Transport and Storage Options for Future Fuels: Hydrogen transport with linepack and underground storage

Milestone 6

September 29, 2023

Project number: RP1.1-02B

Transport and Storage Options for Future Fuels

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Business Cooperative Research Centres Program

This work is funded by the Future Fuels CRC, supported through the Australian Government's Cooperative Research Centres Program. We gratefully acknowledge the cash and in-kind support from all our research, government and industry participants.

IMPORTANT DISCLAIMER

ACKNOWLEDGEMENT

This work is funded by the Future Fuels CRC, supported through the Australian Governments' Cooperative Research Centres Program. The cash and in-kind support from the industry participants is gratefully acknowledged.

PROJECT INFORMATION	
Project number	RP1.1-02B
Project title	Transport and Storage Options for Future Fuels
Research Program	RP1
Milestone Report Number	6
Description	Hydrogen transport with linepack and storage
Research Provider	University of Melbourne
Project Leader and Team	Prof Pierluigi Mancarella (Lead), University of Melbourne Dr. Sleiman Mhanna, University of Melbourne Isam Saedi, University of Melbourne
Industry Proponent and Advisor Team	Dennis Van Puyvelde (ENA), Nick Kastelein (GPA), Sheila Krishnan (APA), Allison Smith (APA), David Moore (NSW Government), Jordan McCollum (APGA)
Related Commonwealth Schedule	Output Milestones 1.2 and 1.3.
Project start/completion date	July 2021/June 2023
IP Access	**Open** – available publicly to all parties outside the CRC.
Approved by	Dennis Van Puyvelde
Date of approval	11 October 2023

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EXECUTIVE SUMMARY

Widespread adoption of hydrogen raises the central question of which of the two options, transporting “green” molecules, or transporting “green” electricity, is the most cost-effective one. This report introduces a first-of-its-kind mathematical optimisation framework for finding the optimal *greenfield* integrated planning of electricity and hydrogen transmission and storage infrastructure. The capabilities of this model are demonstrated on two sets of major case studies. The first is a canonical case study that consists of an assessment of the three fundamental drivers: (i) supply capacity, (ii) corridor length, and (iii) storage requirements, and how they influence the investment decision over a *single corridor*. The second is a proof-of-concept case study that considers all the renewable energy zones (REZ) stipulated in the 2022 *Integrated System Plan* (ISP) published by the Australian Energy Market Operator (AEMO) and connects them with provisional corridors to the hydrogen export ports whose demands are specified in the same ISP under the *Hydrogen Superpower* scenario for 2050. The case study also considers candidate underground hydrogen storage (UHS) facilities in the form of depleted gas fields, which can offer medium and long duration storage that can play a crucial role in buffering the variability of renewable energy sources (RES).

In contrast to most existing works, the developed optimisation framework not only considers all relevant infrastructure technologies such as high voltage direct current (HVDC), high voltage alternating current (HVAC), reactive power plants, battery energy storage systems (BESS), and hydrogen pipelines and compressors, but also incorporates all the essential nonlinearities that directly influence the optimal infrastructure investment decision, such as voltage drops due to impedances in HVAC and HVDC transmission lines, losses in HVDC converter stations, reactive power flow, pressure drops in pipelines, linepack, and nonlinear withdrawal/injection rates of UHS systems. The model adopts a relatively high temporal resolution that aligns with the resolution of the forecast VRE traces in AEMO’s 2022 ISP to fully capture the variability of RES, the ability of storage technologies in buffering this variability, and their impact on the optimal investment decision.

The findings in this report are summarised as follows:

A. Point-to-point analysis (single corridor):

In this case study, supply capacity is selected from the set [169 MW, 536 MW, 1000 MW, 1900 MW, 2000 MW, 2400 MW, 2900 MW, 6080 MW], corridor length is varied from 25 km to 800 km, and storage duration is varied between 0 and 8 hours. Under the specific cost and technical assumptions, corridor lengths, energy volumes, and storage requirements in this case study, the findings suggest that:

- Under steady-state throughputs (where no storage is required) hydrogen pipelines are more cost effective than their electricity counterparts across all the capacities and distances considered in this report.
- In cases where more than 2 hours of storage duration are required, hydrogen pipelines are more cost effective than their electricity counterparts over most distances and capacities, owing primarily to the observation that the increase in cost due to increasing *both* the diameter of the pipeline (to provide additional storage through the linepack) *and* the capacity of electrolysers (to accommodate the extra energy required for charging the linepack) is outweighed by a larger increase in cost due to additional investment in BESS over most of the considered distances.

- In cases where only 1 hour of storage is required, the optimal transmission and storage infrastructure is heavily influenced by the cost of BESS *relative* to the cost of electrolysers. In particular, electricity transmission lines and BESS are chosen for distances smaller than 100 km in this case.

B. Optimal integrated transmission and storage infrastructure over a network with variable supplies and demands (REZ and hydrogen demands from AEMO's 2022 ISP for 2050)

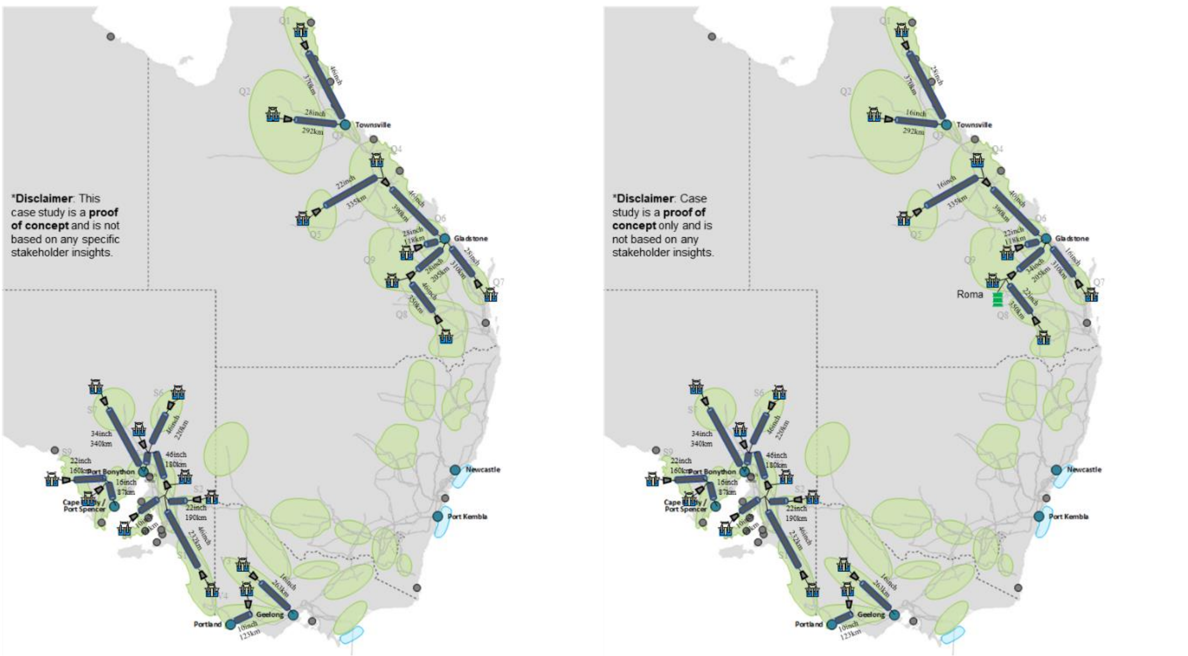
Under the specific cost and technical assumptions, corridor lengths, energy volumes, storage requirements, VRE forecasts, and hydrogen export demand forecasts in this case study, the findings suggest that:

- Only pipelines are deemed as the optimal transport infrastructure. This is predominantly due to the high variability of RES, which requires in some cases more than 8 hours of storage to buffer this variability. Linepack storage is of utmost importance in this case as the RES supply is variable and the hydrogen export demand is assumed constant in each state (QLD, SA, and VIC) but distributed, not necessarily equally, over the envisaged hydrogen export ports in each state. These results align with the observations in the above case for a single corridor. This is another way of saying that in this case it is more cost effective to co-locate large-scale electrolysis and VRE, and transport the produced green hydrogen in pipelines, as opposed to installing large-scale electrolysis at the location of the hydrogen demand (in this case the export ports).
- Investing in UHS in the form of depleted gas fields in specific locations in Australia can significantly *decrease* the total investment costs of transport and storage infrastructure. This is because the marginal cost of storage in the considered UHS facilities is much lower than that of a pipeline, and as a result the storage capacity gained from installing the UHS can displace more expensive storage (linepack) in adjacent pipelines, thereby resulting in the downsizing of these pipelines. The optimal greenfield integrated infrastructure designs for the two studies considering REZ and hydrogen export demands from AEMO's 2022 ISP in 2050 are shown in Figure 1.
- In contrast to existing works, which are predominantly limited to a single corridor with static supplies and demand profiles, the developed optimisation-based modelling can find the *optimal* integrated transport and storage infrastructure design over a *network* with arbitrary topology and with multiple variable supplies and demands. In contrast to a single corridor, optimising over a network with more than one corridor adds *geographical location* and RES variability to the list of defining factors that impact the optimal infrastructure and storage design. In other words, having more than one corridor entails finding the *optimal* compromise between (i) energy volumes, (ii) distance, (iii) storage requirements, *and* (iv) geographical location, in addition to (v) variability RES, thus making the analysis much more complex. Despite this complexity, the novel insights and assessments in this report are made possible thanks to state-of-the-art mathematical optimisation methods and scalable numerical algorithms.

It should be emphasised that the assessment and case studies in this report are considered as *greenfield* integrated expansion planning that optimises newly built electrolysis, transmission, and storage infrastructure network in *isolation* from existing infrastructure, for a specified constant hydrogen export demand distributed (not necessarily equally) over the envisaged hydrogen export ports in each state. In other words, this greenfield assessment does not consider the interactions between this newly built infrastructure network and the existing electricity transmission infrastructure such as the one in the National Electricity Market

(NEM). The findings in this report may change if these interactions are considered as the electricity system (including flexible generation, BESS, pumped hydro energy storage (PHES), and transmission network) can provide flexibility to buffer variability from RES, thereby potentially displacing additional storage requirements in pipelines, or even pipelines altogether depending on the case. The assessment also neglects water requirements (and water networks) for electrolysers due to lack of data, which might also alter the findings when included. All the cost assumptions in this report are for year *2023*. Their NPV also considers 2023 as reference year. In addition to pipelines, other viable options for hydrogen transportation include tanker trucks and tube trailers. These options are discussed in more detail in the *Milestone 3: Literature review* of the project.

Finally, the modelling of UHS in this project, together with the electricity network modelling developed in “RP1.1-02A: Regional case studies on multi-energy system integration”, will pave for the way for project “*RP1.1-07: Integrated electricity-hydrogen: future system and market interactions under different storage considerations*” which will kick-off in October 2023.



a) Without UHS. b) With UHS.

Figure 1: Optimal greenfield integrated infrastructure and storage designs for the two cases: a) without UHS, and b) with UHS. Notice the difference in pipeline diameters in Queensland between the two cases.

ACRONYMS

AACE	Association for Advancement of Cost Engineering
AEMO	Australian Energy Market Operator
AUD	Australian Dollars
BESS	Battery energy storage systems
CapEx	Capital expenditure
EVR	Erosional velocity ratio
H_2	Hydrogen gas
HHV	Higher heating value
HSC	Hydrogen supply chain
HVAC	High voltage alternating current
HVDC	High voltage direct current
ISP	Integrated system plan
LCC	Line commutated converters
LCOE	Levelised cost of energy
LHV	Lower heating value
MMC	Modular multilevel converters
NEM	National Electricity Market
NG	Natural gas
NPV	Net present value
NSW	New South Wales
OHL	Overhead line
OpEx	Operating expenditure
PEM	Proton exchange membrane
PHES	Pumped hydro energy storage
PtG	Power-to-gas
PV	Photovoltaic
QLD	Queensland
RES	Renewable energy sources
REZ	Renewable energy zones
SA	South Australia
SMYS	Specified minimum yield stress
SVC	Static VAr compensator

UHS	Underground hydrogen storage
USD	United State Dollars
VIC	Victoria
VRE	Variable renewable energy
VSC	Voltage-source converters

1. INTRODUCTION

Most energy system planners in countries with an abundance of renewable energy sources (RES), including the Australian Energy Market Operator (AEMO), are now considering in their transport infrastructure planning scenarios the potential deployment of large-scale green hydrogen production (through electrolysis) for export of green fuels and decarbonisation of heavy industry, which will lead to a massive increase in demand associated with such developments and thereby create major interactions between electricity and future green hydrogen systems. Depending on the evolution of hydrogen technology, its industry uptake, and the State and Federal Governments' support schemes and strategies, the impact on the planning of the electricity system can be substantial. AEMO's *Hydrogen Superpower* scenario in the 2022 *Integrated System Plan* (ISP) [1] envisions that by 2050 the National Electricity Market (NEM) would need approximately 269 GW of wind and approximately 278 GW of solar - 34 times its current capacity of variable renewable energy (VRE) – to export green hydrogen, and support decarbonisation of heavy industry (e.g., green steel making), gas-fired generation (through hydrogen turbines), and end-use (by progressively switching households with natural gas (NG) connections to hydrogen-NG blend). This monumental scale of development will require the NEM to deliver eight times its current energy delivery by 2050.

Hydrogen can be produced from renewable energy through a power-to-gas (PtG) process [2],[1] and transported and stored in liquid or compressed forms, or as a chemical compound such as ammonia [3]–[6]. This imminent advent of large-scale green hydrogen production raises the central question of which of the two options, transporting green hydrogen from distributed hydrogen producers co-located at the renewable energy zones (REZ), or transporting green electricity from REZ to a central hydrogen production hub, is the most cost-effective one across different distances, for different renewable energy portfolios, and subject to local availability of water and multi-vector storage options. The role of hydrogen as a way to transport renewable energy over long distances was identified in a 2018 report from IRENA [7], in light of the emissions reduction targets outlined in the Paris Agreement. IRENA's roadmap for the energy transition towards low-carbon emissions is centred on key green hydrogen production technologies as the main drivers, particularly proton exchange membrane (PEM) electrolysers and fuel cells, which are approaching technical maturity and economies of scale. According to a recent study by CSIRO, the cost of PEM hydrogen electrolysers is projected to drop to nearly a third of its current costs by 2035 [8].

Large-scale renewable energy hubs connected to hydrogen production hubs can unlock substantial economies of scale predicated on building a *cost-effective* VRE transport infrastructure that will address the challenging questions of (i) whether VRE hubs and electrolysers should be co-located, (ii) whether to transport[2] VRE as molecules in hydrogen pipelines or as electricity in electricity transmission lines, and (iii) the drivers and conditions that favour one investment option over another. Answering the above questions is a massive undertaking that requires new optimisation-based models for the planning of integrated electricity and hydrogen system (IEHS) to assess costs and benefits of different investment options.

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[1] The terms "PtG" and "electrolyser" are used interchangeably in this report.
[2] The terms "transport" and "transmission" are used interchangeably in this report.

As many of the challenges identified here are relatively new, existing knowledge and modelling tools are inadequate for performing such a large-scale *optimal* integrated infrastructure design exercise. In particular, existing state-of-the-art literature is either limited in scope to hydrogen supply chain (HSC) only [9]–[12], i.e., disregarding electricity infrastructure options, or is limited in the variety of considered infrastructure technologies [13]–[16]. Considering all the relevant transport and storage technologies in an integrated framework can unlock superior design solutions. This is especially true when considering the specific features associated with RES, and in particular when they are clustered in large-scale renewable energy hubs where wind and solar farms may be located far from the location of hydrogen utilisation.

Other essential aspects that are ignored in the literature include voltage drops due to impedances in transmission lines, pressure drops in pipelines, linepack,[3] compressor sizing, water availability for electrolysers, reactive power compensation, and nonlinear withdrawal/injection rates of underground hydrogen storage (UHS) systems, all of which play an important role in determining the optimal infrastructure investment decision. The modelling of the linepack is instrumental in quantifying the VRE storage capacity of the hydrogen pipeline network, which can in turn influence the sizing of hydrogen pipelines and compressors. In fact, most (if not all) existing works use *steady-state* gas flow models, which are generally inadequate in gas transmission networks where hydrogen injections from VRE introduce time-varying accumulation rates. More importantly, with the exception of [13], [14], the majority of existing works, including [10], [11], [15], [16], [17], only examine transport options between two nodes (point-to-point transmission), as opposed to over a network with a general topology (which may include loops and parallel corridors).

In light of the knowledge gaps identified above, this report introduces a novel mathematical optimisation model that can find the optimal *greenfield* integrated planning of transport and storage infrastructure for transporting large-scale VRE to hydrogen export demand locations in either electricity lines and/or hydrogen pipelines. Specifically, the model not only considers all relevant infrastructure technologies such as HVDC, HVAC, reactive power plants, battery energy storage systems (BESS), and hydrogen pipelines and compressors, but also incorporates all the essential nonlinearities that directly influence the optimal infrastructure investment decision, such as voltage drops due to impedances in HVAC and HVDC transmission lines, losses in HVDC converter stations, reactive power flow, pressure drops in pipelines, linepack, and nonlinear withdrawal/injection rates of UHS systems. Additionally, the model adopts a relatively high temporal resolution to suitably capture the variability of RES and its impact on the optimal investment decision.

The developed greenfield integrated planning model is demonstrated on a case study that considers all the REZ stipulated in AEMO's 2022 ISP [1] and connects them with provisional corridors to the hydrogen export ports whose demands are specified in AEMO's 2022 ISP under the *Hydrogen Superpower* scenario. The case study is conducted with VRE traces and hydrogen export demand for 2050. As the widespread adoption of hydrogen in Australia may require medium and long duration storage, beyond typical storage capacities (linepack) of pipelines, to buffer the fluctuations in supply and demand [18], the model is further extended to incorporate candidate UHS facilities in the form of depleted gas fields, as identified in FF CRC project "RP1.1-04: Underground storage of hydrogen: mapping out the options for

[3] The linepack is the amount of pressurised gas stored in a pipeline network.

Australia” [19], as an initial test bed. Depleted gas fields are identified in project RP1.1-04 as a viable option for hydrogen storage in Australia as they can provide safe large-scale storage at a lower cost compared to saline aquifers [20].

Compared to the Milestone 5 report of this project, this milestone report is different in the following ways:

- The analysis is extended to the whole east coast of Australia, as opposed to only Queensland.
- Pipeline diameter options are increased from 3 (20 inches, 36 inches, and 46 inches) in the previous Milestone 5 report to 22 options, ranging from 4 inches to 46 inches in 2-inch increments, in this report.
- Cost and technical assumptions are updated to align with AEMO’s 2022 ISP for HVAC and HVDC options, CSIRO’s 2022 GenCost report [8] for BESS, and with the report by GPA Engineering [21] for hydrogen pipelines and compressors.
- The mathematical optimisation model is extended to include candidate UHS facilities (see [19] and [20]) in the form of depleted gas fields.
- The canonical point-to-point (single corridor) analysis first presented in Section 3.1 of Milestone 5 is repeated under the updated cost and technical assumptions in this report.

All the cost assumptions in this report are for year *2023*. These are then projected to the respective years (epochs) under study (e.g., 2050) using a constant inflation rate of 2.5% per year. Their NPV also considers 2023 as reference year.

2. MODELLING

A prototype of the scope of the developed *greenfield* integrated VRE transport and storage infrastructure planning model is shown in Figure 2, where three different technologies, namely, (high-pressure) hydrogen pipeline links (including carbon steel pipelines and inlet compression stations), HVAC transmission links (including overhead lines (OHL), transformer substations, and reactive power compensation), HVDC links (including OHL and converter stations) are considered as transport infrastructure options. Detailed mathematical modelling can be found in the Milestone 3 report and in [22]. Storage technologies (in addition to pipeline storage) consist of UHS and BESS.

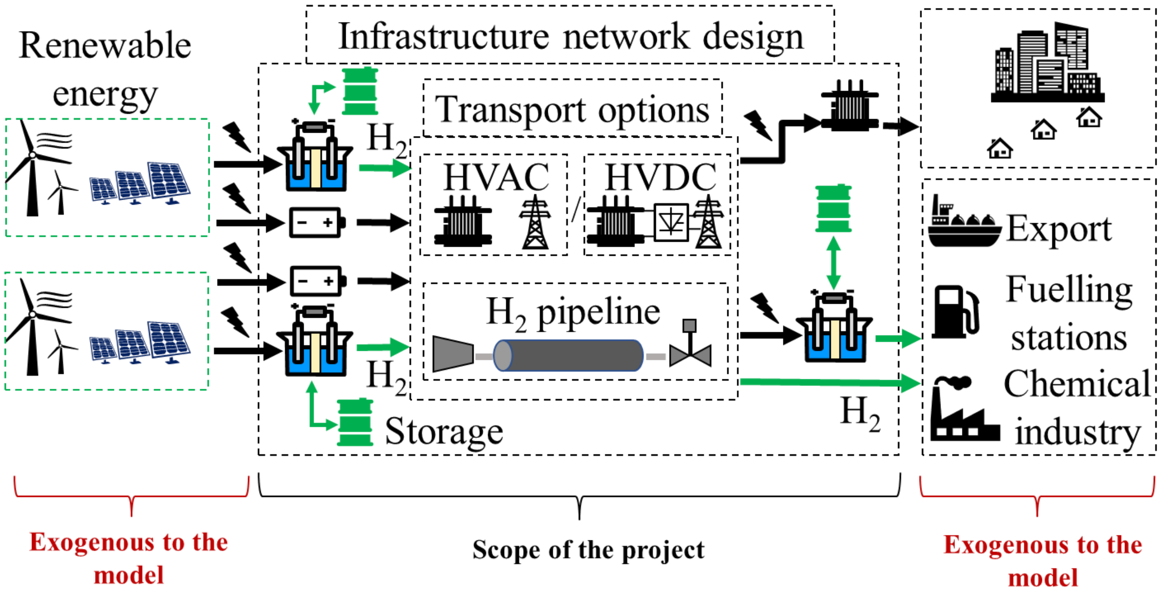

Figure 2: Illustrative scope of the integrated VRE transport and storage infrastructure model where the energy from multiple VRE hubs can be transported to a hydrogen demand hub using electricity lines and/or hydrogen pipelines over a network with arbitrary topology.

Mathematically, the objective of the integrated infrastructure planning problem is to minimise the total *net present value* (NPV) of both investment and operational costs for a predetermined hydrogen demand over the whole planning horizon as

$$\text{minimise} \quad CapEx^{\text{ptg}} + CapEx^{\text{pipe}} + CapEx^{\text{uhs}} + CapEx^{\text{hvdc}} + CapEx^{\text{hvac}} + CapEx^{\text{bess}} + OpEx^{\text{ptg}} + OpEx^{\text{pipe}} + OpEx^{\text{uhs}} + OpEx^{\text{hvdc}} + OpEx^{\text{hvac}} + OpEx^{\text{bess}}$$

subject to

- H_2 demand
- Operational constraints
- Investment constraints
- Physics of flow of electricity
- Physics of flow of H_2 (Quasi-dynamic gas flow model)
- UHS constraints (nonlinear injection/withdrawal rates)
- BESS constraints
- Coupling constraints (through PtG)

Typical injection and withdrawal rates as functions of storage levels for underground natural gas (NG) storage facilities are shown in Figure 3 (see [23] for more details). Similar behaviour is assumed for UHS in this report.

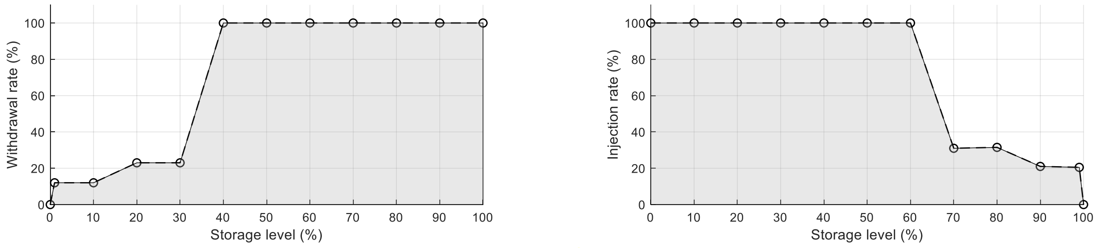

Figure 3: Typical withdrawal (left) and injection (right) rates as a function of gas storage level of underground NG storage facilities.

The following assumptions are adopted in the above integrated planning model:

- Project life is 20 years.
- The optimisation model considers 4 representative weeks, one in each season, that are carefully selected the reflect the seasonable variability of RES. This reduction is necessary to ensure that the computational requirements fall within the current capabilities of current state-of-the-art industrial optimisation solvers such as Gurobi [24].[4]
- A 30-minute temporal resolution is considered, which aligns with the resolution of the VRE forecasts in AEMO’s 2022 ISP. A less granular temporal resolution may not capture the variability of RES and linepack[5] to sufficient accuracy, which can in turn be detrimental to the quality of the computed solutions.
- Inflation rate is 2.5% per year.
- Lead time of each asset is 5 years.
- Discount rate is 6% per year.

In contrast to existing works, the above model is not limited to point-to-point instances (i.e., single corridor) but can find the optimal integrated transport and storage infrastructure design over a *network* with arbitrary topology and multiple variable supplies and demands. In a nutshell, the capabilities of the modelling so far include:

- Optimal investment planning of large-scale integrated electricity and hydrogen transmission and storage infrastructure networks, including UHS and BESS,
- Multiple variable supplies and demands,
- Essential physics such as
  - Conversion and transportation losses,
  - Linepack (to manage RES variability),
  - Nonlinear injection and withdrawal rates of UHS.

[4] Even after this careful reduction in problem size, a typical single-stage integrated planning problem in this report can take one day on average to solve.
[5] The *linepack* is the amount of pressurised gas stored in a pipeline network.

The mathematical modelling in this project leverages advanced optimisation and computational methods that are designed with maximum flexibility in mind. In other words, the model is fully parametrised to rapidly incorporate and explore stakeholder insights**.**

3. CASE STUDIES

Two sets of major case studies are conducted in this section. The first, described in Section 3.1, is a canonical case study that consists of an assessment of the three fundamental drivers: (i) supply capacity, (ii) corridor length, and (iii) storage requirements, affecting the investment decision over a *single corridor*.

The second case study, which is divided into two parts described in Section 3.2 and Section 3.3 respectively, is a proof of concept of the capabilities of the developed first-of-its-kind optimisation framework to scale up the analysis to a general *network* with arbitrary topology and multiple variable supplies and demands. In particular, these capabilities are demonstrated on a case study involving the whole east coast of mainland Australia (excluding Tasmania) with REZ, VRE traces (30-minute resolution), hydrogen demands (assumed constant), and hydrogen export ports from the *Hydrogen Superpower* scenario in AEMO's 2022 ISP [1] for the year 2050. More specifically, the case study considers all the mainland REZ stipulated in AEMO's 2022 ISP and connects them with provisional corridors to hydrogen export ports whose demands are specified in AEMO's 2022 ISP under the *Hydrogen Superpower* scenario for year 2050. The case study also considers candidate UHS facilities in the form of depleted gas fields, as described in [19] and [20]. These proposed provisional corridors and candidate UHS facilities are shown in Figure 4. This second case study is a *greenfield* expansion planning that optimises newly built electrolysis, transmission, and storage infrastructure network in *isolation* from existing infrastructure for a specified constant hydrogen export demand distributed (not necessarily equally) over the envisaged hydrogen export ports in each state.

All the cost assumptions in this report are for year *2023*. These are then projected to the respective years under study (e.g., 2050) using a constant inflation rate of 2.5% per year. Their NPV also considers 2023 as reference year.

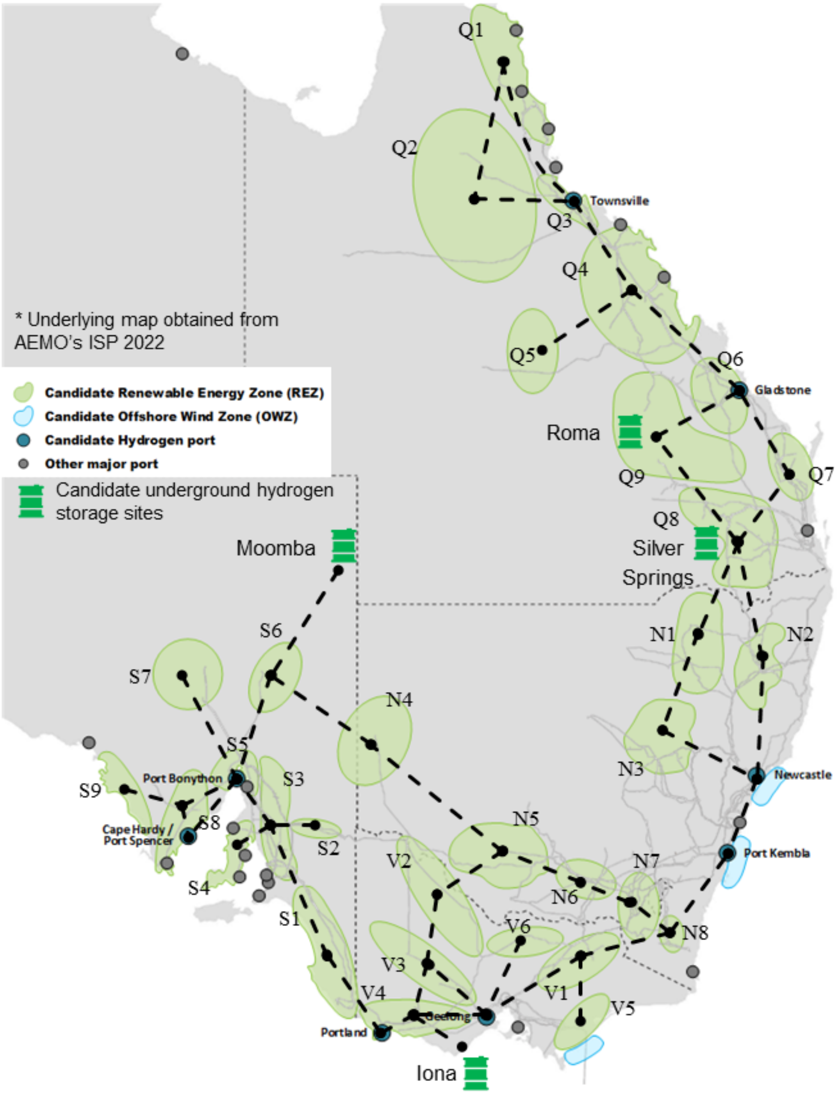

Figure 4: Dashed lines delineating the proposed provisional transmission corridors connecting REZ and hydrogen export ports. The figure also shows the proposed candidate UHS sites [19]. The underlying map is obtained from AEMO's 2022 ISP [1].

The forecast hydrogen export demand from the whole NEM in 2050, obtained from the "Inputs assumptions and scenarios workbook" in [1] under the *Hydrogen Superpower*, is shown in Table 1.[6] The 2022 ISP also envisions that the mainland part of the NEM will have a total installed capacity of 252 GW of solar generation and 233 GW of wind generation by 2050 [25]. A breakdown of the RES capacity of each REZ in 2050 is shown in Table 2.

[6] Forecast hydrogen export demand in 2050 for each state is obtained from http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational.

Table 1: Hydrogen export demand from the whole NEM in 2050 under the ISP's *Hydrogen Superpower* scenario [25]**.**

Unit	Quantity
Mt/year	12.76
m^3/s	4741.69
GW (GW_e)	57.38 (81.97)[7]
PJ/year	1810.33
* An HHV of 141.876 MJ/kg and a density of 0.0853 kg/m^3 are used for hydrogen.	

Table 2: Forecast RES capacity (GW) in each considered REZ in 2050 [25]**.**

State	REZ	Wind generation (GW)	Solar generation (GW)
QLD	Q1	12.5	10.7
	Q2	11.3	8.0
	Q3	0.0	3.4
	Q4	45.2	33.5
	Q5	3.9	8.0
	Q6	24.3	38.2
	Q7	7.6	11.7
	Q8	13.7	13.6
	Q9	3.4	6.1
SA	S1	3.2	0.1
	S2	0.0	4.0
	S3	29.2	1.3
	S4	1.4	0.0
	S5	0.2	2.9
	S6	17.2	41.8
	S7	0.0	3.4
	S8	2.3	5.0
	S9	1.8	4.0
VIC	V1	0.0	0.6
	V2	0.0	4.8
	V3	4.3	5.2
	V4	15.3	0.0
	V5	5.1	0.5
	V6	1.2	11.2

Potential UHS facilities in Australia along with their equivalent envisaged UHS capacities, injection and withdrawal rates, and costs are shown in Table 3. Assumptions on input technical parameters and costs of hydrogen pipeline links (including compressors), HVAC links, HVDC links, electrolysers, and BESS can be found in Appendix A: Cost and Parameter Assumptions.

[7] GWe designates the required electricity to produce that hydrogen. The efficiency of electrolysers is assumed to be 70% (see Table 9).

These assumptions are largely based on the assumptions in (i) [21] for pipelines and compressors, (ii) [8] for BESS, and (iii) AEMO's transmission cost database in the 2022 ISP [1] for HVDC links and HVAC links. The analysis is this section uses the same HVAC and HVDC options described in the REZ augmentation options and the flow path augmentation options in AEMO's 2022 ISP [1].

It should be emphasised that the cost and parameter assumptions in Appendix A: Cost and Parameter Assumptions are for the sole purpose of demonstrating the novel integrated modelling in this report. Therefore, in the context of these specific costs and parameter assumptions, the findings in this report should be considered solely for illustration and demonstration purposes rather than real guidelines for energy infrastructure planners and stakeholders, for which specific studies based on agreed input data and assumptions should be performed.

Table 3: Potential UHS facilities in Australia along with their equivalent UHS capacity, injection and withdrawal rates, and costs [19].[8]

Storage facility	Basin	Injection (TJ/d)	Withdrawal (TJ/d)	Capacity (PJ)	Cost (USD/kg)	OpEx (% of CapEx)	Efficiency (%)
Silver Springs	Bowen-Surat (QLD)	4	5	12	1.73	2	98
Roma	Bowen-Surat (QLD)	29	16	15	1.73	2	98
Moomba	Eromanga (SA)	30	20	23	1.73	2	98
Iona	Otway (VIC)	41	134	6.3	1.73	2	98

[8] The costs in Table 3 are taken from Table 1 in [19] as 1.42 USD/kg H_2 in 2014 and then converted to 2023 equivalents by applying a constant inflation rate of 2.5% per year. An exchange rate of 1 USD = 1.44 AUD is used in this report.

3.1. Point-to-point analysis (single corridor)

This case study assesses the impact of capacity, corridor length, and amount of storage required on the transport and storage infrastructure investment decisions over a single corridor. Hydrogen pipeline options include CapEx and OpEx of inlet compression. HVAC transmission options include the CapEx and OpEx of transformer substations and reactive power compensation equipment. HVDC transmission options include the CapEx and OpEx of converter substations. The exact scope of the assessment is shown in Figure 2 for a point-to-point instance.[9] Supply capacity is selected from the set [169 MW, 536 MW, 1000 MW, 1900 MW, 2000 MW, 2400 MW, 2900 MW, 6080 MW]. This specific range of the capacities was chosen to match exactly the capacities of HVAC and HVDC transmission options specified in AEMO's 2022 ISP [1] (see Table 7 and Table 8 in Appendix A: Cost and Parameter Assumptions). This specific choice ensures a fair techno-economic comparison between hydrogen pipelines and electricity transmission lines, especially that the considered pipelines have diameters that increase in 2-inch increments (see Table 6 in Appendix A: Cost and Parameter Assumptions). This is another way of saying that it is assumed that the specific choices of HVAC and HVDC transmission options in Table 7 and Table 8, respectively, are *optimised* by AEMO for these specific capacities. Other capacity choices would require redesigning HVAC transmission links with appropriate conductor types, number of circuits per phase, number of conductors per circuit, spacing between conductors and bundles, transformer sizes, substation equipment (including reactive power compensation for long lines), right-of-way requirements, etc, to satisfy the following technical constraints [26]:

- Thermal limit of OHL conductors.
- Voltage drop not exceeding 5%.
- Transient and steady-state stability.
- Electricity losses not exceeding 5%.

Analogously, for HVDC transmission links, other capacity choices would require redesigning them with the appropriate HVDC configuration and operating modes (e.g., monopole, bipole, symmetric monopole, asymmetrical monopole with bipole metallic return, etc.) [27], [28], converter station technology (e.g., LCC, VSC, MMC [29]) and corresponding equipment, conductor types, and right-of-way requirements. Corridor length is varied from 25 km to 800 km and storage duration is varied between 0 and 8 hours.[10] In particular, 0 storage requirements entail that the supply always exceeds the demand, and as a result a steady-state throughput in hydrogen pipelines and electricity transmission lines can be assumed. If the constant demand is denoted by y MW, cases where x amount of storage duration is required entail that the supply is exceed by the demand by at most $x \times y$ MWh. In these cases, the supply is assumed as zero over a period of x hours for a requirement of x hours of storage. Storage is especially important when hydrogen is produced from VRE, as is the assumption in this report. It should be noted that the CapEx of pipelines does not consider high amplitude pressure cycling associated with frequent linepack cycling which may require greater pipeline wall thickness, increased diameter, and greater inline inspection frequency, thereby increasing total CapEx and OpEx. A similar assumption is adopted in [21].

[9] No UHS is considered in this point-to-point case study.
[10] Distances smaller than 25 km are not considered because pipelines become less applicable at such small distances.

Results for steady-state throughput (storage duration of 0 hours) are shown in Figure 5, which indicates that, under the cost and technical assumptions in this report, newly built hydrogen pipelines are more cost effective than newly built electricity transmission infrastructure (HVAC and HVDC) across all the considered distances and energy volumes. The main advantage of pipelines is that their capacity is proportional to the *square* of their diameter, meaning that the rate of increase in capacity increases with every inch increase in diameter. At the same time, the capacity of a pipeline is *inversely* proportional to the *square root* of distance, meaning that the rate of decrease of capacity for a unit increase in distance is outweighed by a higher rate of increase in capacity for a unit increase in diameter. Despite including inlet compression cost in the cost of hydrogen pipelines, which was not considered in [21], the results in Figure 5 are congruent with the trends identified in [21].

When storage is required, the cost of the infrastructure is expected to increase compared to the base case with no storage. For hydrogen pipelines, additional storage comes at the expense of increasing the diameter of the pipeline for the same distance, whereas for electricity options storage is provided by BESS, which is generally invariant to corridor length. If a pipeline is operating at flow rates below its maximum capacity, it is possible to store more gas in the pipeline by increasing the inlet pressure (and appropriately setting outlet pressure). However, if the pipeline is operating at maximum flow capacity, no additional gas can be stored as the pipeline has no room to vary its pressure profile. Like pipeline capacity, pipeline storage is also proportional to the *square* of the diameter, but unlike pipeline capacity, pipeline storage is directly proportional (linear relationship) to the length of the pipeline. Therefore, as the length of the corridor increases and the cost of the pipeline increases, a smaller increase in diameter is required to accommodate storage. This is because the required storage volume can be accommodated by the increase in length of the pipeline as opposed to an increase in diameter for shorter lengths. In other words, the longer the pipeline and the larger its diameter, more room is available to accommodate additional gas storage, which manifests in lower marginal costs of pipeline storage (linepack).

In a scenario where 2 hours of storage duration are required (i.e., when the supply is zero for a duration of 2 hours for the same constant demand), the results shown in Figure 6 point out that hydrogen pipelines a generally more cost effective than electricity transmission infrastructure (HVAC + BESS or HVDC + BESS) across most of the considered distances and energy volumes. In this case, the unit cost of BESS for 2 hours of storage (see Table 9) is 0.55 M AUD/MWh and its OpEx is 7.5 AUD/kWh/year, whereas the unit cost of a PEM electrolyser is 0.864 M AUD/MW and its OpEx is 2% of CapEx per year. The equivalent unit NPV for BESS would then be 0.641 M AUD/MWh compared to 1.073 M AUD/MW for PEM electrolysers. This means that installing a BESS to provide 2 hours of storage would result in a cost of PtG + BESS that is 9.7% more expensive than the cost of doubling the size of PtG to accommodate the extra storage requirements in a pipeline. This 9.7% difference is enough the tip the scale in favour of pipeline options over most distances, under the cost and technical assumptions in this report. The only exception in Figure 6 is the case with capacity of 6080 MW and a distance of 25 km, where the cost of HVAC + BESS is more competitive at this short distance than hydrogen pipelines. This is mainly because at these short distances the pipeline does not have enough volume to accommodate enough storage without significantly increasing its diameter under this high supply capacity of 6080 MW. In fact, under these specific conditions (capacity of 6080 MW, distance of 25 km, storage of 2 hours), it would require installing *two* 40-inch hydrogen pipelines in parallel, whose total NPV (including the

NPV of the electrolyser station) of 14.84 B AUD is slightly higher than the 14.79 B AUD of the chosen 500 kV 6080 MW HVAC line, the 12.16 GWh BESS, and the 6.08 GW PEM electrolyser.[11]

Similar trends are observed in a scenario where 4 hours of storage duration are required (i.e., when the supply is zero for a duration of 4 hours for the same constant demand), whose results are shown in Figure 7, except in this case the cost of BESS becomes too prohibitive, even for small distances and high supply capacities, which explains why pipelines are chosen in all the cases. In light of the above discussion on the relationship between pipeline storage and diameter and length, it is not surprising to find that the cost does not necessarily increase with distance when storage is required. This is evidenced in Figure 7 for capacities higher than 2400 MW and where 4 hours of storage duration are required. Similar reasoning can be adopted to explain the findings for a scenario where 8 hours of storage duration are required, shown in Figure 21 in Appendix B: Supplementary Material. In summary, in storage scenarios with high supply capacity and short distance (e.g., 6080 MW and 25 km), hydrogen pipelines do not have sufficient volume to accommodate the energy storage requirement as pipeline volume increases with length, thus requiring installing pipelines in parallel and thereby significantly increasing the overall cost.

[11] M AUD and B AUD refer to Million Australian Dollars and Billion Australian Dollars, respectively.

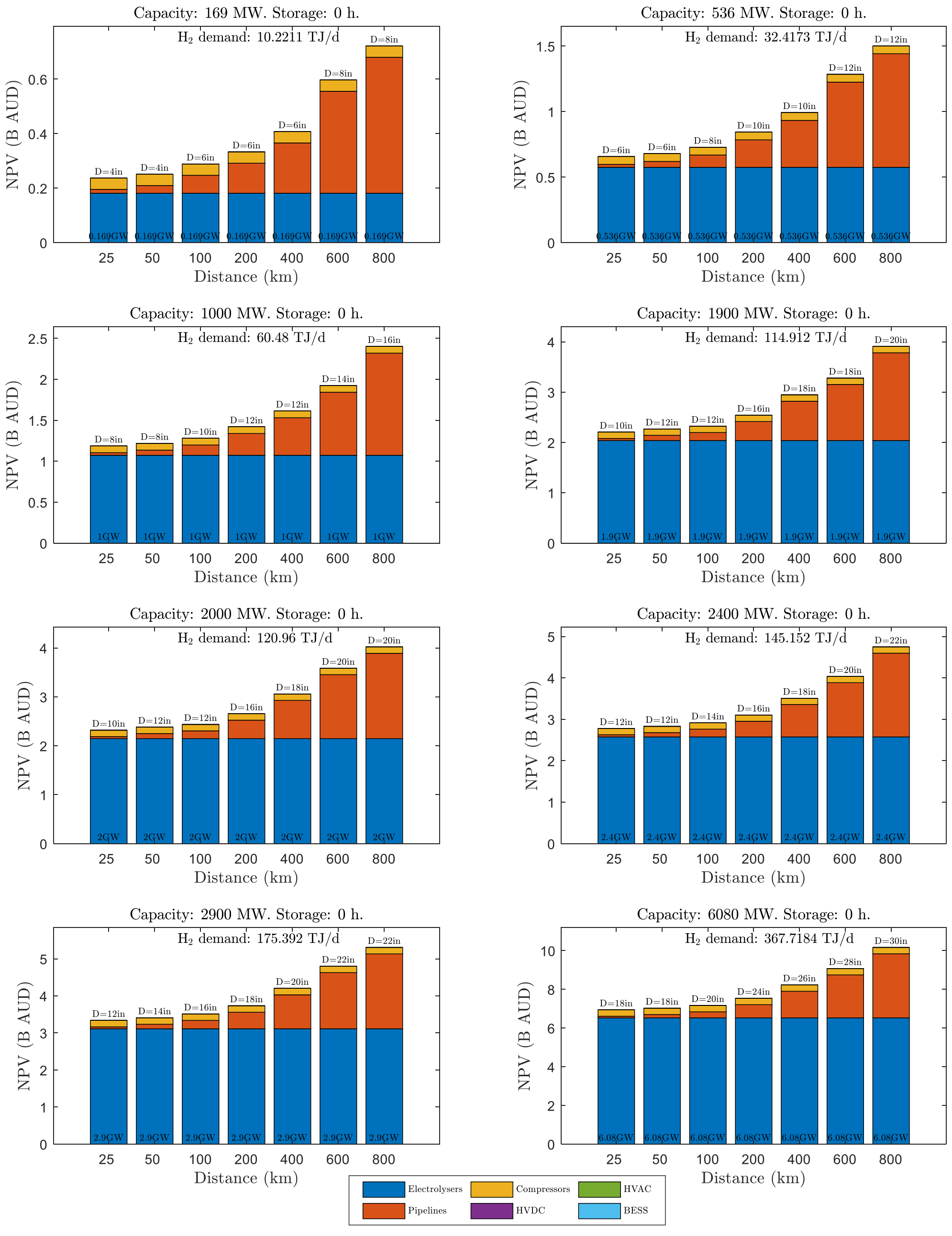

Figure 5: Optimal transmission infrastructure across the considered capacities and distances, for a scenario without storage (Storage: 0 h), i.e., where supply always exceeds the demand. Note the difference in y-axis scale between each case.

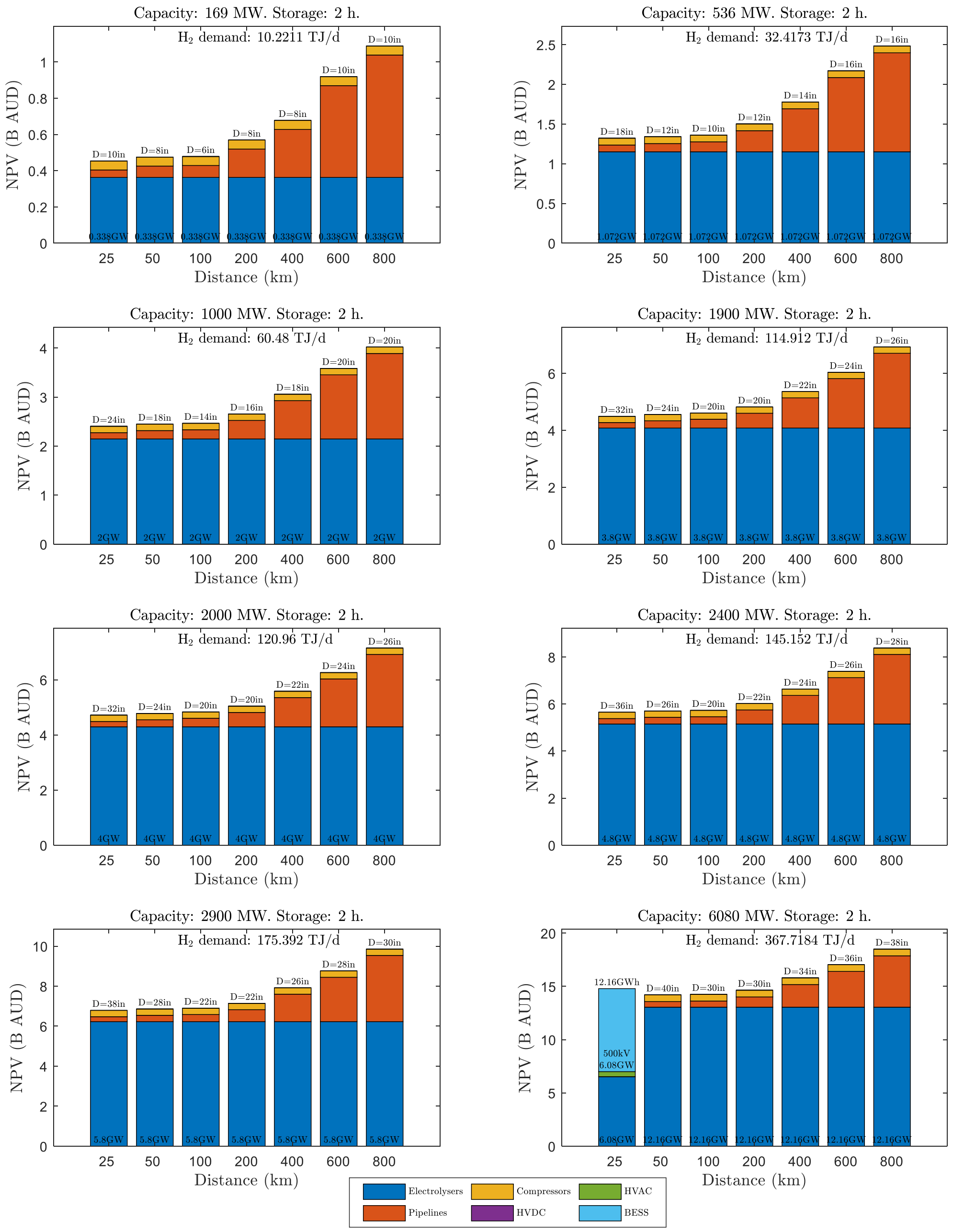

Figure 6: Optimal integrated transmission and storage infrastructure across the considered capacities and distances, for a scenario requiring 2 hours of storage duration (Storage: 2 h). Note the difference in y-axis scale between each case.

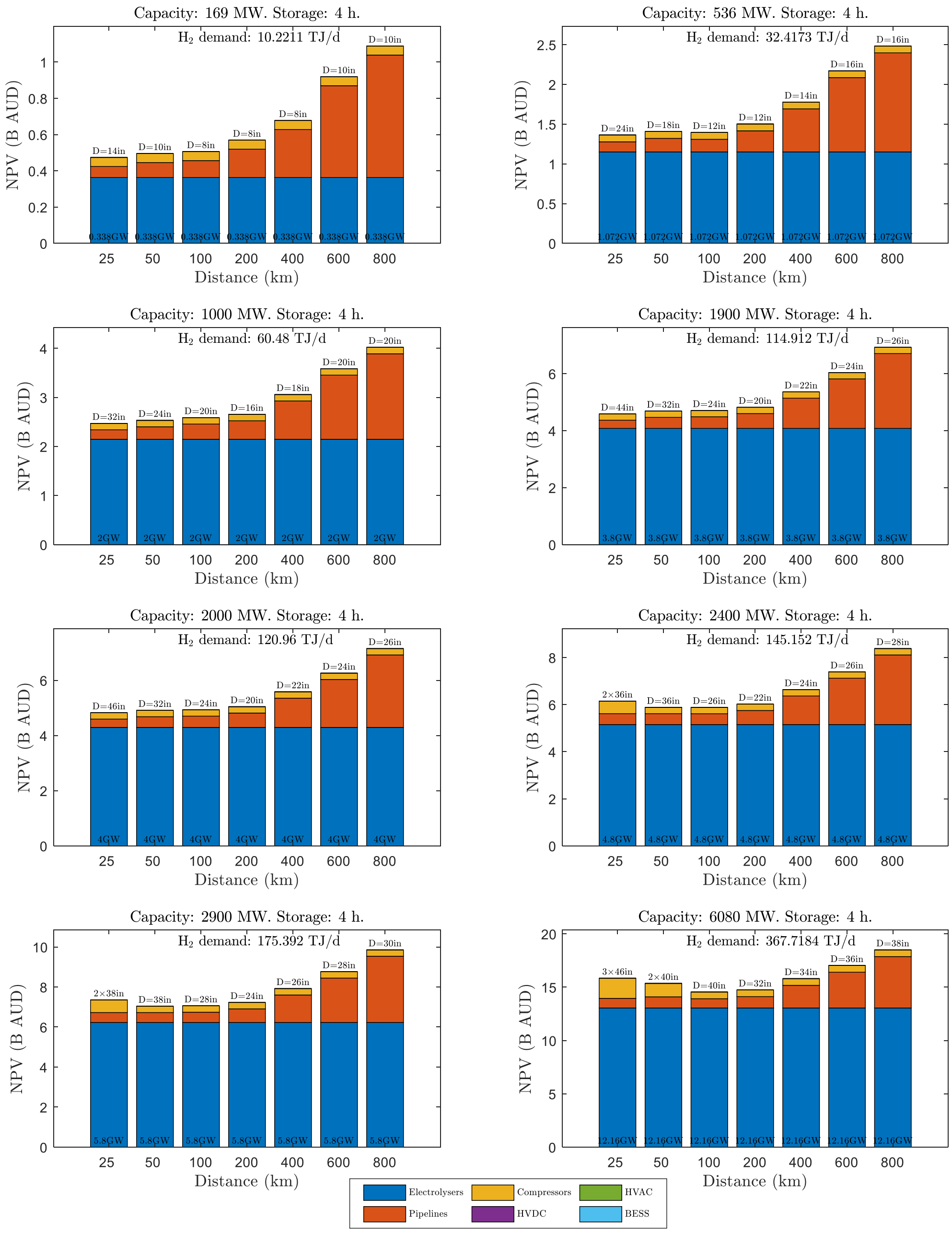

Figure 7: Optimal integrated transmission and storage infrastructure across the considered capacities and distances, for a scenario requiring 4 hours of storage duration (Storage: 4 h). Note the difference in y-axis scale between each case.

More interestingly, not the same trends seen above apply for a case where 1 hour of storage duration is required. In this case, the (current) cost curve economics of electrolysers and BESS (see Table 9 and Table 10 in Appendix A: Cost and Parameter Assumptions) become the defining factors for the optimal choice of infrastructure, and in this particular setting, tip the scale in favour of electricity options in (i) scenarios with capacities higher than 1900 MW across distances up to 200 km and (ii) all scenarios with distances below 50 km, as shown in Figure 8. In more detail, in addition to increasing the diameter of the pipeline, providing 1 hour of storage in a pipeline would also entail doubling the size of the electrolyser (assuming twice as much supply power over 1 hour). In this case, the unit cost of BESS for 1 hour of storage (see Table 10) is 0.82 M AUD/MWh and its OpEx is 7.5 AUD/kWh/year, whereas the unit cost of a PEM electrolyser is 0.864 M AUD/MW and its OpEx is 2% of CapEx per year. The equivalent unit NPV for BESS would then be 0.91 M AUD/MWh compared to 1.073 M AUD/MW for PEM electrolysers. This means that installing a BESS to provide 1 hour of storage would result in a cost of PtG + BESS that is 7.6% cheaper than the cost of doubling the size of PtG to accommodate the 1 hour of storage requirements in a pipeline. Under the cost and technical assumptions in this report, this 7.6% difference is enough the tip the scale in favour of electricity options where applicable (see Figure 8).

To eliminate doubt, Figure 9 shows the optimal transmission and storage infrastructure across for the same case but now *without* any electricity options, i.e., considering only hydrogen pipelines. Comparing Figure 8 and Figure 9, it can be inferred that the relative difference between the two cases is more pronounced at 25 and 50 km. That difference becomes smaller as the distance increases. It is worth noting that if the cost of PtG is not included the results in this section, in particular for the case with 1 hour of storage duration, would be different. In contract, for storage durations of 2 hours would now require doubling the size of BESS whereas the size of PtG, which was already doubled in the case with 1 hour of storage, may not necessarily further increase. Similarly, for storage durations of 4 hours, the size of BESS will quadruple, whereas the size of the PtG may not necessarily increase more than double. This therefore (in general) shifts the cost competitiveness back to hydrogen pipelines for storage durations higher than 2 hours.

Interestingly, Figure 8 also shows that an HVDC option (refer to Table 8 for more details) is chosen for a distance of 800 km and capacities of 1900 MW and 2000 MW. Recall, that the 2000 MW capacities was taken directly from AEMO's 2022 ISP, which we assume was optimised by AEMO for that VSC HVDC option. Compared to HVAC, HVDC becomes more cost competitive at these distances greater than around 600 km. Despite lower losses in HVDC systems, the high cost of converter stations places them at a disadvantage compared to HVAC systems for short to medium distances. However, the larger cost of overhead conductors of HVAC tips the scale in favour of HVDC systems for medium to long distances. Additionally, angle displacement constraints on HVAC systems require shunt reactors, or more generally static VAr compensators (SVCs), to absorb the large reactive power induced by inductive and capacitive effects of long-distance AC transmission, which further increases the cost of HVAC links.[12] These results are congruent with HVAC vs HVDC comparisons in existing literature, which identify a break-even distance of around 600 km, beyond which HVDC becomes more competitive [16].

The slight discrepancy between the findings in this section and the ones in [21] can be explained by the following three main factors:

1) In contrast to [21], the analysis is this project considers the cost of electrolysers, which when included can have a substantial impact on the optimal sizing of transport and storage infrastructure when storage is needed, especially when less than 2 hours of

[12] Maintaining an angular displacement below 45°is usually desirable to maintain steady-state and transient stability of HVAC power systems.

storage duration are required, under the specific cost and technical assumptions in this report (see discussion above).

2) The analysis in [21] does not consider the cost of inlet compression (only the cost of midline compression) or the cost of HVAC transformers and substations.

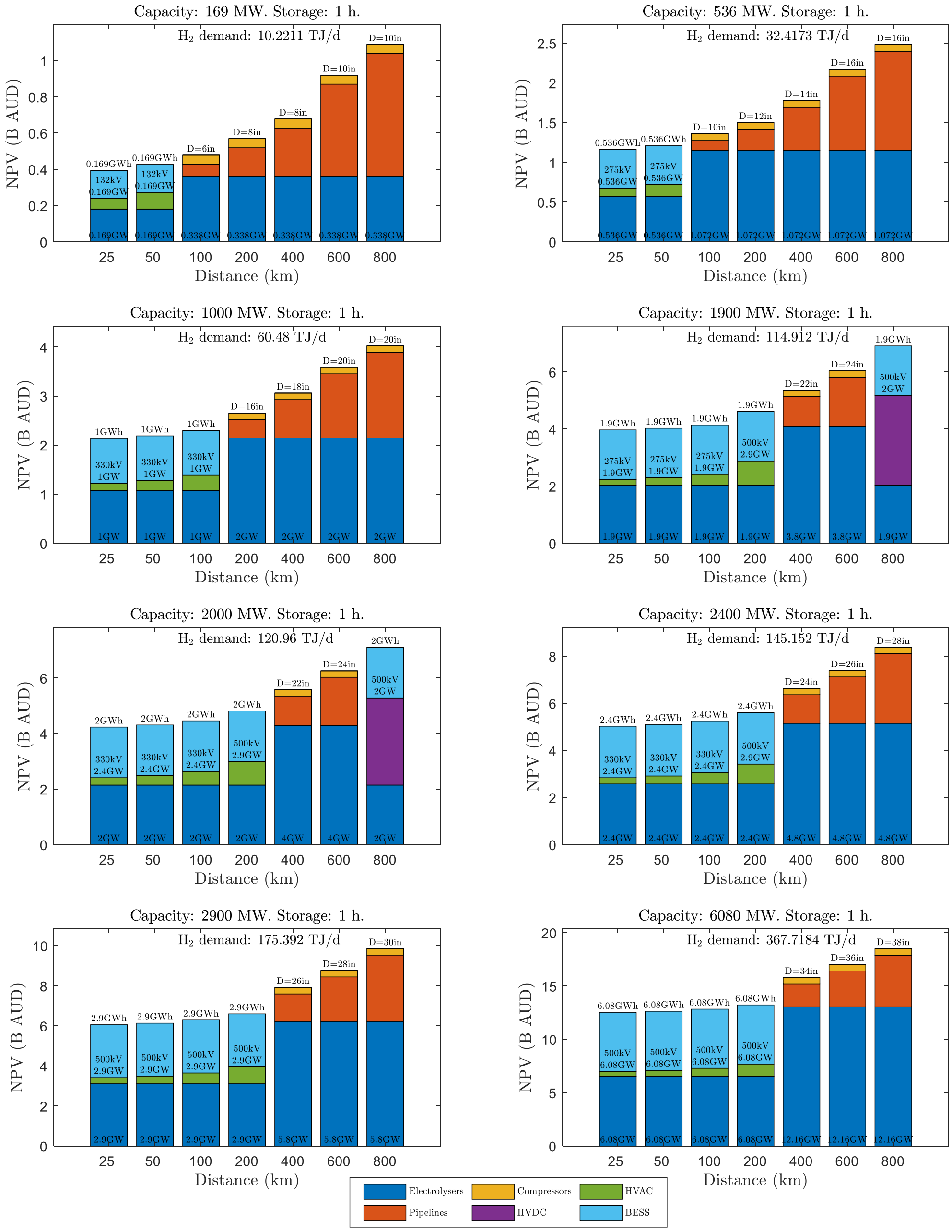

Figure 8: Optimal integrated transmission and storage infrastructure across the considered capacities and distances, for a scenario requiring 1 hour of storage duration (Storage: 1 h). Note the difference in y-axis scale between each case.

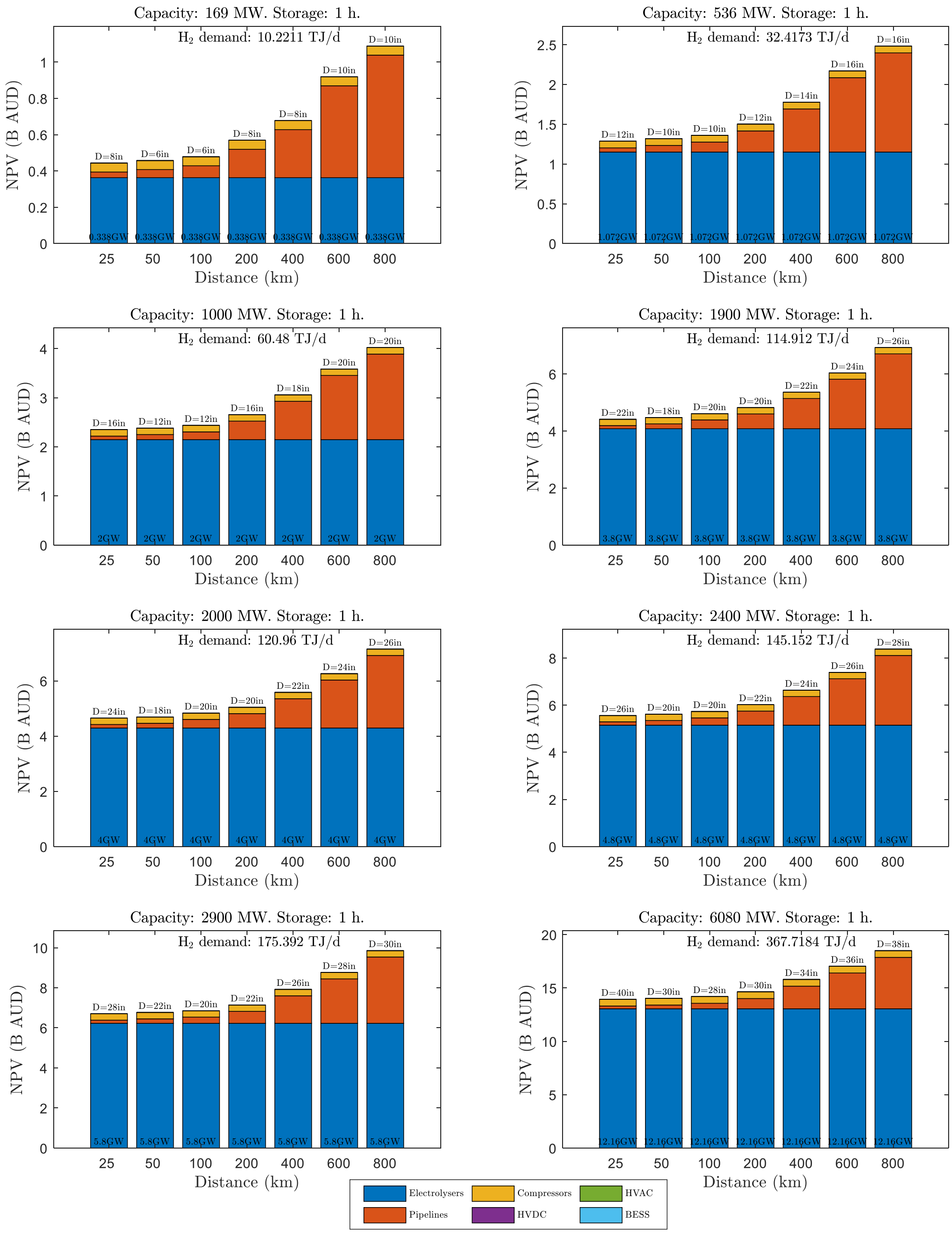

Figure 9: Optimal transmission and storage infrastructure across the considered capacities and distances, for a scenario requiring 1 hour of storage duration (Storage: 1 h), and with electricity options removed (only hydrogen pipelines are considered). Note the difference in y-axis scale between each case.

3.2. REZ in the NEM in 2050: Without UHS

For comparison purposes, this second case study excludes the candidate UHS facilities shown in Figure 4. The optimal *greenfield* integrated infrastructure design for this case is shown in Figure 10, which indicates that the optimisation model chooses pipelines exclusively as the most cost-effective transport infrastructure. Figure 10 also shows the optimal diameter of each hydrogen pipeline, along with the length of the pipeline. The total NPV of this optimal integrated infrastructure design is 52.8 B AUD. A breakdown of this total NPV is shown in Table 4 for each technology and for each considered state (excluding Tasmania). It is evident from Table 4 that electrolysers constitute the largest proportion (~70%) of the total cost under today's cost curves which estimate the cost of PEM electrolysers at around 0.864 M AUD/MW (see Table 9 in Appendix A: Cost and Parameter Assumptions).

Table 4: Breakdown of the total NPV for each technology and for each considered state (excluding Tasmania) at the optimal solution of the integrated transport infrastructure problem for the considered *Hydrogen Superpower* scenario (see [1]) in 2050.

		NPV (M AUD)						
State	**H_2 export (Mt/yr)**	**Pipelines**	**Compressors**	**HVAC**	**HVDC**	**BESS**	**PtG**	**Total (B AUD)**
NSW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
QLD	6.3	5296.2	3109.7	0.0	0.0	0.0	22571.1	**31.0**
SA	3.3	3728.3	3787.1	0.0	0.0	0.0	13326.8	**20.8**
VIC	0.2	227.3	104.2	0.0	0.0	0.0	699.2	**1.0**
	9.8	9251.8	7001.0	0.0	0.0	0.0	36597.1	**52.8**

Under the cost and technical assumptions of the specific case study in this section (see Table 3 and Appendix A: Cost and Parameter Assumptions), in which a greenfield integrated electricity and hydrogen infrastructure planning model is used to find the most cost-effective infrastructure design that connects the REZ in AEMO's 2022 ISP (see Figure 4) *directly* to a single type of demand, namely large-scale green hydrogen (i.e., molecules), results show that hydrogen pipelines are more cost effective than their electricity counterparts under the specific corridor lengths and energy volumes in this case study (see Figure 4). This is another way of saying that in this case it is more cost effective to co-locate large-scale electrolysis and VRE, and transport the produced green hydrogen in pipelines, as opposed to installing large-scale electrolysis at the location of the hydrogen demand (in this case the export ports).

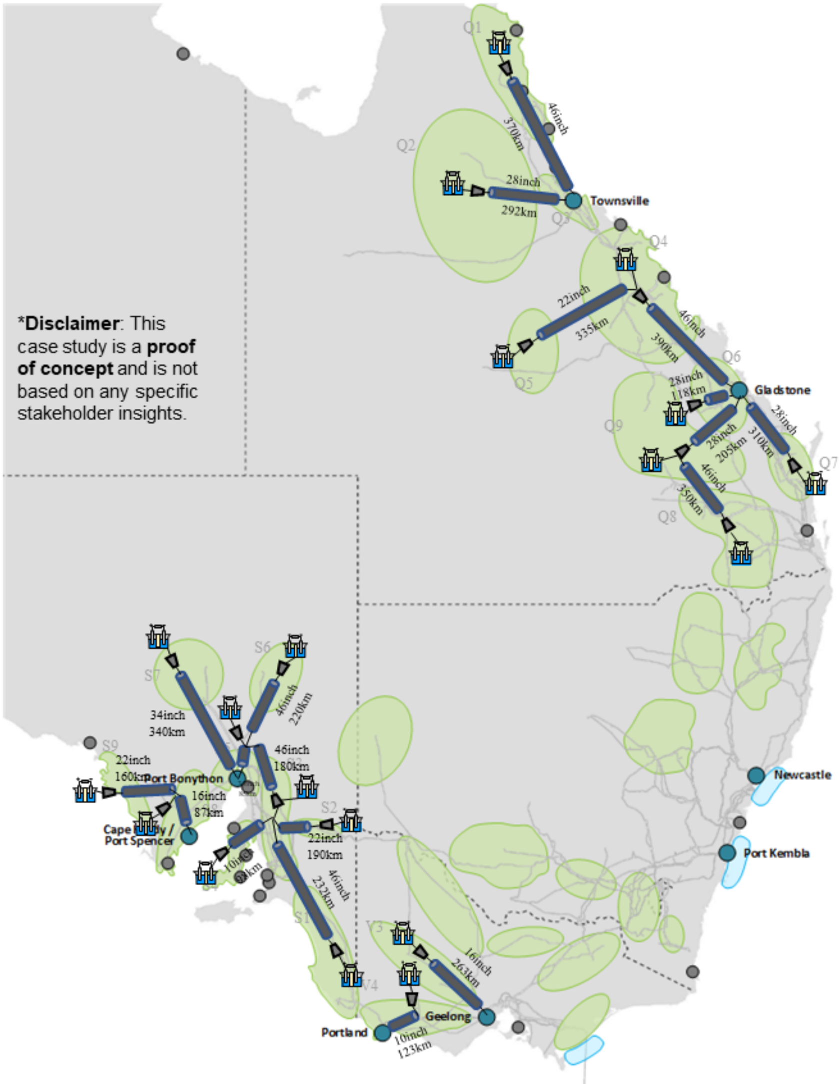

Figure 10: Optimal solution of the integrated infrastructure planning problem for the considered 2050 scenario. Only pipelines are deemed as the optimal transport infrastructure in this case study.

Under the specific cost assumptions in this report, there are two main reasons why hydrogen pipelines are preferred over their electricity counterparts in this case study:

1) Under steady-state conditions where the demand for hydrogen is constant and the supply always exceeds the demand (i.e., where storage is not needed), hydrogen pipelines (including compressors) are in general more cost effective than both HVAC and HVDC technologies across most distances and energy volumes in this study. This is demonstrated in Section 3.1.
2) In the case where more than around 2 hours of storage duration is needed (e.g., to buffer the variability of RES), the increase in cost due to increasing *both* the diameter of the pipeline (to provide additional storage through the linepack) *and* the capacity of electrolysers (to accommodate the extra energy required for charging the linepack) is outweighed by a larger increase in cost due to additional investment in BESS over most of the considered distances. This is also demonstrated in Section 3.1.
3) The developed optimisation model is capable of *optimising* the linepack (oversizing the pipelines to accommodate more storage) for an arbitrary variable supply.

4) In contrast to a single corridor, optimising over a network with more than one corridor adds *geographical location* and RES variability to the list of defining factors that impact optimal infrastructure and storage design. In other words, having more than one corridor entails finding the optimal compromise between (i) energy volumes, (ii) distance, (iii) storage requirements, *and* (iv) geographical location, in addition to (v) variability RES.

As shown in Section 3.1, in a scenario where 2 hours of storage duration are required, hydrogen pipelines are generally more cost effective than electricity transmission infrastructure (HVAC + BESS or HVDC + BESS) across most of the considered distances and energy volumes. In fact, the linepack profiles in Queensland and South Australia in Figure 11 and Figure 18, respectively, show that the optimal pipeline network in Figure 10 is providing around 6.5 hours of storage in Queensland (~660 TJ) and around 10.3 hours of storage in South Australia (~546 TJ), both of which are much higher than 2 hours. The total storage capacity contained in the pipeline network (in the form of linepack) is in fact much higher, ~12 hours (1222.5 TJ) in Queensland as per Figure 11, and ~15.5 hours (~820 TJ) in South Australia as per Figure 18. The profile of total linepack for Victoria is shown in Figure 20 in Appendix B: Supplementary Material. Corresponding profiles of total available (forecast) VRE, total accommodated VRE, and total hydrogen demand (GW) for Queensland are shown in Figure 12. Similar profiles for South Australia and Victoria are shown in Figure 17 and Figure 19, respectively, in Appendix B: Supplementary Material.

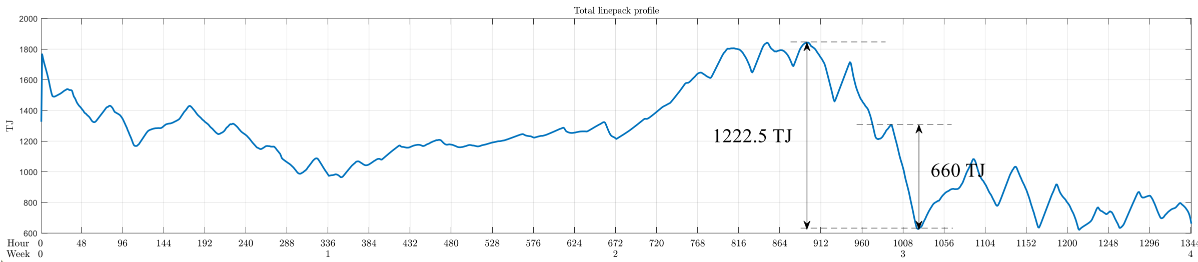

Figure 11: Profile of total linepack in the optimal hydrogen pipeline network in Queensland (see Figure 10). Note that the y-axis scale is from 600 TJ to 2000 TJ.

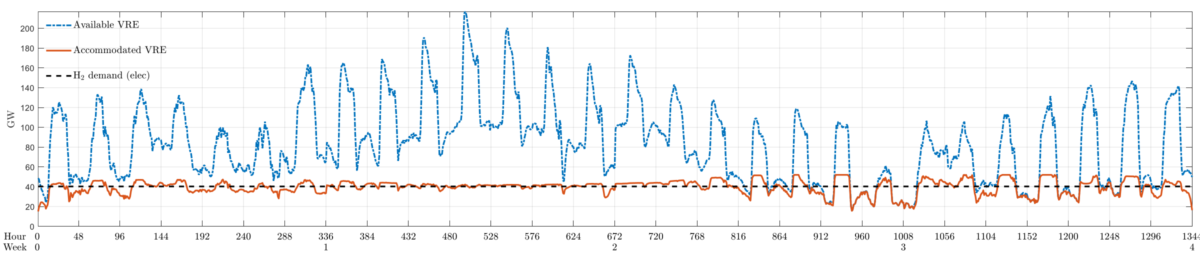

Figure 12: Profiles of total available (forecast) VRE, total accommodated VRE, and total hydrogen demand (GW) for Queensland under the optimal solution illustrated in Figure 10.

Figure 12, Figure 17, and Figure 19 also show that the profile of total accommodated VRE has a much lower variability compared to the available VRE, and this is because the optimisation model finds the optimal compromise between minimising the installed capacity of electrolysers and the capacity of the transmission infrastructure (in this case hydrogen pipelines) subject to geographical information. The optimisation model does that by finding the optimal location for the minimum possible capacity of electrolysers to ensure supplying the total (constant) hydrogen demand using the smallest possible pipeline diameters that provide adequate storage capacity (linepack).

3.3. REZ in the NEM in 2050: With UHS

In the case where the candidate UHS facilities (shown in Figure 4) are included in the optimisation model described in Section 2, the optimal *greenfield* integrated infrastructure and storage design shown in Figure 13 indicates that the model chooses to install only one of the candidate UHS facilities in Queensland. All other UHS facilities were not deemed as economically competitive in this greenfield integrated planning problem. Interestingly, investing in the UHS facility in Roma substantially decreases the total NPV by around 6.1 B AUD (11.5%), from 52.8 B AUD to 46.7 B AUD. A breakdown of this total NPV is shown in Table 5 for each technology and for each considered state (excluding Tasmania).

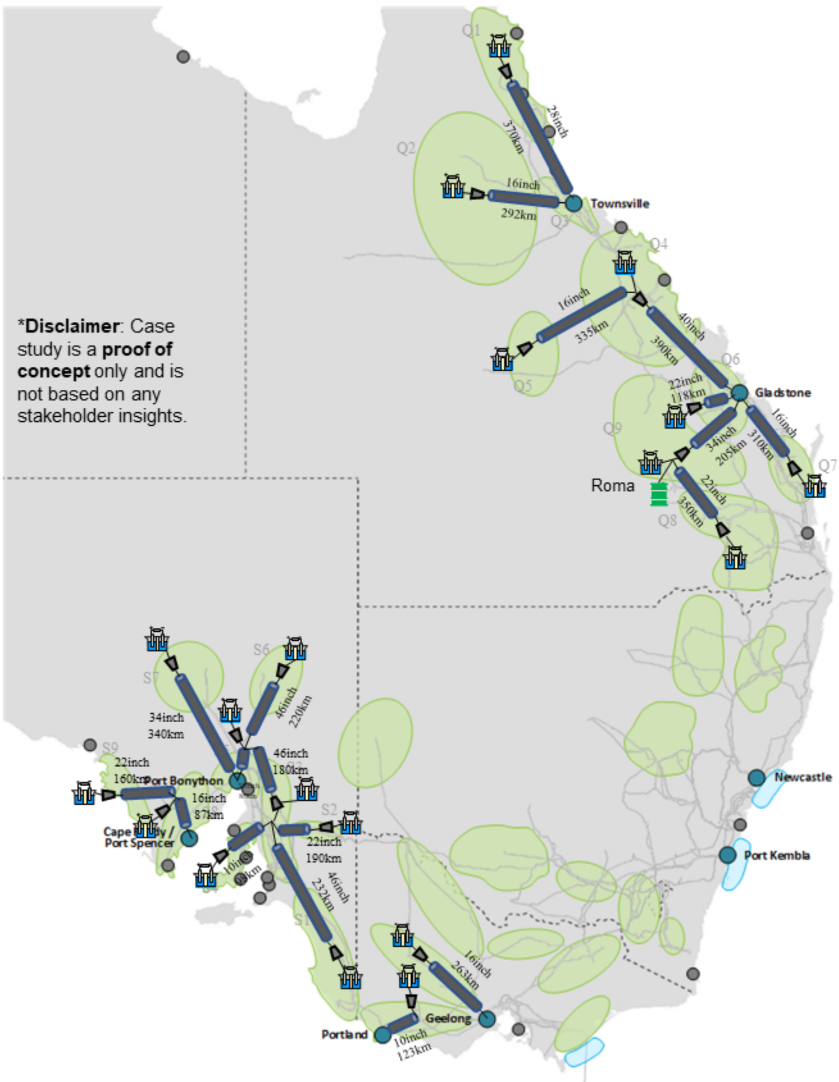

Figure 13: Optimal solution of the integrated infrastructure and storage planning problem. The model chooses to invest in only one of the two UHS facilities in Queensland (Roma).

Table 5: Breakdown of the total NPV for each technology and for each considered state (excluding Tasmania) at the optimal solution of the integrated transport and storage infrastructure problem for the considered *Hydrogen Superpower* scenario (see [1]) in 2050.

State	H_2 export (Mt/yr)	NPV (M AUD)					Total (B AUD)
		Pipelines	Compressors	HVAC+ HVDC+ BESS	UHS	PtG	
NSW	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
QLD	6.3	3249.1	1510.8	0.0	132.3	19977.8	**24.9**
SA	3.3	3728.3	3787.1	0.0	0.0	13326.8	**20.8**
VIC	0.2	227.3	104.2	0.0	0.0	699.2	**1.0**
	9.8	7204.6	5402.1	0.0	132.3	34003.8	**46.7**

The main reason for this decrease in NPV is that the marginal cost of storage of the UHS facility in Roma is much lower compared to that of a pipeline, which generally requires increasing its diameter to provide additional storage, as described in Section 3.1. If there is not enough headroom in the pipeline the extra storage requirement comes at the expense of increasing its diameter, and thereby its overall cost. As a result, the storage capacity gained from installing the UHS in Roma displaces more expensive storage (linepack) in adjacent pipelines as well as other remote pipelines in the Queensland network, thereby resulting in the downsizing of these pipelines. In other words, the increase in cost (132.3 M AUD) due to investing in the UHS facility in Queensland is offset by a much larger decrease in cost (8405.88 + 22571.12 – (4759.86 + 19977.84 + 132.35) = 6.11 B AUD) from downsizing adjacent pipelines (and also PtG). This downsizing can be seen by comparing the pipeline networks in Queensland in Figure 13 and Figure 10. The total storage profile of the UHS facility in Roma (see Table 3), which can provide ~3215 TJ of storage over the considered 4 representative weeks, is shown in Figure 14, and the associated profiles of injections and withdrawals are shown in Figure 15. In fact, this displacement in linepack capacity can be seen in Figure 16, which shows the profile of the total linepack in Queensland for the optimal solution shown in Figure 13. The total linepack capacity is now ~547 TJ compared to ~1222.5 TJ in the case without the UHS facility in Roma, Queensland (see Figure 11), a ~675.6 TJ decrease thanks to the additional UHS storage capacity.

Although the UHS facility in Moomba (see Table 3 and Figure 4) is expected to have a larger capacity compared to the one in Roma, the main reason the model did not choose to invest in it is because of its remoteness from the REZ identified in AEMO's 2022 ISP, which would require building an additional pipeline of length of around 300 km to connect it to the rest of the hydrogen pipeline network in South Australia, thus increasing the total NPV instead of decreasing it. Similar reasoning applies to the Iona UHS facility in Victoria.[13]

[13] Results may be different if the analysis considered the cost of repurposing existing natural gas pipelines to support 100% hydrogen, alongside installing new hydrogen pipelines.

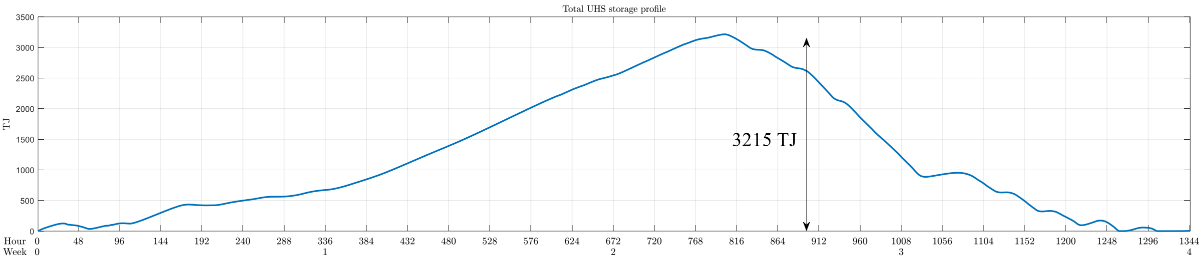

Figure 14: Total storage profile of the UHS facility in Roma (see Table 3). This UHS facility can provide ~3215 TJ of storage over the selected 4 representative weeks.

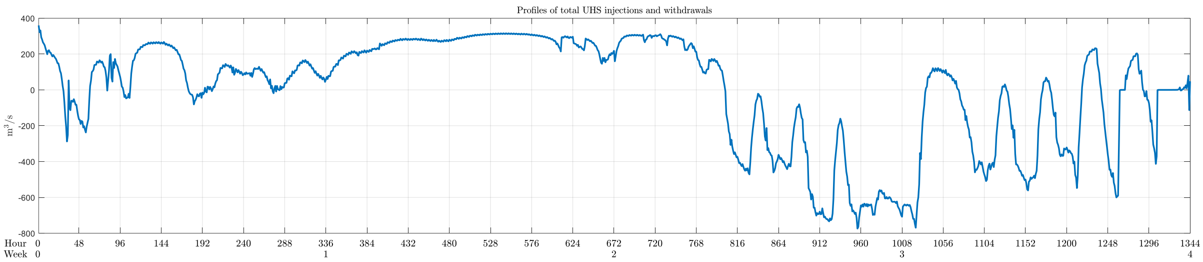

Figure 15: Total profiles of injections (positive) and withdrawals (negative) of the optimally selected UHS facility in Roma (see Figure 13).

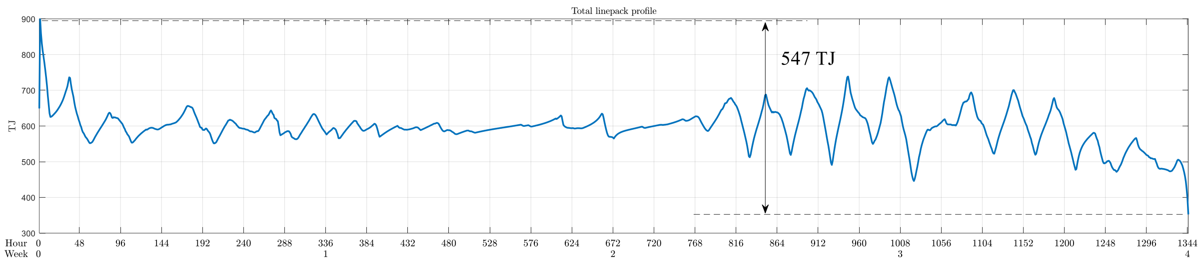

Figure 16: Profile of total linepack in the optimal hydrogen pipeline network in Queensland (see Figure 13) with the UHS in Roma. Note that the y-axis scale is from 300 TJ to 900 TJ.

It should be noted that the UHS is assumed completely empty at the start of the planning (optimisation) horizon to ensure fairness. Any other assumption on the initial storage would engender an unfair economic advantage in favour of installing the UHS, as the cost of that initial storage will be assumed as zero. Assuming the UHS is full greatly impacts the optimal solution, which not only manifests in smaller pipelines but also in much smaller PtG capacity, as this assumption also entails that the required capacity of electrolysers to convert VRE to the green hydrogen initially present in the UHS and the cost of that conversion are *not* accounted for.

4. CONCLUSION

To address the challenging question of whether to transport large-scale VRE as molecules in hydrogen pipelines or as electricity in electricity transmission lines, this report introduced a first-of-its-kind mathematical optimisation framework for finding the optimal *greenfield* integrated planning of electricity and hydrogen transmission and storage infrastructure. The model fills the gap in existing state-of-the-art literature by (i) considering all relevant infrastructure technologies such as HVDC, HVAC, reactive power compensation, and hydrogen pipelines and inlet compressors, and by (ii) incorporating essential nonlinearities such as voltage drops due to impedances in HVAC and HVDC transmission lines, losses in HVDC converter stations, reactive power flow, pressure drops in pipelines, linepack, and nonlinear withdrawal/injection rates of UHS systems, all of which play an important role in determining the optimal infrastructure investment decision.

The capabilities of this model are demonstrated on two sets of major case studies. The first is a canonical case study that consists of an assessment of the three fundamental drivers: (i) supply capacity, (ii) corridor length, and (iii) storage requirements, and how they affect the investment decision over a *single corridor*. The second is a proof-of-concept case study that demonstrates the scalability of the developed model over a network with multiple variable supplies and demands by considering all the REZ stipulated in AEMO's 2022 ISP and connecting them with provisional corridors to the hydrogen export ports whose demands are specified in AEMO's 2022 ISP under the *Hydrogen Superpower* scenario for year 2050. This case study also considers candidate UHS facilities in the form of depleted gas fields, which can offer medium and long duration storage that plays a crucial role in buffering the variability of RES.

The findings in this report are summarised as follows:

A. <u>Point-to-point analysis (single corridor):</u>

In this case study, supply capacity is selected from the set [169 MW, 536 MW, 1000 MW, 1900 MW, 2000 MW, 2400 MW, 2900 MW, 6080 MW], corridor length is varied from 25 km to 800 km, and storage duration is varied between 0 and 8 hours. Under the specific cost and technical assumptions, corridor lengths, energy volumes, and storage requirements in this case study, the findings suggest that:

- Under steady-state throughputs (where no storage is required) hydrogen pipelines are more cost effective than their electricity counterparts across all the capacities and distances considered in this report.
- In cases where more than 2 hours of storage duration are required, hydrogen pipelines are more cost effective than their electricity counterparts over most distances and capacities, owing primarily to the observation that the increase in cost due to increasing *both* the diameter of the pipeline (to provide additional storage through the linepack) *and* the capacity of electrolysers (to accommodate the extra energy required for charging the linepack) is outweighed by a larger increase in cost due to additional investment in BESS over most of the considered distances.
- In cases where only 1 hour of storage is required, the optimal transmission and storage infrastructure is heavily influenced by the cost of BESS *relative* to the cost of electrolysers. In particular, electricity transmission lines and BESS are chosen for distances smaller than 100 km in this case.

B. Optimal integrated transmission and storage infrastructure over a network with variable supplies and demands (REZ and hydrogen demands from AEMO's 2022 ISP for 2050)

Under the specific cost and technical assumptions, corridor lengths, energy volumes, storage requirements, VRE forecasts, and hydrogen export demand forecasts in this case study, the findings suggest that:

- Only pipelines are deemed as the optimal transport infrastructure. This is predominantly due to the high variability of RES, which requires in some cases more than 8 hours of storage to buffer this variability. Linepack storage is of utmost importance in this case as the RES supply is variable and the hydrogen export demand is assumed constant in each state (QLD, SA, and VIC) but distributed, not necessarily equally, over the envisaged hydrogen export ports in each state. These results align with the observations in the above case for a single corridor. This is another way of saying that in this case it is more cost effective to co-locate large-scale electrolysis and VRE, and transport the produced green hydrogen in pipelines, as opposed to installing large-scale electrolysis at the location of the hydrogen demand (in this case the export ports).
- Investing in UHS in the form of depleted gas fields in specific locations in Australia can significantly *decrease* the total investment costs of transport and storage infrastructure. This is because the marginal cost of storage in the considered UHS facilities is much lower than that of a pipeline, and as a result the storage capacity gained from installing the UHS can displace more expensive storage (linepack) in adjacent pipelines, thereby resulting in the downsizing of these pipelines.
- In contrast to existing works, which are predominantly limited to a single corridor with static supplies and demand profiles, the developed optimisation-based modelling can find the *optimal* integrated transport and storage infrastructure design over a *network* with arbitrary topology and with multiple variable supplies and demands. In contrast to a single corridor, optimising over a network with more than one corridor adds *geographical location* and RES variability to the list of defining factors that impact the optimal infrastructure and storage design. In other words, having more than one corridor entails finding the *optimal* compromise between (i) energy volumes, (ii) distance, (iii) storage requirements, *and* (iv) geographical location, in addition to (v) variability RES, thus making the analysis much more complex. Despite this complexity, the novel insights and assessments in this report are made possible thanks to state-of-the-art mathematical optimisation methods and scalable numerical algorithms.

It should be emphasised that the assessment and case studies in this report are considered as *greenfield* integrated expansion planning that optimises newly built electrolysis, transmission, and storage infrastructure network in *isolation* from existing infrastructure, for a specified constant hydrogen export demand distributed (not necessarily equally) over the envisaged hydrogen export ports in each state. In other words, this greenfield assessment does not consider the interactions between this newly built infrastructure network and the existing electricity transmission infrastructure such as the one in the National Electricity Market (NEM). The findings in this report may change if these interactions are considered as the electricity system (including flexible generation, BESS, pumped hydro energy storage (PHES), and transmission network) can provide flexibility to buffer variability from RES, thereby potentially displacing additional storage requirements in pipelines, or even pipelines altogether depending on the case. The assessment also neglects water requirements (and water networks) for electrolysers due to lack of data, which might also alter the findings when included. All the cost assumptions in this report are for year *2023*. Their NPV also considers 2023 as reference year. In addition to pipelines, other viable options for hydrogen transportation include tanker trucks and tube trailers. These options are discussed in more detail in the *Milestone 3: Literature review* of the project.

Finally, the modelling of UHS in this project, together with the electricity network modelling developed in “RP1.1-02A: Regional case studies on multi-energy system integration”, will pave for the way for project “*RP1.1-07: Integrated electricity-hydrogen: future system and market interactions under different storage considerations*” which will kick-off in October 2023.

5. NEXT STEP AND FUTURE WORK

The immediate next step consists of extending the capabilities of the model to *multi-stage* planning that considers multiple investment stages (epochs) in the aim of capturing the gradual growth in hydrogen demand and VRE capacity, lead time of building the assets, in addition to non-anticipativity constraints which ensure that an investment made at a certain stage (epochs) will be present in subsequent epochs.

APPENDIX A: COST AND PARAMETER ASSUMPTIONS

This appendix lists the assumptions on input technical parameters and costs of hydrogen pipeline links in Table 6, HVAC links in Table 7, HVDC links in Table 8, electrolysers in Table 9, and BESS in Table 10. These cost estimates are obtained from various reliable publicly available sources, including AEMO [1] and the peak body representing Australian pipeline infrastructure [21]. Cost estimates of pipelines and compressors fall under Class 4 of the Association for Advancement of Cost Engineering (AACE) classification system with a CapEx accuracy of -30%/+50%, whereas cost estimates of HVAC and HVDC links fall Class 5 (±30%). Cost assumptions for UHS facilities can be found in Table 3. All the cost assumptions in this report are for year *2023*. These are then projected to the respective years under study (e.g., 2050) using a constant inflation rate of 2.5% per year. Their NPV also considers 2023 as reference year.

Table 6: Cost and parameters assumptions of pipelines and compressors [21].

Parameter		Option			
Diameter (inch)		4	6	…	46
Minimum pressure (MPa)		3	3	…	3
Maximum allowable operating pressure (MPa)		12	12	…	12
Specified minimum yield strength (psi)		52000	52000	…	52000
Design factor		0.5	0.5	…	0.5
Erosional velocity ratio		0.8	0.8	…	0.8
Manufacturing cost (USD/Tonne)		2649	2649	…	2649
Insurance and freight (USD/Tonne)[14]		218	218	…	218
Installation cost (kAUD/inch/km)[15]	<100 km	70	70	…	70
	<250 km	50	50	…	50
	<500 km	40	40	…	40
	>500 km	37.8	37.8	…	37.8
Engineering costs (% of procurement and installation costs)	≤100 km	10	10	…	10
	>100 km	5	5	…	5
OpEx (% of CapEx)	≤50 km	3.75	3.75	…	3.75
	≤100 km	3.25	3.25	…	3.25
	≤200 km	2.25	2.25	…	2.25
	≤500 km	2.11	2.11	…	2.11
	>500 km	1.875	1.875	…	1.875
Compressors		See Tables 6, 26, and 27 in [21].			

[14] Insurance and freight costs are from the supplier (Welspun) to Port Hedland, Western Australia [21].
[15] The reader is referred to [21] for a full list of factors that installation costs include.

Table 7: Cost and parameters assumptions of HVAC links [25], [30].

Parameter		Option						
Voltage (kV)		500	500	330	275	330	275	132
OHL cost (M AUD/km)		3.747	2.907	2.839	2.205	2.041	1.717	1.241
OpEx (% of CapEx)	<250 km	0.5	0.5	0.5	0.5	0.5	0.5	0.5
	≥250 km	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Capacity (MVA)		6080	2900	2400	1900	1000	536	169
Circuits		Double	Single	Double	Double	Single	Single	Single
Conductor		Orange	Orange	Mango	Olive	Orange	Lemon	Mango
Bundle		4	4	3	2	2	2	1
Resistance (Ω/km)		0.0207	0.0207	0.0322	0.0358	0.0413	0.0835	0.0967
Reactance (Ω/km)		0.2603	0.2603	0.2685	0.3027	0.3051	0.3149	0.3994
Shunt admittance (μS/km)		4.22	4.22	4.09	3.63	3.60	3.49	2.75
Substation 1 cost (M AUD)		178.5	107.9	89.7	78.9	45.8	26	12.3
Substation 2 cost (M AUD)		172.2	107.9	89.7	54	45.8	26	12.3

Table 8: Cost and parameters assumptions of HVDC links [25], [30].

Parameter		Option	
Voltage (kV)		±320	±500
Capacity (GW)		1.5	2
OHL cost (M AUD/km)		1.99	2.54
Resistance (Ω/km)		0.0119	0.0119
Converter station 1 (M AUD)		474.68	507.37
Converter station 2 (M AUD)		357.82	509.20
OpEx (% of CapEx)	<250 km	0.5	0.5
	≥250 km	0.25	0.25
Alpha (MW)		6.62	6.62
Beta (V)		1800	1800
Gamma (Ω)		1.98	1.98
Technology		HVDC - VSC	HVDC - VSC
Details		2 × Asymmetrical Monopole (Bipole metallic return)	2 × Asymmetrical Monopole (Bipole metallic return)

Table 9: Cost and parameters assumptions of electrolysers [31], [32].[16]

Parameter	Value
Capacity of a single electrolyser (MW)	17.5
Electrolyser unit cost (M USD)	10.5
OpEx (% of CapEx)	2
Efficiency (%)	70
Water consumption (kg/kg H_2)	10
Technology	PEM

Table 10: Cost and parameter assumptions of BESS [8], [21].

Parameter		Value (AUD/MWh)
CapEx (AUD/MWh)	1 h	820,000
	2 h	550,000
	3 h	500,000
	4 h	450,000
	8 h	410,000
OpEx (AUD/kWh/year)		7.5
Efficiency (%)		95
Technology		Lithium-Ion

[16] The model can readily include different sizes and types of electrolysers.

APPENDIX B: SUPPLEMENTARY MATERIAL

Profiles of total available (forecast) VRE, total accommodated VRE, and total hydrogen demand (GW) for South Australia and Victoria are shown in Figure 17 and Figure 19, respectively. Profiles of total linepack in the optimal hydrogen pipeline network in South Australia and Victoria are shown in Figure 18 and Figure 20 respectively.

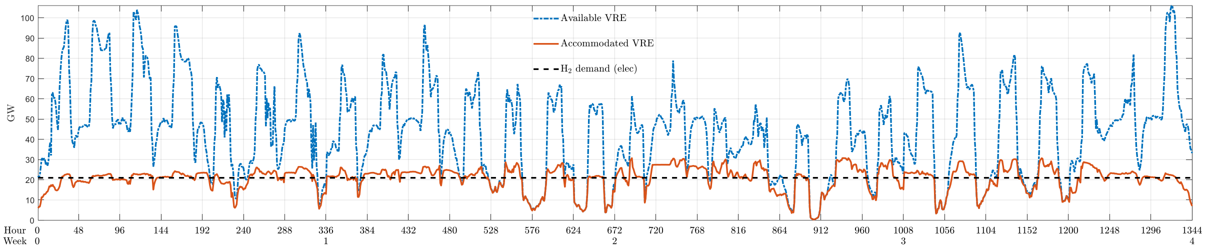

Figure 17: Profiles of total available (forecast) VRE, total accommodated VRE, and total hydrogen demand (GW) for South Australia under the optimal solution shown in Figure 10.

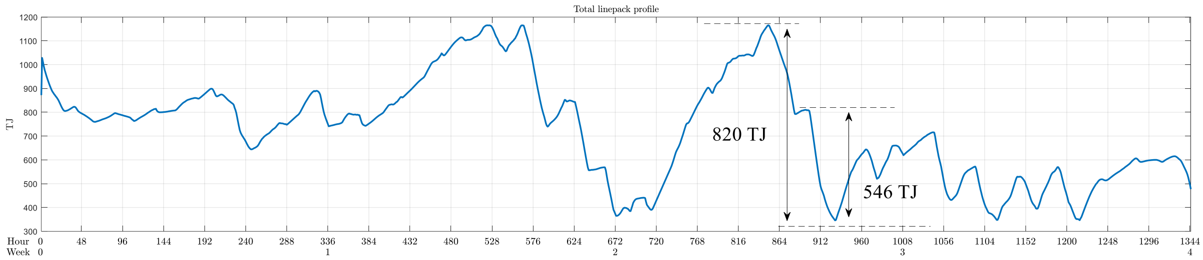

Figure 18: Profile of total linepack in the optimal hydrogen pipeline network in South Australia (see Figure 10).

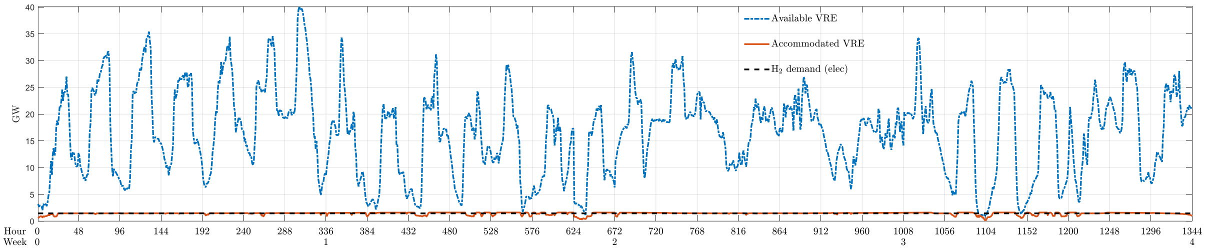

Figure 19: Profiles of total available (forecast) VRE, total accommodated VRE, and total hydrogen demand (GW) for Victoria under the optimal solution shown in Figure 10.

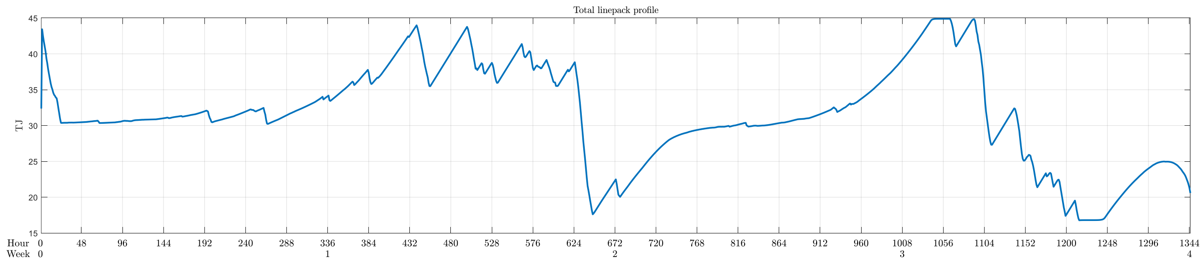

Figure 20: Profile of total linepack in the optimal hydrogen pipeline network in Victoria (see Figure 10).

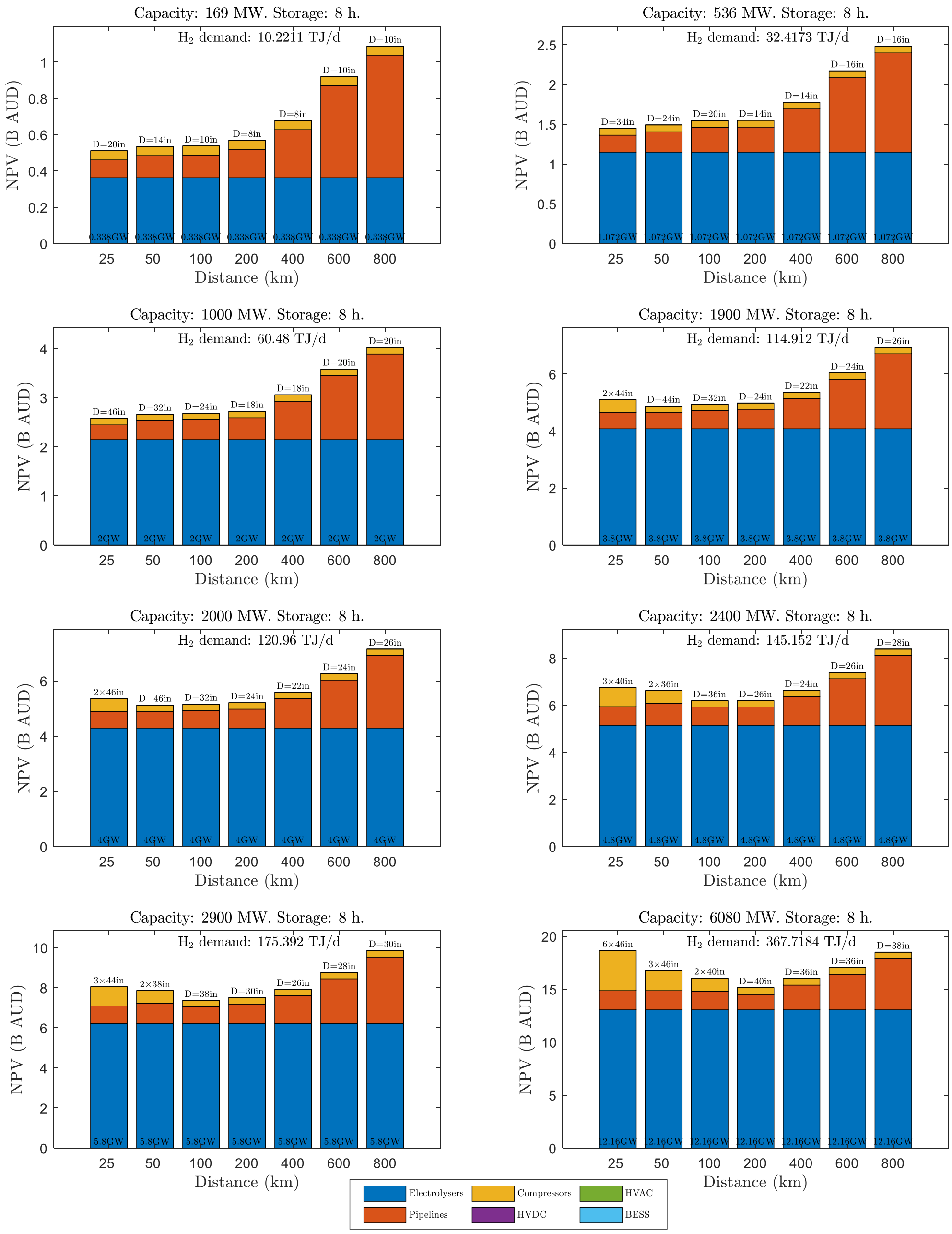

Figure 21: Optimal integrated transmission and storage infrastructure across the considered capacities and distances, for a scenario requiring 8 hours of storage duration (Storage: 8 h). Note the difference in y-axis scale between each case.

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