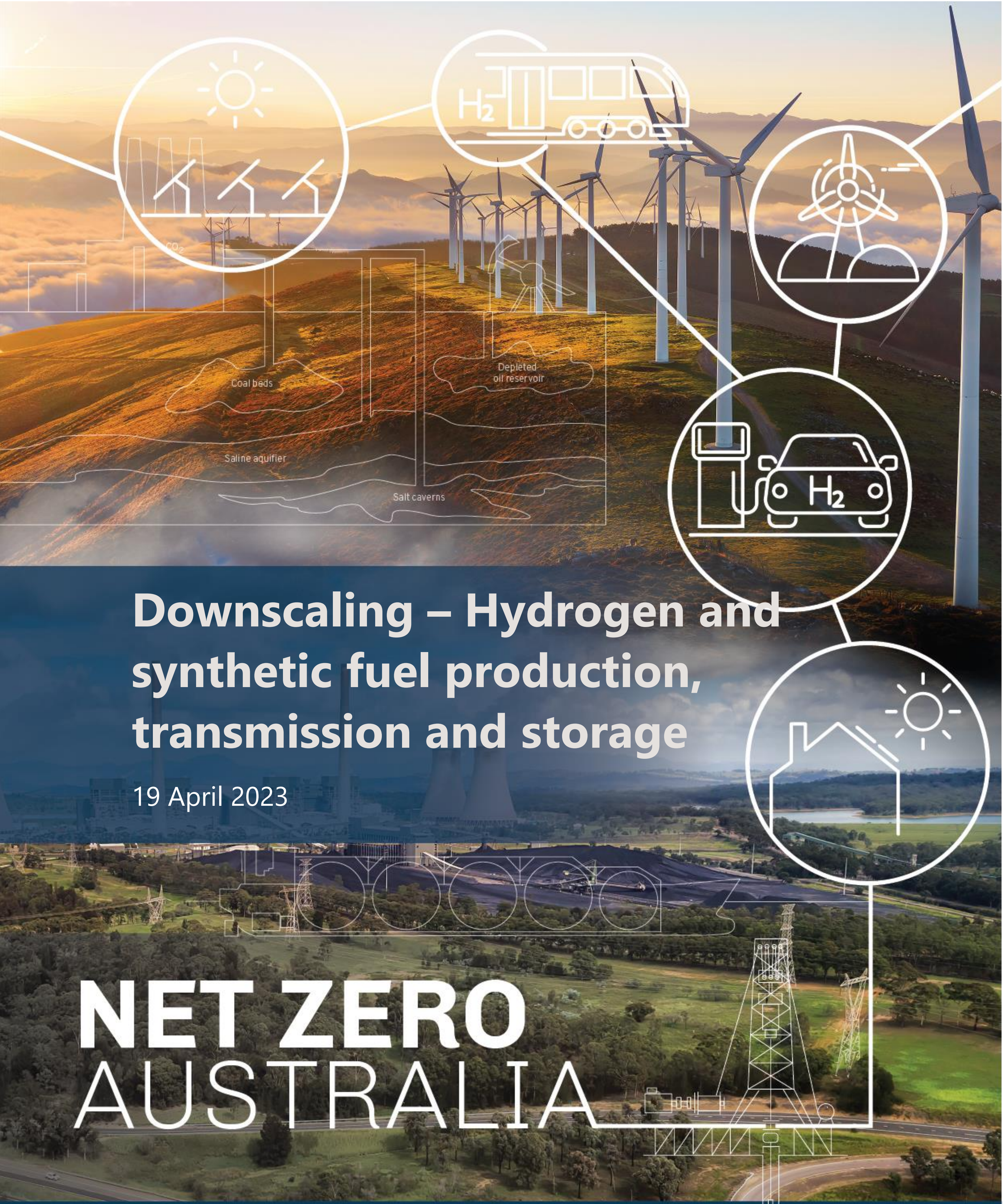

Downscaling – Hydrogen and synthetic fuel production, transmission and storage

19 April 2023

NET ZERO AUSTRALIA

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The Net Zero Australia (NZAu) project is a collaborative partnership between the University of Melbourne, The University of Queensland, Princeton University and management consultancy Nous Group. The study examines pathways and detailed infrastructure requirements by which Australia can transition to net zero emissions, and be a major exporter of low emission energy and products.

Net Zero Australia

Downscaling – Hydrogen and synthetic fuel production, transmission and storage

19 April 2023

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Contents

1 Introduction

Hydrogen, synthetic pipeline gas, ammonia and synthetic liquid fuels are included in Net Zero Australia (NZAu) modelling as options for fuel switching. *Fuel switching* covers measures that change the share of a delivered energy service satisfied by a specific energy carrier. Energy services that are difficult to electrify often undergo fuel switching with energy demand met by hydrogen or synthetic methane; for example, the energy required for iron reduction, alumina refining or aluminium smelting. In the NZAu onshoring scenario, it was decided that the domestic pig iron transformation process would employ the Direct Reduction Iron (DRI) process, use hydrogen, and be concentrated in Western Australia [1].

Hydrogen and ammonia are drawn on extensively in NZAu modelling due to a decision to maintain the energy value of Australia's exports while also meeting a zero emissions constraint by 2060. NZAu modelling attempts to satisfy these competing constraints by replacing fossil exports with forms of energy that either have no associated greenhouse gas (GHG) emissions when used (e.g., hydrogen, hydrogen derivatives and electricity), or the carbon content of which is biogenic or directly captured from the atmosphere [1].

Hydrogen, synthetic pipeline gas, and synthetic liquid fuels also have domestic uses in NZAu modelling. Synthetic pipeline gas and liquid fuels are allowed as 'drop in' fuels in all portions of the domestic economy – modelled as residential, commercial, and industrial – during the 30-year transition (the domestic economy decarbonization target is 2050). Hydrogen's introduction in transportation and industry is specified for individual sectors and transport types in modelling parameters [1].

Hydrogen blending in the general pipeline gas network is not pursued as a strategy, in line with the Net Zero America study [2]. NZAu does allow domestic hydrogen storage and CCGT and OCGT plant to be fired on any blend of natural gas and hydrogen from 2035 onwards [1]. Hydrogen is transferred to both export ports and domestic locations using hydrogen pipelines along pre-determined potential corridors [1].

Table 1 lists the maximum annual national production (in TWh) for any hydrogen (H_2) and synthetic fuel technology that has a minimum annual fuel production of more than 7.1 PJ in any core scenario. 7.1 PJ was chosen as it is approximately equal to the annual energy output of a 50 kt-H2/year plant (0.23 GW-H_2) – which NZAu considers its minimum build size for hydrogen plant. For reference, 7.1 PJ is also equal to the combined capacity of one and a half average tankers transporting crude oil to/from Australia [3]–[6]; or the annual output of an 820 MW solar PV farm located in one of Australia's top solar locations [7]).

Steam reforming is not included in modelling or Table 1 as its technical attributes make it less suitable than autothermal reforming for use in Australia with carbon capture technology [1]. Methanation of pipeline gas and gasification of black coal to hydrogen technologies [1] are not listed in Table 1 as they fail to reach the minimum annual fuel production level in all core scenarios.

The core NZAu scenarios that are included in Table 1 and will be discussed in this document include the high electrification (E+), 100% renewables (RE+), renewables constrained (RE–), slow electrification (E–), and the onshoring (ONS) scenarios. A detailed description of each of these scenarios can be found in the MASS document [1].

Table 1 | Maximum annual national production (in PJ) for any hydrogen and synthetic fuel technology utilised for more than 7.1 PJ of fuel production a year in any core scenario

Technology	Fuel	REF	E+	RE+	RE–	E–	ONS
Autothermal reforming	hydrogen (H_2)	0	1,073	0	9,696	504	986
Biomass-gasification	pipeline gas (CH_4)	0	655	607	981	533	600
Biomass-gasification	hydrogen (H_2)	0	57	91	107	11	107
Brown coal gasification	hydrogen (H_2)	8	0	0	0	0	0
Electrolysis	hydrogen (H_2)	19	18,921	20,781	9,485	19,544	10,985
Fischer-Tropsch liquids	drop-in fuels & products	0	180	752	263	377	209
Haber-Bosch	ammonia	0	13,726	14,127	13,488	13,906	2,357

While all technologies listed in Table 1 play a role in net-zero transition scenarios, the largest roles played by any technologies are those fielded to meet export demand: electrolysis, Haber-Bosch, and autothermal reforming (ATR) with carbon capture (w/cc). The hydrogen and synthetic fuel technologies included in this section are electrolysis and autothermal reforming for H_2 production[1, pp. 128–132]; and Fischer-Tropsch liquids for drop-in fuels & products. While brown coal gasification is listed in Table 1, it only barely reaches the minimum annual fuel production level in the reference scenario and will not be discussed in this document. All technologies listed in Table 1 are detailed in the MASS [1]. Technologies from Table 1 that are covered in companion downscaling reports are biomass-gasification to CH_4 and H_2 (see *Downscaling – Biomass*); and Haber-Bosch for conversion of hydrogen to ammonia (see *Downscaling – Exports*).

2 Hydrogen

2.1 Demand

Figure 1presents hydrogen demand in exajoules (EJ) by end-use, scenario, and year.

Figure 1 | Hydrogen demand in EJ by end-use, scenario, and year

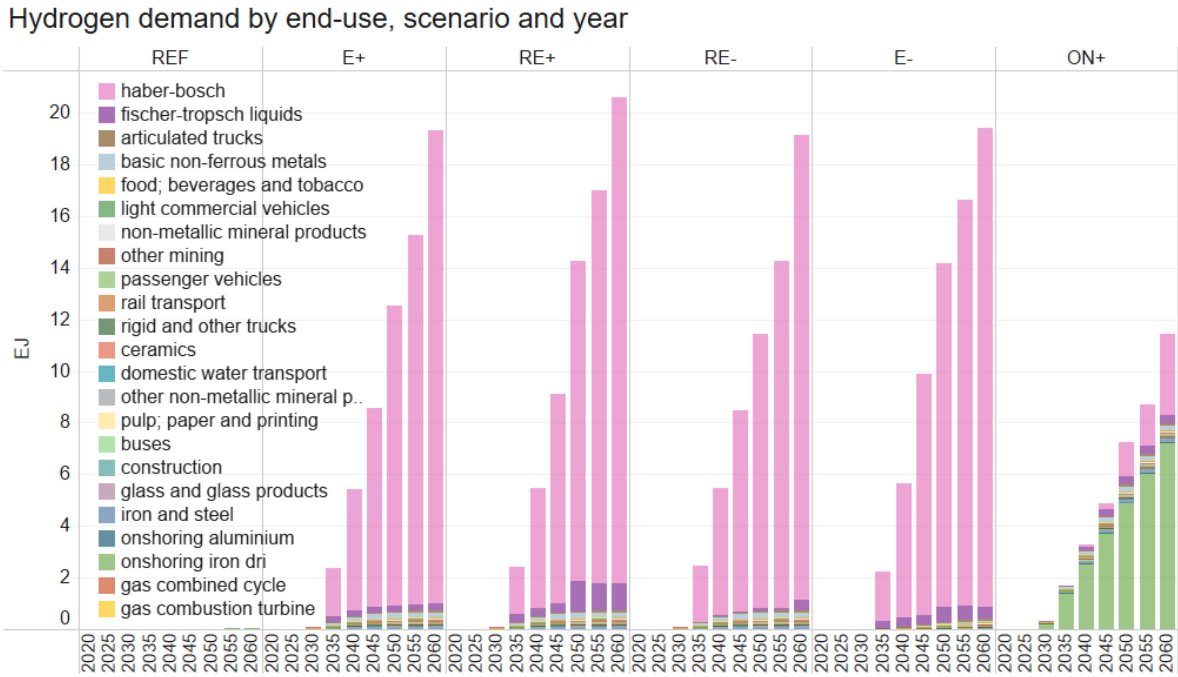


Figure 1 indicates that except for the ONS scenario, nearly all hydrogen flows into Haber-Bosch processes for export. In the ONS scenario, the amount of hydrogen used for DRI production in steel making exceeds the amount sent to Haber-Bosch processing for export. Other uses with notable energy flows include Fisher-Tropsch liquids in the RE+ and E– scenarios and basic non-ferrous metal production in all but the E– scenario. Figure 2 presents hydrogen demand in exajoules (EJ) by location, scenario, and year.

Figure 2 | Hydrogen demand in EJ by location, scenario, and year

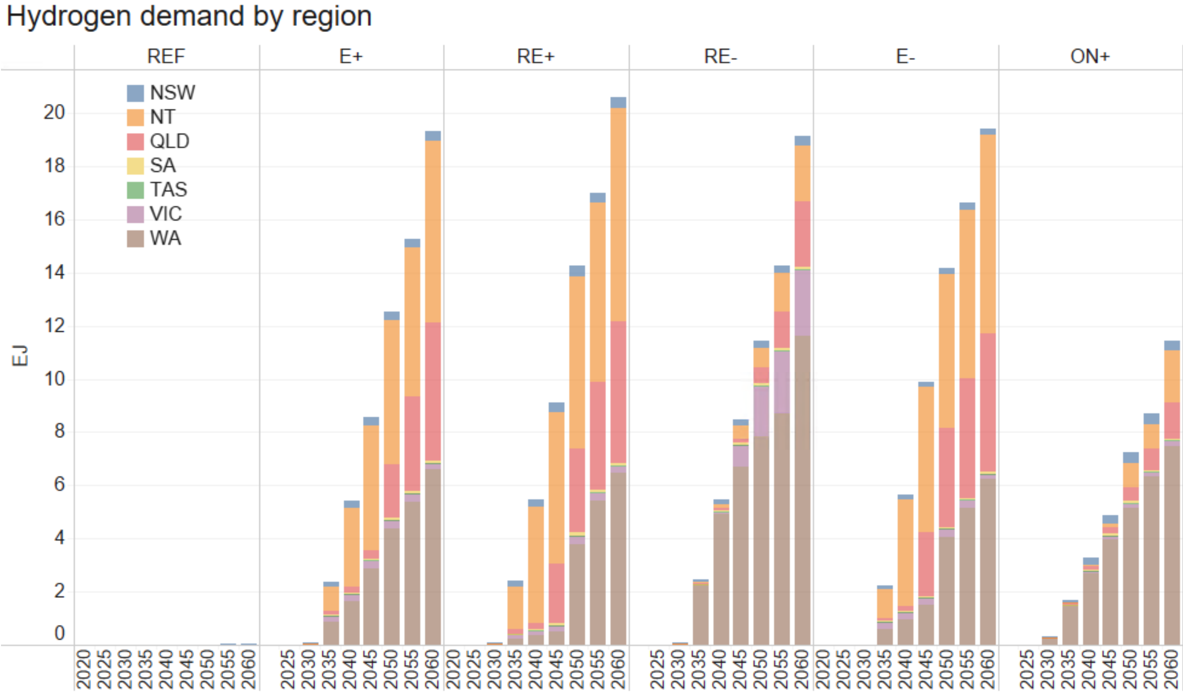
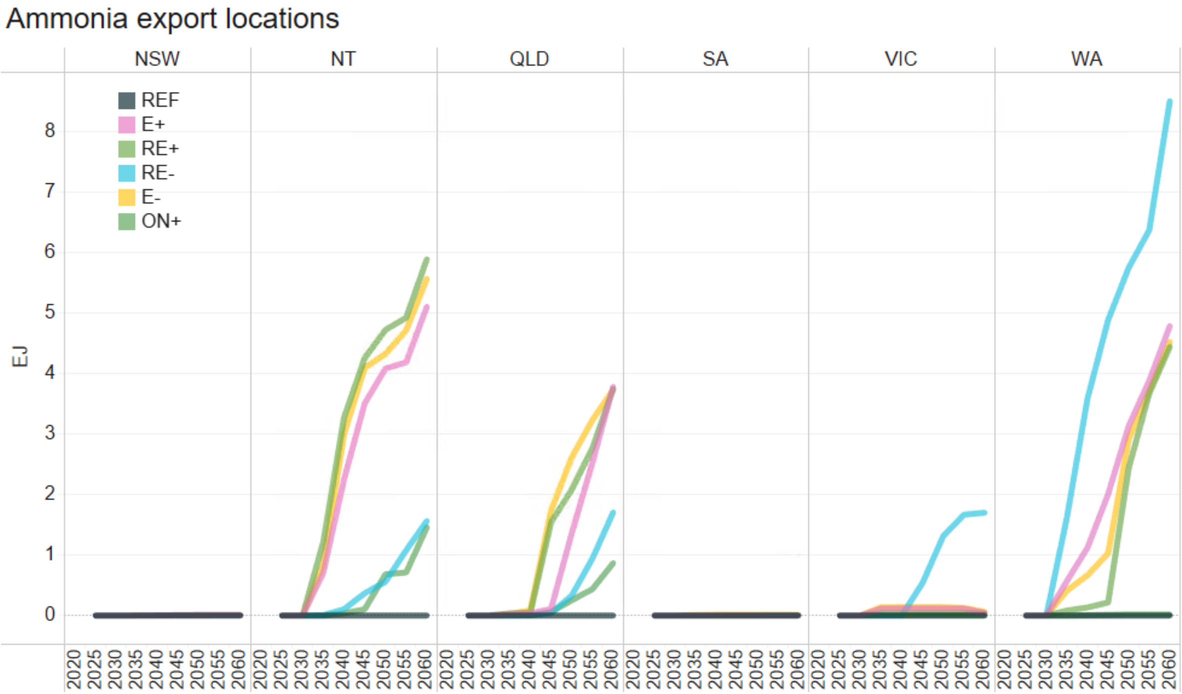


Figure 2 shows Western Australia (WA), the Northern Territory (NT), and Queensland (QLD) as major sources of hydrogen demand across all scenarios. Victoria (VIC) is a major source of hydrogen demand in the RE– scenario and shows a consistent but minor demand in Figure 2 across the remaining core scenarios. Figure 2 also indicates a minor demand for hydrogen from New South Wales (NSW) and South Australia (SA) in all core scenarios. Major clean energy export ports in WA, the NT, QLD, and VIC (in RE– as shown in Figure 3) combined with the penetration of clean fuels in populous domestic markets – at a much smaller scale relative to exports – provide the drivers underpinning.

Figure 3 | Ammonia export locations by scenario, and year



2.2 Supply

Figure 4 presents hydrogen supply in exajoules (EJ) by technology, scenario, and year.

Figure 4 | Hydrogen supply in EJ by technology, scenario, and year

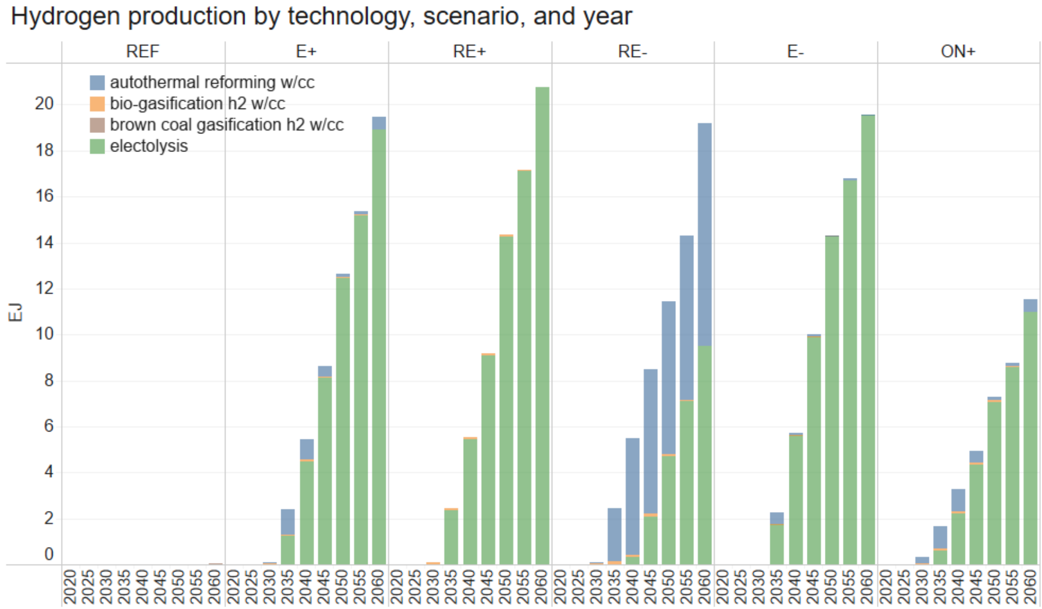


Figure 4 indicates that except for the RE– scenario, electrolysis is projected to be the most cost-effective – and available – hydrogen making technology for both domestic and export needs. Autothermal reforming with carbon capture (ATR w/cc) appears in RE–, and in the early years of all transitions which allow fossil fuel use. The RE– scenario is the only scenario which sees larger production flows from ATR w/cc than electrolysis. Bio-gasification w/cc for hydrogen production occurs in (relatively) small amounts in most scenarios. Brown coal gasification w/cc shows up in very small quantities only in the reference scenario.

2.2.1 Electrolysis

Figure 5 presents hydrogen supply from electrolysis in EJ by location (state/territory), scenario, and year.

Figure 5 | Hydrogen supply from electrolysis in EJ by location (state/territory), scenario, and year.

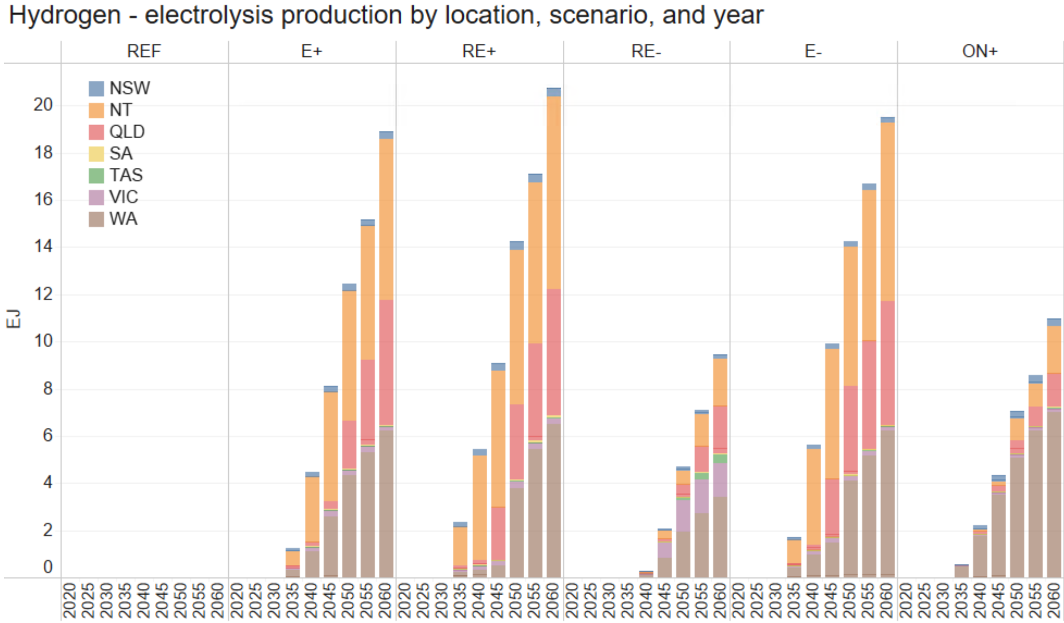


Figure 5 shows electrolysis taking placing in significant quantities in all scenarios in WA, the NT, and QLD. Smaller quantities of hydrogen are produced from electrolysis in SA, Tasmania (TAS), VIC, and NSW in Figure 5, with only VIC extending to significant hydrogen production from electrolysis levels in the RE– scenario. All electrolysis occurring in WA, the NT and QLD takes place in designated export zones in low population density areas with good VRE resources near ports [1]. As for other regions (SA, NSW, TAS, and VIC) in the NZAu core scenarios, electrolysis is assumed to occur in domestic areas near to both variable renewable resources and end uses. For sensitivities where SA and NSW contribute to clean energy exports, electrolysis occurs in designated export zones. Figure 6 details the driver for production of hydrogen from electrolysis (in EJ) in each scenario and model year.

Figure 6 | Driver for hydrogen production from electrolysis in EJ by scenario and year.

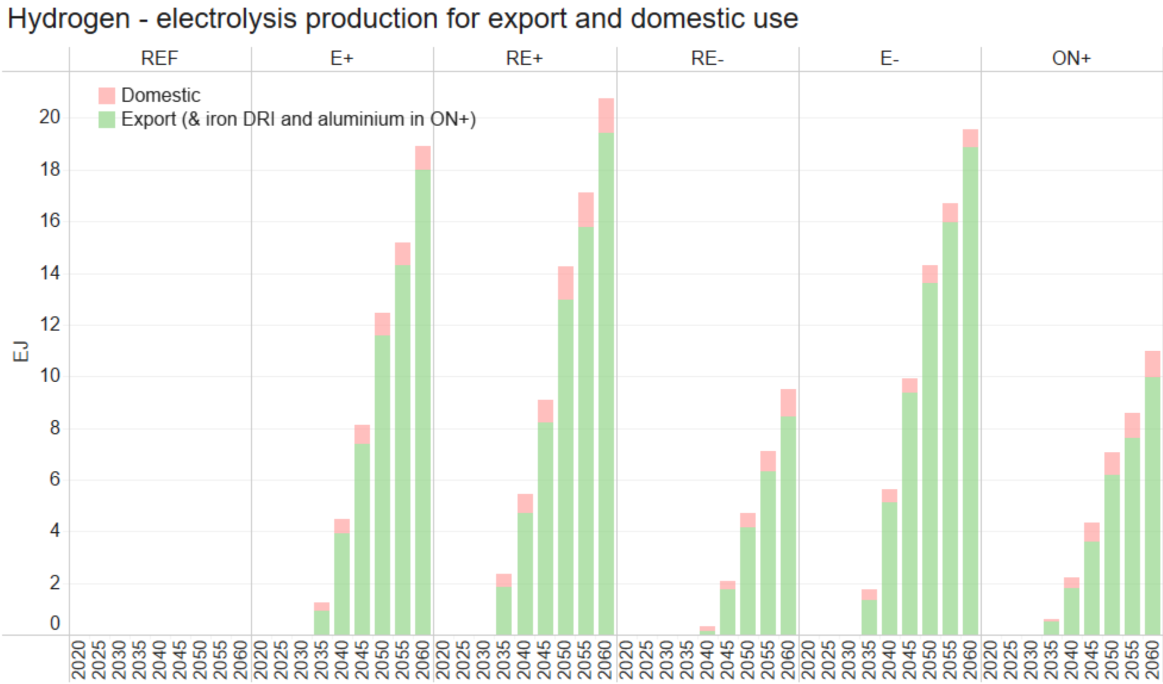


Figure 6 shows electrolysis serving extensive export markets, with a steady but much smaller amount going to domestic uses – noting that the export zone in VIC is fully integrated with the surrounding domestic economy which makes the allocation of electrification drivers in that area of the country much less clear than the more cleanly divided export and domestic zones in the rest of the country. Further, in Figure 6 in the ONS scenario, the hydrogen serving the domestic onshoring of iron DRI and aluminium production is modelled to occur in export regions, thus allowing Australia to build infrastructure that can flexibly serve either hydrogen exports or flourishing domestic iron and steel and aluminium industries.

Both alkaline and proton exchange membrane (PEM) electrolysis technologies are discussed in the MASS document [1]. Table 2 details selected aspects of the electrolysis plants serving exports (and domestic industry in ONS) by 2060 in each core scenario. The variable renewable energy (VRE) capacities listed in Table 2 provide power to both electrolysers and connected infrastructure (storage), as well as export connected technologies (e.g. hydrogen to ammonia, desalination for all H_2 export technologies, and autothermal reforming facilities) sited in export ports. For the offshore wind values listed in Table 2, both the eastern portion of Victoria and Tasmania have been included in the export connected build. The footprint values in Table 2 are estimated using a value of 60m^2/MW for the combined area needed for the electrolyser building (50m^2/MW) and electrical switchyard (10m^2/MW) [8]. Hydrogen storage is not included as it is discussed on its own in a later section in this document. Also, while the NZAu electrolysis footprints have been estimated using literature, electrolysis footprints are expected to change considerably when engineers tackle the problem at the scale required and innovative and multi-story facilities are designed.

Table 2 | Selected aspects of the electrolysis technologies sited for export (and onshored industry in ONS) by 2060 in each core scenario

Selected aspect of electrolysis	REF	E+	RE+	RE–	E–	ONS
Dominant technology type	NA	PEM	PEM	PEM	PEM	PEM
Hydrogen produced (EJ HHV) in 2060	0.0	18.0	19.4	8.4	18.9	10.0
Electrolyser capacity (GW) in 2060	0	1,591	1,697	618	1,656	884
Footprint electrolyser and switchyard (km^2) in 2060	0	95	102	37	99	53
Solar PV capacity (GW)	4	2,714	2,902	860	2,830	1,531
Onshore wind (GW)	0	30	46	68	40	12
Offshore wind (GW)	2	20	12	247	19	19
Battery storage at electrolysis node (GWh)	0	704	850	512	785	395
Underground hydrogen storage at electrolysis node (TWh)	0	43	58	11	56	23

Improvements in PEM costs and efficiencies [1] result in the siting of only PEM based electrolysis plant after 2025 in Table 2 in all scenarios. Table 2 indicates that there are substantial footprints of up to 102 km^2 connected to the use of electrolysis for the production of hydrogen for export and onshored industry across the modelled scenarios. The incorporation of the electrolysis locations in Figure 5 with the detail in Table 2 indicate that nearly all of the land footprint incurred by hydrogen production from electrification will be at sites around export zones in WA, NT, and QLD.

Table 2 also indicates that the widespread use of solar PV to support hydrogen production via electrolysis leads to a substantial need for onsite hydrogen storage. The locations and land footprints of hydrogen storage will be discussed in a later section in this document. All aspects of VRE (including locations and implications of the land footprints) are discussed in the companion report, *Downscaling – Solar PV, wind and electricity transmission*.

Table 2 also indicates that although offshore wind capacity for export increases by over 12x in the RE– scenario when compared to the E+ scenario, hydrogen produced from electrolysis is roughly half of other export focused scenarios (all but ONS) and an alternative hydrogen producing technology is needed to maintain hydrogen exports at projected levels in the RE– scenario.

2.2.2 Autothermal reforming

Figure 7 presents hydrogen supply from autothermal reforming (ATR) with carbon capture (w/cc) in EJ by technology, scenario, and year.

Figure 7 | Hydrogen supply from ATR w/CC in EJ by technology, scenario, and year

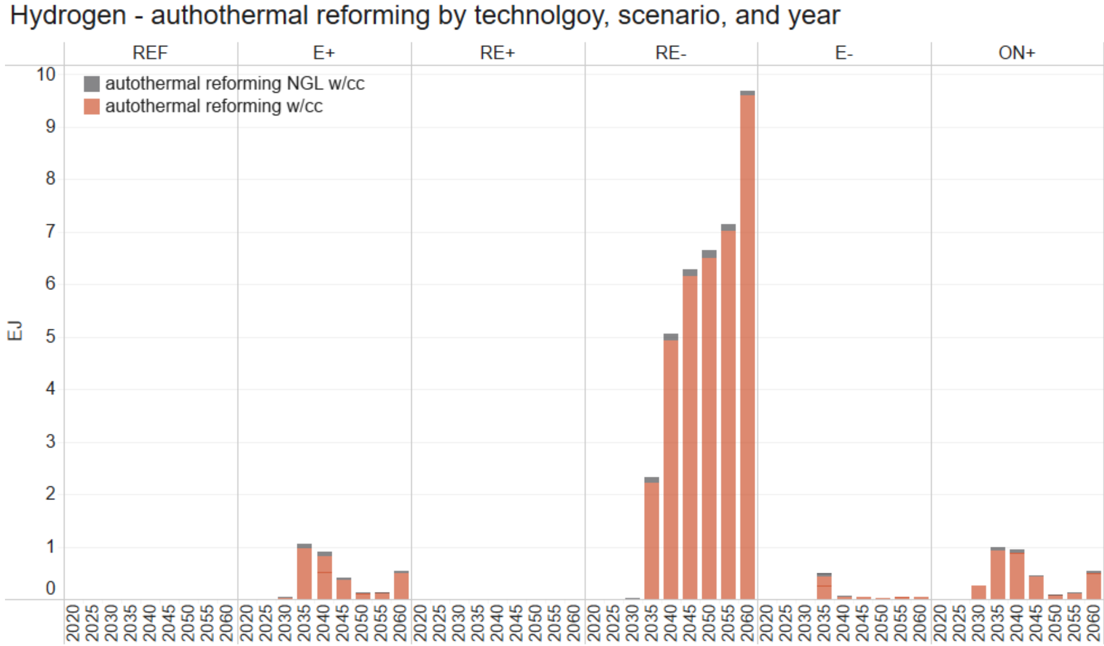


Figure 7 shows the production of hydrogen from ATR w/cc occurring in modest amounts (relative to electrolysis) in all scenarios but the RE+ scenario in which no fossil fuel use is allowed, and in the RE– scenario in which build-rate limits are placed on onshore renewable technologies. The technology most employed in all scenarios in Figure 7 is ATR from pipeline gas, with relatively minor production from natural gas liquids (NGL) in all scenarios. Figure 8 presents ATR capacity (in GW) by location (state/territory), scenario, and year.

Figure 8 | ATR capacity (in GW) by location (state/territory), scenario, and year

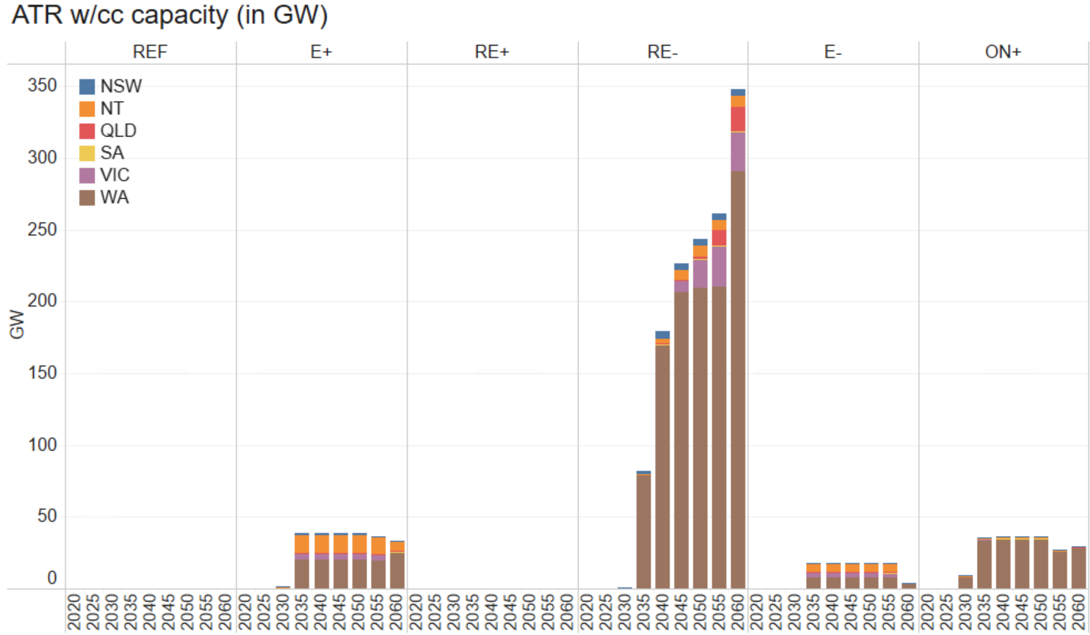


Figure 8 shows most ATR w/cc capacity being sited in WA across all scenarios, with modest amounts appearing in the NT in the E+, RE+, and E– scenarios. Increased roles for ATR w/cc appear in Figure 8 in NSW, VIC, and QLD in the RE– scenario. Trace amounts of ATR w/cc occur in SA in most scenarios.

With the exception of NSW, NZAu assumes that ATR w/cc facilities are placed in the NZAu export port locations in each of the regions specified by the balancing model (Table 3). For NSW, ATR is placed in Port Kembla instead of Newcastle as no H_2 is exported from Port Newcastle in any core scenario and Port Kembla is better served by both the pipeline gas network [9] and NZAu's planned CO_2 pipeline network (see companion report, *Downscaling - CCUS*). Table 3, which provides H_2 production values in PJ HHV, indicates the sites selected for ATR facilities in NZAu downscaling and maps.

Table 3 Selected ATR facility locations and maximum production level of H_2 (in PJ HHV) by scenario

Region	ATR location(s)	REF	E+	RE+	RE–	E–	ONS
NSW	Port Kembla*	0	36	0	143	0	23
NT	Port Darwin	0	337	0	197	180	16
QLD	Gladstone	0	19	0	490	0	0
SA	Port Bonython	0	9	0	0	16	0
VIC	Port of Hastings	0	118	0	713	84	25
WA	Ashburton, Dampier, and Port Hedland	0	552	0	8211	220	934

* Port Kembla has been selected over Port Newcastle as is better served by the pipeline gas network and NZAu's notional CO_2 pipeline network.

Table 3 indicates that WA, NT, and VIC export ports will have ATR w/cc facilities in all but the RE+ scenario. Port Kembla in NSW will have an ATR w/cc facility in the E+, RE–, and ONS scenarios. The Port of Gladstone in QLD will only have an ATR w/cc facility in the E+ and RE– scenarios. Port Bonython in SA will only have an ATR w/cc facility in the E+ and E– scenarios.

Table 4 lists the maximum regional capacity of ATR w/cc during any modelled year of the scenarios shown in Figure 8, with the number of facilities in each region listed in parenthesis. Facility numbers are estimated using a plant size of 1.5 GW-H_2 or ~316 kt-H_2/year [1] – which are designed to be modular and can be aggregated to larger sized facilities, such as a proposed 12.15 GW-H_2 facility in England [10]. The smallest plant allowed in Table 4 is a 0.24 GW-H_2 (50 kt-H_2/year) facility.

Table 4 The GW capacities of ATR w/cc facilities by location (number of facilities) for each core scenario

Region	ATR location(s)	E+	RE+	RE–	E–	ONS
NSW	Port Kembla*	1.5 (1)	0 (0)	5.1 (4)	0 (0)	1 (1)
NT	Port Darwin	11.9 (8)	0 (0)	7.6 (6)	6.3 (5)	0.9 (1)
QLD	Gladstone	0.7 (1)	0 (0)	17.3 (12)	0 (0)	0 (0)
SA	Port Bonython	0.3 (1)	0 (0)	0 (0)	0.5 (1)	0 (0)
VIC	Port of Hastings	4.2 (3)	0 (0)	28.2 (19)	2.9 (2)	1 (1)
WA	Ashburton, Dampier, and Port Hedland	25.7 (18)	0 (0)	291.1 (195)	7.8 (6)	33.9 (23)
AUS	**All locations**	**44.2 (32)**	**0 (0)**	**349.2 (236)**	**17.6 (14)**	**37.0 (26)**

Table 5 provides the combined footprint (in km_2) of the ATR w/cc facilities capacities listed in Table 4, using a footprint conversion factor of 0.074 km^2 per GW of H_2 production capacity [10].

Table 5 Combined regional ATR w/cc facility footprint (in km_2) for each core scenario

Region	ATR location(s)	E+	RE+	RE–	E–	ONS
NSW	Port Kembla*	0.11	0.00	0.38	0.00	0.07
NT	Port Darwin	0.88	0.00	0.56	0.47	0.07
QLD	Gladstone	0.05	0.00	1.28	0.00	0.00
SA	Port Bonython	0.02	0.00	0.00	0.04	0.00
VIC	Port of Hastings	0.31	0.00	2.09	0.22	0.08
WA	Ashburton, Dampier, and Port Hedland	1.91	0.00	21.56	0.57	2.51
AUS	**All locations**	**3.28**	**0.00**	**25.87**	**1.30**	**2.73**

The regional footprints for ATR w/cc listed in Table 5 are all less than a square kilometre, except for the ATR w/cc footprint for QLD and VIC in the RE– scenario, and for WA which is more than 1 km^2 in three core scenarios and ranges up to 22 km^2 in the RE– scenario. For a description of the resource inputs and costs of the ATR w/cc facilities sited by NZAu, see the MASS document [11]. For a description of the water used by ATR w/cc facilities, see the companion report, *Downscaling – Water*.

3 Fischer-Tropsch liquids for drop-in fuels and products

3.1 Demand

Figure 9 presents demand for Fischer-Tropsch liquids (FTL) for drop-in fuels and products (in EJ) by end-user, scenario, and year.

Figure 9 | Fischer-Tropsch liquids for drop-in fuels and products (in EJ) by end-user, scenario, and year

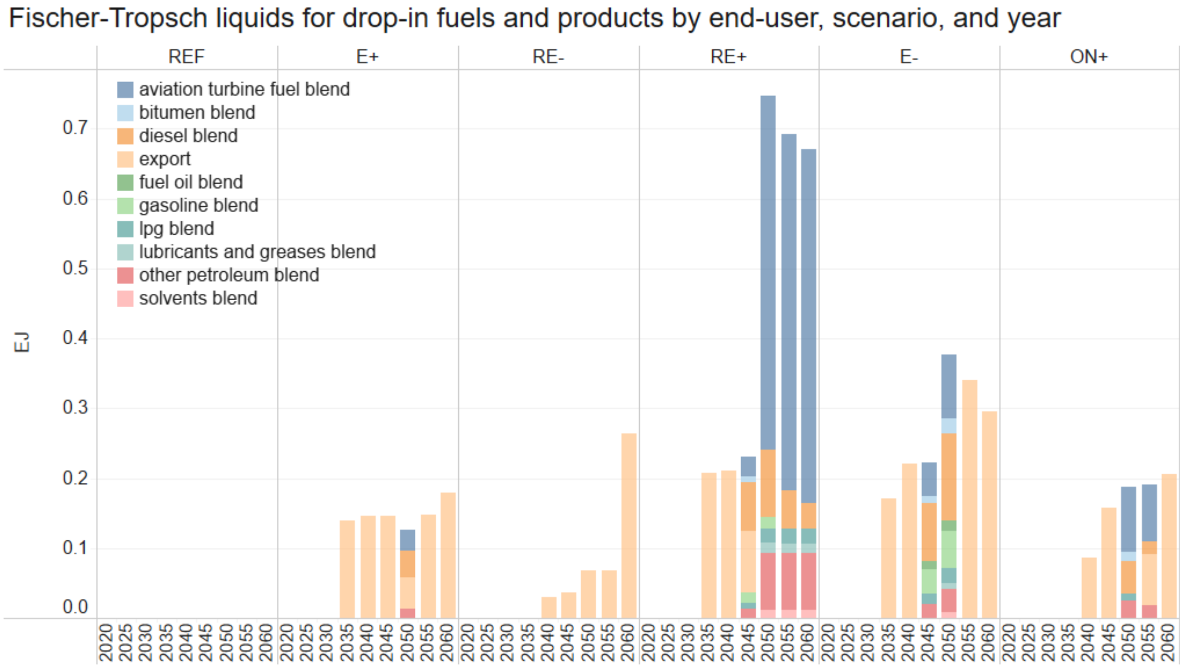


Figure 9 indicates that while fuels and products produced from FTL show up in small amounts for a diversity of domestic end-uses in all scenarios but RE–, they are consistently used across all scenarios as part of clean energy exports starting in 2035/2040. Domestically, Figure 9 shows different scenarios making greater use of FTL for different end-uses and in different time periods. For instance, the RE+ scenario uses FTL in large quantities from 2045 onwards to replace aviation fuel, diesel fuels, and 'other petroleum products'. Figure 9 also indicates that, with the exception of the RE– scenario, 2050 is a challenging year in the transition away from domestic fossil fuels products, as that year sees FTL being diverted from export markets to focus on a diversity of domestic products. In some scenarios in Figure 9 this challenge occurs earlier in 2045 (RE+ and E–), or lasts for ten (E–, ONS) or more (RE+) years.

3.2 Supply

In all scenarios, the supply of FTL matches the demand in Figure 9. Production for the stockpiling of strategic reserves is not included in modelling.

The Fischer-Tropsch process employed in NZAu modelling is based on the design of a "once-through" Fischer-Tropsch process described by Greig et al. [12], which employs modular tubular fixed-bed reactors – using hydrogen and carbon inputs – to nominally produce 80.2 MW or 1,182 actual barrels of oil – petroleum equivalent – a day (bbl (equiv. petroleum)/day) HHV [13]. The NZAu process adds internal syngas recycling to boost production by 43% from this design [1], which results in an actual capacity of 114.7 MW or 1,690 bbl (equiv. petroleum)/day. While biomass based FTL technologies are allowed in NZAu modelling [1], the companion report, *Downscaling – Biomass* explains that biomass based FTL technologies are not selected by the model. This analysis assumes that any hydrogen produced from biomass (Figure 4 indicates a small amount of H_2 production from biomass), is produced off-site and piped to the FTL facility.

Table 6 provides the maximum regional capacity (in GW HHV) of the Fischer-Tropsch facilities needed to produce drop in fuels for the entire transition, by scenario, along with the number of 114.7 MW modular facilities needed in each region. A minimum capacity of 114.7 MW is needed in a region to trigger a regional facility in Table 6.

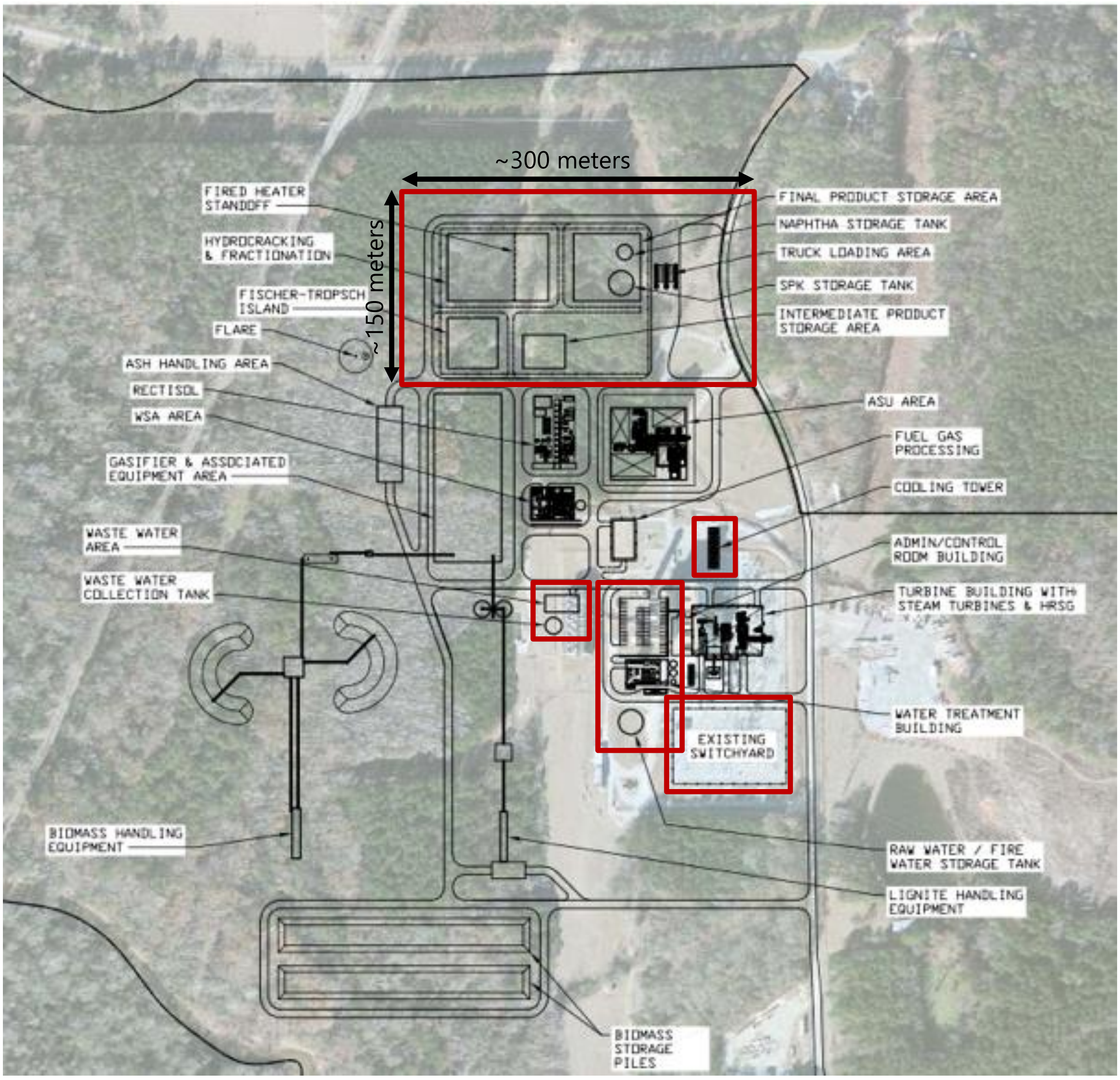
Table 6 | Maximum regional Fischer-Tropsch capacities in GW (number of modular facilities), by scenario

Region	REF	E+	RE+	RE–	E–	ONS
NSW	0 (0)	3.82 (34)	5.17 (46)	2.93 (26)	5.21 (46)	4.75 (42)
NT	0 (0)	0 (0)	6.67 (59)	0 (0)	1.78 (16)	0 (0)
QLD	0 (0)	2.65 (24)	8.46 (74)	2.24 (20)	6.85 (60)	2.55 (23)
SA	0 (0)	0 (0)	1.23 (11)	0 (0)	0 (0)	0 (0)
VIC/TAS	0 (0)	2.54 (23)	6.09 (54)	5.07 (45)	3.29 (29)	2.82 (25)
WA	0 (0)	2.07 (19)	10.7 (94)	3.37 (30)	5.04 (44)	2.18 (19)
Total	**0 (0)**	**11.08 (100)**	**38.33 (338)**	**13.6 (121)**	**22.21 (195)**	**12.31 (109)**

Table 6 suggests that FTL capacity is needed in all scenarios in NSW, QLD, VIC/TAS, and WA. Table 6 reports that FTL facilities are needed in the NT in the RE+ and E– scenarios, and only in SA in the RE+ scenario.

The layout for the Greig et al. [12] plant is shown in Figure 10, with the areas that are expected to be used for the NZAu plant circled in red.

Figure 10 | Fischer-Tropsch plant layout [12], with NZAu minimum plant requirements indicated in red



Using Figure 10, a rough approximation of the total area needed for the NZAu plant, with the addition of backup H_2 and CO_2 storage (which will be minimal as the plant will have a dedicated connection to both H_2 and CO_2 trunk pipelines), is 90,000 square meters (300m x 300m). This leads to an estimated footprint conversion factor of 785 m^2/MW, HHV (90,000m^2/114.7 MW). Table 7 provides the footprints (in km^2) of the regional Fischer-Tropsch capacities found in Table 6.

Table 7 | Footprints of Fischer-Tropsch regional capacities in km^2, by scenario

Location	REF	E+	RE+	RE–	E–	ONS
NSW	0.0	3.0	4.1	2.3	4.1	3.7
NT	0.0	0.0	5.2	0.0	1.4	0.0
QLD	0.0	2.1	6.6	1.8	5.4	2.0
SA	0.0	0.0	1.0	0.0	0.0	0.0
VIC/TAS	0.0	2.0	4.8	4.0	2.6	2.2
WA	0.0	1.6	8.4	2.6	4.0	1.7
Total	**0.0**	**8.7**	**30.1**	**10.7**	**17.4**	**9.7**

NZAu expects that the repurposing of existing infrastructure will be explored for conversion to Fischer-Tropsch facilities to lower capital costs and potentially ease the acquisition of building and operating permits. Table 8 lists the sites of current and closed Australian oil refineries, in order of reported oil refining capacity [14], [15] along with year closed [14]–[17] if applicable, and the estimated output of the facility if repurposed to fit NZAu modular facilities.

A repurposed refinery's FTL output is estimated using conversion coefficient of 0.3608 MW/reported capacity (in Ml/year). This conversion coefficient is arrived at by dividing the estimated repurposed capacity of the 2.5 km^2 Kwinana Refinery [18], which on a land footprint basis is expected to be able to support 3.2 GW, HHV of modular FTL capacity, by its estimated refining capacity of 8,830 Ml/year [15]. The NZAu conversion estimate is notional and is expected to change considerably once plant engineers tackle the problem in earnest and FTL facilities are designed to produce synthetic fuels in greater quantities than the first-of-a-kind (FOAK) facility found in Greig et al. [12].

Table 8 | Repurposed refining capacities (in GW, HHV) of Australian oil refineries in order of reported oil refining capacity (in Ml/year), with year closed

Facility	Closed	Region	Refining capacity (Ml/year)	FTL capacity (GW, HHV)
Kwinana	2021	WA	8,830	3.2
Kurnell	2014	NSW	7,820	2.8
Geelong	--	VIC	7,470	2.7
Lytton	--	QLD	6,300	2.3
Bulwer	2015	QLD	5,910	2.1
Altona	2021	VIC	5,220	1.9
Clyde	2012	NSW	4,990	1.8
Port Stanvac	2009	SA	4,520	1.6
Totals (kbbl/day)		**AUS**	**51,060**	**18.4**

A comparison of the repurposed FTL capacities in Table 8 with the total scenario capacities in Table 6 suggests that the repurposing of Australia's retired and operating refining capacities for FTL outputs would be sufficient in three of the five modelled scenarios (E+, RE–, ONS). However, in two scenarios (RE+ and E– scenarios), additional FTL production capacity would need to be found – either through improved plant conversion efficiencies and/or by siting additional FTL facilities.

To place future FTL facilities on maps and consider related infrastructure needs (H_2, CO_2, and pipeline gas pipelines), NZAu has taken the notional stance that – in all locations but WA – all future FTL facilities will be built on or near the sites of the existing facilities listed in Table 8. In WA, FTL production will be split between Kwinana and the northern export ports depending on the regional availability of hydrogen and CO_2 (much more of both in northern WA ports) and the intended use of the FTL (production for export makes more sense at northern export ports). The relatively small quantity of FTL liquids produced for export in QLD

(Figure 9) are expected to be exported directly from Lytton/Bulwer rather than siting a second facility for export in Gladstone. The notional locations for FTL facilities are listed in Table 9, along with the estimated repurposed capacity for included refinery sites (in GW) and the required 2060 site capacities (in GW) in each NZAu scenario. Scenarios in which the required FTL capacities exceed the notional repurposed capacities are shown in red in Table 9.

Table 9 | Notional (mapped) sites of FTL facilities with estimated repurposed capacity for selected refinery sites (in GW), and required 2060 site capacities (in GW), by scenario

Region	Repurposed GW	E+	RE+	RE–	E–	ONS
NSW (Kurnell/Clyde)	4.6	3.82	5.17	2.93	5.21	4.75
NT (Darwin)	0	0.00	6.67	0.00	1.78	0.00
QLD (Bulwer/Lytton)	4.4	2.65	8.46	2.24	6.85	2.55
SA (Port Stanvac)	1.6	0.00	1.23	0.00	0.04	0.00
VIC (Altona/Geelong)	4.6	2.54	6.09	5.07	3.29	2.82
WA (Kwinana + Dampier)	3.2	2.07	10.70	3.47	5.04	2.18
Total	**18.4**	**11.08**	**38.33**	**13.60**	**22.21**	**12.31**

Table 9 indicates that if the repurposing of oil refinery sites is used as a strategy in the production of FTL, then (aside from portion produced in northern WA) full FTL production might be achieved using repurposed sites in the E+ scenario. In the ONS and RE– scenarios, repurposed site capacity could cover required capacities with the shifting of overflow amounts in NSW (ONS), VIC (RE–), and WA (RE–) to repurposed refineries in other regions (SA, QLD, NSW). For the RE+ and E– scenarios meeting FTL demand appears highly unlikely without both improving the efficiency of FTL retrofits, and building new greenfield facilities in WA and NT. Figure 11 presents notional mapping of the FTL facilities listed in Table 9. Each of these sites requires connection to hydrogen, CO_2, water, and electricity infrastructure. Table 10 presents the number of aggregate FTL facilities estimated for each region in each scenario, with NZAu assuming initial small efficiency improvements (10%) in brownfield site repurposing; the construction of high efficiency state-of-the-art plants on greenfield sites in export locations in WA and the NT; and later transitions to either higher efficiencies or expansions in footprints at repurposed locations.

Figure 11 | Notional mapping of the FTL production facilities

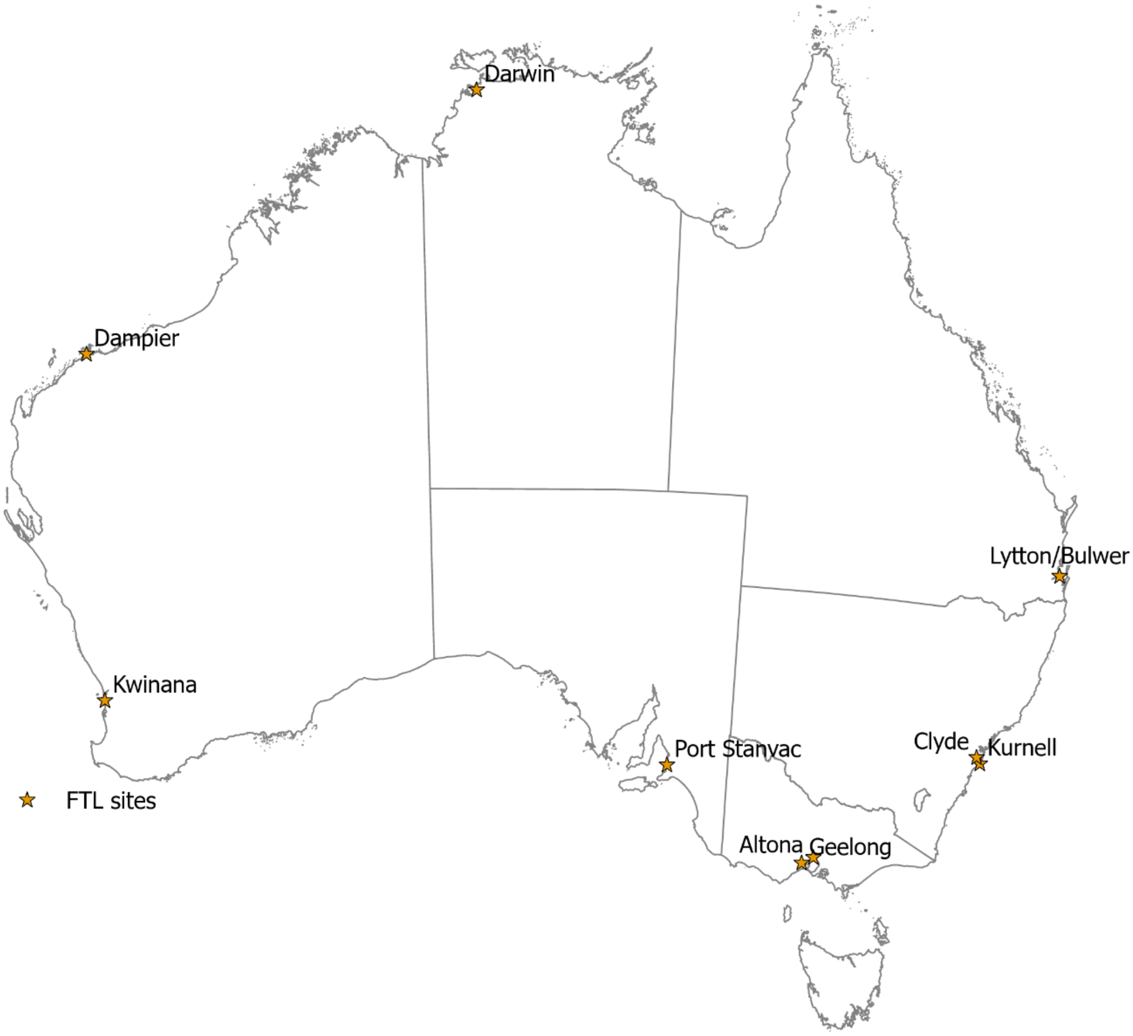


Table 10 | Number of FTL facilities in each region in each scenario

Region	REF	E+	RE+	RE–	E–	ONS
NSW	0	2	2	1	2	2
NT	0	0	1	0	1	0
QLD	0	2	2	1	2	2
SA	0	0	1	0	0	0
VIC	0	1	2	2	2	1
WA	0	2	2	2	2	2
ALL	**0**	**7**	**10**	**6**	**9**	**7**

4 Hydrogen pipelines and storage

The NZAu model was provided the option of building either H_2 pipelines from VRE aggregation nodes to port locations, or of building only electricity transmission from VRE aggregation nodes to port locations. The model chose to build both H_2 pipelines and electricity transmission lines between the VRE nodes and ports, with hydrogen being produced in electrolysis facilities at VRE aggregation nodes before being piped to the port, and electricity lines being run in parallel to support the electricity requirements of other new industrial infrastructure (e.g. Haber Bosch, ATR w/cc, FTL, desalination, etc) in ports. Coverage of new electricity transmission lines can be found in the companion report, *Downscaling - VRE and electricity transmission*.

4.1 Pipelines

Figure 12 presents the transportation capacity of major hydrogen pipelines in GW, by scenario, location, and year.

Figure 12 | The transportation capacity of major hydrogen pipelines in GW by scenario, loaction, and year

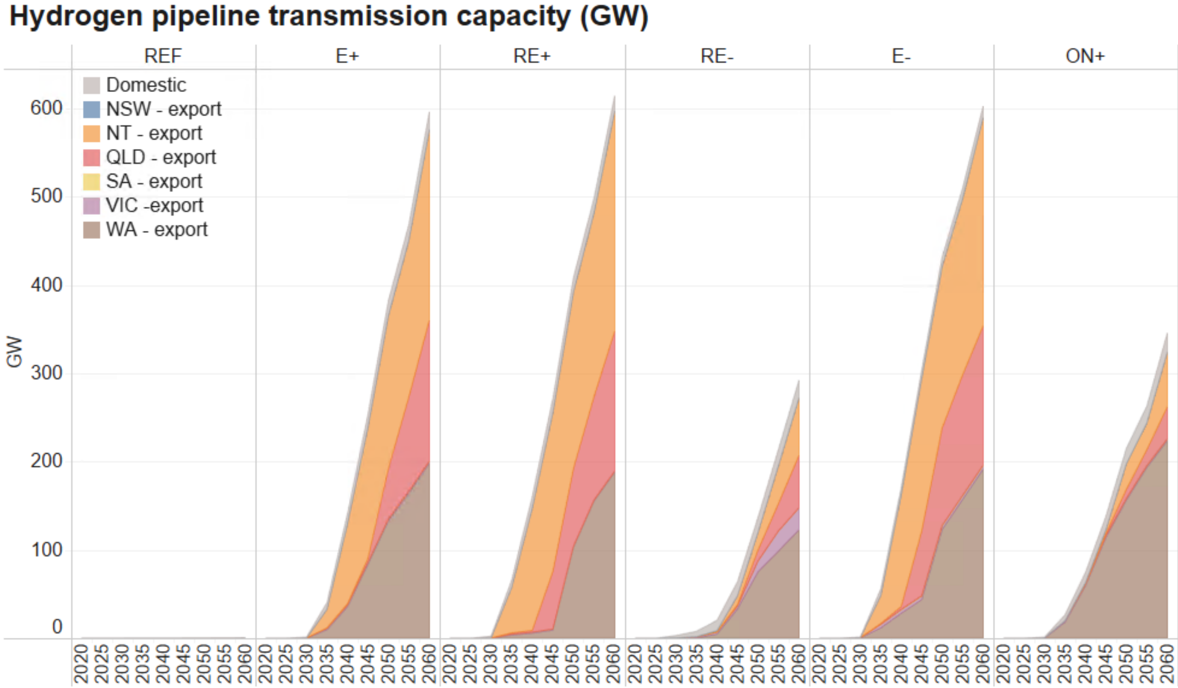


Figure 12 indicates that all core scenarios involve the construction of substantial capacities of hydrogen pipelines by 2060, with the RE– and ONS having the least capacities at 292 GW and 346 GW respectively. The E+, E– and RE+ all see around 600 GW of hydrogen pipelines built by 2060. Figure 12 also indicates that hydrogen pipelines for export comprise at least 93% of all hydrogen pipelines in all scenarios, with the percentage rising to at least 97% in the E+, E– and RE+.

Table 11 provides hydrogen corridor capacities in TJ HHV per day in 2060 by scenario, and also estimates the number of parallel pipelines (each allowing a maximum throughput of 1893 TJ HHV per day [19]) needed in each corridor. A minimum pipeline capacity of 50 TJ day is employed in Table 11 for all inter-regional connections but those running long distances between WA and SA, and WA and the NT for which a 100 TJ/day minimum threshold is used.

A location prefix of "ex-" in the corridor column in Table 11 indicates an electrolysis node at which VRE transmission lines terminate and hydrogen is produced. A location prefix of "port-" in the corridor column in Table 11 indicates an export port at which ATR w/cc and FTL facilities are sited, and at which ammonia production facilities convert hydrogen to ammonia for export.

Table 11 | Hydrogen corridor capacities in TJ HHV/day in 2060 by scenario, (with the number of parallel hydrogen pipelines [each allowing a maximum throughput of 1893 TJ HHV per day and a minimum of 50 TJ per day] required in each corridor in parentheses)

Location	REF	E+	RE+	RE–	E–	ONS
ex-NSW to port- NSW	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
ex-NT to port-NT	0 (0)	18,620 (10)	21,523 (12)	5,605 (3)	20,348 (11)	5,329 (3)
ex-QLD to port- QLD	0 (0)	13,786 (8)	13,687 (8)	5,130 (3)	13,626 (8)	3,133 (2)
ex-SA to port-SA	0 (0)	0 (0)	0 (0)	0 (0)	50 (1)	0 (0)
ex-WA to port-WA	0 (0)	17,117 (10)	16,233 (9)	10,596 (6)	16,536 (9)	19,323 (11)
NSW-central to NSW-south	0 (0)	0 (0)	0 (0)	194 (1)	73 (1)	95 (1)
NSW-north to NSW-central	0 (0)	85 (1)	150 (1)	87 (1)	101 (1)	74 (1)
NSW-north to NSW-outback	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
NSW-outback to NSW-central	0 (0)	146 (1)	121 (1)	0 (0)	83 (1)	169 (1)
NSW-outback to NSW-south	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
NSW-outback to SA	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
NSW-south to VIC-east	0 (0)	0 (0)	0 (0)	246 (1)	104 (1)	78 (1)
NSW-south to VIC-west	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
NT to QLD-north	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
NT to QLD-outback	0 (0)	101 (1)	86 (1)	0 (0)	75 (1)	84 (1)
NT to SA	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
QLD-north to QLD-outback	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
QLD-north to QLD-south	0 (0)	95 (1)	84 (1)	205 (1)	68 (1)	111 (1)
QLD-outback to NSW-outback	0 (0)	101 (1)	0 (0)	0 (0)	0 (0)	132 (1)
QLD-outback to QLD-south	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
QLD-outback to SA	0 (0)	157 (1)	110 (1)	0 (0)	119 (1)	152 (1)
QLD-south to NSW-north	0 (0)	57 (1)	150 (1)	87 (1)	79 (1)	67 (1)
QLD-south to NSW-outback	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
SA to NSW-south	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
VIC-east to TAS	0 (0)	0 (0)	0 (0)	934 (1)	0 (0)	0 (0)
VIC-east to VIC-west	0 (0)	129 (1)	62 (1)	961 (1)	206 (1)	68 (1)
VIC-west to SA	0 (0)	101 (1)	0 (0)	68 (1)	123 (1)	74 (1)
VIC-west to TAS	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
WA-central to NT	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
WA-central to SA	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
WA-central to WA-north	0 (0)	383 (1)	250 (1)	476 (1)	143 (1)	398 (1)
WA-north to NT	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
WA-south to SA	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
WA-south to WA-central	0 (0)	435 (1)	377 (1)	446 (1)	183 (1)	437 (1)
Total	**0 (0)**	**51,312 (40)**	**52,833 (37)**	**25,037 (23)**	**51,916 (40)**	**29,723 (29)**

Table 11 indicates that except for the RE– and ONS scenarios, over 96% of all hydrogen pipeline capacity is sited between hydrogen production nodes and ports in WA, QLD and the NT to serve export markets (in the RE– and ONS scenarios, 85% and 93% of the total capacity respectively is sited in WA, QLD, and NT export corridors). If considering the H_2 pipeline network outside of those three corridors, and assuming a minimum pipeline transfer capacity of 50 TJ HHV per day, then between 8 and 13 additional hydrogen pipeline corridors are built to serve domestic (and VIC export in RE–) demand across all core scenarios.

Table 12 lists the estimated widths of each hydrogen corridor's right-of-way (ROW) in meters in 2060 by scenario along with estimates of the number of parallel pipelines needed in each corridor (in parentheses). Location prefixes in Table 12 have the same designations as in Table 11. ROW widths and design are based on expert elicitation [19], which estimated a 40 metre (m) ROW width for a single 56 inch pipeline, with the centreline of the pipeline being placed 12 m from the edge of the ROW. In corridors requiring multiple pipelines, the expert then estimated a separation of 12 m between each pipeline – pending a full safety and operational security review of each corridor to adjust widths as required [19] – while always allowing 27.2 m for non-pipeline infrastructure to one side of the corridor.

Table 12 | The estimated widths of each hydrogen corridor's ROW in meters in 2060, by scenario (with the number of parallel hydrogen pipelines in each corridor in parentheses)

Location	REF	E+	RE+	RE–	E–	ONS
Ex-NSW to port-NSW	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
Ex-NT to port-NT	0 (0)	162 (10)	189 (12)	67 (3)	176 (11)	67 (3)
Ex-QLD to port-QLD	0 (0)	135 (8)	135 (8)	67 (3)	135 (8)	54 (2)
Ex-SA to port-SA	0 (0)	0 (0)	0 (0)	0 (0)	40 (1)	0 (0)
Ex-WA to port-WA	0 (0)	162 (10)	148 (9)	108 (6)	148 (9)	176 (11)
NSW-central to NSW-south	0 (0)	0 (0)	0 (0)	40 (1)	40 (1)	40 (1)
NSW-north to NSW-central	0 (0)	40 (1)	40 (1)	40 (1)	40 (1)	40 (1)
NSW-north to NSW-outback	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
NSW-outback to NSW-central	0 (0)	40 (1)	40 (1)	0 (0)	40 (1)	40 (1)
NSW-outback to NSW-south	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
NSW-outback to SA	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
NSW-south to VIC-east	0 (0)	0 (0)	0 (0)	40 (1)	40 (1)	40 (1)
NSW-south to VIC-west	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
NT to QLD-north	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
NT to QLD-outback	0 (0)	40 (1)	40 (1)	0 (0)	40 (1)	40 (1)
NT to SA	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
QLD-north to QLD-outback	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
QLD-north to QLD-south	0 (0)	40 (1)	40 (1)	40 (1)	40 (1)	40 (1)
QLD-outback to NSW-outback	0 (0)	40 (1)	0 (0)	0 (0)	0 (0)	40 (1)
QLD-outback to QLD-south	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
QLD-outback to SA	0 (0)	40 (1)	40 (1)	0 (0)	40 (1)	40 (1)
QLD-south to NSW-north	0 (0)	40 (1)	40 (1)	40 (1)	40 (1)	40 (1)
QLD-south to NSW-outback	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
SA to NSW-south	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
VIC-east to TAS	0 (0)	0 (0)	0 (0)	40 (1)	0 (0)	0 (0)
VIC-east to VIC-west	0 (0)	40 (1)	40 (1)	40 (1)	40 (1)	40 (1)
VIC-west to SA	0 (0)	40 (1)	0 (0)	40 (1)	40 (1)	40 (1)
VIC-west to TAS	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
WA-central to NT	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
WA-central to SA	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
WA-central to WA-north	0 (0)	40 (1)	40 (1)	40 (1)	40 (1)	40 (1)
WA-north to NT	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
wa-south to sa	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
WA-south to WA-central	0 (0)	40 (1)	40 (1)	40 (1)	40 (1)	40 (1)

Table 12 indicates that outside of the WA, NT, and QLD export corridors, all other H_2 pipeline corridors will have a maximum ROW of 40 m (most corridors will have single pipelines with a smaller capacity the NZAu maximum size). The ROW widths in the WA, NT, and QLD corridors will vary depending on the scenario and year, with the NT export corridor reaching a maximum value of 189 m in the RE+ scenario. Maps showing the hydrogen pipeline networks for each scenario are provided later in this document.

4.2 Storage

Figure 13 presents hydrogen storage capacity in TWh by detailed location/use, scenario, and year.

Figure 13 | Hydrogen storage capacity in TWh by detailed location/use, scenario, and year

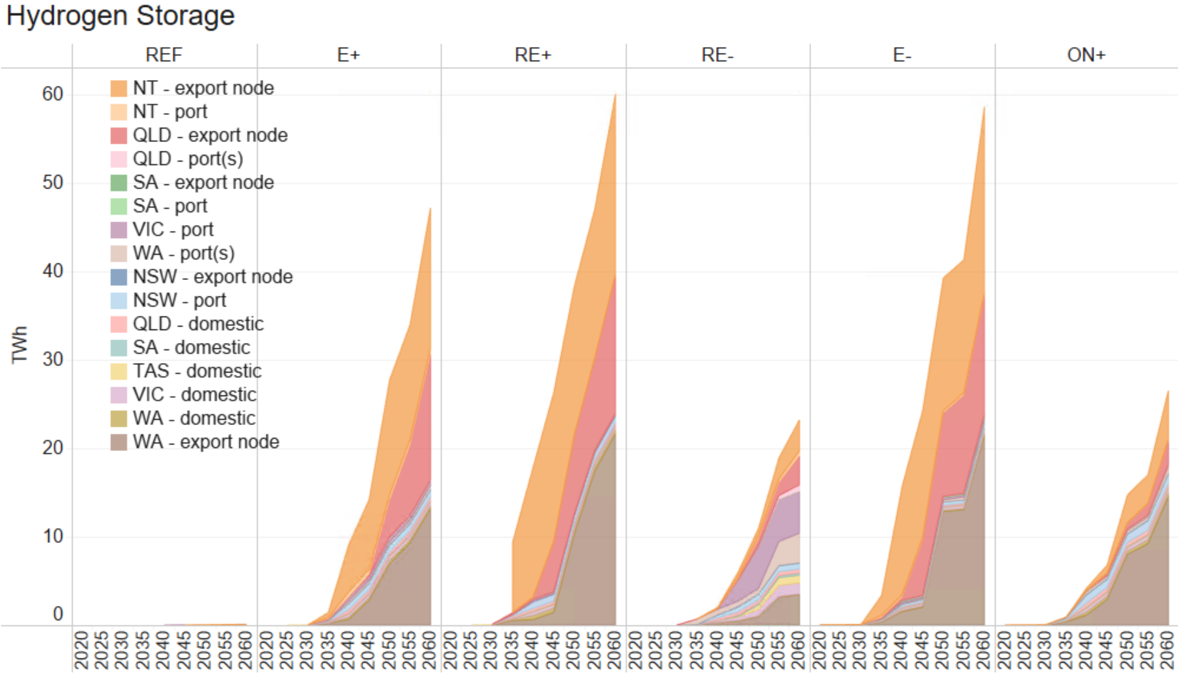


Figure 13 indicates that while there is some hydrogen storage sited in domestic locations, nearly all hydrogen storage is built in WA, QLD, and the NT to serve export markets. Figure 13 also indicates a correlation with hydrogen production locations, with most storage being sited at electrolysis nodes ("export node") in all but the RE– scenario. In the RE– scenario storage appears to be split between electrolysis locations in WA, QLD, and the NT, electrolysis locations in VIC and surrounds driven by offshore wind (VIC and TAS), and port locations containing ATR w/cc facilities ("port").

Table 13 presents the number of storage facilities and total land footprint of storage in 2060 at key locations, if each storage facility is constructed by burying 300 x 960 meter parallel pipe strings of 24 inch outer diameter Schedule 60 pipes, which store 20 GWh of hydrogen, and have a land footprint of 0.45 km^2 [20].

Table 13 | Key H_2 storage location details – Facilities in 2060 (footprint in km^2)

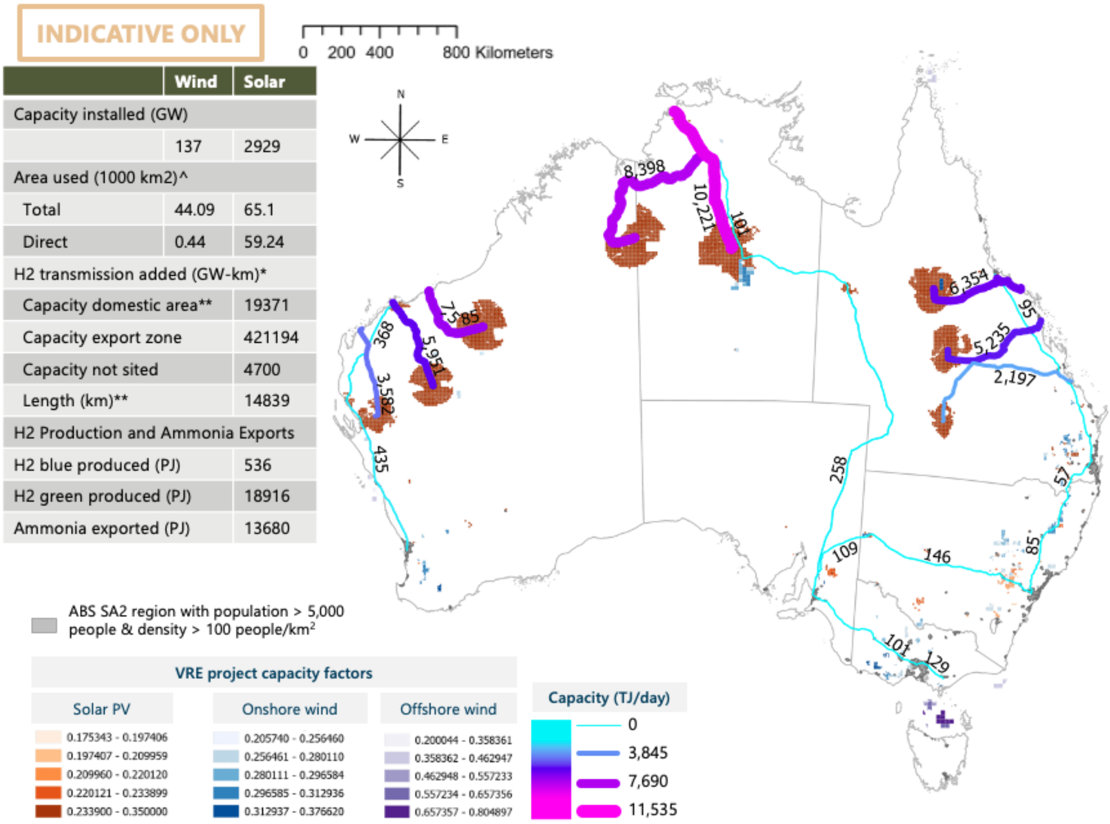
Location	REF	E+	RE+	RE–	E–	ONS
NSW - export node	0 (0)	3 (1)	2 (1)	3 (1)	2 (1)	3 (1)
NSW - port	2 (1)	40 (18)	38 (17)	34 (15)	24 (11)	54 (24)
NT - export node	0 (0)	794 (357)	1,023 (460)	178 (80)	1,049 (472)	277 (125)
NT - port	0 (0)	34 (15)	3 (1)	27 (12)	14 (6)	8 (4)
QLD - domestic	2 (1)	22 (10)	17 (8)	22 (10)	12 (5)	25 (11)
QLD - export node	0 (0)	713 (321)	782 (352)	166 (75)	676 (304)	136 (61)
QLD - port(s)	0 (0)	6 (3)	0 (0)	37 (17)	5 (2)	6 (3)
SA - domestic	0 (0)	3 (1)	3 (1)	13 (6)	4 (2)	4 (2)
SA - export node	0 (0)	0 (0)	0 (0)	0 (0)	4 (2)	0 (0)
SA - port	0 (0)	0 (0)	0 (0)	0 (0)	2 (1)	0 (0)
TAS – domestic/node	0 (0)	3 (1)	3 (1)	45 (20)	3 (1)	4 (2)
VIC – domestic/node	0 (0)	22 (10)	18 (8)	63 (28)	15 (7)	22 (10)
VIC – port/node	0 (0)	23 (10)	12 (5)	236 (106)	21 (9)	5 (2)
WA - domestic	0 (0)	19 (9)	25 (11)	4 (2)	16 (7)	23 (10)
WA - export node	0 (0)	659 (297)	1,083 (487)	173 (78)	1,073 (483)	726 (327)
WA - port(s)	0 (0)	25 (11)	0 (0)	169 (76)	18 (8)	39 (18)
Total	**4 (2)**	**2,366 (1065)**	**3,009 (1354)**	**1,170 (527)**	**2,938 (1322)**	**1,332 (599)**

The number of facilities and land footprint reported in Table 13 suggests that the modular facility size used as a reference for NZAu modelling is much too small for the hydrogen storage challenge faced by an ambitious clean energy export system. It is expected that once design engineers tackle the challenge of designing (non-natural formation based) hydrogen storage systems aimed at the scale discussed in NZAu, both facility numbers and footprints would decrease significantly. Alternatively, if storage costs play a sizable role in the transition, a hydrogen focused export economy might put greater consideration into sites that offered the potential for lower cost natural storage formations [1].

5 Notional mapping of hydrogen production nodes, hydrogen transportation pipelines

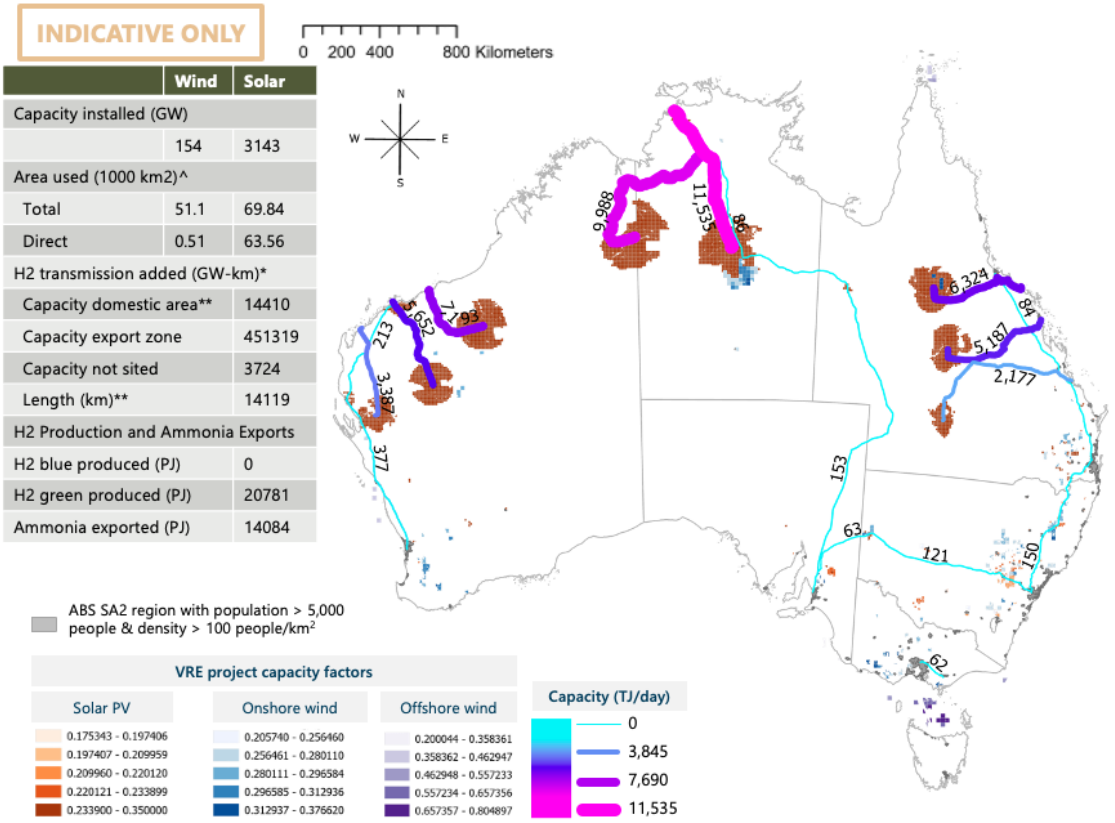
Figure 14 through Figure 19 present notional mapping of the hydrogen pipelines listed in Table 11 for each scenario in 2060 (in TJ/day), along with variable renewable resources powering export (and domestic) infrastructure. Five-year transition maps for all core scenarios are provided in an Appendix to this document. Table 14 provides a summary of the 2060 H_2 transition characteristics reported on tables contained in Figure 14 through Figure 19.

Figure 14 | Notional mapping of the hydrogen pipelines for the E+ scenario in 2060 (in TJ/day), along with the variable renewable resources powering export (and domestic) infrastructure



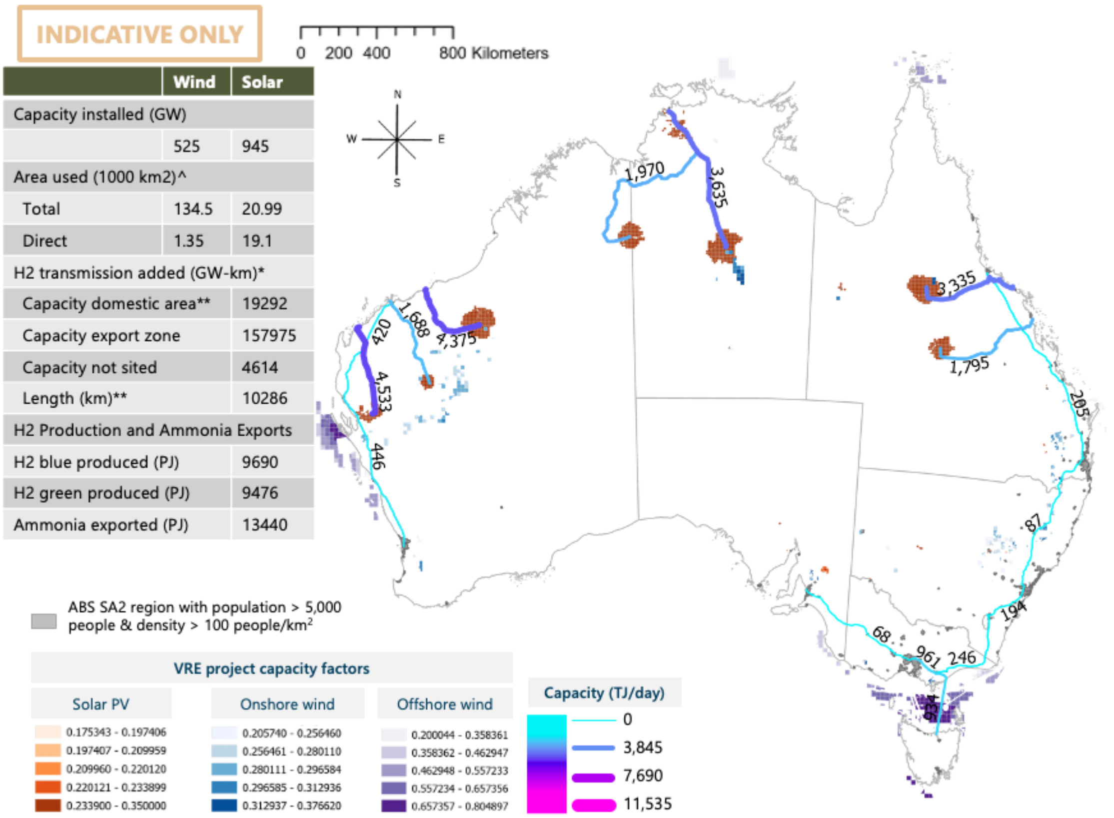
	Wind	Solar
Capacity installed (GW)		
	137	2929
Area used (1000 km2)^		
Total	44.09	65.1
Direct	0.44	59.24
H2 transmission added (GW-km)*		
Capacity domestic area**		19371
Capacity export zone		421194
Capacity not sited		4700
Length (km)**		14839
H2 Production and Ammonia Exports		
H2 blue produced (PJ)		536
H2 green produced (PJ)		18916
Ammonia exported (PJ)		13680

Figure 15 | Notional mapping of the hydrogen pipelines for the RE+ scenario in 2060 (in TJ/day), along with the variable renewable resources powering export (and domestic) infrastructure



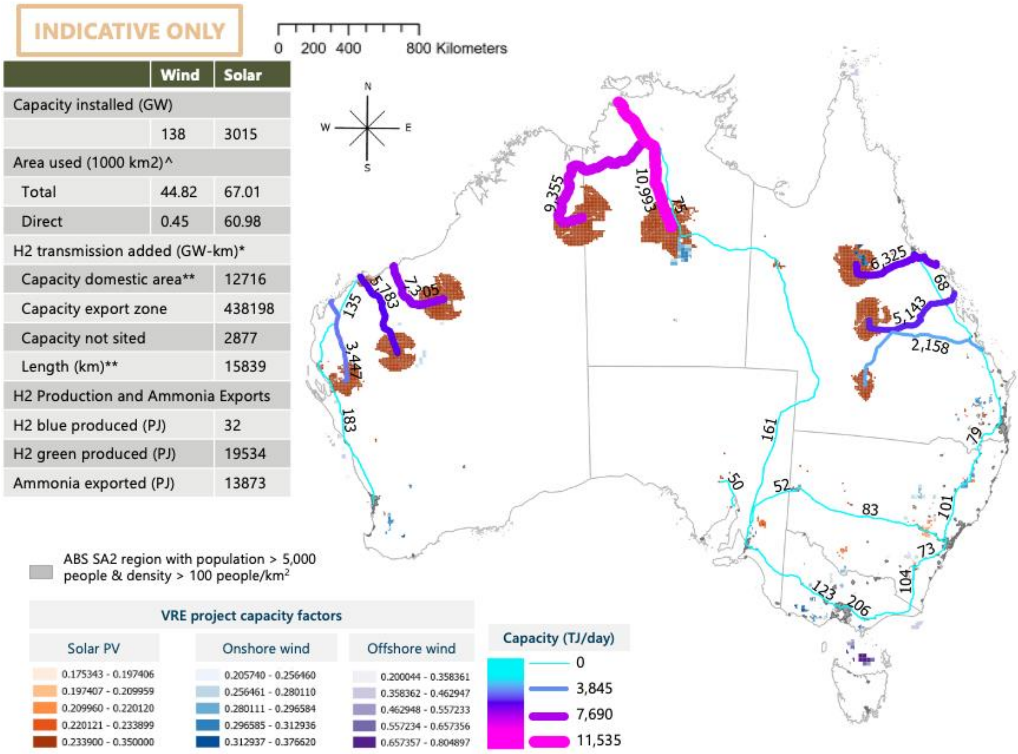
	Wind	Solar
Capacity installed (GW)		
	154	3143
Area used (1000 km2)^		
Total	51.1	69.84
Direct	0.51	63.56
H2 transmission added (GW-km)*		
Capacity domestic area**		14410
Capacity export zone		451319
Capacity not sited		3724
Length (km)**		14119
H2 Production and Ammonia Exports		
H2 blue produced (PJ)		0
H2 green produced (PJ)		20781
Ammonia exported (PJ)		14084

Figure 16 | Notional mapping of the hydrogen pipelines for the RE– scenario in 2060 (in TJ/day), along with the variable renewable resources powering export (and domestic) infrastructure



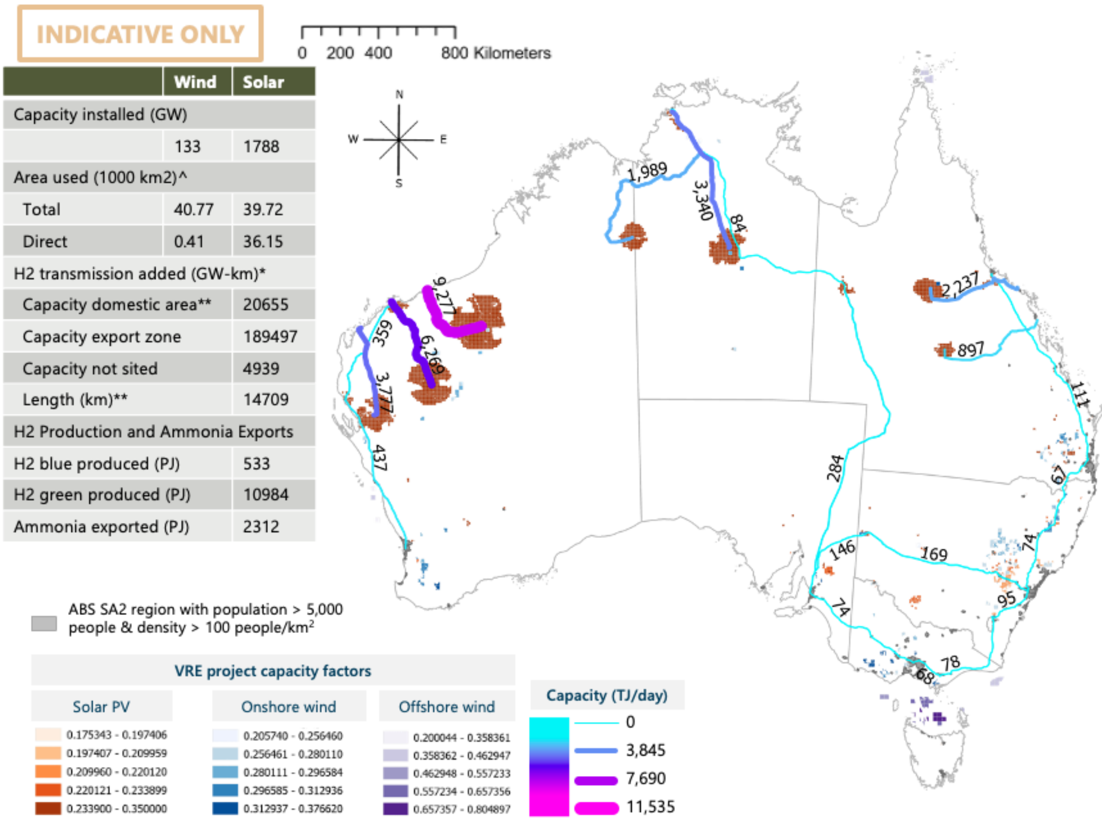
	Wind	Solar
Capacity installed (GW)		
	525	945
Area used (1000 km2)^		
Total	134.5	20.99
Direct	1.35	19.1
H2 transmission added (GW-km)*		
Capacity domestic area**		19292
Capacity export zone		157975
Capacity not sited		4614
Length (km)**		10286
H2 Production and Ammonia Exports		
H2 blue produced (PJ)		9690
H2 green produced (PJ)		9476
Ammonia exported (PJ)		13440

Figure 17 | Notional mapping of the hydrogen pipelines for the E– scenario in 2060 (in TJ/day), along with the variable renewable resources powering export (and domestic) infrastructure



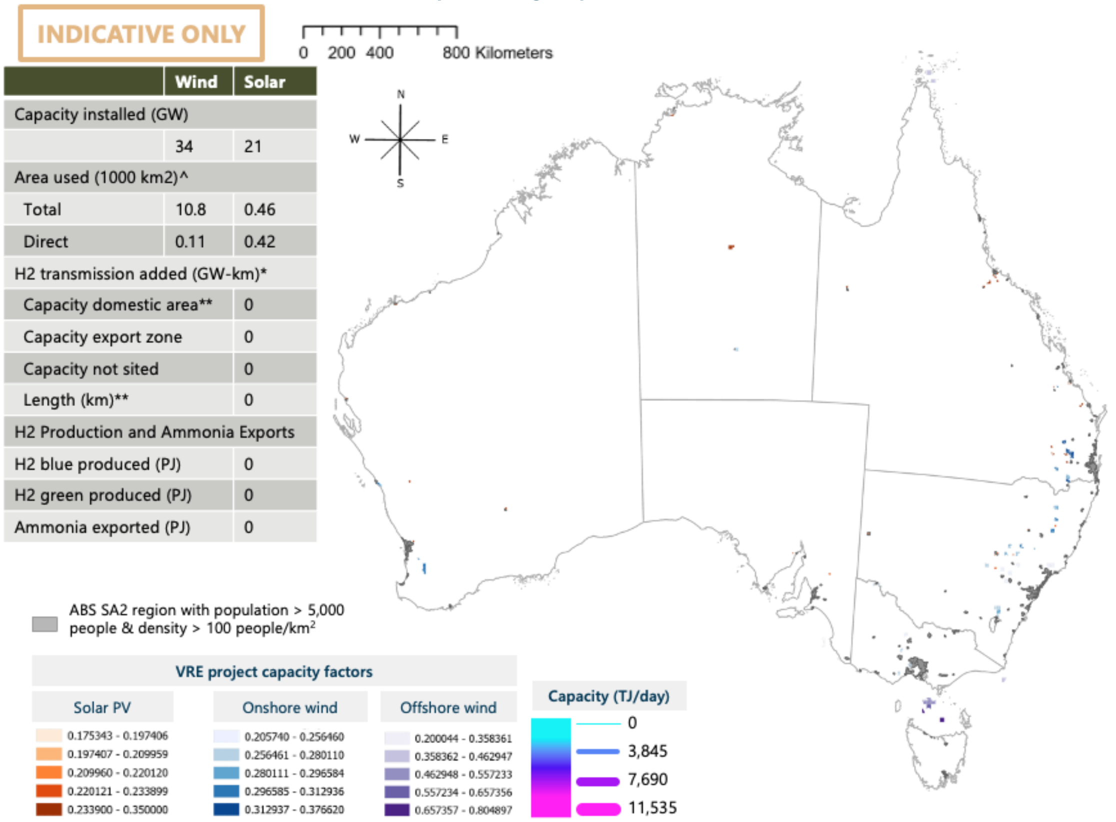
	Wind	Solar
Capacity installed (GW)		
	138	3015
Area used (1000 km2)^		
Total	44.82	67.01
Direct	0.45	60.98
H2 transmission added (GW-km)*		
Capacity domestic area**		12716
Capacity export zone		438198
Capacity not sited		2877
Length (km)**		15839
H2 Production and Ammonia Exports		
H2 blue produced (PJ)		32
H2 green produced (PJ)		19534
Ammonia exported (PJ)		13873

Figure 18 | Notional mapping of the hydrogen pipelines for the ONS scenario in 2060 (in TJ/day), along with the variable renewable resources powering export (and domestic) infrastructure



	Wind	Solar
Capacity installed (GW)		
	133	1788
Area used (1000 km2)^		
Total	40.77	39.72
Direct	0.41	36.15
H2 transmission added (GW-km)*		
Capacity domestic area**		20655
Capacity export zone		189497
Capacity not sited		4939
Length (km)**		14709
H2 Production and Ammonia Exports		
H2 blue produced (PJ)		533
H2 green produced (PJ)		10984
Ammonia exported (PJ)		2312

Figure 19 | Notional mapping of the hydrogen pipelines for the REF scenario in 2060 (in TJ/day), along with the variable renewable resources powering export (and domestic) infrastructure



The following notes apply to Table 14 and Figure 14 through Figure 19, as well as all maps in the Appendix, and the maps provided for sensitivities as supplementary materials:

- (^) Area totals reported on maps include marine areas. Solar PV project areas shown in map cover the entire candidate area considered for a project, of which only 20% will be used on final siting of the project. Depicting solar PV projects 5x larger than total areas listed in the map tables aids in making smaller projects visible on maps and underscores a flexibility for accounting for local contexts in determining the final siting for projects. Area totals do not include the land used by the transmission lines connecting projects to loads. The direct areas listed are 91% and 1% of total areas for solar and wind respectively [21]. The minimum project sizes for depiction on maps are 5 MW for solar, 50MW for onshore wind, and 100MW for offshore wind.
- (*) Transmission expansions are mapped to follow existing rights of way for existing TX > 132kV, national roads, railroads, pipelines; paths are indicative not definitive. Inter-regional transmission expansions of below 50 TJ/day (578 GW) are not mapped. Nor are expansions of longer than 2000 km with flows of less than 100 TJ/day. Transmission expansions not mapped are tallied in the "Capacity not sited" line item. Transmission expansions are built five years before the full H2 transfers they are intended to allow.
- (**) Currently reported lengths cover the length of corridor added, and not total pipeline distance (e.g. a 100 km corridor with two pipelines reports 100km, not 200km).

Table 14 | Summary of H_2 transition aspects from 2060 maps of core scenarios

H2 downscaling aspect	REF	E+	RE+	RE–	E–	ONS
H2 blue produced (PJ)	0	536	0	9,690	32	533
H2 green produced (PJ)	0	18,916	20,781	9,476	19,534	10,984
Ammonia exported (PJ)	0	13,680	14,084	13,440	13,873	2,312
H2 transmission domestic area (GW-km)*	0	19,371	14,410	19,292	12,716	20,655
H2 transmission export zone (GW-km)*	0	421,194	451,319	157,975	438,198	189,497
H2 transmission not sited (GW-km)*	0	4,700	3,724	4,614	2,877	4,939
Length of H2 corridor (km)**	0	14,839	14,119	10,286	15,839	14,709

The siting of extensive hydrogen infrastructure in the northern half of Australia (WA, NT, QLD) by 2060 in is evident for all scenarios shown in Figure 14 through Figure 19. The scenario that sees the least infrastructure built in WA, NT and QLD, and which also has the largest H_2 build around the export zone in VIC, is the RE– scenario shown in Figure 16. All scenarios but the RE– see a North to South pipeline built between the NT, QLD and SA with the E+ (Figure 14) and ONS (Figure 18) having the largest builds. While all scenarios see an H_2 pipeline from Townsville to Sydney, only the RE– (Figure 16), E– (**Figure 17**), and ONS (Figure 18) see that pipeline extend to connect with pipelines in Victoria. All scenarios but the RE– include a pipeline between Sydney and SA.

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