

¹ The role of Projects of Common Interest in reaching
² Europe's energy policy targets

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⁴ **Abstract**

⁵ The European Union aims to achieve climate-neutrality by 2050, with interim
⁶ 2030 targets including 55 % greenhouse gas emissions reduction compared to
⁷ 1990 levels, 10 Mt p.a. of a domestic green H₂ production, and 50 Mt p.a.
⁸ of domestic CO₂ injection capacity. To support these targets, Projects of
⁹ Common and Mutual Interest (PCI-PMI) — large infrastructure projects for
¹⁰ electricity, hydrogen and CO₂ transport, and storage — have been identified
¹¹ by the European Commission. This study focuses on PCI-PMI projects re-
¹² lated to hydrogen and carbon value chains, assessing their long-term system
¹³ value and the impact of pipeline delays and shifting policy targets using the
¹⁴ sector-coupled energy system model PyPSA-Eur.

Our study shows that PCI-PMI projects enable a more cost-effective transition to a net-zero energy system compared to scenarios without any pipeline expansion. Hydrogen pipelines help distribute affordable green hydrogen from renewable-rich regions in the north and southwest to high-demand areas in central Europe, while CO₂ pipelines link major industrial emitters with offshore storage sites. Although these projects are not essential in 2030, they begin to significantly reduce annual system costs — by more than €26 billion — from 2040 onward. Delaying implementation beyond 2040 could increase system costs by up to €24.2 billion per year, depending on the extent of additional infrastructure development. Moreover, our results show that PCI-PMI projects reduce the need for excess wind and solar capacity and lower reliance on individual CO₂ removal technologies, such as Direct Air Capture, by 13 to 136 Mt annually, depending on the build-out scenario.

¹⁵ *Keywords:* energy system modelling, policy targets, infrastructure,
¹⁶ resilience, hydrogen, carbon, Europe

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¹⁷ **1. Introduction**

¹⁸ With the European Green Deal, the European Union (EU) set a strate-
¹⁹ gic path to become climate-neutral by 2050, with interim Greenhouse Gas
²⁰ (GHG) emission reduction targets of 55 % by 2030 compared to 1990 levels
²¹ [1]. Both the net-zero target and the interim 2030 goals are legally bind-
²² ing under the European Climate Law [2]. In practice, these policy targets
²³ mean transforming the EU into ‘a modern, resource-efficient and competitive’
²⁴ economy with net-zero GHG emissions [3]. Current industrial processes and
²⁵ economic growth will need to be decoupled from fossil fuel dependencies. To
²⁶ achieve this transition across all sectors, the EU needs to scale up a portfolio
²⁷ of renewable energy sources, power-to-X solutions, Carbon Capture, Utilisa-
²⁸ tion and Storage (CCUS), and Carbon Dioxide Removal (CDR) technologies,
²⁹ such as Direct Air Capture (DAC). In parallel, complementing investments
³⁰ into the electricity grid, hydrogen (H_2) and carbon dioxide (CO_2) transport
³¹ and storage infrastructure are essential for efficient distribution across the
³² European continent [4].

³³ *Hydrogen.* Hydrogen is expected to occupy a key position in this transition
³⁴ as it is considered essential for decarbonising hard-to-abate sectors, such as,
³⁵ but not limited to steel, refining, fertilisers, shipping, and aviation [5, 6].
³⁶ To lay out the foundation for a future hydrogen economy, the EU has set
³⁷ ambitious targets for domestic hydrogen production and infrastructure build-
³⁸ out. Under the EU Hydrogen Strategy [7], reinforced by REPowerEU [8]
³⁹ and the Net-Zero Industry Act (NZIA) [9], the EU aims to install at least
⁴⁰ 40 GW electrolysis capacity by 2030, domestically (with an additional 40
⁴¹ GW to be installed in so-called European Neighbourhood countries [10]).
⁴² REPowerEU foresees the annual production of 10 Mt of domestic renewable
⁴³ hydrogen by 2030, alongside an additional 10 Mt sourced through imports
⁴⁴ [8]. Initiatives like the European Hydrogen Backbone (EHB) aim to support
⁴⁵ this transition by proposing a hydrogen transport network across Europe.
⁴⁶ The EHB initiative envisions a H_2 pipeline network of almost 53 000 km by
⁴⁷ 2040 [11], including repurposing existing natural gas infrastructure and new
⁴⁸ potential routes.

⁴⁹ *CCUS.* Complementing its hydrogen ambitions, the EU has proposed simi-
⁵⁰ larly strategic plans for the carbon economy. In the Industrial Carbon Man-
⁵¹ agement Strategy, the EU envisages a single market for CO_2 in Europe, to
⁵² enable CO_2 to become a tradable commodity for storage, sequestration, or

53 utilisation [12]. Beyond a net-zero emission target in the European Climate
54 Law [2], CO₂ serves as a key feedstock for the production of synthetic fuels,
55 such as methanol, methane, as well as high-value chemicals [6]. Outside of
56 CO₂ utilisation, Carbon Capture and Storage (CCS) is considered indispensable
57 for achieving net-zero emissions in sectors with unavoidable process-
58 based CO₂ emissions, such as cement, chemicals, and waste-to-energy. Here,
59 the NZIA mandates that all EU member states collectively ensure that at
60 least 50 Mt p.a. of CO₂ can be injected and stored by 2030. The European
61 Commission further estimates that up to 550 Mt p.a. of CO₂ will need to be
62 captured by 2050 [9]. At least 250 Mt p.a. will need to be sequestered in the
63 European Economic Area [13].

64 *Transport infrastructure and PCI-PMI projects.* To meet the need for green
65 electricity, green H₂ and CO₂, significant investments into its transport and
66 storage/sequestration infrastructure are needed. A recent report by the Eu-
67 ropean Commission confirms that investment needs into the EU's energy
68 infrastructure will continue to grow [14], estimating planned expenditures
69 of around €170 billion for H₂ and up to €20 billion for CO₂ infrastructure
70 by 2040, respectively. It also emphasises that these investments face higher
71 uncertainty, as both sectors are still in their infancy.

72 Within the transition towards net-zero, the EU has established a frame-
73 work to support the development of key cross-border and national infrastruc-
74 ture projects, which are considered essential for achieving the EU's energy
75 policy targets. These Projects of Common Interest (PCI) are projects that
76 link the energy systems of two or more EU member states [15]. In a biennial
77 selection process, PCIs are identified through regional stakeholder groups
78 and evaluated based on their contribution to the EU's energy security, e.g.
79 by improving market integration, diversification of energy supply, and inte-
80 gration of renewables. So-called Projects of Mutual Interest (PMI) transfer
81 the same concept to projects that link the EU's energy system with third
82 countries, such as Norway or the United Kingdom, the Western Balkans or
83 North Africa, as long as they align with EU climate and energy objectives
84 [16]. Approved PCI-PMI projects benefit from accelerated permitting and
85 access to EU funding under the Connecting Europe Facility (CEF). Given
86 the strong political and project promoter support, comprehensive reporting
87 and monitoring processes, as well as their role as technological lighthouses,
88 projects on the PCI-PMI list are more likely to be implemented than others
89 [14]. Nonetheless, large infrastructure projects—including those on the PCI-

90 PMI list—often face delays due to permitting hurdles, financing constraints,
91 procurement bottlenecks, and other implementation challenges [17].

92 As a direct result of the revised TEN-E Regulation (Regulation (EU)
93 2022/869)) [18], the 2023 PCI-PMI list [16, 19] for the first time includes
94 H₂ and CO₂ transport and storage projects, alongside electricity and gas
95 projects. A continent-wide hydrogen backbone — connecting regions rich in
96 renewable energy potential to industrial and storage hubs — is viewed es-
97 sential for transporting H₂ where it is needed. Likewise, CO₂ pipelines and
98 sequestration sites are needed to capture, transport and sequester emissions
99 from industrial processes and power plants. With around 14 projects in the
100 priority thematic area ‘cross-border carbon dioxide network’ and 32 projects
101 listed in ‘hydrogen interconnections’ (including pipelines and electrolyzers),
102 this PCI-PMI list lays the foundation for a future pan-European H₂ and CO₂
103 value chain [20].

104 *Contribution of this paper.* In light of the evolving infrastructure landscape,
105 the question arises as to what the long-term value of these PCI-PMI projects
106 is under varying implementation risks and policy uncertainties. This paper
107 contributes to the policy debate around H₂ and CO₂ by quantitatively as-
108 sessing the long-term value of strategic cross-border infrastructure, such as
109 Projects of Common Interest and Projects of Mutual Interest. Given the
110 interdependencies between the energy sectors, system energy system mod-
111 elling approaches are needed that account for the complexity of interactions
112 among different energy carriers. Hence, we build on the open-source en-
113 ergy system model PyPSA-Eur to assess their value in fully sector-coupled
114 decarbonisation pathways — linking electricity, heating, industry, and agri-
115 culture, transport, shipping, and aviation — under varying events such as
116 infrastructure delays and shifts in policy ambition.

117 2. Literature review & identified research gaps

118 We structure the literature review into two three main sections: research
119 work focusing on (i) the value of CO₂ and H₂ in low-carbon energy systems
120 and (ii) addressing uncertainty in energy system models. Based on this re-
121 view, we identify research gaps and position our work as a novel contribution
122 to the current state of the art in Section 2.3.

123 2.1. *The value of CO₂ and H₂ in low-carbon energy systems*

124 A growing body of literature has been investigating the long-term role
125 of H₂ and CO₂ in low-carbon or net-zero energy systems. Both carriers see
126 their primary value outside the electricity sector, i.e., in the decarbonisation
127 of hard-to-abate sectors such as industry, transport, shipping, and aviation
128 [21]. While there are direct use cases for H₂ in the industry sector such as
129 steel production, it is primarily expected to serve as a precursor for synthetic
130 fuels, including methanol, Fischer-Tropsch fuels (e.g. synthetic kerosene and
131 naphta) and methane. The demand for these fuels is driven by the aviation,
132 shipping, industry, and agriculture sectors [6]. To produce these carbona-
133 ceous fuels, CO₂ is required as a feedstock (Carbon Utilisation — CU). This
134 CO₂ can be captured from the atmosphere via DAC, biomass plants, or from
135 industrial and process emissions (e.g. cement, steel, ammonia production) in
136 combination with Carbon Capture (CC) units. Béres et al. [5] evaluate the
137 interaction between electricity, H₂, and synthetic fuel demand using the JRC-
138 EU-TIMES long-term energy system model. In their findings, H₂ production
139 varies between 42 (1400 TWh) and 66 Mt (2200 TWh) p.a. in 2050. Van
140 Greevenbroek et al. [22] investigate the cost-optimal deployment of green
141 hydrogen (H₂) through a comprehensive assessment of the near-optimal sol-
142 lution space across a wide range of scenarios. Their findings suggest that a
143 moderate production target of approximately 25 Mt p.a. by 2040 is close
144 to cost-optimal, with the specific level of green H₂ production depending
145 largely on the availability of green fuel imports and the feasibility of carbon
146 capture and storage (CCS). Their study concludes that Europe would have
147 ‘little to lose’ by pursuing such a target — completely eliminating green H₂
148 production instead would increase total system costs by about 2 %. In a re-
149 gional case study on Germany, Cerniauskas et al. [23] use a hydrogen supply
150 chain model [24] to evaluate the feasibility of repurposing existing natural
151 gas pipelines for hydrogen transport. Their findings show that in the case o
152 Germany, more than 80 % of the existing natural gas pipeline network show
153 a technically viable potential for hydrogen reassignment. Compared to com-
154 pletely new pipeline construction, this could reduce the costs of hydrogen
155 transmission by more than 60 %.

156 Neumann et al. [6] examine the interaction between electricity grid ex-
157 pansion and a European-wide deployment of hydrogen pipelines in a net-zero
158 system (new and retrofitting of existing gas pipelines). While H₂ pipelines
159 are not essential, their build-out can significantly reduce system costs by
160 up to €26 billion per year (3.4 % of annual CAPEX and OPEX) by con-

necting regions with excessive renewable potential to storage sites and load centres. Extending their previous work, Neumann et al. [25] investigate the trade-off between relying on different energy import strategies and domestic infrastructure build-out. By coupling the global energy supply chain model TRACE [26] and the sector-coupled PyPSA-Eur model, they assess different energy vector import combinations (e.g. electricity, H₂ or H₂ derivatives) and their impact on Europe's infrastructural needs. By allowing for green energy imports, they observe system cost reductions of around 5% (€39 billion per year), ranging between 1% and 14% depending on the import cost assumptions. With an increasing share of H₂ imports, the need for domestic H₂ pipelines would decrease, accordingly.

In a study by Kontouris et al. [27], the authors explore pathways for a potential integrated hydrogen infrastructure in Europe while considering sector-coupling and energy imports. Using the European energy system model Balmoral [28], the authors implement three scenarios varying between domestic and imported H₂ levels as well as H₂ production technologies. In their findings they identify important H₂ transport corridors between Spain and France, Ireland and the United Kingdom, Italy, and Southeastern Europe. When synergies through sector-coupling are exploited, domestic H₂ production can be competitive, seeing an increase in up to 3% in system costs.

Fleiter et al. [29] use a mixed simulation and optimisation method to model H₂ uptake and transport by coupling three models, (i) FORECAST for buildings and industry, (ii) ALADIN for transport together with (iii) the European energy system model Enertile. Total demand for H₂ ranges from 690 TWh to 2 800 TWh in 2050, with 600 TWh to 1 400 TWh for synthetic fuels. In their study, the chemical and steel industry in Northwest Europe (including western regions of Germany, Netherlands and northern regions of Belgium), display a demand of more than 100 TWh each. With regard to crossborder transport, they mainly observe hydrogen flows from Norway, UK and Ireland to continental Europe (around 53 TWh to 72 TWh). Depending on the scenario, the Iberian Peninsula exports around 72 TWh to 235 TWh via land and to France.

Bakken and Velken [30] formulate linear models for the optimisation of CO₂ infrastructure — including pipelines, shipping, CO₂ capture, and storage — and demonstrate the applicability in a regional case study for Norway. [31–35]

198 *2.2. Addressing uncertainty in energy system models*

199 While the reviewed research works examined the value of CO₂ and H₂ in
200 low-carbon energy systems, they do not account for potential uncertainties
201 regarding future policy targets or infrastructure build-outs. Energy system
202 models can address such uncertainties through a range of approaches, includ-
203 ing, but not limited to, scenario analysis, Modelling to Generate Alternatives
204 (MGA) and exploration of near-optimal solution space [22, 36, 37], stochastic
205 programming, and others.

206 Yue et al. [38] provide a comprehensive review of approaches to uncer-
207 tainty in energy system models. Having performed a broad literature review
208 on primary studies involving energy system models and uncertainty, the au-
209 thors provide guidance for selecting the appropriate approach based on the
210 the modelling context and problem size.

211 Van der Weijde and Hobbs [35] demonstrate the importance of considering
212 uncertainty in energy system models, by applying a two-stage optimisation
213 model to evaluate grid reinforcements in Great Britain (GB). Including the
214 status quo scenario, they consider six scenarios, which represent different fu-
215 ture developments of electricity demand, generation, fuel, and CO₂ prices.
216 As part of their study, they calculate the regret for given first-stage trans-
217 mission decisions under the realisation of second-stage scenarios. For GB,
218 they find that the expected cost of ignoring uncertainty can be as high as up
219 to £111 million (present value) over a planning horizon of 50 years.

220 Möbius and Riepin [34] investigate the regret of investment decisions into
221 electricity generation capacities, by developing a two-stage, stochastic cost-
222 minimisation model of the European electricity and gas markets. They find
223 that electricity system planning exercise that ignores uncertainty associated
224 to electricity demand yields an expected regret of €674 million per year and
225 ignoring CO₂ price uncertainty by €314 million per year. This underscores
226 the importance of accounting for these uncertainties in energy planning, as
227 overlooking them can lead to significantly higher system costs and suboptimal
228 investment decisions.

229 *2.3. Research gaps and contribution of this study*

230 While several studies have begun to explore the interaction between CO₂
231 and H₂ infrastructure in sector-coupled energy system models, important as-
232 pects remain insufficiently addressed — in particular the role of real planned
233 infrastructure projects, transformation pathways, and the influence of uncer-
234 tainties on the long-term performance of these projects. Existing analyses

235 abstract away from actual investment plans, such as those under the PCI-
236 PMI framework, potentially neglecting infrastructure options that are not
237 perfectly cost-optimal but have a high likelihood of implementation, e.g.,
238 due to political support [22, 39].

239 While Hofmann et al. [4] provide valuable insights into the synergies be-
240 tween H₂ and CO₂ infrastructure, the lack of inclusion of planned projects
241 and focus on a single modelling year might yield overly optimistic results. To
242 our knowledge, the contribution of PCI-PMI projects has not yet been eval-
243 uated within a sector-coupled modelling framework that incorporates future
244 policy targets, uncertainty and transformation pathways.

245 Our study addresses these gaps by explicitly including PCI-PMI projects
246 in a sector-coupled model of the European energy system. We assess var-
247 ious build-out levels of CO₂ and H₂ infrastructure across short-term sce-
248 narios and transformation pathways. Using a myopic, iterative modelling
249 approach, we simulate energy system development from 2030 to 2050 under
250 non-anticipative foresight, reflecting the reality that market participants do
251 not have perfect knowledge of long-term developments. This approach helps
252 avoid the overly optimistic outcomes of long-term perfect foresight models.

253 *Regret analysis.* We base our analysis on the concept of regret from decision
254 theory [40], where regret is typically defined as the difference in economic
255 value, payoff, or cost between a chosen strategy and the optimal strategy un-
256 der identical conditions [34]. The regret term then represents the additional
257 cost incurred from not following the cost-optimal strategy. In energy mod-
258 ellling literature [34, 35], a regret analysis is usually designed in two steps,
259 first, a set of scenarios is defined, representing different future developments,
260 e.g. varying in policy targets, infrastructure build-out, or technology costs.
261 In a second step, the performance of first-stage investment is evaluated under
262 the realisation of second-stage or short-term realisations of the future [41]. It
263 is particularly useful in energy system modelling, where future uncertainties
264 can significantly impact the performance of investments in infrastructure and
265 technologies. A regret-based approach enables us to quantify the economic
266 value associated with PCI-PMI projects across scenarios reflecting a selected
267 set of uncertainties, including changes in EU energy policy project delays,
268 and cancellations. By limiting the analysis to a set of scenarios, this regret
269 analysis is manageable and computationally feasible.

270 *Research questions.* This study also aims to reduce the uncertainty surround-
271 ing the ‘chicken-and-egg’ dilemma in infrastructure investment — whether

272 to develop CO₂ and H₂ infrastructure in advance or to wait for demand to
273 materialise. Specifically, we address the following research questions:

- 274 1. What is the long-term value of PCI-PMI projects in supporting the
275 EU's climate and energy policy targets, and what are the associated
276 costs?
- 277 2. What are the costs of adhering to the EU policy targets, even when
278 the implementation of PCI-PMI projects is delayed?

279 **3. Methodology**

280 In this section we first describe the basic energy system model PyPSA-
281 Eur, before detailing the implementation of the PCI-PMI projects, the sce-
282 narios, and the regret matrix.

283 We build on the open-source, sector-coupled energy system model PyPSA-
284 Eur [6, 42–44] to optimise investment and dispatch decisions in the European
285 energy system. The model's endogenous decisions include the expansion and
286 dispatch of renewable energy sources, dispatchable power plants, power-to-
287 X conversion, and storage/sequestration capacities as well as transmission
288 infrastructure for power, hydrogen, and CO₂. It also encompasses heating
289 technologies and various hydrogen production methods (gray, blue, green).
290 PyPSA-Eur integrates multiple energy carriers (e.g., electricity, heat, hy-
291 drogen, CO₂, methane, methanol, liquid hydrocarbons, and biomass) with
292 corresponding conversion technologies across multiple sectors (i.e., electric-
293 ity, transport, heating, biomass, industry, shipping, aviation, agriculture and
294 fossil fuel feedstock). The model features high spatial and temporal resolu-
295 tion across Europe, incorporating existing power plant stocks [45], renewable
296 potentials, and availability time series [46]. It includes the current high-
297 voltage transmission grid (AC 220 kV to 750 kV and DC 150 kV and above)
298 [47]. Furthermore, electricity transmission projects from the TYNDP [48]
299 and German Netzentwicklungsplan [49] are also enabled.

300 *3.1. Model setup*

301 *Temporal resolution.* To assess the long-term impact of PCI-PMI projects
302 on European policy targets across all sectors, we optimise the sector-coupled
303 network for three key planning horizons 2030, 2040, and 2050, myopically.
304 The myopic approach ensures that investment decisions across all planning

305 horizons are non-anticipative and build on top of the previous planning horizon.
306 We use a time series aggregation technique to solve the model with 2190
307 representative time steps. The aggregation is done with the Python package
308 *tsam* developed by Kotzur et al. [50] which ensures that intertemporal char-
309 acteristics including renewable infeed variability, demand fluctuations, and
310 seasonal storage needs are preserved.

311 *Geographical scope.* We model 34 European countries, including 25 of the
312 EU27 member states (excluding Cyprus and Malta), as well as Norway,
313 Switzerland, the United Kingdom, Albania, Bosnia and Herzegovina, Mon-
314 tenegro, North Macedonia, Serbia, and Kosovo. Regional clustering is based
315 on administrative NUTS boundaries, with higher spatial resolution applied
316 to regions hosting planned PCI-PMI infrastructure, producing 99 onshore re-
317 gions (see Table A.5). Depending on the scenario, additional offshore buses
318 are introduced to appropriately represent offshore sequestration sites and
319 PCI-PMI projects. To isolate the effect of PCI-PMI projects, Europe is self-
320 sufficient in our study, i.e., we do not allow any imports or exports of the
321 assessed carriers like electricity, H₂, or CO₂.

322 *Technology assumptions.* As part of the PyPSA-Eur model, all technology-
323 specific assumptions — such as lifetime, efficiency, investment costs, and
324 operational costs — are derived from the public Energy System Technol-
325 ogy Data repository (v0.10.1) [51]. This repository sources most of its data
326 from technology catalogues published by the Danish Energy Agency (Ener-
327 gistyrelsen) [52]. We use values projected for 2030 and apply a discount rate
328 of 7%, reflecting the weighted average cost of capital (WACC). We assume
329 CO₂ sequestration costs of €15/tCO₂ which can be considered in the mid-
330 range of the cost spectrum (cf. €10/tCO₂ [4] and \$12/tCO₂ to \$18/tCO₂
331 [53]). An overview of selected technology assumptions is provided in Table
332 A.4.

333 *Energy demand and CO₂ emissions.* Energy and fuel carrier demand in the
334 modelled sectors, as well as non-abatable CO₂ process emissions are taken
335 from various sources [54–58] and are shown in Figure A.9. Regionally and
336 temporally resolved demand includes electricity, heat, gas, biomass and trans-
337 port.

338 Gas (methane/CH₄) demand includes direct use in gas-based industrial
339 processes, as well as fuel in the electricity and heating sector. Note that we
340 do not explicitly model the gas transmission grid as opposed to the CO₂ and

341 H₂ infrastructure. We do this for the following reasons: (i) The modelled
342 PCI-PMI projects overlap in some parts with the gas grid, i.e., they include
343 CH₄ pipelines that will be retrofitted to H₂ pipelines — information in the
344 PCI-PMI project sheets is not always clear on this; (ii) In the EU energy sys-
345 tem, the transport of natural gas is rarely constrained by the existing gas grid
346 infrastructure, reflecting the grid's robust capacity to accommodate demand
347 fluctuations [59]; (iii) Considering (ii), empirical gains of explicitly imple-
348 menting the gas grid do not justify the additional computational burden.
349 Instead, given this work's focus on the CO₂ and H₂ sector, we have decided
350 to make trade-offs here and assume gas transport to be 'copper-plated'.

351 Internal combustion engine vehicles in land transport are expected to fully
352 phase out in favour of electric vehicles by 2050 [60]. Demand for methanol and
353 hydrocarbons, e.g. kerosene, are primarily driven by the shipping, aviation
354 and industry sector and are not spatially resolved (Figure A.9). To reach
355 net-zero CO₂ emissions by 2050, the yearly emission budget follows the EU's
356 2030 (−55 %) and 2040 (−90 %) targets [1, 61], translating into a carbon
357 budget of 2072 Mt p.a. in 2030 and 460 Mt p.a. in 2040, respectively (see
358 Table 2).

359 *PCI-PMI projects implementation.* We implement all PCI-PMI projects of
360 the electricity, CO₂ and H₂ sectors (excluding offshore energy islands and
361 hybrid interconnectors, as they are not the focus of our research) by access-
362 ing the REST API of the PCI-PMI Transparency Platform and associated
363 public project sheets provided by the European Commission [19]. We add
364 all CO₂ sequestration sites and connected pipelines, H₂ pipelines and storage
365 sites, as well as proposed pumped-hydro storage units and transmission lines
366 (AC and DC) to the PyPSA-Eur model. We consider the exact geographic
367 information, build year, as well as available static technical parameters when
368 adding individual assets to the respective modelling year. An overview of the
369 implemented PCI-PMI projects is provided in Figure 1.

370 Our implementation can adapt to the needs and configuration of the
371 model, including selected technologies, geographical and temporal resolution,
372 as well as considered sectors. Within this study, all projects are mapped to
373 the 99 NUTS regions. In the mapping process, pipelines are aggregated and
374 connect all regions that they are overpassing. Similar to how all electricity
375 lines and carrier links are modelled in PyPSA-Eur, lengths are calculated
376 using the haversine formula multiplied by a factor of 1.25 to account for the
377 non-straight shape of pipelines. We apply standardised cost assumptions [51]

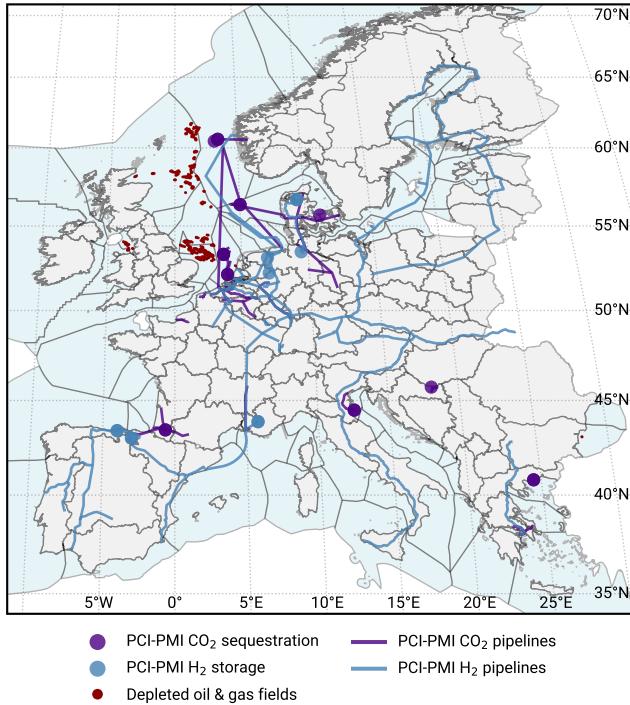


Figure 1: Map of the regional scope including clustered onshore (grey) and offshore regions (blue), as well as PCI-PMI CO₂ and H₂ pipelines, storage and sequestration sites. Depleted offshore oil and gas fields (red) provide additional CO₂ sequestration potential [4].

378 across all existing brownfield assets, exogenously specified PCI-PMI projects,
379 and projects endogenously selected by the model, equally. Our approach is
380 motivated by two considerations: (i) cost data submitted by project promot-
381 ers are often incomplete and may differ in terms of included components,
382 underlying assumptions, and risk margins; and (ii) applying uniform cost
383 assumptions ensures comparability and a level playing field across all poten-
384 tial investments, including both PCI-PMI projects and endogenous model
385 decisions.

386 *CO₂ sequestration and H₂ storage sites.* Beyond CO₂ sequestration site projects
387 included in the latest PCI-PMI list (around 114 Mt p.a.), we consider addi-
388 tional technical potential from the European CO₂ storage database [4, 62].
389 The dataset includes storage potential from depleted oil and gas fields and
390 saline aquifers. While social and commercial acceptance of CO₂ storage has
391 been increasing in recent years, concerns still exist regarding its long-term
392 role and safety [63]. We only consider conservative estimates from depleted
393 oil and gas fields, which are primarily located offshore in the British, Norwe-
394 gian, and Dutch North Sea (see Figure 1), yielding a technical sequestration
395 potential of 7 164 Mt. Our focus is motivated by the following reasons: (i) in-
396 frastructure such as wells, platforms, and pipelines already exist for depleted
397 oil and gas fields and can be repurposed, significantly lowering costs and
398 project risk; (ii) depleted fields are generally better understood geologically
399 and have demonstrated sealing capacities, further reducing uncertainty; and
400 (iii) repurposing former production sites is often more publicly and politically
401 acceptable than developing entirely new storage locations, entirely. In con-
402 trast, while saline aquifers represent a substantial share of the total technical
403 potential, they carry higher development costs and risks and are less likely
404 to be advanced without strong policy and financial support [62]. Note that
405 the PCI-PMI project list includes some aquifer-based sequestration projects,
406 however, their inclusion as PCI-PMI project indicates a higher likelihood of
407 development.

408 We distribute the technical sequestration potential of the depleted oil and
409 gas fields over a lifetime of 25 years (cf. [4]), yielding an annual sequestration
410 potential of up to 286 Mt p.a. We then cluster all offshore potential within a
411 buffer radius of 50 km per offshore bus region in each modelled NUTS region
412 and connect them through offshore CO₂ pipelines to the closest onshore bus.

413 The model also includes H₂ storage sites from the PCI-PMI list and allows
414 for endogenous build-out of additional storage capacities by repurposing salt

415 caverns [6].

416 *3.2. Scenario setup and regret matrix*

417 To assess the long-term impact of PCI-PMI projects on the European
418 energy system and EU energy policies, we implement a regret matrix based
419 approach. This allows us to evaluate the following questions: (i) What ad-
420 ditional costs are incurred/saved by relaxed policy ambitions, delayed or
421 cancelled PCI-PMI projects? (ii) What are alternative investment strategies
422 to react to these events?

423 *3.2.1. Long-term scenarios*

424 *Scenario definition.* We define the long-term scenarios based on the degree
425 of CO₂ and H₂ infrastructure build-out, including the roll-out of PCI-PMI
426 projects as well additional pipeline investments. In total, we implement
427 five long-term scenarios, (i) a pessimistic scenario (Decentral Islands — *DI*)
428 without any H₂ pipeline and onshore CO₂ pipeline infrastructure, (ii) a sce-
429 nario that considers the on-time commissioning of all PCI-PMI CO₂ and H₂
430 projects (PCI-PMI — *PCI*) only, (iii) more ambitious scenarios that further
431 allow investments into national and (iv) international pipelines (PCI-PMI
432 nat. — *PCI-n* and PCI-PMI internat. — *PCI-in*), and (v) a scenario that
433 does not assume any fixed PCI-PMI infrastructure but allows for a cen-
434 tralised, purely needs-based build-out of CO₂ and H₂ pipelines (Centralised
435 Planning — *CP*). An overview of the long-term scenarios and their associated
436 model-endogenous decision variables is provided in Table 1.

437 *Targets.* In all long-term scenarios, emission, technology, sequestration and
438 production targets have to be met for each planning horizon (see Table 2).
439 For the year 2030, these targets are directly derived from the EU's policy
440 targets, including a 55 % reduction in greenhouse gas emissions compared to
441 1990 levels [1], 10 Mt p.a. of domestic green H₂ production [8] and 40 GW
442 of electrolyser capacity [7], and 50 Mt p.a. of CO₂ sequestration capacity
443 [9]. For 2050, the CO₂ are based on the modelling the impact assessment for
444 the EU's 2040 climate targets, in 250 Mt p.a. need to be sequestered [13].
445 H₂ production targets for 2050 are based on the European Commission's
446 'METIS 3 study S5' [64], modelling possible pathways for industry decar-
447 bonisation until 2040. For 2040, we interpolate linearly between the 2030
448 and 2050 targets. The electrolyser capacities for 2040 and 2050 are scaled by
449 the ratio of H₂ production to electrolyser capacity in 2030. An overview of

Table 1: Overview of long-term scenarios and their key assumptions.

Long-term scenarios	DI	PCI	PCI-n	PCI-in	CP
CO₂ sequestration					
Depleted oil & gas fields*	■	■	■	■	■
PCI-PMI seq. sites**	–	■	■	■	■
H₂ storage					
Endogenous build-out	■	■	■	■	■
PCI-PMI storage sites	–	■	■	■	■
CO₂ pipelines					
to depleted oil & gas fields	■	■	■	■	■
to PCI-PMI seq. sites	–	■	■	■	■
CO₂ and H₂ pipelines					
PCI-PMI	–	■	■	■	■
National build-out	–	■	■	■	■
International build-out	–	–	–	■	■
PCI-PMI extendable	–	–	–	–	■

■ enabled – disabled * approx. 286 Mt p.a. ** approx. 114 Mt p.a.

450 the targets and their values is provided in Table 2. We implement the green
 451 hydrogen production target as a minimum production constraint on electrolysis.
 452 Accordingly, we refer to this hydrogen as ‘electrolytic H₂’ throughout
 453 this paper. Note that this implementation is based on an aggregated annual
 454 target without temporal matching rules.

Table 2: Pathway for implemented targets.

Planning horizon	2030	2040	2050
Targets			
GHG emission reduction	–55 %	–90 %	–100 %
CO ₂ sequestration	50 Mt p.a.	150 Mt p.a.	250 Mt p.a.
Electrolytic H ₂ production	10 Mt p.a.	27.5 Mt p.a.	45 Mt p.a.
H ₂ electrolyser capacity	40 GW	110 GW	180 GW

Climate and energy policy targets based on [1, 8, 9, 13, 64]

455 3.2.2. Short-term scenarios

456 In a subsequent step, we examine the impact of various short-term sce-
 457 narios on the long-term decarbonisation pathways. Specifically, we assume
 458 that the CO₂ and H₂ pipeline capacities identified in the long-term modelling
 459 exercise are either maintained at their planned levels, delayed in implemen-
 460 tation, or not built at all. In these short-term scenarios, the model can
 461 still react by investing into additional generation, storage, or conversion, or
 462 carbon-removal technologies, assuming the technical potential was not ex-
 463 ceeded in the long-term optimisation. At this step, we also simulate changes
 464 in energy policy. For example, in *Reduced targets*, we remove all of the long-
 465 term targets (Table 2) except for the GHG emission reduction targets to
 466 assess the value of the CO₂ and H₂ infrastructure in a less ambitious policy
 467 environment [12]. In *Delayed pipelines*, we assume that all PCI-PMI and
 468 endogenous pipelines are delayed by one period, i.e., the commissioning of
 469 the project is shifted to the next planning horizon. Lastly, we remove all
 470 pipeline capacities in *No pipelines*, including the PCI-PMI projects, allowing
 471 us to evaluate the impact of a complete lack of planned infrastructure.

472 Table 3 gives an overview of the regret matrix setup and its underlying as-
 473 sumptions, where the long-term scenario serves as the *planned* or *anticipated*
 474 and the short-term scenario serves as the hypothetically *realised* outcome.

Table 3: Regret matrix setup: Long-term and short-term scenarios.

Short-term	Reduced targets	Delayed pipelines	No pipelines
Long-term scenarios			
Decentral Islands (DI)	■	—	—
PCI-PMI (PCI)	■	■	■
PCI-PMI nat. (PCI-n)	■	■	■
PCI-PMI internat. (PCI-in)	■	■	■
Central Planning (CP)	■	■	■
Targets			
GHG emission reduction	■	■	■
CO ₂ sequestration	—	■	■
Electrolytic H ₂ production	—	■	■
H ₂ electrolyzers	—	■	■
CO₂ + H₂ infrastructure			
CO ₂ sequestration sites	■	■	■
CO ₂ pipelines to seq. site	■	■	■
CO ₂ pipelines	■	□	—
H ₂ pipelines	■	□	—

■ enabled □ delayed by one period — disabled

475 A regret matrix provides a decision-making framework that evaluates the
 476 potential loss (*regret*) associated with choosing one strategy over the other
 477 by comparing the outcomes, i.e., the total system costs. Here, the regret is
 478 quantified as the difference between system costs of the short-term scenario
 479 and the long-term (anticipated) scenario for each scenario. In total, we run
 480 60 optimisations on a cluster: $(n_{LT} \times n_{planning\ horizons}) \times (1 + n_{ST}) = 60$. Each
 481 calculation requires up to 160 GB of RAM and 8 to 16 hours to solve. The
 482 linear optimisation problems are solved using Gurobi.

483 4. Results and discussion

484 We structure the results and discussion into three main sections. First, we
 485 present the results of the long-term scenarios. Then, we look at the impact
 486 of the short-term scenarios on the long-term scenarios, by comparing the

487 economic regret and impacts on CO₂ and H₂ balances. Finally, we assess the
488 benefits of the PCI-PMI projects with regard to reduced system costs and
489 discuss the implications of our findings for the European energy system and
490 its policy targets.

491 *4.1. Long-term scenarios*

492 Figure 2 shows the total annual system costs — distributed over all mod-
493 elled technology groups — for each planning horizon and long-term scenario.
494 We observe the highest total annual system costs in the planning horizon
495 2040, ranging from €912 to €968 billion per year. This cost increase is pri-
496 marily driven by the sharp decarbonisation pathway planned for 2030 to 2040
497 — a carbon budget reduction of more than 1600 Mt p.a. compared to the
498 remaining 460 Mt p.a. in the last decade from 2040 to 2050. In 2030, total
499 system costs are lowest in the *DI* and *CP* scenario, as the model does not see
500 the need for large-scale investments into H₂ and CO₂ infrastructure yet (due
501 to myopic foresight). Adding PCI-PMI projects in 2030 increases costs by
502 less than 1 % (Figure 2). With CO₂ pipelines connecting depleted offshore
503 oil and gas fields to their closest onshore region, the policy targets, including
504 CO₂ sequestration can be achieved at a total of €865 billion per year.

505 Starting in 2040, all scenarios with PCI-PMI and endogenous pipeline
506 investments unlock significant cost savings, from more than €30 billion per
507 year in the *PCI* up to €50 billion per year in the *PCI-in* scenario. By granting
508 the model complete flexibility to expand hydrogen and CO₂ infrastructure at
509 any location beyond the PCI-PMI projects, we unlock additional annual cost
510 savings of €6 to €7 billion per year through investments in fewer, yet more
511 optimally located CO₂ and H₂ pipelines from a systemic perspective (see *PCI-*
512 *in* pipeline utilisation in Figure B.24 compared to *CP* pipeline utilisation in
513 Figure B.25). Further, this reduces the reliance on larger investments into
514 wind generation and costly DAC technologies near the sequestration sites.
515 These effects are slightly less pronounced in the 2050 model results, where
516 system costs can be reduced by €26 to €41 billion per year with PCI-PMI and
517 endogenous pipeline investments. Here, higher carbon capture and utilisation
518 (CCU) via methanol synthesis and Fischer-Tropsch processes, supported by
519 increased H₂ production as a chemical feedstock, enhances system flexibility
520 compared to 2040 (Figures 3 and 4).

521 *CCUS*. We find that most of the differences in system cost and savings can
522 be attributed to the production and utilisation of CO₂, as shown in Figure 3.

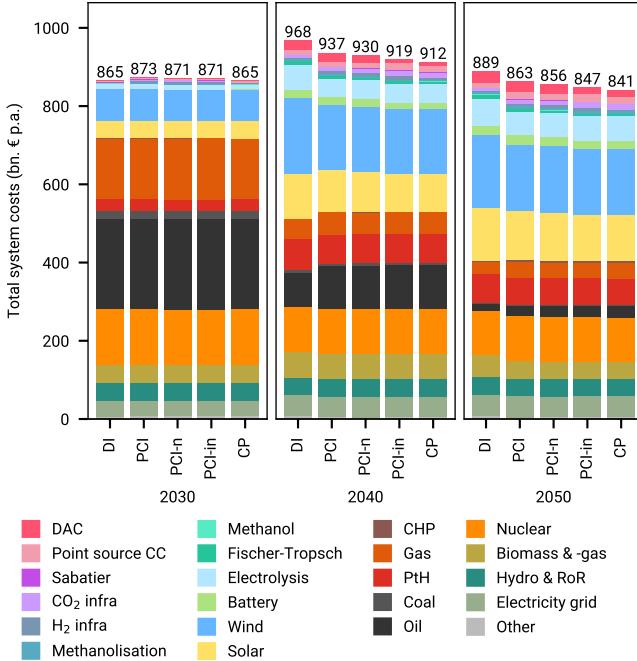


Figure 2: Total annual system costs (CAPEX + OPEX) by technology group. CO_2 and H_2 infrastructure each include pipelines, storage and sequestration sites, respectively. Gas refers to gas power plants and boilers. Coal infrastructure refers to hard coal and lignite power plants. Other includes SMR, rural heat, and thermal storage.

Lacking the option to transport CO_2 from industry and other point sources to the offshore sequestration sites, the system requires expensive DAC in the *DI* scenario. While the sequestration target of 50 Mt p.a. in 2030 is binding only in the *DI* scenario, all other scenarios achieve higher levels of CO_2 sequestration as their CO_2 pipeline build-out increases. The 53.9 Mt p.a. of CO_2 sequestered in the *CP* scenario serves as an indicator of the cost-optimal level of sequestration for the European energy system in 2030 assuming perfectly located pipeline infrastructure. With the inclusion of PCI-PMI projects, CO_2 sequestration ranges from 58.7 Mt p.a. in the *PCI* to 75 Mt p.a. in the *PCI-in* scenario. Looking at 2040 and 2050, in place of expensive DAC in the *DI* scenario, the model equips biomass-based industrial processes — primarily located in Belgium, the Netherlands and Western regions of Germany — with carbon capture (see Figures 5d, 5e, and 5f).

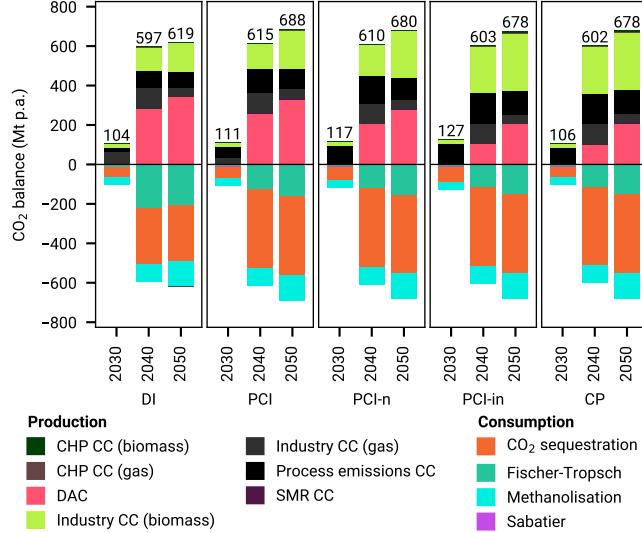


Figure 3: CO₂ balances in long-term scenarios.

In 2040 and 2050, all sequestration targets (Table 2) are overachieved, as the full combined CO₂ sequestration potential of 398 Mt p.a. is exploited in all scenarios where PCI-PMI projects are included (*PCI* to *CP*). Emissions are captured from industrial processes equipped with carbon capture units, with biomass-based industry contributing the largest share of point-source carbon capture. This ranges from 119 to 241 Mt p.a. in 2040 and from 149 to 287 Mt p.a. in 2050, increasing with the build-out of CO₂ infrastructure (from left to right; see Figure 3). As the most expensive carbon capture option, CO₂ capture from SMR CC processes is limited to a maximum of 8 Mt p.a. in the *PCI* scenario by 2050. With a lower sequestration potential of 286 Mt p.a. in *DI* scenario, more CO₂ is used as a precursor for the synthesis of Fischer-Tropsch fuels instead — 221 Mt p.a. vs. 115-127 Mt p.a. in 2040 and 206 Mt p.a. vs. 153-163 Mt p.a. in 2050, to meet the emission reduction targets for 2040 and 2050, respectively. Given the fixed exogenous demand for shipping methanol (Figure A.9), CO₂ demand for methanolisation is constant across all scenarios (39 Mt p.a. in 2030, 89 Mt p.a. in 2040, and 127 Mt p.a. in 2050).

Hydrogen production and utilisation. H₂ production in the model is primarily driven by the demand for Fischer-Tropsch fuels and methanol. In 2030

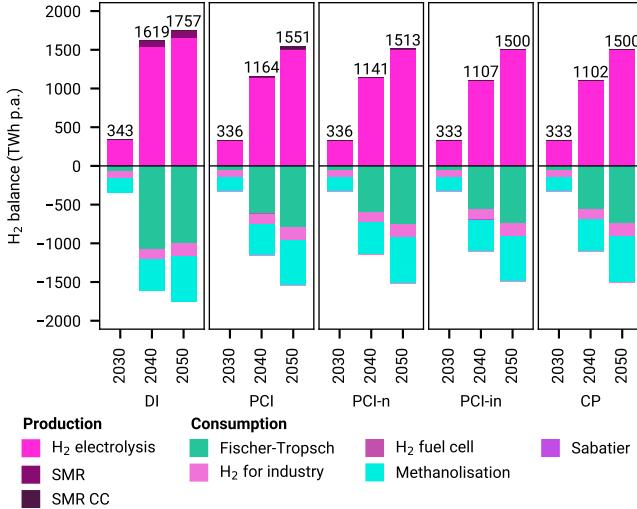
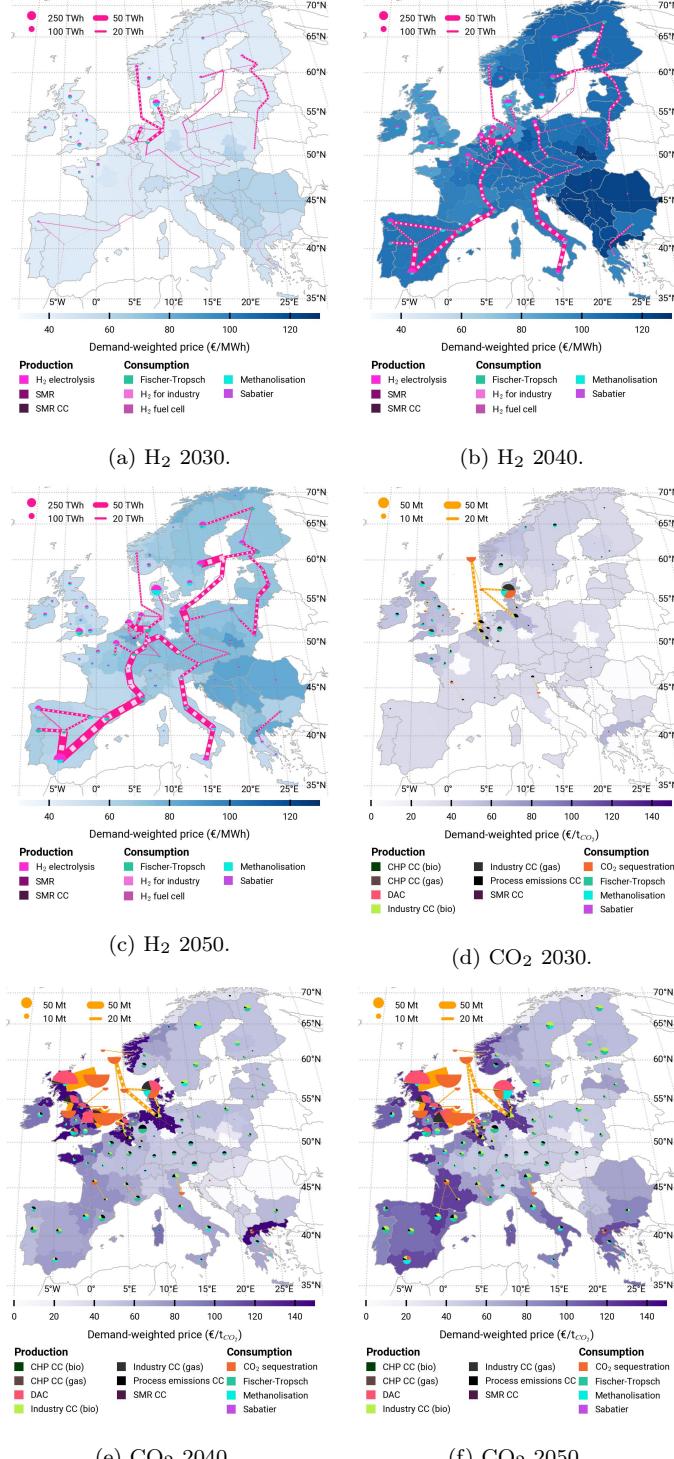


Figure 4: H₂ balances in long-term scenarios.

and 2050, the electrolytic H₂ production target of 10 and 45 Mt p.a. is binding, equivalent to 333 and 1500 TWh p.a. (at a lower heating value of 33.33 kWh/kg for H₂). Only in 2040, the H₂ production target of 27.5 Mt p.a. (917 TWh p.a.) is overachieved by 185-247 TWh p.a. in the *PCI* to *CP* scenarios. H₂ production in the *DI* is significantly higher, given its need for additional Fischer-Tropsch synthesis to bind CO₂ as an alternative to sequestration, as described in the previous section. In 2050, Fischer-Tropsch fuels are primarily used to satisfy the demand for kerosene in aviation and naphta for industrial processes (see Table A.9). Only about 93 to 173 TWh p.a. of hydrogen is directly used in the industrial sector. Across all long-term scenarios, hydrogen is almost exclusively produced via electrolysis. Note that the model includes a green hydrogen production constraint reflecting energy policy targets, though it does not enforce an hourly matching rule. In the *DI* scenario, where there is no hydrogen pipeline infrastructure, the model resorts to Steam Methane Reforming (SMR) to produce 71 to 102 TWh p.a. of hydrogen in 2040 and 2050, respectively.

Geographically, H₂ production is concentrated in regions with high solar PV potential such as the Iberian and Italian Peninsula, as well as high wind infeed regions including Denmark, the Netherlands and Belgium. The produced H₂ is then transported via H₂ pipelines including PCI-PMI projects



22
 Figure 5: *PCI-PMI* long-term scenario — Regional distribution of H₂ and CO₂ production, utilisation, storage, transport and price. Note that both the H₂ and CO₂ price refer to their value as a commodity, i.e., price is higher where there is a demand for it.

576 to carbon point sources in central, continental Europe where it is used as a
577 precursor for Fischer-Tropsch fuels. Onsite H₂ production and consumption
578 primarily occurs in conjunction with methanolisation processes. Figures 5a,
579 5b, and 5c provide a map of the regional distribution of H₂ production, util-
580 isation, and transport in the *PCI* scenario. Additional maps are provided
581 in Appendix B. Note that PCI-PMI projects or candidates (in *CP* scenario)
582 are plotted in dotted white lines.

583 *4.2. Regret analysis*

584 In this section, we discuss the impact of the three short-term scenarios
585 described in Section 3.2.2 on the long-term decarbonisation pathways, by
586 comparing the economic regret, as well as the effects on CO₂ utilisation,
587 sequestration, and H₂ production. We calculate the regret terms by sub-
588 tracting the annual total system costs of the long-term scenarios (row) from
589 the short-term scenarios (columns). The values represent the additional costs
590 incurred by a given short-term scenario relative to the benchmark. Positive
591 values indicate higher costs, driven by increased investments in alternative
592 generation, conversion, storage, and CDR technologies, as well as changes
593 in their operation due to (i) delays or (ii) cancellations of pipeline infras-
594 tructure including PCI-PMI projects. Negative values indicate cost savings,
595 which may arise under relaxed policy ambitions—for example, when CO₂
596 and H₂ targets are removed in the *Reduced targets* scenario.

597 Figure 6 shows the regret matrix for all scenarios and planning horizons.
598 From left to right, the first column shows the regret terms for the *Reduced*
599 *targets* scenario, where all long-term targets are removed except for the GHG
600 emission reduction target. The second column shows the regret terms for the
601 *Delayed pipelines* scenario, where all PCI-PMI and endogenous pipelines are
602 delayed by one period. The third column shows the regret terms for the
603 *No pipelines* scenario, where all hydrogen and CO₂ pipeline capacities are
604 removed.

605 In the *Reduced targets* scenario, overall system costs change only marginally
606 despite the relaxation of specific targets. This is because CO₂ sequestration
607 levels are primarily driven by the overarching GHG emission constraints —
608 particularly the stringent 2040 and 2050 carbon budgets, which remain in
609 place. With regard to hydrogen, the long-term results have previously shown
610 that H₂ production targets were overachieved in 2040. Only in 2030, we see
611 a net negative regret of around €4.3 to €4.6 billion per year, as the min-
612 imum H₂ production target was binding in the long-term scenario. Across

	Δ Reduced targets (bn. € p.a.)			Δ Delayed pipelines (bn. € p.a.)			Δ No pipelines (bn. € p.a.)		
Long-term scenario	2030	2040	2050	2030	2040	2050	2030	2040	2050
DI -	-4.6	0	0	0	0	0	0	0	0
PCI -	-5.0	0	-0.3	-3.4	+0.6	0	-5.1	+14.8	+15.9
PCI-n -	-4.3	0	-0.2	+0.3	+11.1	+1.3	-1.3	+28.6	+28.2
PCI-in -	-4.5	0	-0.2	+2.1	+24.2	+0.9	-0.3	+40.8	+35.6
CP -	-4.7	0	-0.3	+5.1	+35.2	+1.4	+3.9	+45.6	+39.4

Figure 6: Regret matrix. Positive values indicate higher costs, driven by increased investments in alternative generation, conversion, storage, and CDR technologies, as well as changes in their operation due to (i) delays or (ii) cancellations of pipeline infrastructure including PCI-PMI projects. Negative values indicate cost savings, which may arise under relaxed policy ambitions—for example, when CO₂ and H₂ targets are removed in the Reduced targets scenario.

all long-term scenarios, we have observed that CO₂ pipeline infrastructure is not essential in 2030 (see Figure B.25d). In the case of H₂ pipeline infrastructure, the solution appears relatively flat: regrets in the *DI* scenario without any pipelines (Figure B.22d) are nearly identical to those in the *CP* scenario (Figure B.25d) with substantial pipeline deployment. When the H₂ production and CO₂ sequestration targets are removed, pipelines become even less relevant, although the associated cost savings are minimal, ranging from €4.3 to €5 billion per year in 2030 and 2040.

For similar reasons, the 2030 results for the *Delayed pipelines* and *No pipelines* scenarios exhibit small regret terms. Cost savings of €3.4 to €5.1 billion per year in the *PCI* scenario suggest that, for 2030, mandating PCI-PMI projects is neither cost- nor topologically optimal in the short term. In contrast, a regret of €3.9 to €5.1 billion per year in the *CP* scenario indicates some dependency on the invested pipeline infrastructure (Figure B.25) which represents the systemically more optimised solution.

When looking at the more long-term perspective, we see significant regrets in the *Delayed pipelines* and *No pipelines* scenarios. Having originally planned the energy system layout (including generation, transport, conversion technologies and storage) in the long-term scenario with PCI-PMI projects and/or endogenous pipelines, the model has to find alternative

investments to still meet all targets, as the pipelines now materialise one period later or not at all. Regrets peak in 2040, where a delay of pipelines costs the system between €0.6 to €24.2 billion per year. in the scenarios with PCI-PMI projects and up to €35.2 billion p.a. in the *CP* scenario. 2050 regrets are lower than 2040 regrets, as almost all PCI-PMI pipelines are originally commissioned by 2030. Hence, a delay of projects from 2040 to 2050 only mildly impacts the system costs by €0.6 billion per year. The more pipelines invested beyond those of PCI-PMI projects, the higher the regret if they are delayed. In 2050, very few additional CO₂ and H₂ pipelines are built, as such, a delay only increases system costs by €0.9 to €1.4 billion per year. The short-term scenario *No pipelines* shows the highest regrets, ranging from €14.8 to €45.6 billion per year in 2040 and €15.9 to €39.4 billion per year in 2050. Note that this scenario represents a hypothetical worst case, as it is highly unlikely to plan an energy system with pipeline investments in mind yet fail to implement any of them.

Consistently throughout all short-term scenarios, most of the additional cost stem from the need to invest into additional carbon capture, renewable generation, and conversion technologies (see Figure B.11). Additional renewable generation capacities are made up of solar PV and wind. A significant higher amount of electrolyser capacity of more than 50 GW is needed in 2040 if pipelines are delayed.

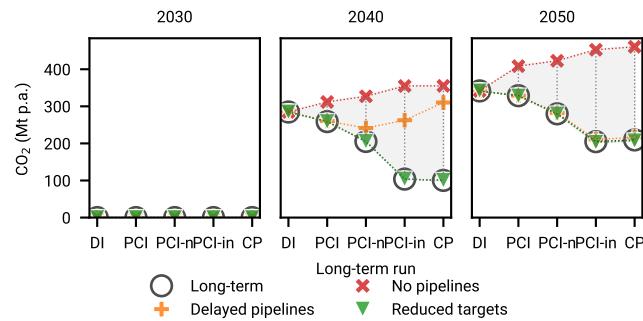


Figure 7: Delta balances — CO₂ from DAC.

Carbon capture. Further, the model has to invest in more than 28 GW of carbon capture units at point sources and an additional 14 GW in DAC technologies to meet the sequestration and emission reduction targets. Cost-wise, the short-term investments into DAC technologies make up to a half

658 of the additional system costs in both the *Delayed pipelines* and *No*
659 *pipelines* scenarios (see Figure B.12). DAC utilisation can increase from 40
660 Mt p.a. in the *PCI-n* to more than 200 Mt p.a. in the *CP* scenario when
661 pipelines are delayed (see Figure B.14). If pipelines are not built at all,
662 additional 60 Mt p.a. in the *PCI* up to 250 Mt p.a. in the *CP* scenario are
663 captured from DAC, substituting a large share of CO₂ previously captured
664 from point sources equipped with carbon capture (biomass-based industry
665 processes and non-abatable process emissions).

666 Note that a clear trade-off between the reliance on pipeline infrastructure
667 and the need for DAC technologies can be observed in Figure 7. While the
668 reliance on DAC decreases with the build-out of pipeline infrastructure, the
669 model in return has to invest in more DAC if pipelines are delayed or not
670 built at all. There is a risk involved, that the need for DAC is even higher
671 in the scenarios with pipeline infrastructure compared to the *DI* scenario,
672 especially in later years (2040 and 2050), if the pipelines do not materialise
673 at all, seeing a potential increase of 50 Mt p.a. in 2040 and 80 Mt p.a. in
674 2050 in the *PCI* scenario.

675 *H*₂ *production*. We find that the electrolytic H₂ production target of 10 Mt
676 p.a. (333 TWh p.a.) in 2030 is overly ambitious. Figure B.15 shows that
677 in the *Reduced targets* scenario, 132 to 151 TWh p.a. of H₂, corresponding
678 to almost half of the target is produced from SMR instead of electrolysis.
679 When pipelines are delayed, the model has to fall back to more decentral H₂
680 production of an additional 55 to 187 TWh p.a. of H₂ from electrolysis, SMR
681 and SMR with carbon capture (the latter being the most expensive option).
682 In the *No pipelines* scenario, this additional H₂ production increases to up
683 to 305 TWh p.a. (see Figure B.15).

684 4.3. Value of PCI-PMI projects

685 Looking at the long-run we find that PCI-PMI projects, while not com-
686 pletely cost-optimal compared to a centrally planned system, are still cost-
687 beneficial. Compared to a complete lack of H₂ and CO₂ pipeline infrastruc-
688 ture as well as lower CO₂ sequestration potential, the *PCI* scenario unlocks
689 annual cost savings in up to €30.7 billion per year. Figure 8 shows the
690 total system costs or Total Expenditures (TOTEX) p.a. split into Capital
691 (CAPEX) and Operational Expenditures (OPEX) p.a., as well as the Net
692 Present Value (NPV) of total system costs, discounted at an interest rate of
693 7% p.a. Even when accounting for the additional costs of €0.6 billion per

	CAPEX (bn. € p.a.)			OPEX (bn. € p.a.)			TOTEX (bn. € p.a.)			TOTEX (bn. €)
Longterm scenario	2030	2040	2050	2030	2040	2050	2030	2040	2050	NPV ₂₀₂₅
DI	498.0	803.6	806.6	367.0	164.1	82.4	865.0	967.7	889.0	8501
PCI	504.6	750.4	770.2	368.4	186.6	92.6	873.0	937.0	862.8	8425
PCI-n	501.9	742.5	764.2	369.3	187.1	91.9	871.2	929.6	856.1	8386
PCI-in	500.2	730.9	755.1	370.6	187.7	92.2	870.9	918.6	847.3	8342
CP	496.8	724.7	750.1	367.7	187.8	91.3	864.5	912.4	841.4	8283

Figure 8: Annual system costs by long-term scenario and planning horizon.

694 year faced in the *Delayed pipelines* and up to €15.9 billion per year in the *No*
695 *pipelines* scenario, a net positive is achieved, indicating that investing into
696 the PCI-PMI infrastructure is a no-regret option. By connecting further H₂
697 production sites and CO₂ point sources to the pipeline network. additional
698 cost savings of up to €18.4 billion per year can be achieved in the *PCI-in*
699 scenario. The *CP* scenario serves as a theoretical benchmark, allowing the
700 model to invest freely, not bound by *forced* PCI-PMI projects. The model
701 can invest in fewer, but more optimally located CO₂ and H₂ pipelines from
702 a systemic perspective. Economic benefits of all pipeline investments mate-
703 rialise after 2030, yielding lower NPV of potentially at least €75 billion over
704 the course of the assets' lifetime.

705 4.4. Limitations of our study

706 While our study assesses a variety of topologies, planning horizons, and
707 potential regret scenarios, it is not exhaustive and comes with limitations. As
708 we focus on the impact of continental European PCI-PMI infrastructure, we
709 neglect fuel and energy imports from outside Europe. H₂ and CO₂ demand
710 is directly driven by fixed, exogenous demands for the respective carrier or
711 their derivatives.

712 Regarding the modelling of both H₂ and CO₂ pipelines, we assume a level
713 playing field for all pipeline projects through standardised costs and apply-
714 ing haversine distance, i.e., no discrimination between PCI-PMI projects and
715 other projects, this is a simplification as real costs may differ. We also do
716 not discretise the endogenously built pipelines (due to computational com-

plexity) and allow any capacity to be built. This assumption can lead to underestimation of the true costs of pipeline investments.

Further, all results are based on a single weather year, i.e., 2013. Other limitations include geographic and temporal clustering to make the problem solving computationally feasible.

5. Conclusion

In this study, we have assessed the impact of PCI-PMI projects on reaching European climate targets on its path to net-zero by 2050. We have modelled the European energy system with a focus on H₂ and CO₂ infrastructure, and evaluated the performance of different levels of pipeline roll-out under three short-term scenarios.

Economic viability and policy targets. Our findings demonstrate that PCI-PMI CO₂ and H₂ infrastructure generate a net positive impact on total system costs, even when accounting for potential additional costs involved with the delay of pipelines. This positions PCI-PMI projects as a no-regret investment option for the European energy system, when treated as a whole. Their economic benefit increases considerably when strategic pipeline extensions are implemented, connecting additional H₂ production sites and CO₂ point sources to the pipeline network. Compared to a system without any pipeline infrastructure, PCI-PMI projects help to achieve the EU's ambitious policy targets, including net-zero emissions, H₂ production and CO₂ sequestration targets, while reducing system costs and technology dependencies.

CCUS and hydrogen utilisation. The pipeline infrastructure serves dual purposes in Europe's decarbonisation strategy: H₂ pipelines facilitate the distribution of more affordable green H₂ from northern and south-western regions rich in renewable energy potential to high-demand regions in central Europe. Complementarily, CO₂ transport and offshore sequestration sites enable industrial decarbonisation by linking major industrial sites and their process emissions to offshore sequestration sites in the North Sea, particularly in Denmark, Norway, and the Netherlands.

Technology and risk diversification. The build-out of CO₂ and H₂ pipeline infrastructure helps utilising renewable energy sources more efficiently. Hydrogen pipelines enable the transport of green H₂ over long distances while CO₂ pipelines reduce the reliance on single carbon capture technologies such

751 as Direct Air Capture and point-source carbon capture, confirming the findings
752 of [4]. This diversification further enhances system resilience towards
753 uncertainties involved with technologies that are not yet commercially avail-
754 able at scale, such as Direct Air Capture.

755 *Political support and public acceptance.* While PCI-PMI may not achieve
756 perfect cost-optimality in their entirety compared to a theoretically centrally
757 planned system, they possess benefits beyond pure economic viability. The
758 success of large-scale infrastructure investments highly depend on continu-
759 ous political support and public acceptance — factors that are particularly
760 favourable for PCI-PMI projects. Backed directly by the European Com-
761 mission, PCI-PMI projects benefit from stronger political endorsement, in-
762 stitutional support structures, enhanced access to financing and grants, and
763 accelerated permitting processes. Additionally, the requirement for frequent
764 and transparent progress reporting increases their likelihood of gaining public
765 acceptance.

766 CRediT authorship contribution statement

767 **Bobby Xiong:** Conceptualisation, Methodology, Software, Validation,
768 Investigation, Data Curation, Writing — Original Draft, Review & Editing,
769 Visualisation. **Iegor Riepin:** Conceptualisation, Methodology, Investiga-
770 tion, Writing — Review & Editing, Project Administration, Supervision.
771 **Tom Brown:** Investigation, Resources, Writing — Review & Editing, Su-
772 pervision, Funding acquisition.

773 Declaration of competing interest

774 The authors declare that they have no known competing financial inter-
775 ests or personal relationships that could have appeared to influence the work
776 reported in this paper.

777 Data and code availability

778 All results, including solved PyPSA networks and summaries in .csv for-
779 mat are published on Zenodo:
780 <https://doi.org/XX.YYYY/zenodo.10000000>

781 The entire workflow, including the custom model based on PyPSA-Eur
 782 v2025.01.0, PCI-PMI project implementation, regret matrix setup, postpro-
 783 cessing and visualisation routines can be completely reproduced from the
 784 GitHub repository:
 785 <https://github.com/bobbyxng/pcipmi-policy-targets>

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793 **Appendix A. Data & methodology**

Table A.4: Cost assumptions for key technologies based on [51].

	Unit	CAPEX	FOM
Pipeline infrastructure			
CO ₂ onshore pipelines	€/tCO ₂ /hkm	2 116	0.9 %/a
CO ₂ offshore pipelines	€/tCO ₂ /hkm	4 233	0.5 %/a
H ₂ onshore pipelines	€/MW _{H₂} /km	304	1.5-3.2 %/a
H ₂ offshore pipelines	€/MW _{H₂} /km	456	3.0 %/a
Conversion			
Electrolysis	€/kW _e	1 000-1 500	4.0 %/a
SMR	€/MW _{CH₄}	522 201	5.0 %/a
SMR CC	€/MW _{CH₄}	605 753	5.0 %/a

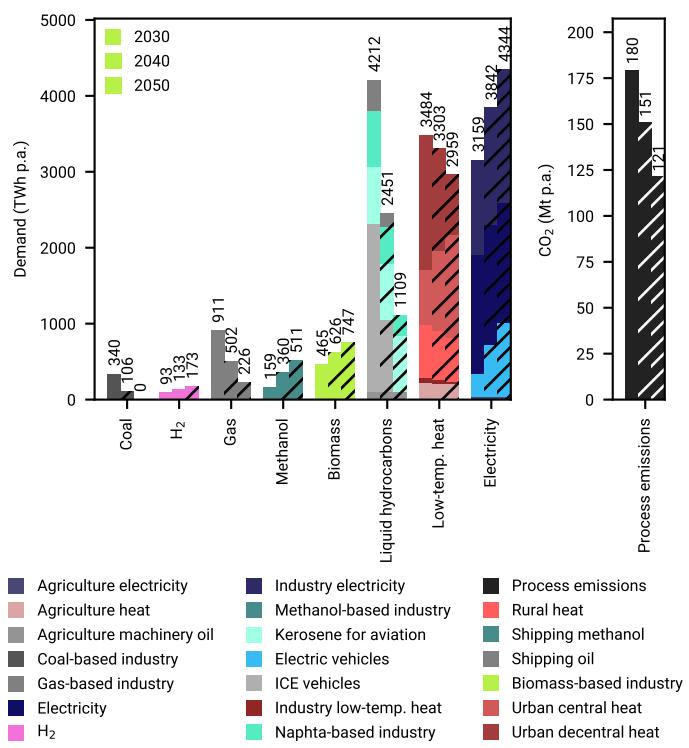


Figure A.9: Exogenous demand.

Table A.5: Regional clustering: A total of 99 regions are modelled, excluding offshore buses.

	Country	Buses
Admin. level	Σ	99
NUTS2	Finland (FI)	4
	Norway (NO)	6
NUTS1	Belgium (BE)**	2
	Switzerland (CH)	1
	Czech Republic (CZ)	1
	Germany (DE)*	13
	Denmark (DK)	1
	Estonia (EE)	1
	Spain (ES)*	5
	France (FR)	13
	Great Britain (GB)*	11
	Greece (GR)	3
	Ireland (IE)	1
	Italy (IT)*	6
	Lithuania (LT)	1
	Luxembourg (LU)	1
	Latvia (LV)	1
	Montenegro (ME)	1
	Macedonia (MK)	1
	Netherlands (NL)	4
	Poland (PL)	7
	Portugal (PT)	1
	Sweden (SE)	3
	Slovenia (SI)	1
	Slovakia (SK)	1
NUTS0	Albania (AL)	1
	Austria (AT)	1
	Bosnia and Herzegovina (BA)	1
	Bulgaria (BG)	1
	Croatia (HR)	1
	Hungary (HU)	1
	Romania (RO)	1
	Serbia (RS)	1
	Kosovo (XK)	1

City-states (*) (i.e., Berlin, Bremen, Hamburg, Madrid, and London) and regions without substations (***) (one in BE) are merged with neighbours. Sardinia and Sicily are modelled as two separate regions.

794 Appendix B. Results

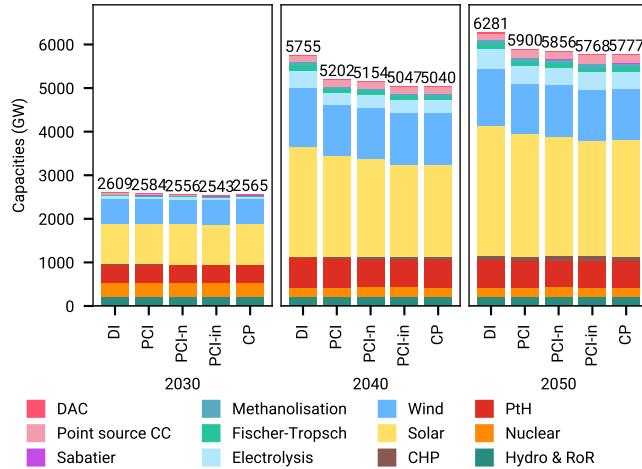


Figure B.10: Installed capacities in long-term scenarios.

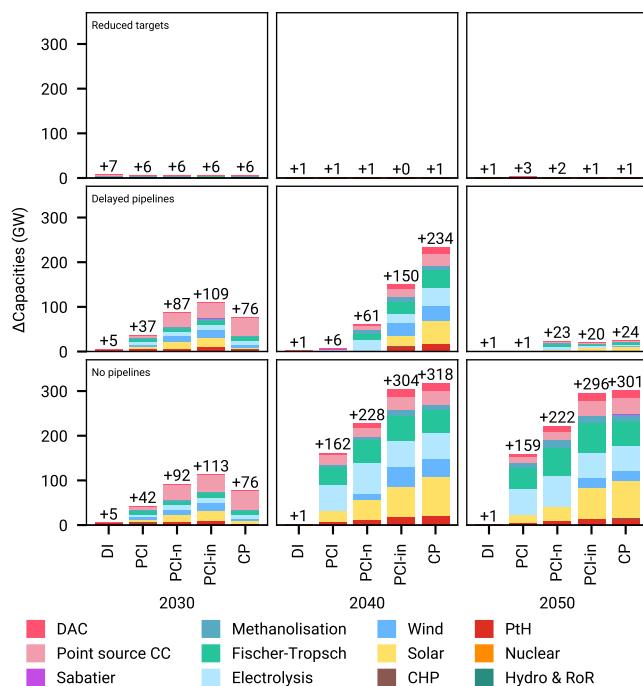


Figure B.11: Δ Capacities — Short-term minus long-term runs.

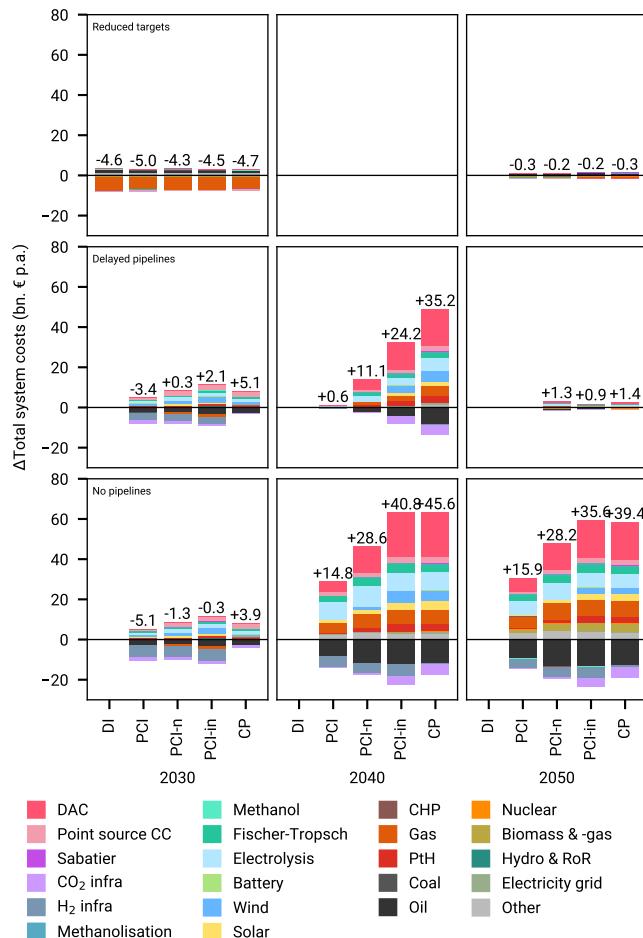


Figure B.12: Δ System costs — Short-term minus long-term runs.

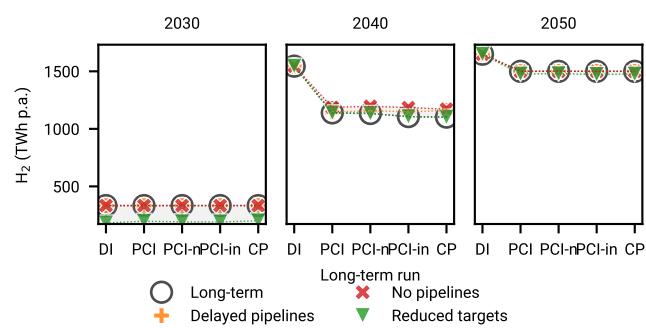


Figure B.13: Delta balances — Electrolytic H₂ production

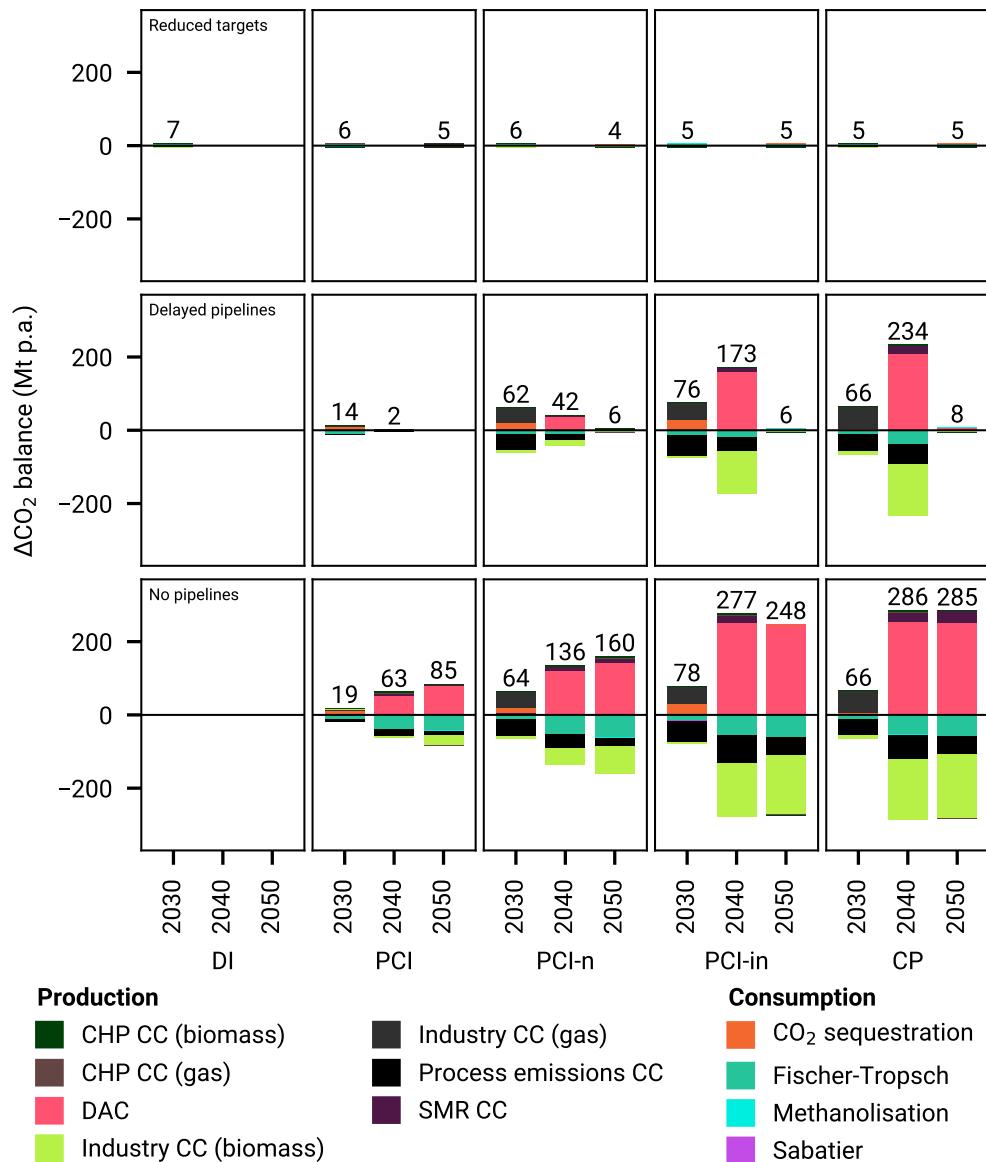


Figure B.14: ΔCO_2 balances — Short-term minus long-term runs.

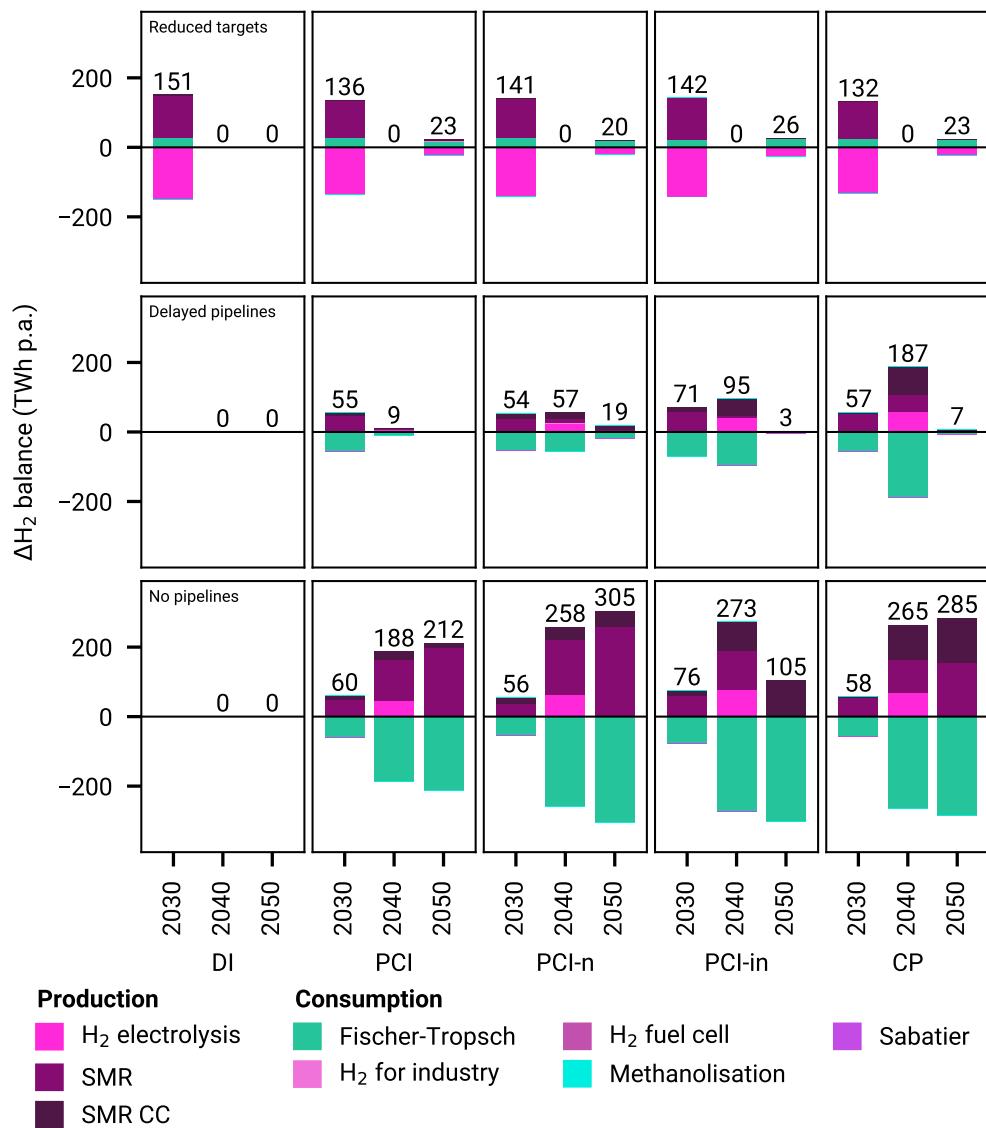


Figure B.15: ΔH_2 balances — Short-term minus long-term runs.

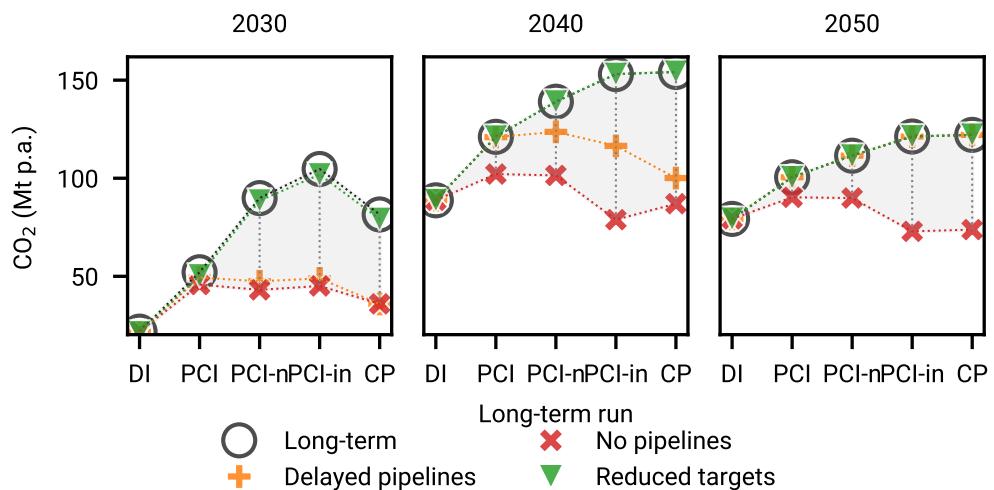


Figure B.16: ΔCO_2 balances — Process emissions including Carbon Capture.

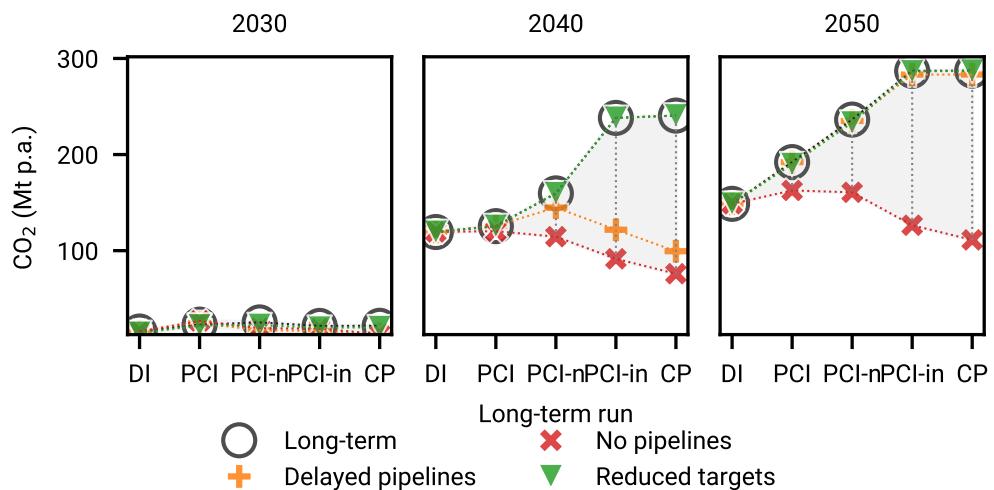


Figure B.17: ΔCO_2 balances — Carbon capture from solid biomass for industry point sources.

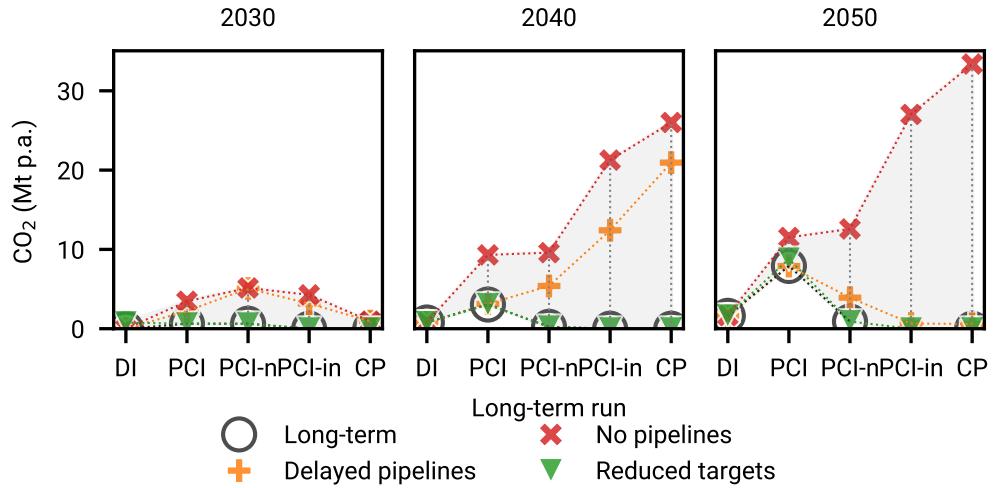


Figure B.18: ΔCO₂ balances — Carbon capture from SMR point sources.

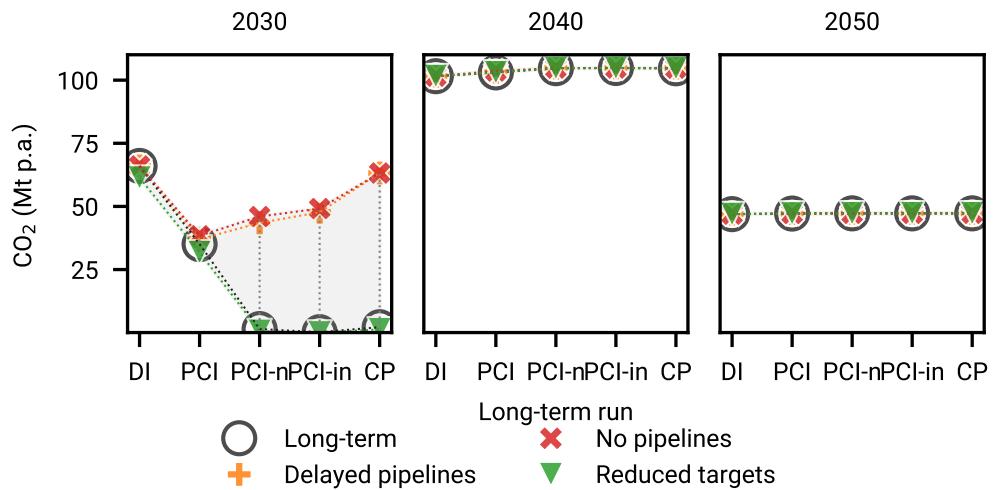


Figure B.19: ΔCO₂ balances — Carbon captured from gas for industry point sources.

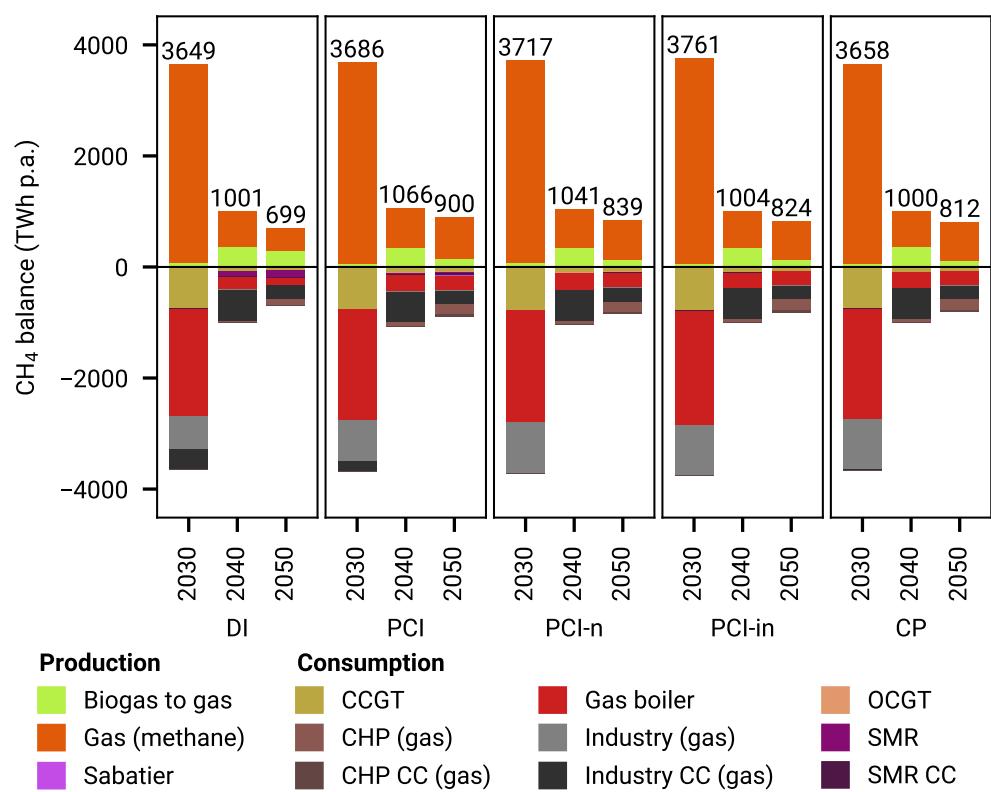


Figure B.20: CH₄ balances in long-term scenarios.

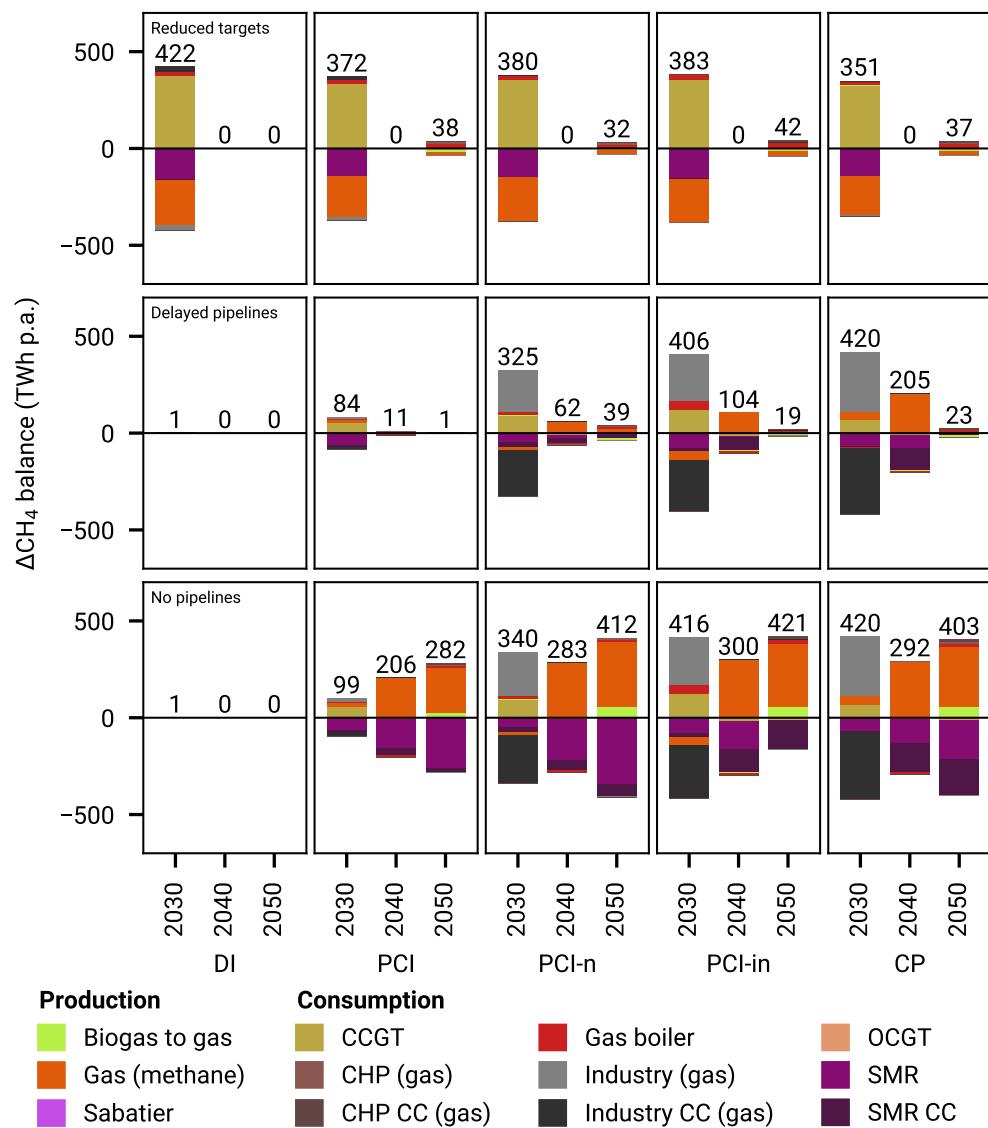
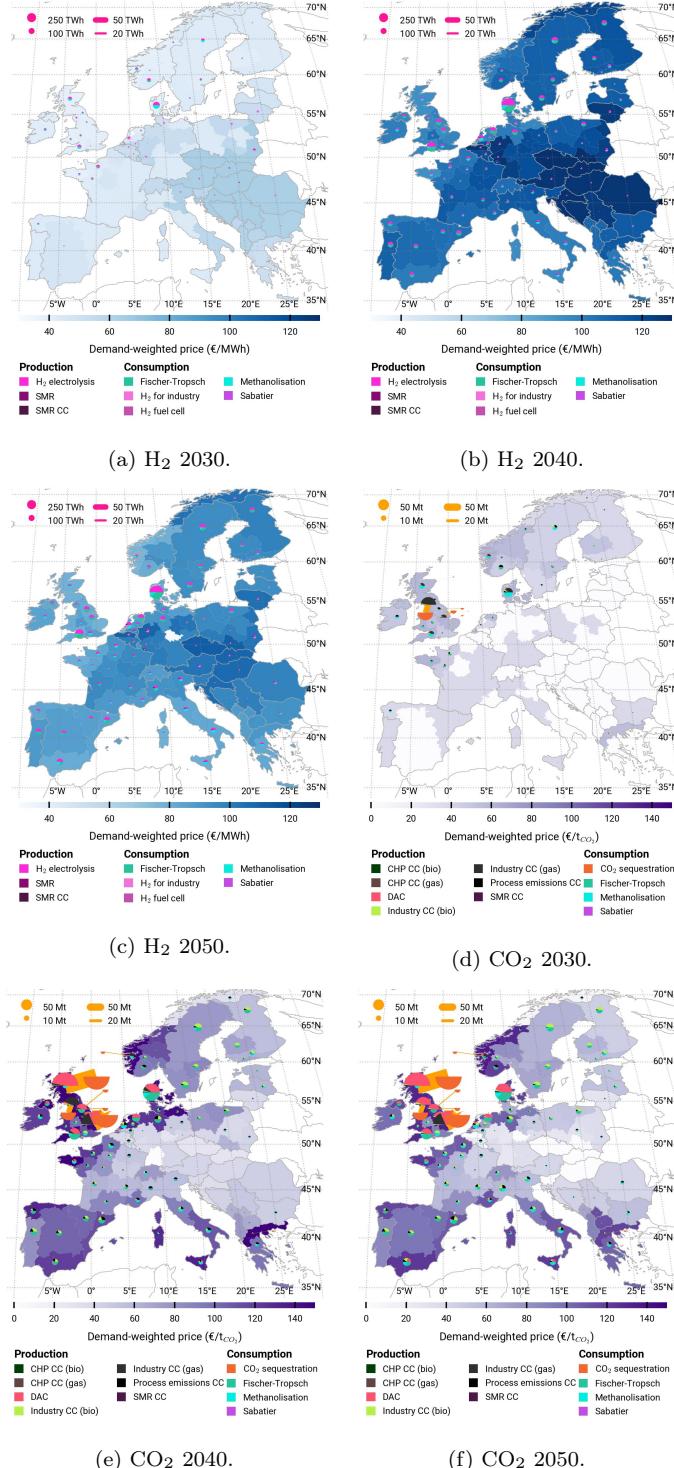
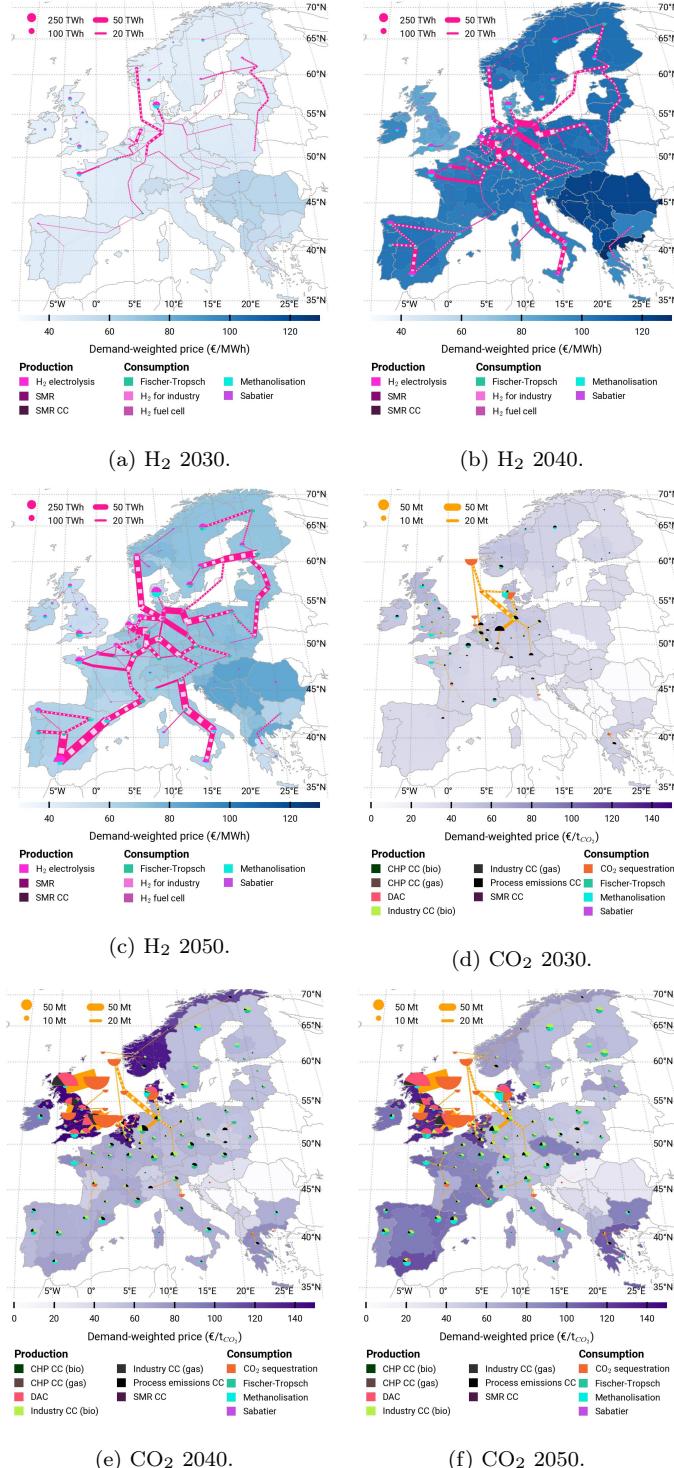


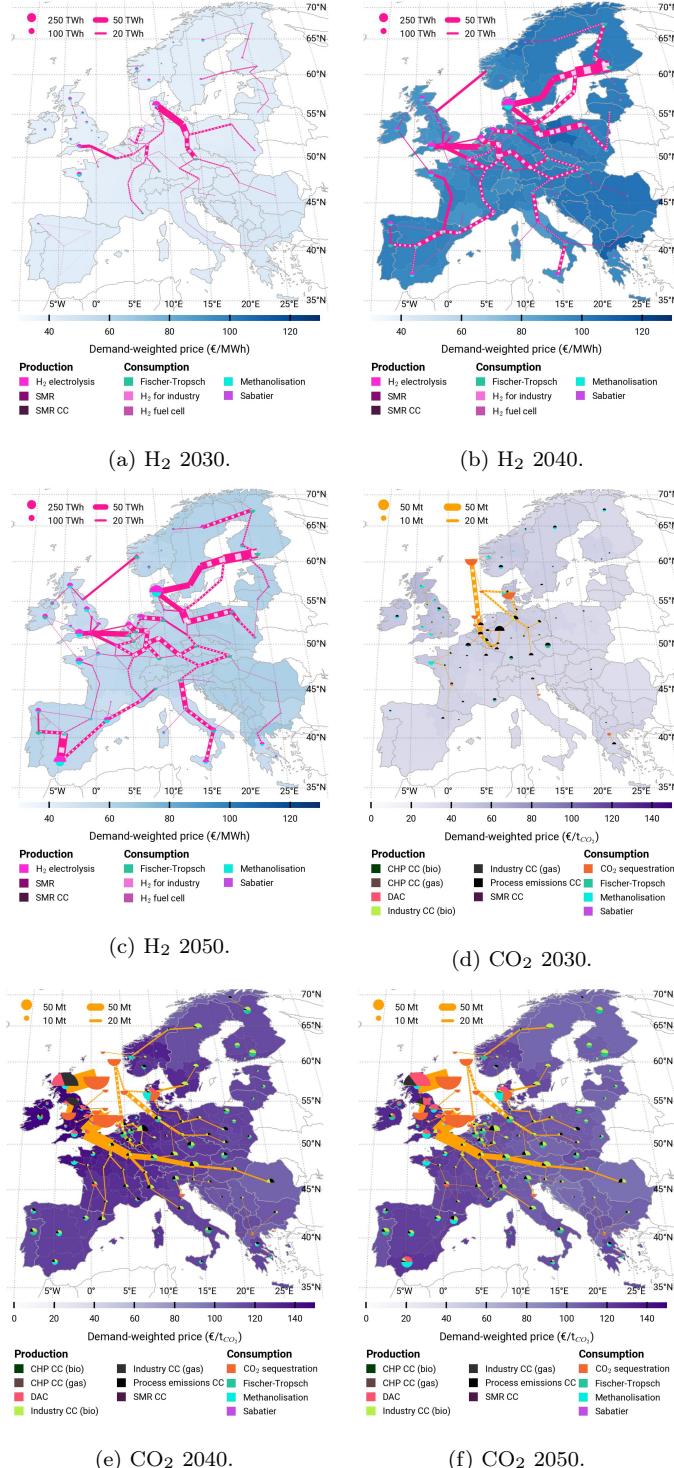
Figure B.21: ΔCH_4 balances — Short-term minus long-term runs.



43
 Figure B.22: *Decentral Islands* long-term scenario — Regional distribution of H_2 and CO_2 production, utilisation, storage, transport and price. Note that both the H_2 and CO_2 price refer to their value as a commodity, i.e., price is higher where there is a demand for it.



44
 Figure B.23: *PCI-PMI nat.* long-term scenario — Regional distribution of H_2 and CO_2 production, utilisation, storage, transport and price. Note that both the H_2 and CO_2 price refer to their value as a commodity, i.e., price is higher where there is a demand for it.



45
 Figure B.24: *PCI-PMI internat.* long-term scenario — Regional distribution of H_2 and CO_2 production, utilisation, storage, transport and price. Note that both the H_2 and CO_2 price refer to their value as a commodity, i.e., price is higher where there is a demand for it.

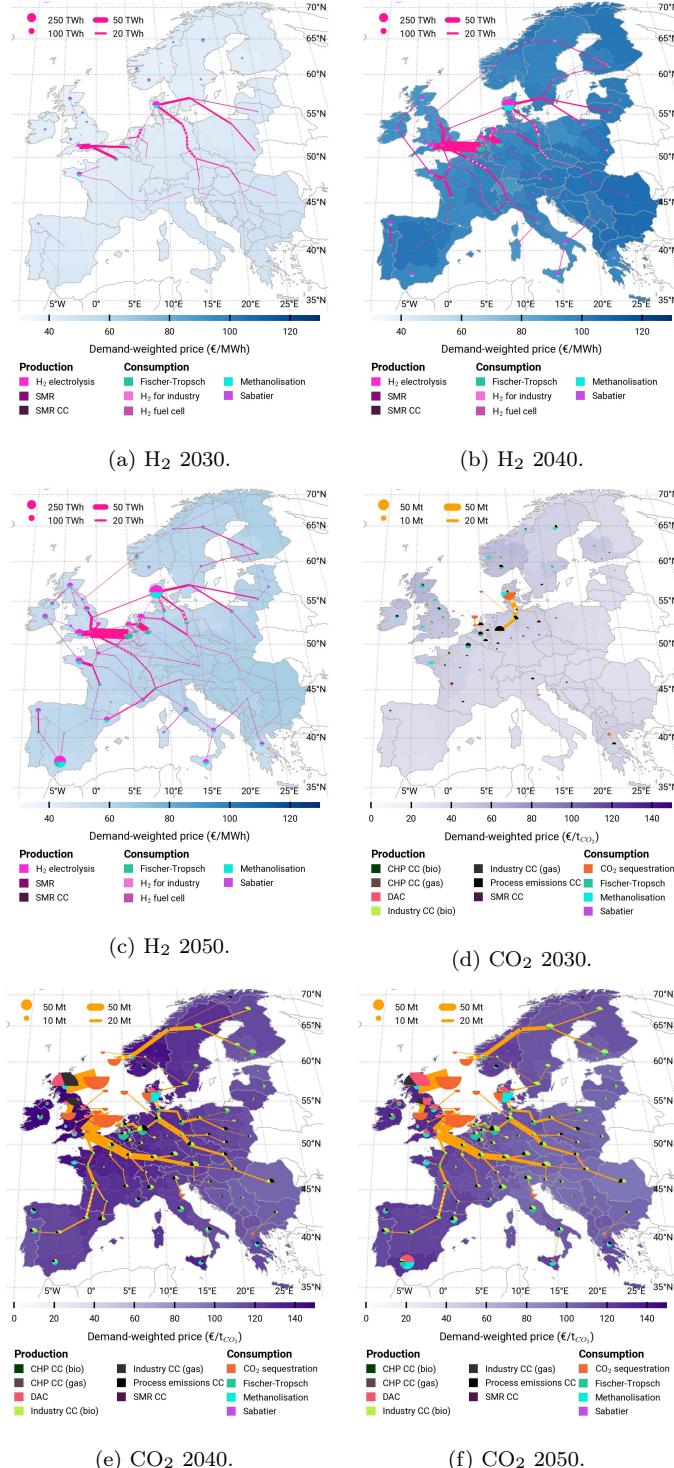


Figure B.25: *Central Planning* long-term scenario — Regional distribution of H_2 and CO_2 production, utilisation, storage, transport and price. Note that both the H_2 and CO_2 price refer to their value as a commodity, i.e., price is higher where there is a demand for it.

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