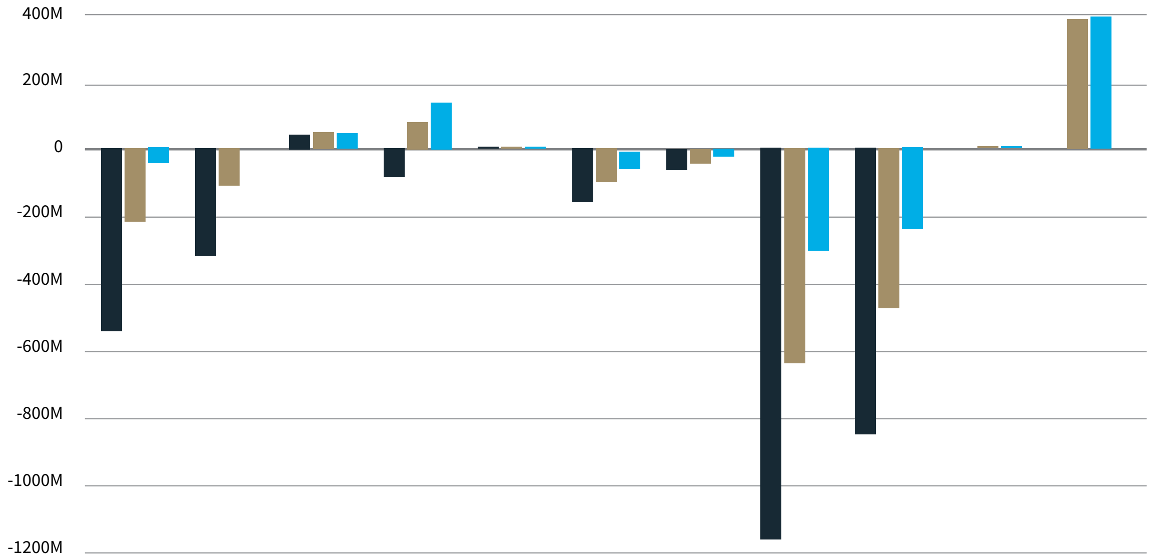
NPV ($ AUD) for 2049 - Indivual Options



	NH3Exp17	MAPDAP17	Crystal17	Explos17	Vehicles17	FuelCell17	EngPower17	H2Injec17	IndustPr17	H2ExpMOD17	H2Exp17
GrnHydro17	-925.8M	-614.8M	7.9M	-454.3M	5.3M	-173.6M	-88.5M	-1.59B	-1.28B	0.000	0.000
GrnHydro22	-482.6M	-277.5M	26.5M	-127.2M	5.8M	-106.4M	-49.1M	-887.7M	-716.4M	-3.2M	124.5M
GrnHydro27	-279.0M	-155.9M	26.1M	-53.02M	4.7M	-65.9M	-27.9M	-539.9M	-466.8M	-1.9M	157.5M

Figure E1 : NPV ($AUD) across 2017, 2022 and 2027 project pathways up to 2049

A sensitivity analysis has been performed to test the financial viability across a range of future scenarios. Figure E2 shows the NPV results if large scale renewable energy generation can be installed behind the meter and a grid support revenue stream is included in the analysis.



	NH3Exp17	MAPDAP17	Crystal17	Explos17	Vehicles17	FuelCell17	EngPower17	H2Injec17	IndustPr17	H2ExpMOD17	H2Exp17
GrnHydro17	-552.3M	-327.6M	39.3M	-90.8M	8.2M	-154.0M	-68.8M	-1.16B	-853.2M	0.000	0.000
GrnHydro22	-223.8M	-114.9M	43.7M	-78.4M	57.0M	-97.9M	-40.6M	-644.9M	-474.6M	14.5M	383.3M
GrnHydro27	-45.7M	-2.9M	39.2M	-139.7M	5.9M	-57.9M	-19.9M	-314.7M	-242.2M	14.93M	390.8M

Figure E2: NPV ($AUD) across 2017, 2022 and 2027 project pathways up to 2049 - behind the meter with grid stabilisation benefit

Results for 2017

For projects implemented in 2017, two pathways are NPV positive using the base assumptions: Pathway C - manufacture of crystal fertilisers at a modular scale and Pathway E - H_2 Vehicle Station for use in a bus fleet in Adelaide.

If input parameters are adjusted it is still difficult to get other options to return a positive NPV for 2017. NPV is sensitive to the revenue of the final products, with Pathways B – MAP and DAP fertilisers, and D – Explosives, both becoming positive with 20% higher revenues. Pathway E – H2 Vehicle Station remains NPV positive until the hydrogen price drops to $7 per kg.

Note that Pathways A2 and J are not considered technically or commercially advanced enough to include in the 2017 analysis.

Results for 2022 and 2027

The financial results are similar for projects implemented in both 2022 and 2027, highlighting the same projects as favourable but with differing levels of NPV.

Pathways C – Crystal Fertilisers and E – H_2 Vehicle Station, remain NPV positive across 2022 and 2027. In addition, Pathway A2 – large scale hydrogen for export, has a positive NPV for 2022 and 2027.

Small reductions in input costs make Pathway J NPV positive. For other options, the most important variable is again the value of products, particularly hydrogen. A less than $1 reduction in the value of hydrogen reduces the NPV of Pathway A2 to zero, indicating that it is very sensitive to the hydrogen price assumptions.

Based on the analysis undertaken, Pathways A2, C and E require further detailed investigation.

Value chain

The implementation of any of the pathways described will have impacts across employment, local development, manufacturing industries and skills development.

The pathways that involve large scale expenditure are more likely to deliver on all these aspects. Of the financially attractive pathways, only Pathway A2 - large scale hydrogen for export, is of a large scale, potentially very large, which can be demonstrated as follows.

Recent news items have publicised the commitment by South Korea to 26,000 hydrogen buses. For South Australia to provide fuel for this fleet, it would require the construction of around 17 plants of similar size to Pathway A1 with an estimated capital requirement of more than $14bn. To provide the electricity to produce hydrogen, the development of approximately 8,700MW of renewable energy projects will also be necessary.

Aside from the direct, project related opportunities in the state, local engineering and manufacturing capabilities related to the automotive and oil and gas industries could potentially be leveraged to design, manufacture, manage and deliver projects from a South Australian base. These projects could be located in the Asia Pacific region or beyond.

Recommendations

Export pathways appear to offer an attractive opportunity in the future and South Australia will need to move quickly to take advantage of this developing market.

A range of demonstration scale Green Hydrogen projects should be developed that could include transport, chemicals and export uses. Keeping in mind the export opportunity, a hydrogen export supply chain demonstration could provide the knowledge, experience and capability for future, large scale Green Hydrogen export developments.

1

Context and Approach

This report is the result of a study undertaken by Advisian, supported by partners ACIL Allen Consulting (ACIL Allen) and Siemens, investigating the viability of a Green Hydrogen industry in South Australia. This was commissioned by the South Australian Department of Premier and Cabinet (DPC).

At the request of the DPC, the study took into account the following key questions:

1. What role can hydrogen play in decarbonising the SA economy, including the transport sector?
2. Can South Australia competitively produce and export Green Hydrogen?
3. Is there scope for South Australia to participate in a Green Hydrogen industry supply chain, exporting manufactured products and services?

A range of industry and government stakeholders have contributed to the study including DPC, wider state government departments, technology developers, equipment providers and project developers. These inputs have been very valuable in ensuring that a broad industry view is incorporated into the study inputs and results.

For the purposes of this study, "Green" Hydrogen was defined as hydrogen either produced from renewable energy sources or which is net carbon zero energy through carbon capture and / or emissions offsets.

The concept of Green Hydrogen is not a new one, but a specific aim of this work is to provide a robust "fact base" to enable the South Australian Government and relevant stakeholders to understand the realities of such developments. Behind this are broad objectives of support for South Australia's future energy needs, particularly the ambition to be net carbon neutral by 2050, as well as the delivery of widespread economic and social benefits to the State.

Green hydrogen could be a very significant new industry with major implications for the existing and new renewable energy industries in the State. The addition of highly controllable hydrogen electrolyser loads to the electricity network could also provide important network stability services, helping to integrate renewable generation. Further, transport and energy markets are now converging, with the predicted rise of Battery Electric Vehicles (BEVs) and potentially Fuel Cell Electric Vehicles (FCEVs) running directly or indirectly on hydrogen further impetus to explore this further.

The results of this study will feed into the Hydrogen Roadmap for South Australia. This Roadmap is being developed by the South Australian Government in conjunction with industry to act as a tool to inform policy and potential investors and developers.

In undertaking this study, Advisian and partners acknowledge the assistance of the DPC and a large number of internal and external stakeholders. A steering committee was appointed by DPC to provide support, guidance and oversight of the study's progress. The steering committee consisted of representatives from a cross section of the South Australian government agencies including the low carbon economy, energy, transport and industry portfolios'.

A consultation process was also undertaken with members of the global hydrogen community in the early stages of this study to help outline the key objectives to establish a baseline for datasets and to test the assumptions applied in the study.

The following sections provide further relevant background information, outline the specific objectives in more detail, and provide an outline of the basic study methodology and approach.

2

Background Information

South Australia has been leading Australia in the take-up of renewable energy with renewable energy supply approaching 50% of electricity generation in the state. Now, with the Green Hydrogen project, the State is considering a significant extension, developing an entirely new related industry by becoming an early entrant for production of Green Hydrogen.

This report is part of broader initiatives aiming to support cross-government efforts to continue to grow renewable energy deployment, low carbon industries and identify opportunities to leverage both private and public investment. In particular, the government seeks to understand options to maintain electricity system security with existing and future levels of renewable market penetration. It also seeks to identify opportunities to leverage South Australia's competitive advantage in renewable energy.

Other opportunities being pursued by the DPC include:

- Facilitating investment in renewable energy, energy efficiency and energy storage at both large and small scale;
- Transitioning South Australia's energy system to low carbon;
- Developing low-carbon industries for local and global markets;
- Accelerating the deployment of zero-emission vehicles; and
- Building a framework for a local carbon offsets industry.

2.1 Study objectives

The key objective of this Green Hydrogen study is an assessment of the economic opportunity for South Australia through the production of Green Hydrogen and potential subsequent uses and products. In approaching this objective, the study takes into account South Australia's comparative and competitive advantages in renewable energy combined with the current and projected technological and commercial advancements in related technologies.

Behind this key objective, three key questions have been addressed, namely:

1. What role can hydrogen play in decarbonising the South Australian economy, including the transport sector?
   - Can the Green Hydrogen concept leverage South Australia's world class renewable energy resources and high levels of renewable generation capacity?
   - Based on current and projected electrolysis technology costs, can South Australia produce Green Hydrogen at a price that would allow the state to further decarbonise its economy while remaining competitive? and,
   - In particular, can the transport sector decarbonise using hydrogen? What hydrogen potential is there for heavy industry and stationary energy to do the same?
2. Can South Australia competitively produce and export Green Hydrogen?
   - Could South Australia use its renewable energy resources, existing gas export infrastructure, proximity to markets and existing trade relationships with energy dependent and hydrogen hungry markets in Asia Pacific to unlock a viable and globally competitive export market?
   - What are the relative merits of different carriers for energy exports, for example hydrogen vs. ammonia? and,
   - What role might project advancements in electrolysis and other technologies play in the development of such markets?
3. Is there scope for South Australia to participate in a hydrogen industry supply chain, exporting manufactured products and/or services?
   - Could Adelaide's comparative advantages in manufacturing and services lead to significant job creation in Adelaide from participating in global hydrogen value chains?
   - Do such opportunities arise even if Adelaide does not make and/or use significant amounts of hydrogen?

2.2 Methodology

The Methodology used by Advisian in this study is one which has been tested and proven for a number of techno-economic assessments for governments, large and small corporations and technology developers across a range of industries and technology types.

At a high level, this methodology consisted of the following key study components:

- **Technical readiness** was assessed using an established TRL Metric developed by NASA[1 2] ;
- **Commercial readiness** was applied using a metric known as CRI developed by ARENA[3 4];
- **Future product and commodity market prices** which established the business case for the investment;
- **Financial evaluation** through the development of technology cost basis information, for example, capital, fuel, commodity and operating costs, and estimation of cost of production using metrics such as levelised cost of production and consideration of network support benefits;
- **Non-financial impacts** that may significantly influence the business case, for example, GHG and other emissions, land use, export earnings, local employment etc; and
- **Technology financial feasibility** which applied metrics such as NPV and IRR to evaluate cost effectiveness and robustness of returns under a range of future conditions.

The flow of work including the interaction with stakeholders is outlined in Figure 1. While the narrative within this report provides details around how this work was implemented, the following sections outline specific details on particularly important aspects of this work, the framing workshop and stakeholder engagement.

1

Project initiation

Weeks 1 -2

- Contract Award
- Team mobilisation
- Kick off meeting in Adelaide

2

Establish basis

Weeks 2 – 3

- Framing Workshop in Adelaide
- Define "Green Hydrogen Project" parameters
- Highlight potential infrastructure requirements in South Australia and beyond
- Consider the pathways for hydrogen based products and energy carriers and the potential for export
- Research hydrogen markets and potential applications including fuel, petrochemical applications, ammonia and fertilisers
- Review the hydrogen supply chain and how South Australia could participate in each step
- Identify competing hydrogen production technologies globally and in the South Australian context
- Perform a Technical Readiness Level and Commercial Readiness Index assessment of the "Green Hydrogen Project" and alternative technologies to estimate feasibility
- Characterise the electricity system benefits in South Australia and comment on current and potential network support markets.

3

Estimate costs and benefits

Weeks 4-6

- Develop capital cost and operating cost estimates for "Green Hydrogen Project"
- Consider the potential development of the hydrogen industry and the likely scale that will be achieved
- Establish product revenue from projections of the market value of a range of products
- Estimate from public domain and Advisian sources the cost of hydrogen production from other, feasible, alternative routes
- Determine the locations on the South Australian electricity network where support benefits are likely to be most effective and quantify the value of these benefits
- Estimate the costs to establish the supporting infrastructure in South Australia

4

Financial feasibility analysis

Weeks 7-8

- Calculate financial feasibility parameters such as Net Present Value (NPV) and Benefit Cost Ratio (BCR) for the "Green Hydrogen Project" and alternatives
- Consider the robustness of results by exploring sensitivity to key inputs
- Apply a learning rate to capital costs to investigate the future cost effectiveness of the "Green Hydrogen Project" technology
- Identify the commercial feasibility 'gap' and potential policy and investment solutions to create a viable project

5

Results and reporting

Weeks 9-14

- Results Workshop with DPC including presentation of sensitivity analysis
- Respond feedback to update analysis
- Draft of public report
- Stakeholder Engagement Workshop
- Respond to DPC feedback
- Delivery of final public report
- Executive briefing session with selected stakeholders

Figure 1 - Green hydrogen study methodology

2.2.1 Framing workshop outcomes

Advisian hosted a project framing workshop on 10 March 2017 with the DPC and South Australian Government steering committee to address the key focus areas, possible constraints, key variables, government levers and general considerations for the study.

The framing workshop identified the following:

Possible constraints

- Possible constraints for a hydrogen project in Adelaide include funding, access to water, access to land, environmental issues, and level of political support, local safety concerns, and demand for the product;
- Access to Power Purchase Agreements and renewable energy, competition for hydrogen production/electricity and transport;
- Power solutions & knowledge; and
- Accessing local capability to deliver.

Key variables

- Capital Expenditure (CAPEX) uncertainty for the applied financial assumptions and learning rates for future technology advancements – suggest a base case and then ±30%;
- Operational Expenditure (OPEX);
- Technologies involved in producing, transporting and utilising Green Hydrogen;
- Nature and scale of policy or program incentives; and
- Product value for possible co products e.g. Oxygen need to be considered.

General considerations

- Screen out non-viable production, delivery and end use options;
- Is hydrogen a viable, low carbon natural gas and liquid fuel alternative for SA Government;
- The scale should be modular; and
- Locations for consideration should be Metropolitan Adelaide, Port Lincoln, Port Pirie, Whyalla, Port Augusta and Eyre Peninsula.

2.2.2 Stakeholders and participants

During the initial stages of the project, Advisian and DPC hosted a webinar for interested stakeholders. The purpose of the webinar was to provide stakeholders with information about the study and to seek submissions to ensure the outcomes of the study are robust.

The South Australia Green Hydrogen feasibility study team prepared a stakeholder questionnaire and circulated to the stakeholders who registered interest in the webinar. The questionnaire was completed by a number of entities who had diverse interests in producing or utilising Green Hydrogen. Some stakeholders also provided information directly to Advisian through telephone calls and emails. A summary of the stakeholder engagement and inputs is included in Table 1.

Stakeholder	Commentary	Inputs provided
Mining developer	New mine requiring 550MW+ of electricity. Power planned to come from the grid but is there a better way? Grid not highly developed in the region. Requires a clean, steady power supply.	
Car manufacturer	Roll out of hydrogen vehicles predicated on the availability of 350 bar and 700 bar refuelling stations.	
Electrolyser technology developer	Developing a 1 MW and 5 MW electrolyser.	Design and pricing information for electrolysers.
Small electrolysers technology developer	Developing large electrolyser installations using other technology providers and developing their own modular technology.	Low cost modular packaged solutions.
Car manufacturer	Plans for a roll-out of fuel cell vehicles. The car manufacturer underlines that it is crucial that the hydrogen refuelling infrastructure is available in South Australia. This infrastructure must include at least two refuelling stations within drivable distance from a consumer.	
Electrolyser technology developer	This electrolyser features novel design that reduces production variability with power load fluctuations. The electrolyser system is highly automated. Currently, the responder has one unit in operation supplying fuel on-site to a client and is working on a larger one. The company's electrolyser units will be modularised to approximately a container size. Similar to other equipment suppliers, this responder also plans to supply packaged systems, including re-fuellers, hydrogen storage, and other system components. They plan to provide these for a number of applications including power grid cycle management by combining the electrolysers with fuel cells.	Has a long-running demonstration plant and has gathered a considerable amount of technical and market information that can help the project.
Ammonia cracking technology development	Working on developing a small-scale technology for cracking ammonia into hydrogen and nitrogen. The units are envisioned to be installed at car fuelling locations to crack hydrogen-carrier ammonia into hydrogen fuel. The technology involves the use of a sophisticated proprietary technology.	
Hydrogen export developer	Developing a project concept to ship ammonia worldwide to locations where it would be cracked into hydrogen and nitrogen to fuel local transportation. Currently conducting a feasibility study on a pilot unit to produce hydrogen and to produce ammonia from the hydrogen as the first two steps of the envisioned energy supply chain.	As part of the project, the company is evaluating two to three different electrolyser technologies which potentially can be scaled to possibly 50 MW in a single stack as part of a future 400 to 500 MW plant.
Local engineering company	Interested in opportunities in this developing sector	

Table 1: Stakeholder engagement and inputs

2.2.3 Green hydrogen roadmap workshop

On 26 May 2017, and close to the conclusion of the study, a Green Hydrogen roadmap workshop was held in Adelaide which was open to broad stakeholder involvement and advertised by the government. Participants registered for attendance and were sent pre-reading material with a series of questions to consider. The purpose of this workshop was to provide the draft results of the study, and then to engage in a dialogue with stakeholders in regards to a roadmap, particularly the elements of that and how the government could assist.

This roadmap workshop was attended by approximately 100 stakeholders, and the key outputs are summarised in Appendix A. This is also discussed with respect to specific government influence in Section 7.5.

2.3 ARENA Investment Plan

The Australian Renewable Energy Agency's (ARENA) investment plan[5] aims to assist in transitioning Australia renewable energy resource to a reliable and affordable source. The focus on achieving a more affordable, higher value energy resource will aim to result in creating increased value, skills and knowledge along with innovative ways to improve energy productivity. The current investment plan ranges from desktop studies to innovative, commercialisation projects such as energy storage, demand response and fuel switching.

As outlined in ARENA's investment plan, the Federal Government are interested in exploring opportunities to develop intensive, large scale export value chains in a focus area titled "Exporting Renewable Energy". This will be achieved by leveraging existing innovative technologies and renewable energy resources.

> 'ARENA will help drive innovation in Australia's renewable export industry and position the industry for long-term growth. Australia has vast renewable energy resources, good export capabilities and strong relationships with key international markets. As the global economy transitions to low emissions energy, Australia will be well positioned to export renewable energy as primary energy (for example as hydrogen or ammonia) or embodied in processed raw materials' – ARENA Investment Plan 2017[6]

The key focus areas as outlined by ARENA include:

1. **Improved cost efficiency and technical or commercial readiness of technologies with renewable energy export potential.** This objective is focused on developing and demonstrating ways to use renewable energy to process raw materials for export along with the application of renewable energy production methods for transportation of energy storage solutions.
2. **New business models to integrate renewable energy into export value chains.** This ranges from undertaking roadmap initiatives and supply chain analysis identifying opportunities for renewable energy export to small scale low cost pilot plants to improve the commercial readiness of the technology.

The South Australian Government is exploring opportunities to co-operate with ARENA on projects that could demonstrate hydrogen's potential as an enabler of renewable energy or a renewable energy export product.

2.4 Report structure

This report is structured so as to build a narrative around the Green Hydrogen proposition and in line with the flow of work according to the methodology outlined in Section 2.2. The structure can be summarised as follows in terms of the key sections;

Section 3 – Provides an introduction to the Hydrogen Market in terms of current production, volumes, uses, the basic hydrogen eco-system and technologies, before introducing the concept of Green Hydrogen, particularly the basic value proposition of such.

Section 4 – Looks at the hydrogen work being carried out in other countries, as a comparison to the state-of-the-art and particularly current policy and support mechanisms.

Section 5 – Analyses the particulars around Green Hydrogen production in the South Australian context, including a readiness assessment of what technologies, what pathways for the hydrogen generated to market would be studied in detail, and where these would be best located. The key output from this section are ten pathways and their basic metrics which are studied and compared in detail in the Financial analyses of Section 6.

Section 6 – Provides the financial analysis of each pathway which are presented in NPV and BCR terms across the three time horizons studies, including the development of key assumptions of the study such as base commodity forecasts and sensitivities. This section concludes with a discussion of these results.

Section 7 – Considers the results of Section 6 in terms of progressing pathways, and the barriers there are to realisation. This also looks at additional opportunities that arise around the Green Hydrogen concept, which could aid the development of the industry.

Section 8 – Provides a summary of findings.

3

The Hydrogen Market

3.1 Upstream - production

Global production of hydrogen is around 60 million tons each year with an annual Compound Annual Growth Rate (CAGR) of around 5%. A simple representation of the "industry" is shown in Figure 4.

Around half of worldwide hydrogen production currently comes from Steam Methane Reforming (SMR) of natural gas, nearly one-third comes from reforming hydrocarbon by-products of chemical and process industries, nearly 20% from coal gasification and only around 4% from water electrolysis – these are shown diagrammatically in Figure 2. Nearly all of the total global hydrogen is produced and consumed on-site, that is, captive generation or used in industrial processing.

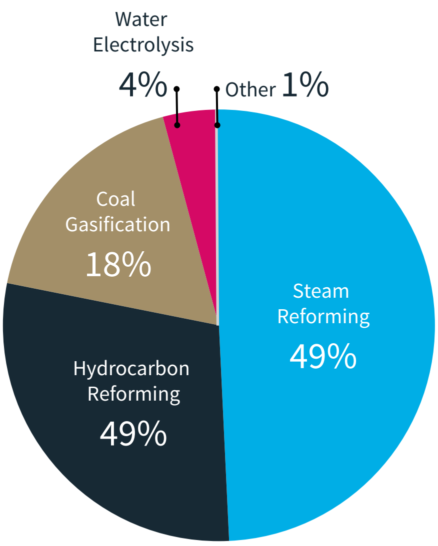


Figure 2: Sources of hydrogen production

Although there are a multitude of hydrogen production methods, some key industrial generation elements in the hydrogen value chain include the following technologies and processes:

Thermal processes

- **Steam Methane reforming** - Catalytic reforming of natural gas, particularly steam reforming of methane is one of the largest sources for industrial hydrogen and can use other feedstock such as methanol, liquefied petroleum gas (LPG), biofuels and diesel in addition to methane. The steam reacts with the feedstock in a series of reactions that produce hydrogen, carbon dioxide and carbon monoxide.
- **Coal and biomass gasification** - Gasification of coal and biomass is an industrial process for large-scale hydrogen production where a carbon source such as coal or biomass is reacted under high pressure and temperature with a hydrogen source. Coal has by far the largest share of hydrogen produced by gasification.
- **Thermochemical production** - Thermochemical splitting of water can use sustainable, non-fossil energy sources such as nuclear and solar heat under high temperatures to produce hydrogen in a closed loop. All reagents are returned within the process and recycled.
- **Photo electrochemical hydrogen production** - With continued advancements in semiconductor technology, the photo electrochemical (PEC) water splitting method for hydrogen production is an increasing focus for research and commercialisation. Specialised semiconductors are immersed in water-based electrolyte solutions and use light energy to directly split water molecules into hydrogen and oxygen.

Electrolytic processes

- **Electrolysers** - Electrolyser units use electricity to split water (H_2O) into hydrogen and oxygen through the electrolysis process which can produce very high purity hydrogen with a very small environmental footprint. It is especially relevant to intermittent renewable energy sources as certain electrolyser technologies can be ramped up/down depending on the availability of input energy.

3.1.1 Midstream - transport and storage

Transport

Four key methods exist for transporting hydrogen:

1. **Pipelines:** Require large capital investments but low operating expenses for transporting large amounts of hydrogen over long distances.
2. **Road tankers:** Liquefied hydrogen can be cost effectively delivered over relatively longer distances using road tankers, particularly where the business case does not justify large pipeline infrastructure investments. Liquid hydrogen tanker trucks can typically cover a range of around 1,000 km with capacities of 3,000 - 4,000 kg of hydrogen.
3. **Gaseous tube trailers:** More cost-effective method for delivering small amounts of hydrogen over short distances. Typically cover a range of around 350 km with capacities of up to 500 kg of hydrogen.
4. **Rail, barge, and ship:** Although not extensively used for transporting hydrogen, there is enough global experience with liquid gas transport infrastructure, such as Liquefied Natural Gas (LNG) and LPG to be relevant for hydrogen as well. Particularly rail and barge transport can offer higher weight limits and delivery capacities over gaseous tube trailers and road tankers.

High pressure storage: When large-scale hydrogen generation is coupled with intermittent renewable energy, there is a considerable scope for seasonal variation and surges in hydrogen production which must be stored. Storage solutions for hydrogen are similar to those for storing natural gas.

Table 2 provides a simple comparison of basic metrics.

	Capacity	Coverage	Loss	CAPEX	OPEX	Deployment Availability
Pipelines	High	High	Low	High	Low	Mid-Long
Road Tankers	Medium	High	High	Medium	Medium	Mid-Long
Gaseous tube trailers	Low	Low	Low	Low	High	Short term
Rail, barge, ship	High	High	Low	High	Low	Mid-Long

Table 2: Midstream transport and storage assessment

3.1.2 Downstream - consumption

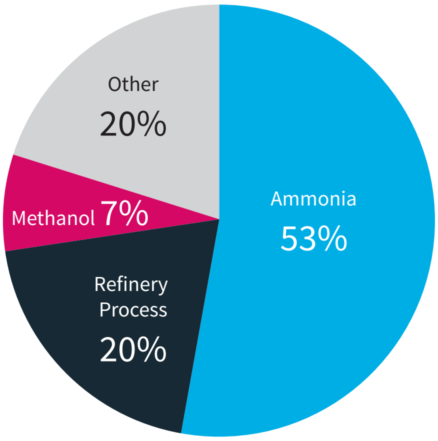


Figure 3: Hydrogen consumption share

The hydrogen market of today is primarily geared towards feeding the chemical and process industry, with hydrogen products such as ammonia and methanol constituting nearly two-thirds of the industrial demand for hydrogen today (Figure 3). Just above 50% of global hydrogen consumption goes towards ammonia production for fertilisers, nearly 7% for methanol, 20% goes into refinery industry and the remaining for chemical, metallurgy, glass, pharmaceuticals and food industries.

1. **Ammonia** is the main feedstock for fertilisers and is typically generated in captive plants onsite by catalytic reactions requiring high volumes of hydrogen recovered from natural gas. Growth in ammonia production around the world is quite stable and no shift in market is anticipated in the future.
2. **Methanol** as an industrial chemical has wide applications in the chemical and process industry. It can be generated in two steps: steam reforming and methanol synthesis. First a catalytic endothermic conversion of methane and steam is used to create syngas which is then converted into methanol in an exothermic reaction.
3. **Refinery processes** Hydrogen is one of the most crucial ingredients in the refining processes for crude hydrocarbons into refined fuels, as well as for removing contaminants such as sulphur.
4. **Other industries** Hydrogen is used in pharmaceuticals, industrial gas purification, metallurgical industry for heat treating steel and welding. In the food industry for hydrogenation of unsaturated fatty acids in animal and vegetable oils to create margarine. In electronics hydrogen as a carrier for removal of trace elements such as arsine. Power plants use hydrogen for cooling of large generators and the aerospace industry uses liquid hydrogen as rocket fuel.

3.2 Eco-system interactions

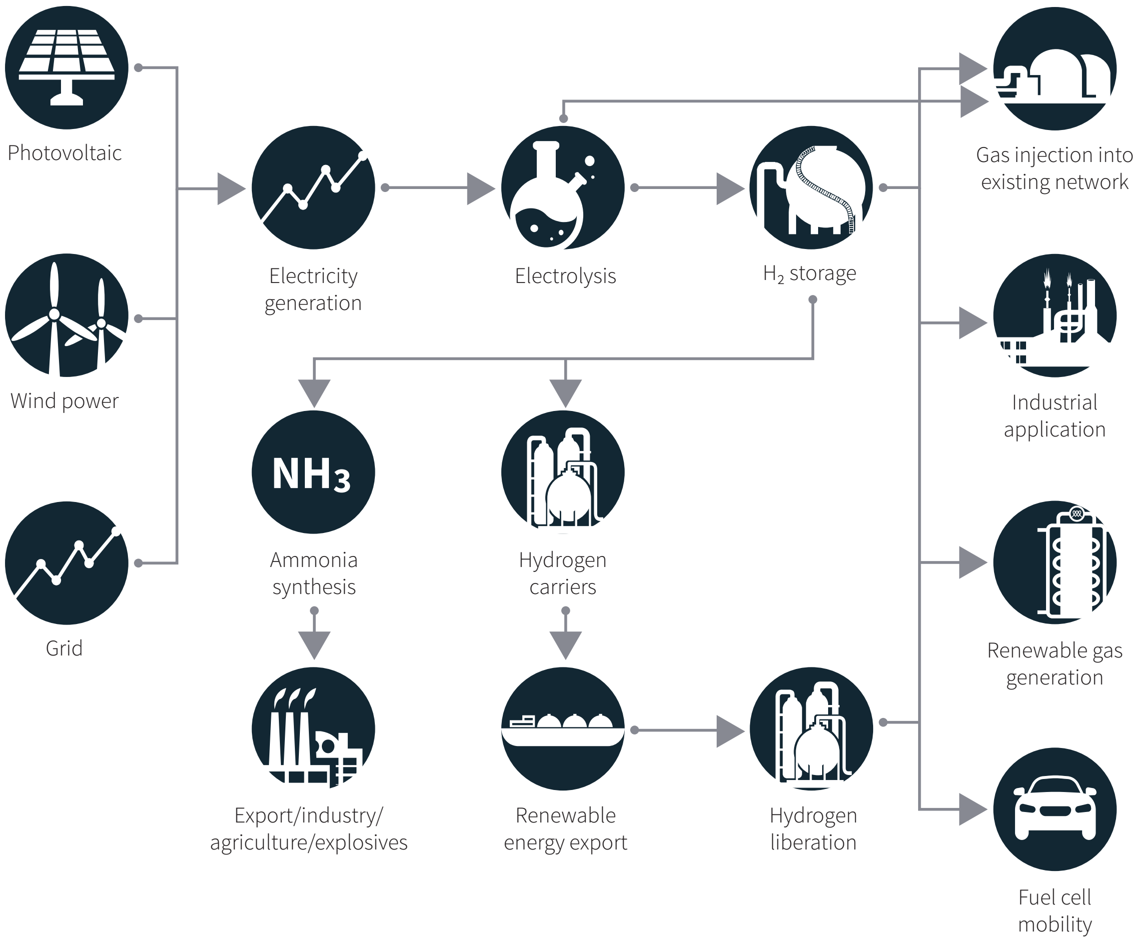


Figure 4: Hydrogen eco-system

Figure 4 shows various elements in the gas and electricity energy generation, transmission and consumption value-chain for a broad Hydrogen eco-system. Electricity provides the input to the hydrogen production process in this diagram, interconnection points between the two networks are through suppliers of natural gas, battery storage systems, electrolysers and fuel cells.

The electricity generation chain starts from the left with the generation which includes conventional power plants, nuclear power, natural gas turbines, solar PV arrays, wind farms or hybrids of these and potentially other sources. Generated electricity is then fed to different electricity loads spanning from commercial, industrial and residential. Surplus power from generation sources at the generation end, as well as from distributed generation sources - smaller gas turbines, diesel gensets, renewable energy sources etc.

Electrolysers can be used to manufacture hydrogen from electricity and water, although hydrogen can also be produced from natural gas, coal or other feedstocks.

Hydrogen production and conversion processes can provide considerable added value potentially for grid support, through such things as ancillary services and controllable load. Connecting the electricity and hydrogen value chains, generated hydrogen can also be directly converted into electricity through fuel cells or hydrogen thermal plants and fed back to the grid, or to an appropriately sized battery storage system.

It is important to point out that this is merely an illustrative and non-exhaustive example of a potential eco-system. In a real world situation there will be much more complexity and interaction between elements than the ones indicated here, while not all elements will necessarily be present as shown in Figure 4.

However, the example eco-system indicates that in the long-term, a fully mature Green Hydrogen eco-system has a very high potential to link different energy sectors, value chains and consumption categories in order to increase overall operational efficiencies, add value across the energy chain and reduce the overall carbon footprint of an inter-connected energy economy.

3.3 The Green Hydrogen market

In the eco-system schematic discussed in Section 3.2, the boxes on the right side indicate different green economy usages of hydrogen. These green usage categories of hydrogen are enabled through a multitude of new carbon-neutral technologies and processes.

Of primary interest for the Green Hydrogen economy are usage categories such as mobility where bus fleets, personal cars, trains etc could be powered by hydrogen fuel cells. Similarly the Power to Gas, Gas to Power, and the combined Power to Power energy chains create considerable flexibility and control possibilities. This is achieved by integrating both electricity and hydrogen storage with reversible conversion of energy between the two energy carriers. Hydrogen utilisation directly as a fuel for internal combustion engines or thermal power plants is another area of active research and commercialisation.

Advancements in increasing conversion efficiencies, development of new technologies and the social pressure for green energy solutions is pushing for an ever-greater use of hydrogen as an energy carrier. This could enable a shift away from fossil sources of energy to renewable sources.

3.3.1 Key technology and infrastructure requirements

Some key technology requirements and infrastructure investments needed for a Green Hydrogen economy include:

- Considerable renewable energy availability and generation;
- Large-scale central electrolysers for bulk production;
- Medium-scale distributed containerised, or small-scale residential electrolysers;
- Water supply to the production sites;
- Hydrogen turbines, engines or fuel cells;
- Hydrogen transport infrastructure - pipelines, terminals, compression stations;
- Fuel cell electric vehicles (FCEVs); and
- Refuelling station network for FCEVs.

3.3.2 Selected value chain utilisation options

The Green Hydrogen economy of the future is enabled by the following key utilisation options:

1. **Electrolysis for grid support.**
   This utilisation option envisions a collection of electrolyser units that are aggregated together as curtailable electricity loads to provide ancillary services to network operators through frequency regulation, voltage control, and ramp up/down services, as well as potentially other services. The general control and monitoring mechanisms for demand side management loads are already in place in most mature markets which assists with adoption of such electrolyser units. The resulting hydrogen can be delivered to end-users for industrial usage, mobility and methanation, amongst other uses.

2. **Network integration of renewable energy**
   In a high penetration renewable energy scenario, intermittent and fluctuating renewable energy can either be directly delivered to the electricity network or diverted to battery storage systems to 'buffer' the variability before supplying energy back to the transmission and distribution networks.

   Complementary to battery storage systems, hydrogen can be used as a bulk energy storage where surplus renewable energy can be converted into hydrogen via electrolysis and stored for later conversion back to electricity. Once surplus energy from large-scale or smaller distributed renewable energy systems is converted to hydrogen, it can be utilised directly or electricity reinjected into the network via fuel cell, engine or turbine generators.

3. **Mobility**
   Fuel cell electric vehicles (FCEV) are an active area of development and commercialisation in the automotive sector. Using high purity compressed hydrogen as the fuel source in a fuel cell, FCEVs generate electrical energy to create mobility with zero carbon exhaust emissions and water as the only by-product. Without internal combustion engines, the noise is extremely low compared to a conventional vehicle engine while refuelling is comparable, taking only 3-5 minutes. The technology has a high potential for widespread adoption in bus fleets, trucks, agricultural equipment, and personal vehicles. Adoption is currently limited by the low penetration of hydrogen refuelling station networks around the world, high vehicle prices and expensive refuelling. Compared to the current generation of light passenger Battery Electric Vehicles (BEVs), FCEVs offer shorter refuelling times, equal or increased driving range and reduced weight. Current BEVs have the advantage on price, fuel cost, variety of models and availability of recharging infrastructure. Multiple international and supranational organisations are however active in promoting and incentivising the refuelling station network to promote heavy and light duty FCEVs, which are predicted to see wider adoption in the medium to long-term.

   However, in the near-term, hydrogen can be used with relative ease as a direct fuel source for such things as backup power systems or hydrogen-powered forklifts, hydrogen combustion engines and for heavy duty FCEVs. Hydrogen powered vehicles, such as buses and waste collection vehicles, could considerably improve city air quality and noise levels.

4. **Renewable energy export**
   Although a number of countries throughout the world have an abundance of renewable energy available, many others do not have the wind, solar, hydro, biomass and, perhaps as technology develops, wave resources to provide for their own energy needs. For some nations, interconnection of electricity and natural gas pipelines provide opportunities to import renewable energy in the future. However, for other countries, their lack of connections to sources of renewable energy means that their energy will have to be imported by ship, in a similar way to conventional energy sources such as coal, uranium, oil and LNG.

   Biofuels such as biodiesel and bioethanol are one way to import renewable energy sourced from biomass. However, international transport of renewable electricity will require conversion of the electrical energy to an energy carrier, such as hydrogen, to make it possible to transport by ship. Currently there are a range of hydrogen carriers under development, including ammonia, toluene, cryogenic liquefied hydrogen and hydrides. A further discussion on energy carriers is included in Section 4.4.

5. **Natural gas replacement**
   With minor modifications to the network, hydrogen can be blended at low concentrations, 2% to 8%, in the existing natural gas pipeline infrastructure, in order to supply end-use gas consumers. The energy value of hydrogen effectively lowers the GHG emissions per unit of energy supplied; when hydrogen is combusted no CO_2 is released. With updated gas networks, up to 100% hydrogen could be supplied to local and export customers, although modifications to consuming equipment would also be required. In future, it is possible that Green Hydrogen costs could lower to the point where there is the opportunity to replace natural gas distribution and export with hydrogen.

6. **Industry and chemicals feedstock**
   Hydrogen is widely used in industries such as crude oil refining, food processing and glass manufacturing. It is also a critical feedstock for the chemicals industry, forming the basis for products such as ammonia and methanol. A Green Hydrogen input to these industries could create new, low carbon products. In particular, there is potential for Green Fertilisers manufactured from Green Hydrogen via ammonia production.

7. **Hydrogen to power conversion**
   The Power to Gas to Power chain combines the Power to Gas with Gas to Power process to reconvert hydrogen to electricity. Although, this utilisation option offers high flexibility, the low round trip efficiencies involved mean reconversion to grid electricity faces many challenges. However, using stationary fuel cells or high efficiency hydrogen oxygen turbines could improve this situation. Reconversion of hydrogen to electricity makes most sense in areas where large seasonal variation results in large amounts of surplus renewable energy which can be stored as hydrogen and then later reconverted when needed.

8. **Methanation for renewable gas synthesis**
   Hydrogen from captive generation plants or from renewable energy sources can be combined with CO_2 through the Sabatier reaction to create synthetic methane, water and heat. Generation of methane also has the considerable advantage of the natural gas storage and distribution infrastructure already being in place in many parts of the world. Although not fully commercialised yet, this process can serve as the bridge to a Green Hydrogen economy by consuming excess CO_2 generated from other industrial processes. Carbon neutral methane could potentially be generated if the CO2 source is biological, such as aerobic or anaerobic digestion.

   As the energy systems of today are heavily fossil fuel dependent, the energy chains of electricity and hydrogen are not yet fully integrated. Increasing commercialisation and technical development of hydrogen could lead to it becoming more than a primarily industrial ingredient, and into an energy vector in its own right. This has intensified active research into all areas of the Green Hydrogen value chain. In a future integrated energy system, hydrogen could play a key role by interconnecting the different layers of the energy systems at different points enabled by increases in deployment of controllable and flexible renewable energy sources, fuel cells and electrolysers.

3.4 Benefits

The benefits of a Green Hydrogen economy can be grouped under three broad headings:

1. **Decarbonising South Australia's economy**
   South Australia demonstrates great solar and wind resources, often in the same location. The state is approaching 50% Renewable Energy generated which has already led to the decarbonisation of the state's economy. Harnessing this natural abundance of green energy towards cost-efficient modern electrolyser solutions can generate H_2 at a significantly lower cost than was possible earlier. Green hydrogen from abundant renewable energy will significantly help further decarbonise South Australia's economy including its transport, energy and industrial sector emissions.

2. **Export potential**
   Manufacturing ammonia for export does not add considerable value in comparison to Hydrogen which can be processed into multiple end-products near consumption sites as needed. Exporting hydrogen products instead of hydrogen therefore limits the possible range of end-uses of hydrogen for the importing economy. Export mechanisms can include physical infrastructure such as pipelines, ports and terminals but for South Australia, this typically means compression stations, hydrogen carrier production facilities and ports for export through existing trade partnerships and similar supply contracts to LNG export. Key markets, notably Korea and Japan are demanding hydrogen, therefore creating an export opportunity for regions that can produce Green Hydrogen at a globally competitive price.

3. **Supply chain integration, sector-coupling**
   As the Green Hydrogen economy ramps up, existing companies will be attracted to the South Australian market. As new businesses and academia collaborate, a start-up culture could take root which could attract high talent and investment from around the world. With an increased number of new and innovative businesses, an expanded tax base and increased job creation is to be expected which would improve the local revenue generation capacity of the region. Overall, concentration of Green Hydrogen pioneers in a region will greatly contribute towards economic development and prosperity.

   As multiple layers of different energy networks are interconnected, sector-coupling value chain optimisations will become possible. On the utility side, peak capacity expansion to accommodate renewable energy sources could be avoided if in-situ hydrogen generation is integrated as a load with renewable generation. As the eco-system develops, outputs of one industry becomes the feedstock of another leading to increased process efficiencies, reduction of waste and unlocking of new value streams. With these developments, new market segments such as grid ancillary services, and even entirely new markets will increasingly come into play. Particularly export of hydrogen to energy-poor Asia Pacific economies.

   Grid support services are already becoming a potential market for hydrogen electrolysers in high renewable energy markets such as South Australia.

4

Green Hydrogen Technology Assessment for South Australia

4.1 Approach

This section outlines the review of Green Hydrogen technology which has been assessed using a methodology that starts with a broad range of solutions, which are then narrowed to a few that are technically and commercially feasible and are likely to have information available. Inputs are then gathered and analysed for each option considering a range of sensitivities to key variables.

The purpose of this was to identify technology options that had the highest likelihood of commerciality for South Australia, which meant consideration of a range of issues which impact both cost and revenues.

4.1.1 Techno-economic assessment

To examine the impact of technology on commercial viability, plausible Green Hydrogen production pathways have been examined and are described in subsections of this chapter. Each of these pathways takes a feedstock and produces an end product that produces revenue, often via an intermediate processing step or steps.

To achieve the transformation from feedstock to final product, costs will be incurred for capital investment, feedstock and operating costs.

Revenues will be received for products, co-products and services provided.

To explore the likely viability of pathways in the future, the analysis has also been projected forward by five years and ten years. This has been achieved by applying learning rates to capital costs, key equipment efficiencies and degradation rates to allow for improved technologies and lower costs.

Each pathway was developed into an option in Advisian's analysis software, DELTA™, to estimate the NPV and BCR over a 20 year lifetime. DELTA™ is a sophisticated options analysis tool that allows the exploration of sensitivities to future conditions through the adjustment of key variables within plausible ranges. This approach provides a check to the robustness of the NPV and BCR of each option.

Further details of the financial assessment are provided in Section 5.

4.1.2 Sources of inputs

The Advisian team has drawn on a range of sources to develop the pathways and populate our techno-economic models. Table 3 shows the technologies considered and the sources of data used.

4.2 Technologies available

A broad range of technologies were considered for inclusion in the study. These covered Green Hydrogen production, intermediate and final processes to create final end products. Table 3 shows the list of technologies considered.

Study No.	Technology	Description	Sources	Comments
1	Hydrogen production - water electrolyser	Polymer Electrolyte Membrane (PEM) or Alkaline Electrolysers.	Siemens data, stakeholder inputs, public domain data, Advisian internal information.	Siemens have provided direct inputs to the project while other stakeholders have submitted written inputs.
2	Hydrogen production – natural gas SMR with CCS	Conventional Steam Methane Reforming (SMR) process as used in many industries with the addition of Carbon Capture and Storage (CCS) to remove CO_2 emissions.	Advisian internal information, public domain data.	Appropriate CO_2 storage sites were considered limited in coastal areas of South Australia based on publicly available information.
3	Hydrogen production – coal gasification with CCS	Production of synthesis gas from coal, shift reaction to enrich the H_2 content, capture and storage of CO_2.	Advisian internal information, public domain data.	Technical viability of coal gasification was based on information relating to Chinese experience. Availability of South Australian storage sites was considered based on public information.
4	Hydrogen production – biomethane SMR.	Substitution of biomethane in the SMR process. CCS is not required to produce Green Hydrogen.	Advisian internal information, public domain data.	Viability of biomethane production and use was based on Advisian internal information.
5	Cryogenic hydrogen liquefaction	Cooling of gaseous hydrogen to extremely low temperature (-253˚C).	Advisian internal information, public domain data.	
6	Ammonia production – Haber process	Combining hydrogen and nitrogen from the air to form ammonia. If used as a hydrogen carrier, ammonia cracking is required to release the stored hydrogen.	Advisian internal information, public domain data.	Ammonia production is a well understood process, mainly at larger scales.
7	Ammonia cracking – hydrogen production	Dissociation of ammonia and membrane separation of fuel cell quality hydrogen.	CSIRO Advisian internal information.	Novel process with estimates based on discussions with CSIRO and Advisian knowledge of chemical processes.

Table 3: Technologies considered

Study No.	Technology	Description	Sources	Comments
8	Compression of gaseous hydrogen	Compression to reduce volume for storage or transport. Pressures up to 70 MPa are used.	Advisian internal information, public domain data.	Hydrogen compression equipment is an established technology.
9	Methane / methanol production – Sabatier process, Methanol synthesis	Combining a carbon compound, such as CO_2, with hydrogen to form methane. Methanol can also be produced from a mixture of carbon compounds and hydrogen.	Advisian internal information, public domain data.	Sabatier and methanol synthesis processes are established technologies.
10	Methylcyclohexane (MCH) production - toluene hydrogenation	Toluene (C_6H_5-CH_3) can be hydrogenated to form Methylcyclohexane (C_6H_{11}-CH_3). The hydrogen can be released at the destination through dehydrogenation to reform toluene.	Advisian internal information, public domain data.	Chiyoda has developed a process and catalyst for the dehydrogenation of MCH.
11	Metal hydrides – hydrogen storage	Hydrogen storage in the form of chemicals, to be released by dehydrogenation at the destination.	Public domain data.	Subject of considerable research.
12	Power generation – hydrogen fuel cell	Includes Polymer Electrolyte Membrane (PEM) and Solid Oxide fuel cells (SOFC).	Advisian internal information, public domain data.	Fuel cells are established technologies with various applications and advantages.
13	Power generation – hydrogen engine or turbine	Pure and high % H_2 mix in gas engines, moderate H_2 mix in turbines.	Advisian internal information, Siemens, public domain data.	Derating required for combustion generation c.f. natural gas.
14	Nitrogen based products – fertilisers, urea, explosives	Conversion of ammonia to final products for sale in agricultural, chemicals and mining industries.	Advisian internal information, public domain data.	Established processes to convert ammonia to final products.
15	Hydrogen for transport	Use of gaseous compressed hydrogen, primarily for fleets such as buses.	Advisian internal information, Siemens, public domain data, stakeholder inputs.	Many pilot programmes in place around the world to obtain inputs.
16	Hydrogen blending into natural gas network	Decarbonise the existing natural gas network by blending Green Hydrogen.	Advisian internal information, Siemens, public domain data, stakeholder inputs.	Limits on H_2 content in natural gas transmission and distribution systems and end user equipment.
17	Hydrogen utilisation in industry	Many industries including food processing, refineries, glass manufacturing and metals utilise hydrogen as an input.	Advisian internal information, public domain data.	Competing with on-site SMR for large users and bulk delivery for smaller customers.

4.3 Readiness assessment

To select technologies that were appropriately developed to study, a review was undertaken to assess the readiness of each technology. This review considered technical and commercial readiness, as described in the following sections. The results of the readiness assessment are shown in Figure 5.

The intention of the assessment is to select those technologies with high TRL and CRI for assessment. The aim was to ensure that TRL9 and CRI2 was achieved for each technology.

To allow a hydrogen carrier to be incorporated, technology 7 hydrogen production from ammonia cracking was included for 2022 and 2027.

Methane/methanol production was not included as a suitable source of pure CO2 could not be identified on the South Australian coast where a Green Hydrogen project is likely to be located.

4.3.1 Technology readiness level

The Technology Readiness Level (TRL) methodology was developed by NASA in the 1970s and since then it has been used in a wide range of sectors, including the energy sector. The index is used for tracking progress of technologies, from applied research (TRL1) to successful system operation in its operating environment (TRL9).

Figure 5 shows the TRL scale alongside the CRI scale.

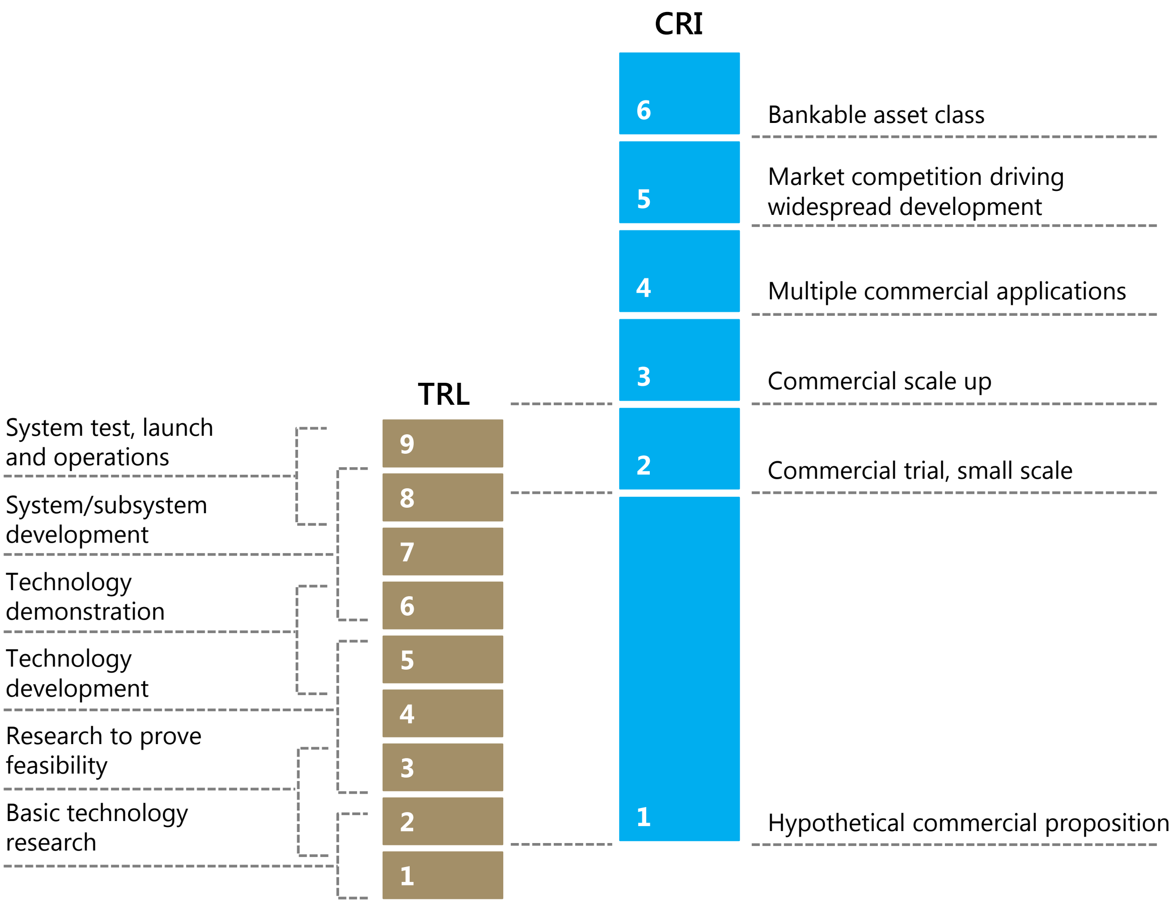


Figure 5: TRL Scale Vs CRI Scale. Commonwealth of Australia (Australian Renewable Energy Agency) 2014

4.3.2 Commercial readiness index

Similarly, the Commercial Readiness Index (CRI) rates technologies on their maturity in relation to being commercial propositions. The CRI scale starts at the level of a hypothetical proposition (CRI1) through to a bankable asset class (CRI6).

4.3.3 Readiness assessment results

Through the readiness assessment, all technologies were rated according to technology and commercial maturity. The results of the assessment of each technology are shown in Table 4.

Study No	Case description	Stage	TRL	CRI
Technologies				
1	Hydrogen by water electrolysis	Production	9	4
2	Hydrogen by natural gas SMR with CCS	Production	5	1
3	Hydrogen by coal gasification with CCS	Production	5	1
4	Hydrogen by biomethane SMR	Production	4	1
5	Cryogenic liquefaction of hydrogen	Carrier	8	2
6	Ammonia production from hydrogen	Carrier	9	4
7	Hydrogen production from ammonia cracking	Production	5	1
8	Compressed gaseous hydrogen	Carrier	9	2
9	Methane / methanol production from hydrogen	Carrier	9	2
10	Toluene as carrier	Carrier	8	1
11	Metal hydrides	Carrier	8	2
12	Power generation fuel cell	End use	9	4
13	Power generation combustion pure or H_2 mix	End Use	9	2
14	Nitrogen based products, fertilisers, explosives, urea, refrigerants	End Use	9	4
15	Transport - heavy vehicles primarily	End use	9	2
16	Green gas - blending H_2 into existing natural gas network	End use	9	2
17	Industrial utilisation of hydrogen/oxygen e.g steel, refineries, glass	End use	9	4

Table 4: TRL and CRI Results

4.4 Electrolyser technologies

There are a variety of electrolyser solutions available with differing levels of maturity, efficiency and cost-points with alkaline water electrolysis being the longest-established, mature and relatively low cost solution. Relatively new market entrants with lower operating costs include Polymer Electrolyte Membrane Electrolysis (PEM), and Solid Oxide Fuel Cell electrolysers.

With inputs from a range of industry stakeholders, this assessment does not assume a particular electrolyser technology, rather uses representative values for the cost and efficiency of Green Hydrogen production from the electrolyser process.

4.5 Hydrogen carriers

As previously mentioned, a number of carriers are under development to allow hydrogen to be exported in large quantities by shipping or rail. Four of the key technologies are described in this section but it is likely that others could emerge in the future.

4.5.1 Ammonia

Ammonia is synthesised from hydrogen and nitrogen extracted from the air in the Haber process. The production of ammonia via the Haber process is an exothermic reaction and is self sufficient for heat and electricity. Other processes for ammonia production are also under development.

For transport purposes, Ammonia has similar properties to Liquid Petroleum Gas (LPG) and can be transported using the same liquid tankers. It is a liquid at -33˚C at atmospheric pressure. Ammonia has a hydrogen density of more than 1000 times that of gaseous hydrogen[7].

Once ammonia is received in the export market, it can be cracked to liberate the hydrogen for use. A recent development in ammonia cracking technology developed by CSIRO in Australia offers the promise of fuel cell quality hydrogen production from the cracking[8] process. Liberation of hydrogen from ammonia is an endothermic process; approximately 20% of the hydrogen is used to drive the cracking process.

This study has adopted ammonia as the hydrogen carrier for export based on the availability of data on the Haber process and inputs from CSIRO on the ammonia cracking technology. There has been no judgement as to which technology or technologies will be preferred in the future and other carriers are just as likely to provide successful forms of hydrogen transport.

4.5.2 Cryogenic liquid hydrogen

Gaseous hydrogen can be cooled and compressed into liquid form at extremely low temperatures, approximately -250˚C[9]. Kawasaki Heavy Industries (KHI) is currently working on projects to source hydrogen from coal with CCS or renewable sources to transport to Japan in the form of liquid hydrogen. A unique design tanker ship is being developed for this purpose. Liquid hydrogen is around 800 times denser than gaseous hydrogen. Up to 30% of the energy contained in the hydrogen is consumed in the liquefaction process.

A key advantage of liquid hydrogen is that utilisation of the hydrogen only requires regasification of the liquid.

4.5.3 Toluene

Hydrogen can be stored in the toluene molecule (C_7H_8) through hydrogenation[10] to form methyl cyclohexane (C_7H_{14}). At the destination, hydrogen can be release by dehydrogenation and the toluene returned to the source to be hydrogenated again. Chiyoda Corporation of Japan has been working on toluene as a carrier for a number of years and has a demonstration facility in Japan.

A great advantage of toluene as a carrier is that it can be transported in vessels designed to carry other liquid fuels such as gasoline and diesel.

4.5.4 Metal hydrides

Hydrogen can be stored in the form of metal hydrides as a solid metal[11] powder. This technique is currently available at small scale and demonstration purposes and offers high hydrogen density approaching that of liquid hydrogen. However, the total system has a low hydrogen weight percentage, being less than 2%.

Further development of these technologies may yield improvements but it is yet to be proven that hydrides could be scaled to provide bulk export of hydrogen.

4.6 Nominated pathways for further analysis

Each of the technologies assessed for readiness in the previous section represent a single processing step rather than a route from a feedstock through to a final product. To evaluate the costs and benefits of a potential investment in Green Hydrogen in South Australia, the technologies need to be combined into pathways to develop plausible feedstock to final product routes.

In addition, technology development will progress over time, so new plausible pathways are likely to emerge over the period of the assessment. To make allowance for such developments, the pathways for 2022 and 2027 assessments have included the use of a hydrogen carrier to permit export of hydrogen to the Asia Pacific region.

It should be noted that the capacity factor for electrolysers has been selected as 80%. This selection is based on the current price duration curve in South Australia and has not been optimised to trade off capital and electricity costs. The assumed capacity factor also allows flexibility to connect directly to a high capacity renewable generator.

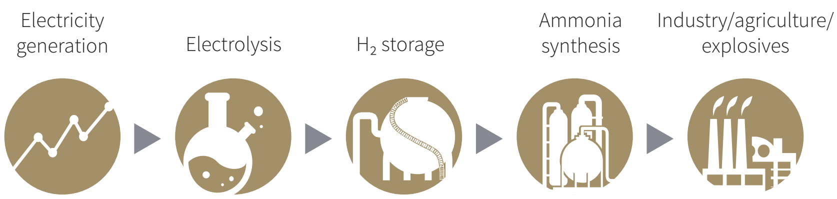
4.6.1 Pathway descriptions

2017 pathways

A1 Large scale ammonia production for export

Hydrogen is produced from water and renewable electricity utilising electrolysers of 283 MW capacity. This MW capacity was chosen to reflect current operating Ammonia plants. Hydrogen is stored in gaseous form to allow a buffer of one day of full ammonia production.

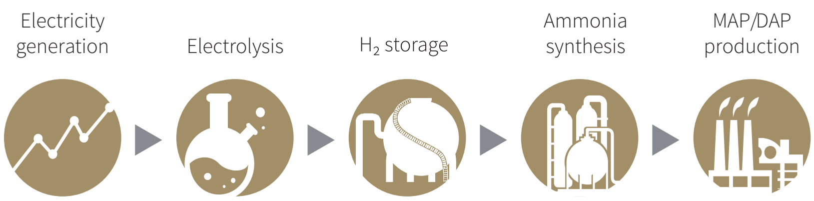
The hydrogen produced is then combined with nitrogen from the air in the Haber process with a 90% utilisation factor to produce 610 tonnes per day (tpd) of liquid ammonia. Ammonia is stored and loaded on bulk carriers for shipping to export markets.



B Large scale ammonia production to produce final MAP/DAP fertilisers

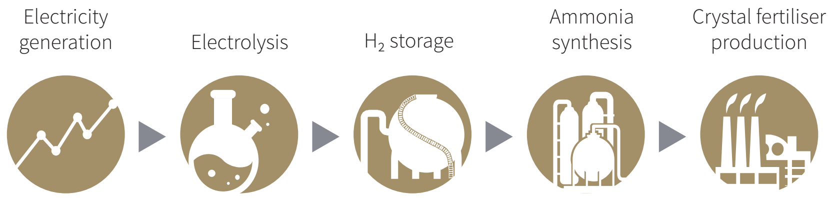
As for pathway A1, hydrogen is produced via electrolysers, 178 MW capacity and 80% capacity factor, and ammonia is produced at a rate of 384 tpd. In this case the ammonia is further processed by combining with phosphoric acid to form 1600 tpd of granular Mono-Ammonium Phosphate (MAP) and Di-Ammonium Phosphate (DAP) fertilisers.

This pathway has been sized based on what was considered a reasonable scale for a fertiliser production plant located in South Australia.



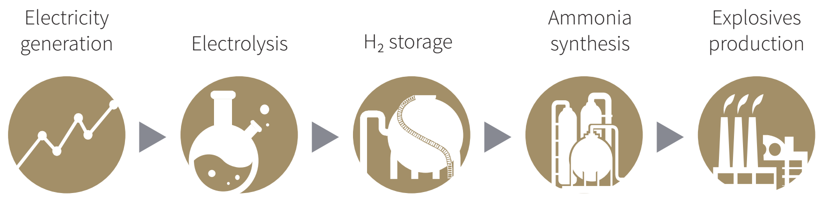
C Modular scale ammonia production to produce final crystal fertilisers

Hydrogen from 18 MW of electrolysers is used to produce ammonia at a modular scale of approximately 39 tpd. That ammonia is then further processed by combining with phosphoric acid and adding coatings to produce 150 tpd of crystal, soluble fertilisers. This plant size has been selected based on the sizing of an available modular ammonia plant.



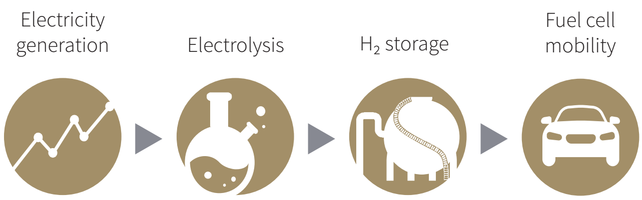
D Large scale ammonia production to produce final ammonium nitrate explosives for export

Hydrogen is produced in 229 MW of electrolysers to produce 493 tpd of ammonia. That ammonia is further processed by reaction with nitric acid to form 1060 tpd of ammonium nitrate explosive. This pathway has been sized based on a currently available explosives plant size.



E Use of gaseous hydrogen for a vehicle fleet in South Australia

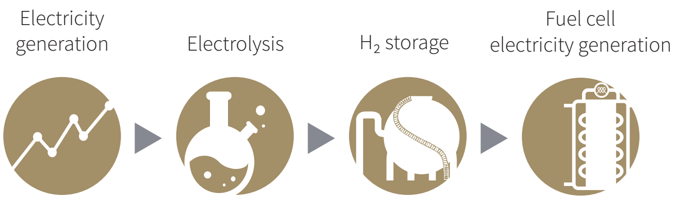
1.4 MW of electrolysers is used to produce 0.5 tpd of gaseous hydrogen which is compressed to 35-70 MPa for storage. The high pressure hydrogen is then used to supply fuel to around 10 buses in South Australia. This pathway represents a single unit suitable for a hydrogen bus demonstration. Multiple units could be added as demand for hydrogen transport increases.



F Storage and use of gaseous hydrogen in a fuel cell to generate electricity during high price periods

10 MW of electrolysers are used to produce gaseous hydrogen, which is compressed and stored at high pressure. Approximately 3 tpd of hydrogen is produced at a plant capacity factor of 80%, assuming operation during low electricity price periods. When prices are high, a 10 MW fuel cell converts the hydrogen back into electricity and water, generating 17,500 MWh per year.

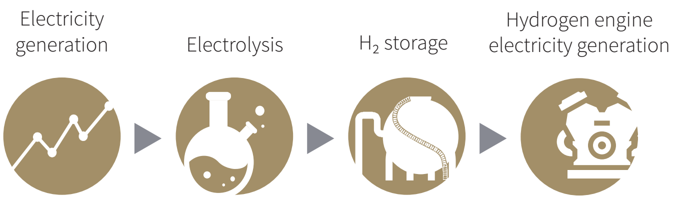
This pathway has been sized assuming the use of a single, 10MW electrolyser and a 10MW fuel cell. No beneficial use of the waste heat from the fuel cell has been assumed. Multiple units could be developed with various ratios of electrolyser to fuel cell capacities to match the expecting pricing profile.



G Storage and use of gaseous hydrogen in a hydrogen engine to generate electricity during high price periods

This pathway is the same as pathway F, except the electricity is generated by a hydrogen fuelled reciprocating gas engine. It is assumed that the gas engine has similar conversion efficiency to the fuel cell, resulting in around 17,500 MWh per year of electricity generation.

As for the fuel cell pathway, a 10 MW electrolyser has been assumed with no heat recovery from the engine.

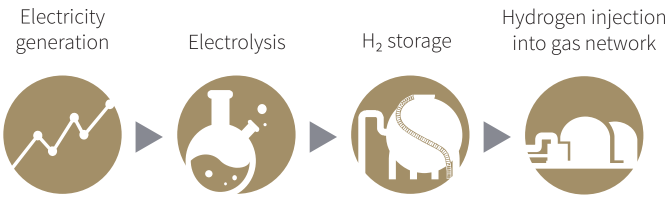


H ‘Hydrogen Blending with Natural Gas

99 tpd of Hydrogen Blending with Natural Gas is produced in 283 MW of electrolysers operating at an 80% capacity factor and compressed and stored. Hydrogen is then blended into the existing natural gas network, providing the equivalent of 11,227 GJ of energy per day.

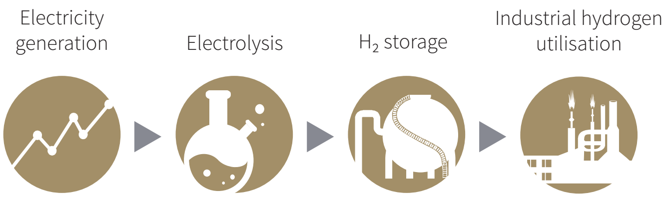
This pathway has been sized based on using the same electrolyser capacity as the large scale ammonia plant. In reality this pathway could be scaled to suit any quantity of hydrogen blending required.

The costs of conversion of natural gas networks and their end use equipment to operate on hydrogen have not been included in this pathway. These consumers could include domestic, commercial, industrial and power generation assets. Upgraded natural gas networks could also be used for the transmission of hydrogen to facilities for export or vehicle refueling.



I Storage and use of gaseous hydrogen in industrial processes

As for pathway H, 99 tpd of hydrogen is produced, compressed and stored for utilisation in industrial processes such as hydrocarbons refining, food manufacturing and glass making.



2022 and 2027 pathways

The pathways for 2022 and 2027 are the same as for 2017 but with the following changes:

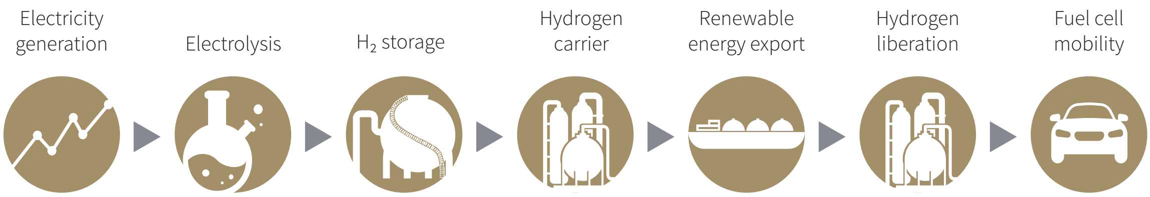
- Updated electrolyser efficiency and capital learning rates applied
- Pathway A2 has been added
- Pathway J has been added

A2 Large scale hydrogen for export

Hydrogen is produced from water and renewable electricity utilising electrolysers of 283 MW capacity operating at 80% capacity factor to allow flexibility to purchase lower priced electricity or connect directly to a high capacity renewable generator. This MW capacity was chosen to reflect current operating Ammonia plants. Hydrogen is stored in gaseous form to allow a buffer of one day of full ammonia production.

The hydrogen produced is then combined with nitrogen from the air in the Haber process with a 90% utilisation factor to produce 610 tonnes per day (tpd) of liquid ammonia. Ammonia is stored and loaded on bulk carriers for shipping to export markets.

Once the ammonia arrives at the destination, it is cracked in modular scale plants to liberate 80% of the hydrogen with the balance being used to provide heat to dissociate the ammonia into hydrogen and nitrogen. The hydrogen product is compressed and dispensed for use in public buses and light vehicles with each cracking, compression and dispensing facility sized to supply around 500 kg per day of hydrogen, enough fuel for around 10 buses.



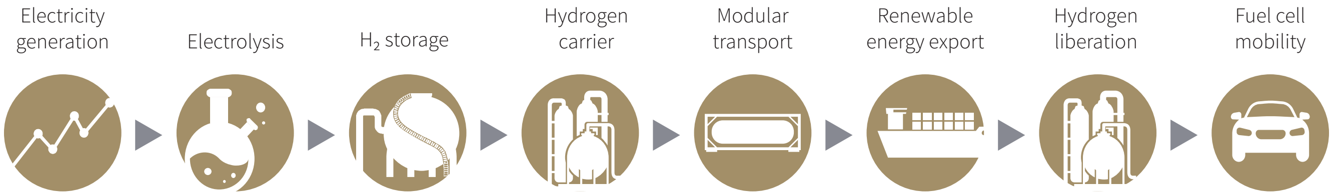
J Modular scale hydrogen for export

Hydrogen from 18 MW of electrolysers is used to produce ammonia using the Haber process at a modular scale of approximately 39 tpd. This capacity has been selected based on the smallest, practical ammonia production unit currently available.

The ammonia is stored and transported to export markets in isotainers via ship. On arrival at the point of use, the same cracking, compression and dispensing processes are undertaken as pathway A2 to produce hydrogen for vehicle use.

This pathway must be located in the Adelaide area to allow access to the container port.

Tables 5–7 show the pathways included in the financial assessments for implantation years of 2017, 2022 and 2027.



Path no	Primary feedstock	Primary process	Capacity			Intermediate product 1
	Name	Name	Utilisation factor	MW	Energy consumption kWh/kg	Name
A	Electricity	Hydrogen by water electrolysis	0.8	283	55	Gaseous hydrogen
B	Electricity	Hydrogen by water electrolysis	0.8	178	55	Gaseous hydrogen
C	Electricity	Hydrogen by water electrolysis	0.8	18	55	Gaseous hydrogen
D	Electricity	Hydrogen by water electrolysis	0.8	229	55	Gaseous hydrogen
E	Electricity	Hydrogen by water electrolysis	0.8	1.4	55	Gaseous hydrogen
F	Electricity	Hydrogen by water electrolysis	0.8	10	55	Gaseous hydrogen
G	Electricity	Hydrogen by water electrolysis	0.8	10	55	Gaseous hydrogen
H	Electricity	Hydrogen by water electrolysis	0.8	283	55	Gaseous hydrogen
I	Electricity	Hydrogen by water electrolysis	0.8	283	55	Gaseous hydrogen

Table 5 : Financial assessment 2017

	Secondary process		Intermediate product 2	Tertiary process			End use
Capacity tpd	**O2 tpy**	**Name**	**Name**	**Name**	**Capacity tpd or MW or GJ**	**Units**	
610	288,578	Ammonia production from hydrogen	Ammonia		-		Export ammonia
384	181,663	Ammonia production from hydrogen	Ammonia	MAP DAP Fertilisers	1600	t	Agriculture / horticulture
39	18,450	Ammonia production from hydrogen	Ammonia	Crystal fertilisers	150	t	Agriculture / horticulture
493	233,181	Ammonia production from hydrogen	Ammonia	Explosives	1060	t	Mining
0.5	1,462	Compressed gaseous hydrogen	Compressed hydrogen	Transport - heavy vehicles primarily	71	GJ	Transport
3	10,164	Compressed gaseous hydrogen	Compressed hydrogen	Power generation Fuel Cell	10	MW	Electricity
3.5	10,164	Compressed gaseous hydrogen	Compressed hydrogen	Power generation combustion pure or H_2 mix	10	MW	Electricity
99	288,578	Compressed gaseous hydrogen	Compressed hydrogen	Green gas - blending H_2 into existing natural gas network	11227	GJ	Gas
99	288,578	Compressed gaseous hydrogen	Compressed hydrogen and oxygen	Industrial utilisation of hydrogen/oxygen e.g steel, refineries, glass	99	t	Industrial products

Path no	Primary feedstock	Primary process	Capacity			Intermediate product 1
	Name	Name	Utilisation factor	MW	Energy consumption kWh/kg	Name
A	Electricity	Hydrogen by water electrolysis	0.8	257	50	Gaseous hydrogen
B	Electricity	Hydrogen by water electrolysis	0.8	162	50	Gaseous hydrogen
C	Electricity	Hydrogen by water electrolysis	0.8	16	50	Gaseous hydrogen
D	Electricity	Hydrogen by water electrolysis	0.8	208	50	Gaseous hydrogen
E	Electricity	Hydrogen by water electrolysis	0.8	1.3	50	Gaseous hydrogen
F	Electricity	Hydrogen by water electrolysis	0.8	9	50	Gaseous hydrogen
G	Electricity	Hydrogen by water electrolysis	0.8	9	50	Gaseous hydrogen
H	Electricity	Hydrogen by water electrolysis	0.8	257	50	Gaseous hydrogen
I	Electricity	Hydrogen by water electrolysis	0.8	257	50	Gaseous hydrogen
J	Electricity	Hydrogen by water electrolysis	0.8	16	50	Gaseous hydrogen

Table 6 : Financial assessment 2022

	Secondary process		Intermediate product 2	Tertiary process			End use
Capacity tpd	O2 tpy	Name	Name	Name	Capacity tpd or MW or GJ	Units	
610	288,578	Ammonia production from hydrogen	Ammonia	Ammonia Cracking	86	t	Transport hydrogen SE Asia
384	181,663	Ammonia production from hydrogen	Ammonia	MAP DAP Fertilisers	1600	t	Agriculture / horticulture
39	18,450	Ammonia production from hydrogen	Ammonia	Crystal fertilisers	150	t	Agriculture / horticulture
493	233,181	Ammonia production from hydrogen	Ammonia	Explosives	1060	t	Mining
0.5	1,462	Compressed gaseous hydrogen	Compressed Hydrogen	Transport – heavy vehicles primarily	71	GJ	Transport
3	10,164	Compressed gaseous hydrogen	Compressed Hydrogen	Power generation Fuel Cell	10	MW	Electricity
3.5	10,164	Compressed gaseous hydrogen	Compressed Hydrogen	Power Generation combustion pure or H_2 mix	10	MW	Electricity
99	288,578	Compressed gaseous hydrogen	Compressed Hydrogen	Green gas – blending H_2 into existing natural gas network	11227	GJ	Gas
99	288,578	Compressed gaseous hydrogen	Compressed Hydrogen and Oxygen	Industrial utilisation of hydrogen / oxygen e.g. steel, refineries, glass	99	t	Industrial products
39	18450.0995	Ammonia production from hydrogen	Ammonia	Ammonia Cracking to Fuel Cell H_2	5.505882353	t	Transport hydrogen SE Asia

Path no	Primary feedstock	Primary process	Capacity			Intermediate product 1
	Name	Name	Utilisation factor	MW	Energy consumption kWh/kg	Name
A	Electricity	Hydrogen by water electrolysis	0.8	232	45	Gaseous hydrogen
B	Electricity	Hydrogen by water electrolysis	0.8	145.81	45	Gaseous hydrogen
C	Electricity	Hydrogen by water electrolysis	0.8	14.81	45	Gaseous hydrogen
D	Electricity	Hydrogen by water electrolysis	0.8	187	45	Gaseous hydrogen
E	Electricity	Hydrogen by water electrolysis	0.8	1.17	45	Gaseous hydrogen
F	Electricity	Hydrogen by water electrolysis	0.8	8.16	45	Gaseous hydrogen
G	Electricity	Hydrogen by water electrolysis	0.8	8.16	45	Gaseous hydrogen
H	Electricity	Hydrogen by water electrolysis	0.8	232	45	Gaseous hydrogen
I	Electricity	Hydrogen by water electrolysis	0.8	232	45	Gaseous hydrogen
J	Electricity	Hydrogen by water electrolysis	0.8	14.81	45	Gaseous hydrogen

Table 7: Financial Assessment 2027

Secondary process			Intermediate product 2	Tertiary process			End use
Capacity tpd	**O2 tpy**	**Name**	**Name**	**Name**	**Capacity tpd or MW or GJ**	**Units**	
610	288,578	Ammonia production from hydrogen	Ammonia	Amonia Cracking	86	t	Transport hydrogen SE Asia
384	181,663	Ammonia production from hydrogen	Ammonia	MAP DAP Fertilisers	1600	t	Agriculture / horticulture
39	18,450	Ammonia production from hydrogen	Ammonia	Crystal fertilisers	150	t	Agriculture / horticulture
493	233,181	Ammonia production from hydrogen	Ammonia	Explosives	1060	t	Mining
0.5	1,462	Compressed gaseous hydrogen	Compressed hydrogen	Transport – heavy vehicles primarily	71	GJ	Transport
3	10,164	Compressed gaseous hydrogen	Compressed hydrogen	Power generation Fuel Cell	10	MW	Electricity
3.5	10,164	Compressed gaseous hydrogen	Compressed hydrogen	Power Generation combustion pure or H_2 mix	10	MW	Electricity
99	288,578	Compressed gaseous hydrogen	Compressed hydrogen	Green gas – H_2 into existing gas network	11227	GJ	Gas
99	288,578	Compressed gaseous hydrogen	Compressed hydrogen and oxygen	Industrial utilisation of hydrogen / oxygen e.g. steel, refineries, glass	99	t	Industrial products
39	18450	Ammonia production from hydrogen	Ammonia	Ammonia cracking to fuel cell H_2	5.5	t	Transport hydrogen SE Asia

4.7 Electricity system assessment and supporting infrastructure requirements

Table 8 below summarises the electrical system requirements for each of the options.

Option	Pathway	Energy (GWh/yr)	Average MW demand
A1	Ammonia Export	2,063	236
A2	Hydrogen Export	2,063	236
B	MAPDAP	1,345	154
C	Crystal Fertiliser	150	17
D	Explosives	1,694	193
E	H_2 Vehicle Station	10	1
F	H_2 Fuel Cell Power	70	8
G	H_2 Engine Power	70	8
H	H_2 Gas Blending	1,962	224
I	Industrial Products	1,962	224

Table 8 - Electrical system requirements for 2017 pathways

Given the magnitude of the power requirements of pathway A, D, H and I, a voltage level connection of at least 275 kV is recommended. Pathway B would also preferably be connected at 275 kV, but there are also many locations in the state that would support this load to be connected at 132 kV.

Pathway C, E, F and G may be connected at lower voltage levels such as 66 kV, 33 kV or even 11 kV in some locations.

As most of the transmission system in Adelaide uses 275 kV – the existing transmission infrastructure is capable of supporting all pathways.

Each project pathway will also require its own internal electrical infrastructure such as transformers, circuit breakers, lines and cables, and protection and control systems.

4.8 Location assessment

For each pathway, a location was selected to use as an example of where the pathway could be most successfully applied. A range of criteria were considered, that allowed an estimate to be developed of the best location.

The locations selected for the study were:

- Northern Adelaide
- Tonsley
- Port Lincoln
- Whyalla
- Port Bonython
- Port Pirie
- Cape Hardy

4.8.1 Location criteria and characteristics

For each location, the following criteria were rated on a scale of 0 (lowest) to 5 (highest):

- Electricity network [E] - availability and capacity
- Water [W] – fresh water availability
- Natural gas network [G] – availability and capacity
- Port facilities [P] – distance and type of facility
- Land [L] – availability of suitable industrial land
- Hydrogen demand [H] – existing or anticipated industries that could require hydrogen
- Oxygen demand [O] – existing or anticipated industries that could require oxygen

Each location and the scores for each of the criteria are shown in Table 9.

While this assessment has assumed the use of fresh water as feed to the water treatment and electrolyser system, sea water is also a possible source with additional treatment steps

Location	Criteria / Score						
	E	W	G	P	L	H	O
Northern Adelaide	5	3	5	2	3	3	3
Tonsley	5	3	5	2	3	2	2
Port Lincoln	2	3	0	5	3	1	1
Whyalla	5	3	3	5	5	2	5
Port Bonython	5	3	3	5	5	3	1
Port Pirie	3	3	3	5	5	2	5
Cape Hardy	3	0	0	5	3	1	1

Table 9: Location criteria and characteristics

4.8.2 Pathway requirements

For each pathway, the requirements for infrastructure vary depending on the process involved, the feedstocks required and the final products produced and whether they will be consumed locally or exported.

In a similar way to the locations, each pathway has been given a score for each criteria that reflects the relative importance. As for the locations, the score range is from 0 (lowest) to 5 (highest). Referring to the pathways described earlier in this section, Table 10 shows the scores for each pathway.

Pathway		Criteria / Score						
		E	**W**	**G**	**P**	**L**	**H**	**O**
A1.	Large ammonia for export	5	5	5	5	5	0	3
A2.	Large H_2 for export	5	5	5	5	5	0	3
B.	Large ammonia MAP/DAP	5	5	5	3	5	0	3
C.	Mod. ammonia crystal fertilisers	5	5	5	3	5	0	3
D.	Large ammonia explosives	5	5	5	3	5	0	3
E.	H_2 Vehicle Station	5	5	0	0	2	5	2
F.	Hydrogen fuel cell	5	5	0	0	2	0	2
G.	Hydrogen engine	5	5	3	0	3	0	2
H.	Blending into natural gas network	5	5	5	0	2	0	3
I.	Industrial utilisation	5	5	0	0	5	5	5
J.	Mod. H_2 for export	5	5	0	5	3	0	3

Table 10 : Pathway location assessment

4.8.3 Location selections

Based on the scores described in the previous sections, Table 8 and Table 9 were multiplied together and the total score for each pathway at each location summed to give a total score for each pathway at each location.

The results of this calculation are shown in Table 11. The results are colour coded to reflect the relative scores, with dark green indicating the most attractive location / pathway combinations and dark red the least attractive.

Pathway	Location / Score						
	Northern Adelaide	Tonsley	Port Lincoln	Whyalla	Port Bonython	Port Pirie	Cape Hardy
A1. Large ammonia for export	99	96	68	120	108	110	58
A2. Large H_2 for export	99	96	68	120	108	110	58
B. Large ammonia MAP/DAP	95	92	58	110	98	100	48
C. Mod. ammonia crystal fertilisers	95	92	58	110	98	100	48
D. Large ammonia explosives	95	92	58	110	98	100	48
E. H_2 Vehicle Station	67	60	38	70	67	60	28
F. Hydrogen fuel cell	52	50	33	60	52	50	23
G. Hydrogen engine	70	68	36	74	66	64	26
H. Blending into natural gas network	80	77	34	80	68	70	24
I. Industrial utilisation	85	75	50	100	85	90	40
J. Mod. H_2 for export							

Table 11: Site location outcome

Note that for pathway J, proximity to the port of Adelaide was required to allow export of isotainers via the container handling facilities.

In addition to this analysis, it was decided that a range of locations should be studied. Therefore, although a given location did not necessarily score the highest for a given pathway, if it did achieve a score at the high end and the highest scoring location was already included in the analysis, it was selected for the pathway.

The results of the location selections are included in Table 12.

Pathway	Criteria / Score
A1. Large ammonia for export	Port Pirie
A2. Large H_2 for export	Port Pirie
B. Large ammonia MAP/DAP	Port Bonython
C. Mod. ammonia crystal fertilisers	Port Pirie
D. Large ammonia explosives	Whyalla
E. H_2 Vehicle Station	Northern Adelaide
F. Hydrogen fuel cell	Whyalla
G. Hydrogen engine	Whyalla
H. Blending into natural gas network	Tonsley
I. Industrial utilisation	Whyalla
J. Mod. H_2 for export	Northern Adelaide

Table 12: Pathways and selected locations

5

Financial Analysis

5.1 Approach

To estimate the optimal development approach an option analysis process was undertaken on each pathway that considers the financial implications of decisions, by quantifying in monetary terms, the financial impact of a pathway. The process includes elements of cost benefit analysis, life-cycle assessment, risk assessment, optioneering and sensitivity analysis. The financial analysis refers to the private costs and benefits that accrue to the project or business entity. An economic assessment incorporating social, the implications of taxation regimes, and environmental costs and benefits has not been incorporated into this assessment.

To establish the net benefits of the pathways over the project life, the flow of costs has been deducted from the flow of benefits. Thus, the present value of the net benefits (NPV) (benefits minus costs) of the selected project or action in any year, t, is given by:

$$NPV = \sum_{0}^{T}\left[\frac{(B_p)-(C_p)}{(1+r)^T}\right]$$

Where NPV is the total NPV of project p, B_P and C_P are the private or internal costs and benefits of the project. Benefit Cost Ratio (BCR) (ratio of the present value of benefits to the present value of costs) has also been undertaken in some instances as a performance indice comparator.

Due to the high level nature of the information provided during the study, the financial results presented are indicative only. A sensitivity analysis has been adopted to test the impact of key financial parameter assumptions on NPV.

Three financial models have been developed for the project which analyse the costs and benefits of executing a Green Hydrogen project in 2017 or delaying execution for 5 or 10 years to potentially obtain learning rate benefits in regards to emerging technology capital expenditure (CAPEX) and operational expenditure (OPEX) improvements.

5.1.1 DELTΔ™ financial model

Advisian's financial modelling is performed using the proprietary DELTΔ™ software. Within DELTΔ™, base case deterministic analysis and probabilistic (monte-carlo) analysis functionality is available, quantified in NPV and benefit cost ratio (BCR) terms.

DELTΔ™ has been independently validated using a test process consistent with the principles of ISO 1702.

5.1.2 Energy and commodity price projections

Input on electricity, natural gas and ammonia price projections has been provided by ACIL Allen. Each of these is discussed in the following sections.

Electricity price projections

The key assumptions are shown in Appendix B.

The electricity prices used for grid electricity including Large-scale Generation Certificates (LGCs) to create 100% green electricity supply area shown in Figure 6. Note that the assumed pricing for the LGC component falls rapidly from $74 in 2017 to zero in 2024.

Green power costs Real $/MWh

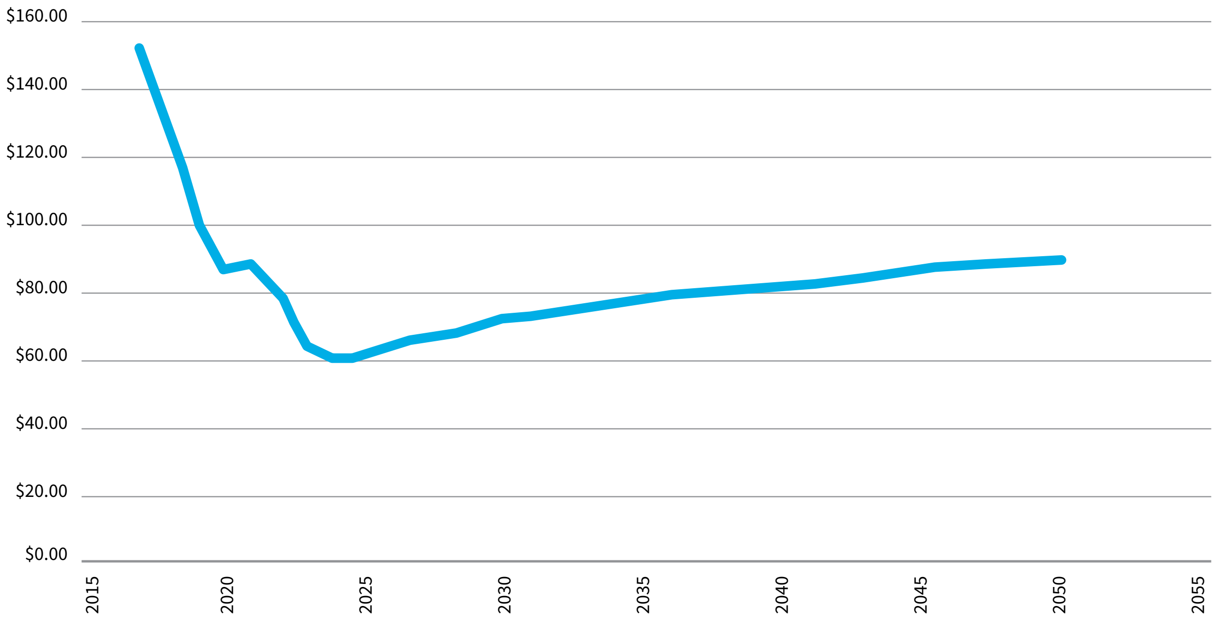


Figure 6: Electricity price projections

The average price projected reflects an assumed utilisation factor for the hydrogen electrolyser of 80%, that is, the electrolyser will operate during the lowest 80% of price periods throughout the year. Figure 7 shows the price / duration curve for grid electricity in 2017. The curve shows that electricity prices begin to rise steeply in the most expensive 20% of electricity periods while remaining relatively flat the preceding part of the curve. No attempt has been made to optimise the trade-off between the capital cost of increasing the electrolyser capacity and the ability to operate more selectively to minimise electricity cost from the grid per kg of hydrogen produced.

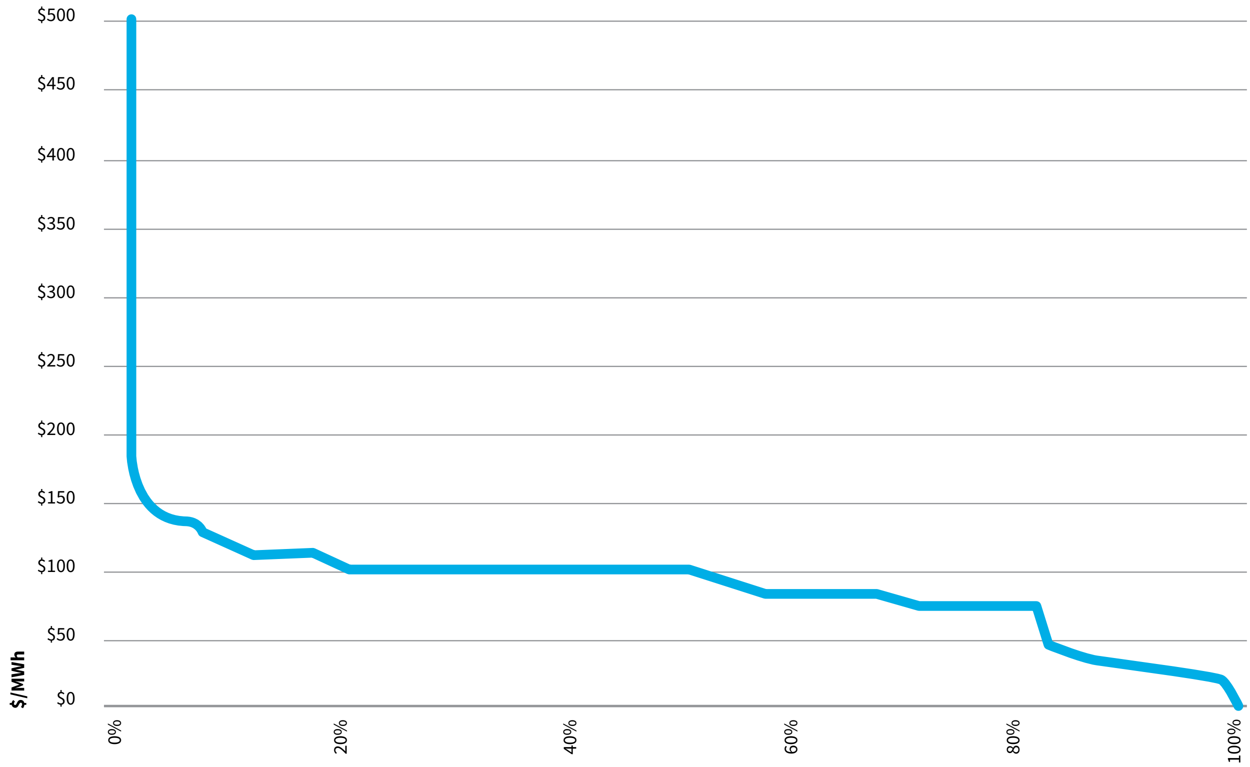


Figure 7 - Electricity price duration curve 2017

For electricity generation pathways, the system is assumed to generate during the top 20% of electricity price periods.

Natural gas price projections

The natural gas price assumptions used in the study are shown in Figure 8. These figures are for natural gas delivered to an Adelaide customer. The assumptions used in developing these projections are shown in Appendix B.

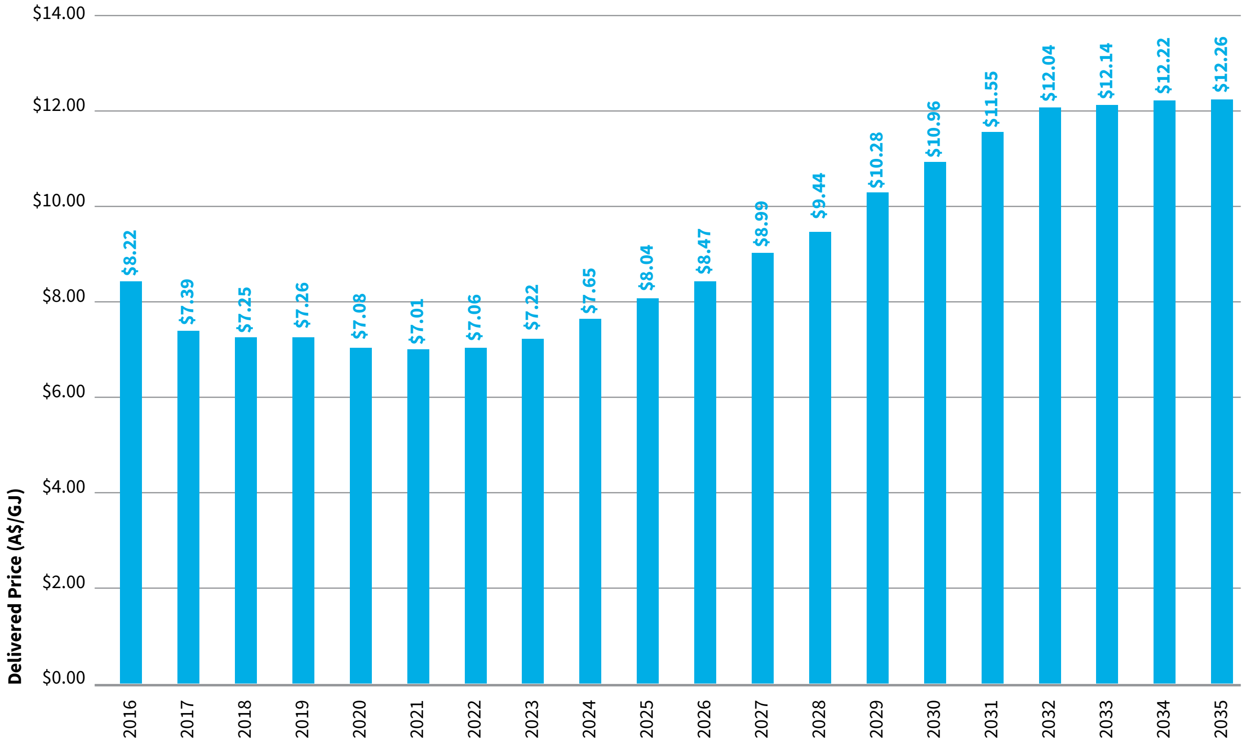


Figure 8 - Natural gas price projections

Ammonia price projections

Ammonia market pricing has been developed for the ammonia export pathway for 2017, 2022 and 2027. In this pathway, ammonia is produced in South Australia in bulk and sold into the local or export market. The market price is used to represent the value of the ammonia product. The ammonia price projection used is shown in Figure 9. The projections of future prices are driven by gas prices predicted for the major international regions where ammonia is produced. The basis for these projections are contained in Appendix B.

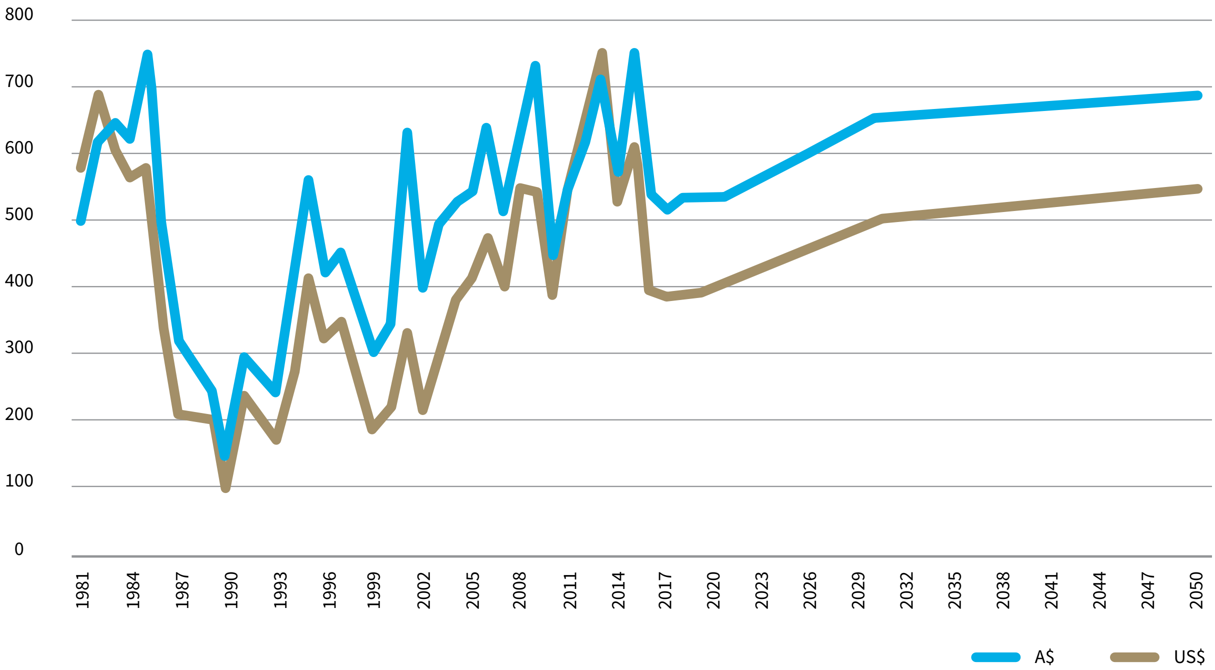


Figure 9 - Ammonia price projections

5.2 2017 analysis results

A summary of the 2017 analysis results and each pathway's key technical and financial assumptions is provided below in Table 13.

Option	Pathway	Core capital components
A1	Ammonia export	Electrolysis plant, ammonia plant, utility units
B	MAPDAP	Electrolysis plant, ammonia plant, MAPDAP plant, utility units
C	Crystal fertiliser	Electrolysis plant, ammonia plant, MAPDAP crystal plant, utility units
D	Explosives	Electrolysis plant, ammonia plant, AN plant including nitric acid production, utility units
E	H_2 vehicle station	Electrolysis plant, storage, compressor, 2x fueling stations
F	H_2 fuel cell power	Electrolysis plant, fuel cell, BoP, storage tank, compressor
G	H_2 engine power	Electrolysis plant, engine package, storage tank, compressor
H	H_2 gas blending	Electrolysis plant, storage, compressor
I	Industrial products	Electrolysis plant, storage, compressor

Table 13 : Core capital components of each Green Hydrogen

Modelling assumptions (base case)

- The cost and benefit valuations described above apply and have been sourced from vendor surveys and Advisian costing engineers;
- The project lifecycle (excluding construction timeframes) is assumed to be 20 years;
- The pathway sizing and associated costs and benefits are based on typical industry standard plant sizes;
- Development activities start in 2017;
- Pathway E, F, and G commence operation in 2018, Pathway B, C, D, H and I commence operation in 2019, and Pathway A1 commences operation in 2020 based on construction timeframes;
- Internal Discount Rate – 6%;
- The assessment is based on real dollar values and hence inflation has not been incorporated into the model;
- Benefits, OPEX and/or revenue associated with each pathway are assumed to commence on the following year of CAPEX spend. This is due to the assumption that construction schedules would be at least 1 year;
- O&M includes labour and other management costs, maintenance costs for main equipment and insurance;
- Sustaining CAPEX of electrolyser is 50% of initial CAPEX in Year 10 of project. Sustaining CAPEX of other infrastructure differs between pathways depending on characteristics; and
- H_2 production electrolysis, CAPEX @ rated power is $3.7M per t H_2 per day.
- H_2 production electrolysis, energy consumption @ rated power is 55kWh per kgH_2 ;
- H_2 production electrolysis, water consumption @ rated power is 125L per MWh;
- 80% utilisation for electrolyser;
- H_2 production electrolysis, efficiency degradation @ rated power is 2% per year;
- 90% utilisation for ammonia and fertiliser plants;
- Capital cost estimating power factor for parallel plants e.g. two trains is 0.9;
- Location CAPEX escalation factor as per site study analysis;
- Electricity Price ($/MWh) (On Grid) projection as per ACIL Allen analysis;
- Electricity Price ($/MWh) (behind the meter private offtake) projection - $60 per MWh;
- Pathway F (Fuel Cell) and Pathway G (Engine) assume utilisation during top 20% of available electricity prices to maximise revenue;
- Costs of conversion of natural gas networks (Pathway H) and their end use equipment to operate on hydrogen has been excluded;
- Phosphoric Acid, key input to Pathway 2 and 3, is $1,200 per tonne flat over 20 years;
- A range of other associated and utility connections costs have been included in the CAPEX; and
- Taxation regimes and external social and environmental costs or benefits have been excluded from the analysis.

Option	Pathway	Commodity	Price	Unit	Source
A1	Ammonia export	Anhydrous ammonia	$535	$ / t NH_3	ACIL Allen (2017)
B	MAPDAP	Granular fertiliser	$780 flat	$ / t	Advisian research
C	Crystal fertiliser	Soluble fertiliser	$1,100 flat	$ / t	Advisian research
D	Explosives	Ammonium nitrate	$645 flat	$ / t	Advisian research
E	H_2 vehicle station	Gaseous hydrogen (fuel cell grade)	$10 flat	$ / kg H_2	Advisian research
F	H_2 fuel cell power	Electricity	$171 (2018) projection	$/MWh	ACIL Allen (2017)
G	H_2 engine power	Electricity	$171 (2018) projection	$/MWh	ACIL Allen (2017)
H	H_2 gas blending	Gaseous hydrogen (natural gas displacement)	$7.25 (2018) projection	$/GJ	ACIL Allen (2017)
I	Industrial products	Gaseous hydrogen (industrial grade)	$2 flat	$ / t H_2	Advisian research
All	Oxygen sale	Gaseous hydrogen	$40 flat rate	$ / t	Advisian research

Table 14 : Commodity price assumptions (base case)

5.2.1 Cost and benefit summary (base case assumptions)

A breakdown of the key costs and benefits of each pathway is provided below. The option sizing and associated costs and benefits are based on typical industry standard plant sizes.

			Cost				Revenue		
Option	Pathway	Electrolysis block size	CAPEX ($AUD)	OPEX (% CAPEX)	Energy (GWh/yr)	Water (ML/annum)	Output product	Unit	Output O_2 (kt/yr)
A1	Ammonia export	280	$465m	4%	2,063	245	200	kt/yr	288
B	MAPDAP	180	$456m	4%	1,345	158	500	kt/yr	182
C	Crystal fertiliser	20	$81m	4%	150	18	50	kt/yr	18
D	Explosives	230	$1b	4%	1,694	201	330	kt/yr	233
E	H_2 vehicle station	1.4	$4.3m	2%	10	1.2	183	t/yr H_2	2
F	H_2 fuel cell power	10	$95m	2%	70	8.7	17,500	MWh/yr	10
G	H_2 engine power	10	$33m	2%	70	8.7	17,500	MWh/yr	10
H	H_2 gas blending	280	$282m	2%	1,962	245	4,100	GJ/yr	288
I	Industrial products	280	$324m	2%	1,962	245	361	kt/yr H_2	288

Table 15: Cost and benefit summary across project pathways (base case)

5.2.2 Results – NPV Lifecycle and BCR Analysis (Base Case Assumptions)

The results and outputs of the Base Case DELTAΔ™ financial modelling are presented in Table 16 and Figure 10. These represent the NPV in present day (2017) dollars over the entire 23 year planning horizon including construction time. A graphical breakdown of the financial costs and benefits across all pathways can also be observed in Figure 11. In all cases, pathways are shown in numerical pathway order.

The financial results in Table 14, which relate to each pathways' internal costs (CAPEX, OPEX) and revenue at base case conditions at a discount rate of 6%, demonstrate the following:

- Pathway C (Crystal Fertiliser) exhibits the highest return over the project lifecycle under base case financial conditions with an NPV of $440 million with a slightly NPV positive $8 million and and a BCR of 1.01. To achieve this, an average of $1,100 per tonne for Crystal Fertiliser would be required over the life of the project
- Pathway E (Vehicles) also exhibits a positive return over the project lifecycle under base case conditions with an NPV of $5 million and a BCR of 1.32. To achieve this, an average of $10 per kg of hydrogen would be required over the life of the project
- All other pathways are NPV negative under base case conditions.

Option	Pathway	Capex	Energy OPEX	O&M OPEX	Revenue	Total financial NPV	BCR
A1	Ammonia export	-$513	-$1,654	-$124	$1,365	-$926	0.60
B	MAPDAP	-$509	-$1,175	-$3,230	$4,299	-$615	0.88
C	Crystal fertiliser	-$88	-$131	-$376	$595	$441	1.01
D	Explosives (ammonia nitrate)	-$1,100	-$1,479	-$280	$2,404	-$454	0.84
E	H_2 vehicle station (diesel replacement)	-$6	-$10	-$1	$22	$5	1.32
F	H_2 fuel cell power	-$114	-$68	-$22	$30	-$174	0.15
G	H_2 engine power	-$43	-$68	-$8	$30	-$88	0.26
H	H_2 gas blending	-$348	-$1,713	-$65	$536	-$1,590	0.25
I	Industrial product	-$401	-$1,713	-$74	$907	-$1,280	0.41

Table 16: Core cost and revenue components (6% discount rate applied)

NPV ($ AUD) for 2039 - Indivual Options

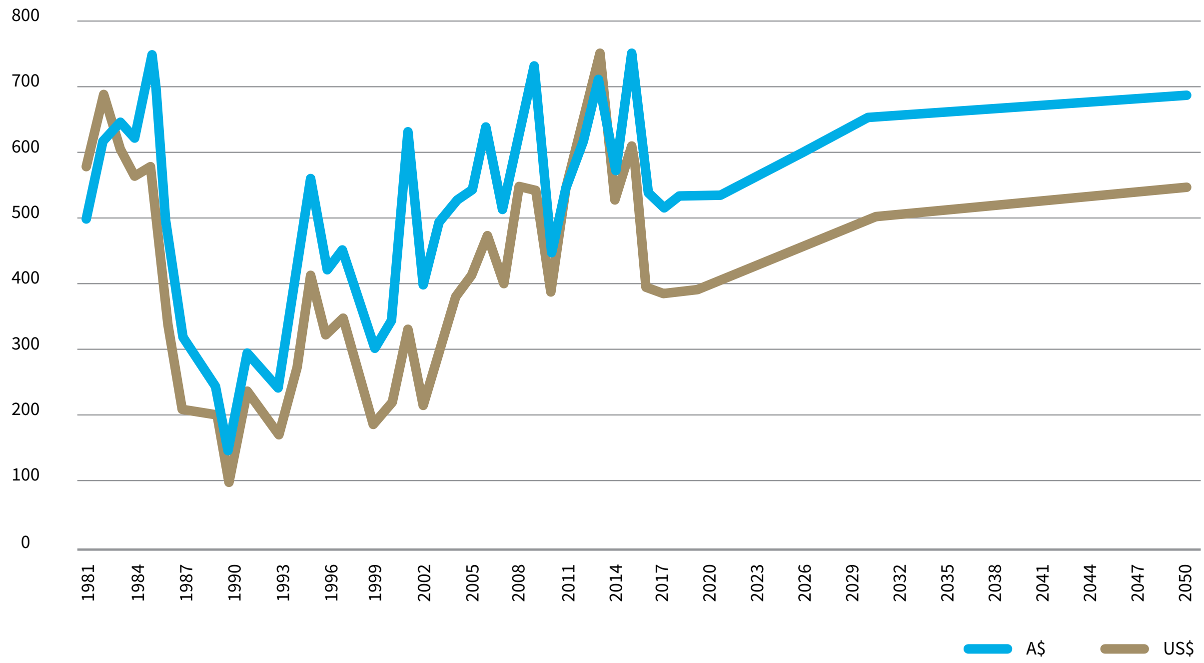


Figure 10 : NPV ($AUD) across project pathways up to 2039

Figure 11 presents a graphical (stack bar) breakdown of the financial parameters across each pathway. The breakdown shows that energy consumption is the highest cost component for most pathways. For the fertiliser pathways the ongoing phosphoric acid reagents represent the highest cost. In most cases, the revenue generated from the sale of products does not offset the upfront capital and operational costs over the lifecycle. A summary of core cost and revenue components is provided in Table 16.

Cost-Benefit Breakdown to 2039 - Individual Options

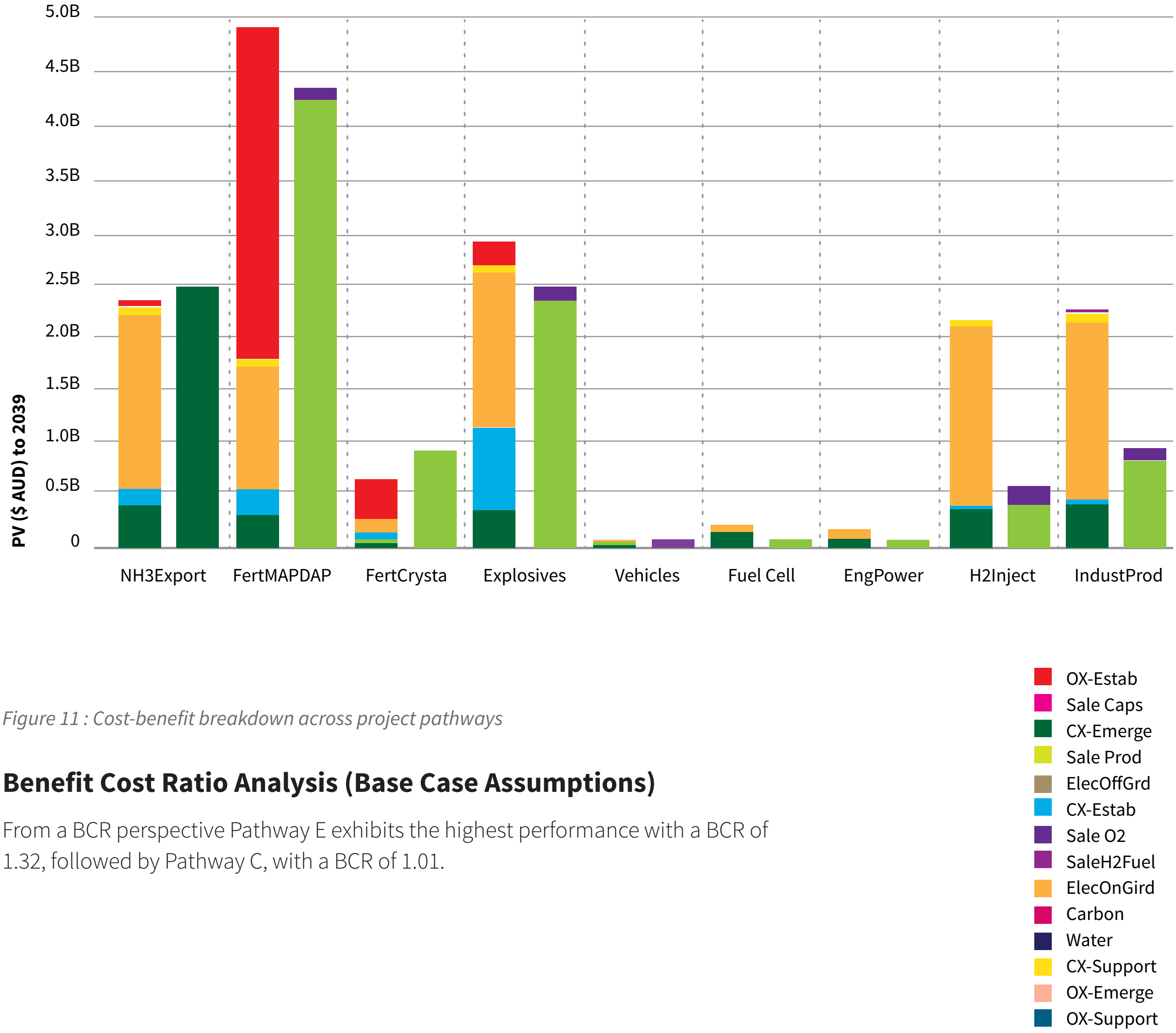


Figure 11 : Cost-benefit breakdown across project pathways

Benefit Cost Ratio Analysis (Base Case Assumptions)

From a BCR perspective Pathway E exhibits the highest performance with a BCR of 1.32, followed by Pathway C, with a BCR of 1.01.

5.2.3 Sensitivity analysis

Any analysis of this type is inherently subject to uncertainty. Capital and operating costs are planning level estimates suitable for comparison purposes, but are subject to change. The valuation and estimation of other benefits and dis-benefits and certain costs are subject to even larger variations.

The ranges of values for key financial parameters for this assessment are presented in Table 17.

Description	Unit	Low	Base case	High	Source
CAPEX (emerging tech)	%	-50	100	+50	Advisian / Siemens / stakeholders
CAPEX (established)	%	-30	100	+30	Advisian / Siemens
Electricity (on grid)	%	-10	100	+10	ACIL Allen electricity projections
Electricity (behind the meter renewable hybrid)	\$/MWh	50	60	70	Industry Vendors
Water	%	-10	100	+10	Advisian / public data
OPEX (emerging)	%	-50	100	+50	Advisian / Siemens / stakeholders
OPEX (established)	%	-30	100	+30	Advisian / Siemens
Sale product	%	-10	100	+10	ACIL Allen, Estimating
Sale O_2	%	-10	100	+10	Advisian / public data
Sale caps (grid stabilisation)	\$/MWh	0	0	10	Advisian / public data
Sale H_2 fuel	\$/kgH_2	2	10	20	Advisian / stakeholders / public data
Discount rate	%	5	6	8	Advisian

Table 17: Range of key parameters

Minimum and maximum parameter values adopted in Table 17 have been based on reference values and values provided by ACIL Allen, or selected from available research. In the absence of appropriate references for minimum or maximum values, the base value is multiplied or divided by an estimated confidence level. The range of this confidence level is dependent on the parameter. A higher sensitivity range (+-50%) was applied to capital components deemed 'emerging' technology due to their relatively low adoption worldwide. This technology includes electrolysers, fuel cells and H_2 engines. Established technologies such as ammonia plant, compressor units and storage facilities were given a lower sensitivity range (+-30%).

Utilising the DELTA™ software, the sensitivity analysis revealed that the NPV of all pathways were highly influenced by changes in particular financial assumption values across the full ranges considered (Table 18).

Key Parameter	Description
CAPEX	With the exception of Pathway C and E, a reduction of CAPEX of 50% and 30% respectively for emerging and established technologies fails to deliver a positive NPV outcome.
Electricity price (on grid)	Very large reductions in the price of electricity (at least 30%) are required for additional projects (other than Pathway C and E) to achieve positive NPV.
OPEX (established)	Significant reductions in OPEX are required for options (other than Pathway C and E) to exhibit a positive return. A 20% reduction in phosphoric acid agent price (currently $1200 per tonne) would result in a positive NPV outcome for a MAPDAP plant.
Revenue (sale of product)	An increase in revenue/unit of product of 20% results in MAPDAP and explosive manufacturing options achieves positive NPV. At least a 50% increase in revenue is required for all other options to be NPV positive. A decrease in crystal fertiliser price of approx. 2% would be required to return a negative NPV result. A price of $7 per kg H_2 is required to reduce the vehicle refueling facility to break even. Increasing revenue through trading electrical capacity, a product which protects the purchaser from price spikes in the wholesale market, up to $10 per MWh average, does not enable negative NPV pathways to become positive.
Discount rate	With a rising discount rate, options with significant up-front costs fare worse, compared to those that have low up-front costs or defer expenditure over time. Variations in the discount rate have a significant impact on the overall NPV of the options and relative NPV comparison. A very low discount rate assumption fails to create positive NPV outcomes across all project pathways (with the exception of Pathway C and E).

Table 18 : Key sensitivity findings

5.2.4 Behind the meter generation

Under a behind the meter scenario, by which the project pathway is purely supplied through a renewable energy private offtake agreement, an assumption of $60 per MWh average over the project lifecycle has been adopted. Even with this electricity discount applied, compared to an approximate $75 per MWh average sourcing electricity from the grid during the lowest 80% pricing available, the only projects to exhibit positive NPV are Pathways C and E.

An electricity price on average over the project life in the range of $25-50 per MWh is required for ammonia and MAP/DAP fertiliser pathways to become financially viable, with other financial parameters set at base case values. For industrial use or H_2 blending into natural gas pipelines to be viable, a price of under $20 per MWh would be required. The high up front costs of fuel cell and H_2 engine pathways, even under conditions of free electricity and applying favourable CAPEX, OPEX and revenue assumptions, it is difficult to find conditions where these pathways become viable.

5.2.5 Cumulative probability plot

While the previous section examined the variability of each pathway's NPV and BCR to a single parameter, with all other variables remaining at base case values, this section examines the overall variability of the results across the full range of parameter variability.

The cumulative probability financial and economic graphs (Figure 12 and Figure 13) presents an ordered plot of all the possible NPV values (n=5,000, the result of 5,000 iterations of the model) that occur for every combination of the input parameters under the defined ranges. Each pathway is represented by a coloured probability curve. All results are considered equi-probable in this analysis with the lowest possible NPV figure occurring at 0% and the highest NPV figure occurring at 100%.

These graphs demonstrate:

- The overall sensitivity of each pathway to variations in the input parameters; and
- How this sensitivity impacts on the order of pathways in terms of how financially attractive they are.

A pathway that is consistently to the right of the zero NPV line (L to R = negative to positive NPV) is considered financially sustainable. If that pathway is furthest to the right, and is not intersected by any others, then that pathway is the most financially attractive over the full range of conditions being tested. Note that electricity prices are constrained to a range 90%-110% of market values for this analysis with behind the meter pricing set to zero to avoid double counting of electricity costs.

Financially, based on the sensitivity ranges applied, there is a higher likelihood of the project being NPV negative overall across all pathways with the exception of Pathways C and E. Pathway B – MAPDAP has a very high sensitivity impact of phosphoric acid reagent price on the plants OPEX. Lower CAPEX and OPEX pathways have relatively low quantum sensitivity in NPV compared to the very large CAPEX and OPEX intensive industrial facilities.

The best NPV pathway, over 45% of all applicable combinations of sensitivity values is Pathway E - Vehicles, followed closely by Pathway C - Fertiliser Crystal with 33%. Pathway C is the second best option in 53% of applicable combinations of values. From a BCR perspective, Pathway E is the best pathway and Pathway C the second best option under 73% and 70% of applicable combinations respectively.

Under a behind the meter' scenario ($50-$70/MWh), there is a similar result, however an explosive facility exhibits a higher share of best outcome applicable combinations (25%), with a MAPDAP. This is also the case when viewed from a BCR perspective.

If BCR is plotted, it produces a similar result with the exception of Pathway E, which has high possibility of achieving a BCR greater than 1 in 80% of potential combinations.

NPV Cumulative Distribution for 2039 - Individual Options

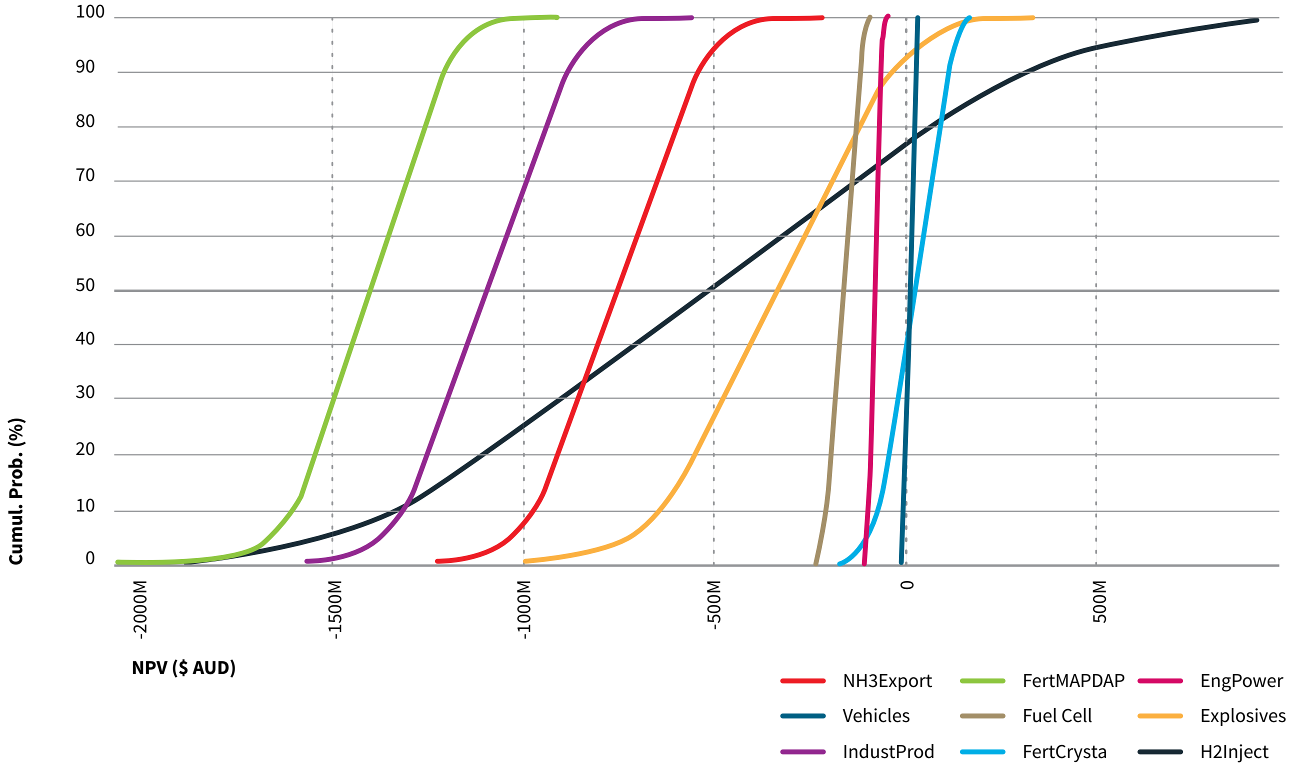
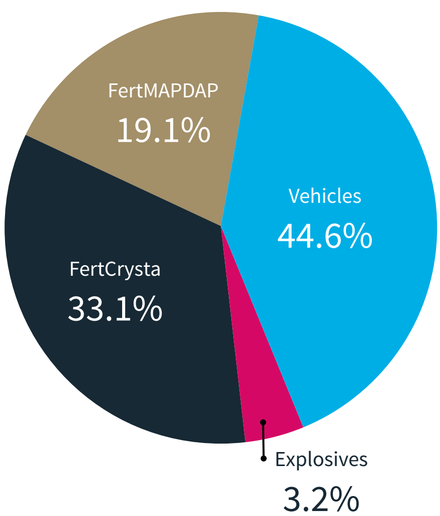


Figure 12 : NPV cumulative distribution across project pathways - 2017

Best Outcome Makeup (n=5000)



Second Best Makeup (n=5000)

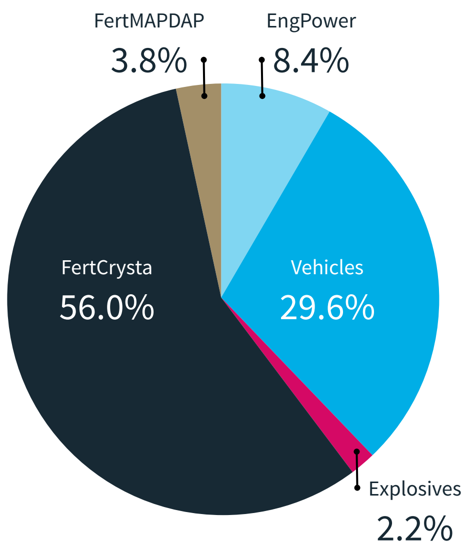


Figure 13 : Best and second best NPV outcome makeup across full sensitivity ranges - 2017

5.3 2022 and 2027 learning rate analysis

Based on discussion and feedback from vendors and technical experts, a range of technologies examined for the study have the potential to improve over time from a capital and efficiency perspective, also known as learning rates. Established technologies, albeit to a lesser extent also have the potential to improve over time.

For the purposes of this study a start date of 2022 and 2027 were examined. ACIL Allen have undertaken an analysis of learning rates that might apply to the technologies involved in this study and this has been used as a reference as stakeholder inputs have been reviewed. The learning rates analysis is included in Appendix C. The study and input received from Siemens and other technology providers are generally in agreement with the ACIL Allen analysis. A summary of the key capital, energy efficiency and plant degradation conversion efficiency is provided below.

Description	Unit	2017	2022	2027
H_2 production electrolysis, CAPEX @ rated power	% improve	0%	12.5%	25%
Established technology	% improve	0%	1%	2%
H_2 production electrolysis, energy consumption @ rated power	kWh / kgH_2	55	50	45
H_2 production electrolysis, efficiency degradation @ rated power	% / year loss	2	1.5	1

Table 19: Key learning assumptions for 2022 and 2027

It has been assumed the learning rate benefits for CAPEX and energy efficiency are fixed for the duration of the project lifecycle, including sustaining capital requirements over time. This is based on new technology having the inability to be retrofitted to potentially older technology. Efficiency degradation is reset at 10 years when it is assumed a major refurbishment of equipment will take place, and this refurbishment is on a like for like basis. Projected electricity prices, sale of product prices and discount rate (time value of money) also impact the financial outcomes of the project pathways compared to executing the project in 2017.

There is the potential for new Green Hydrogen pathways to emerge post 2022 due to advances in technology as research benefits are realised, and demand from countries wishing to transition to a hydrogen transport economy. As previously described in Section 5, two new paths have been evaluated in 2022 and 2027; Pathway A2 Large hydrogen export and J Modular hydrogen export. The end use for both these Pathway J is FCEVs in the Asia Pacific region.

Pathways A2 and J produce 28,300 tonnes and 1,835 tonnes hydrogen per annum respectively.

5.3.1 Results 2017, 2022 and 2027

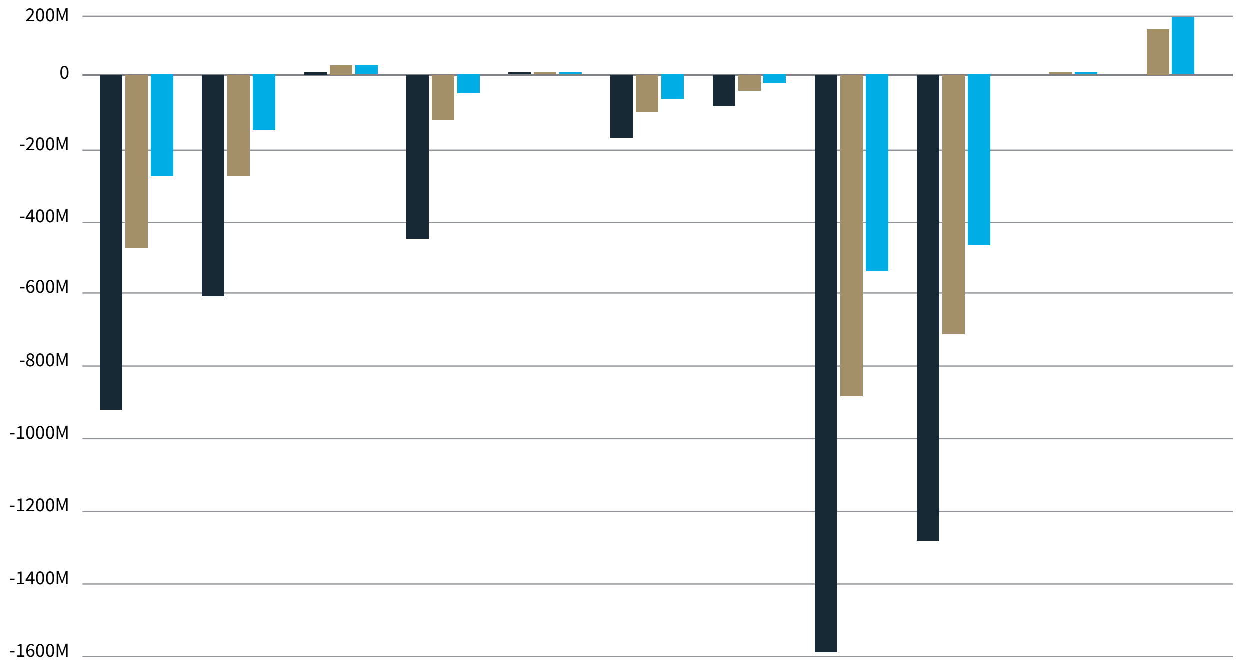
The improvement of CAPEX of the pathways over time is presented below in Table 20. OPEX does not necessarily decrease over time for each pathway due to assumed energy and revenue projection fluctuations at base case.

Pathway	Pathway	Capex 2017 $	Capex 2022 $	Capex 2027 $
A1	Large ammonia export	$465m	$412m	$368m
A2	Large hydrogen export	N/A	$902m	$852m
B	MAPDAP	$456m	$421m	$382m
C	Crystal Fertiliser	$81m	$77m	$74m
D	Explosives (Ammonia Nitrate)	$1b	$988m	$940m
E	H_2 Vehicle Station (Diesel Displacement)	$4.3m	$4.0m	$3.8m
F	H_2 Fuel Cell Power	$95m	$86m	$76m
G	H_2 Engine Power	$33m	$30m	$27m
H	H_2 Gas Blending	$282m	$236m	$197m
I	Industrial Products	$324m	$271m	$226m
J	Modular hydrogen export	N/A	$63m	$61m

Table 20 : CAPEX of each pathway over time incorporating assumed learning rates in Table 18

The graphical results and outputs of the Base Case DELTA™ model in 2017, 2022 and 2027 are presented in Figure 14. These represent the NPV in 2017 dollars over the planning horizon used across all planning scenarios. Each pathway, based on start year, is presented side by side until 2049 when the lifecycle of the 2027 pathways cease. Each project's operational lifecycle is 20 years plus two years for construction.

NPV ($ AUD) for 2049 - Individual Options



	NH3Exp17	MAPDAP17	Crystal17	Explos17	Vehicles17	FuelCell17	EngPower17	H2Injec17	IndustPr17	H2ExpMOD17	H2Exp17
GrnHydro17	-925.8M	-614.8M	7.9M	-454.3M	5.3M	-173.6M	-88.5M	-1.59B	-1.28B	0.000	0.000
GrnHydro22	-482.6M	-277.5M	26.5M	-127.2M	5.8M	-106.4M	-49.1M	-887.7M	-716.4M	-3.2M	124.5M
GrnHydro27	-279.0M	-155.9M	26.1M	-53.02M	4.7M	-65.9M	-27.9M	-539.9M	-466.8M	-1.9M	157.5M

Figure 14 : NPV ($AUD) across 2017, 2022 and 2027 project pathways up to 2049

The financial results in Figure 14, which relate to each pathways' internal costs (CAPEX, OPEX) and revenue at base case conditions at a discount rate of 6%, demonstrate the following:

- Pathway A2 (H_2Exp) has the highest positive return in 2022 and 2027, in excess of $100m under base case assumptions (BCR of 1.1). All other options, with the exception of Pathway C and E, continue to exhibit negative NPV of <1 BCR outcomes. Pathway C and E have a BCR of 1.06 and 1.56 in 2022 respectively.
- Each path shows improvement in financial performance in the future, with the exception of Pathway C (Crystal Fertiliser) and Pathway E (Vehicles), which decrease in value in 2027. This decrease in 2027 can be attributed to the discount rate, demonstrating earlier investment (2022) would be beneficial to return on NPV positive projects.
- Pathway J (H_2ExpMOD) under base case assumptions makes a marginal loss.

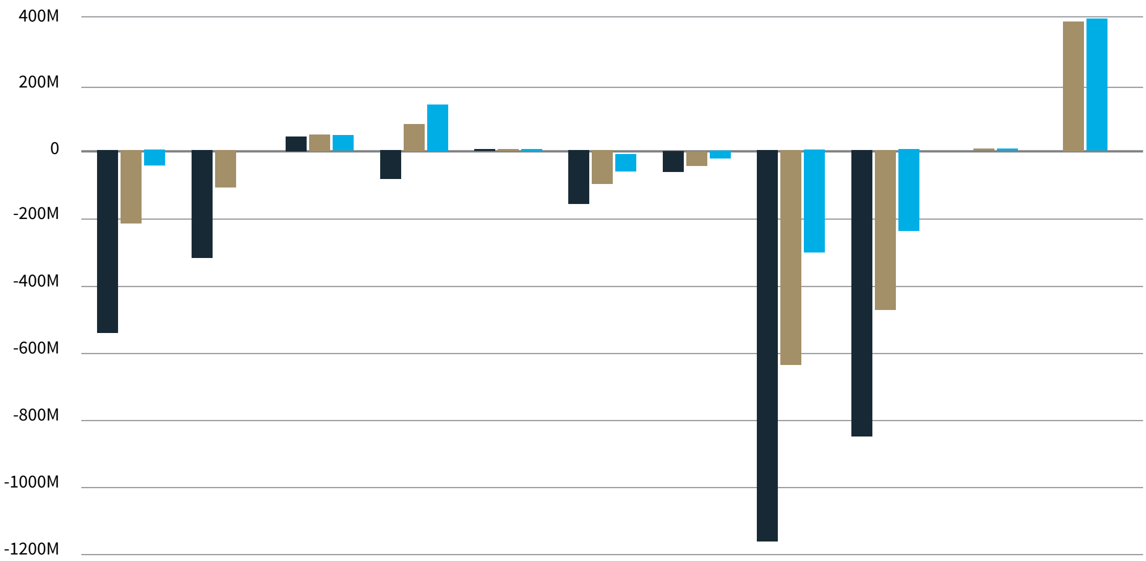
5.3.2 Sensitivity analysis

Utilising the DELTA™ modelling software, the sensitivity analysis revealed that the NPV and BCR of all pathways were highly influenced by changes in particular financial assumption values across the full ranges considered.

Key parameter	Description
CAPEX and non-energy OPEX	With the exception of Pathway A2, C, D, E and J, significant reductions in CAPEX and OPEX (at least 20%) are required for any pathway to exhibit positive NPV. This could be considered unlikely given the already allocated learning rates.
Electricity price	Large reductions in the price of on-grid electricity (at least 10-40%) are required for any project other than Pathways A2, C, E and J to have positive NPV. Behind the meter available electricity of $60 per MWh over the project lifecycle would also result in Pathway D – Explosives to become positive in 2022 and 2027.
Price of hydrogen	Whilst Pathway A2 has positive NPV and Pathway J an almost positive NPV in 2022 and 2027 at base case financial assumptions, these pathways have a very high sensitivity to the price of hydrogen received. A reduction of only $0.8 per kg H_2 on average across the project lifecycle would result in a loss of more than $50 million and $15m for Pathway A2 and Pathway J respectively in 2022.
Revenue	An increase in product revenue across the project lifecycle of 10% would result in Pathway B (MAPDAP) and Pathway D (Explosive) to have a positive return.
Discount rate	Variations in the discount rate have a significant impact on the overall NPV of the options and relative NPV comparison. A very low discount rate assumption also fails to create positive NPV outcomes across all project pathways with the exception of Pathways A2, C and E.

Table 21 : Key sensitivity findings

Under a combined behind the meter (with grid stabalisation benefits) scenario, each option exhibits improved NPV and BCR performance, as highlighted in Figure 15.



	NH3Exp17	MAPDAP17	Crystal17	Explos17	Vehicles17	FuelCell17	EngPower17	H2Injec17	IndustPr17	H2ExpMOD17	H2Exp17
GrnHydro17	-552.3M	-327.6M	39.3M	-90.8M	8.2M	-154.0M	-68.8M	-1.16B	-853.2M	0.000	0.000
GrnHydro22	-223.8M	-114.9M	43.7M	-78.4M	57.0M	-97.9M	-40.6M	-644.9M	-474.6M	14.5M	383.3M
GrnHydro27	-45.7M	-2.9M	39.2M	-139.7M	5.9M	-57.9M	-19.9M	-314.7M	-242.2M	14.93M	390.8M

Figure 15 : NPV ($AUD) across 2017, 2022 and 2027 project pathways up to 2049 - behind the meter with grid stabilisation benefit

5.3.3 Cumulative Probability Plot

The cumulative probability (monte-carlo) analysis for 2022 is provided below. The findings are similar for 2027. Note that electricity prices are constrained to a range 90%-110% of market values for this analysis.

NPV Cumulative Distribution for 2049 - Individual Options

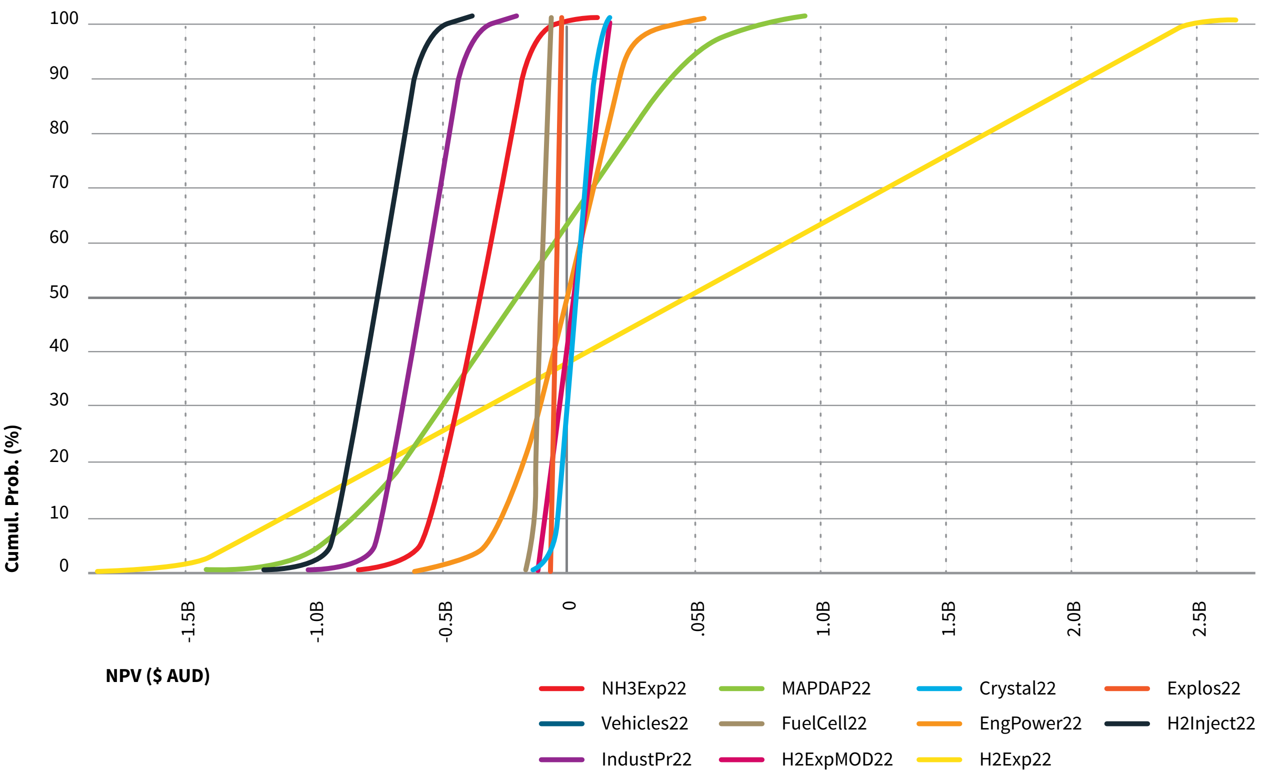


Figure 16 : NPV cumulative distribution across project pathways - 2022

The plot illustrates the high range of NPV based on the range of hydrogen price currently available in the marketplace for industrial quantities from natural gas steam reforming ($2 per kg H_2) for industrial uses, to prices being asked by hydrogen refuelling station in the United States ($AUS 20[12] per kg of fuel cell grade H_2). Similar to 2017, based on the cumulative distribution assessment, it can be considered each project has elevated risk in terms of return on investment.

Under the potential sensitivity range applied, the best pathway Pathway A2 (H2Exp), under 57% of possible combinations. The second best pathway is evenly split between a number of options. Under a more optimistic maximum price of hydrogen ($12 per kg H_2), Pathway A2 drops to 25% (similar to MAPDAP at 25%) of applicable combinations. From a BCR perspective, Pathway E (75% of applicable combinations) exhibits the best pathway, with Pathway A2 being the second best (57% of applicable combinations). A behind the meter scenario, makes little difference to the best outcome makeup.

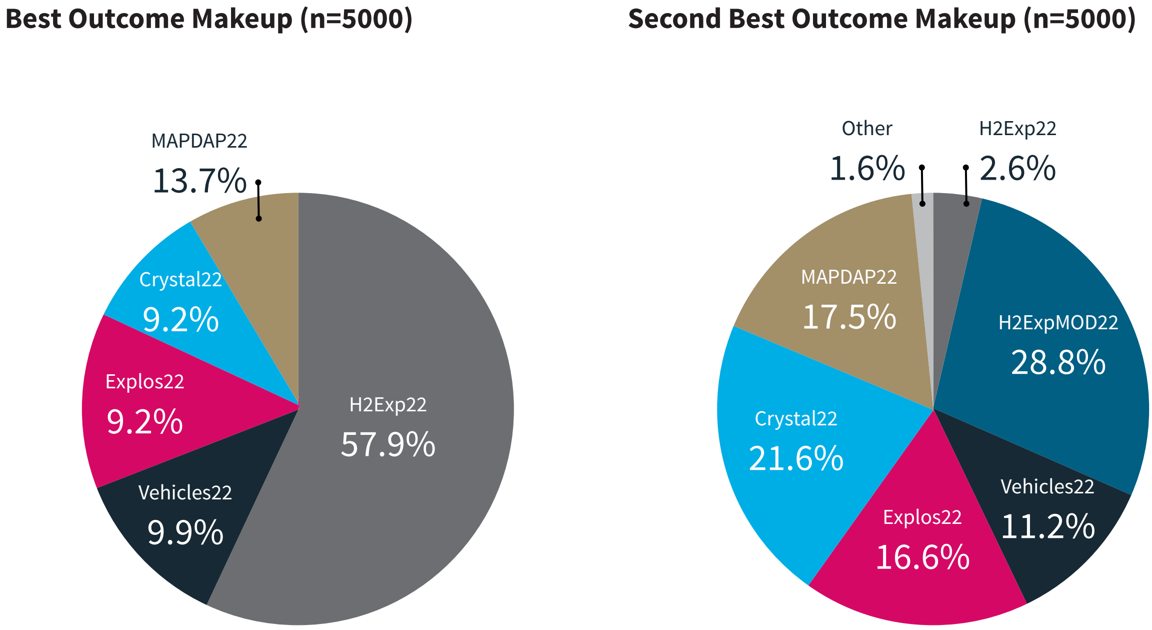


Figure 17 : Best and second best outcome makeup across full sensitivity ranges - 2022

5.4 Discussion and implications

Based on the pathways investigated, currently in 2017, pathways that show most promise include Pathways C (Fertilister Crystal) and E (Vehicles), however confidence levels of a positive return on investment are moderate. An average of at least $1,100/tonne of fertilliser crystal product and $7/kg H_2 would be required over the project lifecycle to support the project. $1,100 is approximately the price of the crystal fertiliser product from China at present. Under a competitive market scenario, (i.e. if increased fertiliser supply were to reduce the market price by approximatively 5-10%), this could potentiality have implications on the profitability of the plant.

With improvements in electrolysis technology and marginal improvements in established technology, by 2022 there is the potential for a viable hydrogen fuel pathway, A2 and J, if the price of hydrogen can remain at least $10 per kg H_2. However, given the emerging nature of this technology and uncertainty regarding projected H_2 prices (supply and demand), the commercial risk of this pathway will need to be managed appropriately.

Similarly, MAPDAP Fertiliser and Explosive pathways have potential if future commodity price and electricity price conditions become more favourable.

Based on the financial analysis undertaken and technical learning rate assumptions used, it will be challenging for Fuel Cell, Engine, Natural Gas Blending and Industrial use pathways to be viable in the near future. Significant technology advancements and favourable future economic and/or regulatory conditions, will be required for their uptake.

pathway

6

Barriers and Opportunities

6.1 Commercial feasibility gap

The results in Section 6 show the relative financial performance of each pathway studied and the conditions under which they could potentially have a positive return. What may also be important to private and government investors is the gap between a project's project financial performance and achieving a positive return, that is, what support is required to make a project viable.

To consider this question, each of the pathways have been analysed to estimate the level of one-off capital injection or recurring annual operational revenue support that would be required to achieve break even, NPV $0, over the 20 year assessment period. This has been undertaken using base case values for all variables and is presented in Table 22 assuming a single, minimum sized plant for each pathway. No analysis has been undertaken on the improvement to financial viability from building multiple plants.

Option	Pathway	Capex 2017 $	Capex 2022 $	Capex 2027 $	Opex 2017 $m/yr	Opex 2022 $m/yr	Opex 2027 $m/yr
A1	Ammonia export	>$500m	>$500m	$210m	>$50m	>$50m	$50m
A2	Hydrogen export	N/A	$0m	$0m	N/A	$0m	$0m
B	MAPDAP	>$500m	$270m	$360m	>$50m	$35m	$25m
C	Crystal fertiliser	$0m	$0m	$0m	$0m	$0m	$0m
D	Explosives	$450m	$170m	$100m	$40m	$15m	$10m
E	H_2 vehicle station	$0m	$0m	$0m	$0m	$0m	$0m
F	H_2 fuel cell power	$180m	$140m	$120m	$15m	$12m	$10m
G	H_2 engine power	$85m	$65m	$50m	$8m	$6m	$5m
H	H_2 gas blending	>$500m	>$500m	>$500m	>$50m	>$50m	>$50m
I	Industrial products	>$500m	>$500m	>$500m	>$50m	>$50m	>$50m
J	Modular hydrogen export	>$500m	$5m	$3m	>$50m	$0.5m	$0.4m

Table 22 : Commercial feasibility gap for each pathway – CAPEX or OPEX support required

As illustrated in Table 22, under the majority of pathways there are significant commercial feasibility gaps. Pathway A2 in 2022 and 2027, and pathways C and E are the only pathways which would not require upfront or ongoing financial assistance. At least a $50m CAPEX injection would be required for most pathways or at least a $5m ongoing OPEX subsidy.

Pathway J has a relatively modest CAPEX support ($3-5m) or OPEX support requirment ($400-$500K) preventing it from becoming NPV positive in 2022 or 2027.

Support for a hydrogen electrolyser project could come from a range of sources, including payment for network support and energy storage services.

6.2 Regulations associated with industry standards

To establish a Green Hydrogen project and potential industry in South Australia, close attention will need to be paid to appropriate regulations and industry standards. It would be a major setback for the development of hydrogen as an energy carrier if a project was to be developed that was not designed with appropriate consideration of safety aspects. If a safety incident was to occur it could cause the uptake of hydrogen based systems to be delayed for a long period. There is also a risk that delay in uptake of hydrogen could allow other competing technologies to further develop and supersede the hydrogen based approaches. This risk is most likely in transport markets where BEVs are developing rapidly in capability and falling in price.

As the Green Hydrogen sector is one which is still in its infancy globally, it is possible to relate current regulations to the existing sectors which include:

- International Electro-technical Commission (IEC). The commission is working in the area of
  - Equipment for Explosive Atmosphere (IEC- Technical Committee 31)
  - Fuel Cell Technologies (IEC - Technical Committee 105)
- The international Organisation for Standards (ISO)
  - Road Vehicles (ISO-Technical Committee 22)
    - SC 37 Electrically Propelled Vehicles
    - SC25 Vehicles using gaseous fuels per WG5 Fuel system components for gaseous hydrogen
    - Gas Cylinder (ISO-Technical Committee 58)
    - Hydrogen Technologies (ISO-Technical Committee 197)

With the use of hydrogen for low carbon mobility gaining momentum, there are a number of countries globally integrating national codes and standards. For the purpose of scaling and international sales of hydrogen products and related technologies along the value chain, it is recommended to consider compliance with international codes, as well as the relevant national codes.

The published international and national standards referenced in this section cover the entire value chain for hydrogen:

- Stationary fuel cells
- Hydrogen and fuel cell vehicles
- Portable and micro fuel cells
- H_2 infrastructure.

6.3 Electrical System benefits

The conversion of water to hydrogen will require large amounts of electricity which will be present as a power system load. If the intention is to maintain a constant production of product then the effect on the power system will be similar to the effect that existing large loads have on the system for example mining loads such as Olympic Dam, or other large industrial loads such as smelters/steel works etc. In order to supply a large amount of power a connection to the high voltage transmission system is required, preferably the 275 kV network because it can support the large amounts of power that are envisaged.

However, if the proposed installation is able to vary its rate of production and as a consequence its electrical load, then additional electrical system benefits can be realised – this may provide an additional revenue source to the Projects. These proposed benefits are described below.

6.3.1 Mitigating effects of renewable generation intermittency

The first benefit that varying the production can provide to the overall power system is its effect on the renewable generation intermittency issue. As more renewable generation is connected to the system, the availability of power is determined by environmental factors such as how much sunshine or how much wind is available to produce the power balanced with load, which also varies during the day and season. Having a large load on the system that has the ability to vary its demand allows the load to use power when it is freely available and cheap, and refrain from use of power when it is not being produced and hence is usually expensive.

The benefits to the load are that it can decide to buy power when it is cheap and refrain from buying power when it is expensive. This allows it to manage its expenditure on energy which can also be viewed as demand response measure.

The effect on the power market would be a reduction in the volatility of electricity prices. These are currently very volatile in South Australia in part due to oversupply during periods of high wind and under supply during calm weather. Obviously the size of the load relative to the size of the system determines the degree to which this occurs.

This would be of overall benefit to all market participants because it increases the predictability of the market which assists long term planning of future investments.

6.3.2 Frequency Control Ancillary Services (FCAS) and Load shedding

The National Electricity Market (NEM) as a whole requires constant adjustment of the amount of generation to match the load on the system to ensure that the system frequency remains within engineering defined bounds. An ancillary services market has been set up in order to allow generation to vary their energy market set points to prevent the system frequency from varying outside those bounds.

In practice the design of this market is far from perfect so that we now have degraded system frequency control relative to what existed before the introduction of the various FCAS markets. This is currently under review by various working groups set up by The Australian Energy Market Operator (AEMO) and the Australian Energy Market Commission (AEMC) to suggest solutions to this issue. However, regardless of the outcome of the reviews currently underway, the engineering necessity for good system frequency control is undeniable, and it has an economic value in the same way that energy itself has economic value.

Varying load is one possible way of managing power system frequency which has traditionally only been used in automated load shedding systems. These systems are triggered if there is a mismatch between load and generation sufficient to cause a rapid reduction in frequency. Accordingly a variable load can be used to provide frequency control ancillary services to the system for both regulation purposes and during times of system emergencies when rapid response load shedding is often required.

6.3.3 Voltage control ancillary services

Similar to frequency control, the power system cannot operate effectively unless it also has good voltage control. There is a relationship between system voltage and the concept of reactive power on power systems. It requires a long detour into electrical engineering theory to adequately describe reactive power which will not be entered into here, sufficient to say that the concept of reactive power is related to the short term (~ 10 milliseconds) storage of power in electric and magnetic fields which occurs in AC power systems.

The envisaged electrolysers being of power electronic design are expected to be able to vary their use or generation of reactive power and hence be able to change the system voltage at the point of connection. This can be used to assist voltage control over the South Australian power system and thus provide this service.

Unlike FCAS, voltage control ancillary services are not procured via a spot market, but are derived from generator control systems (Automatic voltage regulators or AVRs), network equipment such as transformers, capacitor banks, static var compensators and Statcoms. Static var compensators (SVCs) and Statcoms are power electronic devices which are designed to rapidly vary their reactive power output in response to voltage changes. They are often deployed to regulate power system voltage. The cost is considered part of the equipment installation and is negotiated as part of the load or generator performance standards. The financial benefits are accordingly difficult to quantify because they cannot be separated from other costs associated with the installation.

6.3.4 Deferral of transmission augmentations

A potentially major benefit for the market as a whole is that a controllable variable load can be used to defer the construction of large expensive transmission infrastructure. In particular there are several proposals to install additional interconnectors to Adelaide to either NSW or Victoria, and also to install large battery installations. Having the ability to rapidly vary load can provide a similar degree of system security at a reduced capital cost, and also a revenue stream from the output product.

Similar benefits are available within the Adelaide transmission system by dispatching the load to avoid system congestion and curtailment of renewable generators.

Deferral of transmission augmentations results in significant cost savings for all market participants but may be difficult to capture for accrual to the project itself.

6.4 Scale of industry / future renewable uptake

The proceeding sections have demonstrated that under certain conditions there may be a commercial opportunity for Green Hydrogen in South Australia and that the prospect may improve if the full value proposition can be realised. It is worth considering in very coarse terms what the size of the opportunity might be.

What might the Green Hydrogen market look like in the future? This requires consideration of not just production cost but policy, social and political drivers. It is these factors which largely set any green premiums available to Green Hydrogen and ultimately market size. This is difficult to predict, so a real opportunity can be used to illustrate by example.

In 2016, South Korea's finance minister was reported[13] to announce plans to replace the country's 26,000 CNG powered buses with hydrogen-powered buses, representing around 475,000 tonnes of hydrogen consumption per year. This is to be undertaken progressively, replacing around 2000 buses per year. If this final consumption was to be fuelled by Green Hydrogen, a prospect that many Governments are likely to consider, what would the "Green Hydrogen" industry production be to meet this demand?

Assuming that hydrogen is produced in South Australia from renewable energy, a hydrogen carrier, such as ammonia, is used to transport the fuel to South Korea, and based on metrics for the 2027 full scale ammonia plant involving around 28,000 tonnes of H_2 per year per plant, 17 full scale 600t per day ammonia production facilities are required to meet this demand. This would be an investment of approximately $15bn in the plant alone, representing approximately 700 full time jobs.

This level Green Hydrogen production would require approximately 28TWh per year in electricity input, which is more than twice the current South Australian yearly consumption. To meet this demand for renewable energy would require the installation of around 11GW of solar photovoltaic generation, or likely more than $15B in generation investment. To put the size of the construction required into perspective, AEMO estimated that there was 679MW of rooftop solar PV installed in South Australia in 2015[14]-16 and 1,576MW of wind generation[15].

To consider just what size the Green Hydrogen market could grow to, considering more than 60 million tonnes per year of hydrogen are currently consumed by industry, a factor of more than 100 times the South Korean example cited above. The Green Hydrogen opportunity size could be a very significant export industry for South Australia.

6.5 Potential levers or interventions

A public stakeholder workshop was held in Adelaide on 26 May 2017. As part of the workshop and to support the development of Green Hydrogen roadmap, stakeholders were asked to identify the most important levers that the South Australian government could utilise to support and encourage potential projects. Figure 17 below shows the relative importance of each lever as rated by the workshop attendees.

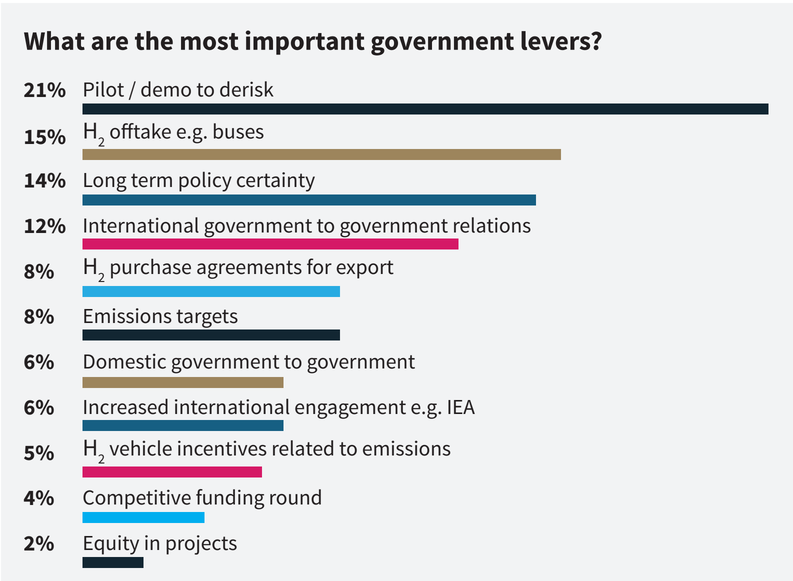


Figure 17: Stakeholder workshop - most important government levers

It is clear from this result that risk is important from a technical and commercial viewpoint.

Stakeholders can see the value in the industry gaining experience from some key demonstration projects and knowledge sharing. Success at demonstration scale is likely to give investors confidence to implement larger and more complex projects.

Likewise, if the South Australian Government can provide long term offtake agreements for hydrogen and keep policy settings consistently supportive of hydrogen projects, then investors are more likely to view projects as bankable.

Also important to stakeholders is the role that the South Australian Government can play in developing and facilitating relationships with governments of nations that are interested in importing Green Hydrogen. They would like this to also include the creation of government to government contracts for supply that South Australian based project proponents could then compete to fulfil.

GHG emissions targets, domestic and international engagement and vehicle emissions related incentives were also mentioned but not highly rated, as was the potential for competitive funding rounds and government equity in projects.

6.6 Pathways to project implementation

The implementation of a renewable energy project can take many forms. One of the main drivers for a successful methodology is the risk profile of the project development stage.

Site, resource, and off-take are the core elements of project development. Together they create value that promotes further investment. Securing these three elements by contract is a significant milestone for a project developer. During the implementation of a new disruptive concept such as Green Hydrogen it is vital to ensure a scale-able proof of concept demonstration can be implemented to validate the commercial readiness of the technology/project.

Without the constraints of a physical location for the Green Hydrogen concept, a project will simply fail. Furthermore, as outlined in this study a site selection methodology is required given the number of inputs needed to ensure an economically functioning project; for example, access to grid and gas infrastructure, port and renewable energy resources.

For early feasibility studies, a general assessment of resource availability is required. Based on the methodology being applied in this Green Hydrogen study, it is assumed that a prospective developer will leverage South Australia's comparative advantage for existing renewable energy developments to power the Green Hydrogen solution.

The purchaser of the renewable energy fuel and additional characteristics of output, for example renewable energy credits and oxygen, will need to be secured by a contract over the project term. For existing renewable energy projects this process is referred to as a Power Purchase Agreement (PPA) - in this instance a general term "offtake" can be applied. This implies that there is an economic and executable agreement by the project parties, and that it is ultimately confirmed by a written contract.

Based on the financial investigation undertaken and assumed technical and financial parameters, Pathway A2 and J – hydrogen export 2022 and 2027, Pathway C - Crystal Fertiliser and Pathway E - Vehicles will be considered in this section.

- **Pathways A2 & J Hydrogen export:** The proof of concept plant may qualify for ARENA grant funding given its innovative approach in developing an exportable commodity. Focus areas which will need to be considered include access to renewable energy, securing an offtake and securing a contract for the green product. Once obtained, a scalable proof of concept plant should be considered. To minimise project risk, an integration approach should be adopted by using existing operational technology where applicable. These pathways involve investment in the export market to convert the carrier back to hydrogen for use in FCEVs. It is likely to require the South Australian government assistance with relationships with those nations to develop the required infrastructure in the target market.
- **Pathway C - Crystal Fertiliser:** Given the scale of this plant, the study has identified key locations in South Australia where this concept has potential. As this is a unique product with a renewable energy element, ARENA grant funding should be considered for a scalable prototype plant. Such a project could assess the value streams of production to improve the future productivity. As the method of production is already in existence, learnings from the prototype plant will help clarify supply chain requirements, learning rates, technology/ electrolyser integration and the OPEX learning curves. The South Australian government is likely able to provide supporting consumption and usage patterns for this product across the state and could potentially facilitate the collation of similar data across other Australian states.
- **Pathway E - Vehicles pathways:** This pathway is unique as the capital required is small in comparison to the other pathways and timeline associated for implementation is short. The production of green fuel warrants further investigation. A moderate term offtake agreement from the South Australian Government could be sufficient for a proof of concept plant to be implemented. The plant should be small scale and centrally located, servicing potential bus and other heavy vehicles but having the flexibility to supply to private customers too. The pilot installation has the potential to be scalable, servicing and growing with the mobility market.

6.7 Supply chain impacts

The development of each pathway will provide benefits for South Australia across a number of areas. Four key areas have been highlighted and are discussed in the following sections. A summary of the expected areas of impact are shown in Table 23.

Note that the following discussion does not include the impacts of development of renewable energy projects to supply electricity to these pathways.

6.7.1 Employment

This category relates to direct employment during operation of the facility in South Australia. Large scale fertiliser or explosives plants are likely to be the largest employer, with 40 to 70 personnel required to run these types of facilities. Smaller, modular facilities such as a crystal fertiliser plant may employ 20 to 25 people.

Pathways where hydrogen is produced and then either stored or immediately consumed are likely to provide less employment opportunities. For example, only 5 to 10 people might be required to operate a hydrogen production and bus refuelling station. In other cases, the addition of hydrogen production would be an add-on to the current industrial operations and therefore the employment impact could be almost zero.

The number of people employed during the construction of projects are likely to be many times the number that are actually required to operate the completed facility. If a pipeline of construction projects was developed in the Green Hydrogen industry, it is possible that a few hundred people could be employed constructing Green Hydrogen projects.

6.7.2 Local development

The construction and operation of a significant facility will have local development impacts in the regions in which they operate. The larger the investment, the greater the impact.

The pathways that involve large scale and/or value add to hydrogen production through the manufacture of final products are the ones that will add the most value to the local community. For example, the manufacture of ammonia is large scale and would have a significant local development benefit, but the further use of ammonia to manufacture explosives would have a greater impact through greater investment in construction and operations.

Conversely, those paths that have the least investment and value add are likely to provide lower levels of local development.

6.7.3 Manufacturing industries

If major facilities or a number of smaller facilities are to be built in South Australia, it is likely that a reasonable proportion of the heavy, bulky, and therefore expensive to ship, components will be manufactured locally. This will provide a significant boost to local fabrication industries. For example, components such as hydrogen storage pressure vessels could be made locally for all of the pathways studied.

There are many other technologies and components involved in the pathways that would not be considered for local manufacturing initially, but if the scale of the industry develops, many other equipment items could also be made locally. For example, in the hydrogen production process, a range of core and balance-of-plant equipment is required that could potentially be manufactured in South Australia if a local or international technology company committed to having a manufacturing base in the state. To achieve this, significant investment will be required in manufacturing facilities and equipment and training personnel to produce the high technology components.

6.7.4 Skills development

As highlighted in the previous section, manufacturing of core components of the Green Hydrogen pathways will require the development of advanced manufacturing capabilities. These capabilities will need to be supported by appropriate training and vocational development, but will result in a workforce that is more highly skilled. Some of these skills will be transferable across from other industry sectors currently in decline, such as car manufacturing.

	Pathway	Employment	Local development	Manufacturing industries	Skills development
A1	Large ammonia for export	✓	✓	✓	✓
A2	Large hydrogen for export	✓	✓	✓	✓
B	Large ammonia MAP/DAP	✓	✓	✓	✓
C	Mod. ammonia crystal fertilisers	✓	✓	✓	✓
D	Large ammonia explosives	✓	✓	✓	✓
E	H2 Vehicle Station	x	x	✓	✓
F	Hydrogen fuel cell	x	x	✓	✓
G	Hydrogen engine	x	x	✓	✓
H	Blending into natural gas network	x	x	✓	✓
I	Industrial utilisation	x	x	✓	✓
J	Mod. ammonia export to H_2	✓	✓	✓	✓

Table 23: Skills development table

6.7.5 Other opportunities for a hydrogen industry in South Australia

The development of a hydrogen industry in South Australia is not dependant on the implementation of hydrogen production projects in the state, although some heavy and bulky manufactured items are more likely to be produced close to the project location. If project related local development drivers are not present, South Australia will have to ensure that businesses in the hydrogen industry are attracted to develop and set up in the state.

As for the project related opportunities, South Australia could leverage its automotive sector manufacturing capabilities to develop advanced manufacturing centres for the key hydrogen supply chain items. This is likely to require significant investment by equipment manufacturers and potentially incentives from the government to get these developments established.

South Australia is also likely to have key skills in other areas related to the existing oil and gas industry in the state. In particular, engineering and project management capabilities could easily be leveraged into the development of hydrogen industry projects. The state could provide a base for local and international equipment manufacturers, project developers and engineering companies to design, manufacture, manage and deliver projects throughout the Asia Pacific region.

7

Study Conclusions

7.1 2017 outcomes

Nine pathways from feedstock to final product were assessed for implementation in 2017. Each option is described in Section 5.

7.1.1 Technical and commercial feasibility

To develop the pathways, technologies were reviewed using the Technology Readiness Level (TRL) and Commercial Readiness Index (CRI) scales. This narrowed down the range of technologies for hydrogen manufacture and subsequent processes to produce final products. Only those technologies that were considered feasible were included in the final pathways.

The technologies selected are shown in Table 10.

It should be noted that only a single hydrogen production technology, water electrolysis, was selected. Other hydrogen production technologies were not considered technically and commercially ready, in particular, options that require CCS to be considered Green Hydrogen.

7.1.2 Uses for Green Hydrogen

A range of end uses for Green Hydrogen have been considered. These are:

- Bulk ammonia production for local use and export;
- MAP and DAP fertilisers for local use and export;
- Crystal fertilisers for local use;
- Explosives for local use and export;
- Transport fuel in South Australia;
- Electricity generation via fuel cells;
- Electricity generation utilising gas engines;
- Blending of hydrogen into the natural gas network; and
- Industrial utilisation of hydrogen in food, glass, chemicals, hydrocarbons industries.

7.1.3 Financial results

The 2017 analysis shows that the only pathways with a positive NPV under base conditions are C - crystal fertiliser production and E – H_2 Vehicle Station.

The sensitivity analysis considered a range of values for the key variables. This analysis showed that although the pathways are sensitive to the price of electricity, using the range of values considered for grid and off grid electricity, none of the other pathways change to a positive return.

As shown in the financial analysis, the only pathways that have a positive NPV are crystal fertilisers and H_2 Vehicle Station. The crystal fertilisers pathway has been assessed with plant based in Port Pirie. Use of hydrogen for transport can also achieve a positive NPV. This path has been assessed for a Northern Adelaide location.

7.1.4 Supply chain

The pathways considered encompass a range of project scales and capital investment levels. The largest scale being pathway D - explosives with a potential investment of $1bn required, and the smallest is pathway E - hydrogen for transport at $4.3m.

As described in Section 7.7 there are a range of potential supply chain benefits to South Australia. The key ones are:

- Employment and local development could be significant if large scale projects and/or multiple projects are implemented. Pathway A2 Large scale hydrogen export is the most financially viable large scale project;
- For all pathways there is potential to manufacture bulky and heavy items, such as hydrogen pressure vessels, locally. As the Green Hydrogen industry develops it may become effective for more of the high technology equipment to be manufactured in South Australia, bringing with it advanced manufacturing and skills utilisation and development opportunities ; and
- South Australia could become a base for hydrogen equipment manufacture, design, engineering and project management, utilising existing skills from the automotive and oil and gas sectors. This base could potentially service the Asia Pacific region and beyond.

7.1.5 Impact of government incentives

In Section 6 an estimate was made of the levels of government or other non-commercial sources of funding that would be required to make a pathway achieve breakeven, NPV=0.

This demonstrated that:

- Pathway A2 – large hydrogen export, pathway C - Crystal fertilisers and pathway E – H_2 Vehicle Station, are projected to be NPV positive without support; and
- Other pathways are estimated to be a long way from commercial breakeven, requiring capital injection of $85m to more than $500m, or annual opex support of $8m to more than $50m.

7.2 2022 and 2027 outcomes

For the 2022 and 2027 implementation year assessments, pathway A2 has been added to demonstrate a hydrogen carrier for export into the Asia Pacific region for transport fuel. Pathway J is also added, producing a hydrogen carrier in South Australia in a modular plant for export and liberation of hydrogen in the Asia Pacific region.

The outcomes for 2022 and 2027 are very similar and have been grouped together for this summary.

7.2.1 Technical and commercial feasibility

The technologies considered technically and commercially mature in 2017 were included in the 2022 and 2027 assessments.

The addition of the use of a hydrogen carrier has been introduced for both the 2022 and 2027 assessments. Ammonia has been used in the analysis, it is recognised that it is one of a number of potential future hydrogen carriers, which include liquid hydrogen, toluene or metal hydrides. Although the technology to produce ammonia is well proven, the technology to crack ammonia back to hydrogen and nitrogen is currently under development. Ammonia has been assessed due to availability of engaged stakeholders and key data.

7.2.2 Financial results

In addition to pathway C – Crystal fertilisers, Pathway A2 – Large hydrogen export for transport and pathway E – H_2 Vehicle Station become NPV positive for both 2022 and 2027.

7.2.3 Uses for Green Hydrogen

For the 2022 and 2027 assessments, the use of export hydrogen in transport applications in the Asia Pacific region was added. As previously described, a hydrogen carrier is produced in South Australia and the hydrogen is liberated in the target export market.

7.2.4 Favourable pathways

The favourable pathways for the 2022 and 2027 assessments are A2 – Large ammonia export for transport, C – Crystal fertilisers and E – H_2 Vehicle Station. The selected locations are Port Pirie, Port Pirie and Northern Adelaide respectively.

7.2.5 Supply chain

As for the 2017 assessment:

- Larger investments yield greater employment and local development outcomes; and
- Potential exisits for advanced manufacturing and skills utilisation and development to support the low and high technology aspects of Green Hydrogen equipment supply.

7.2.6 Impact of government incentives

As for the 2017 assessment, an estimate was made of the levels of government or other non-commercial sources of funding that would be required to make a pathway achieve breakeven, NPV=0.

This demonstrated that:

- Pathway A2 – Large hydrogen export pathway C - Crystal fertilisers and pathway E – H_2 Vehicle Station, are projected to be NPV positive without support; and
- Other pathways are estimated to be a long way from commercial breakeven, requiring capital injection of $3m to more than $500m or annual opex support of $0.4m to more than $50m.

7.3 Feasibility of Green Hydrogen export

During the study it has become apparent that although none of the hydrogen carrier technologies can be considered technically or commercially proven in 2017, the assessment of a carrier to allow export of hydrogen was important for the study to be relevant to current opportunities and projects being proposed.

This study has focused on ammonia as a potential carrier for hydrogen export. This does not imply that this is the only technology, or that it will become the dominant technology. It has been selected purely due to the availability of stakeholders and data to assess the potential costs. By introducing a carrier, a more realistic export value, has been calculated for hydrogen.

Creating a hydrogen carrier involves additional steps in the production chain, for example liquefaction, ammonia production, hydrogenation of toluene. Each step creates complexity, adds cost and involves losses. These impacts will need to be minimised to achieve a price of hydrogen at the pump in the Asia Pacific region attractive to end users.

As stakeholders have recognised, technical risk and supply agreements are critical areas that will need to be addressed for projects to be financed by the private sector. A proof of concept development could be feasible if an off-take agreement can be established at a price and volume that allows project proponents to build and operate a suitably sized demonstration facility.

It seems certain that the demand for Green Hydrogen will exist based on statements from the Japanese and South Korean governments. South Australia will need to move quickly to capitalise on the opportunity as many other regions, including other Australian states, are likely to also pursue it aggressively.

7.4 Potential hydrogen value chain

Large scale pathways such as ammonia manufacture and further value add products are likely to deliver the most benefits to South Australia from the hydrogen value chain. The investment of significant capital and ongoing operating expenses will have positive local impacts on employment and economic development.

In addition, it is likely that even early plants will require an important local manufacturing contribution, with potential for South Australia to become an advanced manufacturing centre as the scale of industry develops. This will require investment in skills development and training, but could provide a new wave of manufacturing jobs to replace some of those currently under threat.

Local engineering and manufacturing capabilities related to the automotive and oil and gas industries could potentially be leveraged to design, manufacture, manage and deliver projects from a South Australian base, even if these projects are not implemented in South Australia. South Australian based equipment manufacturers, engineering and project management companies could use the state to deliver projects located in the Asia Pacific region or beyond.

7.5 Recommended way forward

From the results of this Green Hydrogen study, export pathways appear to offer an attractive opportunity in the future. To capitalise on this opportunity, South Australia will need to position itself early to ensure that the experience, knowledge and capability is ready when large scale export markets develop.

The recommendation from this study is for the South Australian government to move quickly to establish a range of demonstration scale Green Hydrogen projects. These could include transport, chemicals and export uses.

In particular, if South Australia can develop a hydrogen export supply chain demonstration for transport use in South East Asia, this is likely to provide extremely valuable lessons for future, large scale development.

8

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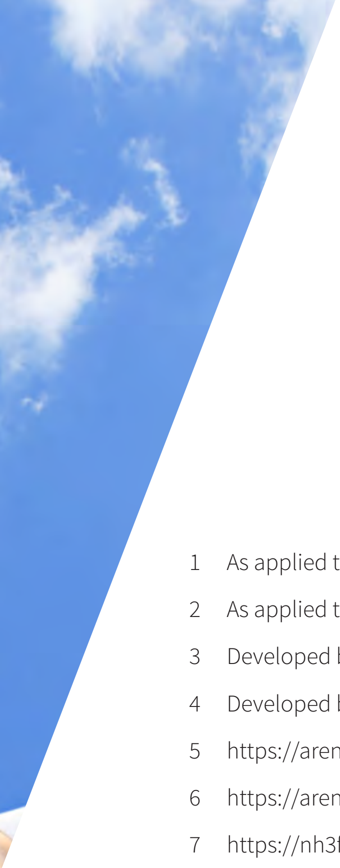

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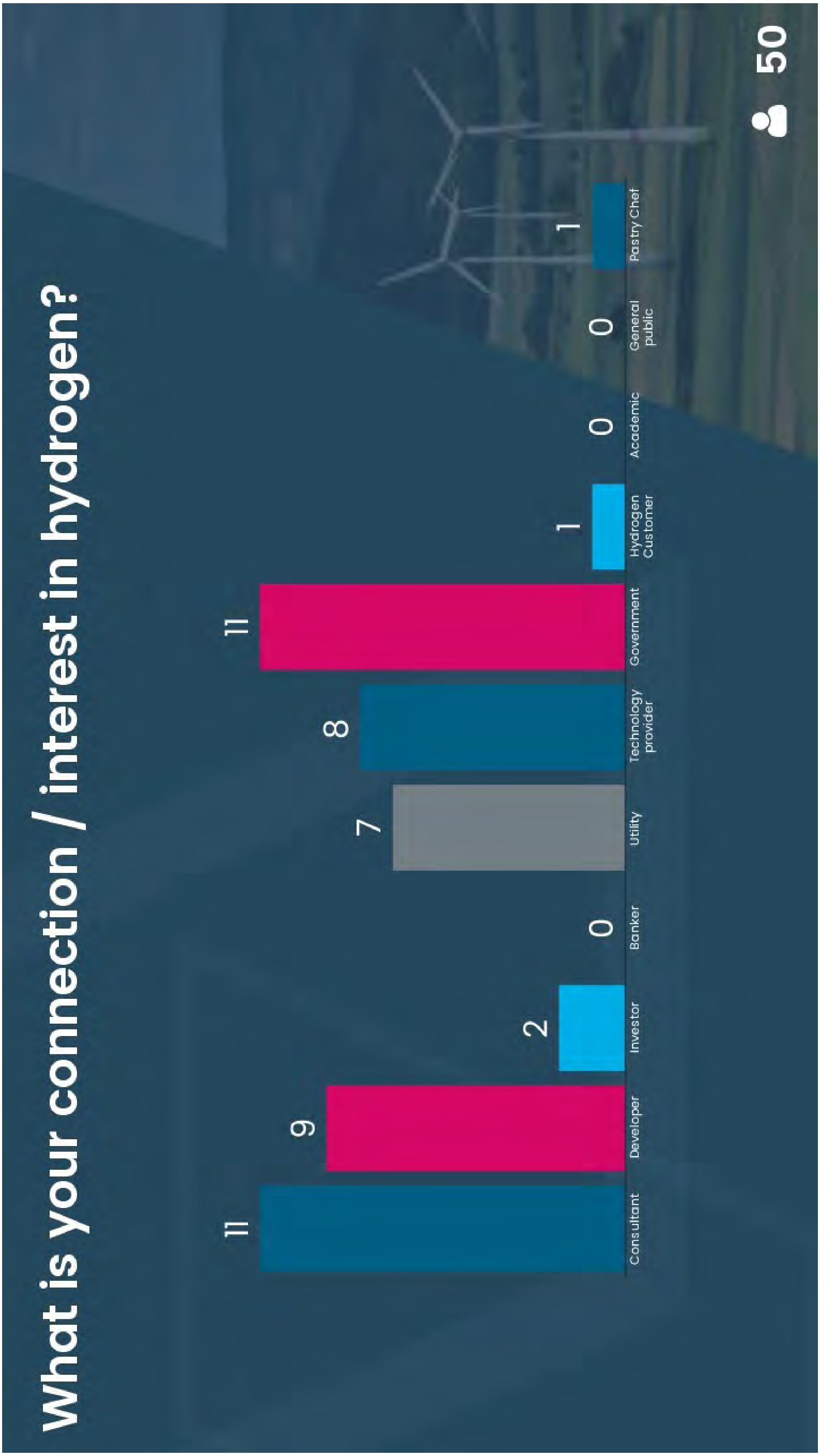
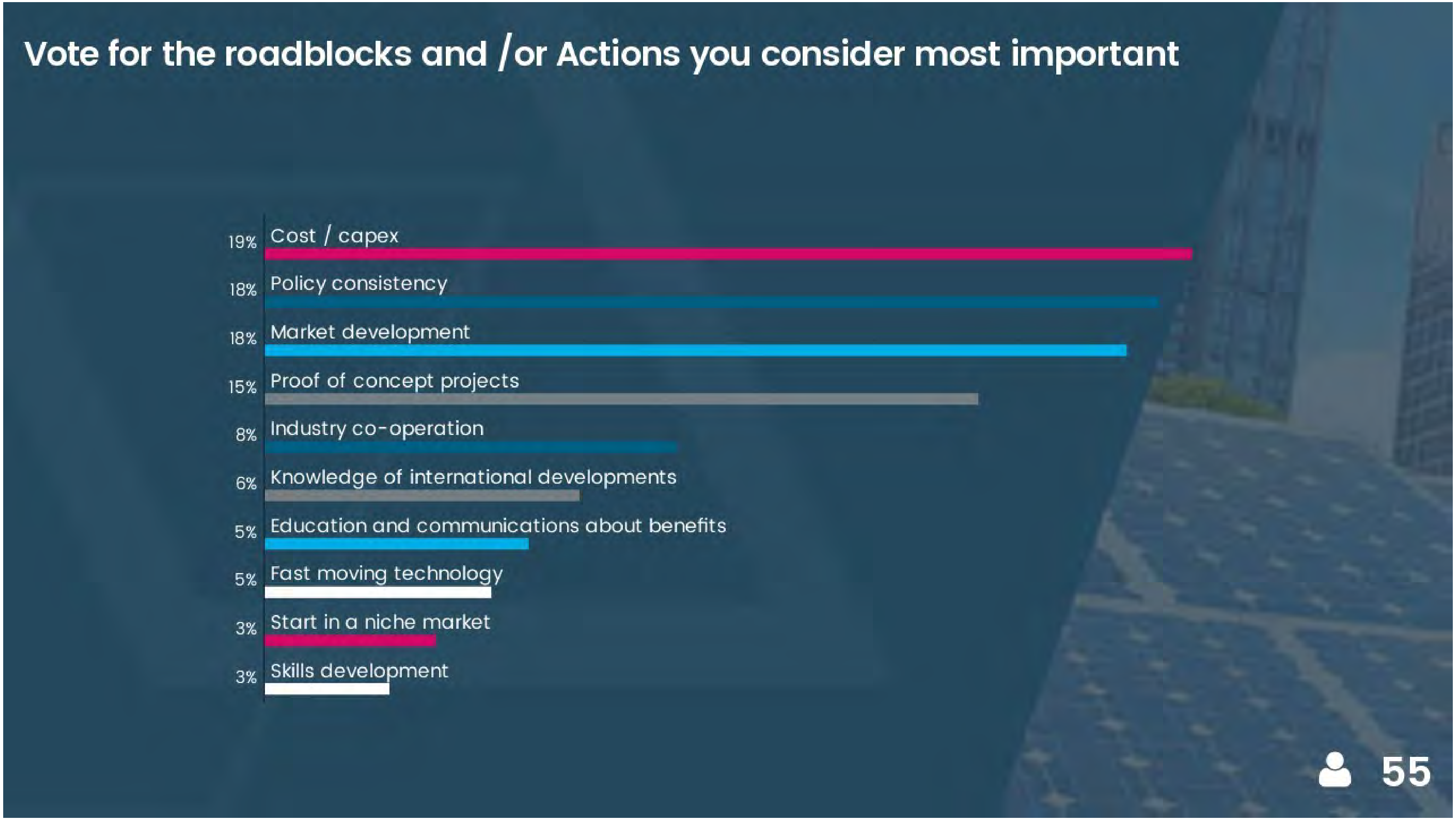
Appendix A

Stakeholder workshop results



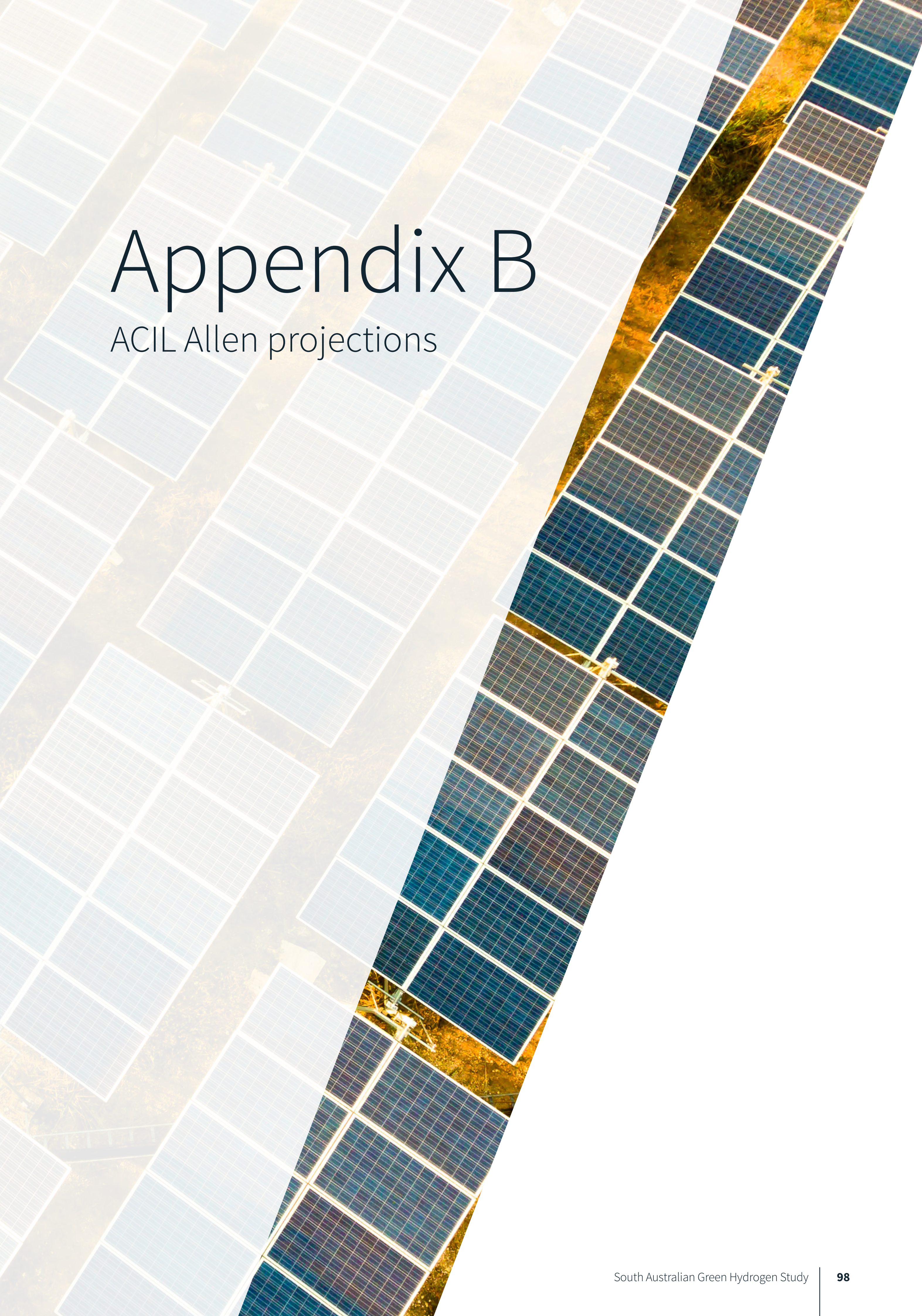
What is your connection / interest in hydrogen?
11
9
2
0
7
8
11
1
0
0
1
Consultant
Developer
Investor
Banker
Utility
Technology provider
Government
Hydrogen Customer
Academic
General public
Pastry Chef
50


What is your vision for hydrogen in South Australia?
Storm in a teacup
$5M PA fringe industry employing 50 people
$100M PA industry employing 200 people
$5B PA industry employing 1,000 people
1.3
1.9
2.8
7.0
61



Vote for the roadblocks and /or Actions you consider most important
19% Cost / capex
18% Policy consistency
18% Market development
15% Proof of concept projects
8% Industry co-operation
6% Knowledge of international developments
5% Education and communications about benefits
5% Fast moving technology
3% Start in a niche market
3% Skills development
55


What are the most important government levers?
54
21% Pilot / demo to derisk
15% H2 offtake e.g. buses
14% Long term policy certainty
12% International govt to govt relations
8% H2 purchase agreements for export
8% Emissions targets
6% Domestic govt to govt
6% Increased International engagement e.g. IEA
5% H2 vehicle incentives related to emissions
4% Competitive funding round
2% Equity in projects



Appendix B

ACIL Allen projections

1 ELECTRICITY MODELLING ASSUMPTIONS

OVERVIEW OF PROPOSED NEM ASSUMPTIONS

Item	Summary of assumption	Rationale
Assignment specific assumptions	– Inclusion of SA Government's recently announced package including: – New reserve 250 MW OCGT – 100 MW/100 MWh battery system	– As announced
Macro-economic variables	– Exchange rate of 0.75 AUD/USD – Inflation of 2.5% p.a.	– Long term average – Mid-point of RBA range
Greenhouse gas emission policies	– Explicit pricing of carbon emissions from July 2020 at $20 per tonne of CO2-e; rising at 3% real per annum – Retention of the LRET in its current form; No implementation of state based renewable energy schemes in Victoria and Queensland – Include renewable generation projects committed in the ACT Wind FiT Auctions; Include ARENA and Queensland Government Solar 150 funded large-scale solar projects	– Task of achieving Australia's 2030 emissions target will require substantial emissions reductions in the electricity sector – Victorian and Queensland renewable energy policies are not firm at this stage
Electricity demand	– AEMO 2016 NEFR with adjustments for smelter closures, ACIL Allen's projections for PV, storage uptake and electric vehicle uptake – Smelters assumed to close include Portland (August 2021); Tomago (2027) and Boyne Island (2029)	– Aluminium smelters with long term electricity supply agreements in place are assumed to become uncompetitive once these long term agreements expire

Item	Summary of assumption	Rationale
Supply side assumption	– Specific named new entrant projects are included in the modelling only where projects have reached FID status – Other new entrants projected to enter are generic entrants based on commercial price signals for entry – Retirements of existing generators are included in the modelling where the retirement has been announced by the participant or where the generator is projected to be unprofitable over an extended period of time – Specific major coal-fired retirements include: Hazelwood (March 2017); Liddell (2022); Vales Point (2027) and Gladstone (2029)	– The number of announced projects far exceeds the requirements of the electricity market and hence only those that are firmly committed to go ahead are included in the modelling – The assessment of generator profitability under the modelled scenario provides a consistent method to assess closure decisions
Gas a fuel for electricity generation	– Gas market is modelled in ACIL Allen's GasMark Australia model	– The combined demand for gas from Australia's domestic gas users and the LNG export industry means higher cost gas resources need to be developed to satisfy demand

Coal as a fuel for electricity generation	– The marginal price of coal for electricity generation is assessed in consideration of the specific circumstances for each generator taking into account:
	  – Suitability of coal for export and the assumed international thermal coal price
	  – Location of power station in relation to the mine and export terminals
	  – Mining costs
	  – Existing contractual arrangements
	– International thermal coal prices are assumed to converge to U$ 60/t in the long term
		– International thermal coal prices are assumed to converge to their long term average price

Representation of bidding behaviour	– Contracted capacity:
	  – Minimum generation levels are offered at negative of zero price
	  – Remaining contracted capacity offered at short run marginal cost
	– Remaining capacity:
	  – Maximisation of dispatch for price takers
	  – Maximisation of net uncontracted revenue for larger generator portfolios
		– Observations of generator bidding behaviour in the NEM

SOURCE: ACIL ALLEN

2

GAS MODELLING ASSUMPTIONS

The gas price forecasts set out in this report represent ACIL Allen's current "central view" **Base Case** which we regard as a reasonable mid-line scenario based on the current market situation and recent developments in relation to key market drivers. ACIL Allen's Base Case corresponds broadly with the Australian Energy Market Operator (AEMO) Neutral scenario as set out in the 2016 *National Gas Forecasting Report*. The AEMO forecasts do not, however, cover the Northern Territory nor do the supporting gas price forecasts[1] take into account gas supply from the Northern Territory into eastern Australia.

The following global assumptions are incorporated into the Base Case:

— Consumer Price Index (CPI) of 2.5 per cent per year.

— Long-run oil price of US$60/barrel

— Long-run exchange rate 0.75 USD/AUD

— Gladstone LNG price (delivered) = ((0.135 x Oil Price US$/bbl)/Exchange Rate + A$1.5)/1.055 = A$12.15/GJ.

— No explicit carbon pricing arrangements from mid-2014. However from 2020 the assumed levels of gas use for electricity generation reflect an assumption that a carbon pricing mechanism is reintroduced.

  – ACIL Allen's current electricity Base Case assumes explicit carbon pricing comes into force from July 2020 at a level of around \$20/tonne CO_2-e escalating in real terms at about 3 per cent per annum. This can be thought of as either a change in policy (replacing the ERF) or an adjustment to the ERF policy resulting in a lowering of the sectoral baseline and allowing generators to purchase and surrender international permits.

With regard to gas demand the following assumptions are made:

— **Retail loads** (residential, commercial and small industrial customers serviced by gas distribution businesses and retail energy sellers) closely reflects the current AEMO forecasts.

— **Large industrial and mining customers** demand projections are based on the known gas requirements of existing large industrial and mining consumers that contract for gas directly, plus gas requirements of any new large industrial or mining loads that we consider to be committed or advanced projects.

— **Gas-for-power generation** (GPG) assumptions are based on ACIL Allen's modelling of the hourly dispatch of individual generating units in the National Electricity Market, with annual gas requirements and daily gas consumption profiles calculated from modelled plant dispatch by applying assumed operating efficiency/heat rate for each plant.

[1] Core Energy Group: *"NGFR Gas Price Assessment"*, October 2016

— **LNG:** We assume that liquefaction capacity at Gladstone is limited to the currently committed six trains (nominal 25.3 Mtpa LNG) with each plant operating at a level corresponding to its current LNG contract levels. As a result the effective output of the six trains is limited to 23.8 Mtpa LNG.

With regard to gas supply, the Base Case assumptions incorporate some 108 gas fields and field aggregates, including both existing sources of supply and potential new gas field developments. These include conventional gas fields, coal seam gas projects and future unconventional gas projects (shale gas, tight gas).

— **New conventional supply:** we assume new sources of conventional gas supply in the Bass Strait region including Halladale/Blackwatch (offshore Otway) from 2016; Kipper-Tuna-Turrum (offshore Gippsland Basin) from 2017 and Sole (offshore Gippsland Basin) from 2019. We also assume tie-in of additional gas reserves in the Bass Basin (Trefoil, Gentoo/Rockhopper). "Yet-to-be-discovered" fields in the offshore Gippsland and Otway Basins are assumed to offer new gas supply, at relatively high cost, with production capacity ramping up over the period 2020 to 2025.

— **Cooper Basin unconventional** capacity limited to 50 PJ/a by 2022 with all production directed to the Santos – GLNG Easternhaul supply contract to Gladstone.

— **NSW CSG:** We assume no growth in NSW CSG production during the projection period.

— **Northern Territory supply:** Additional gas resources are found and developed in the Northern Territory, supporting long-term supply to Eastern Australian via the Northern Gas Pipeline (NGP) from Tennant Creek to Mount Isa. We assume that the NGP proceeds with capacity of 90 TJ/day available from 2018.

3 AMMONIA PRICE PROJECTION ASSUMPTIONS

3.1 Ammonia price projection

Ammonia production is dependent on energy supplies, particularly natural gas (or coal) which accounts for the majority of production costs. High transportation costs and the rapidly changing dynamics of gas markets within different regions has meant that there has been volatility in realised ammonia prices in the short term in different regions. In the medium term, however, we believe that there is still a strong correlation between the regional gas prices and ammonia prices. Consequently, we propose to develop the medium- to long-term projections of the price of anhydrous ammonia based on the longer term cost of gas and conversion costs in the markets of key producers.

Currently China is world's largest producer of ammonia followed by India and the Russian Federation. Together, these three countries produce over half of the world's supplies. The increased supply of low cost gas in the United States associated with the rapid growth in shale oil production has meant that the economics of ammonia production in the US has undertaken a substantial shift. Prior to 2007 production had been declining due to increased gas costs but since 2012 has been increasing with further increases expected over the next few years. Although producers in the Russian Federation have recently undertaken major refurbishments to modernise their plants and have also added significant production capacity, they are primarily located in the Black Sea region. The high transport costs limits their potential to compete effectively with producers in the Asia Pacific region.

Consequently, for gas prices, we propose to use the latest Asian gas price forecasts from the International Energy Agency (see **Figure 3.1**) as the basis for projecting the change in Australian ammonia prices. More specifically, we recommend using the New Policies Scenario.

FIGURE 3.1 IEA WORLD ENERGY OUTLOOK 2016 ENERGY PRICE FORECASTS

Table 1.4 ▷ Fossil-fuel import prices by scenario

		New Policies Scenario			Current Policies Scenario			450 Scenario		
Real terms ($2015)	**2015**	**2020**	**2030**	**2040**	**2020**	**2030**	**2040**	**2020**	**2030**	**2040**
IEA crude oil ($/barrel)	51	79	111	124	82	127	146	73	85	78
Natural gas ($/MBtu)										
United States	2.6	4.1	5.4	6.9	4.3	5.9	7.9	3.9	4.8	5.4
European Union	7.0	7.1	10.3	11.5	7.3	11.1	13.0	6.9	9.4	9.9
China	9.7	9.2	11.6	12.1	9.5	12.5	13.9	8.6	10.4	10.5
Japan	10.3	9.6	11.9	12.4	9.9	13.0	14.4	9.0	10.8	10.9
Steam coal ($/tonne)										
OECD average	64	72	83	87	74	91	100	66	64	57
United States	51	55	58	60	56	61	64	53	52	49
European Union	57	63	74	77	65	80	88	58	57	51
Coastal China	72	78	86	89	79	92	98	73	72	67
Japan	59	66	77	80	68	84	92	61	59	53

Notes: MBtu = million British thermal units. Gas prices are weighted averages expressed on a gross calorific-value basis. All prices are for bulk supplies exclusive of tax. The US price reflects the wholesale price prevailing on the domestic market. The China and European Union gas import prices reflect a balance of LNG and pipeline imports, while the Japan import price is solely LNG.

SOURCE: INTERNATIONAL ENERGY AGENCY (2016), WORLD ENERGY OUTLOOK, OECD, FRANCE, PAGE 45.

Appendix C

Learning rates report

REPORT TO
ADVISIAN

11 MAY 2017

BRIEFING NOTE ON LEARNING RATES

PREPARED FOR THE SOUTH AUSTRALIAN GREEN HYDROGEN STUDY

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CONTENTS

LEARNING RATES 1

Discussion

Experience curves, also called learning curves, are commonly used to predict cost paths in the mid- to long-term. Essentially, an experience curve relates production costs to the accumulation of experience in making a particular product (often measured by cumulative production). Experience curves are based on the theory of learning-by-doing. This was explained by Arrow in the following way:

…technical change in general can be ascribed to experience, that it is the very activity of production which gives rise to problems for which favourable responses are selected over time.[1]

There are many examples of the application of learning curves to energy technologies. One example of successful learning is the production of the Liberty Ship, a single type of cargo vessel built in 14 U.S. shipyards during World War II. From 1941 through 1944 cumulative production was 2,458 Liberty Ships, all to the same standardized design, and "the reductions in man-hours per ship with each doubling of cumulative output ranged from 12 to 24 per cent."[2]

A more recent example is provided by the decline in the price of photovoltaic (PV) panels. The drop in PV panel prices has received a lot of attention and it provides a good case study of successful learning by doing. As such, it provides an upper bound to the gains which can be expected from learning.

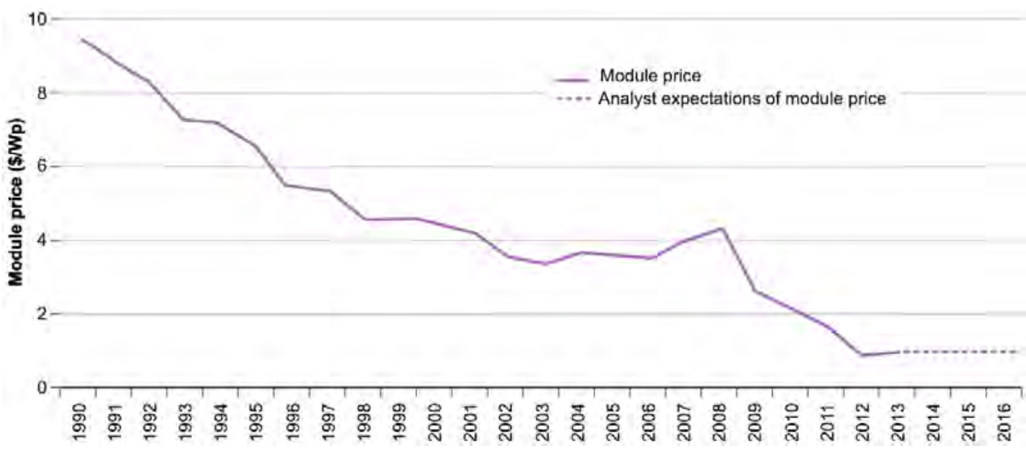
In 2013 Arnaud De La Tour and others reviewed 17 studies that examined PV module prices over time.[3] Based on these studies they produced the learning curve shown in **Figure 1.1**. They concluded that the average learning rate was 20.2 per cent. This can also be represented in a per year basis, which gives a rate of cost reductions of 8.4 per cent per year. However, one must be careful in noting that learning rates apply to cumulative production or rollout of a technology, and time-based mappings are contingent upon a given production trajectory. Hence, any changes to the production profile over time imply that time-based learning rates will need to be recalibrated.

A review of 26 different studies by Schrattenholzer and McDonald calculated experience curves and rates of learning for many energy-related technologies. They found that the majority of learning rates were around 20 per cent.[4]

Technology learning is typically represented in the form of an 'experience curve', where unit costs of a technology or process decrease by a certain percentage (the learning rate) for every doubling of cumulative capacity or output.[5] In other words, in the case of the PV example above, PV module prices experienced cost reductions of 20.2 per cent for each doubling of cumulative capacity.

1 Arrow, K.J., 1962. *The economic implications of learning by doing*, The Review of Economic Studies, Vol. 29, No. 3 (Jun., 1962), pp. 155-173
2 Lucas (1993). *Making a Miracle*. Econometrica, Vol. 61, No. 2. (Mar., 1993), pp. 251-272.
3 Arnaud De La Tour, Matthieu Glachant, Yann Ménière, *What cost for photovoltaic modules in 2020? Lessons from experience curve models*, Working Paper 13-ME-03, CERNA, MINES ParisTech, Working Paper 13-ME-03 March 2013.
4 Alan McDonald, Leo Schrattenholzer, *Learning rates for energy technologies*, Energy Policy 29 (2001) 255}261
5 Experience curves are also commonly referred to as learning curves.

FIGURE 1.1 EVOLUTION OF PV MODULE PRICE FROM 1990 TO 2016



Note: The increase in module prices between 2004 and 2008 was due to a shortage of silicon as silicon manufacturers struggled to keep up with demand from the growing number of PV panel manufacturing plants.

SOURCES: PRICES TO 2011 BASED ON: ARNAUD DE LA TOUR, MATTHIEU GLACHANT, YANN MÉNIÈRE, WHAT COST FOR PHOTOVOLTAIC MODULES IN 2020? LESSONS FROM EXPERIENCE CURVE MODELS, WORKING PAPER 13-ME-03, CERNA, MINES PARISTECH, WORKING PAPER 13-ME-03 MARCH 2013. PRICES BEYOND 2011 BASED ON: US DOE PRESENTATION ON PHOTOVOLTAIC SYSTEM PRICING TRENDS, SEPTEMBER 2014 (POST 2013 PRICES BASED ON ANALYST EXPECTATIONS)

A report on experience curves by the IEA in 2000 included analysis of the change in PV module prices as a function of cumulative sales (see **Figure 1.2**). The shape of the curve is described by the following formula:

Price at year t $= P_0 \times C^{-E}$

P_0 is a constant equal to the price at one unit of cumulative production or sales. C is cumulative production or sales in year t. E is the (positive) experience parameter, which characterises the inclination of the curve. Large values of E indicate a steep curve with a high learning rate. In the literature, comparisons between different experience curves are made by doubling the cumulative volume; the corresponding change in price is referred to as the progress ratio. The relation between the progress ratio, PR, and the experience parameter is:

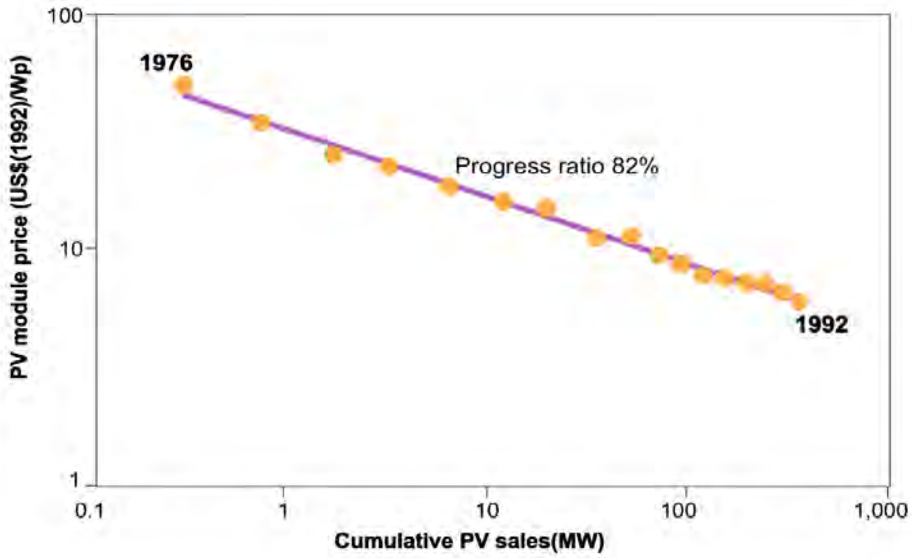
$PR = 2^{-E}$

The term learning rate (LR) is also commonly used in the literature on this subject. It is defined as:

$LR = (100 - PR)$

For example, in **Figure 1.2**, P_0 is the price at 1 MW of cumulative sales and is equal to 32 US$(1992)/$W_p$. In the year t = 1992 the price had fallen to 5.9 US$/$W_p$ and the sum of all sales up to that point was 340 MW.

FIGURE 1.2 EXPERIENCE CURVE FOR PV MODULES, 1976-1992



SOURCE: EXPERIENCE CURVES FOR ENERGY TECHNOLOGY POLICY, IEA, OECD, 2000

The experience parameter (E) for the curve in **Figure 1.2** is 0.29 which gives a progress ratio of $2^{-0.29}$ = 0.82, or 82 per cent, meaning that the that price is reduced to 0.82 of its previous level after a doubling of cumulative sales. The learning rate for PV modules in the period 1976-1992 was thus 18 per cent (=100-82), meaning that each doubling of sales reduced the price by 18 per cent. In terms of yearly rates for cost savings, this translates to 10 per cent per year, with the corresponding caveat that learning rates apply to cumulative production and their mapping to a time-based rate is only appropriate for a given production profile over time, requiring recalculation when the production profile over time changes.

It is generally accepted that learning rates vary over time as the experience with a particular technology increases. The US Energy Information Administration (EIA) breaks the evolution of a technology into three stages, *revolutionary*, *evolutionary* or *mature*.[6] They argue that different learning rates apply at each stage, with those rates declining as the technology moves from the *revolutionary* stage through to the *mature* stage.[7] Some examples of the learning rates assumed by the EIA for different stages of technology development are shown in **Table 1.1**.

TABLE 1.1 LEARNING RATES FOR SELECTED TECHNOLOGIES BY STAGE OF TECHNOLOGY DEVELOPMENT (PER DOUBLING OF PRODUCTION)

Technology	Learning Rate (LR)		
	Period 1 *(revolutionary)*	**Period 2 *(evolutionary)***	**Period 3 *(mature)***
Fuel cell	20%	10%	1%
Geothermal	-	8%	1%
Municipal solid waste	-	-	1%
Hydropower	-	-	1%
Wind	-	-	1%
Offshore wind	20%	10%	1%
Solar thermal	20%	10%	1%

6 The EIA also refer to these stages as Period 1, Period 2 and Period 3 respectively.
7 U.S. Energy Information Administration, Assumptions to the Annual Energy Outlook 2013, Electricity Market Module

Technology	Learning Rate (LR)		
	Period 1 *(revolutionary)*	Period 2 *(evolutionary)*	Period 3 *(mature)*
Solar PV (modules)	-	10%	1%
Solar PV (balance of system)	-	10%	1%

SOURCE: : U.S. ENERGY INFORMATION ADMINISTRATION, ASSUMPTIONS TO THE ANNUAL ENERGY OUTLOOK 2013, ELECTRICITY MARKET MODULE, TABLE 8.3

Summary of evidence

In conclusion, it is commonplace to find successful examples with learning rates of 10 to 20 per cent for every doubling of production during the revolutionary and evolutionary phases of the technology, and lower learning rates around 1 per cent once the technology has reached maturity. With a 5 to 6 year time period per doubling of production (implying a 12-15 per cent growth rate per year), these learning rates per doubling of production imply yearly learning rates as set out in **Table 1.2**.

TABLE 1.2 MAPPING OF LEARNING RATES PER DOUBLING OF PRODUCTION TO YEARLY LEARNING RATES

	Yearly Learning Rate		
Time to double production	**20% per doubling of production *(revolutionary)***	**10% per doubling of production *(evolutionary)***	**1% per doubling of production *(mature)***
5 Years to double production	4.4%	2.1%	0.2%
6 Years to double production	3.7%	1.7%	0.2%

SOURCE: ACIL ALLEN CALCULATIONS

Green Hydrogen - Proposed learning rates

The proposed yearly learning rates for the Green Hydrogen project are shown in **Table 1.3**. Learning rates are specified for three stages of technology development, defined as *revolutionary, evolutionary* and *mature,* as defined by EIA's definitions of the stages of technology development. Comparison of **Table 1.2Table 1.2** and **Error! Reference source not found.** shows that the learning rates proposed for the Green Hydrogen project are consistent with average industry learning rates, assuming a 5-6 year period per doubling of production.

The Green Hydrogen project considers plants that are *n+1*, that is, the n^{th} plus 1 plant of a given technology. Accordingly, the scope of the Green Hydrogen project does not include *revolutionary* technologies. Technologies at a *revolutionary* stage are deferred until they become *evolutionary*, so the upper end of the learning rate spectrum is not considered.

TABLE 1.3 GREEN HYDROGEN – PROPOSED LEARNING RATES (TIME-BASED, PER YEAR)

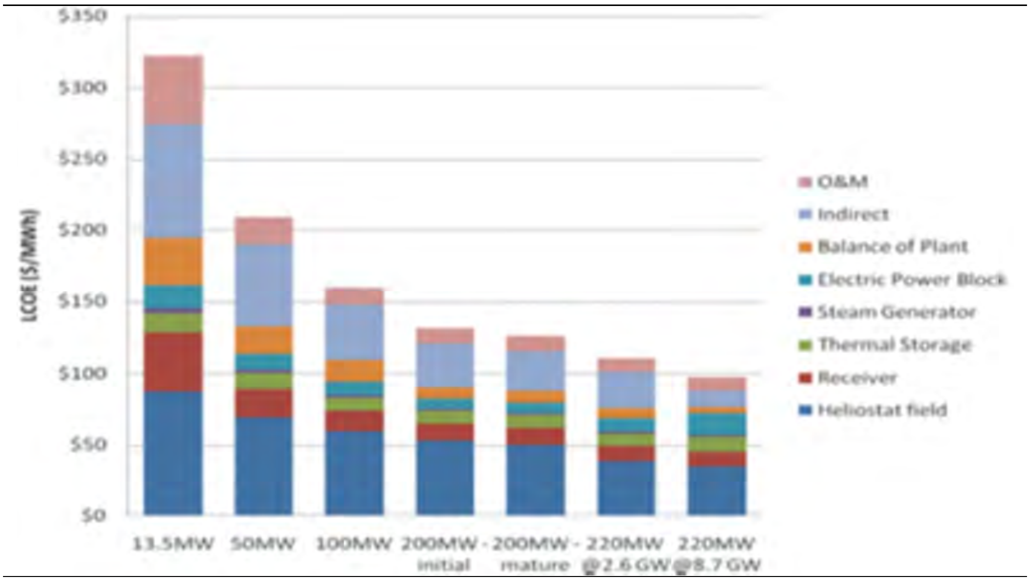
Learning Rate (technology stage)	2015	2020	2025	2030	2040	2050
O&M (mature)	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
O&M (evolutionary)	1.5%	1.5%	1.5%	0.2%	0.2%	0.2%
O&M (revolutionary)	3%	3%	3%	1.5%	1.5%	1.5%
Capital Cost (mature)	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
Capital Cost (evolutionary)	2%	2%	2%	0.2%	0.2%	0.2%
Capital Cost (revolutionary)	4%	4%	4%	2%	2%	2%

SOURCE: ACIL ALLEN

The learning rates in **Table 1.3** decline as the technology moves from the *emerging* to the *established* stage of development, as well as from the first half to the second half of the period under analysis.

Table 1.3 also provides learning rates for operation and maintenance (O&M) costs. There is very little discussion in the literature about O&M learning rates. Researchers who do mention O&M costs acknowledge that those costs also decline due to 'learning by doing'. Certainly, given that O&M costs are often taken to be a fixed percentage of capital costs, one might intuitively expect learning rates for O&M to largely match the learning rates for capital costs. While the lack of data makes it difficult to be definitive, an examination of the literature also suggests that O&M learning rates are similar, or slightly less than, capital cost learning rates. The information shown in **Figure 1.3** supports this view. While the costs shown in the figure are not strictly linked to cumulative level of production of solar thermal tower technology, they do illustrate the nature of the change in O&M costs as the amount of technology being rolled out increases.

FIGURE 1.3 LCOE OF SOLAR THERMAL POWER TOWERS



Note: LCOE refers to unit cost of electricity (eg $/MWh) over the full life cycle of the plant.

SOURCE: : MELBOURNE ENERGY INSTITUTE, TECHNICAL PAPER SERIES, RENEWABLE ENERGY TECHNOLOGY COST REVIEW, MAY 2011 (FIGURE 26). (BASED ON SARGENT & LUNDY CONSULTING LLC, (2003), ASSESSMENT OF PARABOLIC TROUGH AND POWER TOWER SOLAR TECHNOLOGY COST AND PERFORMANCE FORECASTS, NATIONAL RENEWABLE ENERGY LABORATORIES & US DEPARTMENT OF ENERGY)

Table 1.4 lists the proposed stages of technological development used for hydrogen production. Only electrolysis is considered in the green hydrogen study. We have proposed that electrolysis be considered as currently in the *evolutionary* stage, but that it transitions to the *mature* stage post 2025. This approach aligns well with the US Department of Energy's technical targets for the capital cost of central electrolysis facilities.[8] They were projecting average annual declines in capital cost of around 7 per cent between 2011 and 2015 and 3.5 per cent between 2015 and 2020. Steam reformation is regarded as a mature technology.

TABLE 1.4 THE PROPOSED TECHNOLOGICAL STAGE OF DEVELOPMENT OF GREEN HYDROGEN TECHNOLOGIES

Green hydrogen technologies	Technology Stage					
	2017	2020	2025	2030	2040	2050
Electrolysis (*central plants*)	Evolutionary	Evolutionary	Evolutionary	Mature	Mature	Mature
Steam reformation of methane	Mature	Mature	Mature	Mature	Mature	Mature

SOURCE: ACIL ALLEN BASED ON US DOE: HTTPS://ENERGY.GOV/EERE/FUELCELLS/DOE-TECHNICAL-TARGETS-HYDROGEN-PRODUCTION-ELECTROLYSIS#CENTRAL

[8] https://energy.gov/eere/fuelcells/doe-technical-targets-hydrogen-production-electrolysis#central accessed 11 May 2017.

The other main mechanism for manufacturing hydrogen is by the steam reformation of methane. This is a well-established technology and we propose that it be treated as a *mature* technology over the period covered by this study.

There are a number of hydrogen production technologies that are still in the R&D or revolutionary stage of development however these are not considered as part of this study as we are limiting the analysis to *n+1* plants, that is, the n^{th} plus 1 plant of a given technology. Hence, the scope of the Green Hydrogen project does not include *revolutionary* technologies.

Conclusions

1. Learning rates are important in driving reductions in the cost of technologies. There is a well-established relationship between learning rates and cumulative production. It is possible to express learning rates as time-based learning rates, which are contingent upon a given production profile over time.
2. There are three stages to the learning rates for a technology: *revolutionary*, *evolutionary* and *mature*. The first two stages are particularly important as the learning rate tends to be higher for these stages of technology development.
3. It is proposed that the analysis for the Green Hydrogen project be based on plants that are classed as *n+1*, which by definition excludes *revolutionary* technologies.
4. The only hydrogen production technology considered for the Green Hydrogen study is electrolysis. We propose that electrolysis be considered as currently in the *evolutionary* stage, but that it transitions to the *mature* stage post 2025.

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Appendix D

Selected H_2 deployment projects

This section gives an overview on the global activities and pilots deployed for hydrogen and explicitly green hydrogen.

United Kingdom - National Grid Hydeploy consortium

Scope: Proof of Concept for hydrogen in natural gas network of Keele University Campus (~ 10.000 resident students, 0,5 MW Electrolyser). Testing whether hydrogen can help to decarbonise gas networks by blending natural gas with up to 20% hydrogen on Keele University's gas network (National Grid Gas Distribution), facilitating 25 TWh of decarbonised heat.

Duration: 3 years, awarded in November 2016, starting April 2017

Budget: Total cost £8,1 m, of which funded £6,8 million

United Kingdom - Developing a new billing system for greener gas, technical standards for connection to high pressure NG pipelines

Scope: Injection of hydrogen into the National Transmission System (NTS). Develop and demonstrate the technical standards, innovative engineering connection solutions and new commercial arrangements for hydrogen injection into a high pressure natural gas pipeline. Acting as a catalyst to drive industry change, the project will deliver a standardised approach to customer connections of this type. This will be a first for the UK and will enable the full potential of hydrogen injection into the high pressure gas grid to be realised.

Duration: awarded in November, 2016

Budget: Total cost £6 m, of which funded £4,8 million

Germany –Green Hydrogen from biomass

Scope: Proof of concept - Linde Engineering has developed a method of manufacturing green hydrogen from biogenic glycerine and is currently trialling this technology at one of its pilot plants in Germany. The plant covers the entire production process from purification and distillation through pyroreforming to steam reforming. To save costs, the synthesis gas from the pilot plant is then fed into the conventional H_2 production process, where it is purified to increase the yield. The project shall proof the new process' ability to reduce total CO2 emissions from a commercial-scale hydrogen production plant by 80%. Research efforts in other ways of producing H_2 from biogenic substances (organic waste, other biomass feedstock) are ongoing.

Duration: ongoing

Budget: n.a.

Germany – Power-to-gas plant Energiepark Mainz

Scope: The energy transition requires a prompt advancement of environmentally friendly technologies and processes to convert and store energy. In this context the "Power-to-Gas"-process will play a significant role. The process aims at storing wind and solar energy by converting it to hydrogen or methane.

Energiepark Mainz" is under realization at a suitable site in the commercial area of Mainz-Hechtsheim. From 2015 on, an innovative research facility will produce green hydrogen.

At "Energiepark Mainz" hydrogen will be produced by electrolysis. The energy required for this will partially be supplied by excess power of adjacent wind energy plants.

Details: Industrial Park, connected to a wind-farm (8 MW)

6.3 MW peak electrolyzer (3 stacks, each 2.1 MW)
1000 kg storage (33 MWh)
200 tons target annual output
Power –to Gas - Injection in local gas grid
Multi-use trailer-filling

Primary objective the development, testing and application of innovative technologies for the production of hydrogen by means of electrolysis powered by renewable energies.

Duration: 2013 investment decisions, From 2017: Testing of Commercial operations

Budget: 17 m€, Funding: ~50% (German Ministry of Economics - BMWi)

Aberdeen Scotland - Largest hydrogen fuelling station in the UK

Scope: Fuelling of Europe's largest H_2 bus fleet
More than 80t H2 /year
Alkaline water electrolysers, hydrogen generation based on green electricity
35 MPa (2 x IC 90)

Duration: not available

Budget: not available

EU – Hydrogen "hy-tec" Transport in European Cities

Scope: Key Objectives of the project

The HyTEC project will expand the existing European network of hydrogen demonstration sites into two of the most promising early markets for hydrogen and fuel cells, Denmark and the UK. The key objectives are:

- Demonstrate up to 30 new hydrogen vehicles in the hands of real customers, in three vehicles classes: taxis, passenger cars and scooters. These will be supported by new hydrogen refuelling facilities, which combine with existing deployments to create two new city based networks for hydrogen fuelling.

- Analyse the results of the project, with an expert pan-European research team considering full well-to-wheel life cycle impact, demonstrating technical performance of the vehicles and uncovering non-technical barriers to wider implementation.
- Plan for future commercialisation of the vehicles.
- Disseminate the results of the project widely to the public to improve hydrogen awareness.

Duration: September 1, 2011 (40 months (originally), extended to 48 months)

Budget: Project cost: € 29.256.315,.91, of which Project funding: € 11.948.532

U.S.A. BMW Plant Greer (SC) - H_2 for transports

Scope: 14 H_2 dispensers for hydrogen-fuelled material handling vehicles

- Fuelling of more than 380 material handling vehicles
- Fuelling in only 3 minutes
- More than 3,000 m of pipeline from the compressor to the dispensers
- 2.5 MPa (IC with additional capacity)

Duration: n.a.

Budget: n.a.

U.S.A. Landfill gas to fuel has arrived Altamont LNG Plant, Livermore, California

Scope: LNG Plant, based on green hydrogen (commercial plant)

- Joint Venture between "Waste Management, Inc." and Linde Gas North America LLC
- Landfill gas from the natural decomposition of organic waste.
- World's largest landfill gas (LFG) to liquefied natural gas (LNG) plant.
- Produces up to 50.000 l (13.000 gal) of LNG a day
- Pilot aspect: Diversification and greening of fuels, i.e. landfill gas can also be used to produce clean hydrogen.
- Altamont project is expected to reduce carbon dioxide emissions by nearly 30,000 tons a year.

Duration: start-up of plant in

Budget: n.a.

Osaka Gas: "ENE-FARM" Home-use Fuel Cell Cogeneration System

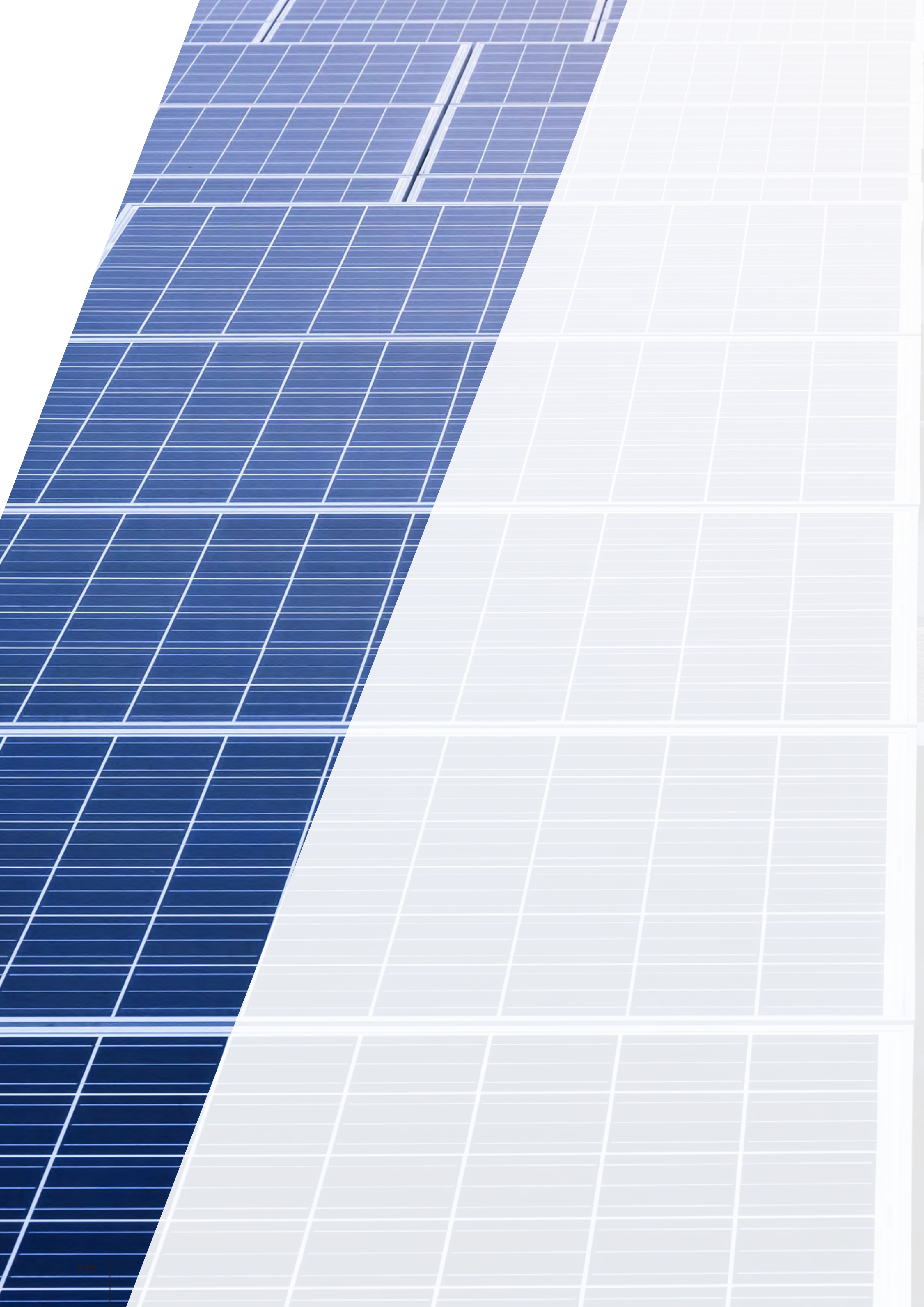
Scope: "ENE-FARM" is a high-efficiency energy system that generates electricity by a chemical reaction between hydrogen extracted from gas and oxygen in the air and effectively uses the heat generated in the power generation process for hot water supply and space heating.

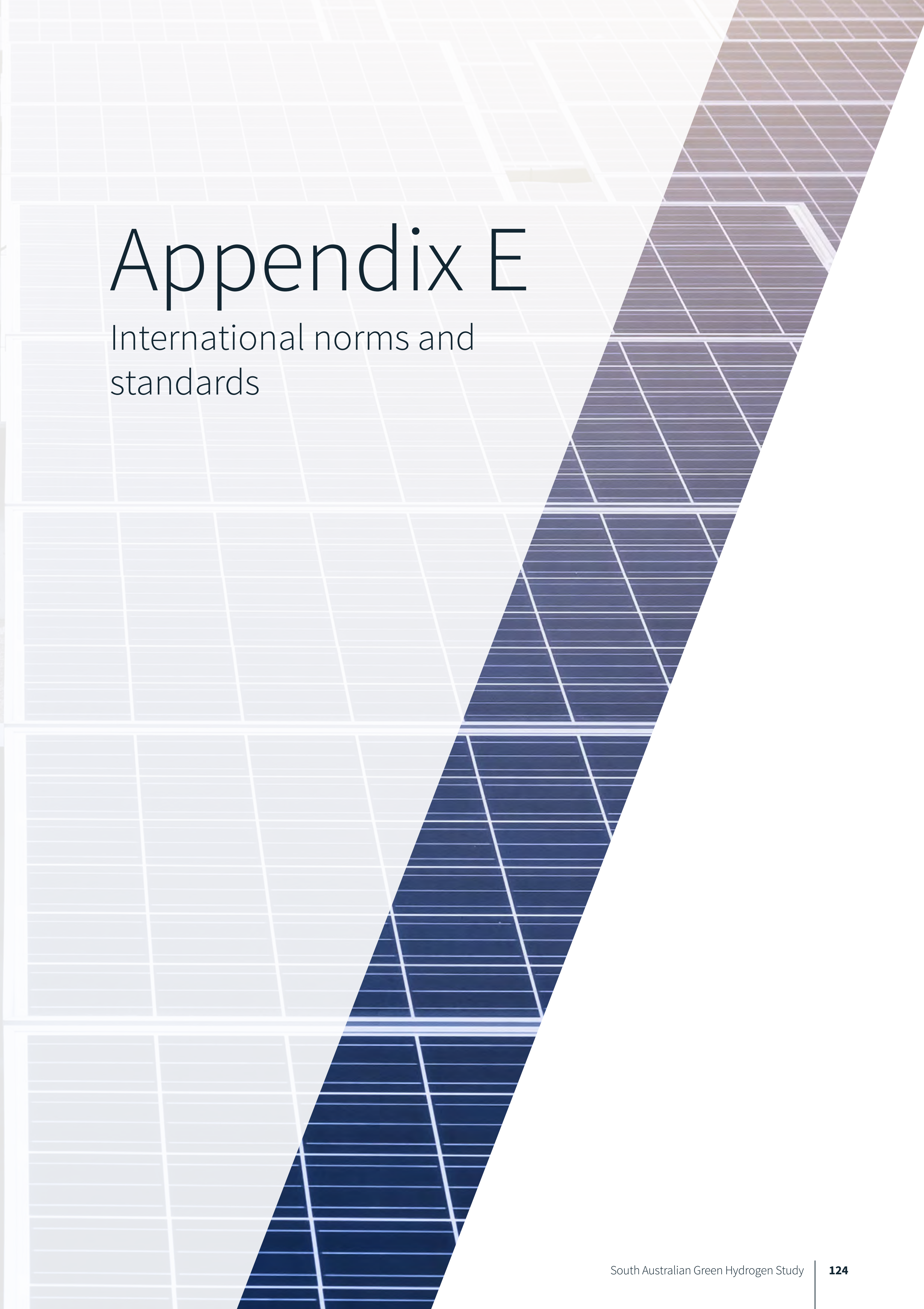
As of the end of FY2014, a total of 23,258 units had been introduced, reducing our customers' CO2 emissions by an estimated 33,000 tons annually[10] (equating to the planting of 2.37 million Japanese cedar trees).

April 2014 saw the launch of "ENE-FARM," a home-use fuel cell (polymer electrolyte fuel cell: PEFC) that has achieved a world-class (based on our survey) total efficiency of 95%. The new model "ENE-FARM type S" (solid oxide fuel cell: SOFC), a home-use fuel cell with a power generation efficiency of 46.5% will presumably reduce carbon footprint further.

Japan's ENE-FARM program is arguably the most successful fuel cell commercialization program in the world. ENE-FARM has supported the deployment of well over 120,000 residential fuel cell units and is providing proof that long term public-private partnerships can push new technology into the marketplace.

[10] CO2 absorbed by a ceder tree: 13.9kg-CO2/tree annually (from 1997 Forestry White Paper; 50-year-old Japanese cedar with a diameter of 26cm and a height of 22m)





Appendix E

International norms and standards

Codes & Standards, and Regulations Codes and standards are technical definitions and guidelines. They affect equipment and site design as well as the interaction between user and equipment, such as through the public sale of hydrogen. From a practical perspective, codes and standards are only enforceable as adopted by law.

Main institutional bodies, relevant for H_2 standard development:

- International Civil Aviation Organization (ICAO)
- Electrotechnical Commission (IEC).
- International Organization for Standards (ISO) United Nations
- United Nations (UN)
- Other: Various national / regional bodies such as ASME International, CSA International

The published international and national standards are covering the areas of

- Stationary Fuel Cells
- **Hydrogen & Fuel Cell vehicles**
- Portable & Micro Fuel Cells
- **H_2 Infrastructure**
- Misc. (Forklift Trucks, Aviation & Marine Applications, Other Fuels and Definitions)

As non-exhaustive example, some standard for **Hydrogen & Fuel Cells** cover the areas:

- Vehicles - System Design/Testing
- Vehicles - Safety
- Vehicles - Performance - efficiency, emissions, durability
- Vehicles – Terminology
- **Vehicles - Fuel Systems**
- Fuel Tanks - Refuelling / Dispensing Connections
- Fuel Specifications

Applicable Vehicle Fuel System Standards

With respect to the focus areas of **Vehicles Fuel Systems** the following standards are published:

United States

CSA America HGV3.1 Fuel System Components for Hydrogen Gas Powered Vehicles

NFPA 52 Vehicle Fuel System Code

SAE J2579 Standard for Fuel Systems in Fuel Cell and Other Hydrogen Vehicles

CGA Publication PS31 Cleanliness for PEM Hydrogen Piping / Components (United States)

European Union

EC No.79/2009 Type-approval of hydrogen-powered motor vehicles (European Union)

International

ISO 12619-1 Road vehicles – Compressed gaseous hydrogen and hydrogen/methane blends fuel components Part 1: General requirements and definitions

ISO 12619-2 Road vehicles – Compressed gaseous hydrogen and hydrogen/methane blends fuel components Part 2: Performance and general test methods

ISO 12619-3 Road vehicles – Compressed gaseous hydrogen and hydrogen/methane blends fuel components Part 3: Pressure regulator

As another non-exhaustive insight standards for H2 Infrastructure cover areas such as

- Hydrogen – Properties
- Hydrogen – Safety
- Hydrogen - Fuel Specifications
- Hydrogen Storage & Transport - Piping & Pipelines
- Other

Hydrogen Storage and Transport – Piping and Pipelines Standards

With respect to the focus areas of Hydrogen Storage & Transport - Piping & Pipelines, the following standards are published:

United States and other Locales

ASME B31Series Piping and Pipelines

ASME B31.12 Hydrogen Piping and Pipelines

ASME STP-PT-006 Design Guidelines for Hydrogen Piping and Pipelines

CGA Publication G5.7 (EIGA Doc 120/04) Carbon Monoxide and Syngas Pipeline Systems (United States / Europe)

United States

CGA Publication G5.4 Hydrogen Piping Systems at Consumer Locations

CGA Publication G5.6 Hydrogen Pipeline Systems

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