02

IEA'S HYDROGEN TCP TASK 41

ANALYSIS AND MODELLING OF HYDROGEN TECHNOLOGIES

Final Report

Applications

Technology Collaboration Programme
by iea

Data:
June 2023

Contributing participants in Task e-meetings in alphabetical order:
Farzaneh Amir Kavei (Polito University, Italy), Herib Blanco (IRENA, McKinsey)[b], Claudia Bassano (ENEA, Italy), Bruno Baldissara (ENEA, Italy), Martin Baumann (Austrian Energy Agency)[b], Markus Blesl (IER Institute, Germany)[c2], Rubén Canalejas (Aragon Hydrogen), Pierre Cayet (Persee, France), Jonathan Davies (EC/EU), Janis Danebergs (IFE, Norway)[b], Paolo Deiana (ENEA, Italy), Robert Dickinson (Hydricity Systems, Australia)[b], Paul Dodds (UCL, UK)[b,c1], Jan Duerinck (VITO Institute, Belgium)[c2], Kari Espegren (IFE, Norway)[c1], Patrícia Fortes (Uni. Nova de Lisboa, Portugal)[c2], Diego Garcia Gusano (Tecnalia, Spain)[b], Oualid Gharbi (CEA France), Alberto Giaconia (ENEA, Italy), Santiago González Herraiz (IDAE, Spain), Francesco Gracceva (ENEA, Italy), Laurence Grand-Clément (Persee, France), Hiroshi Hamasaki (Deloitte, Japan)[c2], Diego Iribarren (IMDEA, Spain)[b], Andreas Indinger (Austrian Energy Agency), Cecile Lavernhe (Persee, France), Jonathan Leaver (Unitec Polytechnic, New Zealand)[b], Raian Lefgoum (Persee, France), Antti Lehttila (VTT Research Centre, Finland)[c2], Daniele Lerede (Polito University, Italy), Arne Lind (IFE, Statkraft, Norway)[b], Johannes Lindorfer (Linz Energy Institute, Austria), Jochen Linssen (Julich Research Centre, Germany), Paulo Martins (DGEG Portugal), Shivika Mittal (UCC, Ireland)[c2], Robin Molinier (Airliquide, France), Matteo Nicoli (Polito University, Italy), Larissa Nogueira (TNO, Netherlands), Paulo Partidário (DGEG Portugal), Simon Pichlmaier (FFE, Germany), Kannan Ramachandran (PSI Research Institute, Switzerland)[c2], Stefan Reuter (Austrian Energy Agency), Simón Romay Guillermo (Persee), Eva Rosenberg (IFE, Norway)[c2], Valentina Ruiz (Persee, Woodmac), Kostis Sakellaris (FCH / EU), Pernille Merethe Sire Seljom (IFE, Norway), Laura Savoldi (Polito University, Italy), Daniel Scamman (UCL, UK)[c1], Ezequiel Serwatka (Hychico, Argentina), Horst Steinmueller (Linz Energy Institute, Austria), Roberto Sunyé (NRC Canada), Changlong Wang (Monash University, Australia)[b], Omar Jose Guerra Fernandez (NREL, USA).

b Co-authors of Sub-Task b's "A taxonomy of models for investigating hydrogen energy systems"
c1 Lead authors of Sub-task c's Final Report
c2 Modelling contributions to Sub-task c's Final Report

Editor and Corresponding Author:
Robert Dickinson, (Hydricity Systems, and The University of Adelaide)

IEA's Hydrogen TCP Task 41

ANALYSIS AND MODELLING OF HYDROGEN TECHNOLOGIES

Final Report

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IEA'S HYDROGEN TECHNOLOGY COLLABORATION PROGRAM TASK 41

DATA AND MODELLING INTRODUCTION

Final Report

Until about 2018, many energy industry leaders had a limited appreciation of the potential for clean hydrogen to contribute to the transition to a net zero economy. Recognising the role that modelling could play in supporting evidence-based evaluation of opportunities, IEA Hydrogen TCP defined a new Task (Task 41): Data and Modelling.

By the time the definition process for Task 41 began in late 2018, the energy systems sector, more widely, was starting to appreciate that hydrogen could be a critical component of future energy systems. Government policies began to change. Private investment skyrocketed. Scientific research and publication grew exponentially (Fig. 1). These changes were primarily driven by increasing recognition that climate change already had severe consequences, leading to a more urgent need to transition away from fossil fuels quickly. Fig. 2 presents the overlap between Task 41 and these global changes.

Section 1 abbreviations

CCS(U)	Carbon Capture and Storage (with optional utilization)
CO_2	Carbon Dioxide
CO_2-e	Carbon Dioxide equivalent GHG emissions
ETSAP TCP	The IEA's Energy Technologies Systems Analysis Program TCP
H_2	Hydrogen
H_2 TCP ExCo	The Executive Committee of the IEA's Hydrogen TCP
IEA	International Energy Agency
IEA Hydrogen TCP	The IEA's Hydrogen TCP
IEA TCPs	The IEA's Technology Collaboration Programs
power-to-X	Production of renewable hydrogen from renewable electricity followed by production of other commodities
Task	Each IEA TCP designates major projects as numbered Tasks
Task 38	The IEA Hydrogen 's Task 38 dealt with "Power to Hydrogen - Hydrogen to X..."
Task 41	The IEA Hydrogen 's Task 41's work documented in this final report

Another climate-action-inspired modelling activity that emerged parallel to Task 41 was "Electrify Everything" [1,2]. This paradigm depends on intensive modelling but uses one dominant archetype: Power Models. It takes a narrow view of the potential for clean energy. Its simplicity led to a great deal of media attention. Yet models focused on "Electrify almost everything, and for everything else, there's clean hydrogen" are only marginally more complex. By clean hydrogen, we mean hydrogen produced with near zero CO_2 emission: This could be via coal or methane reformation with carbon capture utilization and storage. Or the more likely to lead in the coming years: power-to-hydrogen using zero-carbon electricity. Given uncertainties about CCS costs and reductions in renewable power generation and electrolyser costs, we expect power-to-hydrogen will take the lead. Indeed, in the long term, the order of cost of production ($ / kg H_2) from the bottom up might be large-scale solar photocatalysis[1], power-to-hydrogen with fossil hydrogen, with CCS having the highest cost of production.

1. e.g., https://sparctechnologies.com.au/

At the other end of the scale from the narrow focus of "Electrify Everything", the opportunity for deploying green hydrogen at scale in some parts of the world is so enormous that conventional economic modelling is sufficient, perhaps more akin to natural resource extraction/economics focused opportunities modelling than energy systems modelling. Examples include [3-12]. Similarly, in the commercial sector, PLEXOS[2] provided no support for hydrogen until about 2019, then progressively released support to customers over 2021-2023: [13-22]. Extending these observations to all relevant institutions and commercial modelling vendors worldwide, it becomes clear that growth has generally become exponential since 2017-18, not just as measured by publications (Fig. 1).

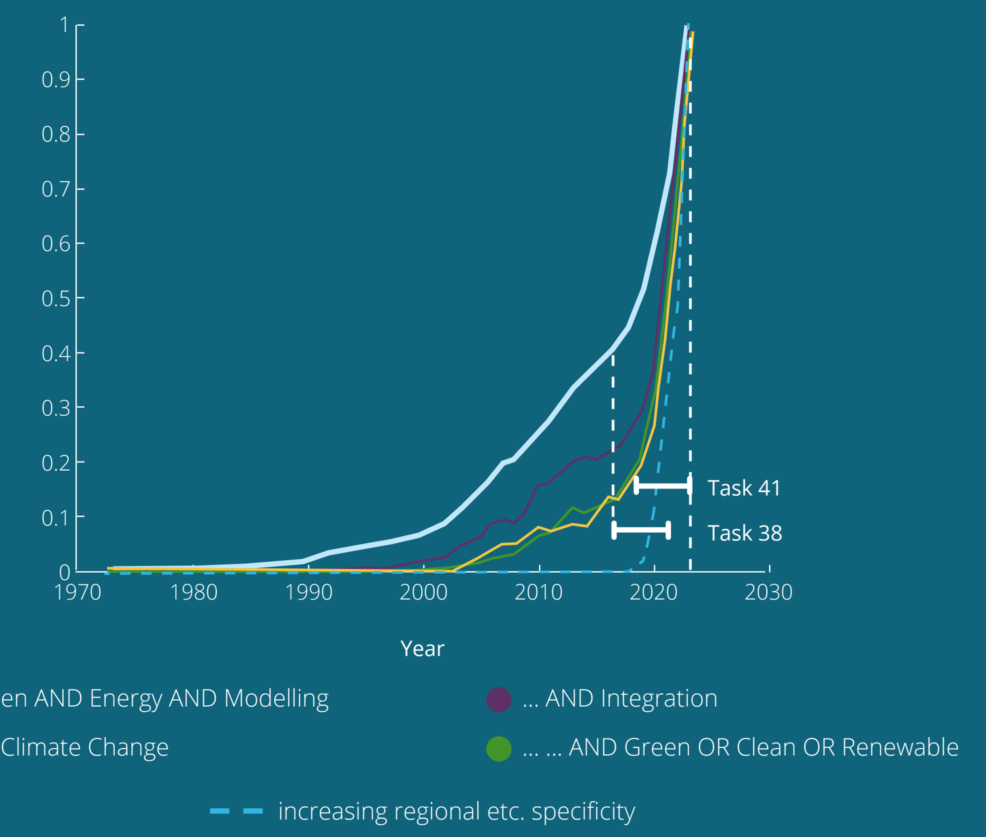
In this new rapidly evolving context, modelling capability became less of a perceived limit to the appreciation of hydrogen's potential. To some extent, modelling activities were in need of catching up with hydrogen industry and policy aspirations and initiatives.

Task 41 consisted of four Sub-tasks (Table 1).

Section 2 outlines the challenges of Sub-task a) and provides a connection to ongoing work by others. Section 3 summarizes a journal article outcome from Sub-task b) and recent critical developments in commercial modelling systems. A recurring theme in the challenges reviewed in the first part of Section 3 is the conflict between the need for high resolution (small time steps) and computational tractability. Accordingly, the latter part of Section 3 presents a potential approach for deploying multi-resolution modelling. This approach leads to a long-term vision for price modelling to capture the market forces required to efficiently transition from fuel-to-power (generating power from fossil fuel) to power-to-fuel (generating clean hydrogen from renewable energy). Chapter 4 presents the Final Report of Sub-task c), and Chapter 5 presents our overall conclusions and recommendations.

2. https://plexos9.com/

Fig. 1
The acceleration in publicatiion rates since 2017. Number of publications per year *



*Searched using Scopus.com, normalized for relative comparison of acceleration of publication rate since 2017; 2023 numbers extrapolated from May 2023

Table 1
List of leaders of Task 41 and its sub-tasks

	Task leaders	*Arne Lind*	IFE and Statkraft, **Norway**
		Rob Dickinson	Hydricity Systems, **Australia**
Sub-task	**Description**	**Sub-task leaders**	**Affiliation**
a)	Data: parameters describing hydrogen technologies	*Laurence Grand-Clement*	Persee, **France**
b)	Develop knowledge of how to model hydrogen in the value chain and improve current methods	*Rob Dickinson*	Hydricity Systems, **Australia**
c)	Collaboration with analysts in IEA HQ Analytics and the ETSAP community	*Paul Dodds*	University College London, **UK**
d)	Review reports from IEA	*Arne Lind*	IFE and Statkraft, **Norway**

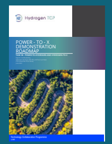
Fig. 2
The rapid growth of national and international engagement in hydrogen, in parallel with Task 41

2016	2017	2018	2019	2020	2021	2022	2023

Transition of Power-to-X from fringe to mainstream

Task 38 kick off meeting in Paris

Task 38 Final Report published



State of the industry internationally: hydrogen "opportunity" perceived to be constrained due to deficiencies in modeling

Exclusively e-collaboration throughout pandemic

1st Task 41 Task Definition e-meeting

Task 41 kick off e-meeting

Task 41 Wrap presented to H_2 TCP ExCo in Paris, Dec 2022

Key quote from Task definition:
… *"to improve collaboration between the TCP and ETSAP."*

Global engagement and interest in hydrogen's role *vis-à-vis* action on climate change took off despite modeling constraints

Observed trends of the state of the industry:

Very limited awareness outside a small group of "experts in the field"; near zero commercially viable projects

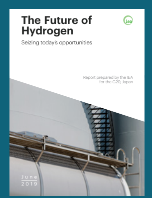
Emergence of …

- … national hydrogen Roadmaps
- … enterprises exploring investing in green hydrogen opportunities
- … enterprises reaching Financial Investment Decision (FID) on very large scale projects and component factories.
- … participation of venture capital in deals.

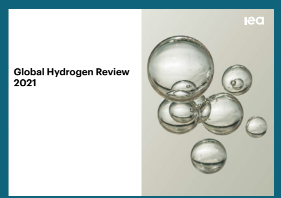
Characterization of the evolution hardware components:	kW-input scale demonstration electrolysers	MW-input scale public-private-partnership electrolyser deployments	GW-input scale factories under development; 60-GW plant for Space X fuel[1]
Scale:	~10^3 W	~10^6 W	~10^9 W

1. https://www.rechargenews.com/energy-transition/world-s-largest-green-hydrogen-project-unveiled-in-texas-with-plan-to-produce-clean-rocket-fuel-for-elon-musk/2-1-1178689

Characterization of the evolution of hydrogen energy opportunity reporting by the IEA:

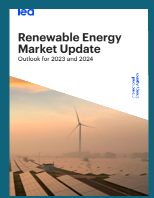


For G20 in Japan



Global Hydrogen Review 2021

Global Hydrogen Review 2022



Renewables 2022 includes renewable hydrogen

DATA:
PARAMETERS DESCRIBING HYDROGEN TECHNOLOGIES

Section 2 abbreviations

H_2 and H_2	Hydrogen
HRS	Hydrogen Refuelling Station
power-to-X	Production of renewable hydrogen from renewable electricity followed by production of other commodities
TRL	Technology Readiness Level

The objectives of Sub-task a) were to establish a data structure and data acquisition process for a sustainable database that could provide input to models used to assess hydrogen in energy systems. We aimed to provide systematic and robust data acquisition support and record valid, consistent, and boundary-constrained data. The emphasis was on recording accurate, consistent, and boundary-constrained data and supporting data acquisition and validation systematically and robustly. Each row in our database contained a technology component, a data source, a boundary condition specification, a technology readiness level (TRL, Table 2), and metadata specific to this row.

Table 2
TRLs for recording data in Sub-task a)

TRL for Sub-task a) data	Description
1-3	concept
4-5	prototype
6-7	pre-commercial demonstration
8-9	first-of-a-kind commercial demonstration
> 9	early adoption and mature

We grouped rows into:

1. **Technical specifications and parameters.**
2. **Economics parameters.**
3. **Materials, CO_2-e emissions.**
4. **Metadata that is not specific to a technology.**
5. **References and citation data.**

We aimed to record data for hydrogen production, supply chains and utilisation. We anticipated obtaining data from publications, quotes, and public reports. We planned to assemble data in a multi-tab spreadsheet, with tabs for the following categories:

- **production (SMR, green hydrogen, photocatalysis)**
- **conversion (power-to-X)**
- **transportation (energy transmission)**
- **distribution (incl. HRS)**
- **storage (of H_2 or its derivatives)**
- **end-use (final consumption of H_2 or its derivatives, incl. buildings, services, industry, transport)**

In turn, for each model in the Sub-task b) taxonomy, relevant data could be entered by participants contributing to both Sub-tasks a) and b). The generic list in Table 3 presents an early draft of our proposed top level data structure.

Similarly, the specific list in Table 3 summarises data types applicable to numerous technologies.

As we worked through this Sub-task in a rapidly evolving changing industry, the volume and scope of relevant data became increasingly challenging for a small team. Further, static tables are not well suited to rapidly evolving data, and extracting data from vendors is not trivial.

We have proposed that the Hydrogen Council develop a long-term, annually updateable online and printed report as a companion to its annual Hydrogen Insights report. To address vendors' concerns over data privacy, we propose using "data clean rooms" (walled data centres that provide aggregated performance data without disclosing data specific to any given vendor). The Hydrogen Council applied this data acquisition and recording process to the Critical Minerals data acquisition process. As presented in Fig. 3, it is easier to enumerate the Hydrogen Council members that are NOT likely to be in a position to contribute to an annual "Hydrogen Insights ++" modelling data project than it is to count the members that are likely to contribute.

"Hydrogen Insights++" could similarly be developed in collaboration with McKinsey and Company, but additionally in collaboration with modellers from IEA Hydrogen TCP and modellers from industry and commercial modelling firms.

Given the trustworthiness of the use of data "clean rooms" and the reputation and status of the Hydrogen Council, it is likely that manufacturers other than existing Council members would be willing to collaborate on providing annual updates of modelling data. Examples might include Boeing, Embraer, Zero Avia, De Havilland, ITM Power, John Cockerill, Nel, thyssenkrupp, Fortescue Future Industries, Howden, Provaris and many others.

Table 3
Preliminary draft of proposed database structure and field definitions

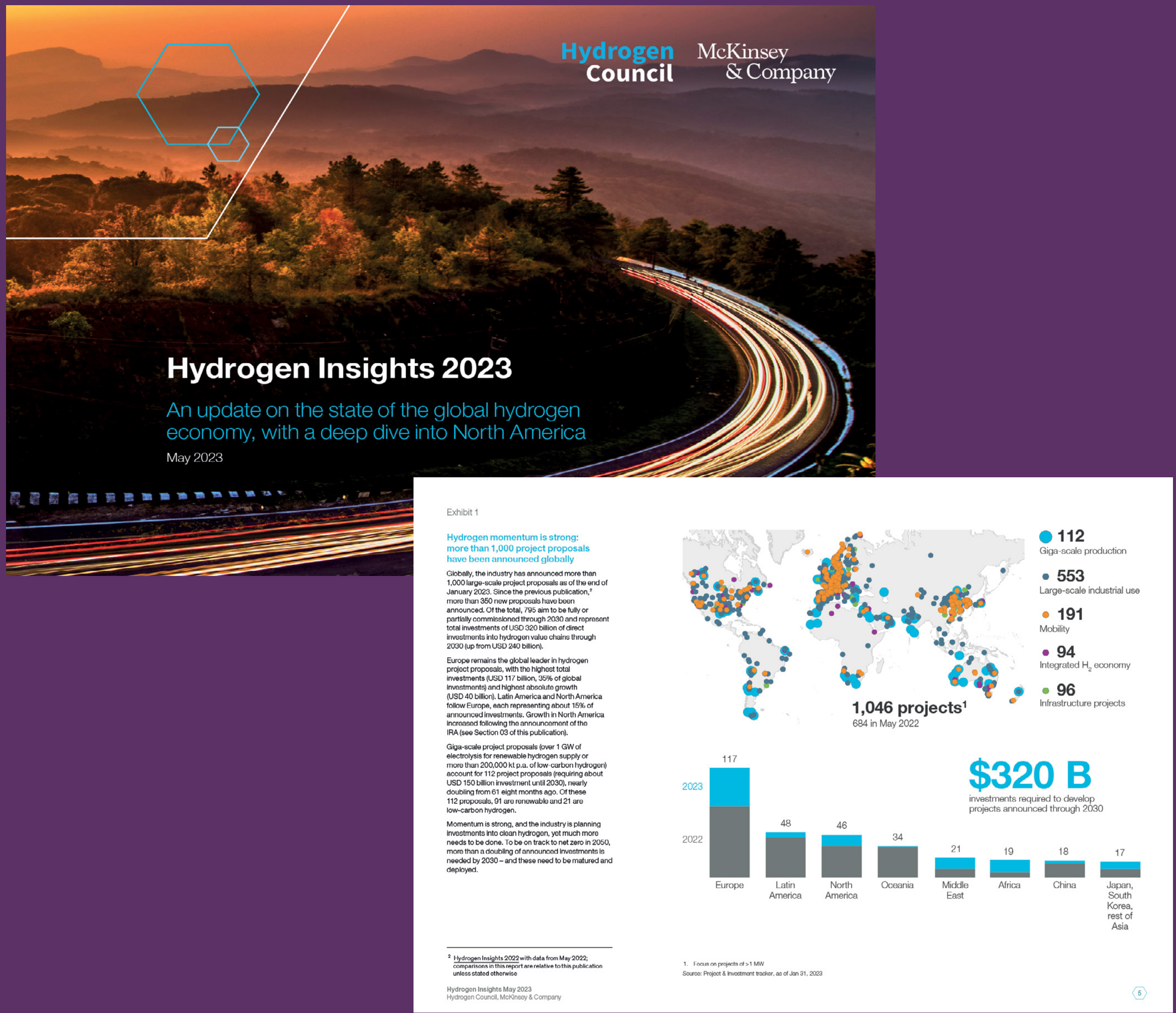
DATA SECTION	FIELD NAME	FIELD DEFINITION
Technical specification	Short name	General equipment process step (process step/value chain) [Dropdown menu]
	Technology	Equipment detailed technology (e.g.: electrolyser, reciprocating compressor, ...) [Dropdown menu]
	Description	More information and details on the equipment description and arrangement, relevant . [User free field]
	Main input commodity	Defining property of equipment - main energy or material required to fulfil its purpose. [Automatically generated from technology]
	Main output commodity	Defining property of equipment - main energy or material as a result from the process. [Automatically generated from technology]
	Other input commodities	Other defining property of an equipment - energies & materials required for operations (inputs), to be expressed as a flow. Remember to add the corresponding units.
	Other output commodities	Other property of equipment - energies & materials as a result from the process (outputs), to be expressed as a flow. Remember to add the corresponding units.
	Other specific properties	Additional relevant information that helps differentiate technologies (e.g. purity, pressure, technology type). For more detailed information please refer & link the documentation/ source of the data.
Technical parameters (General)	Capacity	Maximum output flow or available storage that the equipment has of the main output commodity. Remember to add the corresponding units.
	Conversion efficiency	The ratio between the main output commodity over the main input commodity of an energy consuming component, in energy terms.
	Losses	Losses of the main output commodity throughout operation of the equipment.
	Partial load	Define a representative partial load the equipment typically operates.
	Partial load conversion efficiency	Define the conversion efficiency given the defined partial load above.
	Operating range	% range in which the technology can operate (min/max level to start)
	Availability factor (max)	Relates the theoretical activity limit (given by the capacity) with the actual activity over a period of time, typically a year. % we can operate in a year by the equipment
	Ramp up-times (warm, cold)	Duration it takes to achieve normal output from a defined start: warm (hot idle), cold
	Technical lifetime	Technical lifetime for operation. Remember to define the unit either in years, cycles, hours, ...
	Application specific information	Open field for extra related information to the equipment.

DATA SECTION	FIELD NAME	FIELD DEFINITION
Economic parameters	Investment cost	Total CAPEX associated with installing the H_2 based product. For more detailed information of what's included please refer & link the documentation/source of the data.
	Equipment cost	Purchase costs of the H_2 based product. [Non mandatory]
	Fixed annual costs	Fixed annual costs. For more detailed information of what's included please refer & link the documentation/source of the data.
	Variable costs	Variable annual costs, related to the operation. Remember to add the corresponding units.
	Economic lifetime	Amortization period in years.
	Ramping-Costs	Costs associated with changes in operation level
	Start-Up-Costs	Costs associated to cold start
	IO cost split factors	To assess the impact of the construction of new capacities of a technologies, the split of the (economic) investment on the different economic sectors is needed (IO - Input-Output- Table)
	Learning progress/ratio	Open text field, the user should/can describe the expected cost development over time or installed capacity.
	Decomissioning costs	Costs associated to removing the equipment/process from active status.
Materials and emissions	Material for construction	Specifies the (modelled) commodities required for the contruction
	Quantity	Quantity of materials consumed for the construction
	Materials for operations	Specifies the (modelled) commodities required for the operation
	Quantity	Quantity of materials consumed for the operation
	Emissions from operations	Specifies the emissions equired from the operation - Emissions in terms of inventory (not cumulated such as GHG emissions)
	Quantity	Quantity of emissions released during the operation
Meta-data	Project size	Capacity of the overall project context where the equipment is planned or installed.
	Project year	Year the project has been built
	Reference year	Data field considered for equipment not yet installed, or built. Year the data concern (typically future equipment, or targetted technology). If they are historical data and come from a project they should match the correspond meta-data.
	Project region	World region/country where the project has been built
	TRL	Maturity of the technology/equipment. [Dropdown menu list: TRL 1-3 (concept),TRL 4-5 (prototype), TRL 6-7 (pre-commercial demonstration), TRL 8-9 (first-of-a-kind commercial demonstration), TRL >9 (early adoption + mature)]
	Construction time	Average duration it takes from equipment ordering to commisioning and start up

DATA SECTION	FIELD NAME	FIELD DEFINITION
Reference	Year	Year of the data source.
	Author	Author of the original data.
	DOI	Location of the original data.
	Contributor	Person who added the data to the database (and contact information).
	Contribution date	Date the dataset has been added to the database.
	Update date	Date the dataset in the database has been updated.

Fig. 3
Hydrogen Council's Hydrogen Insights, and potential Council contributors to "Insights++"

Existing Hydrogen Council Annual Report: "Hydrogen Insights"



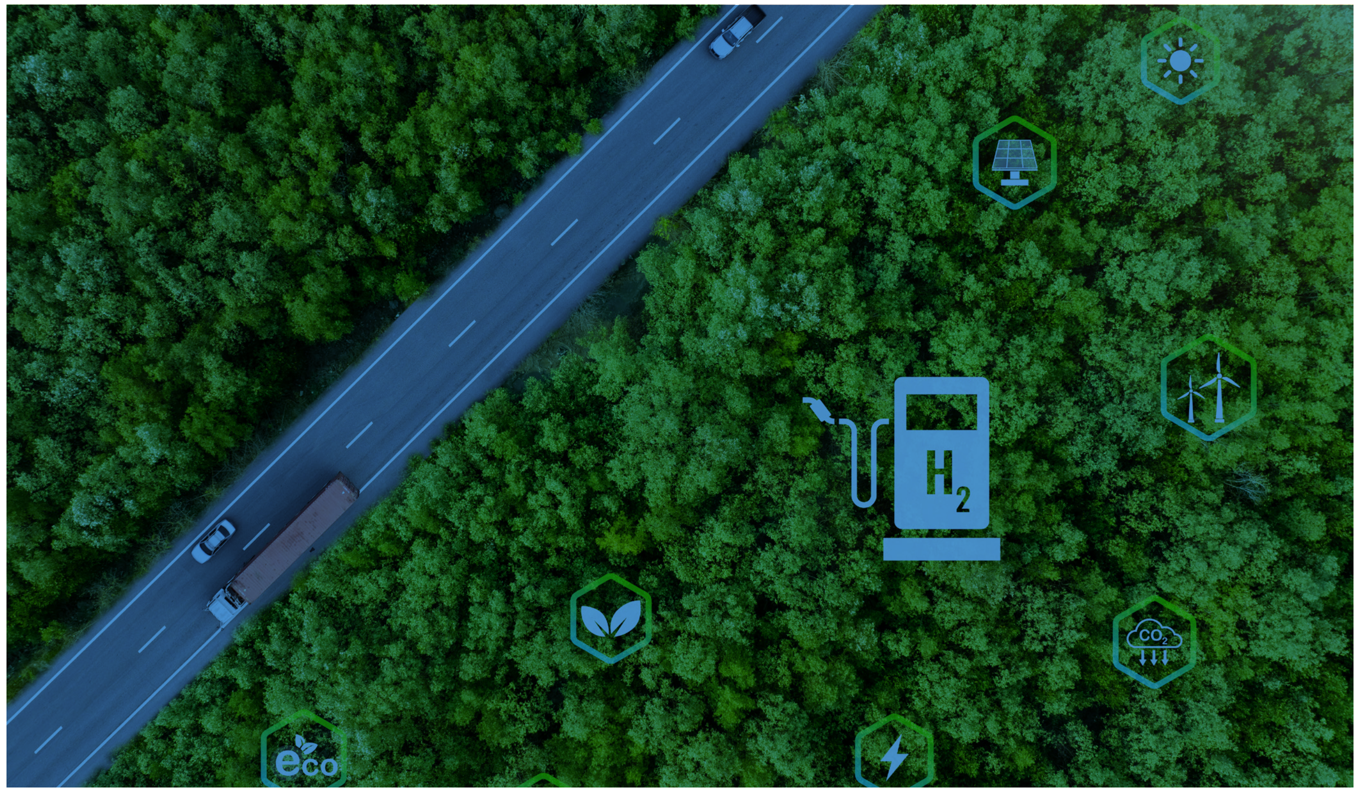
Current Hydrogen Council Members

Prospective contributors to Hydrogen Insights ++ modeling data

TOWARDS IMPROVING CURRENT MODELLING METHODS

Section 3 abbreviations

AEMO	Australian Energy Market Operator
BEVs	Battery Electric Vehicles
ESM	Energy Systems Model
ESOM	Energy Systems Optimisation Model
EU	European Union
FCEVs	Fuelcell Electric Vehicles
GHG	Greenhouse Gas
IAM	Integrated Assessment Model
IPCC	International Panel on Climate Change
ISEE Systems	Name of a modelling and simulation software developer
ISP	AEMO's Integrated Systems Plan (updated annually)
LCA	Life Cycle Assessment (i.e. assessment of the inputs and outputs across an entire commodity or product's lifecycle
LOHC	Liquid Organic Hydrogen Carrier
MWh	Megawatt hours
NEM	In Australia: National Electricity Market; In US NREL reports: Net energy metering
PJ	Petajoules
PLEXOS	Energy Exemplar product name derived from *plexus* but with OS == optimisation and simulation
PtX	See "power-to-X"
PV	Photo-voltaic solar panels
RE	Renewable Energy
SA	South Australia (the state of Australia)
SAF	Sustainable Aviation Fuel
SC	Sector Coupling
SHIPMod	UK Spatial hydrogen infrastructure planning model
SI	Sector Integration
SMR	Steam Methane Reforming
STELLA	The name of ISEE's System Dynamics Architect software
TIMES	The Integrated MARKAL EFOM Model; There are numerous versions of TIMES adapted to specific Regions and sectors
TWh	Terawatt hours
UniSyD	Unitec Polytechnic (New Zealand)'s System Dynamics energy model
VRE	Variable Renewable Energy (generally wind and solar)
VRM	... Model (Check)



The objective of Sub-task b) was to develop knowledge of how to improve modelling methods. After considering several prospective projects, we focused on a project to classify and categorise existing energy models. The outcome of this work was published in Renewable and Sustainable Energy Reviews [23]. We present a summary in Section 3.1. and highlight a specific commercial case study in Section 3.2. This work identified the need for multiresolution modelling, an approach presented in Section 3.3.

3.1 Accounting for hydrogen across a diversity of energy systems models

Energy models are computational tools used to determine the technology mix that will satisfy foreseen energy demand given expected constraints, including cost, environmental impact and resilience.

As energy systems change, new energy models emerge. Differentiators among models include a) the part of the energy system that is covered, b) geographical boundaries, and c) spatial and temporal resolution.

Given the growing role of hydrogen in energy systems, current and future energy models need to account for hydrogen, including the ways (such as flexibility) in which it differs from other energy carriers. Accordingly, we sought to understand the scopes of existing models and the questions each model is best suited to address and identify gaps and synergies.

3.1.1 Survey of modelling reviews

Following a broad overview of about 50 reviews, we assessed 29 reviews, focused on the following four steps. These steps are unpacked in more detail in Table 4.

Step 1: Identify energy model reviews with high citation score.

Step 2: Expand the selection based on references known by the authors.

Step 3: Select recent energy systems reviews that cited those from **Steps 1 and 2**.

Step 4: Identify remaining energy systems reviews not covered in **Step 3**.

We identified 124 energy model categories, aggregated them into 27 dominant classes and then clustered them into six groups for ongoing assessment (Fig. 4). Additional information on categorization is presented in Appendix A.

3.1.2 Systems characteristics for accounting for hydrogen

Having classified general energy models, we identified nine system characteristics that would be required to robustly account for hydrogen in energy models (Table 5) and determined that the general taxonomy (Fig. 4) needed to be adapted to the specificities of hydrogen. We developed a taxonomy for hydrogen models (Fig.4) that uses four of the nine system characteristics (methodology, complexity, topology, spatio-temporal representation) in the top level of its hierarchy.

The above characteristics highlight the need to adapt the general taxonomy (Fig. 4) to the specificities of hydrogen (Fig. 5). The four significant categories of

1) methodology,
2) complexity,
3) topology, and
4) spatial and temporal representation,

provide the top level of the taxonomy hierarchy.

3.1.3 Strengths, weaknesses, applications and challenges of each model archetype

Based on the new taxonomy, we identified nine archetypes (Fig. 6, Table 5) and considered the relationships among them (Fig. 6) and their attributes (Table 6).

The figures referred to in Table 5 are presented below Table 6.

3.1.4 Other challenges

Other challenges we highlighted in the taxonomy work, applicable to various archetypes, included the following:

Uncertainty from innovation processes (learning curves):

- On-site hydrogen production at community, commercial, and industrial levels.
- Process and delivery methods for import/export of hydrogen.
- Ships, aircraft, trains, and heavy vehicles that use hydrogen fuel.
- Recovery of high-purity hydrogen from geological storage in abandoned oil and gas reservoirs
- Recycling and disposal of hydrogen technology components.
- Fuel cells, electrolysers, and batteries.

Emerging technologies, such as:

- Both transportation and stationary applications could potentially benefit from solid storage.
- All models will potentially need to account for hydrogen production using emerging technologies, including catalyst-based hydrogenation from renewable resources and photocatalysis.

Table 4
The criteria used to include/exclude reviews

Include reviews if:	Exclude reviews if:
They had an extensive classification system and involved a cross-comparison of specific models.	They only had a few non-exhaustive categories to classify models or did not apply them to specific models **[24-38]**
They did not include an extensive survey of models but propo-sed a model taxonomy that was complex enough to compare with other reviews **[39-43]**.	They focused exclusively on challenges and gaps **[44, 45]**.
They reviewed many models despite using limited categories **[46, 47]**	They focused on a narrow aspect of the energy system or the energy transition without extensively reviewing the classification **[48-54]**
They were a meta-analysis of reviews **[55-58]**	They focused on a scenario or output comparison rather than a model comparison **[59-62]**.

Fig. 4
Taxonomy to classify energy system models; Source: Adapted from **[23]**

Table 5
Nine system characteristics for accounting for hydrogen in energy models

Characteristic	Description
1. System-wide scope	Hydrogen energy involves multiple sources, applications, sectors, and derived outputs. Hence, modelling must account for all production, transmission, transformation, and application pathways.
2. Services to power grids	Electrolyzers can adjust their load to follow VRE generation and provide frequency control ancillary services. Robust modelling needs to account for these capabilities.
3. High temporal resolution	Modelling the flexibility of electrolysers requires an adequate time resolution. For example, a coarse time resolution is inadequate for assessing the potential for integrating electrolysers and VRE production.
4. Life cycle assessment	Hydrogen does not emit CO_2 when burned or reacted in fuel cells. But there are CO_2-e emissions associated with production, transport, and conversion.
5. Systemic drivers	System drivers, such as GHG mitigation ambitions and carbon taxes, motivate hydrogen deploy-ments.
6. High spatial resolution	VRE production and water availability distribution each require sufficient spatial resolution to capture spatial constraints.
7. Consumer behavior	Many models use cost optimization, but a broader range of consumer behaviours drives some hydrogen applications.
8. Development uncertainty	No one can predict the future with certainty. But model features such as assessing the sensitivity of respective parameters are as crucial to hydrogen modelling as they are for net zero energy production.
9. Climate variability	Weather and climate affect VRE production and hence hydrogen storage capacity requirements.

Fig. 5
Taxonomy to classify models based on hydrogen modelling requirements; Source: [24]

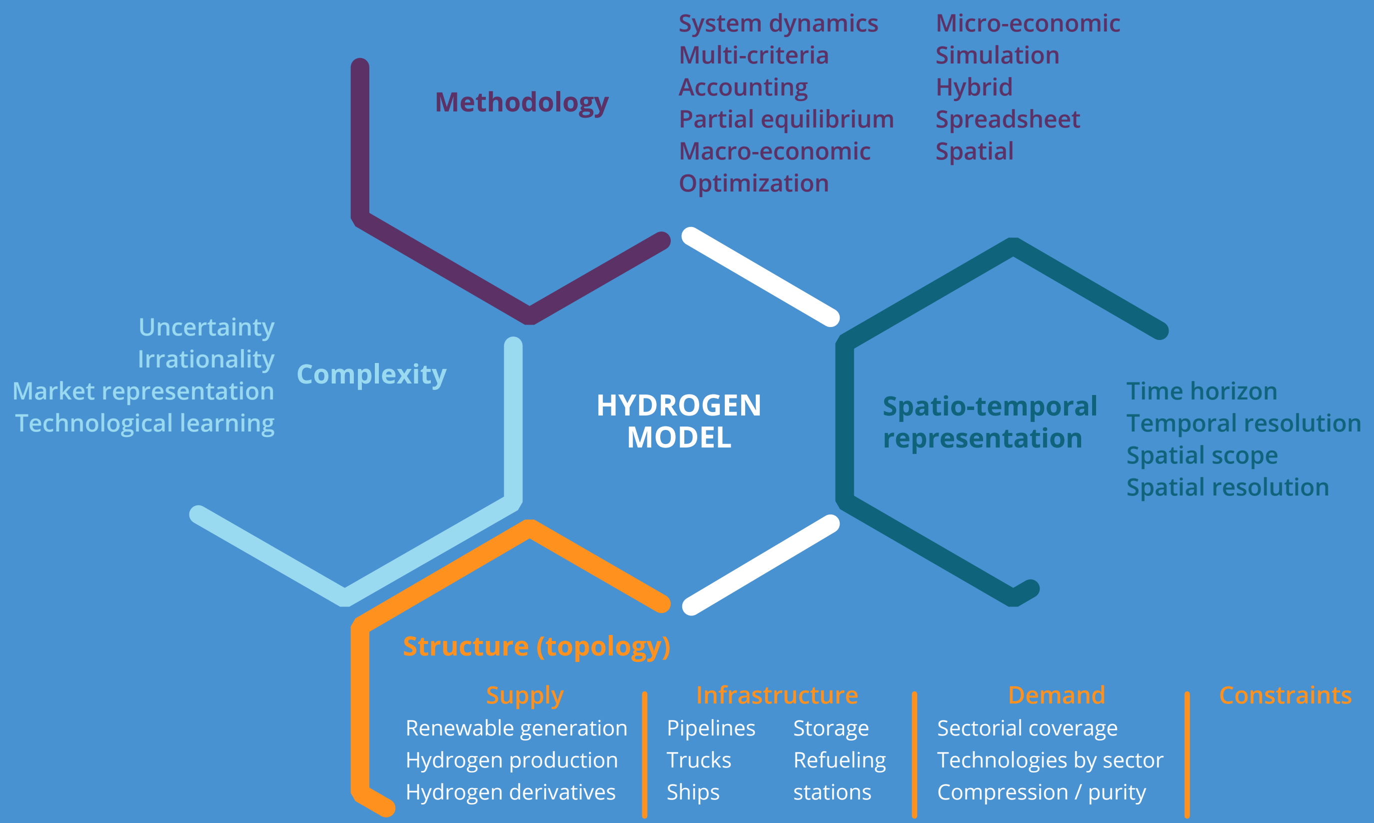


Fig. 6
Boundaries, overlaps, and interconnections between archetypes; adapted from [23]

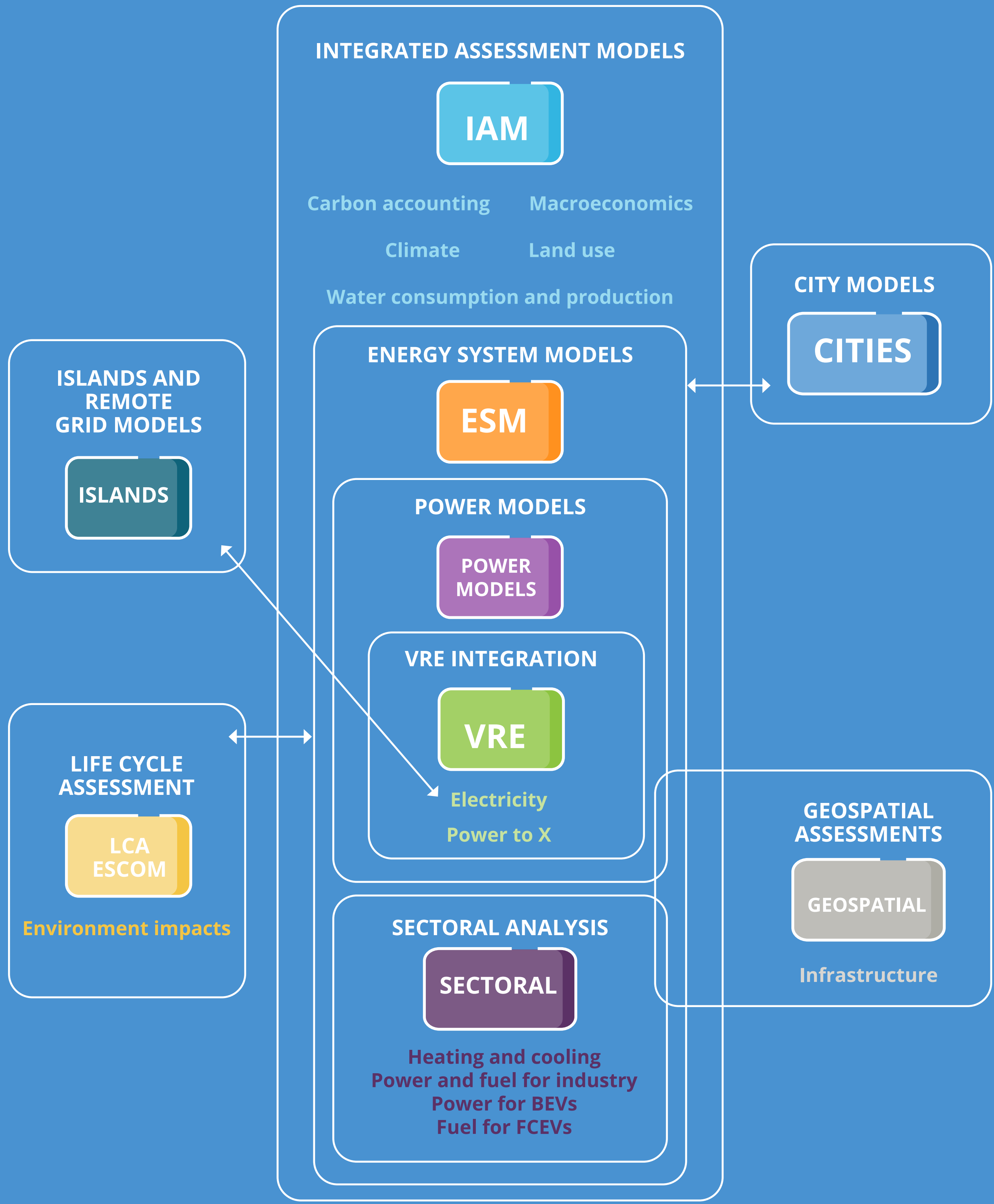


Table 6
Overview of applications, strengths, weaknesses, and challenges of each model archetype

Archetype	Context and applications	Strengths		Weaknesses	Challenges	Archetype
Integrated Assessment Models (IAM) IAM	***Integrated assessment models (IAMs)*** are widely used to understand the options for and consequences of reducing greenhouse gas (GHG) emissions and have featured prominently in all five IPCC reports. They are valuable because they represent the development of interacting human and earth systems (e.g., energy, economy, climate, and land use) **[63]**. Ten of the 18 examples in Table 7 describe hydrogen production. Fig. 7 presents a screenshot of some of the datasets used in IAMs.	• Relationship with climate and global heating • Coverage of land use and total CO_2-e emissions • Consideration of macroeconomy • All energy consumption included		• Conversion of hydrogen to derivative products is usually excluded • Some hydrogen pathways are excluded • IAMs have limited temporal and spatial resolution • Some models can lack technological detail	Integrated assessment models (IAMs) Most IAMs and ESMs only deal with FCEVs, leaving many other valuable applications unaccounted for. Hydrogen derivatives such as ammonia and synthetic aviation fuels (SAF) have future roles but are typically not accounted for. ESMs model vast areas and long periods, so they must have low spatial and temporal resolutions to remain tractable. These resolutions are incompatible with the need to capture dispatch interval variability in grid-connected green hydrogen production.	Integrated Assessment Models (IAM) IAM
Energy System Models (ESM) ESM	***Energy system models (ESMs)*** provide for exploring the potential evolution of energy systems in future decades [52]. ESMs deliver an understanding of economically efficient decarbonization pathways by counting GHG emissions from all sources and constraining total future GHG emissions. Very few ESMs have sufficient spatial resolution to adequately model the lower initial costs of developing hydrogen valleys or industrial clusters. And for electricity specifically, regions with a high proportion of VRE require a high temporal resolution to capture the economic opportunity of power to fuel integration. This resolution is much higher (smaller time interval) than that used in ESMs in the past. The adaptation of the ETSAP TIMES model presented in Section 4 of this report is an example of an optimization application of an ESM. ETSAP users have applied this model to develop least-cost energy production predictions in many countries. Fig. 8 presents the inputs and outputs of generic TIMES models. Another approach to ESM modelling is System Dynamics [64], an example of which in our Task is UniSyD [65-67]. UniSyD (e.g., Fig. 9) is a model developed at New Zealand's Unitec using STELLA Architect by ISEE Systems [78].	• All energy consumption included • More detail of all hydrogen pathways and trade-offs with alternative carriers • Constraints can be added to capture aspects not covered in the model • Adaptable in scale and scope • Can evaluate the potential of power-to-X pathways		• Limited temporal and spatial resolution • Limitations for VRE integration and storage representation • No market representation • Environmental aspects beyond CO_2-e emissions are usually excluded • Hydrogen is typically only defined as an energy carrier • ESMs do not account for consumer behavior	Energy System Models (ESM)s also have resolutions that are incompatible with the need to capture dispatch interval variability in grid-connected green hydrogen production	Energy System Models (ESM) ESM

Archetype	Context and applications	Strengths		Weaknesses	Challenges	Archetype
Power models POWER MODELS	***Power system models*** optimize generation capacity while fulfilling carbon abatement targets, subject to increased electricity demand [1, 69]. Fig. 10 presents the relationships and connections between VRE, Power, and Off-grid models within power system models. An example of a commercial power system model that integrated hydrogen during Task 41 is Energy Exemplar's PLEXOS. The following sub-section of this report presents this system in more detail.	• Flexibility, VRE integration and grid expansion • Can have technical constraints for operating thermal generators • Can handle individual units instead of aggregated • Can represent day-ahead, reserves and balancing markets • Can represent actual dispatch times series (e.g., 5 minutes) (i.e. High temporal resolution) • Yields an understanding of curtailment and hydrogen storage		• Limited to the power sector and other sectors are fixed demand at best (no PtX pathways) • Hourly resolution limits geographical scope or resolution • No environmental aspects • Hydrogen role is limited to the interface with the electrolyser	Power system models: As with IAMs and ESMs, low spatial and temporal resolution is needed to capture the impacts of long-term weather variability on VRE and hydrogen production. Again, these resolutions are incompatible with the need to capture dispatch interval variability. Simplifications include the use of time slices [70], rolling horizon [71, 72], or a green-field approach [73-78].	Power models POWER MODELS
Integration models for variable renewable energy VRE	***Integrated models for variable renewable energy (VRE)*** are a subset of power models (Figs. 10,11). These models focus on the interfaces between green electrolysis and power grids. Examples of their use are assessing VRE's impact on power price fluctuations [79,80] and off-grid applications [81,82].	• Can assess techno-economic feasibility • Can develop business models for hydrogen production based on VRE • Yields an understanding of curtailment and hydrogen storage • High temporal resolution		• Focused on electrolysers to increase wind penetration • Other sectors are excluded • Lack of environmental, market and policy aspects • Typically static in time	Integration models for variable renewable energy (VRE): For example, quoting [83], "the integration of solar PV and electrolysis is shown to provide a mutually beneficial relationship, both operational and economic. With the exception of the islanded system, when PV and electrolysis are integrated, the breakeven cost for producing hydrogen reduces between 20% (NEM) and 70% (wholesale)." The mutuality (integration) here is PV electricity and hydrogen production. The extent to which these outcomes might apply more generally is unclear.	Integration models for variable renewable energy VRE
Models focused on Cities CITIES	***Energy models for cities:*** Most of the global population lives in cities. Hence the role of local governments is crucial in deploying critical aspects of national hydrogen targets: specific to the scales of given cities. This process defines the role of energy models for cities. This archetype was recently applied to Burdur, Turkey [84]. Other examples of applications to cities include [85,86].	• Supports real-world conditions in with substantial consumer demand for hydrogen • Enriches urban integrated planning		• Few modeling precedents • Focused on transport sector • No precedent for hydrogen	City-level modelling rarely uses ESMs compared to more geospatially broad ESM applications. Hence ESMs or other models capable of accounting for hydrogen will need to be applied to city energy modelling in the coming years.	Models focused on Cities CITIES
Islands and remote off-grid ISLANDS	***Islands and off-grid systems*** are those located on remote islands and on-shore systems where long-distance electricity transmission from grid power is not cost-effective. Renewable energy is increasingly displacing trucked-in fossil diesel and gas. The scope of models in this archetype cover either power and fuel or electricity alone (e.g., Fig. 12). With a modest quantity of off-shore floating wind power production, it would presumably be possible to transform the excess VRE to fuel to make the island in Fig. 12 100% Renewable.	• Can assess techno-economic viability • Provides for a range of optimization objective functions • Enables flexibility to deal better with power surplus and deficit • Provides a range of prospects for 100% VRE on islands		• Requires accurate estimation of meteorological data and load demand • Risk of oversizing storage equipment • Risk of VRE curtailment	Given the variability of RE in remote applications, providing security of supply is often critical. Hybrid energy systems comprising more than one energy source are crucial for optimizing system costs [87, 88] and exploiting the complementarity of diverse resources.Another challenge is the requirement for adequate time resolutions, which is becoming a recurrent theme.	Islands and remote off-grid ISLANDS

Archetype	Context and applications	Strengths		Weaknesses	Challenges	Archetype
Sectoral analysis SECTORAL	***Sectoral applications*** focus on system sectors, including electricity, fuel, transport generally [89], passenger vehicles specifically [90], and heating [91]. These models potentially provide a more focused representation of the technologies, the actors, and the system's evolution, than other archetypes. During the period of Task 41, cross-sector coupling (SC) modelling, otherwise known as sector integration (SI) [92], developed into a mainstream approach frequently presented at industry conferences.	• Allows a detailed technology representation for specific sectors • Enables the use of a wide range of business cases • Allows the use of a broader set of criteria to determine hydrogen use		• Omits interaction with the rest of the energy system • Partial view of climate and economic impacts • Does not fully capture benefit of technologies with multiple carriers and services	Sectoral applications: Focusing on a single sector fails to capture multiple energy carrier price dynamics. This failure led to a recent rise in sector-coupling models [92]. A key challenge for sectoral models is the same as for ESMs and others: transitioning to high temporal resolution while remaining tractable.	Sectoral analysis SECTORAL
Geo-spatial analysis and Networks GEOSPATIAL	***Geospatial and network models*** assess hydrogen supply chains [93]. Examples include the UK's Spatial hydrogen infrastructure planning model, (SHIPMod) [94] and VWM [95-97]. Supply chain models covering various component scales use mixed-integer math. (e.g., Fig. 13)	• High spatial resolution within individual sites and infrastructure • Can optimize infrastructure with increasing demand over time • Provides detailed scenarios for production and transport • Provides connections to population densities for identifying the optimal production sites and distribution centres.		• Hydrogen demand is fixed • Environmental, policy, and market aspects usually excluded • Underutilization of assets • VRE integration and power flexibility typically excluded • Usually limited to a region or single country	Ideally, supply chain models with detailed spatial and temporal resolutions need to consider interactions with other sectors (e.g., through power-to-gas). Low-resolution models do not fully resolve these interactions. Some models (e.g., [96]) selectively represent alternatives to hydrogen. Modelling small regions with high potential demands ("valleys" [98]) is gaining momentum, but work is needed to develop models of large areas across long periods.	Geo-spatial analysis and Networks GEOSPATIAL
Integrated Life Cycle Assessment (LCA) and hydrogen ESOM LCA ESOM	***Integration of Life Cycle Assessment (LCA)*** and Energy Systems Optimization Models (ESOM) augments ESOMs with assessments of the sustainability of the lifetime of systems. There are two integration approaches: 1) the use of ESOM outputs as input to LCA studies [99]; 2) the integration of life-cycle sustainability indicators within ESOMs [100-103]	• Provides knowledge about environmental impacts • Enhances scenario narratives when dealing with sustainability in general		• Difficult to harmonize entities across modeling approaches • Conflicting system boundaries • Risk of double-counting (e.g., CO_2-e emissions)	LCA studies [99,104] can implement foreground and background life-cycle inventories to enhance indicators implemented in the model. Current LCAs are limited to a national scope and road transport [103]. Expanding to broader areas and multiple sectors, including hydrogen, requires care to avoid double counting [100].	Integrated Life Cycle Assessment (LCA) and hydrogen ESMs LCA ESCOM

- Power models must account for electrolysers' benefits to provide revenue-generating services to the grid and dispatch-interval-resolution power price dynamics associated with VRE production.
- Many models will increasingly need to account for combined heat and power applications.

Commerical and resource developer models:

- Rates of return in commercial and industrial sectors on investment in hydrogen technologies and how these may vary as the technology matures.
- The propagation of hydrogen refuelling stations remains a significant uncertainty in many parts of the world.
- Regarding fair comparisons across scenarios, models need to internalize externalities such as health and pollution costs at local, regional, and global levels.
- In large-scale green hydrogen exports, certification processes increase the certainty of the value payable at destinations. Nevertheless, this value remains unproven relative to conventional resources.

3.1.5 Conclusions from Section 3.1

Many energy-consuming services can benefit from hydrogen integration, and no single model archetype can capture all of hydrogen's complex interactions and prospects for contributing to decarbonization. We documented each archetype's strengths, weaknesses, and limitations and considered the relationships between archetypes.

A key recurring theme for modelling green hydrogen integration across many archetypes is the need for dispatch-interval time resolution while maintaining overall computational tractability. Section 3.3 presents an approach to resolving this complex issue.

3.2 A sector-coupling case study

POWER MODELS

GAS MODELS

The following sector coupling case study is pertinent because it uses hydrogen to couple the power and gas sectors [109].

From a techno-economics perspective, the most fundamental difference between the power and gas sectors is that power is sold up to 12 times per hour (5-minute intervals), and gas economics uses long-term marginal costs. The units of electricity sales are MWh per dispatch period. The units of gas sold are petajoules (PJ) per some long-term period.

"Ultimately, we're seeing interest in hydrogen development from both power markets and from gas markets alike. However, the nature of these interests coming from both sectors are different" [109].

"European power markets see the key value in hydrogen as the most commercially ready and scalable technology for energy storage to essentially synchronise the unpredictable intermittency that comes with high grid penetration of renewables" [109].

"On the gas side, hydrogen would basically take over the mantle of a burnable, physical fuel that can relatively easily be incorporated in today's existing gas value chains and infrastructure" [109].

"Commercial optimisation modelling and an acute understanding of how disparate fundamentals interact, hybridise and compete will be critical to make the transition efficient and minimise the costs to consumers"

Table 7
Hydrogen production representation in 18 examples of IAMs; data from **[105]**

IAM	AIM - Enduse Japan	AIM - Hub	BET	BLUES	COFFEE - TEA	China TIMES	DNE21+	GEM - E3	IFs	IMACLIM	IMACLIM - NLU	IMAGE	IPETS	MESSAGE - GLOBIOM	POLES	REMIND	TIAM - UCL	WITCH
Coal w/o CCS					●	●						●		●	●	●	●	
Coal w/ CCS			●		●	●						●		●	●	●	●	
Natural gas w/o CCS				●	●	●						●		●	●	●	●	
Natural gas w/ CCS				●	●	●						●		●	●	●	●	
Oil w/o CCS				●	●							●			●			
Oil w/ CCS				●	●							●						
Biomass w/o CCS				●	●							●		●	●	●	●	
Biomass w/ CCS				●	●							●		●	●	●	●	
Nuclear														●				
Solar												●		●				
Electrolysis	●		●	●	●	●						●		●				

Fig. 7
An example of the vast data sets used in comprehensive IAMs: Source [106].

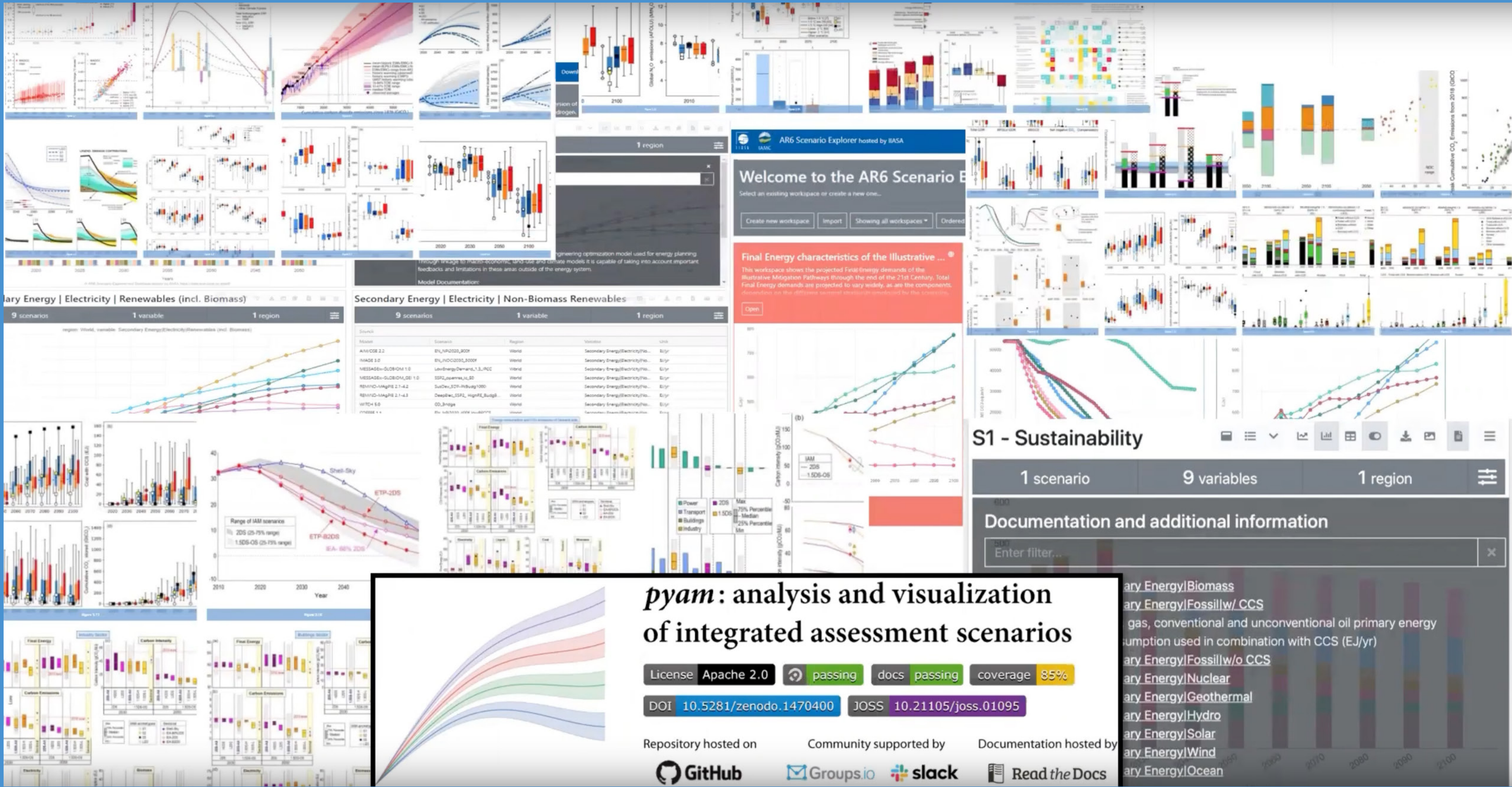


Fig. 8
A simplified representation of data flow into ETSAP TIMES; Source [107]

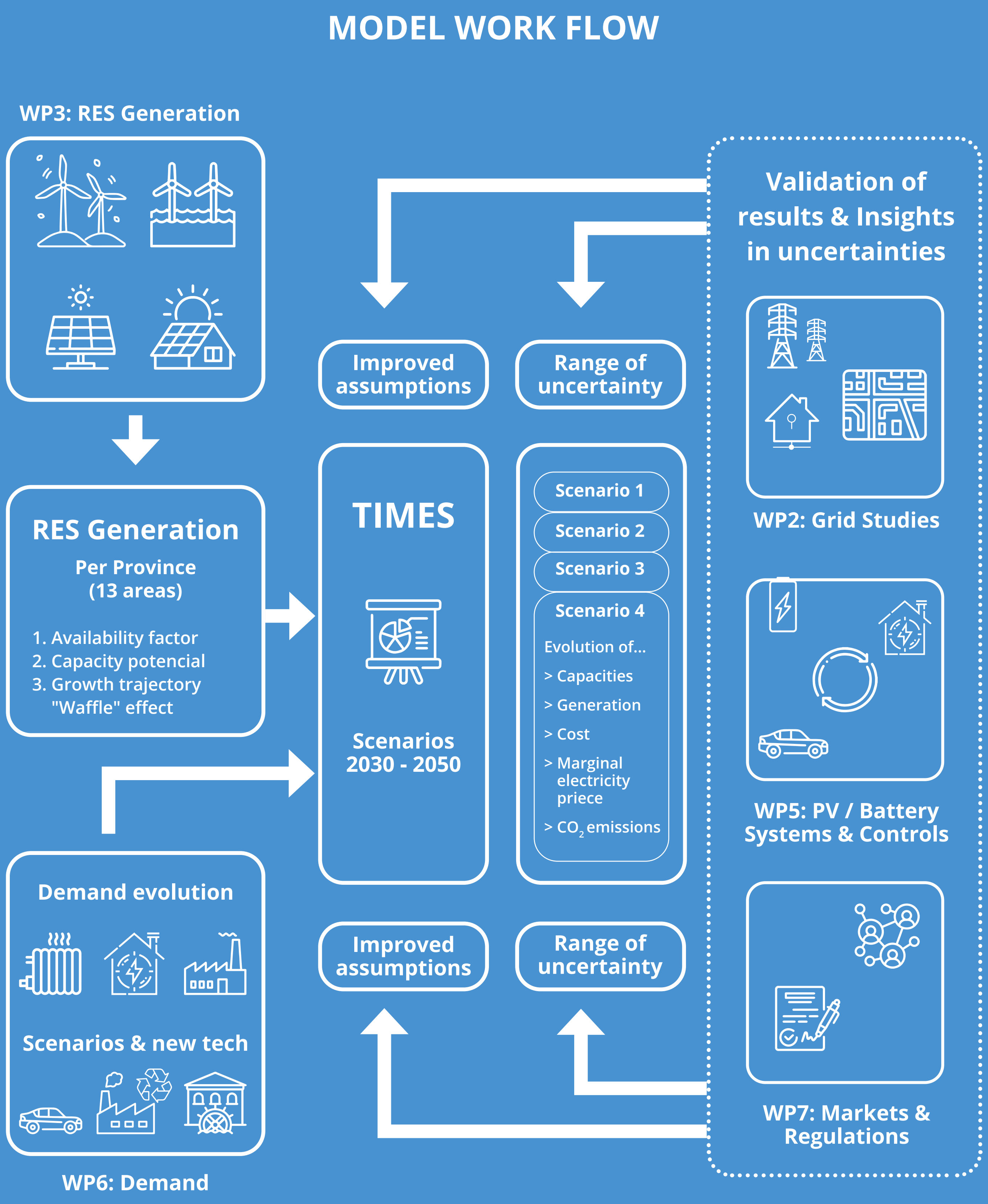


Fig. 9
An example of a UniSyD model block diagram; Source [65]

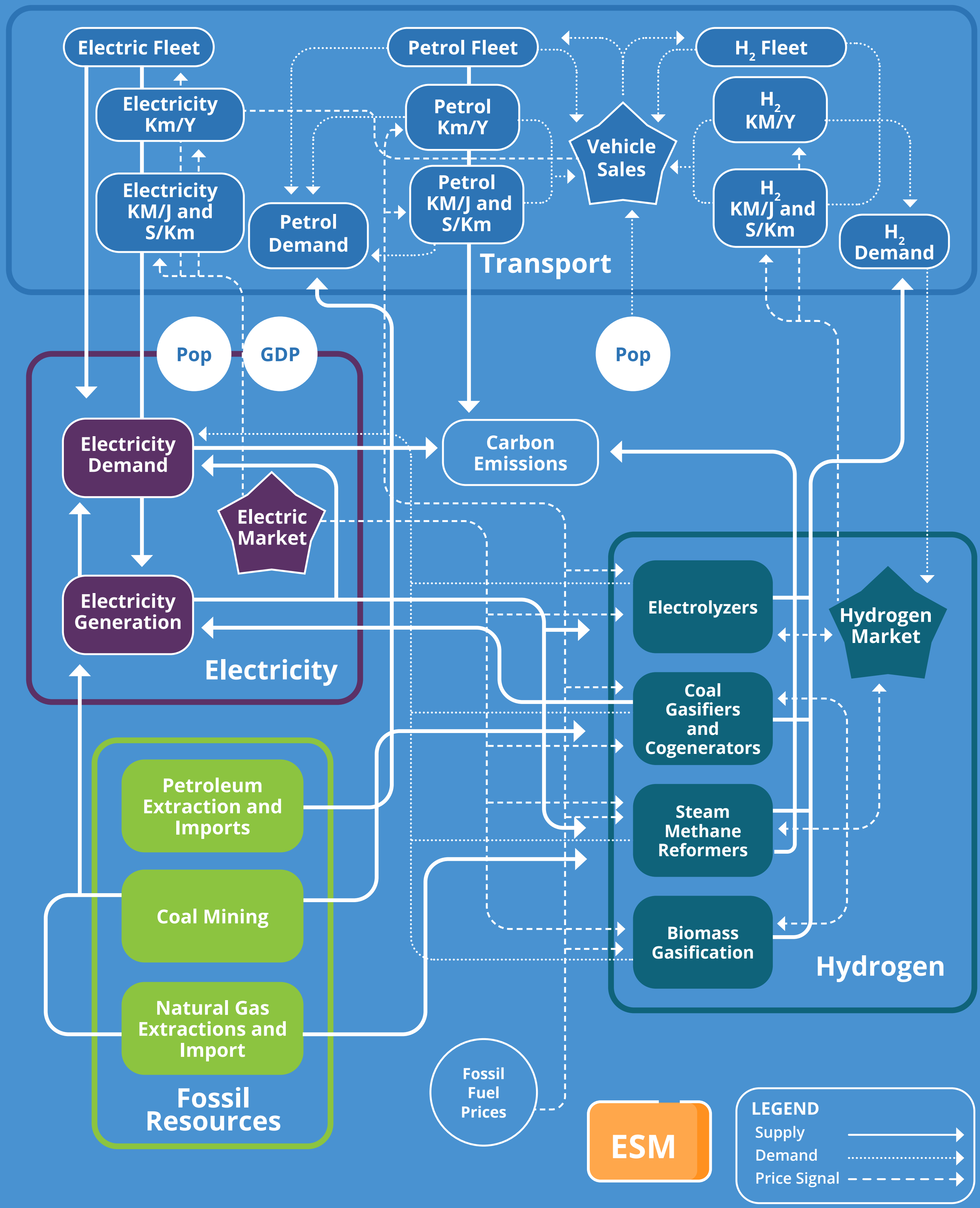


Fig. 10
Roles for VRE models, power models, and off-grid models; Source: [23]

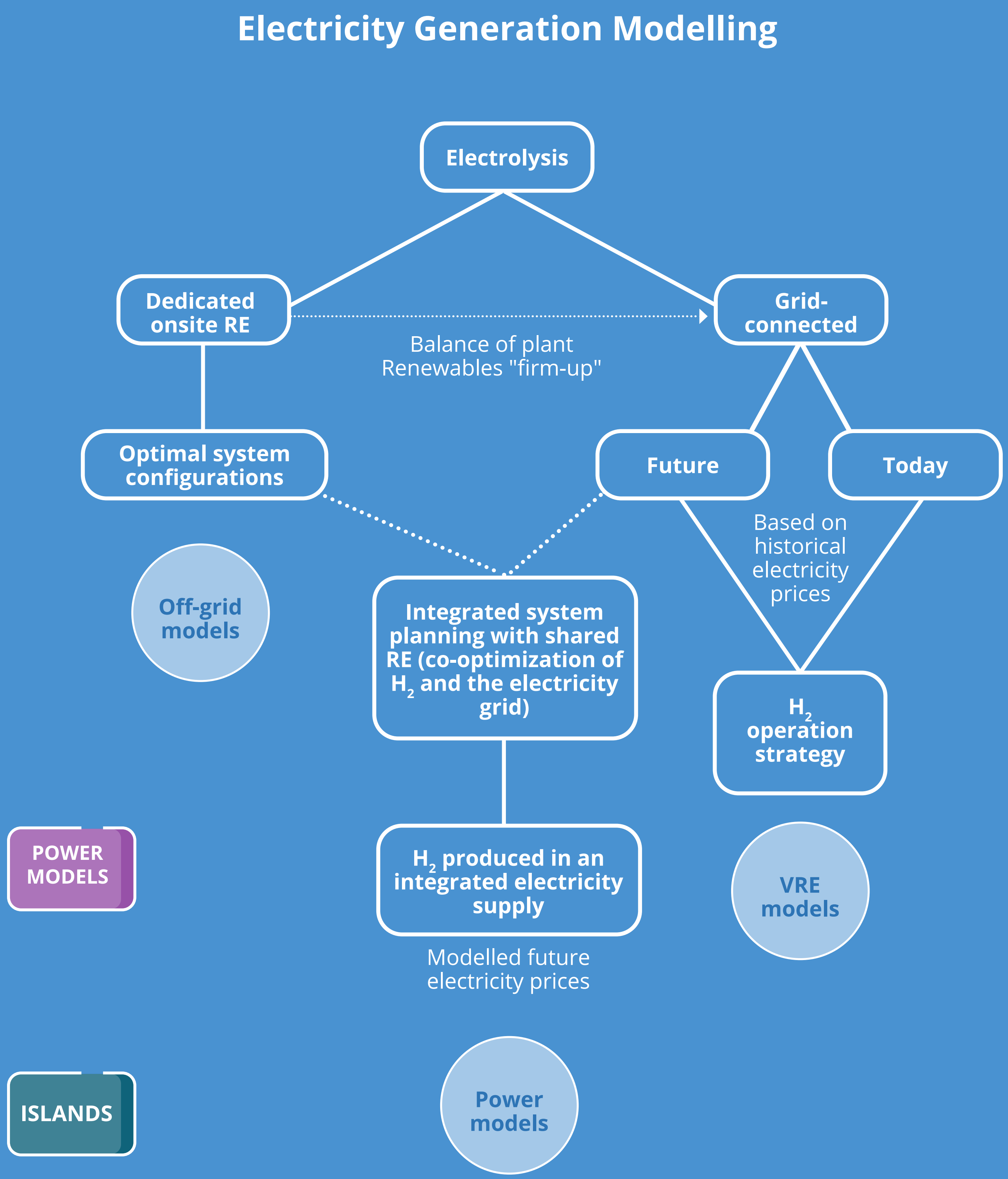


Fig. 11
PV power and electrolysis markets in an integrated VRE model; Source: [83]

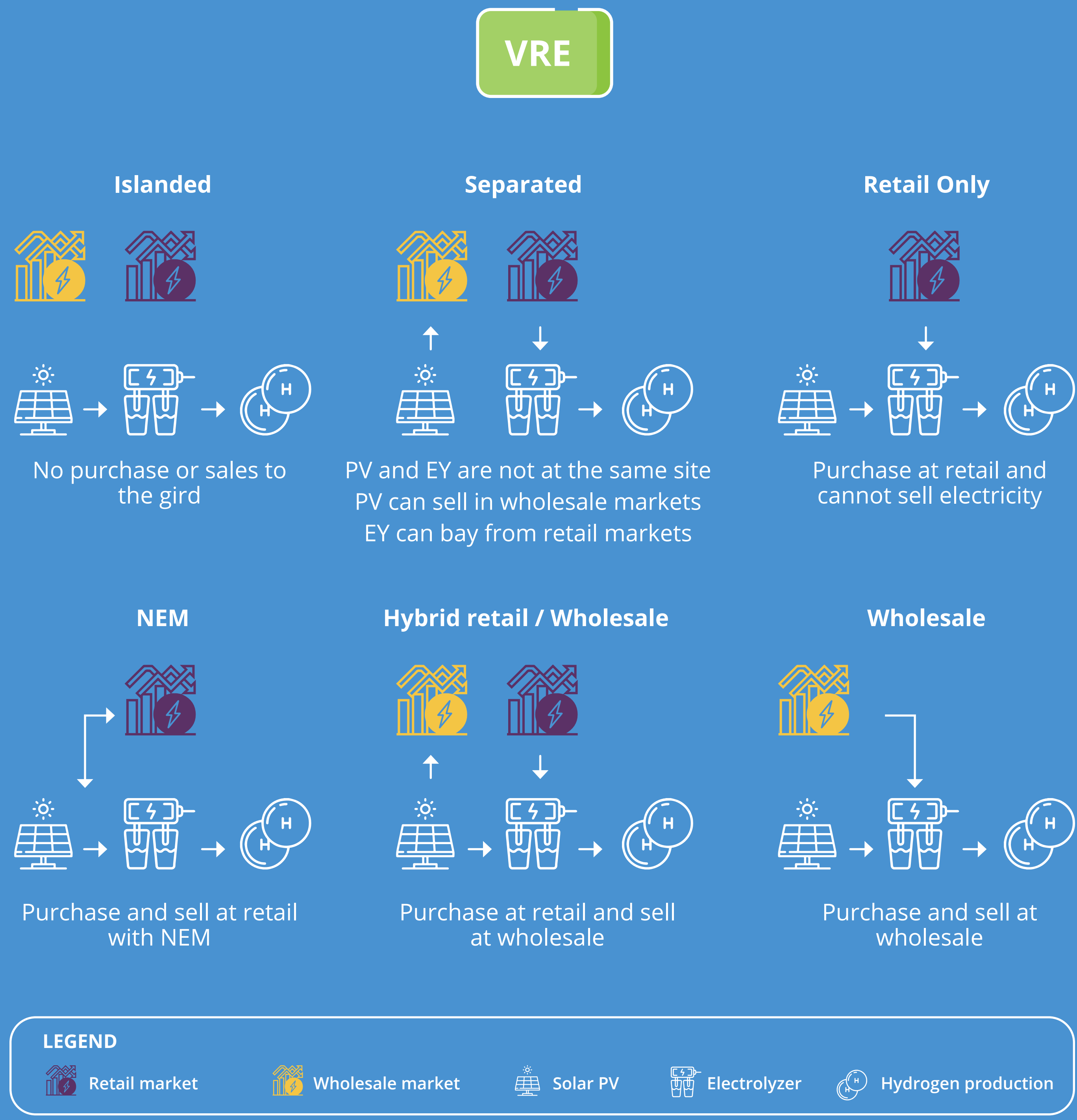


Fig. 12
A UNESCO heritage example of an island electricity-only project: [108]

Fig. 13
Evolution of the UK hydrogen supply across 2 model scenarios: [94]

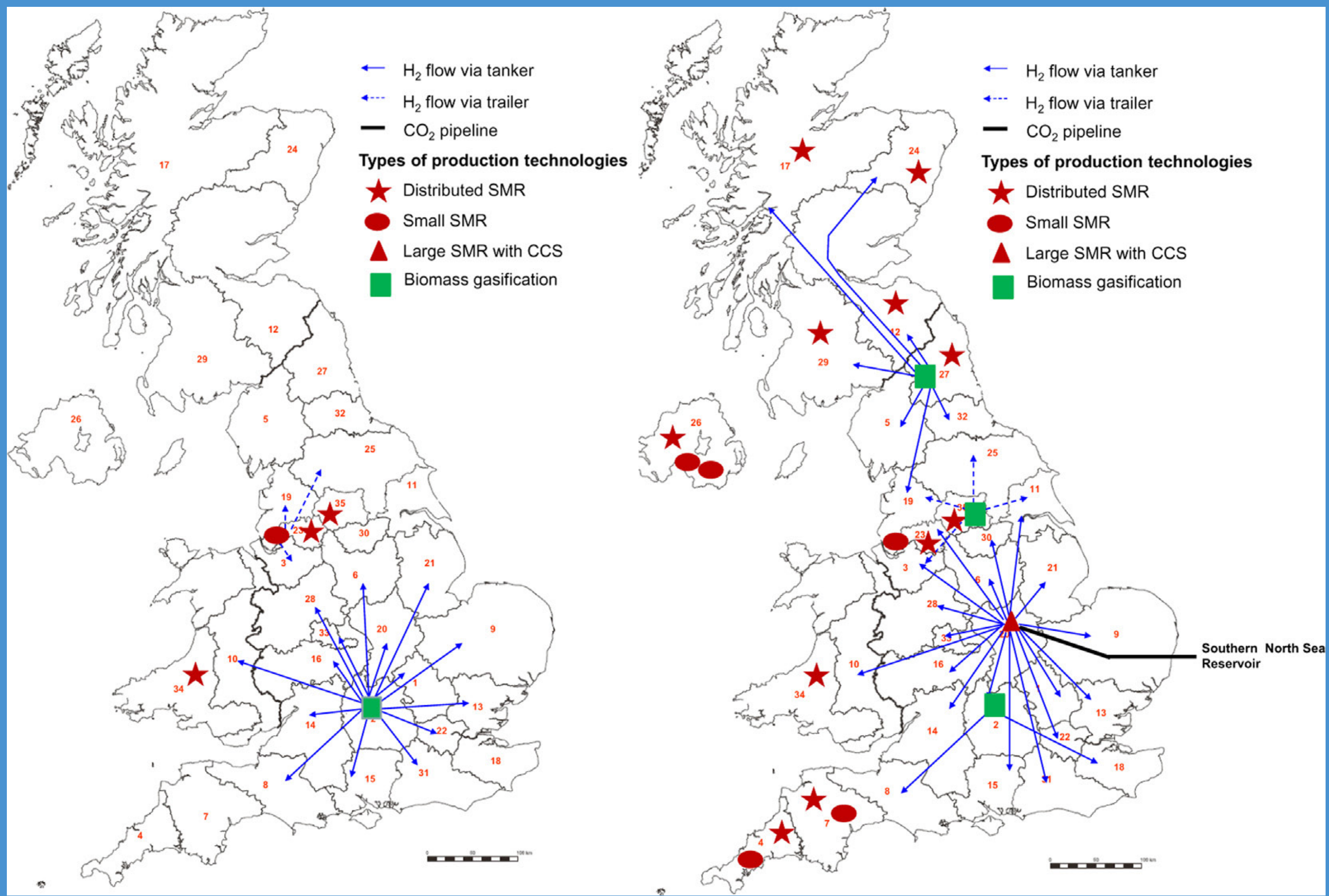


Fig. 14
Case study: Gas and power sectors assessed for coupling using hydrogen [109]

Gas sector data in PLEXOS

Gas:
- > Gas Fields
- > Gas Plants
- > Gas Pipelines
- > Gas Nodes
- > Gas Demands
- > Gas Contracts
- > Gas Transports

Spain, Portugal centric gas network

Power sector data in PLEXOS

Electric:
- > Generators
- > Fuels
- > Emissions
- > Storages
- > Reserves

Transmission:
- > Regions
- > Zones
- > Nodes
- > Lines

Power generation

170 Generators (gas, hydro, nuclear, solar, wind, etc.)

The above quotes about economic drivers for the power and gas sectors are from EU observations, but they apply in many other Regions[1], including Australia [110,111].

This study [109] assesses co-optimised power and gas markets on the Iberian Peninsula (Spain and Portugal), including a commitment to hydrogen until 2030 (Fig. 14). The sector-coupling mechanism arises from observing that hydrogen can uniquely span power and gas market fundamentals. The goals of the study are:

- **to predict the role of hydrogen in the evolution of power or gas fundamentals (prices), and**
- **to estimate the potential price points of merchant hydrogen in the Iberian region.**

1 Regardless of system "optimization" processes, curtailment is always unambiguously an "opportunity lost".

In addition to the potential benefits of spanning power and gas market price drivers, hydrogen offers respective sector benefits as follows, quoting [109, Energy Exemplar User's Conference]

"Power sector:

- Electrolysers provide grid flexibility by helping to mitigate renewable energy intermittency
- Electrolysers can meet demand swings and facilitate seasonal energy storage
- Power to fuel contributes to decarbonising power grids and supply
- Stored hydrogen enhances electricity supply security

Gas sector:

- Hydrogen can reduce emissions in the hard-to-decarbonise sectors, especially where direct electrification is challenging to achieve (e.g. steel manufacturing and chemical production)

- Hydrogen can contribute to decarbonising domestic heat and the heavy transport sectors
- Deploying power to fuel can avoid having to write off [...] assets and infrastructure"

The study's conclusions include:

1. Price cannibalisation from renewables in power markets is commercially unsustainable as it relies on curtailed energy (see Section 3.3 below).
2. We must model and understand power-gas in combination to understand hydrogen's role in the lower-case energy transition.

3.3 Integrating multiple resolution techno-economics assessments

A key outstanding issue for almost all of the model archetypes in Section 3.1 is the trade-off between (1) the need for computational tractability (computing solutions within an acceptable time frame) and (2) the need for dispatch-interval time-resolution to capture variability in VRE production and its influence on electricity prices. The latter is vital because hydrogen plays many roles in the energy system. Let's recap some of these:

- Green hydrogen is a VRE consumer, providing the opportunity for VRE capacity growth in excess by far of supplying conventional operational electricity demand.
- Electrolytic hydrogen from nuclear power balances production during periods when fixed power output exceeds conventional operational electricity demand.
- Dynamically variable green hydrogen production empowers VRE producers to deliver products during periods when they would otherwise be curtailed
- Green hydrogen is a carrier of large-scale VRE production via pipelines or ships and as liquid, gas, or a derived hydrogen carrier such as ammonia or LOHC (liquid organic hydrogen carrier). In the case of pipelines, this can easily be intermittent pumping, accordingly to variable production.
- Green hydrogen is a fuel source for green electricity production in large-scale turbines and transport (e.g. heavy duty road and rail, aviation and shipping).
- Green hydrogen provides a medium for large-scale (even seasonal) energy storage.
- Electrolytic hydrogen production can provide revenue-generating frequency control ancillary services (FCAS). This revenue is over and above the income from selling hydrogen. (Hydrogen production is a commodity \$/kg h_2). FCAS is a service, \$/MWh[2])
- Other hydrogen production pathways (e.g. photocatalytic hydrogen) could potentially compete with other producers in the future.

In summary, hydrogen plays the following concurrent roles:

- Electricity consumer
- Network balancer
- Curtailment avoider
- Large-scale carrier
- Fuel source
- Large-scale storage
- Network services provider

2 e.g., https://wattclarity.com.au/articles/2020/02/fcas-matters-more-than-ever/

All of these roles involve time variation in one way or another. The time scale of large-scale storage is months, and for ancillary services: seconds. But for most of the archetypes in Section 3.1, such short time steps are at odds with a tractable computational model (the time it takes to deliver a solution for a given scenario). Accordingly, in this section, we seek a techno-economics model for this variation first and foremost, initially independently model archetype.

We use the South Australia (SA) Region (market) of Australia's National Electricity Market as a case study because it provides a world-leading instance of a *high and increasing proportion of VRE concurrently with substantial constraints on the capacity to export electricity to adjacent Regions[3] (markets).*

3 We use "region" to refer to areas beyond cities, and "Region" to refer to a specific electricity market.

Along with SA's ambitions to grow towards 200% VRE by the 2030s and 500% by 2050, the SA Region provides an ideal "laboratory" for trialling novel ways of integrating increasingly large-scale VRE production with increasingly large-scale new consumption technologies such as power-to-fuel. It is vital to emphasize that what matters most here, for system design purposes, is the proportion of VRE production, not the overall scale of a Region in terms of TWh of production and consumption per year.

In equations 1 to 4 below, and the following figures, the following variables are set and recorded at each dispatch interval.

RRP_{SA} = Regional Reference Price for the SA Region of the NEM

$f(\dots)$ = a formula of the statistical relationship between the dependent variables and electricity spot prices

$ODem$ = Operational (conventional) demand (load, **consumption**)

$Wprod$ = Wind power **production**

$Sprod$ = large scale* **solar production**
*roof-top solar production is accounted for as reduced operational demand

$VREprod$ = $Wprod + Sprod$

$VREcurt$ = VRE curtailment -- e.g., "spilled" wind and/or rooftop[4] and/or large scale solar excess production supply relative to operational demand

$VREi$ = impact on system design: $VREi = Wprod + Sprod + VREcurt$

$DemMarket$ = future demand market, operated over and above conventional demand. Any low-power-price following electricity-consuming technology can bid to consume at each dispatch interval. Electrolysis is very well suited to this role.

4. e.g. Regulations in Australia already allow AEMO to remotedly shutdown rooftop solar when required.

1998-2010: $$RRP_{SA} = f(ODem) \quad (1)$$

2010-2016: $$RRP_{SA} = f(ODem - VREprod) \quad (2)$$

2017-2024: $$RRP_{SA} = f(ODem - VREprod - VREcurt) \quad (3)$$

2025-2050: $$RRP_{SA} = f(ODem - VREprod - VREcurt + DemMarket) \quad (4)$$

In Figs. 15 to 22 below, we hypothesize that there is a direct relationship between the price at each dispatch interval and the variables on the right-hand side of equations 1 to 4. In subsequent figures, we present statistics that confirm this hypothesis.

Figs. 23a and 23b qualitatively support the notion of an inverse relationship between an increasing VRE proportion and the frequency and values of negative prices. In these dispatch periods, producers effectively pay consumers to consume their product. Theoretically, producers jump out of the market quickly in this circumstance. This is easy for VRE producers but difficult for thermal turbine producers.

As mentioned above, Figs. 15 to 23 present data supporting the hypothesis of the price relationships in equations 1 to 4. They show the impact of increasing VRE power production, exacerbated by decreasing minimum operational demand.

Figs. 24 and 25 below introduce actual price relationship data to support this hypothesis. These graphs were produced using the following continuous statistical distributions.

In the price relationship figures below, equation 5a forms the foundational relationship. Equations 5c and 6 are examples of continuous statistic functions f in equations 1 to 4. These higher-level functions represent the variability of price above and below the linear equation 5a. Equation 5c adapts the Weibull distribution, and equation 6 uses the t-Location-Scale distribution. Pdem can be either operational demand (actual), market demand (modelled), or both.

$$RRP_0 = (P_{dem} - S_2) / S_1 \quad (5a)$$

$$\Gamma(x) = \int_0^\infty e^{-t} t^{x-1}\, dt \quad (5b)$$

$$RRP_{LD}(P_{dem}) = RRP_0(P_{dem}) + \frac{\Gamma\left(\frac{\upsilon(P_{dem})+1}{2}\right)}{\sigma\sqrt{\upsilon(P_{dem})\pi}\;\Gamma\left(\frac{\upsilon(P_{dem})}{2}\right)} \left(\frac{\upsilon(P_{dem}) + \left(\frac{P_{dem} - \mu(P_{dem})}{\sigma(P_{dem})}\right)^2}{\upsilon(P_{dem})} \right)^{-\left(\frac{\upsilon(P_{dem})+1}{2}\right)} \quad (5c)$$

$$RRP_{HD}(P_{dem}) = RRP_0(P_{dem}) + \delta_{HD}(P_{dem}) + \frac{b_{HD}(P_{dem})}{a_{HD}(P_{dem})} \left(\frac{P_{dem}}{a_{HD}(P_{dem})} \right)^{b_{HD}(P_{dem})-1} e^{-\left(\frac{P_{dem}}{a_{HD}(P_{dem})}\right)^{b_{HD}}} \quad (6)$$

Where

a **(*P_{dem}* or *P_{us}* or *P_{os}*)**	= Scale parameter of Weibull distributions
b **(*P_{dem}* or *P_{us}* or *P_{os}*)**	= Shape parameter of Weibull distributions
P	= Power demand or production, MW or GW
dem	= Generic (operational) regional demand
HD	= High Demand RRP(P_{DEM}) model invoked when demand is above $P_{LD\text{-}HDswitch}$
HD-LZ	= High Demand concurrent with Low zero-source-cost supply availability.
LD	= Low Demand RRP (P_{DEM}) model invoked when demand is below $P_{LD\text{-}HD,switch}$
LD-HZ	= Low Demand concurrent with High zero-source-cost supply availability.
os	oversupply = zero-source-cost supply availability minus demand: $P_{Z\,os} = P_Z - P_{dem}$
us	undersupply = demand minus zero-source-cost supply availability: $P_{Z\,us} = P_{dem} - P_Z$
RRP	= Regional Reference Price (t) for a Region, $ / MWh
S	= linear shape match parameters of the 0th order model of RRP (P)
δ (*P_{dem}* or *P_{us}* or *P_{os}*)	= location parameter of Weibull distribution
μ (*P_{dem}*)	= location parameter of t-location-scale distribution, $/ MWh, is a function of P_{dem}
σ (*P_{dem}*)	= scale of t-location-scale distribution, $/ MWh, is a function of P_{dem}
v (*P_{dem}*)	= degrees of freedom of t-location-scale distribution (dimensionless), is a function of P_{dem}
0	as in RRP_0 = 0th order RRP (P_{dem})
1,2	subscripts designating offset and scale parameters in RRP_0 model
Equation 5b)	is the gamma function

Fig. 15
Case study: A decade of continuously declining minimum demand (load); Data from **[112]**

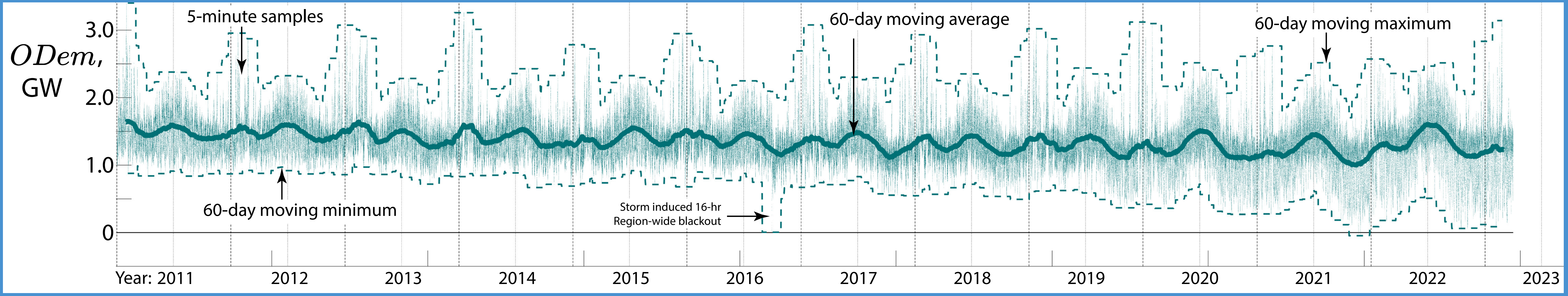


Fig. 16
Case study: A decade of continuously increasing wind power production; Data from **[108]**

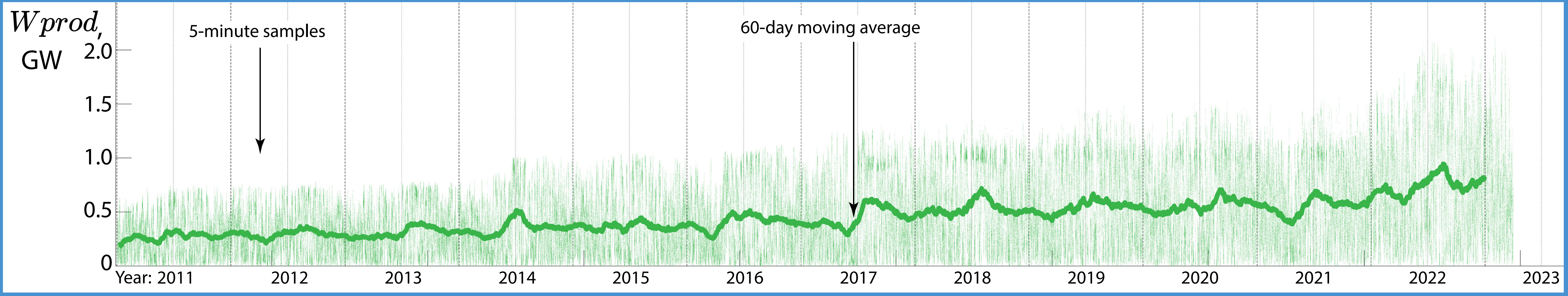


Fig. 17
Case study: 5 years of continuously increasing large scale solar production; Data from **[108]**

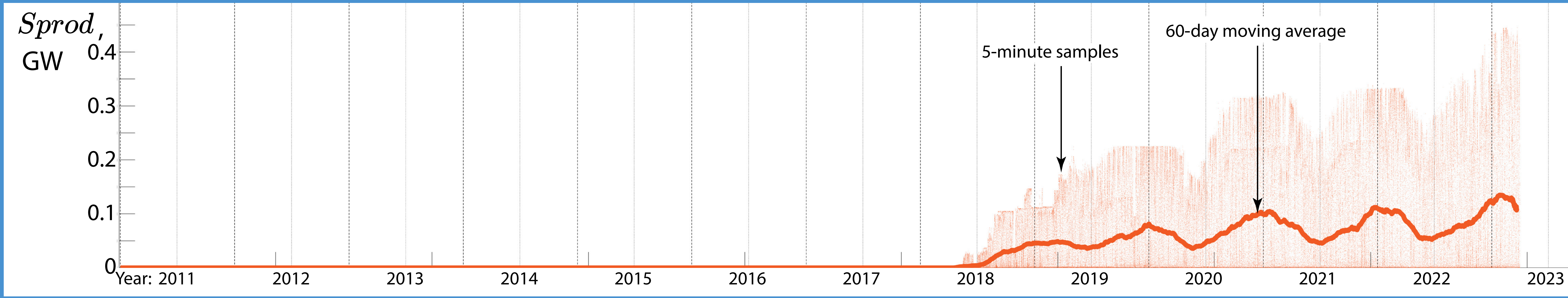


Fig. 18
Case study: 5 years of continuously increasing VRE Curtailment; Data from **[108]**

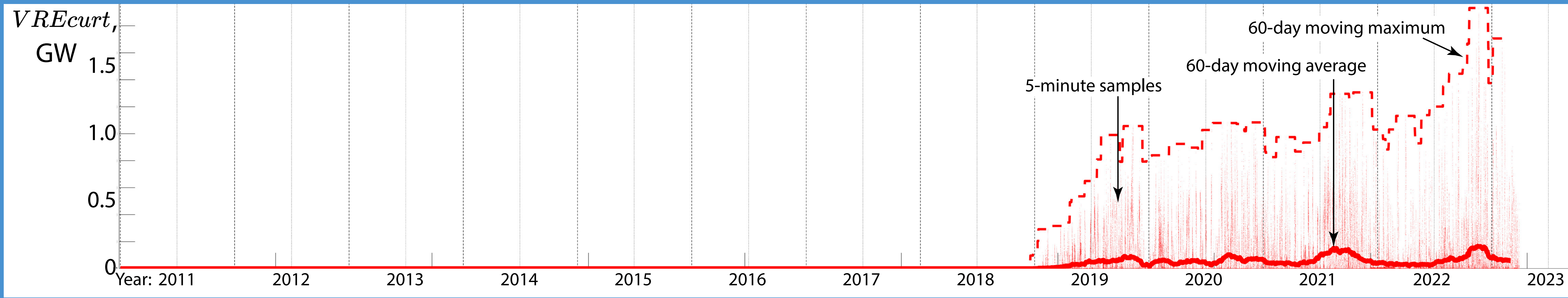


Fig. 19
Case study: a decade of continuously increasing VRE impact on markets; Data from [108]

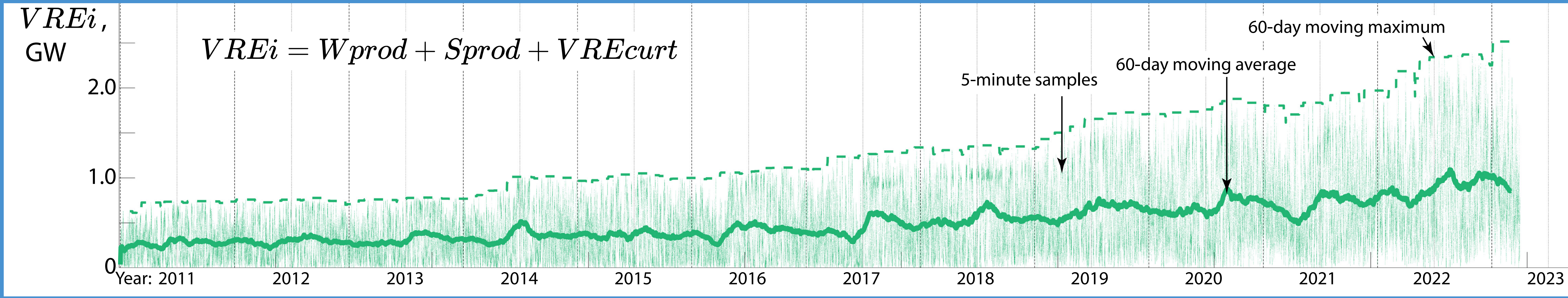


Fig. 20
Case study: a decade of continuously declining miinimum demand minus VRE; Data from [108]

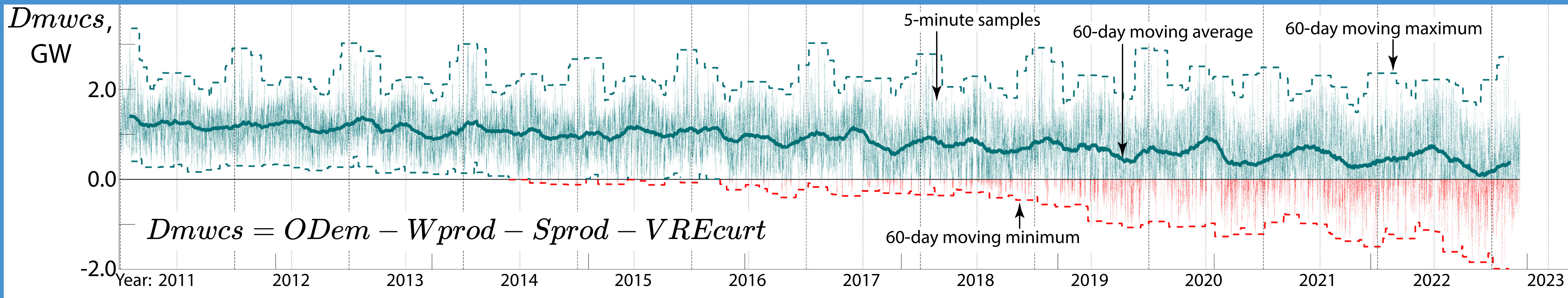


Fig. 21
Case study: increasing availability of low-input-cost power-to-fuel (DemMarket scatter)

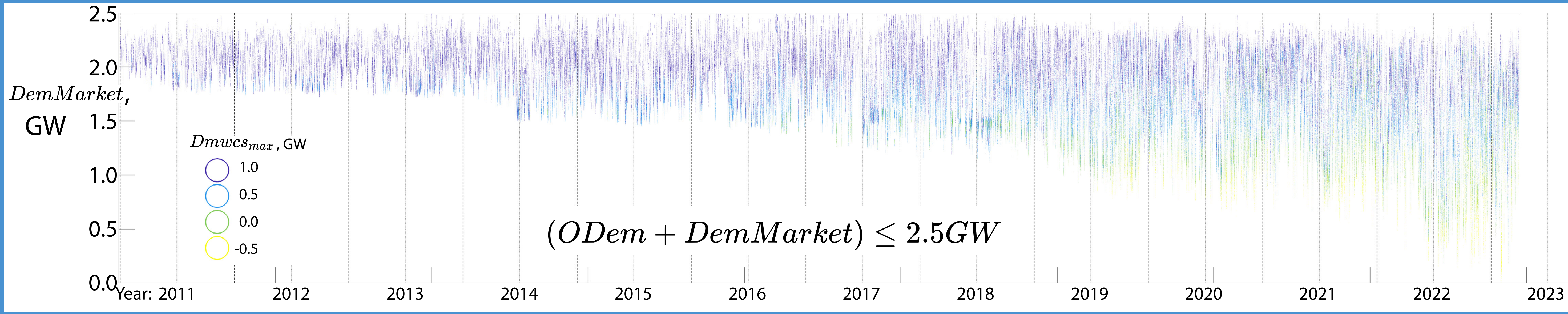


Fig. 22
Case study: increasing availability of low-input-cost power-to-fuel (DemMarket avgs)

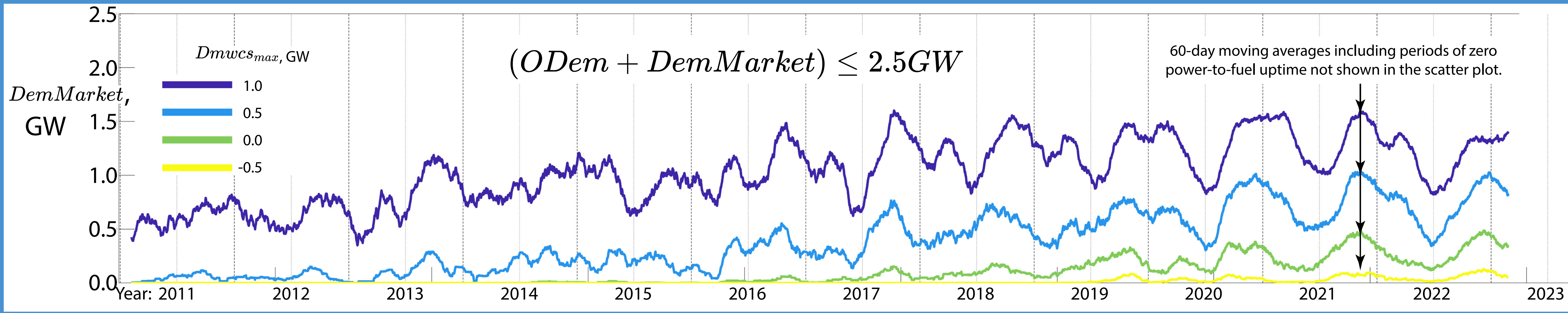


Fig. 23 a
Case study: increasing frequency of negative-prices with increasing VRE

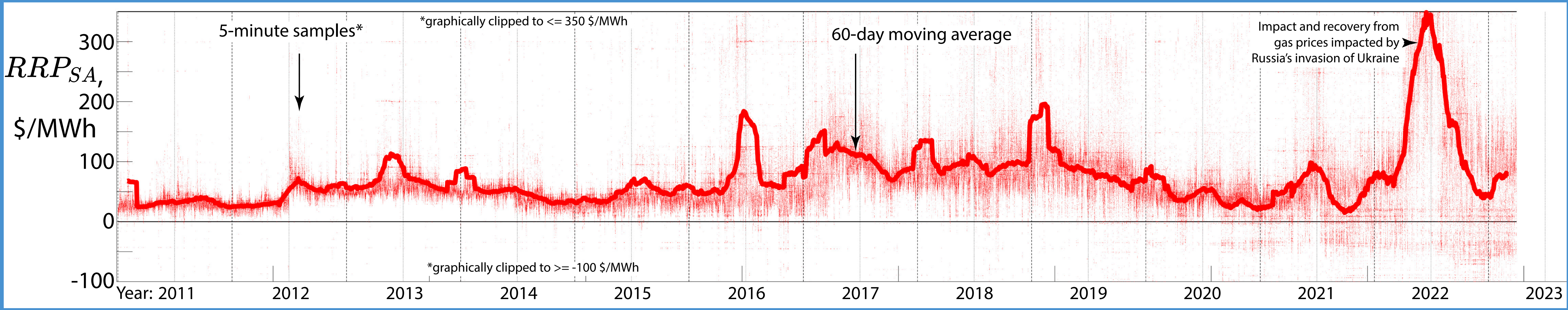
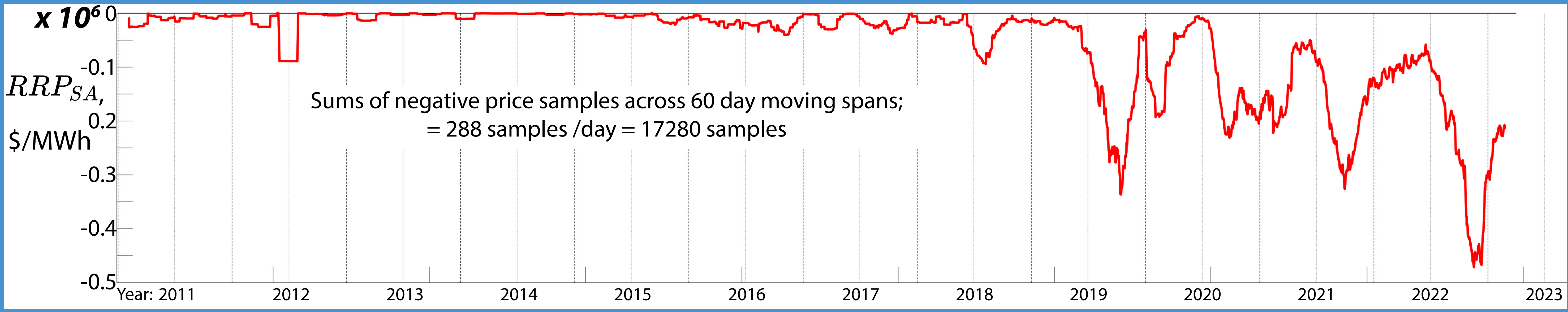


Fig. 23 a
Case study: increasingly negative negative-price accumulation with increasing VRE



Figs. 26 and 27 show the variation of model parameters concerning the proportion of VRE. This sequence does not account for increasing prices from other source drivers (e.g. inflation). However, the significant primary departure from the norm, aside from the downward negative-prices trend, is the peak in 2022 due to Russia's invasion of Ukraine.

The variation of model parameters in equation 5a, used for the plots in Fig. 26, is presented in Fig. 27.

With continuous models of price as a function of operational demand, total VRE production, and a prospective demand market, we can review the numerics of deploying a demand-side bid stack alongside current supply-side bid stacks.

Fig. 24
Case study: A blended probability density surface of demand (eqn 5c, 6)

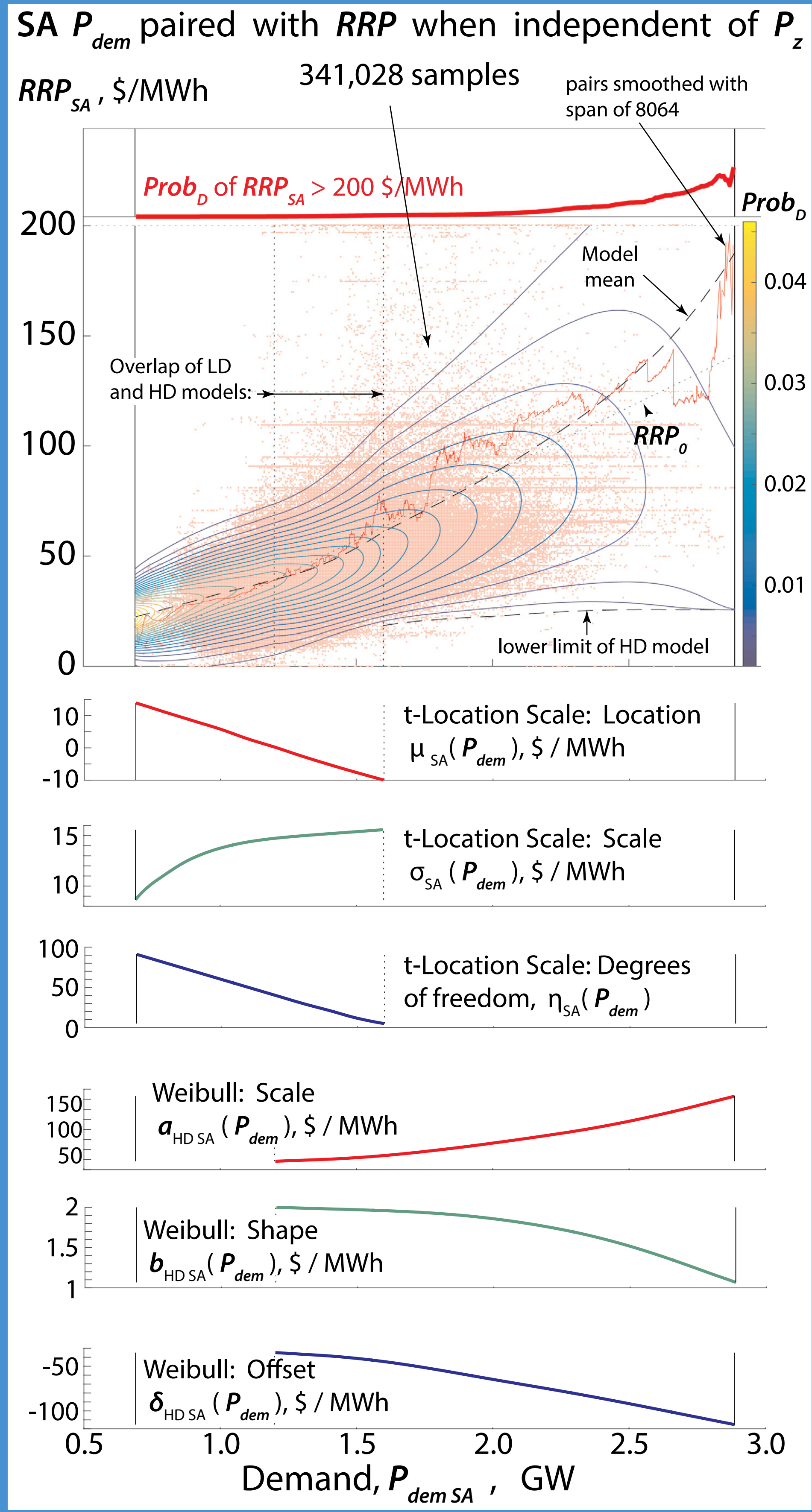


Fig. 25
Case study: A probability density surface of low demand (eqn 5c)

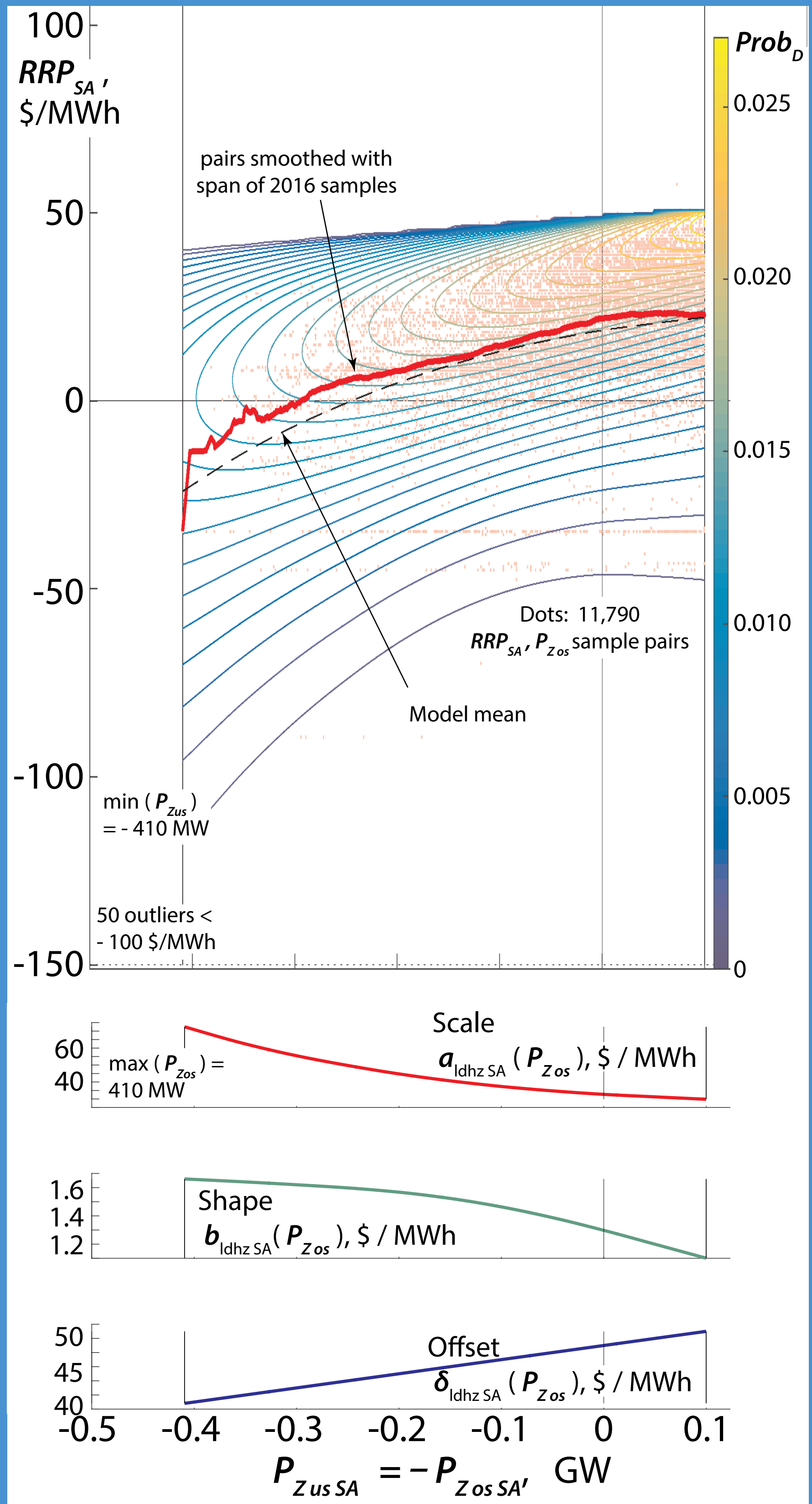
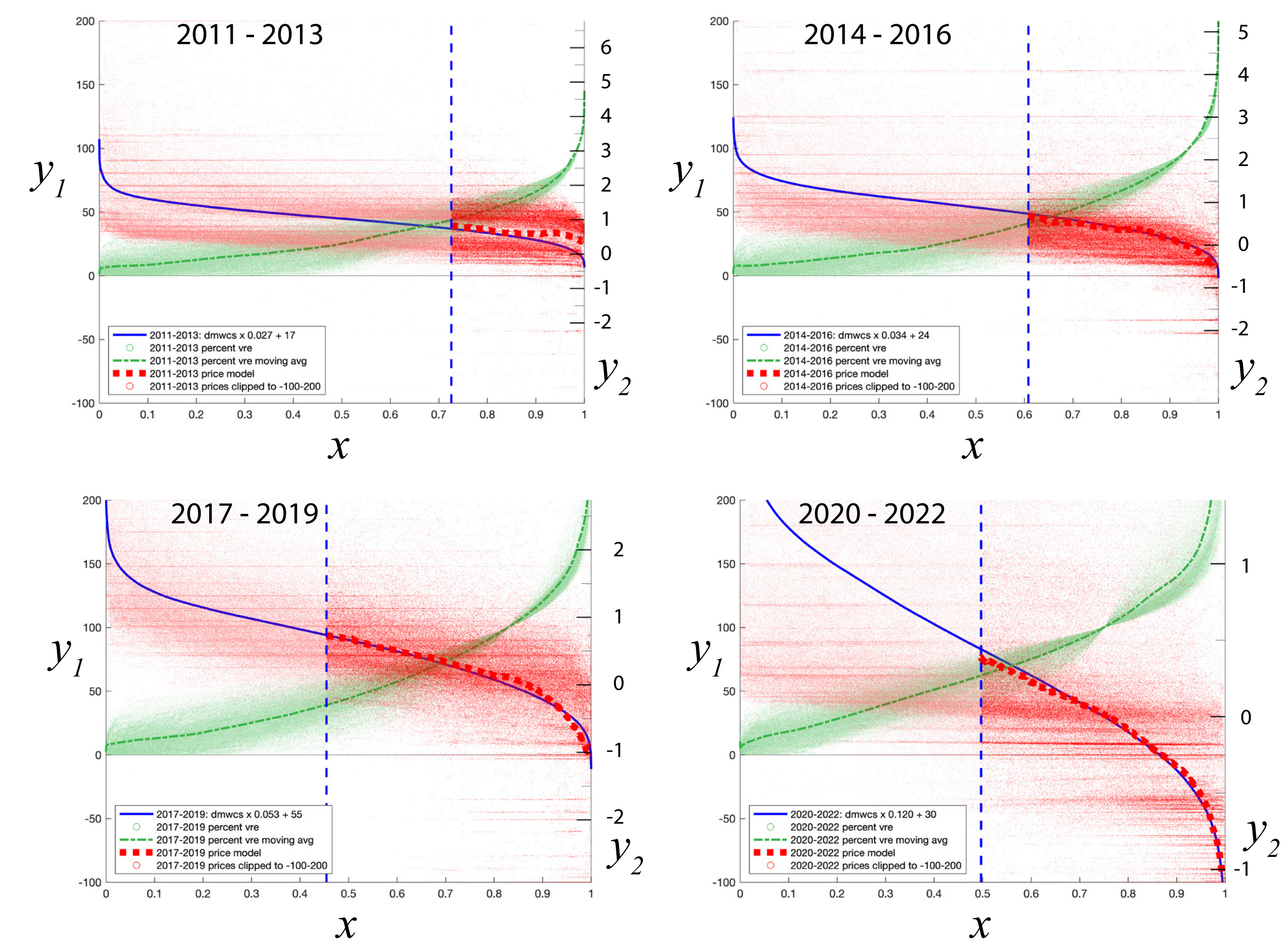


Fig. 26
Case study: Four 3-year spans of model parameter shape matching



x = proportion of pairs of (RRP_{SA}, f) : $RRP_{SA} = f(ODem - VREprod - VREcurt + DemMarket)$

y_1 = RRP_{SA}, \$/MWh and VRE, %; $y2$ = ODem, GW

Fig. 27
Case study: An example of eqn 5a model parameter variation over time

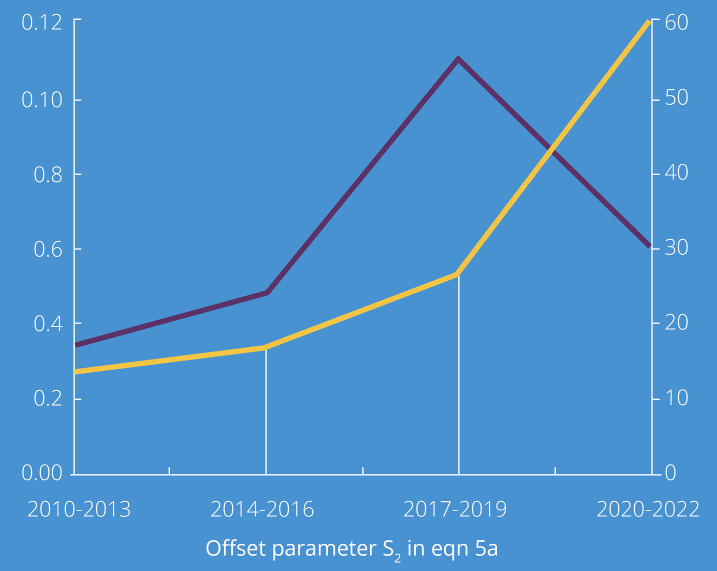


Fig. 28
Case study: A demand market bid stack provides long term sustainability

Fig. 28 presents the effect of a demand-side bid stack in summary form. This graph shows that with a demand-side bid stack, the SA Region can remain stable and viable for decades, concurrently with crossing the 100% VRE annual TWh supply point as early as about 2030.

To help visualize how this works, Fig. 29 and 30 present 2 typical days respectively, that include rare occurrences where a bidder offering a mere -$400 might actually be dispatched, when the VRE scale is at ot upper limit.

The data for Figs. 28 to 30 is from a scenario time series in AEMO's Intergrated System Plan (ISP)

Given the above support for our hypothesis for the value of a demand-side market for our Laboratory Case Study (SA Region of Australia's National Electricity Market (NEM)), it is valuable and productive to review the past 60 years of energy market design and look out how it might evolve more generally over the next 40 years.

Fig. 31 presents the long-term view, and Fig. 32 shows the opportunity to investigate this in more detail over the coming decade. The SA Region could play a key role in transitioning from an investigation to a trial implementation as early as about 2028, in sync with the legislated expiration of the roof-top PV solar feed-in tariff. Unless there is a change to legislation, a substantial surge in roof-top solar deployments will occur at this time.

And finally, Fig. 33 presents a conceptual overview of dispatch-interval resolution models integration into models that use low-resolution time steps (e.g. one year). We designate capacity data flow per year: high-resolution models can synthesize operational demand and VRE production time series from this information. However, "reference time series", such as used in AEMO Integrated System Plan, can also be used.

We also note that synthesizing the above time series is theoretically unnecessary if using analytical models (equations 5 and 6). However, using numerics rather than complex math overlaid with equations like these will likely be sufficiently robust and more flexible for dealing with complex integration problems.

Fig. 29
Case study: An example of bidding for consumption

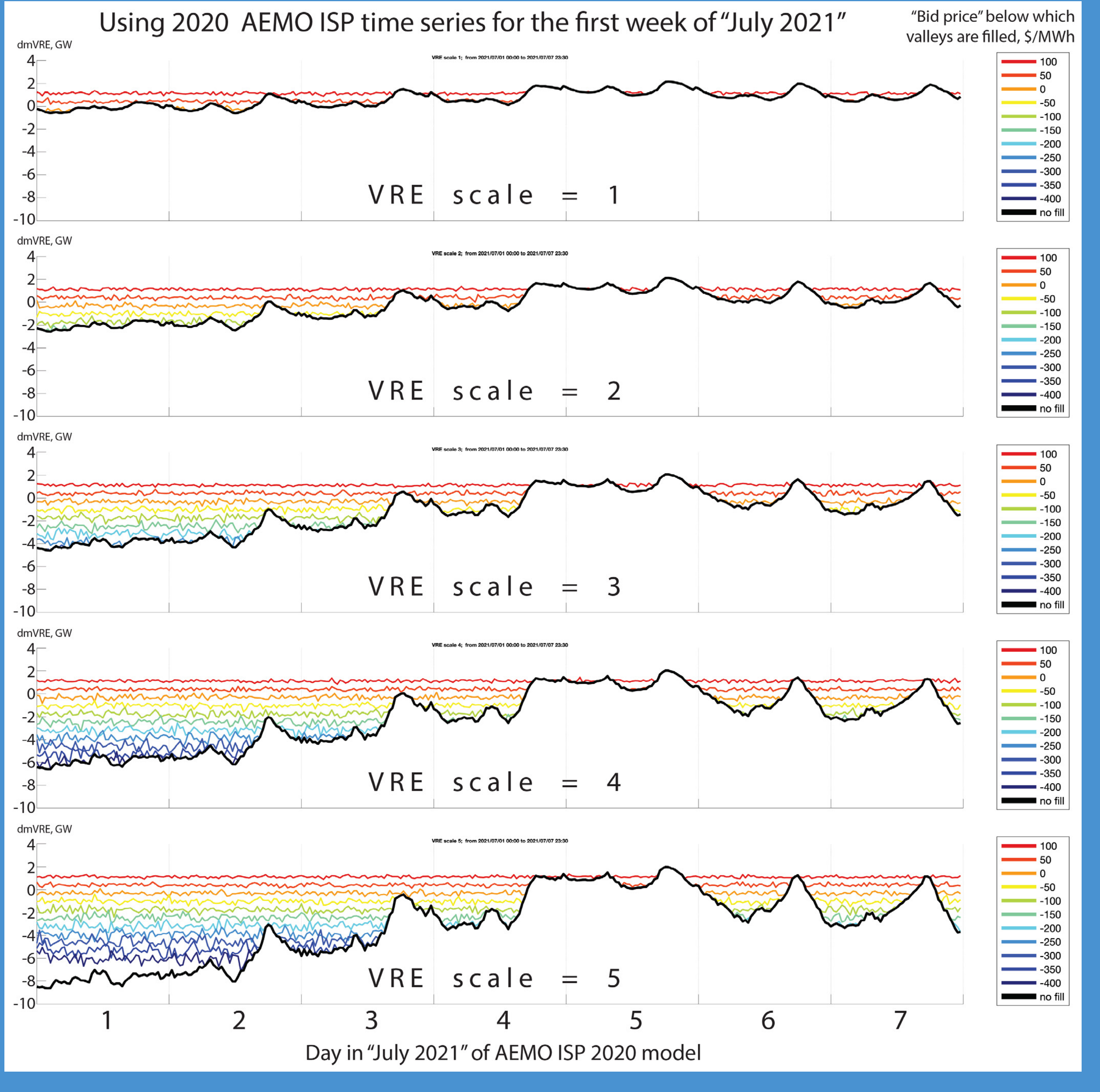


Fig. 30
Case study: Another example of bidding for consumption

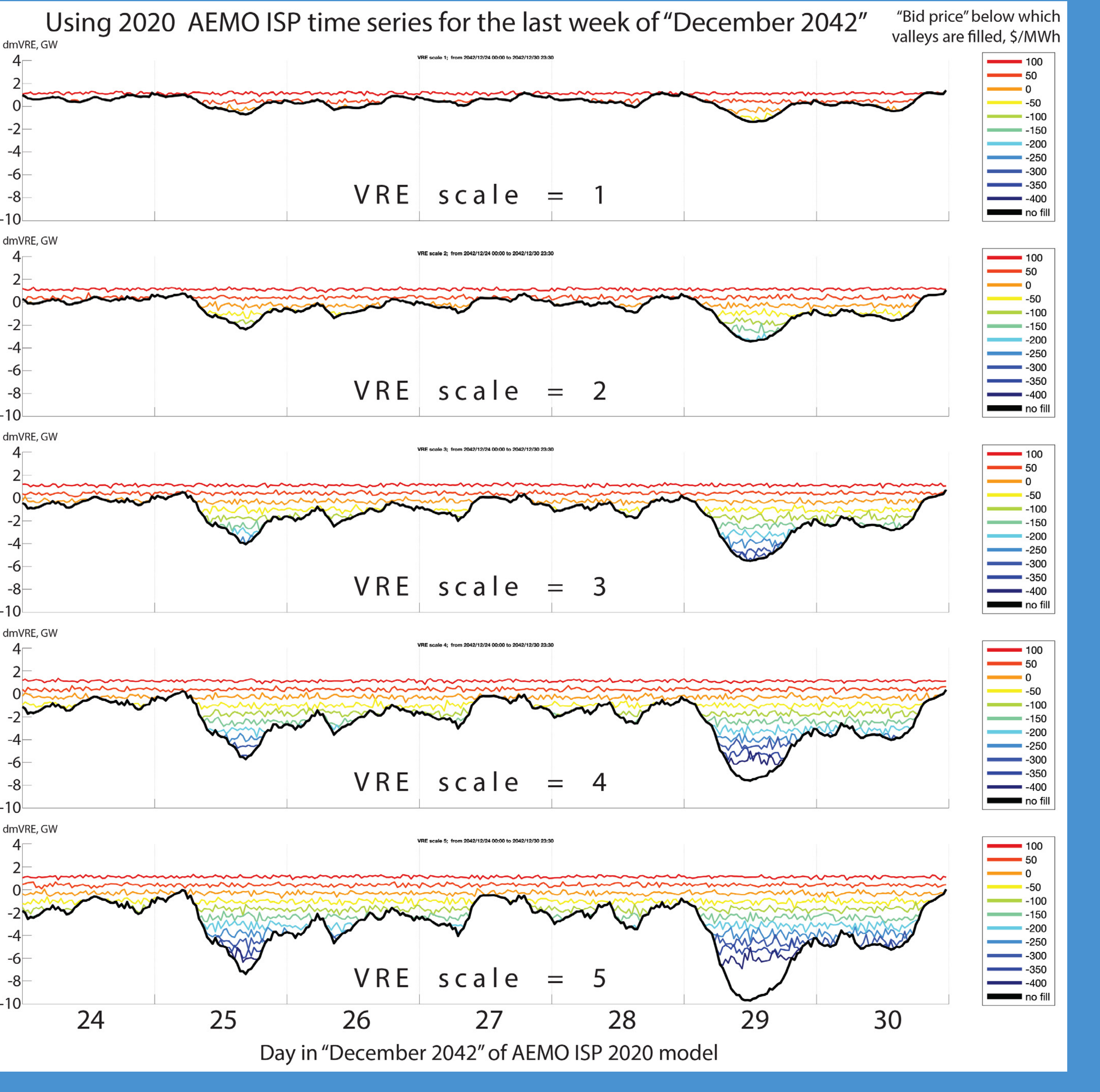


Fig. 31
Price models for a 21st Century high-proportion VRE energy market

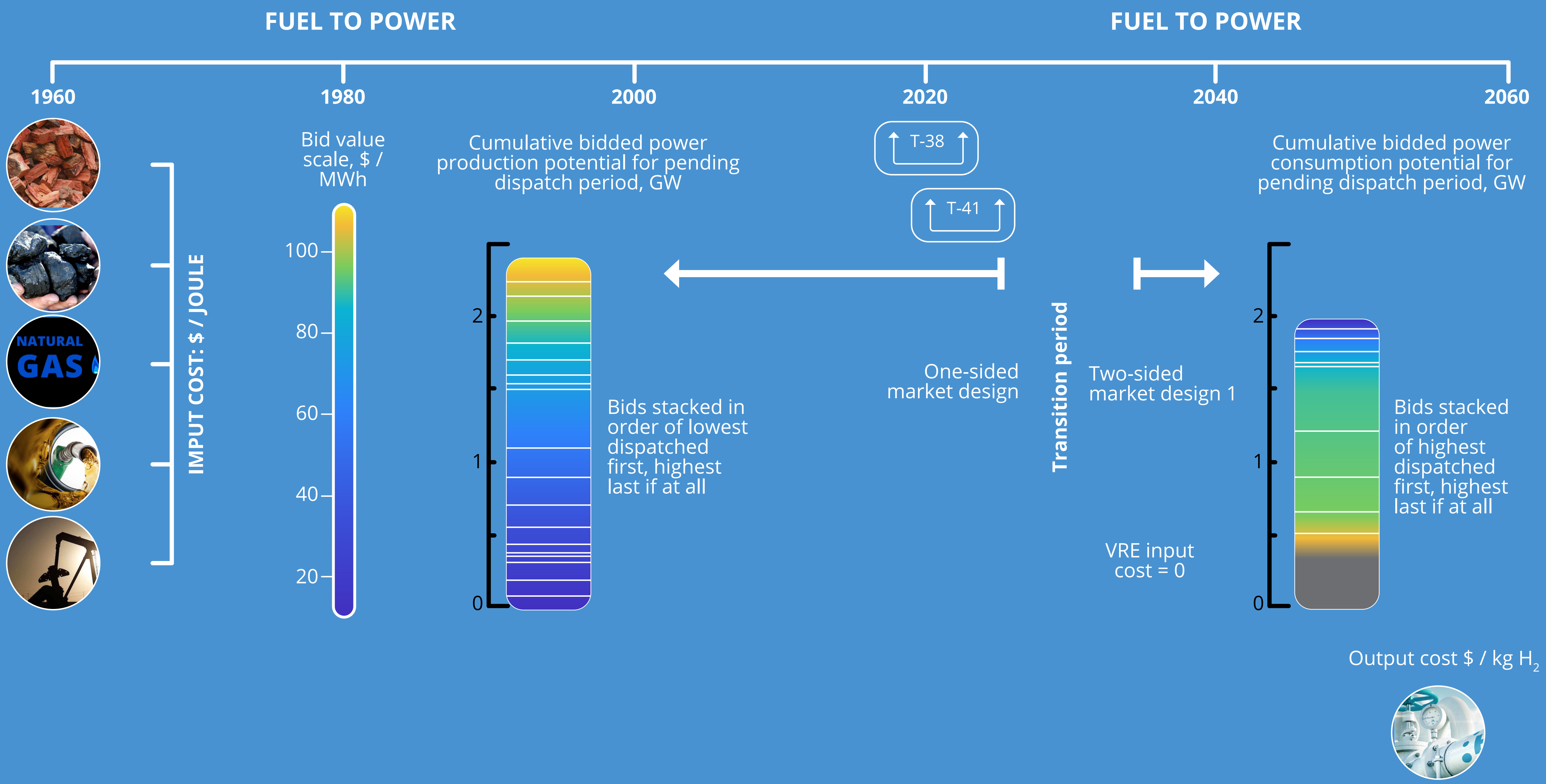


Fig. 32
Price models for a 21st Century high-proportion VRE energy market

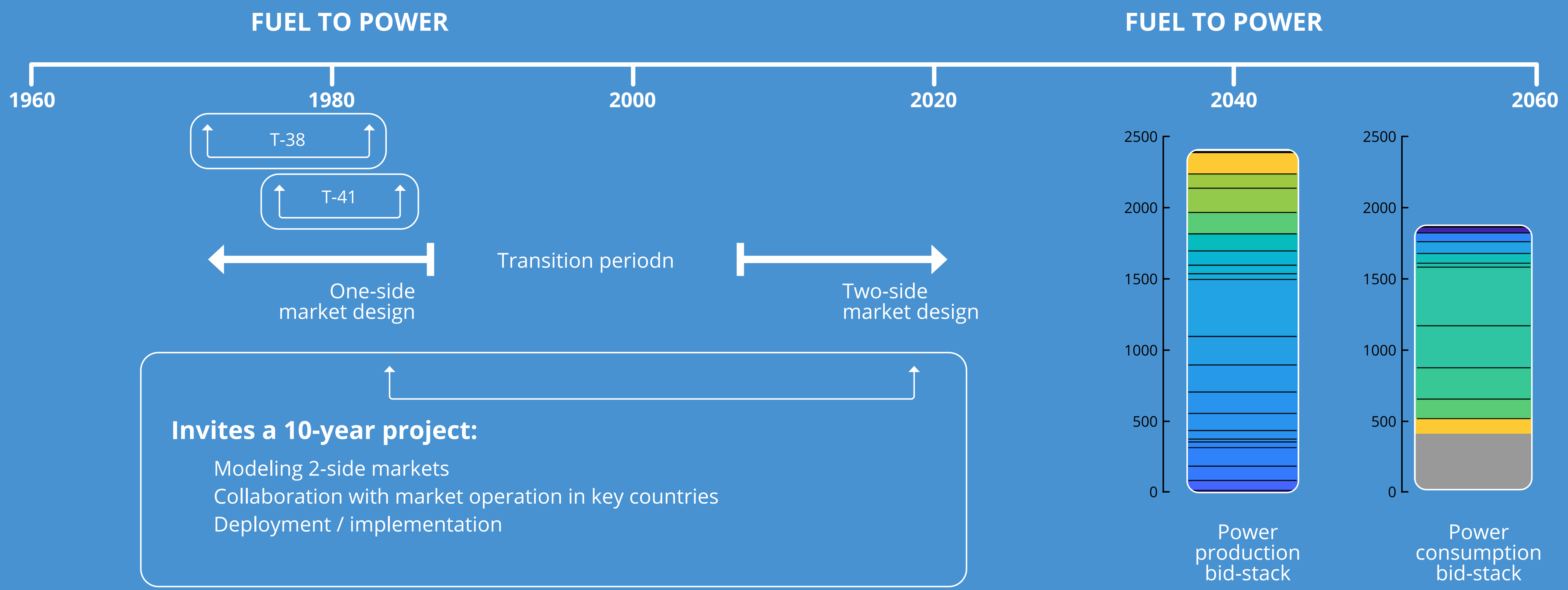
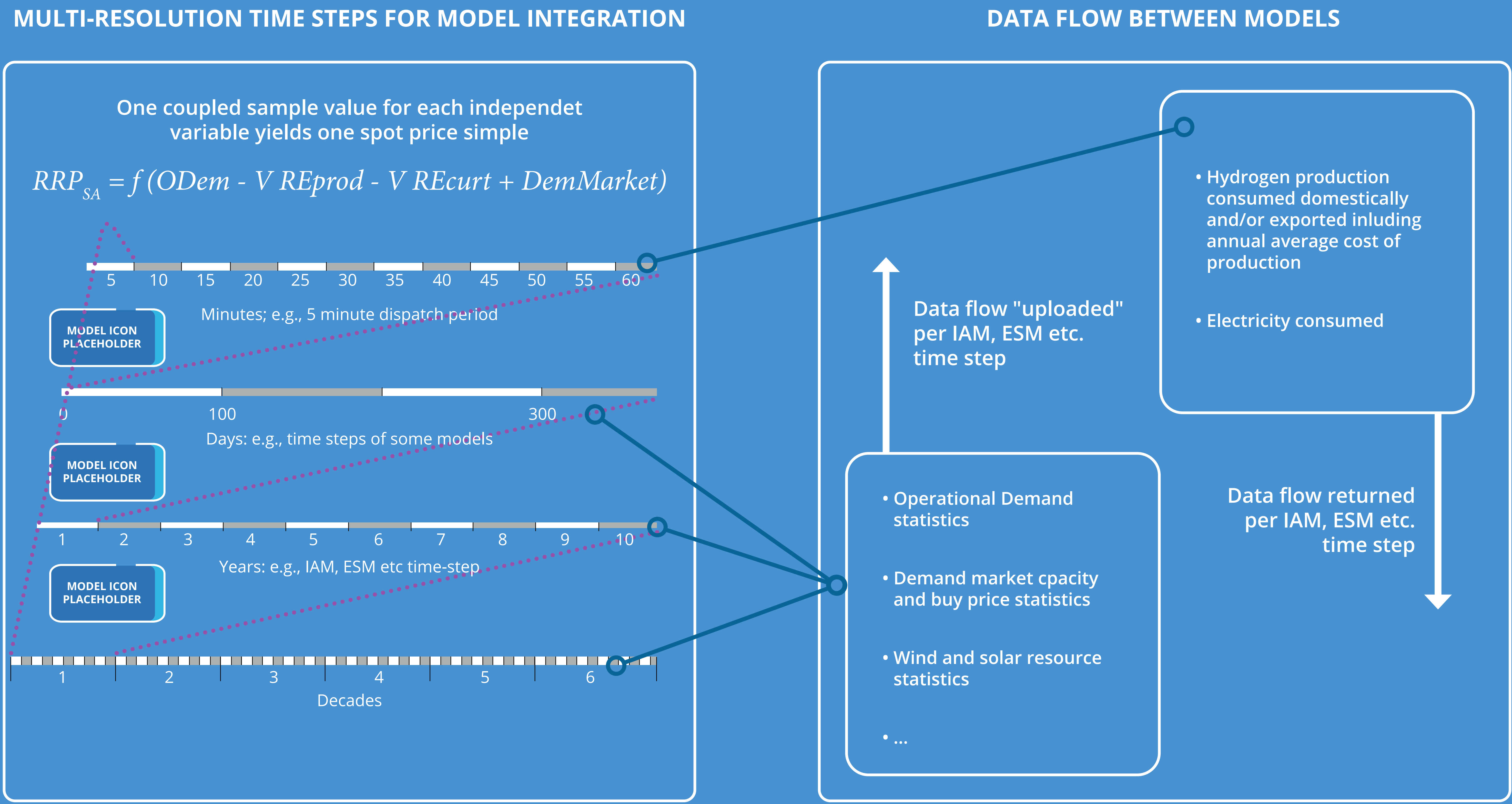


Fig. 33
A conceptual overview of the potential for integrating high resolution model into IAMs, ESMs etc.



INTEGRATING HYDROGEN INTO ETSAP MODELS

FINAL REPORT FOR THE IEA/ ETSAP PROJECT (IEA HYDROGEN TCP TASK 41 SUB-TASK C)

"Modelling of hydrogen"
Paul Dodds[1], Daniel Scamman[1], Kari Espegren[2]

Modelling contributions from:
Markus Blesl (IER), Jan Duerinck (VITO), Patrícia Fortes (UNL), Hiroshi Hamasaki (Deloitte), Antti Lehtilä (VTT), Shivika Mittal (UCC), Kannan Ramachandran (PSI), Eva Rosenberg (IFE).

June 2022

Section 4 abbreviations

ACT	Autothermal reformer
ACT_EFF	E ciency at HHV
AIMMS	Advanced Interactive Multidimensional Modelling System
BECCS	Biomass gasification with CCS
DRI	Direct Reduced Iron
EFOM	Energy Flow Optimization Model
Elc	Fraction of electricity in the energy,inputs.
EnOp-TIMES	EnOp-TIMES has a different scope to the other TIMES models. It focuses on the industrial sector.
ESM	Energy Systems Model
ESME	Energy System Modelling Environment, developed in the UK (UCL) using AIMMS
ETSAP-TIAM	ETSAP-Times Integrated Assessment Model
EU	European Union
GHR	Gas heated reformer
H_2	Hydrogen
HDV	Heavy Duty Vehicles
HHV	High Heating Value
HRS	Hydrogen Refuelling Station
ICE	Internal combustion engine
IER	University of Stuttgart, Institute of Energy Economics and Rational Energy Use
IFE	Norway's Institute for Energy Research
Irish TIMES	An adaptation of TIMES for Ireland

1. University College London, UK;
2. IFE, Norway

Section 4 abbreviations

JMRT Japan	Japan Multi-Regional Transmission Model
JRC-EU-TIMES	European Union's Joint Research Centre's adaptation of TIMES
LDV	Light Duty Vehicles
LHV	Low Heating Value
MARKAL	A predecessor to TIMES
MWh	Megawatt hours
NCAP_COST	Capex : Capital Cost / expenditure
NCAP_FOM	Fixed O&M: are fixed operations and maintenance costs
OECD	Organisation for Economic Cooperation and Development (check)
PEM	Proton Electrolyte Membrane
PJ	Petajoules
PSI	Paul Scherrer Institute, Switzerland
SAF	Sustainable Aviation Fuel
SMR	Steam Methane Reforming
STEM-Swiss	The Swiss TIMES energy system model (*STEM*)
TIAM-UCL	UCL's Times Integrated Assessment Model
TIMES	The Integrated MARKAL EFOM Model; There are numerous versions of TIMES adapted to specific Regions and sectors
TIMES PanEU	The Pan-European TIMES energy system model is a 30 region partial equilibrium energy system model.
TIMES_VTT	VTT's adaptation of TIMES
TIMES-Norway	Norway's adaptation of TIMES
TIMES-PT	Portugal's adaptation of TIMES
UCC	University College Cork, Ireland
UK TIMES	UK's adaptation of TIMES
UNL	Universidade Nova de Lisboa
VITO	VITO is an independent Flemish research organisation in the area of cleantech and sustainable development.
VTT	VTT is research institution owned by the government of Finland
VWM	The VWM (Value Web Model) was developed using AIMMS

4.0 Executive Summary

Green hydrogen has numerous techno-economics advantages wherever electricity is not feasible, particularly in the hard-to-abate sectors: heavy-duty vehicles, heavy industry, mining, shipping and aviation.

Some studies have found contradictory forecasts of future hydrogen across various models [113] [61]. Part of these contradictions can be attributed to the complexity of hydrogen's roles in energy systems. For example, green hydrogen is: a consumer of green electricity a green fuel, and a mechanism for shifting green energy supply in time (storage) and space (pipelines, vehicles).

There was also concern that technology cost and performance assumptions might not be appropriate in some models, and that these data are now evolving faster than modelers can keep up with now let alone forecast meaningfully into the decades to come.

The aim of Task 41 Sub-Task C jointly with IEA ETSAP TCP community was to begin to address some of these issues. Representations of hydrogen integration were compared across a range of TIMES models. A comparison of model outputs was also undertaken, and the insights discussed in a joint IEA ETSAP TCP / IEA Hydrogen TCP workshop. Best-practice guidelines for representing hydrogen in energy system models were also developed.

4.1 Introduction

Hydrogen is a versatile, zero-carbon energy carrier. While electrification has been considered by many as the most appropriate strategy to decarbonise many energy services, hydrogen has received increasing attention in recent years, particularly for hard-to-decarbonise sectors such as heavy-duty vehicles, parts of industry, and shipping and aviation.

A wide range of energy models have been developed that explore the potential role of hydrogen energy systems [22]. As energy system models are designed to explore supply-side decarbonisation across whole economies, for a range of energy sources, many of these models have long represented at least some hydrogen technologies. Yet studies have found a wide range of contradictory projections of future hydrogen use from studies using energy system models [113] [61].

The reasons for these variations are not clear. Hydrogen systems are complex (Fig. 34) and breadth and detail are thought to vary widely between models, for production technologies and particularly for delivery and end-use technologies.

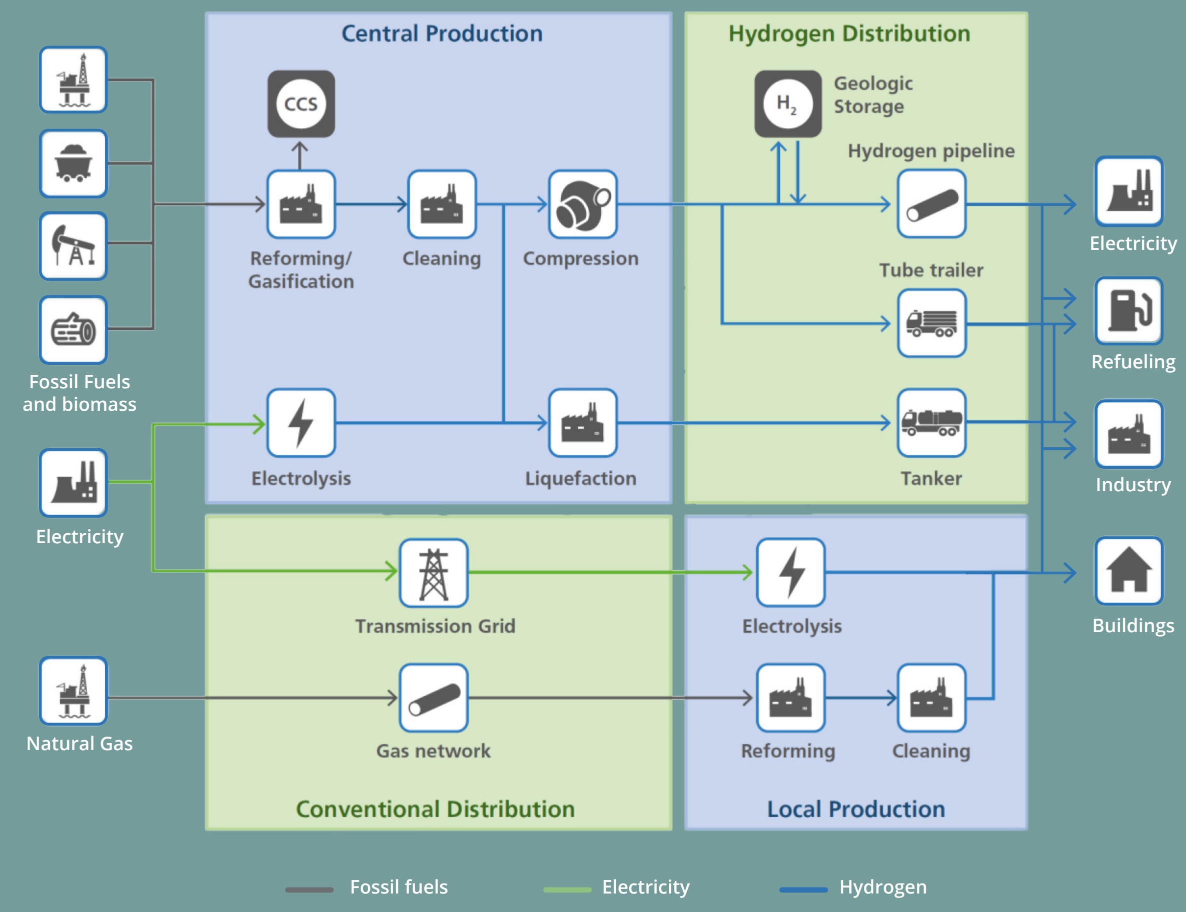
Some of the more technical challenges such as the hydrogen pressure and purity requirements of some technologies are considered by few models. There was also concern that technology cost and performance assumptions might not be appropriate in some models.

The aim of this project was to address these issues by comparing the representation of hydrogen energy systems across a range of TIMES energy system models from the IEA ETSAP TCP community. A comparison of model outputs was also undertaken, and the insights discussed in a joint workshop with the IEA Hydrogen TCP. Finally, best-practice guidelines for representing hydrogen in energy system models were developed. This report presents these insights and guidelines.

4.2 Comparison of community model inputs

The comparison of model inputs focused on the technologies included in each model and the data assumptions for those technologies. It did not focus on other key aspects of the energy system

Fig. 34
Schematic of a hydrogen reference energy system. From **[114]**.



identified by [52] such as spatial and temporal scales, the design of the reference energy system or user constraints affecting hydrogen (e.g. dynamic growth constraints).

4.2.1 Process for data collection

A call for participation was made to the ETSAP community. Eight national, one European and one global model were included in the comparison:

1. ETSAP-TIAM (Global) – Daniel Scamman, UCL
2. TIMES PanEU (EU) – Markus Blesl, IER
3. EnOp-TIMES (Belgium) – Jan Duerinck, VITO.
   EnOp-TIMES has a different scope to the other models as it focuses on the industrial sector rather than the whole economy.
4. TIMES_VTT (Finland) – Antti Lehttila, VTT
5. Irish TIMES (Ireland) – Shivika Mittal, UCC
6. JMRT Japan (Japan) – Hiroshi Hamasaki, Deloitte
7. TIMES-Norway (Norway) – Eva Rosenberg, IFE
8. TIMES-PT (Portugal) – Patrícia Fortes, Universidade Nova de Lisboa
9. STEM-Swiss (Switzerland) – Kannan Ramachandran, PSI
10. UK TIMES (UK) – Paul Dodds, UCL

Each team completed a worksheet, using the template in Fig. 35, to document the hydrogen technologies and data assumptions. The initial model comparison was then discussed in a workshop at the ETSAP meeting in Paris in June 2019. Following that meeting, a number of additional questions were sent to each team and some data was updated. The results presented in this section were recorded at the end of this process. This means that they are relevant to the versions of these models at the end of 2019.

4.2.2 Hydrogen technology comparison

The comparison covered the whole hydrogen supply chain summarised in Fig. 34. In this section, this is split into end uses, delivery and production.

The end uses that drive the use of hydrogen are considered first. Until recently, hydrogen has been viewed primarily as a fuel for road transport and a number of fuel cell vehicles have been launched commercially in recent years. This is reflected in Table 7, in which all of the nine models that represent the transport sector include hydrogen technologies for road transport. In contrast, only three models consider hydrogen for rail transport and only one each for shipping and aviation.

Table 8 examines wider energy system end-uses for hydrogen. Some of these were suggested at the workshop in Paris and so information on them was only requested when the data were revised following the workshop. As only five teams contributed a revision, there are gaps in the data. At least half of all models consider hydrogen applications for electricity generation, industrial decarbonisation and heating buildings. In contrast, few models represent direct reduced iron (DRI) for steel manufacturing or production of synthetic liquid organic fuels.

One model represents hydrogen use in the dairy industry. So while most models represent a core set of hydrogen end-uses, emerging technologies are much less likely to be considered. No model has a comprehensive representation of all end-use technologies for transport or in the wider energy system.

A summary of hydrogen production and delivery options that are represented in each model is shown in Table 9. Most models represent both centralised and decentralised hydrogen production, and the infrastructure required to store and deliver hydrogen. Pressure and purity needs vary across the system, with road transport in particular requiring high-purity hydrogen at very high pressure. The costs of compressing hydrogen to the required pressure are included in almost 80% of models, but only a third consider purification costs (Table 10). A detailed breakdown of delivery technologies by model is shown in Table 11. Hydrogen delivery costs are a relatively small part of the total hydrogen cost (see Section 4.3 for further discussion of this assertion), and that is reflected in the level of detail in the models. While half of the models represent transmission pipelines and liquefied hydrogen road tankers, few consider other delivery options.

One delivery option in countries with substantial natural gas networks is to inject hydrogen into natural gas streams [115] or to repurpose existing natural gas pipes to use hydrogen [116]. Six of the models represent hydrogen injection (Table 12), with maximum injection rates ranging from 2%–15% in terms of energy content, which is around 6%–45%v/v. In practice, most natrual gas appliances are thought to be useable with 3%v/v hydrogen (1% energy content), while exceeding 20%v/v (6% energy content) would require new or altered appliances [116].

Table 8
Transport sectors with/without hydrogen representation in each model

	ETSAP-TIAM	TIMES PanEU	JMRT Japan	TIMES_VTT	STEM_CH	TIMES-Norway	UK TIMES	Irish TIMES	TIMES_PT	EnOp-TIMES	
Hydrogen use in road transport?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	90%
Hydrogen use in rail transport?	No	No	No	No	Yes	No	Yes	No	Yes	No	30%
Hydrogen use in shipping?	No	No	No	No	No	Yes	No	No	No	No	10%
Hydrogen use in aviation?	Yes	No	No	No	No	No	No	No	No	No	10%

The hydrogen production technologies represented in each model are listed in Table 13. All models consider electrolysers for hydrogen production from electricity. Most also include steam-methane reforming, both with and without carbon capture and storage (CCS). While biomass gasification is represented in seven models, only four consider biomass with CCS, despite this being potentially a key negative emissions technology in the future. Half of the models consider coal gasification but only a couple consider waste gasification, which is as yet unproven.

4.2.3 Hydrogen cost and performance data comparison

Capital cost assumptions for hydrogen production are shown by technology for the ten models in Fig. 35. The cost range and the mean cost for each model are shown for the years 2020, 2030 and 2050, for real prices in the year 2018. With the exception of biomass CCS, some models have costs at €500/kW or below for all technologies. Yet there are large cost ranges for each technology; for example, biomass gasification costs range from 400–3700 €/kW in 2020, and coal CCS from €600–3000 €/kW. Even gas SMR, which is widely used globally, has a factor of three difference between the lowest and highest capital cost assumption. Technology learning leading to reduced costs is assumed in several models. This is most apparent for biomass CCS, where costs reduce across most models, and for electrolysis, for which models assuming higher costs today project that they will reduce in the future.

Energy conversion efficiency assumptions for production technologies are shown in Fig. 36 across the ten models. The efficiency range and the mean conversion efficiency for each model are shown for the years 2020, 2030 and 2050, for real prices in the year 2018. These have ranges of 5%–20% across the technologies and are assumed to increase slightly in the future through technological improvements, particularly for electrolysers.

Capital cost assumptions for delivery technologies are compared in Fig. 37. The cost range and the mean cost are shown for each of four scenarios, for the years 2020, 2030 and 2050. A comparison

Table 9
Other than transport sectors with/without hydrogen representation in each model

	ETSAP-TIAM	TIMES PanEU	JMRT Japan	TIMES_VTT	STEM_CH	TIMES-Norway	UK TIMES	Irish TIMES	TIMES_PT	EnOp-TIMES	
Non-energy industrial feedstock?	No	No	No	Yes	No	Yes	Yes	No	No	Yes	40%
Industry fuel for energy?	No	No	No	Yes	Yes	Yes	Yes	No	Yes	Yes	60%
Direct Reduced Iron (DRI)?	Yes				No	No	Yes		No		40%
Synthetic jet fuel?	No				Yes	No	No		Yes		40%
Other synthetic liquid fuels?	No				Yes	No	No		Yes		40%
Dairy industry?	No				Yes	No	No		No		20%
Building heat?	No		Yes		Yes	No	Yes	Yes	Yes	No	50%
Electricity generation?	No	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	No	70%

Table 10
Hydrogen production and delivery system options implemented in each model

	ETSAP-TIAM	TIMES PanEU	JMRT Japan	TIMES_VTT	STEM_CH	TIMES-Norway	UK TIMES	Irish TIMES	TIMES_PT	EnOp-TIMES	
Production plants	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes		100%
Decentralised production	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	90%
Delivery routes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	80%
Storage	No	Yes	No	Yes	Yes	Yes	Yes	No	Yes	Yes	70%

Table 11
Representation of hydrogen compression and purification costs in each model

	ETSAP-TIAM	TIMES PanEU	JMRT Japan	TIMES_VTT	STEM_CH	TIMES-Norway	UK TIMES	Irish TIMES	TIMES_PT	EnOp-TIMES	
Compression	No	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes		78%
Purification	No	No	No	No	Yes	Yes	Yes	No	No		33%

Table 12
Hydrogen delivery system technologies considered in each model

	ETSAP-TIAM	TIMES PanEU	JMRT Japan	TIMES_VTT	STEM_CH	TIMES-Norway	UK TIMES	Irish TIMES	TIMES_PT	EnOp-TIMES	
Liquefaction	No	Yes	Yes	No	No	No	Yes	Yes	No	No	40%
Transmission pipeline HP	Yes	Yes	No	No	Yes	No	Yes	No	Yes	No	50%
Distribution pipeline HP	No	No	No	No	Yes	No	Yes	No	Yes	No	40%
Distribution pipeline LP	No	No	No	No	Yes	No	Yes	No	Yes	No	30%
Building pipes LP	No	No	No	No	No	No	Yes	No	No	No	10%
Road tanker	Yes	Yes	Yes	Yes	No	No	Yes	No	Yes	No	60%
Liquid H_2 refuelling station	No	No	No	No	No	No	Yes	No	Yes	No	20%
Gas H_2 refuelling station	No	No	No	No	No	No	Yes	No	Yes	No	20%
Gas H_2 HRS onsite prod	No	No	No	No	No	No	Yes	No	No	No	10%
Gas field storage	No	No	No	No	No	No	Yes	No	No	No	10%
Salt cavern storage	No	Yes	No	No	No	No	Yes	No	Yes	No	30%

Table 13
Options for using hydrogen in existing gas networks in each model

	ETSAP-TIAM	TIMES PanEU	JMRT Japan	TIMES_VTT	STEM_CH	TIMES-Norway	UK TIMES	Irish TIMES	TIMES_PT	EnOp-TIMES	
Injection of small amounts of hydrogen into gas flows	Yes	Yes		Yes	Yes		Yes	No	Yes	No	60%
Maximum injection rate	15%	2%			4%		3%		7.2%		6%
Repurpose existing gas networks to deliver hydrogen	No	No	No	No	Yes	No	Yes	No	Yes	No	30%

Table 14
Hydrogen production plant technologies considered in each model

	ETSAP-TIAM	TIMES PanEU	JMRT Japan	TIMES_VTT	STEM_CH	TIMES-Norway	UK TIMES	Irish TIMES	TIMES_PT	EnOp-TIMES	
Biomass	Yes	Yes	No	Yes	Yes	No	Yes	Yes	Yes	No	70%
Biomass CCS	Yes	No	No	Yes	Yes	No	Yes	No	No	No	40%
Coal	Yes	Yes	No	Yes	No	No	Yes	Yes	No	No	50%
CoalCCS	Yes	Yes	No	Yes	No	No	Yes	Yes	No	No	50%
Waste	No	No	No	No	No	No	Yes	Yes	No	No	20%
Waste CCS	No	No	No	No	No	No	Yes	No	No	No	10%
Gas SMR	Yes	Yes	No	Yes	Yes	No	Yes	Yes	Yes	No	70%
Gas SMR CCS	Yes	Yes	No	Yes	Yes	No	Yes	No	Yes	No	60%
Electrolysis	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	100%

Fig. 35
Comparison of hydrogen production investment cost assumptions by technology

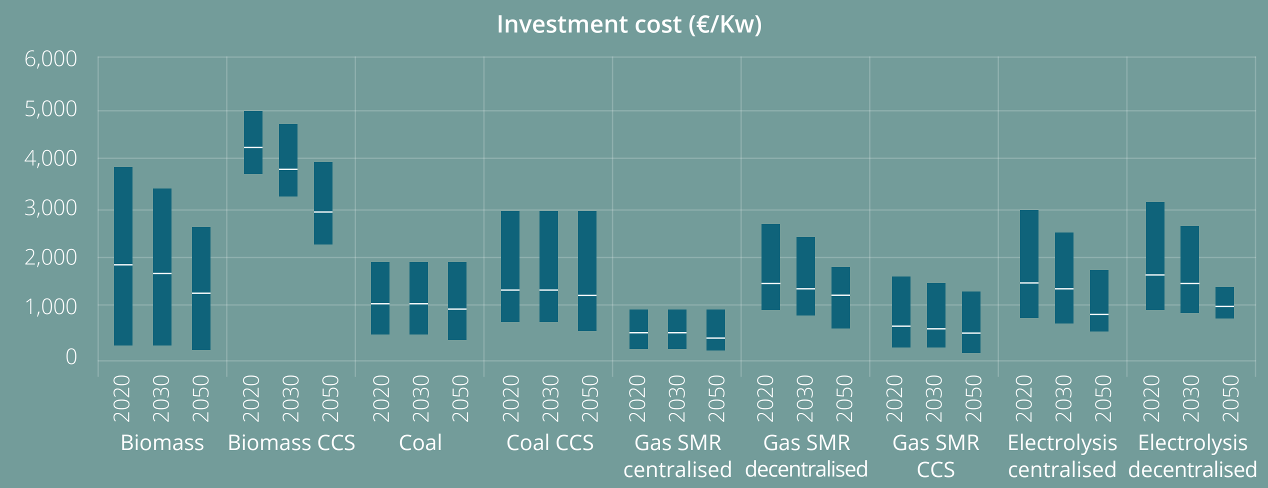


Fig. 36
Comparison of energy conversion efficiency ((HHV) (ACT_EFF) assumptions by technology

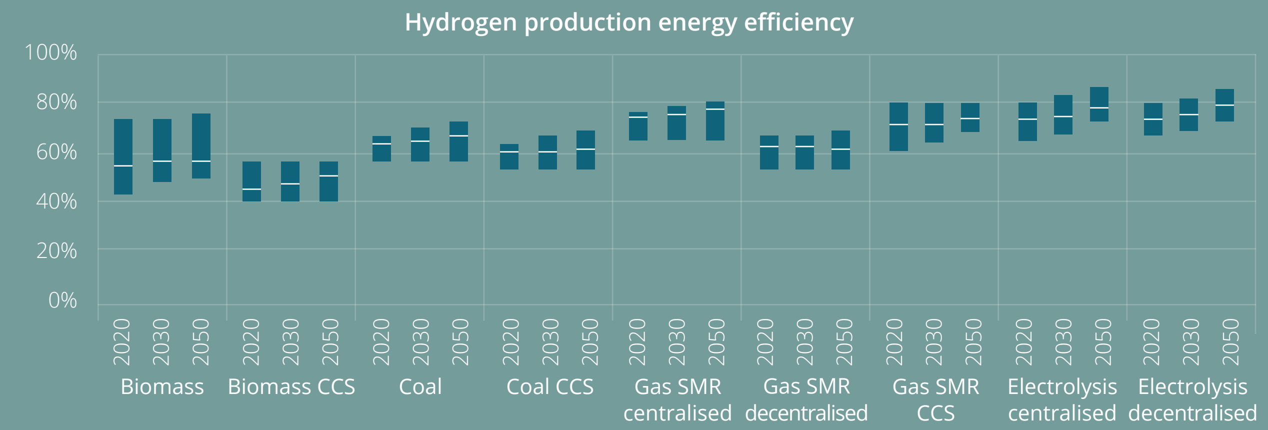
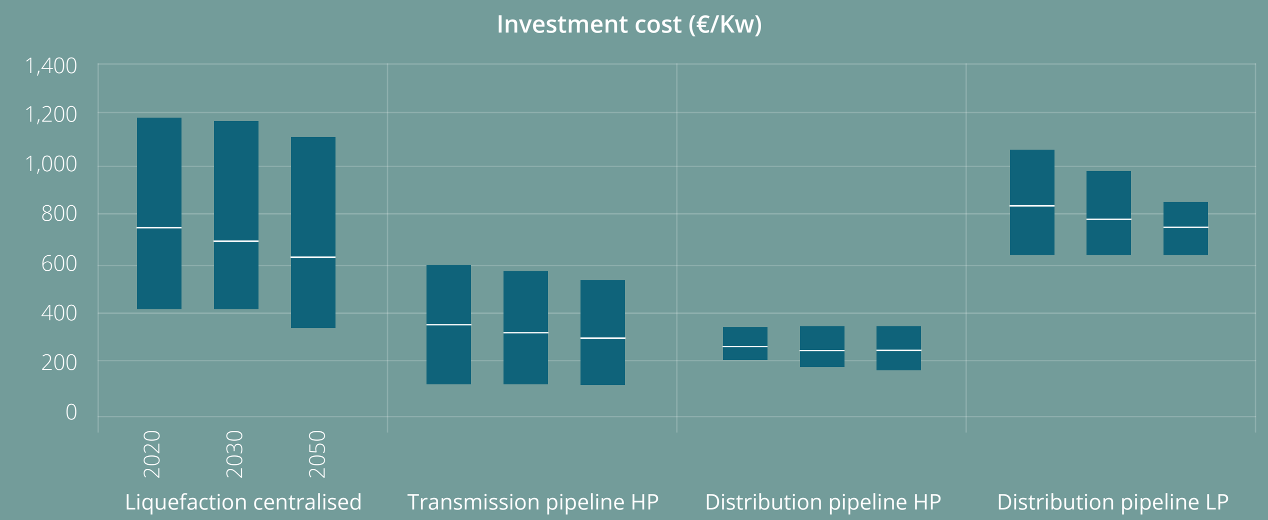


Fig. 37
Comparison of hydrogen delivery infrastructure investment cost assumptions by technology



is less meaningful than for production technologies for two reasons. First, fewer models include these technologies (Section 2.2), so only liquefaction and pipelines are considered in Fig. 37. Second, pipeline costs are sensitive to the geography of supply and demand, which varies by country. Hence transmission pipeline costs range from 100–600 €/kW. As distribution pipelines are found in urban areas, they are less sensitive to geography than transmission pipelines but costs are affected by the urban population density.

The cost ranges are smaller for both high-pressure (HP) and low-pressure (LP) distribution pipe networks. Liquefaction is a relatively mature technology and has high potential for cost reduction through economies of scale. Yet these are not apparent in the model data, with a wide range of costs in all three periods and only minor overall cost reductions assumed in the future.

3.2.4 Discussion

Most models represent a core set of hydrogen end-uses, delivery and production technologies. However, the level of detail varies widely in the models, with most emerging technologies considered by only a few models. No model comprehensively represents all technologies.

Modelling hydrogen delivery is particularly challenging. Two broad approaches are used. The most common is for components of delivery routes (e.g. compression; pipelines; storage; refuelling) to be modelled separately, which enables varying capacities and changes in the choice of delivery systems over time. This is valuable for centralised hydrogen production because pipelines only become economic at high hydrogen demands, which is likely to happen later in a transition. An alternative approach, adopted for example in the JRC-EU-TIMES model, is to define compound technologies that include all parts of the delivery system [117]. The advantages of this approach are fewer technologies, which is an advantage in particular for larger models, and that the modelled delivery systems have internally-coherent costs. The disadvantages are that the number of delivery systems that can be modelled is limited, as each requires a separate technology, and there is no flexibility for parts of the delivery system to evolve over time.

There are substantial differences in investment costs and efficiencies between models. These might be at least partly a result of making different assumptions about the type and size of each technology. For example, cost disparities for liquefiers might reflect different assumptions about economies of scale, while the electrolysers category combines a number of different technologies (alkaline, proton exchange membrane (PEM) and solid oxide).

Only capital costs have been considered in this section. Another approach would have been to compare levelised costs, incorporating operating and fuel costs and energy conversion efficiencies. However, this is difficult for electrolysis in particular as the electricity cost varies between timeslices and the electrolyser capacity factor also varies. Gas prices can also vary substantially between regions. It might be possible to use waste heat from hydrogen production for other purposes, for example low-temperature industrial heat or for heat networks, although improvements in technology efficiency over time would reduce the potential supply of heat. This option is not considered in any of the compared models.

Hydrogen-based energy carriers such as ammonia are not generally considered in energy system models.

Table 15
Hydrogen production per capita in 2050 in the optimal and high hydrogen scenarios

POPULATION		GJ/capita optimal	GJ/capita high hydrogen
Global ETSAP-TIAM	7600	4.1	8.2
JMRT (Japan)	126	8.5	10.1
UK TIMES	67	12.5	37.7
TIMES-Norway	5.4	3.5	11.4
STEM (Switzerland)	8.6	4.5	7.5
Irish TIMES	4.9	4.3	8.0
TIMES-PT (Portugal)	10	10.7	18.2

Yet ammonia is thought to have two potential roles in the energy system. First, it has been identified as a zero-carbon fuel for shipping, as the energy density is much higher than hydrogen. Second, several countries with low-cost solar and wind generation potential (e.g. Australia; Chile; Saudi Arabia) are considering producing cheap green hydrogen for export, but again this international trade is likely to be in the form of ammonia rather hydrogen due to the higher energy density. If countries were importing ammonia, then there would be an opportunity to power some technologies in industry, electricity generation and heavy transport using ammonia rather than hydrogen to reduce costs.

3.3 Comparison of community model outputs

An outcome of the workshop in Paris in June 2019 on model inputs was a need to identify key hydrogen technologies that would ideally be in all models. The suggested approach was to survey the community to understand which hydrogen technologies are deployed by models, as a more detailed representation of hydrogen technologies can be justified if it causes the model outputs to change. Each team in the project was invited to examine the uses of hydrogen in two broad scenarios:

1. “Optimal”: the use of hydrogen in a typical cost-optimal decarbonisation scenario.
2. “High hydrogen”: a decarbonisation scenario in which hydrogen use by 2050 is maximised.This hydrogen maximisation was typically achieved by minimum deployment and consumption constraints, but these were not prescribed in advance since each model is different. Instead, modellers were free to choose how to maximise hydrogen use.

The aim was to consider how differences in inputs affect outputs. This is very difficult to assess quantitatively because each model has a different hydrogen energy system, numerous different data assumptions, and represents a different country.

Also, "typical" decarbonisation varies between countries; for example, it could be an 80% reduction in emissions or a move to net zero CO_2 or net zero greenhouse gas emissions by 2050, and the target will affect the optimum level of hydrogen consumption.

Seven of the ten models also participated in a comparison of model outputs. These are listed in Table 14 and include the global ETSAP-TIAM model and six national models.

3.3.1 Hydrogen production and consumption in each model

Total hydrogen consumption in each model is very sensitive to population, so production per capita for each scenario is listed in Table 14. Four of the models have hydrogen production of 3.5–4.5 GJ/capita in the optimal scenario, which is substantially lower than the 8.5–12.5 GJ/capital production in the other three models. For most models, the increase in hydrogen production in the high hydrogen scenarios is a factor of 2–3 compared to the optimal scenario, except for the JMRT model. The high hydrogen scenarios have a much greater range than the optimal scenarios (7.5–37.7 GJ/capita). This outcome is a result of the UK TIMES (37.7 GJ/capita) and the TIMES-PT (18.2 GJ/capita) having much higher production than the other models.

The rate of deployment of hydrogen industries in each model is compared in Fig. 38 for the optimal scenario, normalized such that production in 2050 for each model = 1.0. Only two models have any demand in 2020. In 2030, demand does not exceed 25% of the 2050 demand in any model. By 2040, there are large production differences across models, with production ranging from 15% to 70% of the production in 2050. The technical feasibility of implementing very high production rates is currently uncertain but need not be dismissed as infeasible in a rapidly evolcing industry.

The technologies used to produce hydrogen in each model in the optimal scenario are listed in Table 15. There are substantial differences across the models. Five models have production dominated by a single technology, of which four have different types of electrolysers and the other has steam-methane reforming. The other two models have production split across 4–5 technologies, with no single technology contributing more than 50% of total production. The proportion of hydrogen produced from electrolysis in each model over the period to 2050 is shown in Fig. 39. Electrolysis dominates in three models by 2040. Only the UK TIMES model has no electrolysis by 2050, with the model using SMR and waste CCS instead as a cheaper option. The costs are strongly sensitive to the assumed cost of electricity (electrolysers) and natural gas (SMR) in the future. In the high hydrogen scenario, the options used are the same in each model, with the exception of UK TIMES which adds decentralised electrolysis to the portfolio. Even the proportions of each technology in each model are similar.

The proportion of hydrogen consumption in each sector in the optimal scenario is shown for each model in Table 16. (In Table 16 The STEM column does not sum to 100% due to rounding.) Transport is the only sector with hydrogen consumption in all seven models. It accounts for almost half of consumption (45%) across the models. The industry sector also has substantial hydrogen use (29%), though only in five models, while remaining consumption is split across the other sectors. The JMRT model of Japan is the only one with substantial hydrogen consumption in buildings. Four models use hydrogen in three or fewer sectors in the optimal

Fig. 38
Normalised total hydrogen production in the optimal scenario

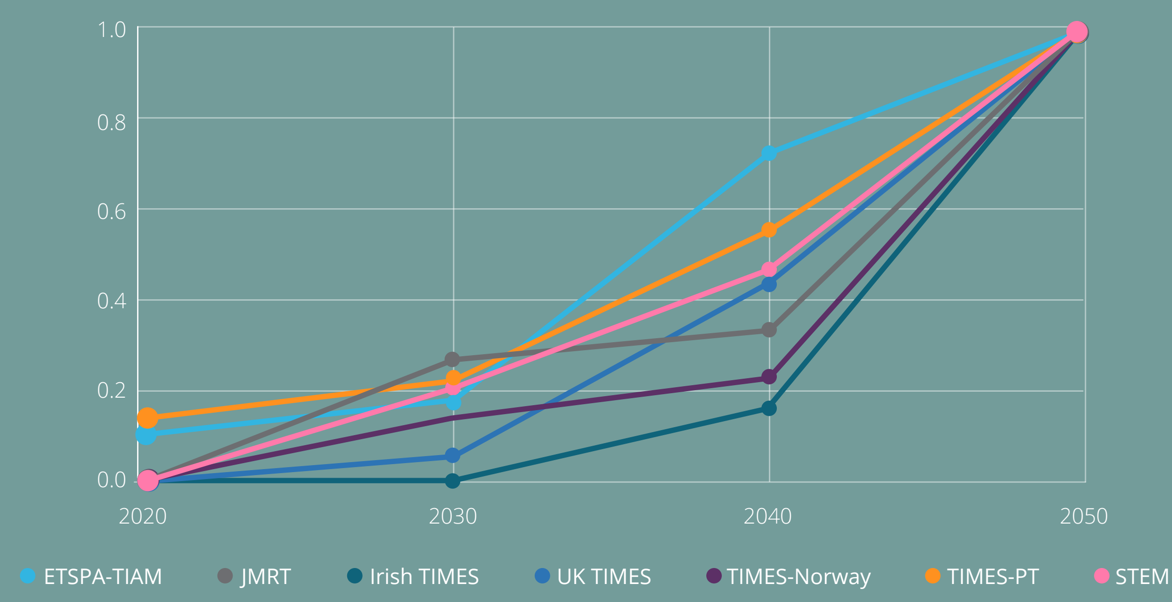


Fig. 39
Fraction of hydrogen production from electrolysers in the optimal scenario in each model

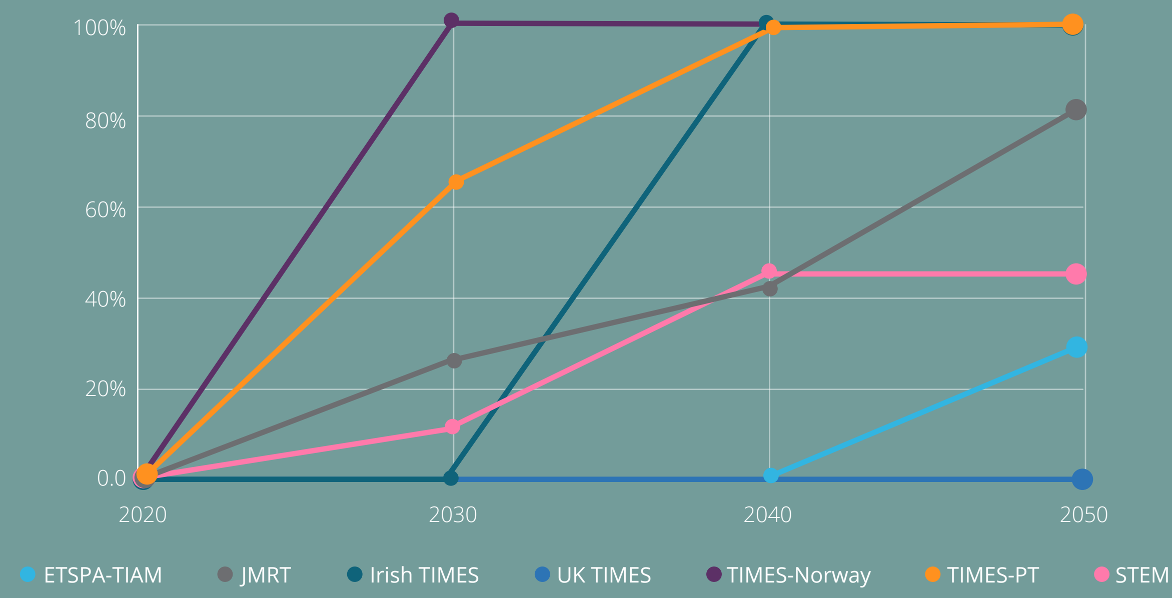


Table 16
Fraction of hydrogen production by technology for the optimal scenario in 2050

	ETSAP-TIAM	JMRT	UK TIMES	TIMES-Norway	STEM	Irish TIMES	TIMES_PT
Biomass	10%				0%		
Biomass CCS					29%		
Coal	14%						
Waste CCS			1%				
Gas SMR	46%				0%		
Gas SMR CCS			99%		24%		
Decentralised electrolysis						100%	3%
Centralised electrolysis	30%				47%		
Alkaline electrolyser		82%					1%
PEM electrolyser			100%				96%
Hydrogen from oil refineries		6%					
Hydrogen from iron and steel		12%					
NUMBER OF OPTIONS USED	4	3	2	1	5	1	3

Table 17
Fraction of hydrogen consumption in each sector for the optimal scenario in 2050

	ETSAP-TIAM	JMRT	UK TIMES	TIMES-Norway	STEM	Irish TIMES	TIMES_PT	AVERAGE
Agriculture			1%					
Services		55%	12%		3%		1%	10%
Industry	39%		65%	52%	6%		38%	29%
Residential		39%	4%					6%
Transport	61%	6%	2%	48%	52%	100%	44%	45%
Process					11%		17%	4%
Electricity			16%		27%			6%

Table 18
Fraction of hydrogen consumption in the transport sector for the optimal scenario in 2050

	ETSAP-TIAM	JMRT	UK TIMES	TIMES-Norway	STEM	Irish TIMES	TIMES_PT	AVERAGE
Car		100%			50%			21%
2-wheel and 3-wheel bikes								0%
Light-duty vehicle					8%			1%
Heavy-duty vehicle	4%			100%	38%	100%	4%	35%
Bus			15%		4%		96%	16%
Train			76%					11%
Shipping			10%					1%
Aviation	96%							14%

Table 19
Fraction of hydrogen consumption in the industry sector for the optimal scenario in 2050.

	ETSAP-TIAM	JMRT	UK TIMES	TIMES-Norway	STEM	Irish TIMES	TIMES_PT	AVERAGE
Iron and steel			8%	19%			3%	7%
Non-ferrous metals			1%				0%	0%
Cement								
Non-metallic minerals			25%				38%	16%
Chemicals			5%	81%	Not known		21%	27%
Paper			3%				4%	2%
Food and drink			18%	2.2			33%	13%
H_2:CH4 blend	100%							25%
Other			40%				2%	11%

scenario; in contrast, UK TIMES uses hydrogen in six scenarios. The only model that uses hydrogen in additional sectors in the high hydrogen scenario is TIMES-PT, which extends consumption to buildings (residential and service).

It is useful to examine three sectors in more detail. Table 17 shows that heavy-duty vehicle (HDV) is the only transport sub-sector to have consumption across several models. Yet the two models without hydrogen use in HDVs, JMRT and UK TIMES, have the highest and third highest hydrogen production per capita overall (Table 14). (In Table 17 The UK TIMES column does not sum to 100% due to rounding.) Use of hydrogen in other sub-sectors varies across the models, with only bikes having no hydrogen consumption in 2050 in any model. Only two models have a role for hydrogen in cars, and only one each for trains, shipping and aviation. With the exception of STEM, each model has a dominant sub-sector that accounts for at least 75% of total hydrogen production for transport, but this dominant sub-sector tends to vary between models. It is surprising that there is so much variation between models within the sector. In the high scenario, consumption patterns are similar except for UK TIMES using hydrogen in light transport (cars, bikes, LDVs), and two models using hydrogen for shipping.

The use of hydrogen in industry has a quite different pattern (Table 18). (In Table 18 the sub-sectoral breakdown is not known for the STEM model.) The UK TIMES and TIMES-PT models use hydrogen across seven industrial sub-sectors. In contrast, the other models use hydrogen in two or fewer sub-sectors. It is possible that potential hydrogen use in many sub-sectors in those models is not represented in those models, and this assumption that it is not technically feasible then restricts cost-optimal hydrogen use in industry. There are very few changes in consumption patterns across the models in the high hydrogen scenario compared to the optimal scenario.

Two models use hydrogen in the process sector. These are for synthetic fuel production, which is not represented in many models, and in oil refineries, which in many models might be implicit as many refineries produce and consume hydrogen internally at present.

4.3.2 Discussion

Two of the models, UK TIMES and TIMES-PT, identify much greater roles for hydrogen than the others. Hydrogen is used more widely across the transport and particularly the industry sectors, but also in the other sectors, and overall production per capita is much higher. The only model that has a comparable production per capita is the JMRT model, which primarily uses hydrogen to decarbonise building heat. Section 2.2 noted that options for hydrogen end-uses are limited in many models outside the transport sector. The breadth of industrial opportunities for hydrogen in the UK TIMES and TIMES-PT models in Table 18 suggests that options for use across industry should ideally be represented. The use of hydrogen across a range of transport modes in Table 17 similarly shows the importance of representing hydrogen decarbonisation options across the whole transport sector. Novel technologies such as direct reduced iron (DRI) for steel production and synthetic jet fuel production from hydrogen could become important in deep decarbonisation pathways and should also be considered.

A wide range of production technologies are used in the scenarios, which suggests that each model should represent a wide range of technologies beyond electrolysers and natural gas SMR. While models of OECD countries tend to focus on CCS technologies for carbonaceous fuels, the use of unabated fossil fuels to produce hydrogen in the TIAM-UCL model show that these could still have a role in some countries, particularly those that are less developed or do not have suitable sequestration storage options for CO_2.

4.4 Guidelines for representing hydrogen in energy system models

For the longer term a proposed annually updateable database for input data has been proposed in Section 2 (Fig. 3). This section presents interim best-practice guidelines for representing hydrogen supply chains in energy system models. It specifically considers improvements to the ETSAP-TIAM model. It focuses primarily on the structure of the reference energy system for hydrogen.

The level of detail that is implemented should reflect the geographical coverage of the model. National models can be much more detailed than global (multi-region) models as they are smaller and can consider local opportunities that might not be available in many countries (e.g. existing gas pipelines that can be repurposed for hydrogen; geology for underground hydrogen and CO_2 storage). An example of a detailed reference energy system for hydrogen is shown in Fig. 40, but a simplified version of that system would likely be more appropriate for many models.

While a linear supply chain model might be considered, with centralised production feeding national then local distribution networks, in reality there could be a series of flows in both directions as shown in Fig. 40. There are a number of options for hydrogen delivery infrastructure and these can be complex to implement, yet are likely to have a relatively small impact on overall costs compared to the costs of production and end-use technologies. Our advice is therefore to start with demand-side options, then production technologies, and finally to choose an appropriate approach to delivery costs.

While hydrogen is the focus of this report, it has become clear that ammonia produced from low-carbon hydrogen is more likely to be traded internationally and used as a shipping fuel, and could also be used elsewhere in the system. For these reasons, models of countries with seaports would ideally consider ammonia-fuelled technologies as well as hydrogen-fuelled technologies.

4.4.1 Hydrogen end-uses

The potential for hydrogen to power end-use technologies, and the costs and implications, are not well understood across the community. There are many potential applications for hydrogen energy. Within the transport sector:

- **Road:** all types of light- and heavy-duty vehicles can use fuel cells and should be represented. Several companies have developed hydrogen internal combustion engines but it is uncertain whether these have a long-term future or will be stopgap technologies. Hybrid and plug-in hybrid fuel cell technologies should be considered.
- **Rail:** hydrogen offers an alternative to diesel, and also a hybrid option for trains on lines that are only partially electrified.
- **Shipping:** hydrogen could replace fuel oil in smaller boats, and ammonia or methanol used by international shipping. Power-to-liquids technologies could be important in the future.
- **Air:** hydrogen and ammonia could power jet engines in new aircraft, and hydrogen could also be used to produce synthetic aviation fuel (SAF) for existing aircraft.

Fig. 40
Simplified schematic of the implementation of hydrogen technology options in an ESM

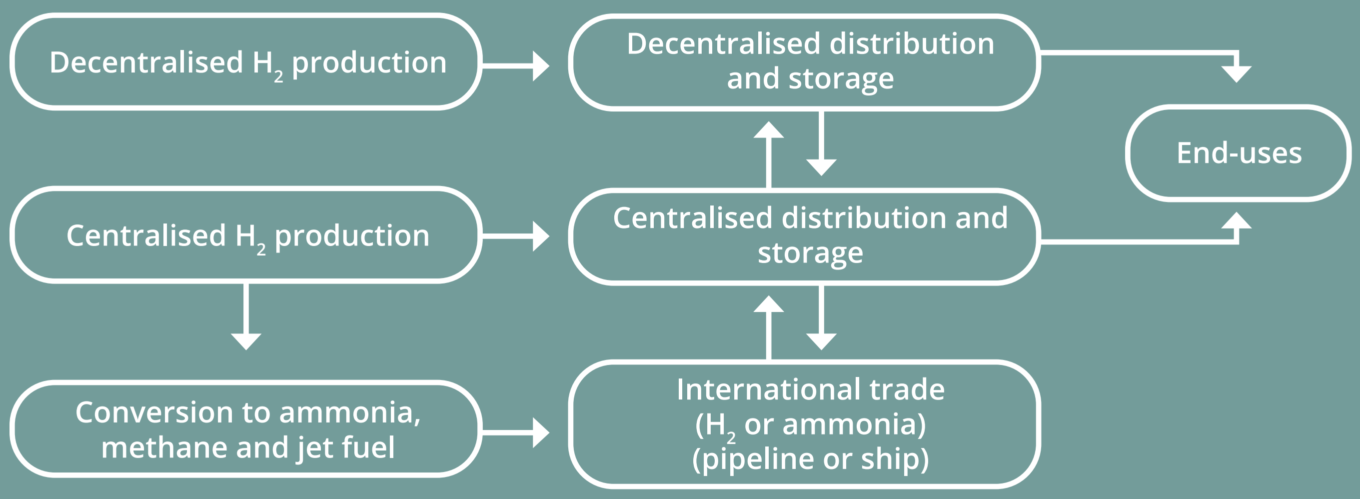


Table 20
Cost/kWe, and production data for hydrogen production technologies adapted from [118]

		CAPEX {€/kW)			Fixed O&M {€/kW)			Efficiency			Elc
		2020	2023	2050	2020	2023	2050	2020	2023	2050	2050
Alkaline electrolyser	Low	796	539	468	33	32	31	66%	70%	74%	100%
	Central	938	732	670	34	33	32	77%	80%	82%	100%
	High	1288	1064	959	40	37	35	80%	83%	84%	100%
PEM electrolyser	Low	1041	473	366	35	34	33	62%	71%	76%	100%
	Central	1265	613	500	40	36	35	72%	79%	82%	100%
	High	2060	1327	979	47	40	38	81%	84%	87%	100%
Solid oxide electrolyser	Low	1475	746	575	57	53	52	70%	74%	77%	73%
	Central	1961	1127	751	60	56	54	74%	79%	86%	76%
	High	2820	1864	1418	61	58	57	87%	93%	96%	83%
SMR+CCS	Central	845	744	577	31	31	31	74%	74%	74%	0%
ATR+CCS	Central	992	894	677	29	29	29	80%	80%	80%	5%
ATR+GHR+CCS	Central	953	831	611	29	29	29	86%	86%	86%	4%
BECCS	Central	2845	2648	1196	109	102	46	65%	66%	69%	0%

Hydrogen is already widely used as an industrial feedstock, for example for ammonia production, and could be used to produce a wide range of synthetic fuels and high-value chemicals in the future with captured CO_2 (carbon capture and utilisation, or CCU) via the Fischer-Tropsch process. The possibilities and costs of these processes are not well understood. Hydrogen offers an option to decarbonise challenging demands such as high-temperature processes and iron reduction, but could more generally be used to replace most heat demands currently met by natural gas. New end-use technologies would be required. Modellers are recommended to consider potential uses across all industrial subsectors in a similar way to the UK TIMES and TIMES-PT models.

While renewables are expected to have a prominent role in future, there will be a need for low capital cost technologies providing peak electricity generation, and studies with the UK TIMES and ESME models have suggested that hydrogen turbines are likely to be the cheapest low-carbon option. Electricity generation using fuel cells would also be possible, particularly in areas with low demand that could take advantage of the modularity (near term) scalability (longer term) of fuel cells[1].

Countries with mature gas networks providing gas for heating (e.g. Japan; Germany) might be able to repurpose those networks to use hydrogen instead of natural gas. In the short-term, hydrogen injection could partially decarbonise the gas supply. Both options could be considered where appropriate.

Cost and performance data for end-use technologies are challenging to obtain as there are wide variations both within and particularly between countries. These variations reflect differences in societal trends and consumption patterns (e.g. cars are generally larger in the USA than Europe). As a rule of thumb, hydrogen combustion technology costs and performance should be similar to the equivalent natural gas technologies for buildings, industry and electricity generation. The future costs of fuel cell vehicles and non-road transport are more difficult to estimate. Costs should be derived using a consistent method for all comparable end-use technologies (e.g. various types of cars) to enable a coherent cost comparison within the model.

1 The subtle distinction between modulatory and scalability similarly applies to electrolysers.
e.g., plans for a 250 MW in SA https://www.hydrogen.sa.gov.au/ are expected to end up with roughly 25 x 10 MW units.

4.4.2 Hydrogen production

Based on the comparison of community model outputs, Section 3.2 argues that a range of production technologies should be included in the models. The minimum recommended set of technologies are:

- ***Electrolysers.*** Alkaline electrolysers operate at high capacity factors and low capital costs. PEM electrolysers offer higher ramp up/down speeds, operating second and sub-second response time required for frequence response services. Solid-oxide electrolysers have high efficiency and low electricity consumption. TIMES enables detailed modelling of electrolysers, for example by including the cost of replacement of the stack, but does not currently provide multi-resolution time steps (see Section 3.3, Fig. 33).
- Steam-methane reforming (SMR) with CCS. This could use both natural gas and biomethane. Non-CCS plants could be included for near-term deployment.
- ***Biomass gasification***. Including CCS and non-CCS versions.

Modellers should also consider including coal, oil, bio-oil and waste plants, with and without CCS as appropriate. Emerging technologies such as the methane pyrolysis, plasma refroming and biological hydrogen production are difficult to represent as the long-term costs are not well understood.

Section 4.3 showed that cost and performance assumptions for hydrogen production technologies vary widely between models. Some cost and performance data ranges for production technologies are shown in Table 19 from a synthesis recently performed by the UK Government. Hydrogen production and electricity generation costs should have a consistent methodology to ensure the model is balanced. (In Table 19 "CAPEX" is the capital expenditure (NCAP_COST). "Fixed O&M" are fixed operations and maintenance costs (NCAP_FOM). Real prices in the year 2018 are used. "Efficiency" is the overall energy conversion efficiency at the higher heating value (HHV) (ACT_EFF)[2]. "Elc" is the fraction of electricity in the energy inputs. "PEM" is proton exchange membrane. "SMR" is steam-methane reformer. "ATR" is autothermal reformer. "GHR" is gas-heated reformer. "BECCS" is biomass gasification with CCS. Source: adapted from [113].)

When comparing cost and performance data, it is important to understand whether energy is specified in terms of higher or lower heating value (HHV or LHV). Data in the literature has a range of approaches

The level of production process detail should reflect the model temporal resolution. The full value of a fast-response capable electrolyser operating a Region with a very high proportion ofVRE production can't be assessed by a model with low temporal resolution Even parameterisation is challenging because excess generation varies and increasing the electrolysis network capacity decreases the capacity factor. Another temporal resolution issue is that some technologies, such as some SMRs, have much reduced energy conversion efficiencies at part loads. Part-load efficiencies can be represented in TIMES models but the operation of such plants will only be represented accurately at high temporal resolution.

2 Note re: efficiency: LHV operating efficiencies are higher than HHV efficiencies due to the lower Btu/GJ value being used in the efficiency calculation.

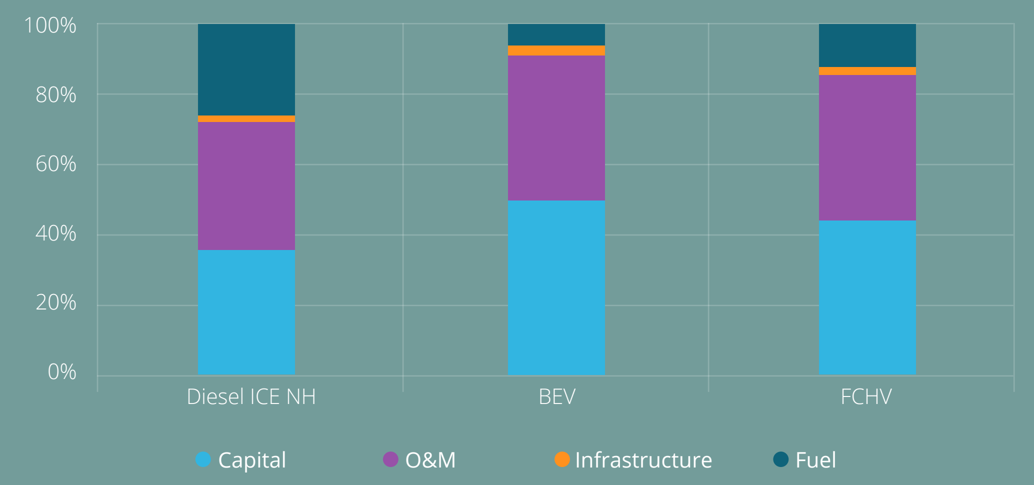
4.4.3 Hydrogen delivery systems

Delivery system data is challenging to find as costs are strongly influenced by topography [119] [120]. This means that costs for one country might not be appropriate elsewhere.

The relative costs of delivery systems depend on both the geography and scale of demand [121], and will change during a transition. For example, pipelines are the most cost-effective method of transporting large quantities of hydrogen, particularly over shorter distances, but require a substantial up-front investment and will have very high costs per unit energy in the early stages of a transition. For this reason, other delivery systems would likely be used early in a transition unless a substantial demand were created in a short space of time, for example by converting a large industrial cluster to use hydrogen. This issue could be circumvented by representing large pipeline systems using lumpy investments or small regions in a model, but such an approach would ideally be informed by an appraisal of how pipelines might develop during a transition (e.g., [122]).

The relative importance and variability of infrastructure costs should be considered when deciding on the level of modelled detail for delivery infrastructure. Fig. 41 shows that the cost of delivery infrastructure for fuel cell cars in a UK scenario was only around 10% of the total fuel cost, and the overall cost was anyway dominated by the capital and O&M

Fig. 41
Breakdown of the total cost of ownership of ICE, battery and fuel cell cars; From: **[123]**



costs of the car rather than the fuel used to power it. The data in Fig. 41 is from cost assumptions for the year 2050.

"Capital" and "O&M" refer to the vehicle costs. "Fuel" is the cost of the fuel, excluding taxes, and "Infrastructure" is the delivery infrastructure used to deliver the fuel from the manufacturing/generating plant to the car. Expending substantial effort to model infrastructural systems for the transport sector would be difficult to justify in this case. Note, however, that fuel and infrastructural costs are likely to be substantially more important for stationary hydrogen technologies such as industry and heating, where end-use technologies are less costly.

Section 2.4 notes that two broad approaches are used to represent delivery systems: (i) representing separate components of delivery routes (e.g. compression; pipelines; storage; refuelling); or, (ii) defining compound technologies that include all parts of the delivery system. Both have advantages and disadvantages for model flexibility and accuracy. The choice of approach should reflect the model design.

It would be appropriate for models to include transmission pipelines, liquefaction and road tanker delivery, and possibly tube trailers. Injection of hydrogen into existing gas streams and repurposing of existing gas networks to deliver hydrogen would ideally be included where this is technically feasible.

Hydrogen pressure and purity are likely to vary throughout a delivery system and compression and purification costs could be substantial at some locations (e.g. refuelling stations), so should be taken into account. The infrastructure costs should be comparable to alternative non-hydrogen technologies; for example, capital costs for battery vehicle on-street and refuelling station chargers should be included if hydrogen refuelling station costs are included. International shipping of "green" renewable-derived ammonia, which can be cracked to hydrogen, is receiving increased attention.

Models would ideally represent maritime imports of ammonia, where feasible, and the use of ammonia as a shipping fuel.

4.4.4 ETSAP-TIAM model improvement

The representation of hydrogen energy systems in the ETSAP-TIAM global energy system model was reviewed as part of this project with the aim of recommending future model improvements. ETSAP-TIAM was first released by IEA ETSAP TCP to Contracting Parties in 2008. Several ETSAP members have created their own model version from the original model and have changed the model regions and resource and technology assumptions, including for hydrogen. These versions have not been made available to the wider ETSAP community. However, a new version of ETSAP-TIAM has been developed by an ETSAP-funded research project. The model design has been improved, and the base year updated from 2005 to 2018. The hydrogen RES was updated in this project, but there are opportunities for further improvements in the modelling of hydrogen.

The principal weakness of ETSAP-TIAM is the lack of end-use options for hydrogen. Hydrogen use is restricted to road and air transport, some parts of industry, and injection into gas streams. There is an opportunity to greatly extend the potential options across the transport and industry sectors, to electricity generation (turbines, fuel cells and even engines), power-to-liquids, and to heating buildings where this is a credible option.

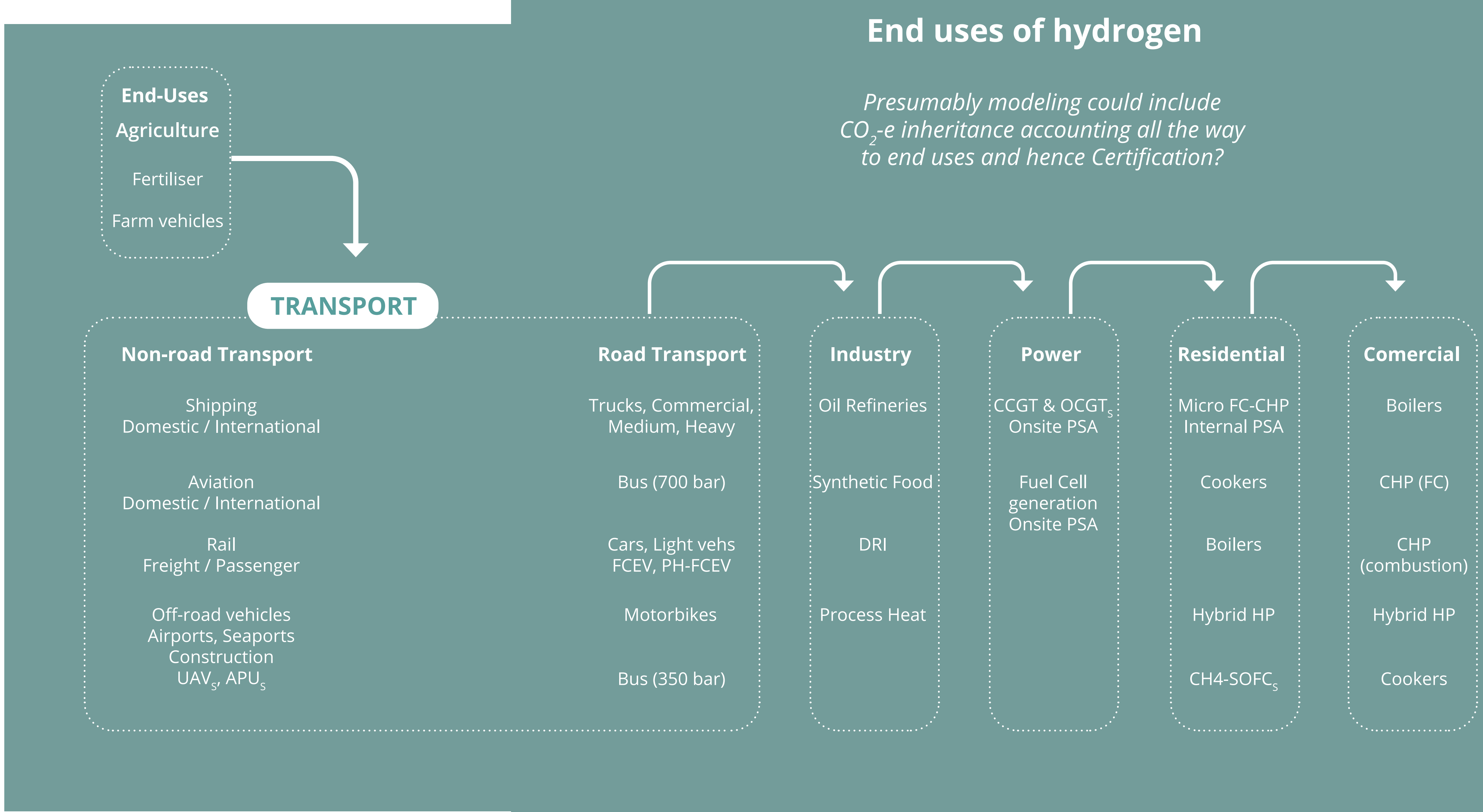
Use of ammonia in shipping and trade of ammonia produced from green hydrogen has received much attention recently. Another priority for ETSAP-TIAM is to represent hydrogen trade by pipeline, where feasible, long-distance ammonia and hydrogen maritime trade, and potential uses of ammonia across the energy system.

Hydrogen delivery infrastructure is very limited in ETSAP-TIAM and could be improved to account for pressure and purity variations across the system. Hydrogen storage needs and opportunities are not considered at present. As timeslicing has been changed in ETSAP-TIAM to represent each of the four seasons separately, there is an opportunity to represent interseasonal hydrogen storage.

Fig. 42
Example data collection input template

Fig. 43
Detailed hydrogen reference energy system example

Fig. 44
End uses (right end) of Detailed hydrogen reference energy system example



ETSAP-TIAM does have a range of hydrogen production technologies. The cost and performance data of these should be reviewed. A wider range of electrolysers could be included, for example high-temperature solid oxide electrolysers that have substantially lower electricity consumption.

4.5 Conclusions

There are many potential applications for hydrogen energy. The aim of this project was to identify best practice for representing hydrogen in energy system models. First, the representation of hydrogen energy systems in a range of TIMES energy system models from the IEA ETSAP TCP community was compared. Next, a comparison of model outputs was undertaken. Finally, best-practice guidelines for representing hydrogen in energy system models were developed and presented in this report.

The level of modelling detail for hydrogen technologies varies widely between models. Most models contain a basic set of technologies (electrolysis; hydrogen for road transport). A few models represent a much wider range of hydrogen end-uses, both in the transport sector and across the wider energy system. These models tend to have higher hydrogen consumption in 2050 in low-carbon scenarios as some of these technologies are cost-competitive. If they are not represented in a model, the modeller is effectively making an assumption that they are not technically-feasible or not economically-viable. There is a need for modellers to review the breadth of end-use technologies represented in their models.

The outputs comparison suggests that models should represent a wide range of production technologies beyond electrolysers and natural gas SMR. Some technologies could usefully be further disaggregated in some models (e.g. PEM, alkaline and solid-oxide electrolysers), but this should take into consideration limitations arising from low temporal resolution. Work is still required to characterise key cost and performance data, hopefully in conjunction with IEA Hydrogen TCP.

There is not a straightforward method to represent hydrogen delivery system infrastructure and there is much diversity between the models. Ammonia is emerging as a hydrogen-based energy vector that is likely to be particularly important for international trade, but is not generally considered by existing models and should be considered for future inclusion.

Fig. 42 presents a visualization of the input data spreadsheet, and Figs. 43 and 44 prresent a comprehensive reference energy system proposal for hydrogen. A lower level of detail is likely to be appropriate for most models, but this diagram is nevertheless useful to understand options and technical requirements across the energy system. Modellers can create coherent reference energy systems from this diagram that are appropriate for the regions that they are modelling.

OVERALL CONCLUSIONS AND RECOMMENDATIONS

There is a clear and vital need for continuously improving the integration of hydrogen into a broad range of model classes and categories. IEA Hydrogen TCP identified this need in about 2017. But we are not alone in highlighting the need for improving modelling.

For example, a leading commercial model vendor with a strong reputation in power and gas modelling added hydrogen modelling in about 2020-21 in response to customer needs. An Iberia-based case study presented in this report used hydrogen pricing in the electricity and gas markets as a foundation for power and gas model coupling.

Another recent example is Australia's Sun Cable project, in which there has been notable disagreement among prospective investors about the most profitable means of exporting very large-scale PV solar power production: green hydrogen or a derivative versus over 4,000 km of submarine cables to Singapore. A diversity of competing public modelling outcomes would benefit stock investors' confidence in the development.

The need is arguably beyond the scope of a single IEA Technology Collaboration Program, be it IEA Hydrogen TCP, ETSAP TCP, or both. Collaborating with commercial vendors might be productive, subject to appropriate IP protection agreements. Hence, we have proposed an annual modeling data companion report to Hydrogen Council / McKinsey and Co's annual Hydrogen Insights report.

Aside from such size and scope issues, it is essential to highlight the most significant integration challenge: deploying muti-resolution assessments that capture the value of power-to-fuel across very short periods while keeping the overall top-level review tractable. This challenge is worth addressing because hydrogen plays the following concurrent roles:

- ***Electricity consumer***
- ***Network balancer***
- ***Curtailment avoider***
- ***Large-scale carrier***
- ***Fuel source***
- ***Large-scale storage***
- ***Network services provider***

All of these roles involve time variation in one way or another. The time scale of large-scale storage is months, and for ancillary services: seconds. Hence finding ways to accommodate multiple resolutions in a given assessment will be crucial to modeling hydrogen integration going forwards.

There is a very large number of ways to categorize energy models, and in turn to assign review / category correlations.
Fig. 4 in Section 3.3 and the table below are two of many approaches

Dimension	Category	Sub-category	Number of reviews including ...
Purpose of the model	General	Forecasting	12
		Exploring	11
		Backcasting	5
	Specific	Energy demand	7
		Energy supply	8
		Environmental impact	6
		Integrated Approach	8
		Modular build-up	2
Structure of the model	Degree of endogenization		9
	Non-energy sectors		3
	Infrastructure/grid		8
	Description of end-uses		14
	Description of storage technologies		14
	Description of supply technologies		19
	Sector coupling technologies		10
	Supply or demand analysis tool		11
			7
Renewable technology inclusion	Hydro		10
	Solar		11
	Geothermal		9
	Wind		11
	Wave		9
	Biomass		7
	Tidal		9
			11
Demand technologies included	Power sector		15
	Transport	ICE, BEV, FCEV, PHEV	12
	Residential	Services, types of building	14
	Commercial	Types of building	14
	Industry		6
	Agricultural		2
			15
Geographical coverage	Global		16
	Regional		17
	National		17
	Local		19
	Single-project		12
			20

Dimension	Category	Sub-category	Number of reviews including ...
Spatial resolution	City		5
	Regional		8
	National		8
	Multinational		4
			10
Sectoral coverage	Energy sectors		10
	Other specific sectors		9
	Overall economy		3
			10
Time horizon	Short		16
	Medium		15
	Long-term		15
			16
Time resolution	Minute		13
	Hour		20
	Month		15
	Year		14
	User-defined		17
			21
Cost scope	Upstream fuel production		7
	Maintenance		7
	CO_2 cost		7
	Beyond investment, fuel, fixed costs		7
			7
Analytical approach	Top-down		14
	Bottom-up		16
	Hybrid		11
			15
Methodology	Macro-economic	Computable General Equilibrium	11
		Econometric	8
		Input-Output	3
	Micro-economic		4
	Partial equilibrium		10
	Optimization		23
	Simulation		21
	System dynamics		3
	Spatial		3
	Spreadsheet/toolbox		5

Dimension	Category	Sub-category	Number of reviews including …
Methodology	Backcasting		3
	Multi-criteria		6
	Accounting		10
	Hybrid		4
			26
Mathematical approach	Linear programing		18
	Mixed-integer programing		13
	Dynamic programing		13
	Fuzzy logic		5
	Agent based		11
	Network model		2
	Heuristic		5
	Single-objective		5
	Multi-objective		2
			23
Data requirements	Qualitative		4
	Quantitative		4
	Monetary		3
	Aggregated		3
	Disaggregated		3
			4
Input data	Demand		4
	Infrastructure		3
	Technology performance		4
	Fuel prices		2
	Distribution profiles		2
	Energy balance for base year		2
	Technical restrictions		6
	Emissions		4
	Weather data		1
	Resource potential		1
	Macro-economic		1
			10
Transformation path analysis	Perfect foresight		2
	Myopic foresight		2
	None		2
			2
Licensing	Open source		10
	Free academic license		7

Dimension	Category	Sub-category	Number of reviews including …
	Commercial		9
	Proprietary		7
			11
Programing environment	Python		6
	GAMS		7
	AIMMS		3
	Java		1
	VBA		5
	Other		7
			8
Training requirements	Low		4
	Medium		4
	High		4
			4
Technology learning	One-factor learning curve		2
	Two-factor learning curve		2
	Multi-Cluster Learning		1
	Multi-Regional Learning		1
			2
Suitability for 100% renewable systems	Electricity		3
	Energy		1
Market	Perfect		2
	Spot		2
	Reserve		1
	Balancing		2
			3
Uncertainty analysis	Deterministic		5
	Stochastic		7
	Possibilistic		1
			8

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Fig. 42 ETSAP example data collection input template

Hydrogen RES

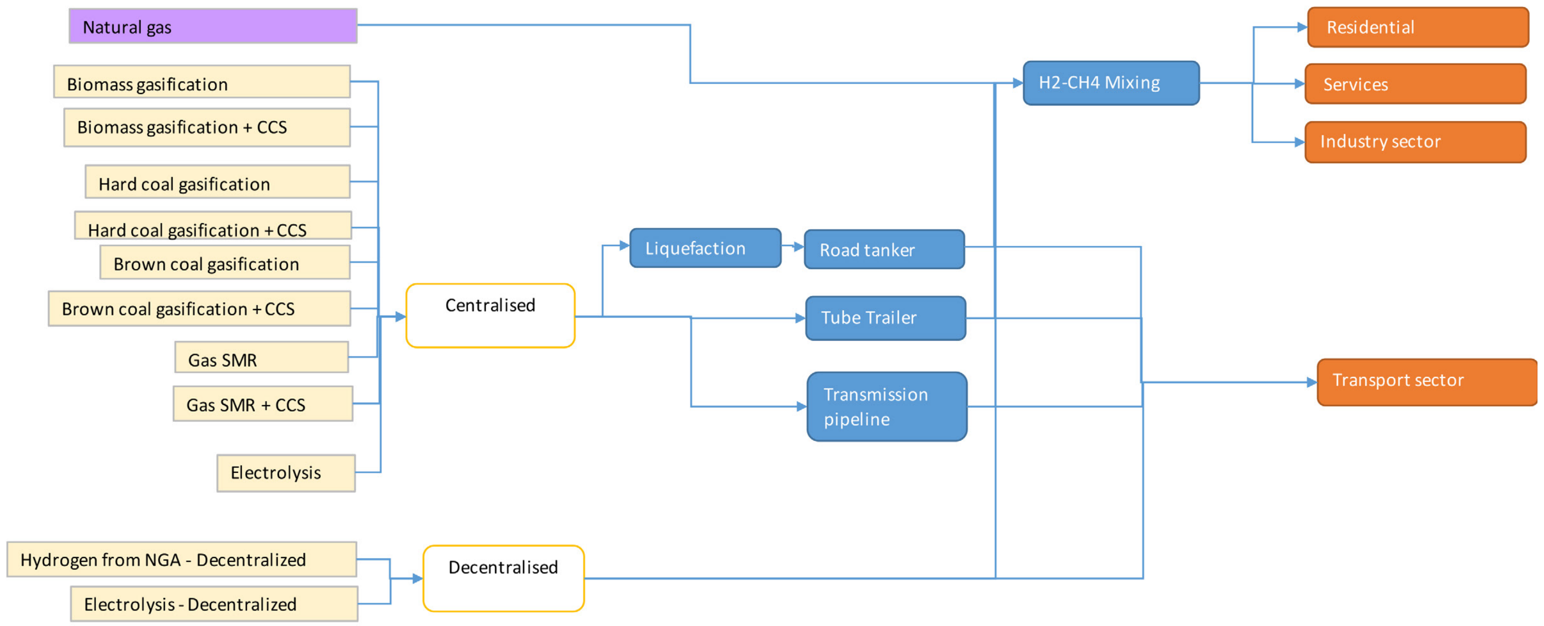
ETSAP-TIAM

All costs data expressed in US$2005

GDP deflator: http://www.imf.org/external/pubs/ft/weo/2009/01/weodata/index.aspx

Currency	USD		
Currency year	2005		
Model base year	2005		
Inflation factor	1.29		
Currency factor	1.18		
Model activity unit	PJ	<--- the data below should be in these units	
Model capacity unit	PJ/a	<--- the data below should be in these units	

1998	96.472
2000	100
2004	109.463
2005	113.034



Hydrogen reference energy system (RES)

Does the model represent:

		Scenario option?	Max injection:
Hydrogen production plants?	Yes		
Decentralised hydrogen production?	Yes		
Hydrogen delivery routes?	Yes		
Hydrogen use in road transport?	Yes		
Hydrogen use in rail transport?	No		
Hydrogen use in shipping?	No		
Hydrogen use in aviation?	Yes		
Hydrogen use in industry as a feedstock?	No		
Hydrogen use in industry decarbonisation?	No		
Hydrogen use for building heat?	No		
Hydrogen for electricity generation?	No		
Injection of small amounts of hydrogen into gas flows?	Yes	Yes	15%
Conversion of existing gas networks to deliver hydrogen?	No	No	
Hydrogen compression costs?	No		
Hydrogen purity and purification costs?	No		
Power-to-gas?	No		
Hydrogen storage?	No		
Compound or component delivery technologies?	Component		

Model notes

1 CCS capture rates recreated using CO2 emissions with and without CCS.
They turn out to be predominantly 90%, so this method seems appropriate.
2 Decentralised electrolyser produces centralised hydrogen.
3 Electrolyers are defined as ANNUAL rather than DAYNITE processes.
4 Liquid and gaseos hydrogen are assumed the same following distribution.
5 H2-CH4 mixing entered as a delivery technology.
6 Don't know what is a carbon storage vehicle technology.
7 2006 and 2008 start dates for cars and LGVs could be rewritten as 2005 and 2010,
according to technology names. FC cars have surprisingly high efficiencies, even in 2005.
Identical car and LGV CAPEX. The carbon LGV ICE efficiency is only 3%; probably a typo.
8 No hydrogen storage, electricity generation, industry, heating, train, shipping or HRS technologies

Hydrogen production technologies

Production plant

	1a	1b	1c	1d	1e	2a
	Description	Type	Location	Timeslice level	Plant output	Availability factor
A1	Hydrogen from biomass gasification	Biomass	Centralised		33	90%
A2	Hydrogen from biomass gasification + CO2 removal	Biomass CCS	Centralised		33	90%
A3	Hydrogen from Hardcoal	Coal	Centralised		1,667	90%
A4	Hydrogen from Browncoal	Coal	Centralised		1,667	90%
A5	Hydrogen from Hardcoal + CO2 removal	Coal CCS	Centralised		1,667	90%
A6	Hydrogen from Browncoal + CO2 removal	Coal CCS	Centralised		1,667	90%
A7	Hydrogen from NGA	Gas SMR	Centralised		1,522	98%
A8	Hydrogen from NGA + CO2 removal	Gas SMR CCS	Centralised		1,667	90%
A9	Hydrogen from NGA - Decentralized	Gas SMR	Decentralised		0.667	90%
A10	Electrolysis	Electrolysis	Centralised		33	90%
A11	Electrolysis - Decentralized	Electrolysis	Decentralised		0.667	90%

Inputs

	3a	3b	3c	3d	3e	3f	3g	3h	3i
	Electricity (.	Electricity (.	Electricity (.	Natural gas	Coal	Oil	Biomass	Waste	<Other>
A1	0.080		0.062				1.00		
A2		0.108					1.00		
A3	0.048		0.015		1.00				
A4	0.048		0.015		1.00				
A5		0.075	0.037		1.00				
A6		0.075	0.037		1.00				
A7	0.016		0.014	1.00					
A8		0.039	0.031	1.00					
A9	0.040		0.036	1.00					
A10	1.00		1.00						
A11	1.00		1.00						

Outputs, Efficiency, CCS

	4a	4b	4c	4d	5a	5b	5c	5d	6a	6b	6c
	Outputs				Efficiency				CCS		
	H2 gas	H2 liquid	Electricity	<Other>	2005	2020	<Year>	2050	Fitted	Capture rate (2020)	Capture rate (2050)
A1	1.00				37%			58%	No		
A2	1.00					36%		57%	Yes	n/a	n/a
A3	1.00				65%			73%	No		
A4	1.00				65%			73%	No		
A5	1.00					63%		71%	Yes	90.0%	90.0%
A6	1.00					63%		71%	Yes	90.0%	90.0%
A7	1.00				75.1%			79.6%	No		
A8	1.00					70%		76%	Yes	89.5%	89.7%
A9	1.00				58%			68%	No		
A10	1.00				61%			70%	No		
A11	1.00				61%			70%	No		

Lifetime and costs

	7a	8a	8b	8c	8d	9a	9b	9c	9d	10a	10b	10c	10d
	Lifetime	Investment costs				Fixed O&M costs				Variable O&M costs			
	(years)	2005	2020	<Year>	2050	2005	2020	<Year>	2050	2005	2020	<Year>	2050
A1	20	120.1			58.5	6.01			2.93	1.33			0.65
A2	20		122.9		60.0		6.15		3.00		1.37		0.67
A3	20	22.6			17.0	1.13			0.85	0.25			0.19
A4	20	22.6			17.0	1.13			0.85	0.25			0.19
A5	20		23.1		17.5		1.16		0.88		0.26		0.19
A6	20		23.1		17.5		1.16		0.88		0.26		0.19
A7	20	9.7			7.0	0.49			0.35	0.10			0.07
A8	20		12.3		8.4		0.62		0.42		0.14		0.09
A9	20	90.8			47.1	4.54			2.36	1.01			0.52
A10	20	84.1			9.6	4.21			0.48	0.93			0.11
A11	20	124.7			28.0	6.24			1.40	1.39			0.31

Hydrogen delivery and storage technologies

0.36711478

Delivery technology

	1a	1b	1c	1d	1e	2a
	Description	Type	Typical size	Location	Timeslice level	Availability factor
B1	Distribution of hydrogen - Truck gaseous	Tube trailer		Centralised		
B2	Distribution of hydrogen - Truck liquid	Road tanker		Centralised		
B3	Distribution of hydrogen - Pipeline	Transmission pipeline		Centralised		80%
B4	Dummy technology for H2 truck distribution	Tube trailer		Centralised		
B5	Dummy technology for H2 truck distribution	Tube trailer		Centralised		
B6	Mix of Gas and Hydrogen - For IND	H2-CH4 mixing		Centralised		
B7	Mix of Gas and Hydrogen - For RES	H2-CH4 mixing		Centralised		
	Mix of Gas and Hydrogen - For COM	H2-CH4 mixing		Centralised		

	3a	3b	3c	3d	4a	4b	4c	4d	5a	5b	5c	5d
	Inputs				Outputs				Efficiency			
	H2 gas	H2 liquid	Electricity	CH4	H2 gas	H2 liquid	Electricity	H2-CH4	2005	2010	<Year>	2050
B1	1				1				100%			
B2		1				1			100%			
B3	1				1					94%		
B4	1				1				100%			
B5	1				1				100%			
B6	0.176			1				1	100%			
B7	0.176			1				1	100%			
	0.176			1				1	100%			

	7a	8a	8b	8c	8d	9a	9b	9c	9d	10a	10b	10c	10d
	Lifetime	Investment costs				Fixed O&M costs				Variable O&M costs			
	(years)	2005	2010	<Year>	2050	2005	2010	<Year>	2050	2005	2010	<Year>	2050
B1	15									11.5			
B2	15									9.2			
B3	100		18.9		14.5		0.47		0.36	3.3			
B4	100												
B5	100												
B6	30												
B7	30												
	30												

Storage technology

	1a	1b	1c	1d	1e	1f	2a	3a	3b	3c	3d
	Description	Type	Storage size (MW)	Typical size (MWh)	Timeslice level	Location	Availability factor	H2 gas	H2 liquid	Electricity	<Other>
C1											

	4a	4b	4c	4d	5a	5b	5c	5d
	Outputs				Round-trip efficiency			
	H2 gas	H2 liquid	Electricity	<Other>	<Year>	<Year>	<Year>	<Year>
C1								

	7a	8a	8b	8c	8d	9a	9b	9c	9d	10a	10b	10c	10d
	Lifetime	Investment costs				Fixed O&M costs				Variable O&M costs			
	(years)	<Year>	<Year>	<Year>	<Year>	<Year>	<Year>	<Year>	<Year>	<Year>	<Year>	<Year>	<Year>
C1													

End-use hydrogen technologies

Road transport technologies

	1a	1b	1c	1d	1e	2a
	Description	Type	Location	Timeslice level	Tech output	Availability factor
D1	CAR: .AFV.HH2.Combustion.Liq sto.	Car HICE	Small		Bv-km	
D2	CAR: .AFV.HH2.Combustion.Carbon sto.	Car HICE	Small		Bv-km	
D3	CAR: .AFV.HH2.Hybrid.Liq sto.	Car Dual HICE	Small		Bv-km	
D4	CAR: .AFV.HH2.Hybrid.Carbon sto.	Car Dual HICE	Small		Bv-km	
D5	CAR: .AFV.HH2.Fuel cell.Liq sto.	Car FC HEV	Small		Bv-km	
D6	CAR: .AFV.HH2.Fuel cell.Carbon sto.	Car FC HEV	Small		Bv-km	
D7	CAR: .AFV.HH2.Fuel cell.Gas sto.	Car FC HEV	Small		Bv-km	
D8	LIGHT TRUCK: .AFV.HH2.Combustion.Liq sto.	LGV HICE	Medium		Bv-km	
D9	LIGHT TRUCK: .AFV.HH2.Combustion.Carbon sto.	LGV HICE	Medium		Bv-km	
D10	LIGHT TRUCK: .AFV.HH2.Hybrid.Liq sto.	LGV Dual HICE	Medium		Bv-km	
D11	LIGHT TRUCK: .AFV.HH2.Hybrid.Carbon sto.	LGV Dual HICE	Medium		Bv-km	
D12	LIGHT TRUCK: .AFV.HH2.Fuel cell.Liq sto.	LGV FC HEV	Medium		Bv-km	
D13	LIGHT TRUCK: .AFV.HH2.Fuel cell.Carbon sto.	LGV FC HEV	Medium		Bv-km	
D14	LIGHT TRUCK: .AFV.HH2.Fuel cell.Gas sto.	LGV FC HEV	Medium		Bv-km	

	3a	3b	3c	3d	3e	3f	3g	5a	5b	5c	5d
	Inputs							Efficiency			
	H2 gas	H2 liquid	Electricity	Natural gas	Petroleum	Biofuels	<Other>	2006	2008	2015	2020
D1		1						37.2%	39.3%	40.4%	41.5%
D2					1						44.6%
D3		1						49.6%	49.8%	51.1%	52.5%
D4					1						59.4%
D5		1						68.5%	68.8%	70.7%	72.6%
D6					1						78.0%
D7	1							73.7%	74.0%	76.0%	78.0%
D8		1						24.8%	26.2%	26.9%	27.6%
D9					1						3.0%
D10		1						33.1%	33.2%	34.1%	35.0%
D11					1						39.6%
D12		1						45.7%	45.9%	47.1%	48.4%
D13					1						52.0%
D14	1							49.1%	49.3%	50.7%	52.0%

	7a	8a	8b	8c	8d	9a	9b	9c	9d	10a	10b	10c	10d
	Lifetime	Investment costs				Investment costs				Variable O&M costs			
	(years)	2006	2008	2015	2020	2006	2008	2015	2020	2006	2008	2015	2020
D1	12.5	2000	1750	1600	1528	2000	1750	1600	1528				
D2	12.5				1929				1929				
D3	12.5	2500	2000	1750	1674	2500	2000	1750	1674				
D4	12.5				2074				2074				
D5	12.5	5000	2500	2200	1892	5000	2500	2200	1892				
D6	12.5				2293				2293				
D7	12.5	2500	2000	1800	1608	2500	2000	1800	1608				
D8	15	2000	1750	1600	1528	2000	1750	1600	1528				
D9	15				1929				1929				
D10	15	2500	2000	1750	1674	2500	2000	1750	1674				
D11	15				2074				2074				
D12	15	5000	2500	2200	1892	5000	2500	2200	1892				
D13	15				2293				2293				
D14	15	2500	2000	1800	1608	2500	2000	1800	1608				

Other transport technologies

	Description	Type	Location	Timeslice level	Tech output	Availability factor
E1	Heavy Truck: HYD Fuel Cell	HGV Rigid FC HEV	Large		Bv-km	
E2	BUS, HYD Fuel Cell	Bus FC HEV	Large		Bv-km	
E3	alternate generic plane domestic	Plane domestic	Large		PJ	
E4	alternate generic plane long dist	Plane long dist	Large		PJ	

	Inputs							Efficiency			
	H2 gas	H2 liquid	Electricity	Natural gas	Petroleum	Biofuels	<Other>	2020	2030	2040	2050
E1	1								10%		10%
E2	1								20%		21%
E3	1									264%	
E4	1									264%	

	Lifetime	Investment costs				Investment costs				Variable O&M costs			
	(years)	2020	2030	2040	2050	2020	2030	2040	2050	2020	2030	2040	2050
E1	15		1500		1300		1500		1300				
E2	15		14000		13000		14000		13000				
E3	25			100				100					
E4	25			100				100					

Electricity generation

F1

Industry

G1

Heat provision

H1

Fig. 43 Detailed ETSAP hydrogen reference energy system example