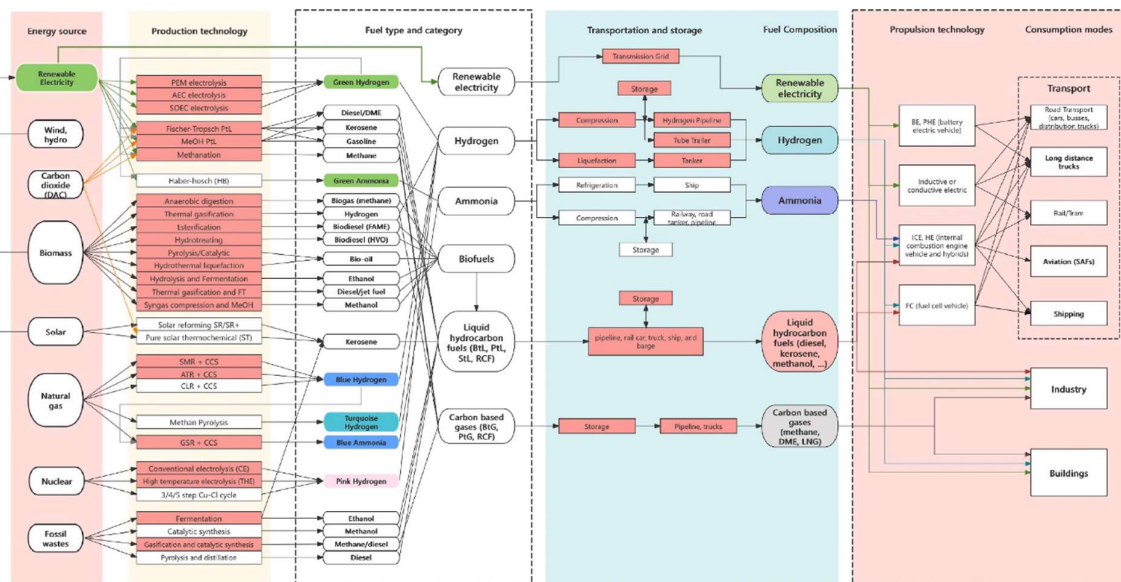




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SHELTERED

Sustainable chemical transport fuels and their role in future Swiss energy supply



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The authors bear the entire responsibility for the content of this report and for the conclusions drawn therefrom.



Summary

Background, goal, and scope

Switzerland aims at reducing domestic greenhouse gas (GHG) emissions to net zero by 2050. Achieving this goal basically requires a phase-out of fossil fuels. These can be replaced by 1) so-called “direct electrification”, i.e., using electricity instead of fossil fuels, which includes switches in end-use technologies, for example, from internal combustion engine to battery electric vehicles, or 2) by using low-carbon fuels (LCF¹), which most often can directly substitute fossil fuels. Low-carbon fuels include hydrogen, ammonia, and liquid and gaseous hydrocarbons made from biomass (“biofuels”), or from hydrogen and CO₂. Such synthetic hydrocarbons are often referred to as “e-fuels” if the hydrogen needed for their production is provided via water electrolysis.

Despite the clear goal – Switzerland being climate neutral by 2050 – it remains partially unclear how to get there. In particular, the role of LCF in the transition of the Swiss energy system, especially in the transport sector, is unclear. This research project SHELTERED² fills knowledge gaps in this context to answer the following questions:

- 1) Which transportation modes will have to rely (partially) on chemical LCF due to the lack of direct electrification options?
- 2) Which of these fuels and which supply pathways are sustainable considering economic, environmental, and social criteria?
- 3) What is the role of these fuels in the Swiss energy system to meet the net-zero GHG emission goals?
- 4) The global perspective: What role will LCF play globally to reach net-zero goals, which LCF will dominate under certain boundary conditions, and which regions will be predestined to provide the global demand?

To answer these questions, a techno-economic and environmental assessment of a broad range of current and future LCF has been performed, considering production locations and their characteristics worldwide, specific LCF supply pathways to Switzerland, and considering future technology development until 2050. Based on the techno-economic assessment of LCF, energy system models for Europe (with Switzerland represented as a single country) and globally have been developed and used to assess transition pathways toward net-zero GHG emissions.

The LCF portfolio covered in our analysis includes hydrogen from fossil and biogenic feedstock with CCS, from methane pyrolysis and water electrolysis, and from nuclear cycles; synthetic kerosene (jet fuel) based on direct use of solar energy (“solar fuels”), electricity- and biomass-based jet fuel, biodiesel, electricity- and biomass-based methane and methanol, and ammonia, both electricity-based and from fossil feedstock with CCS.

The energy system models are used to explore transition scenarios in which net zero GHG emissions are realized by 2050 (CH, EU, some other regions), or later. Those transition scenarios are outcomes of optimizations minimizing overall system costs under specific boundary conditions, such as CO₂ prices, certain policies, renewable resources, and CO₂ storage potentials, and expected technology developments. The scenario results provide the information regarding LCF quantities used for different applications in Switzerland (and other regions) and their origin over time.

Results and discussion

Reliance of transportation modes in Switzerland on LCF

¹ “Low Carbon Fuels” (LCF) are liquid or gaseous energy carriers, which allow for a substantial (without a specific threshold) reduction of GHG emissions compared to fossil fuels from a life cycle perspective. To be considered sustainable, LCFs derived from biogenic feedstocks must not compete with food production.

² SHELTERED stands for “Sustainable cHEmical Transport fuELs foR SwitzERland”. The project was financially supported by the Swiss Federal Office of Energy (SFOE).



While road transport in Switzerland is expected to undergo rapid and nearly full direct electrification using battery electric drivetrains by 2050, several sectors lack viable direct electrification options and will rely on LCF:

- Aviation: This is the primary driver for LCF demand. To achieve full decarbonization by 2050, the Swiss aviation sector (including international flights) must transition entirely to biogenic and synthetic aviation fuels (so-called “Sustainable Aviation Fuels”, SAF), as using battery electric or hydrogen-based propulsion systems does not seem to be a feasible option within this time horizon.
- Heavy-Duty Road Transport: Although light-duty trucks will electrify rapidly, a small portion of the heavy-duty truck fleet continues to utilize internal combustion engines (ICE) throughout 2050 (about 10%), requiring alternative low-carbon fuels (mainly biofuels) to meet emission targets.

Overall, the energy demand for the Swiss transport sector will, despite the expected growth in aviation, decline by about 30%, as electric vehicles are far more efficient than ICE vehicles. The shift in the aviation sector towards SAF in the early period is driven by the blending mandate and later by the climate mitigation target.

Sustainable fuels and economic supply pathways

Sustainable fuel types exhibiting comparatively low production costs and life cycle GHG emissions include hydrogen, biofuels, ammonia, and synthetic hydrocarbons (including solar fuels):

- Hydrogen: Specifically, “green” hydrogen from water electrolysis using low-carbon electricity and “blue” hydrogen from natural gas with Carbon Capture and Storage (CCS)³, as well as hydrogen from residual biomass, are viable options. By 2050, these production pathways will almost approach parity with current hydrogen production costs via unabated steam methane reforming of natural gas.
- Biofuels: Fatty Acid Methyl Ester (FAME), Hydrotreated Vegetable Oil (HVO), and biomethane are viable, though their sustainability depends heavily on using residual biomass rather than feedstocks that cause land-use change or compete with food production. Biogenic feedstocks can also be used to produce hydrogen. Biogenic jet fuels from residual biomass exhibit the lowest costs among SAF options. However, the limited potential of residual biomass must be considered for all biofuel options.
- Ammonia: Produced from green hydrogen instead of natural gas, ammonia represents a sustainable maritime shipping fuel.
- Synthetic Hydrocarbons: Jet fuel and biomethane produced from green hydrogen and CO₂ (ideally sourced via Direct Air Capture, DAC) will be essential for aviation and industry, respectively. However, their future production costs will remain above those of biofuels.

Global fuel economics are characterized by geographic heterogeneity. Renewable resource quality, investment risk profiles, and local energy costs jointly determine the competitiveness of production sites. For example, countries with high solar irradiance and low capital cost – such as Morocco, Chile, and Australia – consistently rank among the most competitive locations for green hydrogen and e-fuel production. Similarly, the availability of abundant biomass resources in Brazil, Indonesia, and parts of sub-Saharan Africa favors biofuel production. Similar parameters determine the environmental performance of LCF. For all electricity-based production pathways, the environmental burdens associated with electricity supply are most important. To be truly “low-carbon”, such production pathways must rely on electricity associated with very low GHG emissions.

For cost-optimal supply pathways to Switzerland, the temporal perspective and import distances are important:

- Near-term: As long as no dedicated hydrogen transport infrastructure exists, compressed hydrogen transport by rail is feasible, though expensive, for intra-European supply. Maritime

³ High CO₂ capture rates, 90% or more, are required.



shipping of ammonia as a hydrogen carrier, though not yet considered as mature technology, would represent the most cost-effective long-distance hydrogen supply route due to existing infrastructure. Also, biofuel imports can rely on existing infrastructure.

- Long-term: Pipeline transport will become the dominant mode for intra-European imports. For remote global sources (e.g., Chile, Australia), Liquid Organic Hydrogen Carriers (LOHC) imported by ship become economically favorable due to technological maturation. Synthetic hydrocarbons ("e-fuels") and solar fuels will continue to face comparatively high production costs, but profit from existing transport infrastructure.

The role of LCF in the Swiss net-zero strategy and domestic production vs. imports

Low-carbon fuels will serve as a critical secondary pillar to direct electrification in Switzerland's transition and meet several purposes:

- Decarbonization of "hard-to-abate" sectors: LCFs are the only current solution for fully decarbonizing the aviation sector by 2050. While aviation (and to a minor extent heavy-duty road transport) dominates bio- and synthetic fuel consumption in the mid-term, the industrial sector will increasingly use these fuels for heat and electricity generation. Further, the services and residential sectors, to some extent, adopt synthetic methane for heating systems where existing (stranded) assets must be utilized or where other constraints limit the direct electrification.
- Energy System Integration: The high share of intermittent renewable electricity from photovoltaics and wind power in 2050 will increase the need for green hydrogen and subsequent synthetic methane production (Power-to-Gas) to support seasonal energy storage, sector coupling, and grid stability.

The majority of LCF, about three-quarters, will have to be imported. While hydrogen and biomethane can mostly be produced domestically, SAF needed for aviation will have to be imported.

In general, the role of domestic biomass in Switzerland is constrained by limited biomass resources. These are primarily used for power generation in combination with CCS to generate "negative emissions", i.e., remove CO₂ from the atmosphere, to compensate residual GHG emissions from the industry and agriculture.

The global perspective

Under the assumption of a stringent, international climate policy towards net zero GHG emissions and of a market-oriented long-term cost-minimization of the global energy system with global trade options and without major international political upheavals, the deployment of alternative fuels depends on three key aspects:

- How to use globally available biomass?
- The availability of geological CO₂ storage capacities needed for natural gas- and biomass-based hydrogen production with CCS
- The availability of cheap CO₂ sources for synthetic hydrocarbon production

According to our model results, biomass is cost-effectively used for liquid fuel production on the global level, even with (relative to default assumptions) reduced global biomass potential and increased biomass production and supply costs. Some other internationally used models tend to favour the use of biomass for power generation, partially combined with CCS to generate negative GHG emissions and balance intermittent renewables. Our results suggest that liquid e-fuels are globally only cost-effective if CO₂ storage is limited, because in that case, biomass is needed to replace natural gas with CCS in the power sector.

Hydrogen is only partially cost-effectively produced from electricity before 2050, mainly due to the high marginal costs of electricity. These are a result of (i) the global decarbonization of electricity generation, (ii) the electrification of demand sectors, and (iii) a substantial increase in energy demand in the developing and transitional countries. Thus, alternative hydrogen production pathways are preferred, mainly natural gas reforming with CCS. Assuming limited CCS, also hydrogen from electrolysis can expand



further, and is deployed at larger absolute amounts earlier (by 2040); but total hydrogen production is roughly reduced by 50% compared to default assumptions regarding CO₂ storage potentials. Solar processes for hydrogen and liquid hydrocarbon production could be cost-effective in the long term, with large-scale deployment starting around 2050. In the long term, the largest export regions of liquid LCF will be Brazil, Canada, Mexico, Russia, and Australia.

Limitations and outlook

The results of the prospective techno-economic assessment of LCF depend to a substantial extent on assumptions regarding future technology and price developments, e.g., of infrastructure components and energy carriers. These are, especially for emerging technologies, as some of the LCF included in our evaluation, associated with high uncertainties. The results of the prospective environmental assessment of LCF are associated with comparatively lower uncertainties, as the underlying technology characterizations are more foreseeable than future cost and price developments. However, the environmental assessment has only been performed at the level of individual technologies and focused on life cycle GHG emissions; future work should link LCA and (Swiss) energy system modelling to quantify the environmental performance of different transition scenarios with specific levels of LCF deployment, considering environmental impacts beyond GHG emissions.

Similar to the techno-economic and environmental assessment, the results of our energy system modelling depend on assumptions regarding future technology, cost, and price developments. It needs to be highlighted that these results, therefore, do not represent forecasts, but “what-if” scenarios. One of the limitations to be acknowledged is the fact that the system models employed are limited to the energy system, focusing on the final energy demand. Not included is, for example, the agricultural sector, which represents an important source of GHG emissions and a competitor for land, which could be used for food production, biofuel production, or renewable power generation infrastructure. Another limitation of the models is the lack of representation of the effects of changes in prices on demand. Future work should, therefore, aim at integrating sectors not included for the time being, as well as considering price elasticities and economic feedback.

Finally, all components of this work – techno-economic and environmental assessment, as well as Swiss, European, and global energy system modelling – are sensitive to short- and long-term political developments. For example, armed conflicts can cause major price fluctuations and supply bottlenecks; disagreement on climate policy can slow down the development of LCF technologies and thus increase their future costs; certain political players can restrict exports of critical materials and technologies, slowing down LCF deployment. The potential effects of such developments have not been considered in our work.



Zusammenfassung

Hintergrund, Ziel und Umfang

Die Schweiz strebt an, die inländischen Treibhausgasemissionen bis 2050 auf «Netto-Null» zu senken. Um dieses Ziel zu erreichen, ist ein weitgehender Ausstieg aus fossilen Brennstoffen erforderlich. Diese können ersetzt werden durch 1) die sogenannte „direkte Elektrifizierung“, d. h. die Nutzung von Strom anstelle von fossilen Brennstoffen, was einen Wechsel bei den Endverbrauchstechnologien beinhaltet, beispielsweise von Verbrennungsmotoren zu batterieelektrischen Fahrzeugen, oder 2) durch den Einsatz von kohlenstoffarmen Brennstoffen (LCF⁴), die in den meisten Fällen fossile Brennstoffe direkt ersetzen können. Zu den kohlenstoffarmen Brennstoffen zählen Wasserstoff, Ammoniak sowie flüssige und gasförmige Kohlenwasserstoffe, die aus Biomasse („Biokraftstoffe“) oder aus Wasserstoff und CO₂ hergestellt werden. Solche synthetischen Kohlenwasserstoffe werden oft als „E-Kraftstoffe“ bezeichnet, wenn der für ihre Herstellung benötigte Wasserstoff durch Wasserelektrolyse gewonnen wird.

Trotz des klaren Ziels – Klimaneutralität der Schweiz bis 2050 – bleibt teilweise unklar, wie dieses Ziel erreicht werden soll. Insbesondere ist die Rolle von LCF bei der Transformation des Schweizer Energiesystems, vor allem im Verkehrssektor, unklar. Das Forschungsprojekt SHELTERED⁵ schliesst Wissenslücken in diesem Zusammenhang, um folgende Fragen zu beantworten:

1. Welche Verkehrsträger werden aufgrund fehlender Möglichkeiten zur direkten Elektrifizierung (teilweise) auf chemische LCF angewiesen sein?
2. Welche dieser Kraftstoffe und welche Versorgungswege sind unter Berücksichtigung wirtschaftlicher, ökologischer und sozialer Kriterien nachhaltig?
3. Welche Rolle spielen diese Kraftstoffe im Schweizer Energiesystem, um die Netto-Null-Ziele für Treibhausgasemissionen zu erreichen?
4. Die globale Perspektive: Welche Rolle werden LCF weltweit spielen, um die Netto-Null-Ziele zu erreichen, welche LCF werden unter bestimmten Rahmenbedingungen dominieren und welche Regionen sind prädestiniert, den globalen Bedarf zu decken?

Um diese Fragen zu beantworten, wurde eine techno-ökonomische und ökologische Bewertung einer breiten Palette aktueller und zukünftiger LCF durchgeführt, wobei Produktionsstandorte und deren Eigenschaften weltweit, spezifische LCF-Versorgungswege in die Schweiz sowie die zukünftige Technologieentwicklung bis 2050 berücksichtigt wurden. Auf der Grundlage der techno-ökonomischen Bewertung von LCF wurden Energiesystemmodelle für Europa (wobei die Schweiz als einzelnes Land dargestellt wird) und weltweit entwickelt und zur Bewertung von Übergangspfaden hin zu Netto-Null-Treibhausgasemissionen herangezogen.

Das in unserer Analyse berücksichtigte LCF-Portfolio umfasst Wasserstoff aus fossilen und biogenen Rohstoffen mit CCS, aus Methanpyrolyse und Wasserelektrolyse sowie aus Kernenergie; synthetisches Kerosin (Flugkraftstoff) auf Basis der direkten Nutzung von Solarenergie („Solarfuels“), Strom- und biomassebasierter Flugkraftstoff, Biodiesel, Strom- und biomassebasiertes Methan und Methanol sowie Ammoniak, sowohl strombasiert als auch aus fossilen Rohstoffen mit CCS.

Die Energiesystemmodelle dienen der Untersuchung von Transitionsszenarien, in denen bis 2050 (CH, EU, einige andere Regionen) oder später Netto-Null-Treibhausgasemissionen erreicht werden. Diese Transitionsszenarien sind Ergebnisse von Optimierungen, die die Gesamtsystemkosten unter bestimmten Randbedingungen minimieren, wie z.B. CO₂-Preise, bestimmte politische Rahmenbedingungen, erneuerbare Ressourcen und CO₂-Speicherpotenziale sowie erwartete technologische Entwicklungen.

⁴ «Low Carbon Fuels» (LCF) sind flüssige oder gasförmige Energieträger, die aus Lebenszyklusperspektive eine erhebliche (ohne spezifische Schwelle) Reduktion der Treibhausgasemissionen im Vergleich zu fossilen Brennstoffen ermöglichen. Um als nachhaltig zu gelten, dürfen LCFs aus biogenen Rohstoffen nicht mit der Nahrungsmittelproduktion konkurrieren.

⁵ SHELTERED steht für «Sustainable cHEmical Transport fuELs foR SwitzErlanD». Das Projekt wurde vom Bundesamt für Energie (BFE) finanziell unterstützt.



Die Szenarioergebnisse liefern die Information über die für verschiedene Anwendungen in der Schweiz (und anderen Regionen) verwendeten LCF-Mengen und deren Herkunft im Zeitverlauf.

Ergebnisse und Diskussion

Abhängigkeit der Verkehrsträger in der Schweiz von LCF

Während für den Strassenverkehr in der Schweiz bis 2050 eine rasche und nahezu vollständige direkte Elektrifizierung mittels batterieelektrischer Antriebe erwartet wird, fehlen in mehreren Sektoren realisierbare Optionen für eine direkte Elektrifizierung, sodass diese auf LCF angewiesen sein werden:

- Luftfahrt: Dies ist der Haupttreiber für die LCF-Nachfrage. Um bis 2050 eine vollständige Dekarbonisierung zu erreichen, muss der Schweizer Luftverkehrssektor (einschließlich internationaler Flüge) vollständig auf biogene und synthetische Flugkraftstoffe (sogenannte „Sustainable Aviation Fuels“, SAF) umstellen, da der Einsatz von batterieelektrischen oder wasserstoffbasierten Antriebssystemen innerhalb dieses Zeithorizonts keine realisierbare Option zu sein scheint.
- Schwerer Strassenverkehr: Während leichte Nutzfahrzeuge rasch elektrifiziert werden, wird ein kleiner Teil der Flotte schwerer Nutzfahrzeuge bis 2050 weiterhin Verbrennungsmotoren nutzen (etwa 10%), was alternative kohlenstoffarme Kraftstoffe (hauptsächlich Biokraftstoffe) erfordert, um die Emissionsziele zu erreichen.

Insgesamt wird der Energiebedarf des Schweizer Verkehrssektors trotz des erwarteten Wachstums im Luftverkehr um etwa 30 % zurückgehen, da Elektrofahrzeuge weitaus effizienter sind als Fahrzeuge mit Verbrennungsmotor. Die Umstellung im Luftverkehrssektor auf SAF in der Anfangsphase wird durch die Beimischungsverpflichtung und später durch das Klimaschutzziel vorangetrieben.

Nachhaltige Kraftstoffe und wirtschaftliche Versorgungswege

Zu den nachhaltigen Kraftstoffarten mit vergleichsweise niedrigen Produktionskosten und Lebenszyklus-Treibhausgasemissionen gehören Wasserstoff, Biokraftstoffe, Ammoniak und synthetische Kohlenwasserstoffe (einschliesslich Solarkraftstoffe):

- Wasserstoff: Konkret sind „grüner“ Wasserstoff aus der Wasserelektrolyse unter Verwendung von CO₂-armem Strom und „blauer“ Wasserstoff aus Erdgas mit CO₂-Abscheidung und -Speicherung (CCS)⁶ sowie Wasserstoff aus Restbiomasse realistische Optionen. Bis 2050 werden diese Produktionswege fast Kostenparität mit den derzeitigen Wasserstoffproduktionskosten durch die ungeminderte Dampfreformierung von Erdgas erreichen.
- Biokraftstoffe: Fettsäuremethylester (FAME), hydriertes Pflanzenöl (HVO) und Biomethan sind realisierbare Optionen, wobei ihre Nachhaltigkeit stark von der Verwendung von Restbiomasse abhängt und nicht von Rohstoffen, die Landnutzungsänderungen verursachen oder mit der Nahrungsmittelproduktion konkurrieren. Biogene Rohstoffe können ebenfalls zur Wasserstoffherzeugung genutzt werden. Biogene Flugkraftstoffe aus Restbiomasse weisen unter den SAF-Optionen die niedrigsten Kosten auf. Allerdings muss bei allen Biokraftstoffoptionen das begrenzte Potenzial von Restbiomasse berücksichtigt werden.
- Ammoniak: Ammoniak, das aus grünem Wasserstoff anstelle von Erdgas hergestellt wird, stellt einen nachhaltigen Kraftstoff für die Seeschifffahrt dar.
- Synthetische Kohlenwasserstoffe: Flugkraftstoff und Biomethan, die aus grünem Wasserstoff und CO₂ (idealerweise durch «Direct Air Capture», DAC, gewonnen) hergestellt werden, werden für die Luftfahrt bzw. die Industrie unverzichtbar sein. Ihre zukünftigen Produktionskosten werden jedoch über denen von Biokraftstoffen liegen.

Die globale Kraftstoffökonomie ist durch geografische Heterogenität gekennzeichnet. Die Qualität der erneuerbaren Ressourcen, die Investitionsrisikoprofile und die lokalen Energiekosten bestimmen gemeinsam die Wettbewerbsfähigkeit der Produktionsstandorte. So zählen beispielsweise Länder mit

⁶ Es sind hohe CO₂-Abscheidungsraten von 90 % oder mehr erforderlich.



hoher Sonneneinstrahlung und niedrigen Kapitalkosten – wie Marokko, Chile und Australien – durchwegs zu den wettbewerbsfähigsten Standorten für die Produktion von grünem Wasserstoff und E-Kraftstoffen. Ebenso begünstigt die Verfügbarkeit reichlich vorhandener Biomasse-Ressourcen in Brasilien, Indonesien und Teilen Subsahara-Afrikas die Biokraftstoffproduktion. Ähnliche Parameter bestimmen die Umweltauswirkungen von LCF. Bei allen strombasierten Produktionswegen sind die mit der Stromversorgung verbundenen Umweltbelastungen am wichtigsten. Um wirklich „kohlenstoffarm“ zu sein, müssen solche Produktionswege auf Strom zurückgreifen, der mit sehr geringen Treibhausgasemissionen verbunden ist.

Für kostenoptimale Versorgungswege in die Schweiz sind die zeitliche Perspektive und die Importentfernungen wichtig:

- Kurzfristig: Solange keine spezielle Wasserstofftransportinfrastruktur existiert, ist der Transport von komprimiertem Wasserstoff per Bahn für die innereuropäische Versorgung zwar teuer, aber machbar. Der Seetransport von Ammoniak als Wasserstoffträger würde, obwohl er noch nicht als ausgereifte Technologie gilt, aufgrund der bestehenden Infrastruktur den kostengünstigsten Weg für die Wasserstoffversorgung über grosse Entfernungen darstellen. Auch Biokraftstoffimporte können auf die bestehende Infrastruktur zurückgreifen.
- Langfristig: Der Pipelinetransport wird zum dominierenden Transportweg für innereuropäische Importe werden. Für weit entfernte globale Quellen (z.B. Chile, Australien) werden per Schiff importierte flüssige organische Wasserstoffträger (LOHC) aufgrund der fortschreitenden technologischen Reife wirtschaftlich vorteilhaft. Synthetische Kohlenwasserstoffe („E-Kraftstoffe“) und Solarkraftstoffe werden weiterhin mit vergleichsweise hohen Produktionskosten konfrontiert sein, profitieren jedoch von der bestehenden Transportinfrastruktur.

Die Rolle von LCF in der Schweizer Netto-Null-Strategie und inländische Produktion vs. Importe

Kohlenstoffarme Kraftstoffe werden als wichtige zweite Säule neben der direkten Elektrifizierung in der Schweizer Energiewende dienen und mehrere Zwecke erfüllen:

- Dekarbonisierung von Sektoren, in denen Emissionsminderungen nur schwer zu erreichen sind: LCFs sind derzeit die einzige Lösung für eine vollständige Dekarbonisierung des Luftverkehrssektors bis 2050. Während der Luftverkehr (und in geringerem Masse der schwere Strassenverkehr) mittelfristig den Verbrauch an Bio- und synthetischen Kraftstoffen dominiert, wird der Industriesektor diese Kraftstoffe zunehmend zur Wärme- und Stromerzeugung nutzen. Darüber hinaus setzen der Dienstleistungs- und der Wohnsektor in gewissem Umfang synthetisches Methan für Heizsysteme ein, wenn bestehende (gestrandete) Anlagen genutzt werden müssen oder andere Einschränkungen die direkte Elektrifizierung begrenzen.
- Integration in das Energiesystem: Der hohe Anteil an intermittierendem Strom aus Photovoltaik und Windkraft im Jahr 2050 wird den Bedarf an grünem Wasserstoff und der daraus folgenden synthetischen Methanproduktion (Power-to-Gas) erhöhen, um saisonale Energiespeicherung, Sektorkopplung und Netzstabilität zu unterstützen.

Der Grossteil der LCF, etwa drei Viertel, muss importiert werden. Während Wasserstoff und Biomethan größtenteils im Inland produziert werden können, muss der für die Luftfahrt benötigte SAF importiert werden.

Generell ist die Rolle der heimischen Biomasse in der Schweiz durch begrenzte Biomasse-Ressourcen eingeschränkt. Diese werden in erster Linie zur Stromerzeugung in Kombination mit CCS genutzt, um „negative Emissionen“ zu erzeugen, d.h. CO₂ aus der Atmosphäre zu entfernen, um verbleibende Treibhausgasemissionen aus Industrie und Landwirtschaft zu kompensieren.

Die globale Perspektive

Unter der Annahme einer strengen internationalen Klimapolitik hin zu Netto-Null-Treibhausgasemissionen und einer marktorientierten langfristigen Kostenminimierung des globalen Energiesystems mit globalen Handloptionen und ohne grössere internationale politische Umwälzungen hängt der Einsatz alternativer Kraftstoffe von drei zentralen Aspekten ab:



- Wie kann die weltweit verfügbare Biomasse genutzt werden?
- Die Verfügbarkeit geologischer CO₂-Speicherkapazitäten, die für die Wasserstoffproduktion auf Basis von Erdgas und Biomasse mit CCS benötigt werden
- Die Verfügbarkeit kostengünstiger CO₂-Quellen für die Produktion synthetischer Kohlenwasserstoffe

Nach unseren Modellergebnissen wird Biomasse auf globaler Ebene kosteneffizient für die Produktion flüssiger Kraftstoffe genutzt, selbst bei (im Vergleich zu Standardannahmen) verringertem globalem Biomassepotenzial und gestiegenen Produktions- und Beschaffungskosten für Biomasse. Einige andere international verwendete Modelle tendieren dazu, die Nutzung von Biomasse zur Stromerzeugung zu bevorzugen, teilweise in Kombination mit CCS, um negative Treibhausgasemissionen zu erzielen und schwankende erneuerbare Energien auszugleichen. Unsere Ergebnisse deuten darauf hin, dass flüssige E-Kraftstoffe weltweit nur dann kosteneffizient sind, wenn die CO₂-Speicherkapazitäten begrenzt sind, da in diesem Fall Biomasse benötigt wird, um Erdgas mit CCS im Stromsektor zu ersetzen.

Wasserstoff lässt sich vor 2050 nur teilweise kosteneffizient aus Strom herstellen, was hauptsächlich auf die hohen Grenzkosten für Strom zurückzuführen ist. Diese resultieren aus (i) der weltweiten Dekarbonisierung der Stromerzeugung, (ii) der Elektrifizierung der Nachfragesektoren und (iii) einem erheblichen Anstieg des Energiebedarfs in den Entwicklungs- und Schwellenländern. Daher werden alternative Wege der Wasserstoffproduktion bevorzugt, vor allem die Reformierung von Erdgas mit CCS. Unter der Annahme begrenzter CCS-Kapazitäten kann auch Wasserstoff aus Elektrolyse weiter ausgebaut werden und wird früher (bis 2040) in grösseren absoluten Mengen eingesetzt; die Gesamtwasserstoffproduktion verringert sich jedoch im Vergleich zu den Standardannahmen bezüglich der CO₂-Speicherpotenziale um etwa 50%. Solarprozesse zur Wasserstoff- und Flüssigkohlenwasserstoffproduktion könnten langfristig kosteneffizient sein, wobei der Einsatz etwa ab 2050 beginnen könnte. Langfristig werden Brasilien, Kanada, Mexiko, Russland und Australien die grössten Exportregionen für flüssige LCF sein.

Einschränkungen und Ausblick

Die Ergebnisse der prospektiven techno-ökonomischen Bewertung von LCF hängen in erheblichem Masse von Annahmen hinsichtlich zukünftiger Technologie- und Preisentwicklungen ab, z.B. bei Infrastrukturkomponenten und Energieträgern. Diese sind, insbesondere bei neuen Technologien wie einigen der in unserer Bewertung berücksichtigten LCF, mit hohen Unsicherheiten verbunden. Die Ergebnisse der prospektiven Umweltbewertung von LCF sind mit vergleichsweise geringeren Unsicherheiten behaftet, da die zugrunde liegenden Technologiecharakterisierungen besser vorhersehbar sind als zukünftige Kosten- und Preisentwicklungen. Die Umweltbewertung wurde jedoch nur auf der Ebene einzelner Technologien durchgeführt und konzentrierte sich auf die Lebenszyklus-Treibhausgasemissionen; zukünftige Arbeiten sollten Ökobilanzen und (Schweizer) Energiesystemmodellierung verknüpfen, um die Umweltbelastungen verschiedener Transitionsszenarien mit spezifischen LCF-Einsatzniveaus zu quantifizieren und dabei Umweltwirkungen über die Treibhausgasemissionen hinaus zu berücksichtigen.

Ähnlich wie bei der techno-ökonomischen und der Umweltbewertung hängen die Ergebnisse unserer Energiesystemmodellierung von Annahmen bezüglich zukünftiger Technologie-, Kosten- und Preisentwicklungen ab. Es muss betont werden, dass diese Ergebnisse daher keine Prognosen darstellen, sondern „Was-wäre-wenn“-Szenarien. Eine der zu beachtenden Einschränkungen ist die Tatsache, dass die verwendeten Systemmodelle auf das Energiesystem beschränkt sind und sich auf den Endenergiebedarf konzentrieren. Nicht berücksichtigt ist beispielsweise der Agrarsektor, der eine wichtige Quelle von Treibhausgasemissionen darstellt und um Flächen konkurriert, die für die Nahrungsmittelproduktion, die Herstellung von Biokraftstoffen oder die Infrastruktur zur Erzeugung erneuerbarer Energien genutzt werden könnten. Eine weitere Einschränkung der Modelle ist die fehlende Berücksichtigung der Auswirkungen von Preisänderungen auf die Nachfrage. Zukünftige Arbeiten sollten daher darauf abzielen, derzeit nicht berücksichtigte Sektoren zu integrieren sowie Preiselastizitäten und wirtschaftliche Rückkopplungen zu berücksichtigen.



Schliesslich sind alle Komponenten dieser Arbeit – die techno-ökonomische und ökologische Bewertung sowie die Modellierung des Schweizer, europäischen und globalen Energiesystems – empfindlich gegenüber kurz- und langfristigen politischen Entwicklungen. So können beispielsweise bewaffnete Konflikte zu erheblichen Preisschwankungen und Versorgungsengpässen führen; Uneinigkeit in der Klimapolitik kann die Entwicklung von LCF-Technologien verlangsamen und damit deren zukünftige Kosten erhöhen; bestimmte politische Akteure können den Export kritischer Materialien und Technologien einschränken und so den Einsatz von LCF verlangsamen. Die potenziellen Auswirkungen solcher Entwicklungen wurden in unserer Arbeit nicht berücksichtigt.



Résumé

Contexte, objectif et portée

La Suisse vise à réduire ses émissions nationales de gaz à effet de serre (GES) à zéro net d'ici 2050. Pour atteindre cet objectif, il faut essentiellement éliminer progressivement les combustibles fossiles. Ceux-ci peuvent être remplacés par 1) ce qu'on appelle l'« électrification directe », c'est-à-dire l'utilisation de l'électricité à la place des combustibles fossiles, ce qui implique des changements dans les technologies d'utilisation finale, par exemple le passage des moteurs à combustion interne aux véhicules électriques à batterie, ou 2) par l'utilisation de combustibles à faible teneur en carbone d'origine fossile (LCF⁷), qui peuvent le plus souvent se substituer directement aux combustibles fossiles. Les carburants à faible teneur en carbone fossile comprennent l'hydrogène, l'ammoniac et les hydrocarbures liquides et gazeux issus de la biomasse (« biocarburants ») ou de l'hydrogène et du CO₂. Ces hydrocarbures synthétiques sont souvent appelés « e-carburants » lorsque l'hydrogène nécessaire à leur production est obtenu par électrolyse de l'eau.

Malgré un objectif clair – la Suisse doit atteindre la neutralité climatique d'ici 2050 –, la manière d'y parvenir demeure en partie floue. En particulier, le rôle des LCF dans la transition du système énergétique suisse, notamment dans le secteur des transports, n'est pas clairement défini. Le projet de recherche SHELTERED⁸ comble les lacunes dans ce domaine afin de répondre aux questions suivantes:

- Quels modes de transport devront s'appuyer, même partiellement, sur des LCF chimiques en raison de l'absence d'options d'électrification directe ?
- Parmi ces carburants, lesquels et quelles filières d'approvisionnement sont durables au regard des critères économiques, environnementaux et sociaux ?
- Quel est le rôle de ces carburants dans le système énergétique suisse pour atteindre les objectifs d'émissions nettes de GES égales à zéro ?
- La perspective mondiale : quel rôle les LCF joueront-ils à l'échelle mondiale pour atteindre les objectifs de zéro émission nette, quels LCF domineront dans certaines conditions, et quelles régions seront prédestinées à répondre à la demande mondiale ?

Pour répondre à ces questions, une évaluation technico-économique et environnementale d'un large éventail de LCF actuels et futurs a été réalisée, en tenant compte des sites de production et de leurs caractéristiques à l'échelle mondiale, des filières d'approvisionnement spécifiques en LCF vers la Suisse, ainsi que des développements technologiques futurs jusqu'en 2050. Sur la base de l'évaluation technico-économique des LCF, des modèles de systèmes énergétiques pour l'Europe (la Suisse étant représentée comme un seul pays) et à l'échelle mondiale ont été développés et utilisés pour évaluer les voies de transition vers la neutralité carbone.

Le portefeuille de LCF couvert par notre analyse comprend l'hydrogène issu de matières premières fossiles et biogéniques, avec captation et séquestration de carbone (CSC), la pyrolyse du méthane et l'électrolyse de l'eau, ainsi que des cycles nucléaires ; du kérosène synthétique (carburant pour avions) issu de l'utilisation directe de l'énergie solaire (« carburants solaires »), du carburant pour avions à base d'électricité et de biomasse, du biodiesel, du méthane et du méthanol à base d'électricité et de biomasse, ainsi que de l'ammoniac, à la fois à base d'électricité et issu de matières premières fossiles avec CSC.

Les modèles de systèmes énergétiques sont utilisés pour explorer des scénarios de transition dans lesquels la neutralité carbone est atteinte d'ici 2050 (pour la Suisse, l'UE et d'autres régions) ou plus

⁷ Les « carburants à faible teneur en carbone » (LCF) sont des vecteurs énergétiques liquides ou gazeux qui permettent une réduction substantielle (sans seuil spécifique) des émissions de gaz à effet de serre par rapport aux combustibles fossiles, dans une perspective de cycle de vie. Pour être considérés comme durables, les LCF issus de matières premières biogéniques ne doivent pas entrer en concurrence avec la production alimentaire.

⁸ SHELTERED signifie « Sustainable chEmical Transport fuELS foR SwitzERland » (carburants chimiques durables pour le transport en Suisse). Le projet a bénéficié du soutien financier de l'Office fédéral de l'énergie (OFEN).



tard. Ces scénarios de transition résultent d'optimisations visant à minimiser les coûts globaux du système dans des conditions limites spécifiques, telles que les prix du CO₂, certaines politiques, les ressources renouvelables, les capacités de stockage du CO₂ et les évolutions technologiques attendues. Les résultats des scénarios indiquent les quantités de LCF utilisées pour différentes applications en Suisse (et dans d'autres régions) ainsi que leur origine au fil du temps.

Résultats et discussion

Dépendance des modes de transport en Suisse vis-à-vis des LCF

Alors que le transport routier en Suisse devrait connaître une électrification directe rapide et quasi totale grâce à des groupes motopropulseurs électriques à batterie d'ici 2050, plusieurs secteurs ne disposent pas d'options viables d'électrification directe et dépendront des LCF :

- Aviation : Il s'agit du principal moteur de la demande en LCF. Pour parvenir à une décarbonisation totale d'ici 2050, le secteur aérien suisse (y compris les vols internationaux) doit passer entièrement aux carburants d'aviation durables (SAF), biogéniques ou synthétiques, car l'utilisation de systèmes de propulsion électriques à batterie ou à hydrogène ne semble pas une option viable dans ce délai.
- Transport routier lourd : bien que les camions légers s'électrifient rapidement, une petite partie du parc de camions lourds continuera d'utiliser des moteurs à combustion interne (ICE) jusqu'en 2050 (environ 10%), ce qui nécessitera des carburants alternatifs à faible teneur en carbone (principalement des biocarburants) pour atteindre les objectifs d'émissions.

Dans l'ensemble, la demande énergétique du secteur suisse des transports diminuera d'environ 30 %, malgré la croissance attendue de l'aviation, car les véhicules électriques sont bien plus efficaces que ceux à moteur à combustion interne. La transition du secteur aérien vers les SAF au début de la période est motivée par l'obligation de mélange, puis par l'objectif d'atténuer le changement climatique.

Carburants durables et voies d'approvisionnement économiques

Les types de carburants durables présentant des coûts de production et des émissions de GES sur le cycle de vie relativement faibles comprennent l'hydrogène, les biocarburants, l'ammoniac et les hydrocarbures synthétiques (y compris les carburants solaires) :

- Hydrogène : Plus précisément, l'hydrogène « vert » issu de l'électrolyse de l'eau à partir d'électricité à faible empreinte carbone, l'hydrogène « bleu » issu du gaz naturel avec des techniques de capture et de stockage du carbone (CSC)⁹, ainsi que l'hydrogène issu de la biomasse résiduelle, constituent des options viables. D'ici 2050, ces filières de production atteindront pratiquement la parité avec les coûts actuels de production d'hydrogène par reformage à la vapeur du méthane à partir de gaz naturel, sans mesures d'atténuation.
- Biocarburants : Les esters méthyliques d'acides gras (FAME), l'huile végétale hydrotraitee (HVO) et le biométhane sont viables, bien que leur durabilité dépende fortement de l'utilisation de biomasse résiduelle plutôt que de matières premières entraînant un changement d'affectation des terres ou entrant en concurrence avec la production alimentaire. Les matières premières biogéniques peuvent également être utilisées pour produire de l'hydrogène. Les carburants d'aviation biogéniques issus de la biomasse résiduelle présentent les coûts les plus bas parmi les options de carburants durables pour l'aviation (SAF). Cependant, le potentiel limité de la biomasse résiduelle doit être pris en compte pour toutes les options de biocarburants.
- Ammoniac : Produit à partir d'hydrogène vert plutôt que de gaz naturel, l'ammoniac constitue un carburant durable pour le transport maritime.
- Hydrocarbures synthétiques : le carburant pour avions et le biométhane produits à partir d'hydrogène vert et de CO₂ non fossile (idéalement issu de la capture directe de l'air, DAC) seront

⁹ Des taux de capture de CO₂ élevés, de 90 % ou plus, sont requis.



essentiels respectivement pour l'aviation et l'industrie. Cependant, leurs coûts de production futurs resteront supérieurs à ceux des biocarburants.

L'économie mondiale des carburants se caractérise par une hétérogénéité géographique. La qualité des ressources renouvelables, les profils de risque d'investissement et les coûts énergétiques locaux déterminent conjointement la compétitivité des sites de production. Par exemple, les pays bénéficiant d'un ensoleillement élevé et de faibles coûts d'investissement – tels que le Maroc, le Chili et l'Australie – se classent systématiquement parmi les sites les plus compétitifs pour la production d'hydrogène vert et de carburants synthétiques. De même, la disponibilité de ressources abondantes en biomasse au Brésil, en Indonésie et dans certaines régions d'Afrique subsaharienne favorise la production de biocarburants. Des paramètres similaires déterminent la performance environnementale de la LCF. Pour toutes les filières de production basées sur l'électricité, les impacts environnementaux liés à l'approvisionnement en électricité sont prépondérants. Pour être véritablement « à faibles émissions de carbone », ces filières de production doivent s'appuyer sur une électricité associée à de très faibles émissions de GES.

Pour des filières d'approvisionnement à coût optimal vers la Suisse, la perspective temporelle et les distances d'importation sont importantes :

- À court terme : tant qu'il n'existe pas d'infrastructure dédiée au transport de l'hydrogène, le transport ferroviaire de l'hydrogène comprimé est envisageable, bien que coûteux, pour l'approvisionnement intra-européen. Le transport maritime d'ammoniac comme vecteur d'hydrogène, bien qu'il ne soit pas encore considéré comme une technologie mature, représenterait la voie d'approvisionnement en hydrogène à longue distance la plus rentable en raison des infrastructures existantes. De plus, les importations de biocarburants peuvent s'appuyer sur les infrastructures existantes.
- À long terme, le transport par gazoduc deviendra le mode dominant pour les importations intra-européennes. Pour les sources mondiales éloignées (par exemple, le Chili, l'Australie), les transporteurs d'hydrogène organiques liquides (LOHC), importés par bateau, deviendront économiquement avantageux grâce à la maturation technologique. Les hydrocarbures synthétiques (« e-carburants ») et les carburants solaires continueront de faire face à des coûts de production relativement élevés, mais bénéficieront des infrastructures de transport existantes.

Le rôle des LCF dans la stratégie suisse de neutralité carbone et la production nationale par rapport aux importations

Les carburants à faible teneur en carbone constitueront un deuxième pilier essentiel de l'électrification directe dans la transition de la Suisse et répondront à plusieurs objectifs :

- Décarbonisation des secteurs « difficiles à décarboner » : les crédits de carbone (LCF) constituent actuellement la seule solution permettant de décarboner entièrement le secteur de l'aviation d'ici 2050. Alors que l'aviation (et, dans une moindre mesure, le transport routier lourd) domine la consommation de biocarburants et de carburants synthétiques à moyen terme, le secteur industriel aura de plus en plus recours à ces carburants pour la production de chaleur et d'électricité. De plus, les secteurs des services et résidentiel adopteront, dans une certaine mesure, le méthane synthétique pour les systèmes de chauffage lorsque des actifs existants (obsoletés) doivent être utilisés ou lorsque d'autres contraintes limitent l'électrification directe.
- Intégration du système énergétique : La part élevée d'électricité renouvelable intermittente issue du photovoltaïque et de l'éolien en 2050 augmentera les besoins en hydrogène vert et en production de méthane synthétique (Power-to-Gas) pour soutenir le stockage saisonnier de l'énergie, le couplage sectoriel et la stabilité du réseau.
- La majorité des LCF, soit environ les trois quarts, devra être importée. Alors que l'hydrogène et le biométhane peuvent être produits en grande partie sur le territoire national, les carburants durables (SAF) nécessaires à l'aviation devront être importés.

En général, le rôle de la biomasse nationale en Suisse est limité par des ressources en biomasse limitées. Celles-ci sont principalement utilisées pour la production d'électricité en combinaison avec le CSC



afin de générer des « émissions négatives », c'est-à-dire d'éliminer le CO₂ de l'atmosphère et de compenser les émissions résiduelles de GES provenant de l'industrie et de l'agriculture.

La perspective mondiale

Dans l'hypothèse d'une politique climatique internationale stricte visant la neutralité carbone et d'une minimisation des coûts à long terme du système énergétique mondial axée sur le marché, avec des options de commerce international et sans bouleversements politiques internationaux majeurs, le déploiement des carburants alternatifs dépend de trois aspects clés :

- Comment utiliser la biomasse disponible à l'échelle mondiale ?
- La disponibilité des capacités de stockage géologique du CO₂ nécessaires à la production d'hydrogène à partir du gaz naturel et de la biomasse avec CSC
- La disponibilité de sources de CO₂ bon marché pour la production d'hydrocarbures synthétiques

D'après les résultats de notre modèle, la biomasse est utilisée de manière rentable pour la production de carburants liquides à l'échelle mondiale, même avec (par rapport aux hypothèses par défaut) un potentiel mondial de biomasse réduit et des coûts de production et d'approvisionnement en biomasse accrus. D'autres modèles utilisés à l'échelle internationale ont tendance à privilégier la biomasse pour la production d'électricité, en partie combinée au CSC, pour générer des émissions négatives de GES et équilibrer les énergies renouvelables intermittentes. Nos résultats suggèrent que les e-carburants liquides ne sont rentables à l'échelle mondiale que si le stockage de CO₂ est limité, car dans ce cas, la biomasse est nécessaire pour remplacer le gaz naturel avec CSC dans le secteur de l'électricité.

Avant 2050, la production d'hydrogène à partir de l'électricité n'est rentable que partiellement, principalement en raison des coûts marginaux élevés de l'électricité. Ceux-ci résultent (i) de la décarbonisation mondiale de la production d'électricité, (ii) de l'électrification des secteurs de la demande et (iii) d'une augmentation substantielle de la demande énergétique dans les pays en développement et en transition. Par conséquent, d'autres voies de production d'hydrogène sont privilégiées, notamment le reformage du gaz naturel avec capture et stockage du CO₂ (CSC). En supposant un CSC limité, l'hydrogène issu de l'électrolyse peut également se développer davantage et être déployé en quantités absolues plus importantes plus tôt (d'ici 2040) ; mais la production totale d'hydrogène est réduite d'environ 50 % par rapport aux hypothèses par défaut concernant les potentiels de stockage du CO₂. Les procédés solaires pour la production d'hydrogène et d'hydrocarbures liquides pourraient être rentables à long terme, avec un déploiement à grande échelle débutant vers 2050. À long terme, les principales régions exportatrices de LCF seront le Brésil, le Canada, le Mexique, la Russie et l'Australie.

Limites et perspectives

Les résultats de l'évaluation technico-économique prospective des LCF dépendent dans une large mesure des hypothèses concernant l'évolution future des technologies et des prix, notamment pour les composants d'infrastructure et les vecteurs énergétiques. Celles-ci sont, en particulier pour les technologies émergentes, comme certaines des LCF incluses dans notre évaluation, associées à de fortes incertitudes. Les résultats de l'évaluation environnementale prospective des LCF sont associés à des incertitudes relativement plus faibles, car les caractéristiques technologiques sous-jacentes sont plus prévisibles que l'évolution future des coûts et des prix. Cependant, l'évaluation environnementale n'a été réalisée qu'au niveau des technologies individuelles et s'est concentrée sur les émissions de GES tout au long du cycle de vie ; les travaux futurs devraient associer l'ACV et la modélisation du système énergétique (suisse) afin de quantifier la performance environnementale de différents scénarios de transition avec des niveaux spécifiques de déploiement des LCF, en tenant compte des impacts environnementaux au-delà des émissions de GES.

À l'instar de l'évaluation technico-économique et environnementale, les résultats de notre modélisation du système énergétique dépendent d'hypothèses quant à l'évolution future des technologies, des coûts et des prix. Il convient de souligner que ces résultats ne constituent pas des prévisions, mais des scénarios hypothétiques. L'une des limites à prendre en compte est que les modèles de systèmes utilisés se limitent au système énergétique et se concentrent sur la demande finale d'énergie. N'inclut pas, par exemple, le secteur agricole, qui constitue une source importante d'émissions de GES et un concurrent



pour les terres, lesquelles pourraient être utilisées pour la production alimentaire, la production de bio-carburants ou la construction d'infrastructures de production d'énergie renouvelable. Une autre limite des modèles est l'absence de prise en compte des effets des variations de prix sur la demande. Les travaux futurs devraient donc viser à intégrer les secteurs non inclus pour l'instant, ainsi qu'à prendre en compte les élasticités-prix et les rétroactions économiques.

Enfin, tous les éléments de ce travail – l'évaluation technico-économique et environnementale, ainsi que la modélisation des systèmes énergétiques suisses, européens et mondiaux – sont sensibles aux évolutions politiques à court et à long terme. Par exemple, les conflits armés peuvent entraîner d'importantes fluctuations de prix et des goulets d'étranglement dans l'approvisionnement ; les désaccords sur la politique climatique peuvent ralentir le développement des technologies LCF et ainsi augmenter leurs coûts futurs ; certains acteurs politiques peuvent restreindre les exportations de matériaux et de technologies critiques, ralentissant ainsi le déploiement des LCF. Les effets potentiels de ces évolutions n'ont pas été pris en compte dans nos travaux.



Main findings («Take-Home Messages»)

- To reach its net-zero greenhouse gas (GHG) emission goal, Switzerland will need chemical energy carriers, which allow for a substantial reduction of GHG emissions compared to fossil fuels. Such “Low Carbon Fuels” (LCF) – including biofuels, hydrogen, and synthetic hydrocarbons – will represent a second mitigation pillar next to direct electrification.
- The largest LCF quantity by far will be needed as low-carbon aviation fuel; smaller amounts in heavy-duty road transport, the industry, the residential and service sector.
- As Swiss potentials for residual, sustainable biomass and cheap renewable electricity are limited, the majority of LCFs will need to be imported.



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List of abbreviations

AD	Anaerobic digestion
AEC	Alkaline electrolysis cell
ASU	Air separation unit
ATR	Auto thermal reforming
ATR+CCS	Autothermal reforming with Carbon Capture and Storage
BEV	Battery electric vehicle
BG+CCS	Biomass gasification with Carbon Capture and Storage
BG-FT	Biomass gasification with Fischer-Tropsch
B-PYR	Biomass pyrolysis
BtG	Biomass-to-Gas
BtX	Biofuels (or Biomass-based fuels)
CAPEX	Capital Expenditures
CCS	Carbon capture and storage
CLR	Chemical looping reforming
CRF	Capital recovery factor
CuCl	Nuclear thermochemical copper-chlorine (Cu-Cl) cycle
DAC	Direct air capture
DETEC	Federal Department of the Environment, Transport, Energy and Communications
FAME	Fatty Acid Methyl Ester (production via Esterification)
FLH	Full load hours
FT	Fischer-Tropsch
GHG	Greenhouse gas
GMM	Global Multi-Regional Energy System Model
HB	Haber-Bosch
HGV	Heavy goods vehicle
HTE	High-temperature electrolysis
HTSE	High-temperature steam electrolysis
HVO	Hydrotreated vegetable oil (production via Hydrotreating)
ICE	Internal combustion engine
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
LCA	Life Cycle Assessment
LCIA	Life Cycle Impact Assessment
LCF	Low carbon fuels
LCOF	Levelized cost of fuel
LEA	Laboratory for Energy Systems Analysis
LGV	Light goods vehicle



LOHC	Liquid Organic Hydrogen Carrier
M-PYR	Methane pyrolysis
NPP	Nuclear Power Plant
OPEX	Operational Expenditures
PEM(EC)	Proton exchange membrane (electrolysis cell)
pLCA	Prospective Life Cycle Assessment
PSI	Paul Scherrer Institut
PtG	Power to Gas
PtX	Power-based fuels (or Power-to-X)
PV	Photovoltaics
RWGS	Reverse water gas shift
RWGS-FT	Reverse water gas shift Fischer-Tropsch
RWGS-MeOH	Reverse water gas shift Methanol synthesis
SAF	Synthetic aviation fuel
SFOE	Swiss Federal Office of Energy
SHELTERED	Sustainable chemical transport fuels and their role in future Swiss energy supply (The project name)
SMR	Steam methane reforming
SMR+CCS	Steam methane reforming with Carbon Capture and Storage
SOEC	Solid oxide electrolysis cell
SR	Solar reforming
SR-FT	Solar reforming Fischer-Tropsch
ST	Solar thermochemical
ST-FT	Solar thermochemical Fischer-Tropsch
StL	Sun to liquid fuels
TRL	Technology Readiness Level
WACC	Weighted Average Cost of Capital



1 Preface and Introduction

To limit global warming well below 2 °C above pre-industrial levels, as set out in the Paris Agreement, global greenhouse gas (GHG) emissions will need to decline to net zero by around 2050, according to the Intergovernmental Panel on Climate Change (IPCC) (IPCC, 2023). However, energy-related CO₂ emissions increased by around 900 Mt in 2021, reaching their highest level ever and completely wiping out the pandemic-related reduction seen in 2020 (IEA, 2022b). According to the International Energy Agency (IEA), the energy sector (including fuels used for transport and in industry) is responsible for approximately two-thirds of global greenhouse gas emissions, of which over 85% of total emissions in 2023 came from the use of fossil fuels (IEA, 2023b). So-called “low carbon fuels (LCFs)”, made from biomass, low-carbon electricity, or fossil resources with carbon capture and storage (CCS), can play an essential role in the energy transition and in addressing climate change.

To achieve the European Union's (EU) and Switzerland's goal of climate neutrality by 2050, one of the most critical applications of using LCFs is the emission reduction in transportation systems (Albrecht & Nguyen, 2020; Brynolf et al., 2018). In 2023, transport (including aviation) was the largest GHG emission source of all economic sectors in the EU and accounted for 26% of the EU's emissions (Brandt et al., 2024), and 40% of Switzerland's (Panos et al., 2023a). Transport modes and other applications that cannot be electrified are likely to rely on liquid or gaseous LCFs to reduce greenhouse gas emissions in the future. Although personal motorized passenger transport can be decarbonized by battery electric vehicles, this direct electrification is more challenging for other transport modes (such as shipping and aviation). Without breakthroughs in battery development, these transport modes may have to rely on gaseous or liquid fuels with high energy density (Degen et al., 2023). Low-carbon fuels are also essential and have enormous decarbonization potential in industry and manufacturing (IEA, 2023b). Therefore, LCFs must be properly represented in future scenarios for energy system decarbonization.

The Swiss Federal Office of Energy (SFOE) provided financial support to PSI to analyse the role of LCF within the future Swiss energy system and its advantages and disadvantages in the context of the Swiss (and European) transition towards net-zero GHG emissions. The key research questions this analysis is supposed to answer are the following:

1. Which transportation modes will have to rely (partially) on chemical LCF due to the lack of direct electrification options?
2. Which of these fuels and which supply pathways are sustainable considering economic, environmental, and social criteria?
3. What is the role of these fuels in the Swiss energy system to meet the net-zero emission goals?

To answer these questions, several methods and models have been (further) developed and applied. This report serves as documentation and highlights the main outcomes of the analysis. In this report, we first evaluate a broad range of LCF from a techno-economic and environmental perspective, quantifying their production and supply costs as well as environmental burdens from a life cycle perspective (sections 2 and 3, respectively). Second, and building on the techno-economic assessment of LCF, we integrate these LCF into a Swiss and European energy system model and apply this model to determine the extent to which and for which purposes such LCF will be needed in Switzerland by 2050 to achieve net-zero GHG emissions (section 4 of this report), considering current and future climate and energy policies. Third, we develop and apply a global energy system model to analyse global LCF production and supply pathways, to assess potential origins of LCF supply for Europe (Section 5 of this report), within the context of global climate change mitigation objectives. Model-specific assumptions, additional input data, and results are included as an appendix.

Beyond this report, several academic articles with direct reference to the research questions listed above have been published (Boyce et al., 2024; Ingwersen et al., 2025; Liu et al., 2025, 2026; Saad et al., 2024; Sacchi et al., 2023; Terlouw et al., 2022, 2024a, 2025; Wei et al., 2024a). These articles provide further insights and often a level of detail that is beyond the scope of this report.



2 A global, regionalized quantification of low-carbon fuel production costs and evaluation of associated transport chains

2.1 Introduction

Low-carbon fuels, also known as alternative or clean fuels, are traditionally defined as fuels able to reduce greenhouse gas emissions compared to traditional fossil fuels, considering their entire value chain or over their life cycle (production and use). Examples of LCFs include biofuels (BtX) using biomass feedstock, renewable electricity, power-based fuels (PtX), and sun to liquid fuels (StL), as well as natural gas-based fuels with reduced carbon emissions due to CCS and nuclear-based fuels (Lepitzki & Axsen, 2018). However, current definitions of different LCFs are ambiguous, and no unified standardisation exists (Liu et al., 2025).

Production costs, environmental impacts, and whether such chemical fuels meet the requirements of low-carbon fuels depend on their sources and production routes, the carbon intensity of power and raw material supply, costs and availability, and the source of CO₂ (Brynolf et al., 2018). The potential technology portfolio in terms of supply and demand is extensive, and there is interdependence and potential synergy between specific options. Assessing supply chains and environmental impacts requires a global perspective, as these parameters depend to a high degree on geographic variability.

Techno-economic analysis serves as a critical evaluation tool to assess the cost-effectiveness and feasibility of emerging fuel technologies. It enables a systematic comparison of LCF production pathways, incorporating capital expenditures (CAPEX), operational costs (OPEX), energy consumption, and financial risk factors. However, many existing TEA studies rely on assumptions rather than empirical data (Albrecht & Nguyen, 2020; Dahal et al., 2021; Frick et al., 2022; Makepa et al., 2023), and they fail to account for the variability of the weighted average cost of capital (WACC) across different geographies, technologies, and time horizons (Calcaterra et al., 2024; Egli et al., 2019; Lonergan et al., 2023). Such limitations often lead to inaccurate cost assessments, resulting in misleading policy recommendations (Lonergan et al., 2023). Country-specific risks, technological maturity, and evolving market conditions are often overlooked in WACC estimations, creating a critical knowledge gap in the global techno-economic assessment of LCF production (Calcaterra et al., 2024; Polzin et al., 2021).

This section of the report aims to develop a consistent techno-economic assessment framework to quantify the production and supply costs of LCFs on a global scale. The methodology integrates technological, geographic, and temporal variations to provide a comprehensive cost evaluation of different low-carbon fuel production pathways (Liu et al., 2026). Furthermore, the study assesses the economic feasibility of transporting LCF to Switzerland, analysing global supply chain costs. By addressing key uncertainties and improving the robustness of LCF cost projections, this research contributes to data-driven decision-making in sustainable energy transitions.

2.2 Methodology

This section outlines the methodology applied, beginning with the technology specification, which details the selected LCF production technologies and target fuel categories. This is followed by the system design and general methodological framework, leading into the detailed TEA approach to calculate levelized costs. Finally, the supply chain cost model is introduced to evaluate the transportation of fuels to Switzerland.

2.2.1. Technology specification

In total, 21 LCF production pathways were selected, specified, and assessed. Their acronyms, technology readiness levels (TRL), and reference literature for process documentation and techno-economic data are listed in Table 1.



Table 1: LCF production technology overview.

No.	Abbreviation	Technology	Product	LCF category	TRL 2022
1	PEM	Proton exchange membrane electrolysis	Hydrogen	Green Hydrogen	8~9
2	AE	Alkali electrolysis	Hydrogen	Green Hydrogen	8~9
3	SOEC	Solid oxide electrolysis cell	Hydrogen	Green Hydrogen	6~7
4	HTSE	high-temperature steam electrolysis	Hydrogen	Pink Hydrogen	5~8
5	CuCl	Nuclear thermochemical copper-chlorine (Cu-Cl) cycle	Hydrogen	Pink Hydrogen	5~6
6	SMR+CCS	Steam methane reforming with CCS	Hydrogen	Blue Hydrogen	8~9
7	ATR+CCS	Autothermal reforming with CCS	Hydrogen	Blue Hydrogen	7~8
8	CLR	Chemical looping reforming	Hydrogen	Blue Hydrogen	6~7
9	M-PYR	Methane pyrolysis	Hydrogen	Turquoise Hydrogen	4~6
10	BG+CCS	Biomass gasification with CCS	Hydrogen	Bio/Green Hydrogen	8~9
11	SR-FT	Solar reforming FT	Kerosene	Solar Fuel	5~7
12	ST-FT	Pure solar thermochemical FT	Kerosene	Solar Fuel	4~6
13	RWGS-FT	Reverse water gas shift FT	Kerosene	Power to X	6~8
14	RWGS-MeOH	Reverse water gas shift MeOH	Kerosene	Power to X	6~8
15	BG-FT	Biomass FT	Kerosene	Biofuel	6~8
16	FAME	Esterification	Diesel	Biofuel	8~9
17	HVO	Hydrotreating	Diesel	Biofuel	6~8
18	B-PYR	Biomass pyrolysis	Diesel	Biofuel	4~6
19	PTG	Power to Methane	Methane	Power to X	7~9
20	BtG	Anaerobic digestion	Methane	Biofuel	7~9
21	HB	Haber Bosch	Ammonia	Ammonia	9

Figure 1 presents an overview of the LCF production system, illustrating the conversion pathways from various primary energy sources and feedstocks to the final fuel products. The diagram integrates renewable electricity, nuclear power, solar thermal energy, biomass, and fossil-based resources into different hydrogen production technologies, carbon capture and utilization processes, and fuel synthesis pathways. Key conversion technologies include electrolysis, thermochemical reforming, biomass conversion, and Fischer-Tropsch synthesis, with hydrogen, carbon dioxide, and syngas serving as major intermediates. The dashed and solid arrows represent hydrogen and material flows, respectively, illustrating the interconnections between different production pathways and fuel categories. This process flow structure forms the foundation for the techno-economic and supply chain cost assessments conducted.

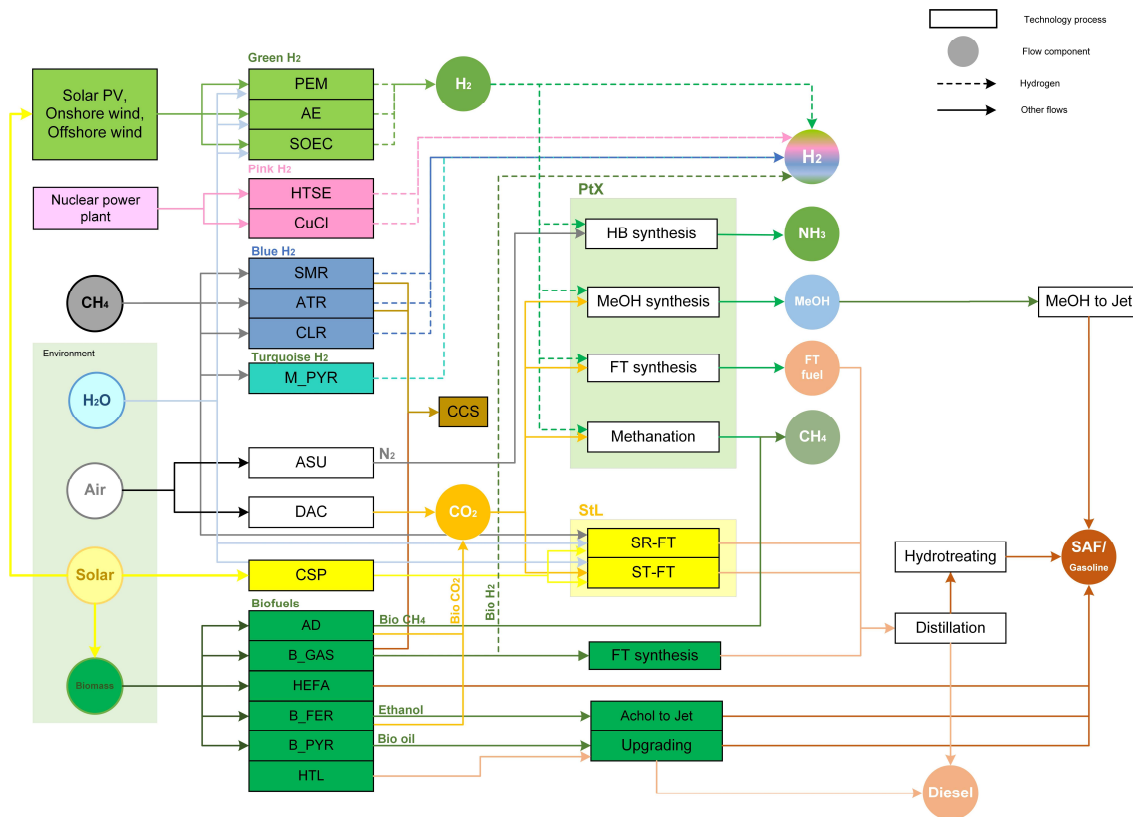


Figure 1: Process flow diagram of low-carbon fuel production processes. Abbreviations: AEC: Alkaline electrolysis cell, PEMEC: Proton exchange membrane electrolysis cell, SOEC: Solid oxide electrolysis cell, HTE: high-temperature electrolysis, SMR: steam methane reforming, ATR: auto thermal reforming, CLR: chemical looping reforming, ASU: air separation unit, DAC: direct air capture, FAME/HVO: esterification/hydrotreating, CCS: carbon capture and storage, HB: Haber-Bosch, RWGS: reverse water gas shift, SR: solar reforming, ST: solar thermochemical, FT: Fischer-Tropsch.

Hydrogen production pathways

Water Electrolysis: PEM, AE, SOEC

Water electrolysis utilizes electricity to separate water into H_2 and oxygen, as represented in equation (1) (Terlouw et al., 2022).



Three major electrolysis technologies are considered viable for large-scale hydrogen production: alkaline electrolysis (AE), proton exchange membrane (PEM) electrolysis, and solid oxide electrolysis cells (SOEC). AE is the most mature technology, operating in an aqueous potassium hydroxide electrolyte at 70–90°C, offering low-cost, high durability, but lower current densities and slower dynamic response. PEM electrolysis utilizes a solid polymer electrolyte membrane, enabling higher current densities and flexible operation at 50–100°C, but requiring expensive catalysts and membrane materials. SOEC operates at 600–900°C, achieving higher efficiencies by utilizing both heat and electricity, but faces challenges in material degradation and commercialization. While AE and PEM are commercially available, SOEC remains in early development, with ongoing research focused on improving system durability and cost-effectiveness.



Nuclear based hydrogen: HTSE, CuCl

High-temperature steam electrolysis (HTSE) utilizes solid oxide electrolyzer cells (SOECs) in conjunction with nuclear power plants (NPPs) to enhance overall efficiency by integrating both thermal and electrical energy. In this process, steam supplied to the hydrogen electrode (cathode) serves to heat the electrochemical stack, where it dissociates into hydrogen and oxygen ions at operating temperatures of 750–950°C and pressures of up to 2 MPa. In this study, we consider an HTSE system coupled with a high-temperature gas-cooled reactor and a light-water reactor as the reference process (Alabbadi et al., 2024; Frick et al., 2022).

Beyond direct electrolysis, the **Cu-Cl thermochemical cycle** is among the most promising nuclear-integrated hydrogen production pathways (Razi et al., 2020, 2023). In this study, we adopt the four-step Cu-Cl cycle (Karaca et al., 2020), which consists of hydrolysis, thermolysis, electrolysis, and drying/separation. Initially, cupric chloride (CuCl_2) reacts with superheated steam in a hydrolysis reactor, forming dicopper oxychloride (Cu_2OCl_2), hydrochloric acid (HCl), and unreacted steam. The Cu_2OCl_2 then undergoes thermal decomposition (thermolysis), producing oxygen gas and cuprous chloride (CuCl). The HCl-steam mixture is condensed and separated via pressure-swing distillation. CuCl is subsequently quenched and solidified, after which it, along with the recovered HCl, is directed to the anolyte make-up vessel (AMV) before entering the electrolyzer. During electrolysis, hydrogen is generated at the cathode, while CuCl_2 , CuCl, HCl, and water are formed at the anode. These products are separated, with water and HCl passing through condensers and separation units. The remaining CuCl_2 is concentrated and dried, and CuCl is recycled back to the AMV, ensuring process continuity and efficiency.

Natural gas based hydrogen: SMR+CCS, ATR+CCS, CLR, M-PYR

Steam methane reforming (SMR) is the most widely used method for hydrogen production, leveraging a catalytic reaction between methane (CH_4) and steam (H_2O) at high temperatures (700–1000°C) in the presence of a nickel-based catalyst. The primary reaction follows: The overall reaction of both processes is represented by equation (2).



SMR is an endothermic process, requiring external heat input to sustain the reaction. It typically operates at pressures between 15 and 30 bar, and the generated synthesis gas (syngas) undergoes further purification through pressure swing adsorption (PSA) to separate pure hydrogen.

Autothermal reforming (ATR) integrates partial oxidation and steam reforming in a single-step process, achieving a thermally self-sustaining reaction without requiring external heat. Methane reacts with oxygen and steam at temperatures of 900–1100°C, facilitated by a nickel-based catalyst:



ATR typically operates at pressures up to 30 bar and achieves higher hydrogen yields than SMR. The exothermic oxidation step provides the necessary heat for the endothermic steam reforming, eliminating the need for an external heat source and improving overall process efficiency. The product gas, primarily composed of H_2 , CO, and CO_2 , undergoes further purification through water-gas shift (WGS) and PSA units. ATR is particularly advantageous for large-scale hydrogen production and can be more compatible with carbon capture and storage (CCS) systems due to its concentrated CO_2 stream.

Chemical loop reforming (CLR) involves the controlled oxidation of methane with a sub-stoichiometric amount of oxygen at moderate temperatures (800–900°C) over a metal-based catalyst, typically nickel or rhodium (Oni et al., 2022), the reactions are the same with ATR.

Unlike SMR, which requires external heat, partial oxidation generates the necessary thermal energy internally, making the process faster and more compact. The synthesis gas (syngas) produced contains CO and H_2 , which can be further processed in a water-gas shift reactor to enhance hydrogen yield.



CLR is particularly well-suited for decentralized and small-scale hydrogen production due to its rapid reaction kinetics and lower operating pressures compared to ATR. However, compared to ATR and SMR, the hydrogen yield per unit of methane is lower, and additional purification steps are required to remove residual CO₂ and CO from the final hydrogen stream. Compared with steam reforming technologies, the advantages of CLR are that the heat is provided by the oxidation with a higher heat transfer coefficient, and no external combustion is needed (Argyris et al., 2023).

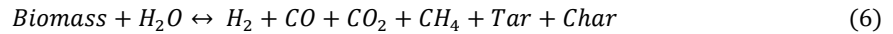
Methane pyrolysis, also known as methane cracking or methane decomposition, is a thermochemical process that decomposes methane into hydrogen and solid carbon directly at high temperatures, catalytically in non-oxidative environments, as in equation (5)



This endothermic reaction requires high temperatures, typically ranging from 800°C to 1200°C, depending on the specific process conditions and reactor design. Various reactor configurations are employed, including plasma, thermal, and catalytic reactors, each offering distinct advantages in terms of efficiency and product quality (Patlolla et al., 2023). A notable advantage of methane pyrolysis is its potential for low-emission hydrogen production. By generating solid carbon as a byproduct, the process inherently avoids the direct emission of CO₂.

Biomass-based hydrogen: Biomass gasification with CCS

Biomass gasification is a thermochemical process that converts biomass into a hydrogen-rich syngas through partial oxidation or steam reforming at high temperatures, typically 800–1000°C. The general reaction is represented as:

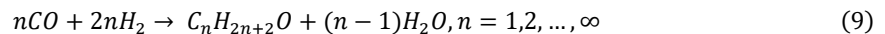
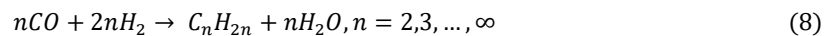
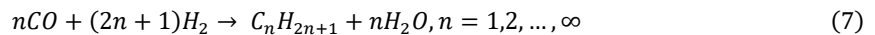


The produced syngas undergoes further water-gas shift (WGS) reactions to increase hydrogen yield, followed by gas cleaning and CO₂ separation. The integration of carbon capture and storage (CCS) enables the sequestration of CO₂ emissions, potentially resulting in negative carbon emissions when combined with sustainably sourced biomass. In this study, we consider a reference process design for hydrogen production via biomass gasification with CCS, as described in (Cormos, 2023). The process includes syngas cooling, gas cleanup, WGS, CO₂ capture, and hydrogen purification, with the captured CO₂ transported and stored in geological formations. Biomass gasification with CCS presents a promising pathway for low-carbon or negative-emission hydrogen production, depending on feedstock sustainability and capture efficiency (Wu et al., 2023).

Hydrocarbons production pathways

Hydrocarbon-based low-carbon fuels can be synthesized through various thermochemical and electrochemical pathways, utilizing renewable energy, captured CO₂, and biomass as feedstocks. This study considers solar-driven reforming, solar thermochemical conversion, Power-to-Liquid (PtL), and Biomass-to-Liquid (BTL) Fischer-Tropsch (FT) synthesis.

Fischer-Tropsch (FT) is a catalytic reaction involving the reaction between the reactants in syngas (CO and H₂) on the catalyst surface. It converts the syngas into a spectrum of liquid hydrocarbon products, such as liquid transportation fuels, alcohols, aldehydes, olefins, paraffins, etc. The main products of FTS are alkanes (Equation (7)), alkenes (Equation (8)), and alcohols (Equation (9)), but the product strongly depends on the catalyst's nature and reaction parameters.



Solar FT fuel: SR-FT, ST-FT

Solar reforming FT synthesis combines methane reforming with concentrated solar power (CSP) to produce syngas (H₂ + CO), which is further converted into synthetic fuels via FT synthesis. Solar reforming utilizes high-temperature solar heat (800–1200°C) in place of conventional fossil-based heating



for steam reforming ($\text{CH}_4 + \text{H}_2\text{O}$) or dry reforming ($\text{CH}_4 + \text{CO}_2$), reducing CO_2 emissions while maintaining high hydrogen yields. The produced syngas is processed through FT synthesis, yielding various products such as synthetic aviation fuel (SAF), diesel, and gasoline.

This pathway reduces fossil fuel dependency while leveraging renewable thermal energy, making it an intermediate solution between fossil-based reforming and fully renewable FT synthesis. CCS is required to capture and store this CO_2 , preventing emissions and ensuring low-carbon fuel production.

Solar thermochemical FT (ST-FT) synthesis offers a fully renewable pathway by directly converting CO_2 and H_2O into syngas using high-temperature solar-driven redox cycles. This process operates at 1000–1900 Kelvin. For the concentration of solar energy, either a field of heliostats focusing on a tower or an array of dishes can be used. The resulting synthesis gas, a mixture of mainly H_2 and CO , is then converted into liquid fuels with the Fischer–Tropsch process. The resulting jet fuel is a drop-in fuel permitted for blends with conventional jet fuel with shares of up to 50% (Falter et al., 2020). Since ST-FT does not rely on fossil feedstocks, it inherently eliminates fossil CO_2 emissions from hydrocarbon conversion (without considering value chain-related emissions).

Power to Liquid fuel: RWGS-FT, RWGS-MeOH

Reverse Water-Gas Shift (RWGS)+FT pathway utilizes electrolysis-derived hydrogen and captured CO_2 to synthesize hydrocarbon fuels. CO_2 reacts with H_2 via RWGS at 800–1100°C, producing syngas. The syngas undergoes FT synthesis, forming liquid hydrocarbons such as SAF and diesel. This process provides high flexibility in integrating renewable electricity and CO_2 capture, offering a scalable alternative to fossil-derived FT fuels (Eyberg et al., 2024).

RWGS-MeOH pathway can produce synthetic jet fuel through methanol synthesis, followed by Methanol-to-Jet (MtJ) conversion (Gonzalez-Garay et al., 2022). CO_2 -derived syngas is first converted into methanol (CH_3OH) via catalytic methanol synthesis. Methanol is then processed into kerosene (jet fuel) via dehydration and oligomerization reactions (Eyberg et al., 2024). This pathway is optimized for aviation fuel applications, providing direct compatibility with existing infrastructure while being fully renewable when powered by green hydrogen and CO_2 capture.

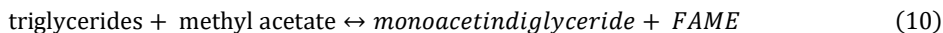
BtL: BG-FT

Biomass gasification FT (BG-FT) technology is considered a good approach to obtaining environmentally friendly transportation fuel and reducing the high dependency on fossil fuels. BTL technology is a multistep process that involves the gasification of carbonaceous material (biomass) into synthesis gas, followed by the conversion of the biomass-derived synthesis gas into synthetic fuel and chemicals.

With only a few BG-FT plants having been built to date at the pilot and demonstration scale, one significant challenge in scaling up the BTL-FT process is the economic aspect, which is a major motivation for developing novel processes that can use existing unit operations in a more effective process design. We considered the biomass gasification and FT process described in (Okoye-Chine et al., 2022). The input materials are woody biomass, and the target fuel is kerosene (SAF). Material and energy balance data are obtained from process modelling (Okoye-Chine et al., 2022).

Biodiesel production pathways

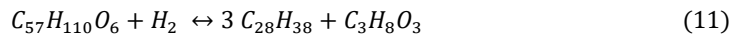
Fatty acid methyl esters (FAME), commonly referred to as biodiesel, are drop-in diesel fuel alternatives produced via transesterification of triglycerides (TGs) from vegetable oils, animal fats, or waste cooking oils. The reaction involves the conversion of triglycerides and methanol into FAME and glycerol as a byproduct (Dougher et al., 2023):



The reaction is typically catalysed by alkaline catalysts (e.g., sodium hydroxide or potassium hydroxide) to enhance reaction efficiency. FAME reduces greenhouse gas (GHG) emissions compared to fossil diesel but has lower oxidative stability and energy density. Commercial biodiesel blends (e.g., B5, B20) contain 5–20% FAME mixed with conventional diesel for compatibility with existing engines. FAME production is a mature and scalable technology, but feedstock availability and land-use constraints remain key challenges in large-scale adoption.

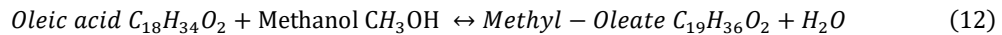


Hydrotreated vegetable oil and hydroprocessed esters and fatty acids (HVO/HEFA) is a mature and commercially deployed technology for producing advanced biofuels, including renewable diesel and sustainable aviation fuel (SAF/kerosene). The process involves catalytic hydrotreating of triglyceride-rich feedstocks (e.g., vegetable oils, animal fats, used cooking oil) with hydrogen (H_2), converting them into paraffinic hydrocarbons suitable for direct use as diesel or jet fuel. The generalized reaction is:



Hydroprocessing removes oxygen from the triglycerides, producing long-chain alkanes (paraffins) with properties similar to fossil diesel. Unlike FAME, HVO is fully compatible with existing diesel engines and jet fuel infrastructure without blending limitations. The process operates at high pressures (30–80 bar) and temperatures (300–400°C) using catalysts such as Ni-Mo or Co-Mo.

Biomass pyrolysis is a thermochemical conversion process in which lignocellulosic biomass is decomposed at 400–600°C in an oxygen-free environment, producing bio-oil (pyrolysis oil), syngas, and bio-char. The general reaction is:



Fast pyrolysis maximizes liquid bio-oil yield, while slow pyrolysis favours biochar production. Catalytic upgrading can convert bio-oil into hydrocarbon fuels via hydrotreatment and hydrocracking.

The resulting biofuels are suitable for blending with conventional diesel and jet fuel, but raw bio-oil requires further refining to remove oxygen, acids, and impurities. In our study, we consider the fast pyrolysis to produce biodiesel.

Methane production: PtM, AD

The PtM production of methane from hydrogen and carbon dioxide is the reverse process of SMR, which is currently the dominant method for hydrogen production from natural gas. The catalytic methanation process was first described by Paul Sabatier in 1902 and has historically been employed to remove CO and CO₂ from hydrogen-rich gas streams, particularly in the fertilizer industry. More recently, research has expanded into biological methanation, wherein microorganisms metabolize hydrogen and CO₂ to produce methane. However, as biological methanation remains at the pilot and demonstration scale and is primarily suitable for small-scale applications, it is not considered in this study. Catalytic methanation occurs at temperatures of approximately 300–400 °C using a nickel-based catalyst. The reaction follows the general stoichiometry (K. Lee et al., 2024):



Anaerobic digestion (AD) is a biochemical process in which microorganisms break down organic biomass in an oxygen-free environment, producing biogas, primarily composed of methane (CH₄) and carbon dioxide (CO₂). This process occurs in four main stages: hydrolysis, acidogenesis, acetogenesis, and methanogenesis, where complex organic matter is progressively decomposed into simpler molecules, ultimately yielding CH₄-rich biogas. The general reaction for anaerobic digestion can be expressed as:



Raw biogas can be upgraded to biomethane by removing CO₂, H₂S, and water vapor, resulting in pipeline-quality renewable natural gas (RNG) or compressed/liquefied biomethane for transportation fuel use.

Ammonia production: HB

Industrial ammonia production is predominantly based on the Haber-Bosch (HB) process, in which nitrogen and hydrogen react catalytically over an iron-based catalyst to form ammonia (del Pozo et al., 2022). This process is thermodynamically characterized by a decrease in entropy, favouring low temperatures and high pressures. However, due to the slow kinetics of the reaction, elevated temperatures of approximately 500 °C and pressures of 200 bar are required to achieve a viable reaction rate. The production of 1 kg of NH₃ requires approximately 0.18 kg of H₂ and 0.84 kg of N₂, resulting in a lower heating value (LHV) efficiency of 87% (del Pozo et al., 2022). Additionally, the process demands around



0.5 kWh_{el}/kgNH₃, primarily for the compression of the input gas streams. The produced ammonia is subsequently liquefied at -33 °C, utilizing cooling from the evaporation of the nitrogen feed. In our analysis, only electrolyzed hydrogen is considered for ammonia production, and ammonia conversion is considered as a transport option for all the hydrogen.



2.2.2. Methodology overview and system configuration

This study develops a comprehensive techno-economic assessment framework to evaluate the production costs and regional feasibility of various low-carbon fuels under different energy system configurations. The methodology encompasses off-grid renewable hydrogen production, grid-connected hydrogen production, power-to-X conversion, CO₂ sourcing, and fuel storage considerations. The system boundaries, methodological flowchart, and key analytical components are illustrated in Figure 2.

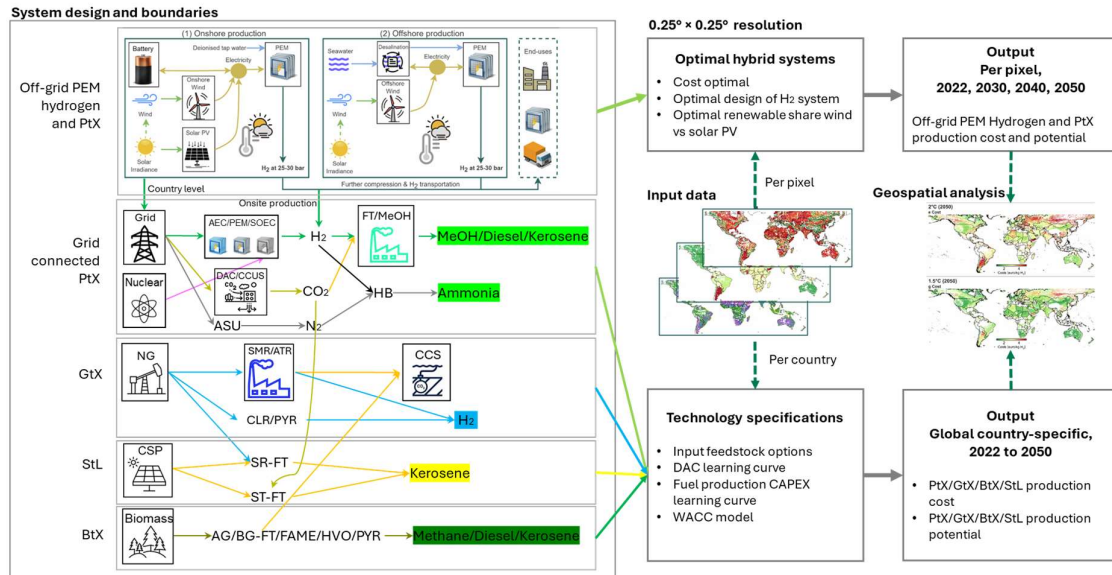


Figure 2: Overview of methodology and scope of system configuration of this work.

Off-grid renewable electricity and hydrogen production

The off-grid electrolytic hydrogen production system is based on the methodology outlined in a previous study (Terlouw et al., 2024a), which assesses potentials, location-specific costs, and environmental impacts using a 0.25° × 0.25° spatial resolution. This analysis includes location-specific potentials for solar PV, onshore wind, and offshore wind, along with system optimization to maximize renewable energy use. For hydrogen production, the PEM electrolyzer is selected due to its suitability for decentralized systems, particularly its ability to efficiently handle intermittent renewable energy and respond dynamically to fluctuations in power supply (Terlouw et al., 2022). The system design is optimized using a mixed-integer linear programming (MILP) model, which determines the least-cost combination of renewable energy sources, storage capacity, and electrolyzer sizing. The MILP model is applied to 100 high-potential locations worldwide, generating cost-optimal configurations for each site. The outputs from these case studies generate non-linear trend correlations, enabling geospatial analysis to estimate near-optimal system configurations, including wind vs. solar PV shares, battery sizes, and electrolyzer capacities for hydrogen production in each grid cell.

Grid-connected hydrogen production

We consider a grid-assisted large-scale hydrogen production system that operates continuously with a capacity factor of 80% (Brandt et al., 2024; Raab et al., 2022). This approach assumes that utilizing the



electricity grid mix for green hydrogen production does not inherently increase greenhouse gas (GHG) emissions relative to grey hydrogen production, provided that grid decarbonization targets are met. The national renewable electricity costs of solar and wind energy are estimated using the LCOEs of each country based on country-level averaged capacity factors calculated from pixel-level simulations, and the share of renewable mix and other electricity technologies in each country's future scenarios in RE-MIND (Sacchi, Terlouw, et al., 2022a). For the electricity production cost of non-renewable options, the future production costs are estimated based on IEA data. For simplicity, it is assumed that grid electricity procurement does not include transmission fees and taxes, reflecting an idealized case (Brandt et al., 2024).

Hydrogen and CO₂ storage for PtX production

Efficient storage solutions are required to balance the spatial and temporal mismatch between hydrogen and CO₂ supply and PtX production. The following storage methods are incorporated into the cost model:

Hydrogen Storage: Hydrogen is stored in high-pressure compressed gas tanks, with associated capital costs, operational costs, and efficiency losses accounted for in the levelized cost of hydrogen (LCOH). To compensate for storage-related inefficiencies, an adjustment factor is applied to increase hydrogen production volume accordingly.

CO₂ Storage: The levelized cost of carbon (LCOC) includes the cost of geological CO₂ storage, which is assumed to be co-located with the PtX facility to minimize transportation costs.

CO₂ sources for PtX production

Two primary CO₂ sources are considered for PtX synthesis:

Biogas from biomass gasification. Synhelion (Synhelion, 2024) and current SAF production (Rojas-Michaga et al., 2023) utilized biomass-based carbon source as input, and this process is modelled in the BG-FT.

Direct Air Capture (DAC). The future cost trajectory of Liquid Solvent DAC technology is estimated using a multi-step cost modeling approach (Sievert et al., 2024), which includes:

Baseline cost assessment from existing literature,

Application of multi-component learning rates, reflecting technology maturation,

Derivation of cost functions linking CO₂ capture cost to electricity input costs (LCOE).

These cost estimates ensure that the comparative economic feasibility of biogenic CO₂ and DAC-based CO₂ supply is adequately evaluated under different energy transition scenarios.

Other fuel production

The production of Gas-to-Liquid (GtL), Solar-to-Liquid (StL), and Biomass-to-Liquid (BtL) fuels is considered under a country-specific feedstock availability framework. The system configuration is designed to reflect representative production scales, technological feasibility, and integration with regional energy resources. For each fuel pathway, a standardized production plant size of 100 MW fuel output scale (based on LHV) is assumed as a baseline for cost and process modelling (Do et al., 2022). The system design follows the general configuration of commercial-scale PtX and thermochemical conversion processes, ensuring consistency in technology comparisons.

2.2.3. Techno-economic assessment

The techno-economic assessment framework in this study evaluates the cost-competitiveness of different LCF production pathways by estimating their Levelized Cost of Fuel (LCOF). The LCOF is determined based on capital expenditure (CAPEX), operational costs (OPEX), energy and feedstock costs, and financial parameters such as the weighted average cost of capital (WACC) and system efficiency. The methodology follows a systematic approach, incorporating both direct production costs and external system interactions (e.g., carbon capture, electricity consumption, and hydrogen input costs).



Levelized cost of fuel (LCOF) calculation

The levelized cost of fuel X (LCOX) is computed using equation:

$$LCOX = \frac{CRF * (CAPEX + FOC)}{8760 * CF * \eta_x} + VOC \quad (6)$$

Where:

LCOX: Levelized cost of fuel X [CHF/kWh]

CRF: Capital recovery factor

CAPEX: Total capital investment cost [CHF/kW]

FOC: Fixed operation and maintenance expenses (as a specific ratio of CAPEX) [CHF/kW]

VOC: Variable operating cost per kWh fuel produced [CHF/kWh], including the costs of raw materials and utilities (e.g., electricity, heat, cooling), which are calculated based on the consumed amount and unit prices.

CF: capacity factor, calculated by working hours in one year, which is assumed as 8000 h/y by default.

η_x : System efficiency of fuel production based on the lower heating value (LHV)

The capital recovery factor (CRF) is derived using equation:

$$CRF = \frac{WACC * (1 + WACC)^N}{(1 + WACC)^N - 1} \quad (7)$$

Where:

WACC: Weighted average cost of capital.

N : Economic lifetime [y] (years)

The variable operating cost (VOC) is calculated using equation:

$$VOC = \sum_{i=1, j=1} (m_i \times p_{mi}) + (e_j \times p_{ej}) \quad (8)$$

Where:

m_i : mass of raw material *i* required to produce per kWh fuel X [kg/kWh],

p_{mi} : price of raw material *i* [CHF/kg],

e_j : energy utility *j* required per kWh fuel X [kWh/kWh],

p_{ej} : price of energy utility *j* [CHF/kWh].

For electrolysis-based hydrogen production, additional cost considerations arise due to the replacement costs of electrolyzer stacks over time. The annualized capital expenditure $CAPEX_{an,unit}$ is calculated using equation:

$$CAPEX_{an,unit} = \frac{CRF \times CAPEX}{8760 * CF \times \eta_x} \quad (19)$$

Given that electrolyzer lifetimes may vary over the study period, the replacement expenditure (REPEX) is modelled as:

$$REPEX_{an,unit} = CAPEX_{an,unit} \times \left(\frac{CF \times t}{t_{ele}} - 1 \right) \times (1 - f_{rep}) \quad (20)$$

Where t_{ele} is the lifetime of the electrolyzer, f_{rep} is the replacement factor.



Cost Components and Sensitivity Analysis

The breakdown of cost components contributing to LCOX is visualized in Figure 3, which details the major cost drivers, including:

- Capital Expenditures (CAPEX): Annualized based on plant lifetime and financial assumptions.
- Fixed and Variable OPEX: Including maintenance, labour, and auxiliary system costs.
- Electricity Costs: Derived from the levelized cost of electricity (LCOE) from country-specific renewable and grid-based power sources.
- Hydrogen Costs: Accounted for when used as an intermediate input in Power-to-X (PtX) synthesis.
- CO₂ or N₂ Costs: Applicable for fuels derived from carbon capture or nitrogen separation.
- Total Fuel Production: Normalized to CHF/kg fuel based on system capacity.

A sensitivity analysis is conducted to assess the impact of WACC, CAPEX reductions, learning rates, and feedstock costs on LCOX. This provides insights into cost reduction pathways for emerging fuel technologies under different global energy scenarios.

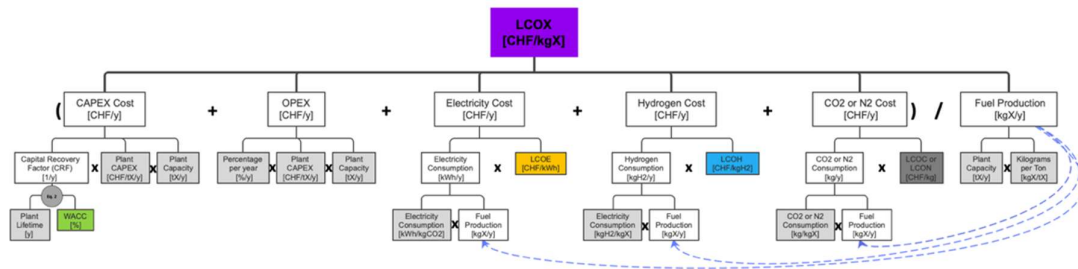


Figure 3: Cost breakdown structure for the Levelized Cost of Fuel (LCOX) calculation. The diagram illustrates the key cost components, including CAPEX, OPEX, electricity, hydrogen, and CO₂ or N₂ costs, normalized by total fuel production. The methodology incorporates financial parameters such as the CRF, as well as process-specific energy and material consumption (Frey, 2023).

Scenario design

To establish a consistent framework for future comparisons, three distinct scenarios have been designed to capture varying trajectories of technology development and policy pathways. Each scenario incorporates specific assumptions regarding the rate at which technologies mature—as reflected by changes in Technology Readiness Levels (TRLs)—and aligns these assumptions with corresponding international energy outlooks. Table 2 summarizes the scenario designs by linking technology assumptions to both International Energy Agency (IEA) (IEA, 2022b) and REMIND (Sacchi, Terlouw, et al., 2022a) scenarios:

- BAU (Business as Usual): Assumes slow technological progress, with TRLs increasing by one level in 2030 and again in 2040, reaching TRL 9 by 2050. This scenario corresponds to the IEA's Stated Policies Scenario (STEPS) and the REMIND >2 °C 2050 (SSP2-Base) pathway.
- 2 °C Scenario: Envisions an intermediate pace of technological development, where TRLs improve by two levels by 2030, and all technologies achieve TRL 9 by 2040. This pathway is consistent with the IEA's Announced Pledges Scenario (APS) and the REMIND 2 °C 2050 (SSP2-PkBudg1150) trajectory.
- 1.5 °C Scenario: Assumes advanced technology development, enabling all technologies to reach TRL 9 as early as 2030. This aggressive scenario aligns with the IEA's Net Zero Emissions by 2050 (NZE) Scenario and the REMIND 1.5 °C 2050 (SSP2-PkBudg500) pathway.



Table 2: Scenario designs.

Scenario	Technology assumptions	IEA scenario	REMIND scenarios
BAU (Business as usual)	Slow technology development (TRL will increase by 1 level in 2030 and 1 level in 2040, reaching 9 in 2050)	Stated Policies Scenario (STEPS)	>2 °C 2050 (SSP2-Base)
2 °C	Intermediate technology development (TRL will increase by 2 levels in 2030, and all will reach 9 in 2040)	Announced Pledges Scenario (APS)	2 °C 2050 (SSP2-PkBudg1150)
1.5 °C	Advanced technology development (all technologies can reach TRL 9 from 2030)	Net Zero Emissions by 2050 Scenario (NZE)	1.5 °C 2050 (SSP2-PkBudg500)

Input data and variable configuration

A comprehensive set of input variables has been defined for the techno-economic analysis, as outlined in Table 3. This configuration ensures that each variable is systematically categorized according to its dependence on technology, time (year), scenario, and country. Key parameters include:

- Capital Expenditures (CAPEX): Measured in CHF/kW and adjusted for technology, temporal, scenario, and country-specific variations. A detailed description of the calculation method follows.
- Operating Expenditures (OPEX): Expressed as a percentage and tailored by technology and country. Data was collected for each technology separately.
- Lifetime: Captured in years and influenced by both technology and scenario.
- Efficiency (η_x): Evaluated as a percentage, with sensitivity to technology, time, and scenario.
- Material and Energy Inputs: Quantified per kWh for material (kg/kWh) and energy (kWh/kWh), respectively. For each technological pathway, data are obtained from detailed techno-economic studies that incorporate process simulations. These simulations are then calibrated against Life Cycle Inventories (LCIs) for unit production.
- Weighted Average Cost of Capital (WACC): Considered across all dimensions. A detailed methodology follows.
- Material and Energy Prices: Prices for materials (CHF/kg) and energy (CHF/kWh) are considered based on time, scenario, and country factors.

This multi-dimensional configuration facilitates a robust sensitivity analysis, capturing the spatial and temporal heterogeneity inherent in low-carbon fuel production.

Table 3: Overview of variable configuration considered in the techno-economic analysis. (2022 CHF is selected as the reference currency).

Variable	Unit	Technology specific	Time (year) specific	Scenario specific	Country specific
CAPEX	CHF/kW	Yes	Yes	Yes	Yes
OPEX	% of CAPEX	Yes	No	No	Yes
Lifetime	year	Yes	No	Yes	No
Efficiency η_x	%	Yes	Yes	Yes	No
Material input	kg/kWh	Yes	No	No	No



Variable	Unit	Technology specific	Time (year) specific	Scenario specific	Country specific
Energy input	kWh/kWh	Yes	No	No	No
WACC	-	Yes	Yes	Yes	Yes
Material price	CHF/kg	No	Yes	Yes	Yes
Energy price	CHF/kWh	No	Yes	Yes	Yes

Energy and feedstock price

Global grid electricity projection

National renewable electricity costs for solar and wind are estimated using country-specific LCOE values. These are derived from detailed pixel-level capacity factor simulations and account for the projected share of renewables in future REMIND scenarios (Sacchi, Terlouw, et al., 2022a). Future costs for non-renewable electricity production are extrapolated from IEA data (IEA, 2022b, 2022a), assuming that grid fees and taxes are excluded from the calculation. The overall grid LCOE of each country is computed as a weighted sum of the technology-specific shares and their respective LCOEs:

$$\text{Grid LCOE} = \sum (\text{Share of Technology}_i \times \text{LCOE of Technology}_i) \quad (21)$$

Feedstock Prices:

- Natural Gas: Global prices are disaggregated into major markets (USA, EU, China, Russia, and Japan) with an averaged value applied for the rest of the world.
- Biomass: A global average price is used due to market complexity.
- Nuclear Electricity: Only countries with existing nuclear facilities are considered, with each country's specific LCOE applied.
- Solar Fuels: The analysis includes countries that either currently operate or plan to install Concentrated Solar Power (CSP) plants, with country-specific CSP LCOE values incorporated.

CAPEX. The capital cost (CAPEX) data are correspondingly extracted from literature sources with the same or similar magnitude production scales. The input data range of the capex value is obtained from literature reviews. If no data points for the future capex value are available from the literature, the capital cost in 2030 and 2050 was estimated using a learning curve model.

The learning curve model reflects the “learning by doing” effect on production costs and describes a fixed percentage (learning rate) by which the unit capital cost of a technology decreases with each doubling of its cumulative installed capacity. The learning curve model has been widely used in studies on the future costs of production technologies. Each technology has its own learning rate for production processes, including multiple technologies, and a composite learning curve can be used. The following equation describes the learning curve of $C_{capex}(t)$ (Sievert et al., 2024; Zhen et al., 2023).

$$C_{capex}(t) = C_{capex,0} * \left(\frac{I(t)}{I_0}\right)^{-\alpha} \quad (22)$$

$$LR = 1 - 2^{-\alpha} \quad (23)$$

Where:

$C_{capex,0}$ is the cost of the technology in the base year,

$I(t)$ is the cumulative capacity of the technology in period t,

I_0 is the cumulative capacity of the technology in the base year, and

α is the learning index, which can be calculated from the learning rate (LR) using (23).



Learning rates for each technology are gathered from various literature sources. When such data are unavailable, estimates are made based on the technology's TRL (Technology Readiness Level) and comparisons within the same technology category. For technologies at TRL 8-9, learning rates are assumed to be 3%, 8%, and 13% for pessimistic, base, and optimistic scenarios, respectively. For less mature technologies (TRL 5-7), learning rates of 5%, 10%, and 15% are applied. The cumulative capacity for fuel production is obtained from the International Energy Agency (IEA)'s projections for hydrogen, synfuel, and biofuel volumes in 2030 and 2050, aligning the Stated Policies Scenario (STEPS), Announced Pledges Scenario (APS), and Net Zero Emissions by 2050 Scenario (NZE) with the pessimistic, base, and optimistic assumptions, respectively. For consistency, it is assumed that global learning rates remain unaffected by exchange rate fluctuations, and the Swiss Franc is used as the reference currency due to its low inflation rate (Lilliestam et al., 2020).

WACC. For renewable electricity production technologies, the baseline WACC values are sourced from a dataset published by IRENA (IRENA, 2023b), which provides country-specific WACC values for solar PV and onshore/offshore wind projects. Average WACC are considered for countries without WACC data.

To consider the factor indicators from geography, time, and technology dimensions that can affect the WACC value (Lonergan et al., 2023). The WACC values of fuel production technologies for each country and time scope are derived through a multi-step approach. A base WACC value of technology x in the year 2022 $WACC_{base}(x)$ is chosen to be 8%, as in most studies. For the WACC value of technology t in country c in year t , the WACC value is calculated as:

$$WACC_{x,y,t}(x, y, t) = WACC_{base}(x) * f_{x,t}^{tech}(x, t) * f_y^{country}(y) \quad (24)$$

In which the $f_{x,t}^{tech}$ reflects technology-specific adjustments based on TRL and subsequent learning rate improvements. Less mature technologies initially have a higher risk—and thus higher WACC—but as they mature (by 2030 and 2050), the associated risks and costs of capital decrease. In addition, the classic experience curve is employed to quantify the reduction in the cost of capital as a function of cumulative capacity growth:

$$WACC_{x,y,t} = WACC_{base}(x) * \left(\frac{I(t)}{I_0}\right)^{-\beta} \quad (25)$$

$$ER = 1 - 2^{-\beta} \quad (26)$$

For our analysis, ER is set at 5%. The country-specific factor, $f_y^{country}(y)$, adjusts for macroeconomic, political, and financial conditions, and is given by:

$$f_y^{country}(y) = \frac{WACC_{base} + CRP(y)}{WACC_{base}} \quad (27)$$

where $CRP(y)$ represents the country's risk premium for country y . The cost of debt is estimated using publicly available data on central bank rates, commercial bank lending rates, and typical risk premiums for similar projects. Due to the confidentiality of internal financial data and return expectations, the cost of equity is estimated using models such as the Capital Asset Pricing Model (CAPM) in conjunction with publicly available financial reports.

2.2.4. Supply chain cost model

Methodology for transport cost assessment

The transport cost calculation methodology employs a comprehensive approach to evaluate the economic viability of hydrogen delivery to Switzerland across multiple carrier types and transport modes. Five hydrogen carriers are considered—compressed hydrogen (CH_2), liquid hydrogen (LH_2), ammonia (NH_3), methanol ($MeOH$), and liquid organic hydrogen carriers (LOHC)—each transported via their suitable modes: truck, rail, ship, pipeline, or barge. The model adheres to physical constraints, ensuring that maritime routes exclusively utilize ships, while land routes employ appropriate ground transportation options. For each country-carrier-mode combination, the total cost is calculated as the sum of conversion costs, transport costs, storage costs, and, where applicable, reconversion costs. Conversion



costs account for the energy and infrastructure requirements to transform hydrogen into transportable carriers, while reconversion costs represent the expenses to recover hydrogen at the destination. Storage costs are determined as a function of carrier type, storage duration, and carrier-specific storage rates, with storage duration calculated based on distance and mode-specific transport speeds (ship: 800 km/day, barge: 480 km/day, rail: 720 km/day, truck: 600 km/day, pipeline: 960 km/day), plus additional handling time (ship: +5 days, barge: +3 days, truck/rail: +1 day, pipeline: 0 days). For direct land routes, costs are calculated based on the total distance, while for maritime routes, the calculation incorporates three segments: from the capital of the country of origin to the port, sea transport, and from the port to the destination. Each segment employs the most economical transport mode, subject to distance constraints.

The route selection algorithm first determines the optimal pathway between each origin country and Switzerland based on geographical considerations. Countries are categorized into direct land routes (short=1) or maritime routes (short=0) based on their accessibility (as shown in the Appendix). The model enforces distance limitations for different transport modes (truck: 1000 km, rail: 2000 km, pipeline: 4000 km, barge: 1500 km), ensuring technological feasibility. For pipeline transport of gaseous hydrogen, the model applies additional geographical constraints, limiting availability to European countries within the pipeline distance threshold. Similarly, barge transport is restricted to a predefined set of countries with significant inland waterway infrastructure (the Netherlands, Germany, Belgium, France, Austria, Hungary, Czech Republic, Poland, Slovakia, Romania). The algorithm further restricts certain carrier-mode combinations based on technological constraints, such as the incompatibility of gaseous hydrogen with ship transport or non-CH₂ carriers with pipeline transport. For maritime routes, the model optimizes multi-segment pathways, selecting the most cost-effective mode for each segment. From origin capitals to ports, either truck or rail is selected based on distance. For the sea segment, appropriate carrier-specific ship transport is calculated. From the import port (Antwerp) to Switzerland, the model selects between truck, rail, barge, or pipeline based on distance constraints and carrier compatibility. After evaluating all feasible pathways for each country, the algorithm identifies the carrier-mode combination that yields the minimum total cost, representing the economically optimal transport route. This systematic approach ensures that the selected hydrogen delivery pathways balance technological feasibility, geographical constraints, and economic considerations while accounting for the unique characteristics of different hydrogen carriers and transport infrastructures.

A schematic overview of the fuel supply chain pathways is illustrated in Figure 4, showing the transport options available for hydrogen, methane, ammonia, and carbon-based synthetic fuels. The total transport cost is calculated as:

$$C_{SC} = C_{compose} + C_{transport} + C_{decompose} + C_{storage}$$

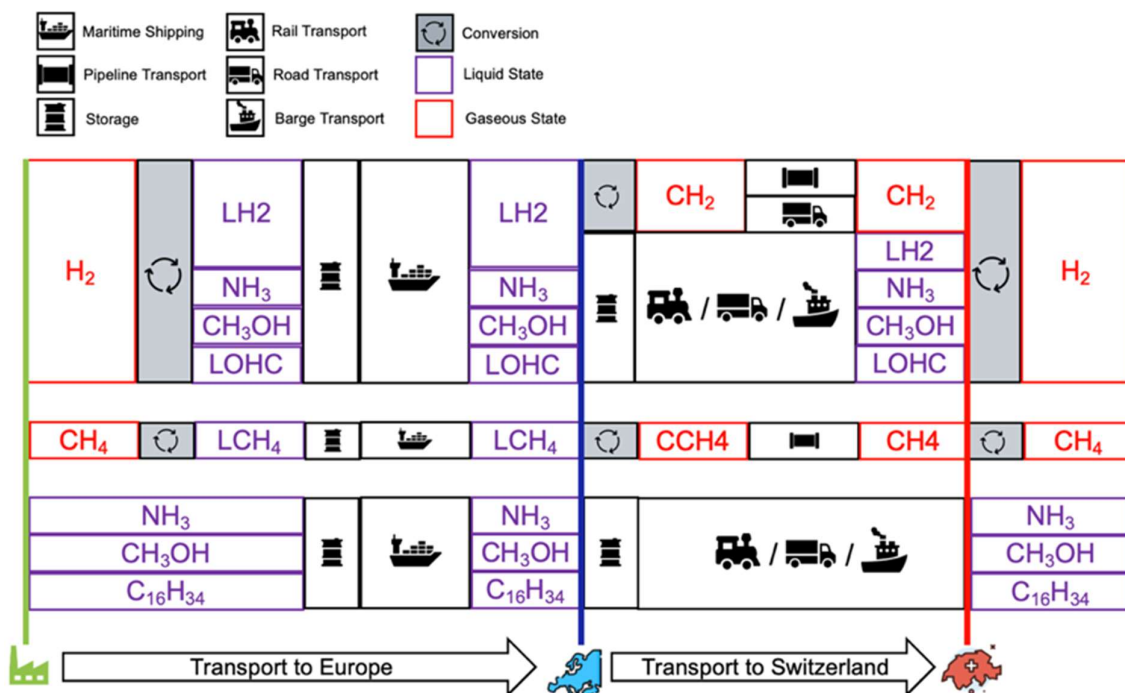


Figure 4: Schematic overview of the fuel supply chain pathways available for the import of fuels to Switzerland (Frey, 2023).

Transport Modes and Cost Estimations

Hydrogen transport options include liquefied hydrogen (LH₂), ammonia (NH₃), methanol (CH₃OH), and liquid organic hydrogen carriers (LOHCs). The cost of LH₂ transport by ship is estimated at 0.1 CHF/t/km in 2020, decreasing to 0.075 CHF/t/km by 2050. Pipeline transport within Europe, primarily via the European Hydrogen Backbone (EHB), is estimated at 0.2 CHF/t/km, while truck transport remains the most expensive option at 0.6 CHF/t/km for LH₂. Rail transport costs are projected to decrease from 0.5 CHF/t/km in 2020 to 0.3 CHF/t/km by 2050, making it a competitive inland option (Frey, 2023; Radner et al., 2024).

Methane transport, either as natural gas or synthetic methane, is facilitated by extensive pipeline infrastructure, with transport costs estimated at 0.033 CHF/t/km, while LNG shipping costs are 0.005 CHF/t/km. Ammonia, a widely traded chemical, is transported using LPG carriers at a shipping cost of 0.006 CHF/t/km. Inland transport costs include 0.021 CHF/t/km for rail, 0.17 CHF/t/km for truck, and 0.036 CHF/t/km for barge transport (Frey, 2023).

Carbon-based synthetic fuels, such as methanol and Fischer-Tropsch fuels, benefit from established transport infrastructure. The fuel shipping cost is 0.005 CHF/t/km, while inland transport costs range from 0.016 CHF/t/km for rail to 0.133 CHF/t/km for truck transport. LOHC transport incurs additional costs due to the need to return the dehydrogenated carrier, doubling its transport expenses compared to other fuels.

A summary of transport costs for each fuel type and transport mode is provided in Table 4, detailing conversion, transport, storage, and reconversion costs.

Storage Considerations and reconversion Costs

Storage plays a critical role in global fuel logistics by providing operational flexibility and supply security. Storage duration varies based on transport mode, with maritime shipping requiring 15 days of storage,



barge transport requiring 5 days, rail and truck transport requiring 3.5 days, and pipeline transport assumed to operate continuously.

Hydrogen storage costs are among the highest, with LH₂ storage at 82 CHF/t/day in 2020, decreasing to 27 CHF/t/day by 2050. Compressed hydrogen storage is less expensive, at 0.179 CHF/t/day, with a projected reduction to 0.160 CHF/t/day by 2050. LNG storage costs are 4.5 CHF/t/day, while ammonia storage is estimated at 0.5 CHF/t/day. Carbon-based fuels, including methanol and Fischer-Tropsch fuels, have lower storage costs at 0.1 CHF/t/day.

For fuels transported in chemical carriers, reconversion costs must be considered. Ammonia cracking to hydrogen incurs a reconversion cost of 1500 CHF/t in 2020, decreasing to 750 CHF/t by 2050. Methanol reforming to hydrogen costs 1300 CHF/t in 2020, reducing to 750 CHF/t by 2050. LOHC dehydrogenation remains the most expensive reconversion process, at 2150 CHF/t in 2020, with an expected decrease to 1000 CHF/t by 2050.

Table 4: Overview of the transport cost of unit fuels used in the calculation⁶⁴.

	H ₂ (as LH ₂)	H ₂ (as NH ₃)	H ₂ (as CH ₃ OH)	H ₂ (as LCOH)	NH ₃	CH ₄	CH ₃ OH	C ₁₆ H ₃₄
Conversion [CHF/t]	2020: 2500 2050: 1500	2020: 750 2050: 550	2020: 1200 2050: 650	2020: 350 2050: 200	n.a.	0.108	n.a.	n.a.
Ship Transport [CHF/t/km]	2020: 0.1 2050: 0.075	see NH ₃	see CH ₃ OH	0.005	0.006	0.005	0.005	0.005
Truck Transport [CHF/t/km]	0.6	see NH ₃	see CH ₃ OH	0.13	0.17	n.a.	0.13	0.13
Rail Trans- port [CHF/t/km]	2020: 0.5 2050: 0.3	see NH ₃	see CH ₃ OH	0.016	0.021	n.a.	0.016	0.016
Barge Transport [CHF/t/km]	2020: 0.56 2050: 0.42	see NH ₃	see CH ₃ OH	0.028	0.036	n.a.	0.028	0.028
Pipeline Transport [CHF/t/km]	0.2	see NH ₃	see CH ₃ OH	n.a.	n.a.	0.033	n.a.	n.a.
Storage [CHF/t/d]	2020: 82 2050: 27	see NH ₃	see CH ₃ OH	0.1	0.5	4.5	0.1	0.1
Reconversion [CHF/t]	180	2020: 1500 2050: 750	2020: 1300 2050: 750	2020: 2150 2050: 1000	n.a.	18	n.a.	n.a.

2.3 Results and discussion

2.3.1. Off-grid green hydrogen production

Off-grid hydrogen production using decentralized renewable energy systems offers a promising avenue for cost-competitive, low-carbon fuel generation. By directly coupling on-site solar PV and/or wind farms with PEM electrolyzers, these systems avoid reliance on centralized grids, reduce transmission losses, and exploit high-quality local resources.

Figure 5 presents the global distribution of hydrogen production costs under various scenarios and time frames. A red-to-green gradient highlights the relative cost levels, with red denoting higher costs and green indicating lower costs. In earlier scenarios or in regions with limited infrastructure and higher



perceived investment risks, much of Africa, Asia, and parts of South America display elevated production costs. By contrast, future projections or more optimistic scenarios show a greater expanse of lighter or green-shaded regions, illustrating the potential for considerable cost reductions. Notably, areas endowed with strong solar irradiance (e.g., northern Africa, Australia) or consistent wind resources (e.g., coastal South America, parts of the United States) often achieve lower LCOH due to higher capacity factors that reduce specific capital costs.

Figure 6 illustrates the global potential for off-grid hydrogen production, measured as hydrogen yield per unit area (e.g., kg H₂/km²/y). Here, green regions correspond to higher yields, while red indicates lower production potential. The maps highlight that regions with abundant solar or wind resources can generate significantly larger volumes of hydrogen. In particular, North Africa, parts of South America, and Australia stand out as prime areas for scaling up off-grid PtX. Over time, improvements in system efficiency, enhanced financing conditions, and infrastructure development can further expand this potential. Even areas with moderate resources may achieve near-competitive yields through policies that promote technology learning and economies of scale.

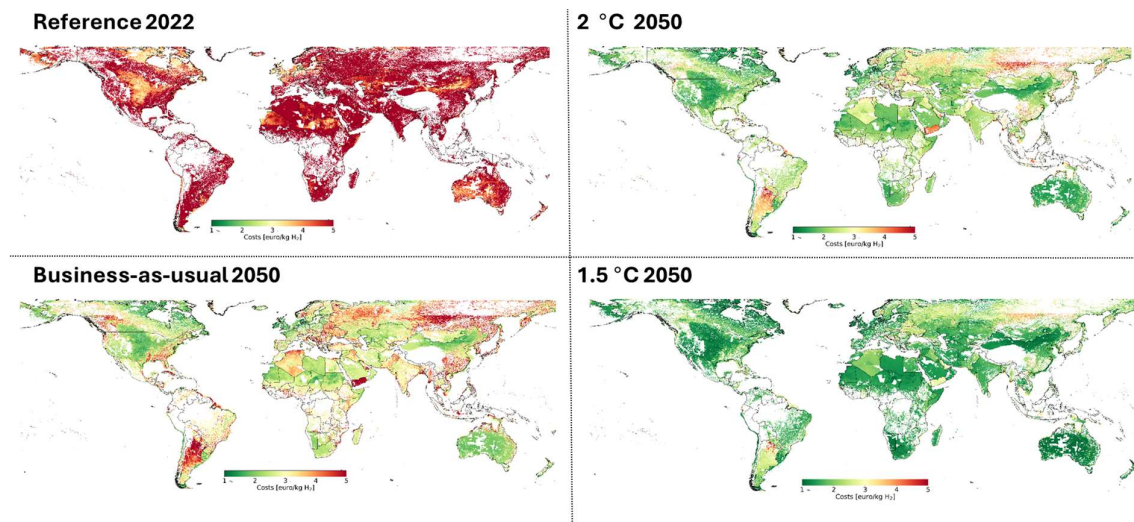


Figure 5: *Global distribution of off-grid hydrogen production costs under 2050 scenarios.* The four maps use a red-to-green gradient to indicate high to low levelized cost of hydrogen (LCOH). The business-as-usual scenario for 2050 represents very limited global climate policy ambitions, thus the least cost reduction for renewables and the highest fossil fuel shares among all scenarios. The 1.5°C scenario represents a development which keeps global warming below 1.5°C with the highest penetration of renewables and highest cost reductions, for e.g. wind and solar PV. The 2°C scenario represents a development in between.

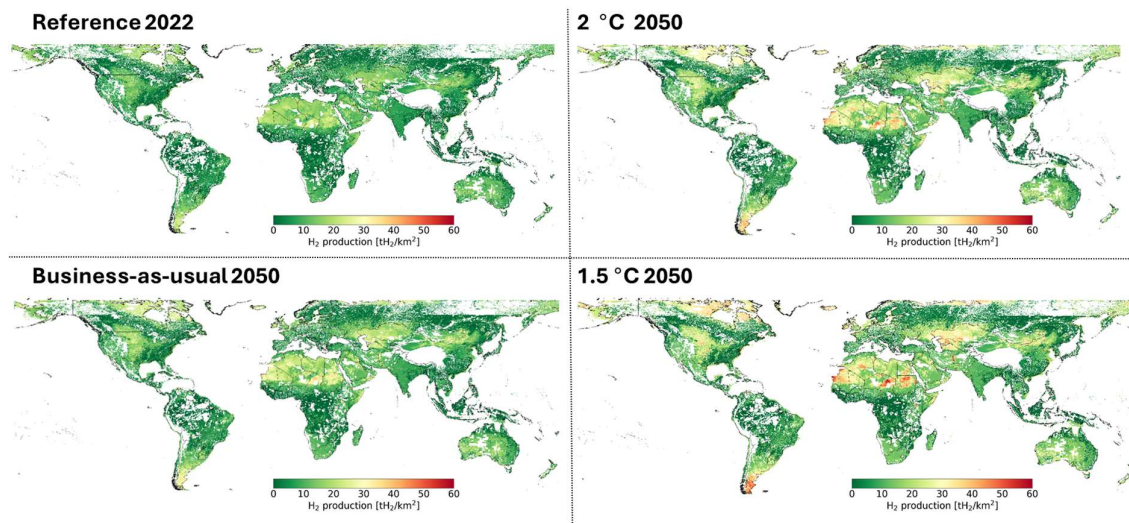


Figure 6: Global off-grid hydrogen production potential across 2050 scenarios.

Taken together, the cost and potential maps underscore both the synergies and trade-offs between resource quality, investment risk, and infrastructure development. Although favourable solar and wind conditions are crucial for minimizing hydrogen production costs, stable policy frameworks and supportive financing structures are equally important in unlocking large-scale deployment. Regions that combine strong renewable resources with reduced investment risks can achieve particularly low production costs and high yields, making them leading candidates for off-grid PtX development.

Overall, these findings highlight the vital role of off-grid PtX production in expanding the global supply of low-carbon fuels. By optimizing site selection and focusing on regions with ample renewable resources, off-grid systems can offer a cost-competitive solution for green hydrogen production, especially in remote or infrastructure-limited areas.

2.3.2. Grid-connected PtX production

Grid-connected green hydrogen

Figure 7, Figure 8 and Figure 9 present the global distribution of the levelized cost of hydrogen (LCOH) for each technology and scenario. These are visualized through world maps, cost breakdown bar charts, and violin plots illustrating global variability.

In 2022, the global LCOH for AE ranged from approximately 0.20–0.38 CHF/kWh (4.8–9.1 CHF/kg), with the highest values observed in Sub-Saharan Africa, Central Asia, and parts of Southeast Asia. These higher costs are primarily driven by elevated grid electricity prices and relatively small-scale deployment. Conversely, lower LCOH values (< 0.25 CHF/kWh) are found in countries with high shares of low-cost renewables or nuclear electricity, such as Norway, Brazil, and Canada, respectively. The cost breakdown indicates that electricity is the dominant component, contributing 60–75% of total LCOH across all regions in 2022. CAPEX contributes a smaller share but remains important in high-cost regions where deployment scale is limited. Under decarbonization scenarios in 2030 and 2050, particularly the 2°C and 1.5°C pathways, LCOH for AE decreases significantly in most regions, with many countries falling below 0.25 CHF/kWh (6.0 CHF/kg) by 2050. The violin plots show a narrowing distribution over time, indicating increasing cost convergence globally, driven by lower electricity prices and steady capital cost learning.

PEM exhibits higher LCOH compared to AE, with values typically in the range of 0.26–0.42 CHF/kWh (≈ 6.2–10.0 CHF/kg). This is especially evident in fossil fuel-dependent regions such as the Middle East, Southeast Asia, and Central Asia. Regions with cleaner or cheaper grid electricity (e.g., Nordic countries, France, and New Zealand) show more favorable LCOH values, albeit still higher than AE.



Cost component analysis reveals that electricity remains the main cost driver (50–65%), but CAPEX accounts for a significantly higher share than in AE—up to 45% in some regions. Under 2°C and 1.5°C scenarios, PEM costs decrease substantially, especially by 2050, with many industrialized or renewable-rich regions falling below 0.28 CHF/kWh (6.7 CHF/kg). However, regional differences persist, as reflected in the wider violin plots. This highlights PEM's stronger dependence on both electricity price and capital cost reductions.

SOEC has the highest LCOH across all three technologies in 2022, with a relatively narrow global range of 0.30–0.44 CHF/kWh (7.2–10.5 CHF/kg). This uniformity is due to the dominance of capital costs (replacement) due to the short lifetime of SOEC electrolyzers, which represent 60–80% of total LCOH in early years. The maps show minor regional differentiation in 2022, reflecting SOEC's early-stage deployment status and the high initial investment required. Significant cost reductions for SOEC are only observed under the 2°C and 1.5°C scenarios by 2050, with a subset of countries reaching below 0.30 CHF/kWh (7.2 CHF/kg). The bar charts confirm that while capital costs remain dominant, electricity gains greater importance over time as CAPEX declines. The violin plots show a partial cost convergence in 2050, although variability remains higher than for AE, reflecting geographic disparities in industrial infrastructure and electricity systems.

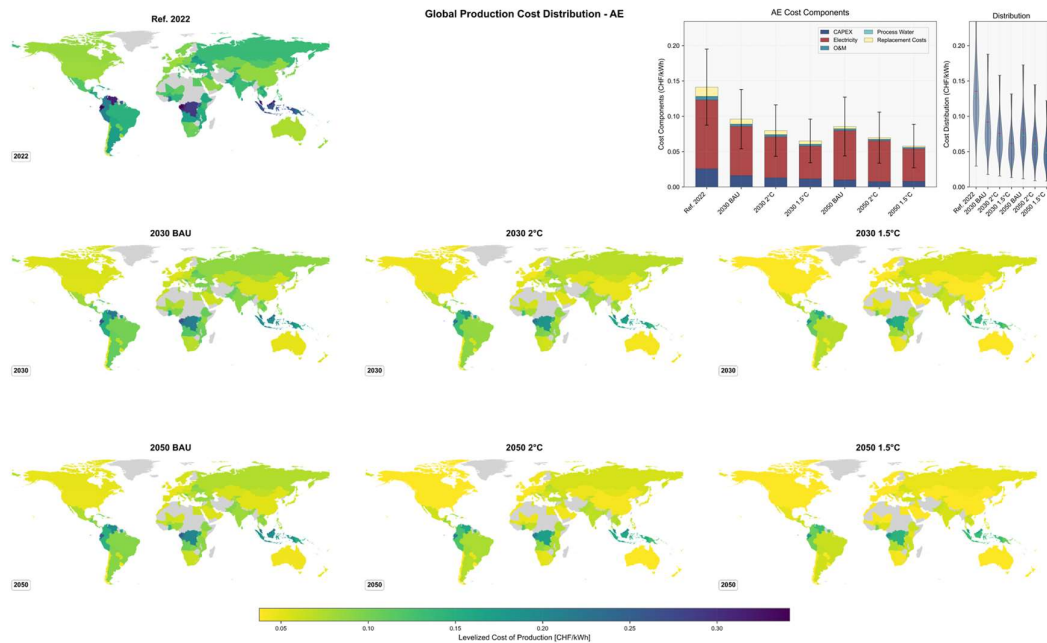


Figure 7: *Global production cost distribution for alkaline electrolysis (AE) under grid-connected conditions.* The seven world maps show the levelized cost of hydrogen (LCOH) in CHF/kWh for the reference year 2022 and for three scenarios (BAU, 2°C, and 1.5°C) in 2030 and 2050. The color scale ranges from lower costs (green/yellow) to higher costs (purple). The bar chart on the top right shows the breakdown of LCOH into major cost components (e.g., electricity, capital expenditure) for each scenario-year combination, with error bars indicating standard deviations (SDs) across countries. The violin plot to the right illustrates the global distribution of LCOH values, showing spread within ± 2 SDs.

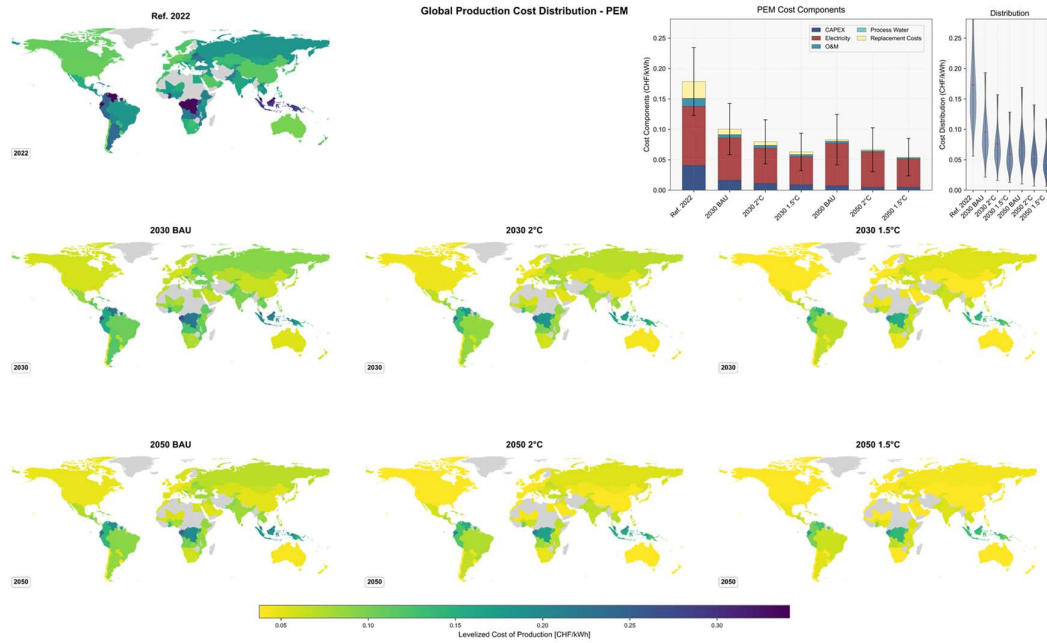


Figure 8: *Global production cost distribution for proton exchange membrane (PEM) under grid-connected conditions.* The seven world maps show the levelized cost of hydrogen (LCOH) in CHF/kWh for the reference year 2022 and for three scenarios (BAU, 2 °C, and 1.5 °C) in 2030 and 2050. The color scale ranges from lower costs (green/yellow) to higher costs (purple). The bar chart on the top right shows the breakdown of LCOH into major cost components (e.g., electricity, capital expenditure) for each scenario-year combination, with error bars indicating standard deviations across countries. The violin plot to the right illustrates the global distribution of LCOH values, showing spread within ± 2 SDs.

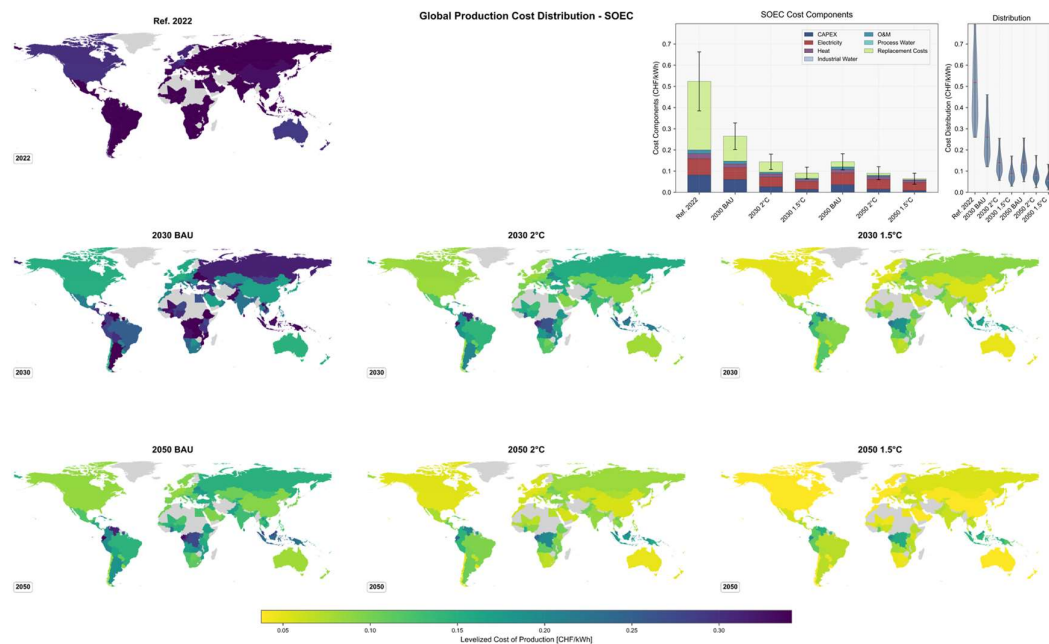


Figure 9: *Global production cost distribution for solid oxide electrolysis cells (SOEC) under grid-connected conditions.* The seven world maps show the levelized cost of hydrogen (LCOH) in CHF/kWh for the reference year 2022 and for three scenarios (BAU, 2°C, and 1.5°C) in 2030 and 2050. The color scale ranges from lower costs (green/yellow) to higher costs (purple). The bar chart on the top right shows the breakdown of LCOH into major cost components (e.g., electricity, capital expenditure) for each scenario-year combination, with error bars indicating standard deviations across countries. The violin plot to the right illustrates the global distribution of LCOH values, showing spread within ± 2 SDs.

Nuclear-based hydrogen

In 2022, HTSE exhibits relatively high LCOH in most regions, as indicated by the dark purple tones on the cost maps in Figure 10. This reflects the capital-intensive nature of SOEC electrolyzers and their limited commercial deployment, particularly when integrated with nuclear reactors. Replacement capex is the dominant cost component, accounting for over 60% of total LCOH, driven by high-temperature electrolysis system costs and the specialized infrastructure required for coupling with nuclear power plants. Electricity costs contribute the second-largest share (~30%), highlighting the importance of nuclear power pricing in HTSE's economic feasibility.

Over time, LCOH declines significantly, especially under the 2°C and 1.5°C scenarios, as technology learning, economies of scale, and improved nuclear reactor efficiency lower both CAPEX and electricity expenses. The cost maps for 2030 and 2050 show a clear transition to lighter shades, indicating widespread cost reductions. Countries with well-established nuclear fleets, such as France and the United States, achieve the fastest cost declines, reaching below 0.10 CHF/kWh (2.4 CHF/kg) by 2050 in the most favorable scenarios. The bar chart confirms a steady decrease in CAPEX and electricity costs over time, while the error bars suggest that financing conditions and local energy prices significantly impact project economics. The violin plot illustrates a narrowing of the global cost range by 2050, suggesting that as HTSE scales up and financing mechanisms improve, it could achieve competitive costs in a broader array of regions.

As shown in Figure 11, the CuCl cycle starts with relatively high LCOH in 2022, largely due to its early-stage development and the need for specialized high-temperature, corrosion-resistant equipment. LCOH values are particularly elevated in regions without established nuclear thermal energy integration, as indicated by darker color gradients in parts of Asia and Central Europe. Heat supply and CAPEX are the dominant cost components, with the requirement for high-temperature process heat (500–600°C) contributing over 40% to total production costs in 2022.



Similar to HTSE, CuCl-based hydrogen sees progressive cost reductions over time, particularly under the 2°C and 1.5°C scenarios, where greater nuclear integration and technology improvements drive down costs. The maps for 2030 and 2050 show clear cost reductions in regions with reliable nuclear capacity, including the U.S., Canada, and parts of Europe, where LCOH drops below 0.12 CHF/kWh (2.9 CHF/kg) by 2050 in climate mitigation scenarios. The bar chart highlights a gradual but steady decline in capital and operating costs, reflecting scaling effects and improved process efficiencies. The error bars indicate continued regional variability in the near term, influenced by variations in nuclear heat supply costs, infrastructure investment risks, and technology deployment scales. However, by 2050, more countries will transition into lighter cost ranges, demonstrating that favorable financing conditions and sustained innovation can enable broader CuCl deployment.

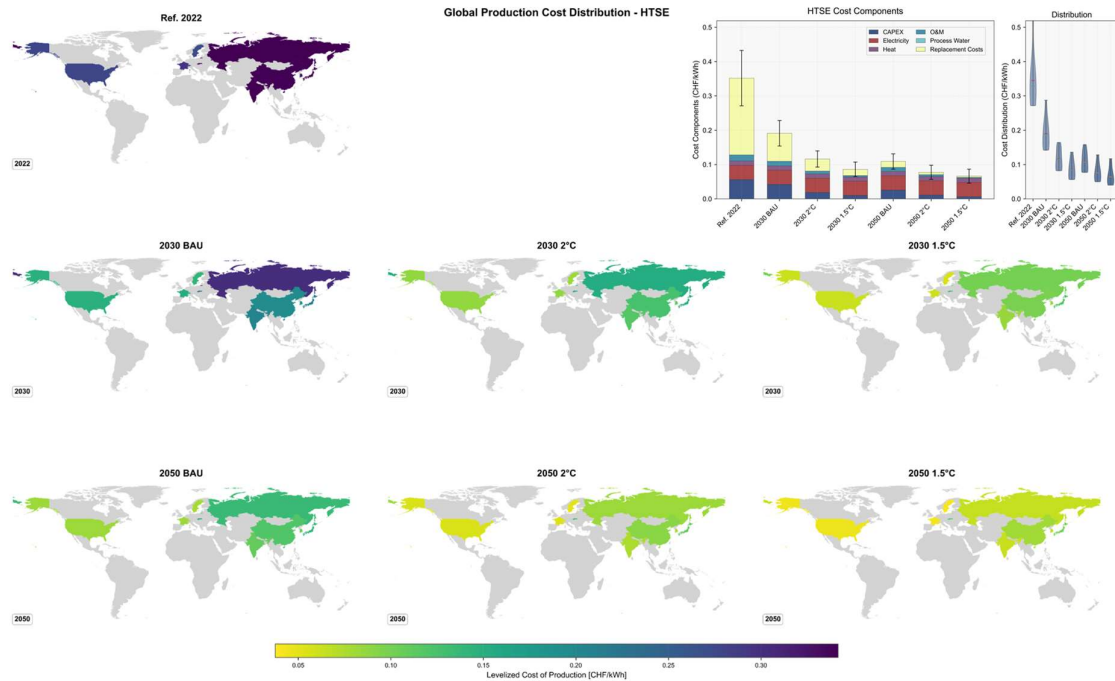


Figure 10: Global production cost distribution for high-temperature steam electrolysis (HTSE) nuclear-based hydrogen production. The seven world maps depict the levelized cost of hydrogen (LCOH) in the reference year 2022 and under three scenarios (BAU, 2 °C, 1.5 °C) for 2030 and 2050, using a color scale from lower costs (green/yellow) to higher costs (purple). The bar chart on the top right shows the breakdown of cost components in each scenario-year combination, with error bars indicating standard deviations across different countries. The violin plot to the right illustrates the global distribution of these LCOH values, showing spread within ± 2 SDs.

Both HTSE and CuCl hydrogen production benefit from the stable, low-carbon electricity (and, in CuCl's case, heat) provided by nuclear reactors, but their cost trajectories differ based on technological maturity and learning rates.

- HTSE has a higher initial readiness for large-scale deployment, as reflected in faster cost convergence and broader cost reductions by 2050. Its primary challenge lies in CAPEX, which remains a major cost component even in later years, making electricity pricing a key factor in its competitiveness.
- CuCl, despite its potential for high efficiency, faces greater early-stage cost barriers, largely due to the need for specialized thermal processing infrastructure. However, it benefits from lower reliance on grid electricity, making it less sensitive to electricity price volatility than HTSE.

Across all scenarios, countries with established nuclear infrastructure and lower financing risks achieve more favorable cost outcomes. The shift from BAU to 2°C and 1.5°C pathways accelerates cost declines, driven by reductions in nuclear electricity prices and CAPEX for advanced hydrogen



technologies. By 2050, both HTSE and CuCl will reach cost levels that position nuclear-powered hydrogen as a highly competitive low-carbon alternative, particularly in regions committed to deep decarbonization and long-term nuclear energy investments.

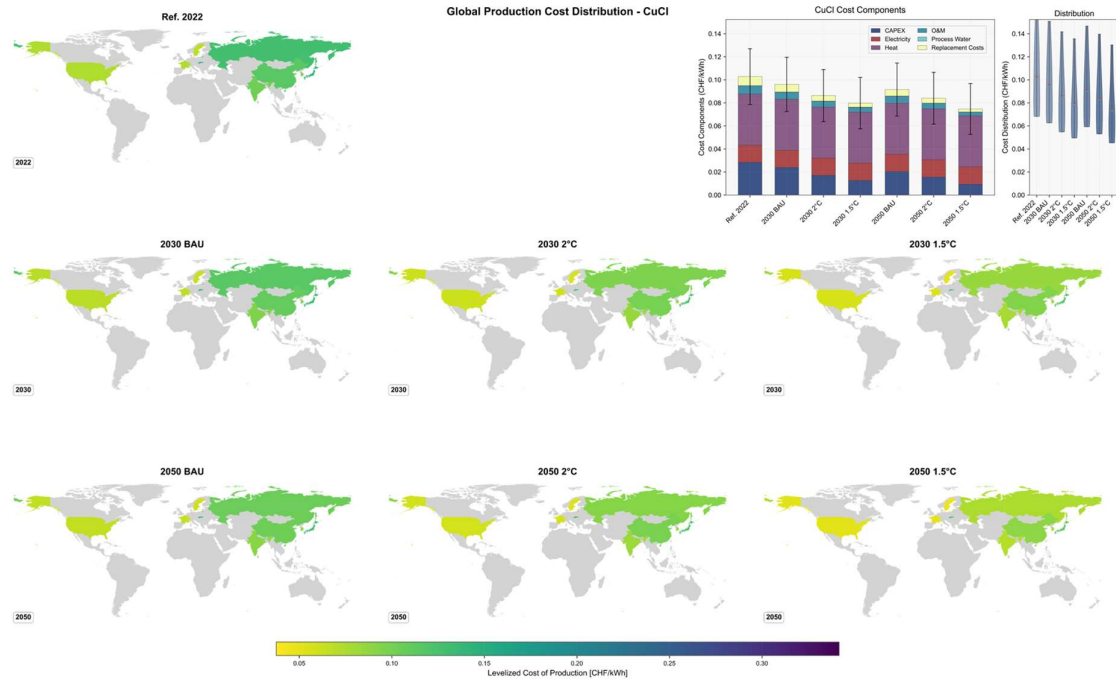


Figure 11: *Global production cost distribution for the Cu–Cl thermochemical cycle (CuCl) nuclear-based hydrogen production.* The seven world maps depict the levelized cost of hydrogen (LCOH) in the reference year 2022 and under three scenarios (BAU, 2 °C, 1.5 °C) for 2030 and 2050, using a color scale from lower costs (green/yellow) to higher costs (purple). The bar chart on the top right shows the breakdown of cost components for AE in each scenario-year combination, with error bars indicating standard deviations across different countries. The violin plot to the right illustrates the global distribution of these LCOH values, showing spread within ± 2 SDs.

PtX fuels

Fischer-Tropsch (FT) kerosene, methanol-based kerosene (RWGS-MeOH), and power-to-methane (PtM) represent key power-to-liquid (PtL) and power-to-gas (PtG) pathways for synthetic fuel production, relying on PEM water electrolysis as the hydrogen source. Their economic viability is largely dictated by electricity and hydrogen input costs, CO₂ sourcing, and infrastructure investment.

In 2022, RWGS-FT exhibits considerable regional cost variation, with high LCOP values (0.20–0.35 CHF/kWh, 2.4–4.2 CHF/l) across most regions, especially in South America, Africa, and Southeast Asia, as shown in Figure 12. Over time, cost reductions are observed, particularly under the 2°C and 1.5°C scenarios, where increased renewable penetration and lower hydrogen prices drive LCOP below 0.15 CHF/kWh (1.8 CHF/l) in multiple countries by 2050. The narrowing spread in the violin plots indicates global convergence toward lower costs, especially in regions with favorable energy prices and established CO₂ infrastructure.

The RWGS-MeOH route shows similarly high LCOP values in 2022 (Figure 13), notably in regions with elevated electricity costs and limited policy support. Under ambitious decarbonization pathways, significant cost declines are achieved, with many industrialized and renewable-rich regions reaching LCOP values below 0.15 CHF/kWh (1.8 CHF/l) by 2050. Although regional variability persists in the near term, the cost distribution narrows substantially under the 1.5 °C scenario, indicating increasing economic feasibility across a broader set of countries.



As shown in Figure 14, PtM follows a comparable trend, with high LCOP in 2022 (up to 0.30 CHF/kWh, ≈ 7.2 CHF/kg) and pronounced reductions by 2050 in decarbonization scenarios. Cost competitiveness improves first in regions with abundant low-cost renewables and mature hydrogen supply chains. By 2050, under the 1.5°C scenario, most countries converge around 0.12–0.15 CHF/kWh (≈ 2.9 –3.6 CHF/kg), as reflected in the tighter cost distributions.

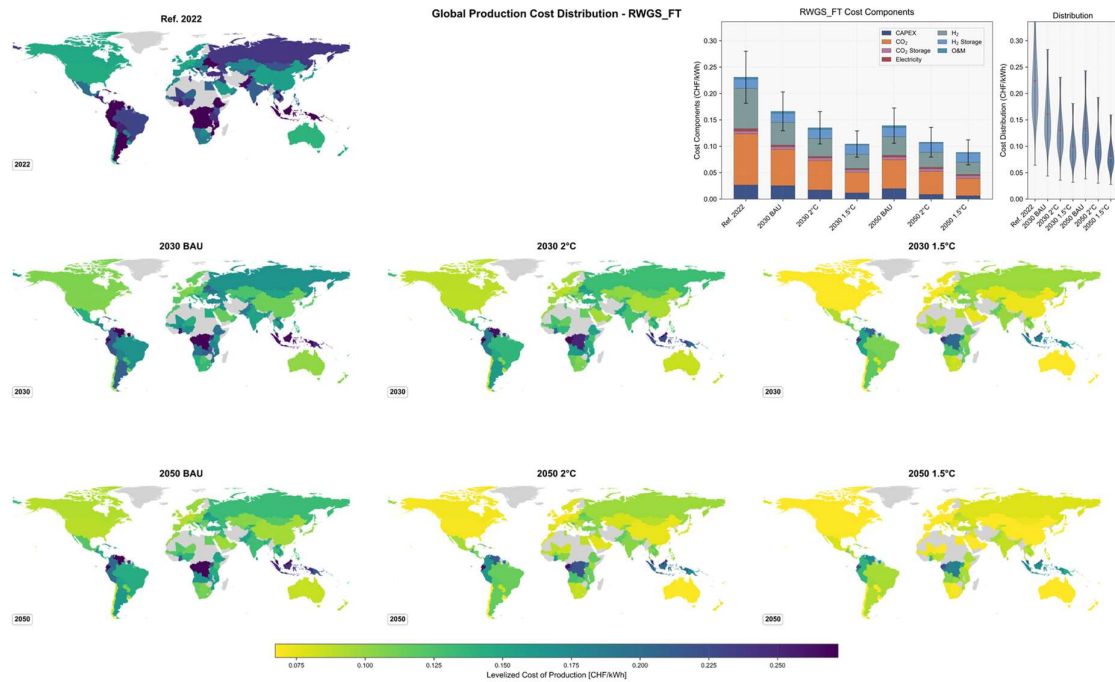


Figure 12: *Global production cost distribution for RWGS-FT under various scenarios and timeframes.* The top-left map represents the reference year 2022, followed by three scenarios (BAU, 2 °C, 1.5 °C) in 2030 and again in 2050, with a color scale transitioning from lower (yellow/green) to higher (purple) levelized costs. The bar chart to the right shows cost component breakdowns (e.g., electricity, hydrogen input, capital expenditures), while error bars reflect standard deviations among countries. The violin plot illustrates the global cost distribution, showing spread within ± 2 SDs.

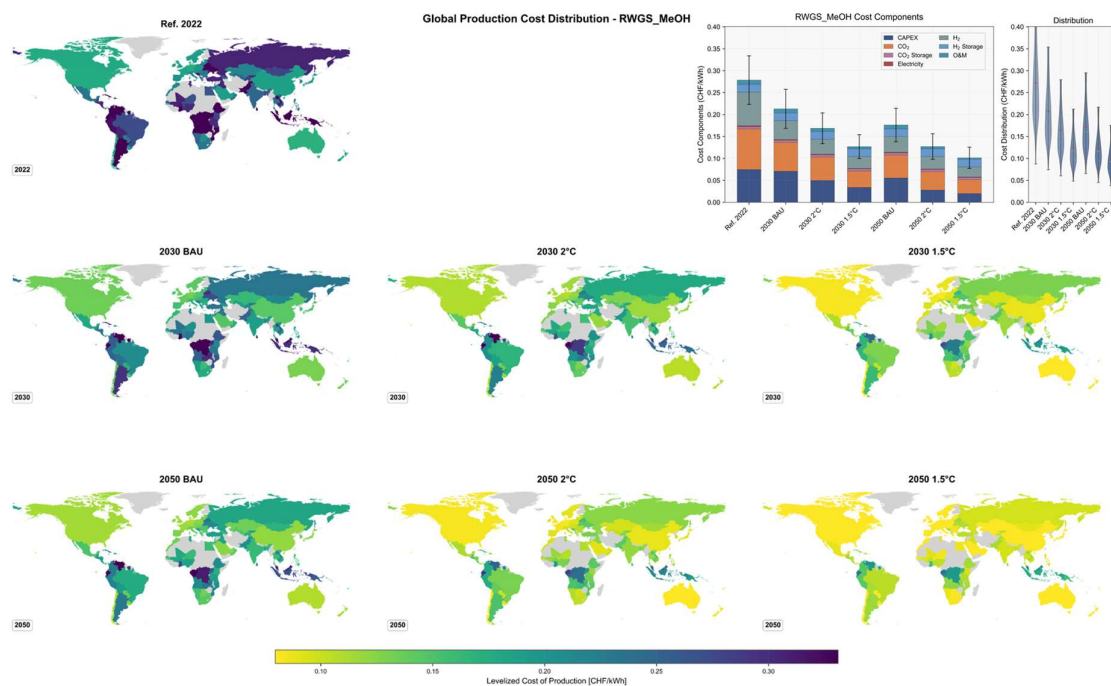


Figure 13: *Global production cost distribution for RWGS-MeOH under various scenarios and timeframes.* The top-left map represents the reference year 2022, followed by three scenarios (BAU, 2 °C, 1.5 °C) in 2030 and again in 2050, with a color scale transitioning from lower (yellow/green) to higher (purple) levelized costs. The bar chart to the right shows cost component breakdowns (e.g., electricity, hydrogen input, capital expenditures), while error bars reflect standard deviations among countries. The violin plot illustrates the global cost distribution, showing spread within ± 2 SDs.

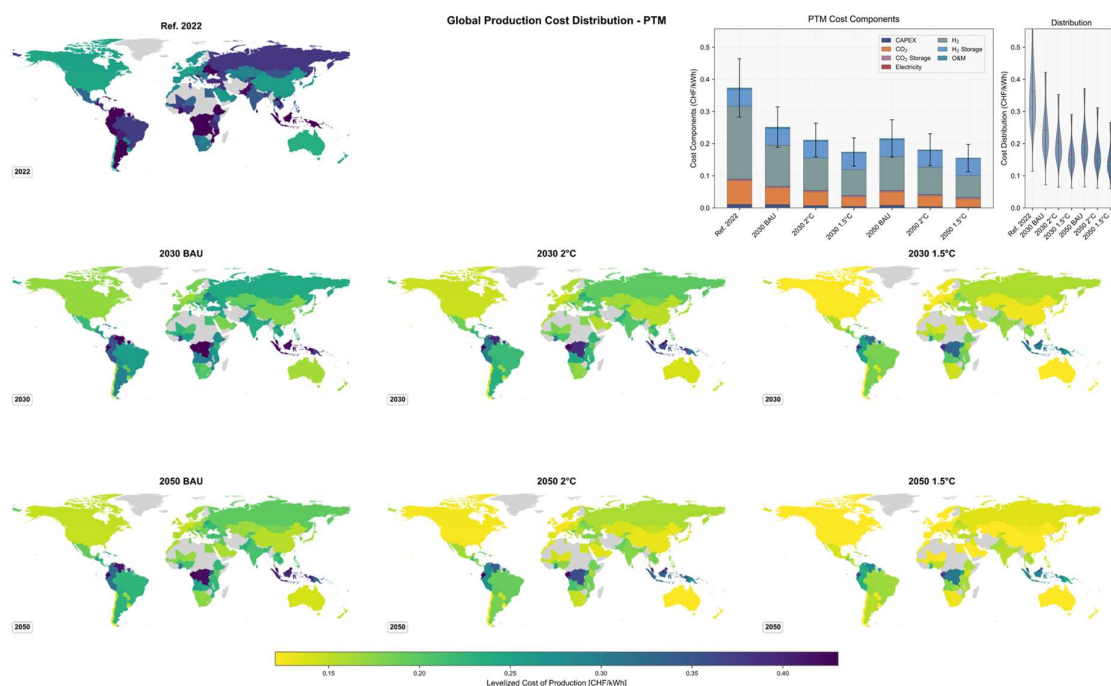


Figure 14: Global production cost distribution for power-to-methane (PtM) under various scenarios and timeframes. The top-left map represents the reference year 2022, followed by three scenarios (BAU, 2 °C, 1.5 °C) in 2030 and again in 2050, with a color scale transitioning from lower (yellow/green) to higher (purple) levelized costs. The bar chart to the right shows cost component breakdowns (e.g., electricity, hydrogen input, capital expenditures), while error bars reflect standard deviations among countries. The violin plot illustrates the global cost distribution, showing spread within ± 2 SDs.

2.3.3. Natural gas-based hydrogen

In 2022, SMR+CCS shows moderate-to-low LCOH in regions with access to low-cost natural gas (e.g., North America, Russia, the Middle East), while higher values persist in import-dependent countries, as shown in Figure 15. The main cost drivers are natural gas feedstock and CAPEX associated with CO₂ capture systems. Over time, especially under the 2°C and 1.5°C scenarios, LCOH declines in many regions, although some areas with high gas prices or financing constraints remain elevated. The cost distribution narrows significantly by 2050, reflecting technology learning and improved carbon management, enabling broader deployment in a decarbonizing world.

Hydrogen produced via ATR+CCS (Figure 16) exhibits a similar spatial cost pattern to SMR+CCS in 2022, with competitive LCOH in gas-rich regions and higher costs elsewhere. The cost breakdown indicates a larger share of capital and O&M costs related to high-pressure operation and integrated capture units. LCOH improves steadily in all scenarios, with more pronounced reductions under climate-constrained futures. By 2050, cost convergence is evident, particularly in countries with infrastructure suited for ATR integration, positioning the technology as a viable option for centralized hydrogen production.

As shown in Figure 17, CLR starts with higher LCOH in 2022 due to lower technology readiness and additional CAPEX for looping reactors. The cost maps reveal fewer low-cost regions initially, but substantial improvements are achieved by 2050 under the 2°C and 1.5°C scenarios. The cost structure remains dominated by natural gas and capital expenses, though these decline over time. The violin plots reflect gradual cost convergence, indicating CLR's potential for competitiveness, contingent on design improvements and supportive policy environments.

M-PYR displays relatively high LCOH in 2022 (Figure 18), particularly in regions with expensive gas or lacking solid carbon valorization pathways. The cost structure is driven by natural gas and reactor CAPEX, with O&M and electricity playing minor roles. In gas-abundant countries, LCOH is already



moderate, and by 2050, many regions will reach lower cost ranges under decarbonization scenarios. The cost spread narrows notably, reflecting expected advances in reactor design and process integration.

All four pathways are highly sensitive to natural gas price and availability, resulting in pronounced regional cost disparities. Countries with abundant domestic gas and mature infrastructure consistently exhibit lower LCOH across scenarios. As climate ambition increases, capture efficiencies improve, and technology matures, resulting in widespread LCOH reductions and convergence by 2050, particularly under 2°C and 1.5°C pathways. These trends underscore the importance of gas market dynamics and technology learning in shaping the future competitiveness of fossil-based low-carbon hydrogen.

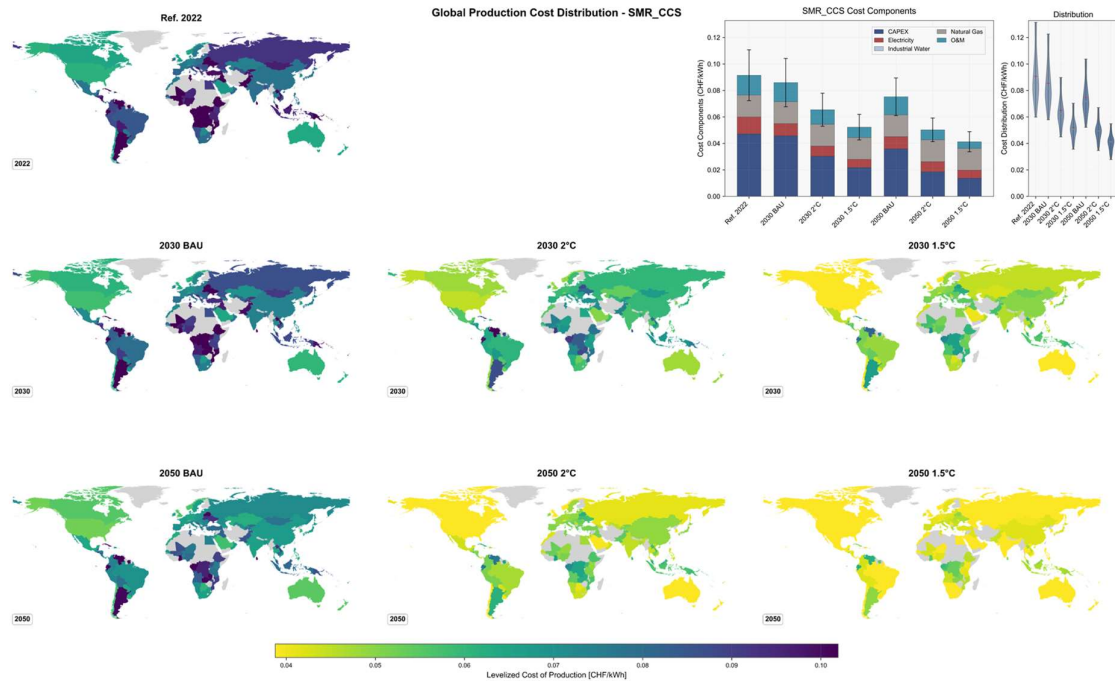


Figure 15: Global production cost distribution for steam methane reforming with CCS under various scenarios. Maps for 2022 and three scenarios (BAU, 2°C, 1.5°C) in 2030 and 2050 use a color scale from lower (green/yellow) to higher (purple) costs. The bar chart highlights capital, operating, and feedstock costs, with error bars showing standard deviations across countries. The violin plot on the right displays the global distribution of costs, showing spreads within ± 2 SDs.

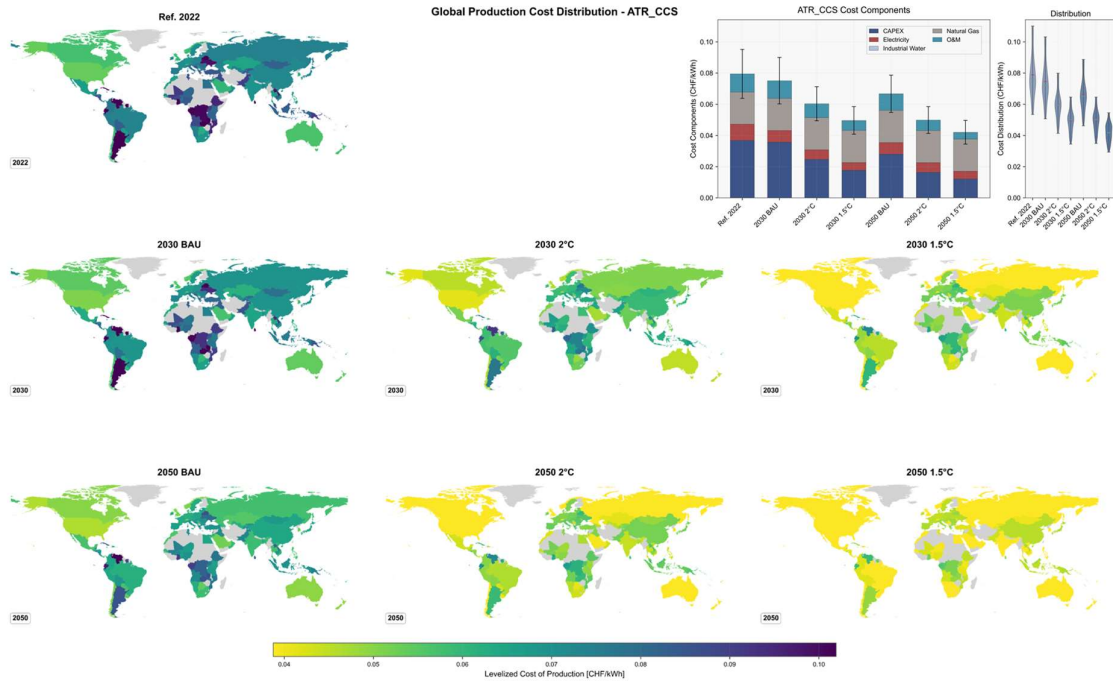


Figure 16: Global production cost distribution for autothermal reforming with CCS under various scenarios. The top-left map corresponds to 2022, followed by BAU, 2°C, and 1.5°C scenarios in 2030 and 2050. Colors shift from green (lower LCOH) to purple (higher LCOH). The bar chart shows the relative contributions of cost elements, the error bars reflect cross-country variability. The violin plot shows the range and median trends of costs, showing spreads within ± 2 SDs.

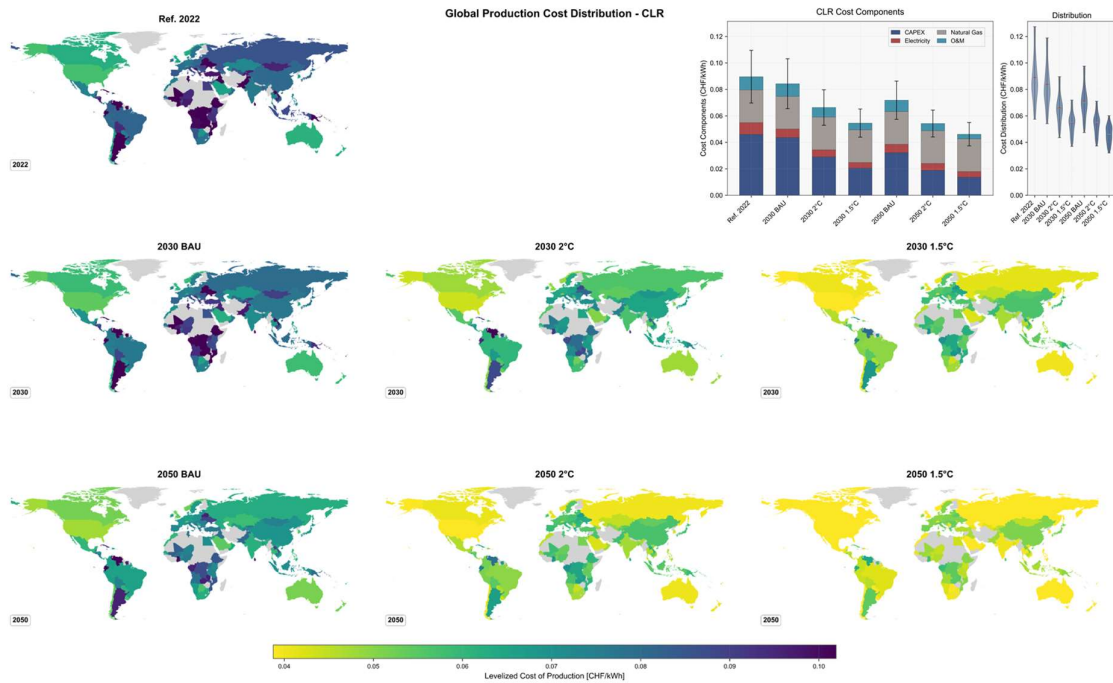


Figure 17: Global production cost distribution for chemical looping reforming (CLR) under various scenarios. Each map displays the LCOH for 2022, BAU, 2 °C, and 1.5 °C scenarios in 2030 and 2050, transitioning from lower costs (green/yellow) to higher costs (purple). The bar chart details major cost components, with error bars illustrating cross-country variation. The violin plot highlights the distribution of costs, showing spreads within ± 2 SDs.

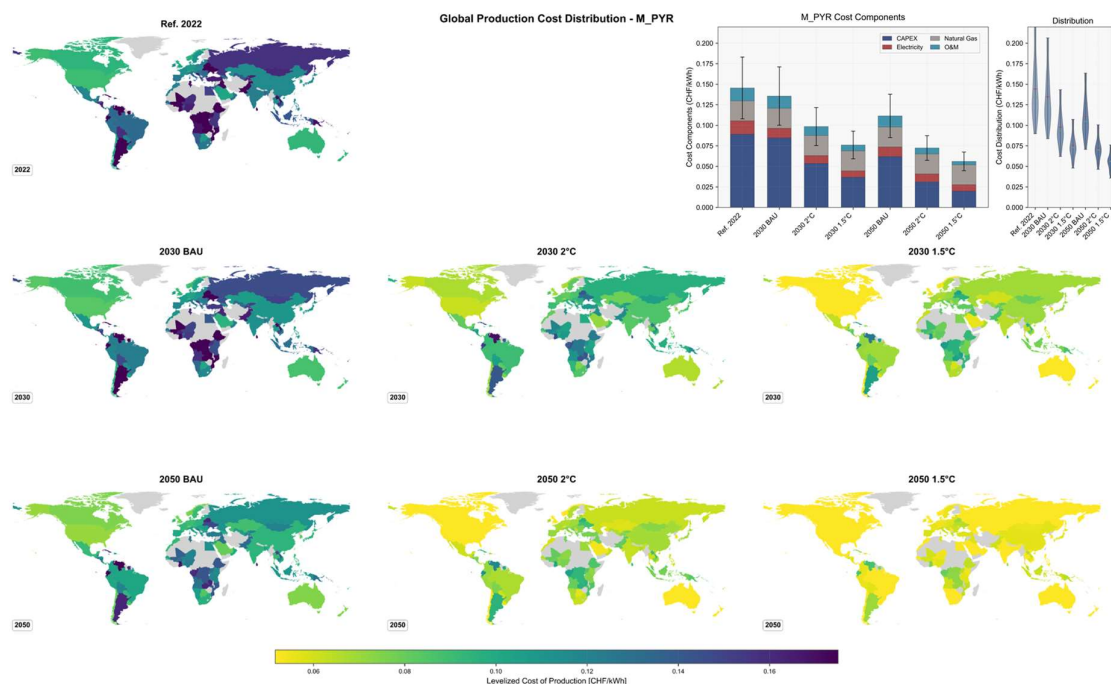


Figure 18: Global production cost distribution for methane pyrolysis (M-PYR) under various scenarios. The series of maps spans 2022 through the BAU, 2 °C, and 1.5 °C scenarios in 2030 and 2050, using a color gradient to represent LCOH. The bar chart details major cost components, with error bars illustrating cross-country variation. The violin plot indicates the overall spread of costs, showing spreads within ± 2 SDs.

2.3.4. Solar fuels

SR-FT combines concentrated solar power for high-temperature heat with natural gas reforming. As shown in Figure 19, in 2022, regions with high solar irradiance—such as North Africa, the Middle East, and Australia—show relatively moderate LCOF values (0.15–0.17 CHF/kWh), while countries with weaker CSP resources or higher gas prices face higher costs. The cost breakdown indicates that natural gas and CAPEX dominate total production costs. Over time, especially under 2°C and 1.5°C scenarios, declining CSP capital costs and improved gas market conditions lead to wider cost reductions, with LCOF falling below 0.15 CHF/kWh in several regions by 2050. The violin plot confirms narrowing cost distribution, suggesting improved cost competitiveness where solar conditions and gas supply are favorable.

ST-FT uses direct thermochemical conversion of H_2O and CO_2 via CSP to produce synthesis gas for Fischer–Tropsch synthesis. As shown in Figure 20, LCOF remains high across most regions (>0.25 CHF/kWh) in 2022, reflecting the technology's low maturity and the high CAPEX of solar thermochemical systems. The cost structure is dominated by capital investment, followed by O&M and CO_2 handling. By 2050, under stringent climate scenarios, significant cost reductions occur in solar-rich regions such as Northern Africa, Australia, and the U.S. Southwest, where LCOF drops to 0.15–0.18 CHF/kWh. The narrowing cost spread in the violin plots indicates increasing viability, contingent on scaling CSP deployment and advancing reactor efficiency.

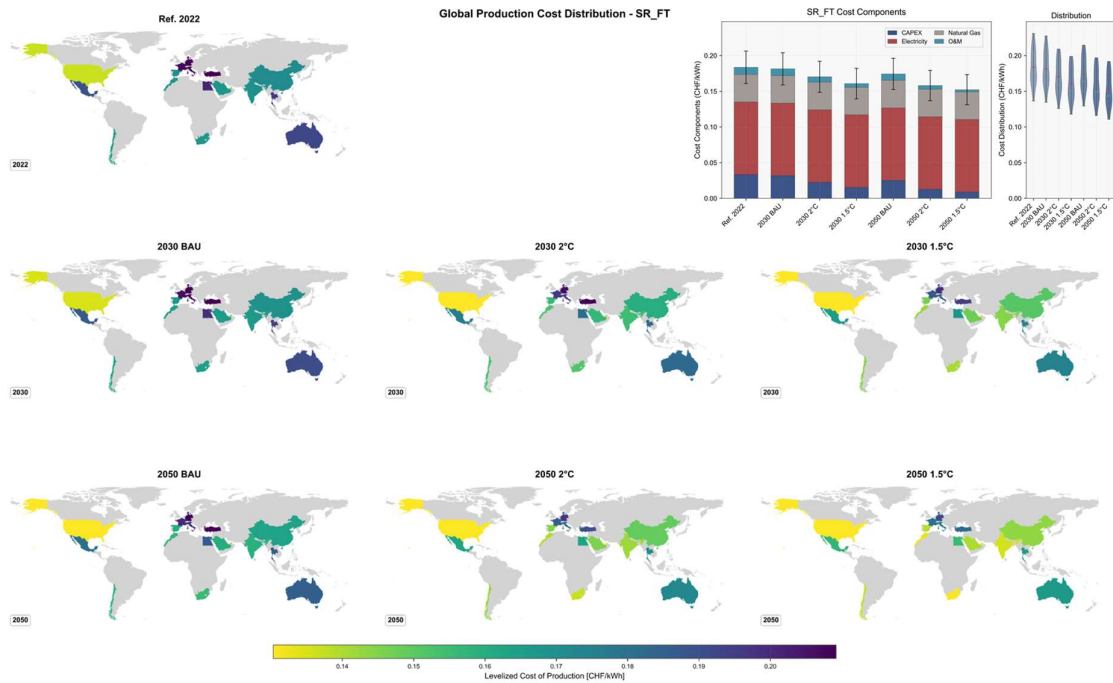


Figure 19: Global production cost distribution for solar reforming Fischer–Tropsch (SR-FT) under various scenarios and timeframes. The top-left map shows 2022 costs, followed by three scenarios (BAU, 2 °C, 1.5 °C) in 2030 and 2050, using a color scale from lower costs (yellow/green) to higher costs (purple). The bar chart details major cost components, with error bars illustrating cross-country variation. The violin plot on the right illustrates the global spread of LCOF values, showing spreads within ± 2 SDs.

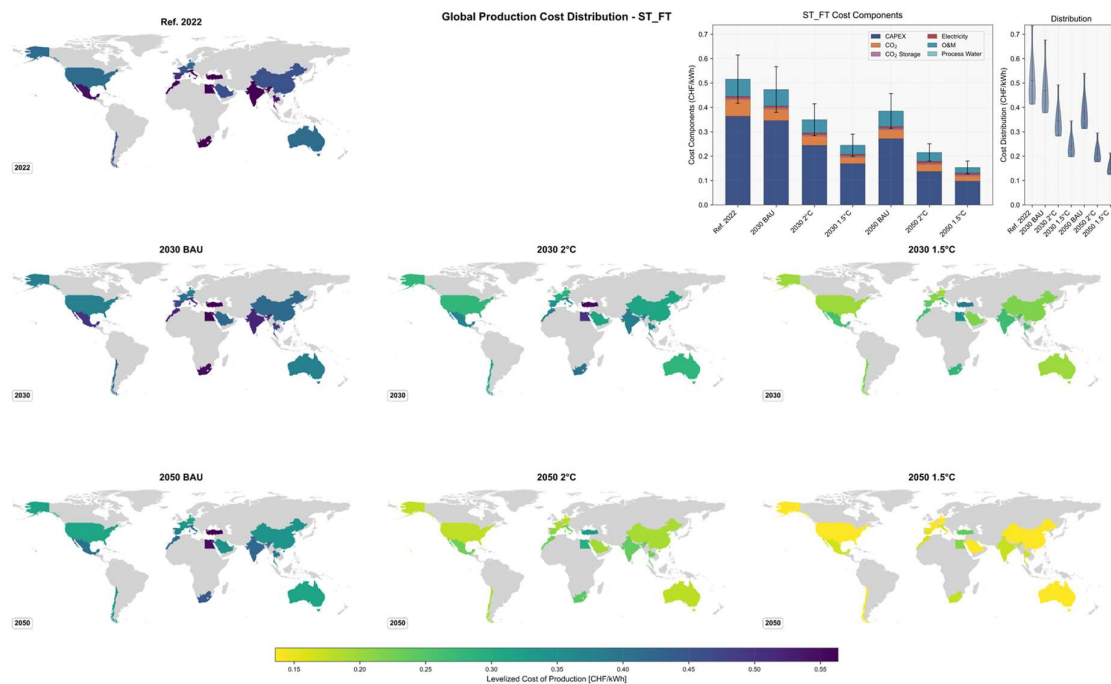


Figure 20: Global production cost distribution for solar thermochemical Fischer–Tropsch (ST-FT) under various scenarios and timeframes. The series of maps spans 2022 through BAU, 2 °C, and 1.5 °C scenarios in 2030 and 2050, using a color gradient from higher (purple) to lower (yellow/green) LCOF. The bar chart details major cost components, with error bars illustrating cross-country variation. The violin plot on the right illustrates the global spread of LCOF values, showing spreads within ± 2 SDs.

2.3.5. Biofuels

Biomass conversion pathways for biofuels show distinct economic trajectories based on the underlying process and end product.

TG-CCS for hydrogen production (Figure 21) shows moderate costs in 2022 across regions with strong biomass availability and existing gasification infrastructure. However, high biomass feedstock prices and capital costs remain key barriers. Under 2 °C and 1.5 °C scenarios, both process efficiency improvements and reduced capture costs drive down LCOH. By 2050, the global cost distribution narrows significantly, particularly in countries with stable feedstock supply and favourable financing conditions, indicating increasing viability for low-carbon hydrogen production from biomass.

TG-FT for kerosene production (Figure 22) exhibits high initial costs due to the complexity of integrating biomass gasification with FT synthesis. In 2022, most regions display elevated LCOF values, particularly where biomass supply chains are underdeveloped. Over time, cost reductions are achieved through reactor optimization and logistics improvements. By 2050, under ambitious climate scenarios, countries with strong biomass infrastructure (e.g., Brazil, Southeast Asia) approach competitive cost levels.

Biodiesel production from biomass is approached via multiple pathways, including FAME production, hydrotreated vegetable oil (HVO), and biomass pyrolysis with subsequent upgrading. FAME production (Figure 23) starts with a relatively high LCOF in 2022, especially in regions with costly lipid-based feedstocks. The cost structure is dominated by biomass input, followed by CAPEX and O&M. HVO (Figure 24) shares a similar trajectory with FAME, though it involves higher CAPEX due to the hydrogenation process. In 2022, costs are high in most regions but decline consistently under climate mitigation pathways. Feedstock remains the largest cost component. By 2050, HVO shows strong convergence in regions with reliable access to lipid-rich biomass and renewable hydrogen, achieving LCOF values comparable to other advanced biofuels. Biomass pyrolysis (Figure 25) initially shows elevated costs due to the capital-intensive nature of reactor systems and upgrading steps. In 2022, LCOF is highest in regions



lacking scale or feedstock integration. Over time, system integration and scale-up reduce both CAPEX and O&M costs. By 2050, under 1.5°C, pyrolysis becomes more cost-competitive in biomass-rich regions, with the violin plot indicating a clear narrowing of global cost variation.

AD-based biomethane production (Figure 26) is highly region-specific. In 2022, costs are higher in urban or feedstock-scarce areas, while agricultural regions with strong organic waste streams already achieve moderate LCOF. CAPEX and biomass costs dominate the early cost structure. Under decarbonization scenarios, improvements in waste management, digester design, and gas upgrading reduce overall costs. By 2050, most regions will converge toward lower LCOF values, suggesting broader applicability of AD with adequate policy and infrastructure support.

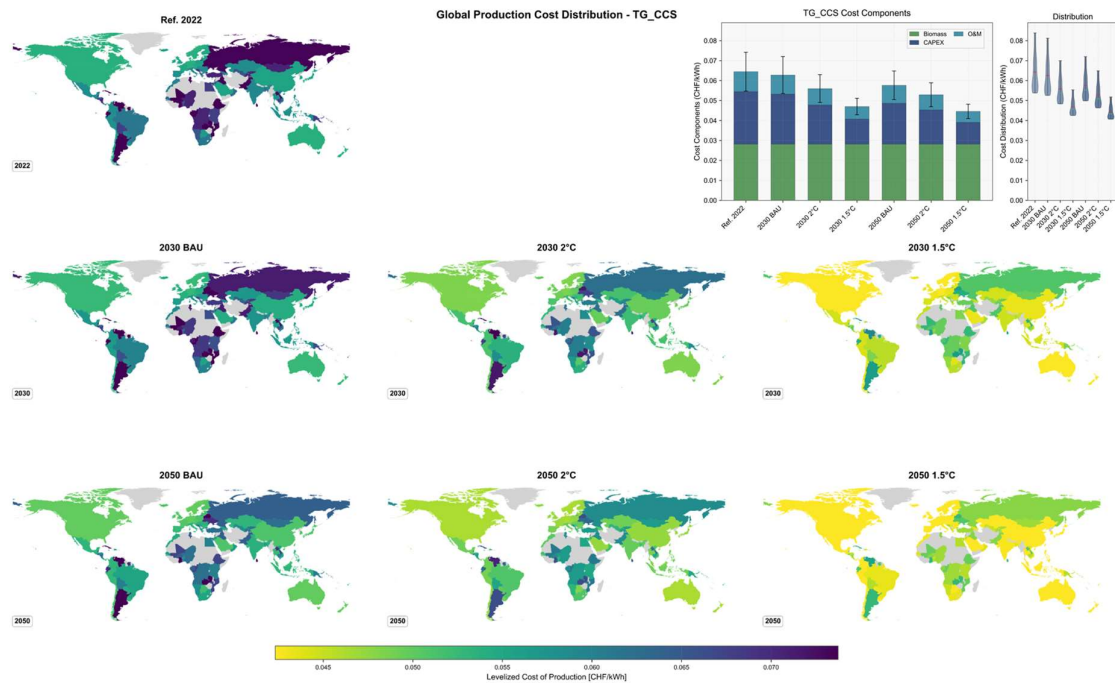


Figure 21: Global production cost distribution for TG CCS (biomass gasification with CCS for hydrogen production) across various scenarios. The series of maps spans 2022 through BAU, 2 °C, and 1.5 °C scenarios in 2030 and 2050, using a color gradient from higher (purple) to lower (yellow/green) LCOF. The bar chart details major cost components, with error bars illustrating cross-country variation. The violin plot on the right illustrates the global spread of LCOF values, showing spreads within ± 2 SDs.

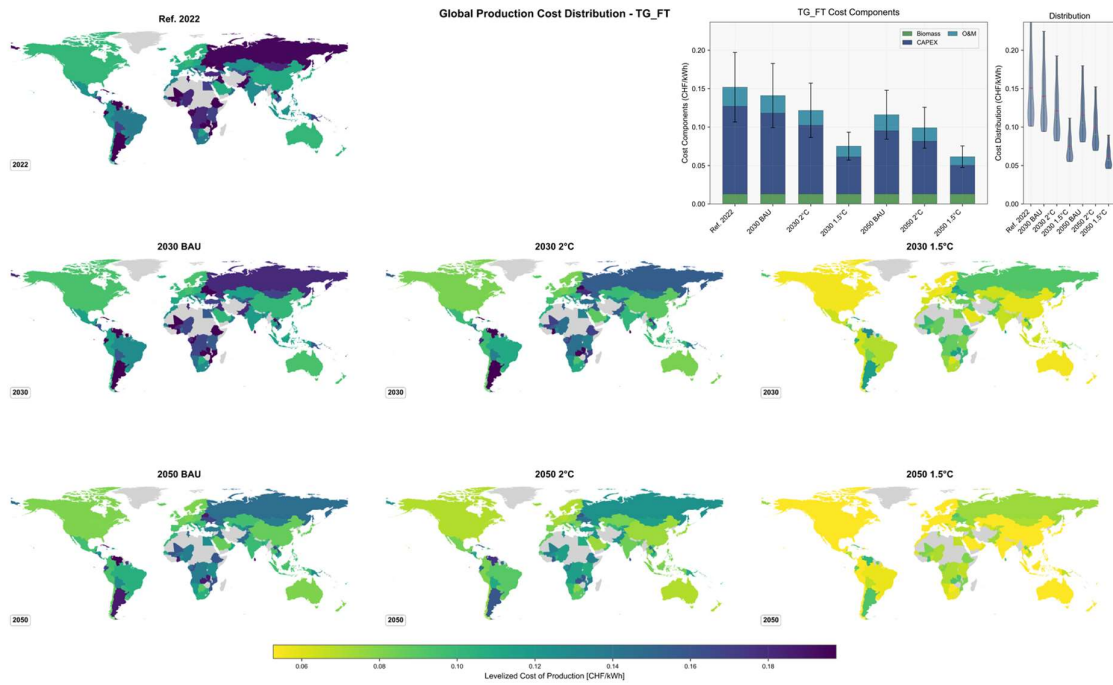


Figure 22: Global production cost distribution for TG FT (biomass gasification with Fischer–Tropsch synthesis for kerosene production) across different scenarios. The series of maps spans 2022 through BAU, 2°C, and 1.5°C scenarios in 2030 and 2050, using a color gradient from higher (purple) to lower (yellow/green) LCOF. The bar chart details major cost components, with error bars illustrating cross-country variation. The violin plot on the right illustrates the global spreads of LCOF values, showing spread within ± 2 SDs.

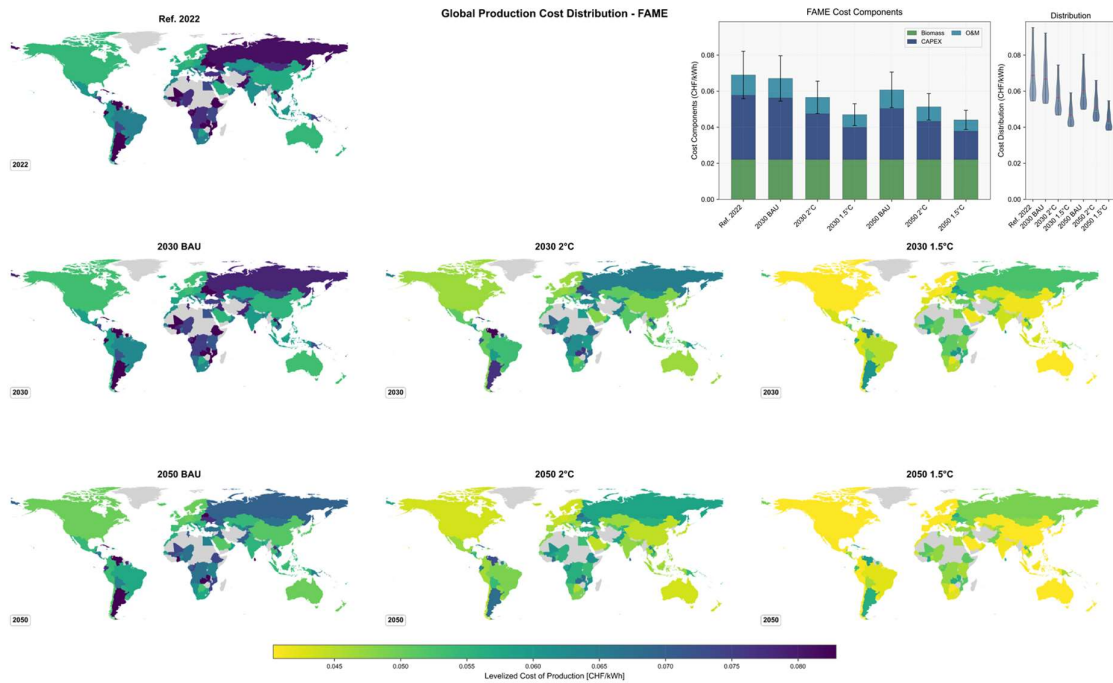


Figure 23: Global production cost distribution for biodiesel production (via FAME) under varying scenarios. The series of maps spans 2022 through BAU, 2°C, and 1.5°C scenarios in 2030 and 2050, using a color gradient from higher (purple) to lower (yellow/green) LCOF. The bar chart details major cost components, with error bars illustrating cross-country variation. The violin plot on the right illustrates the global spread of LCOF values, showing spreads within ± 2 SDs.

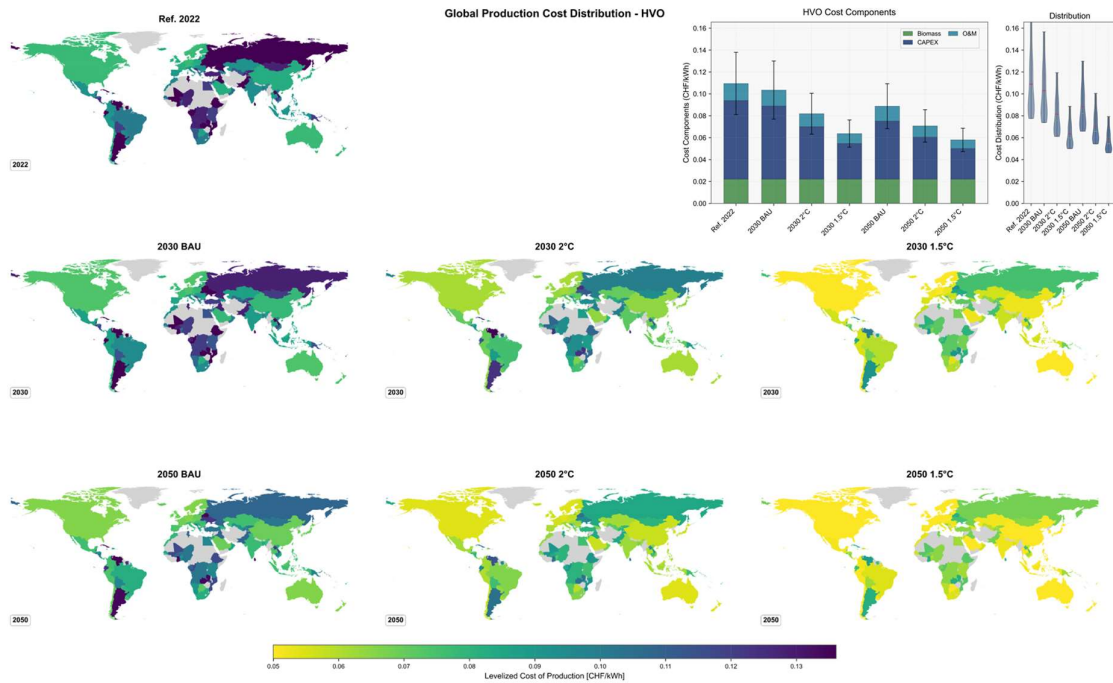


Figure 24: Global production cost distribution for biodiesel production (via HVO) under varying scenarios. The series of maps spans 2022 through BAU, 2°C, and 1.5°C scenarios in 2030 and 2050, using a color gradient from higher (purple) to lower (yellow/green) LCOF. The bar chart details major cost components, with error bars illustrating cross-country variation. The violin plot on the right illustrates the global spread of LCOF values, showing spread within ± 2 SDs.

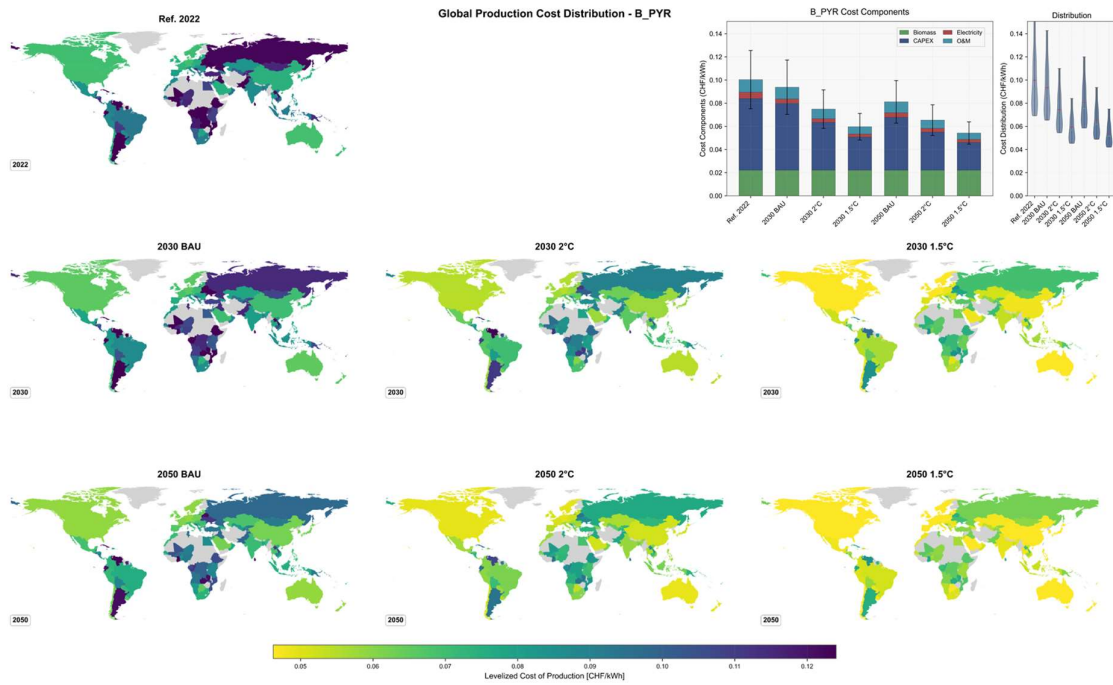


Figure 25: Global production cost distribution for biodiesel production (via biomass pyrolysis) under varying scenarios. The series of maps spans 2022 through BAU, 2°C, and 1.5°C scenarios in 2030 and 2050, using a color gradient from higher (purple) to lower (yellow/green) LCOF. The bar chart details major cost components, with error bars illustrating cross-country variation. The violin plot on the right illustrates the global spread of LCOF values, showing spread within ± 2 SDs.

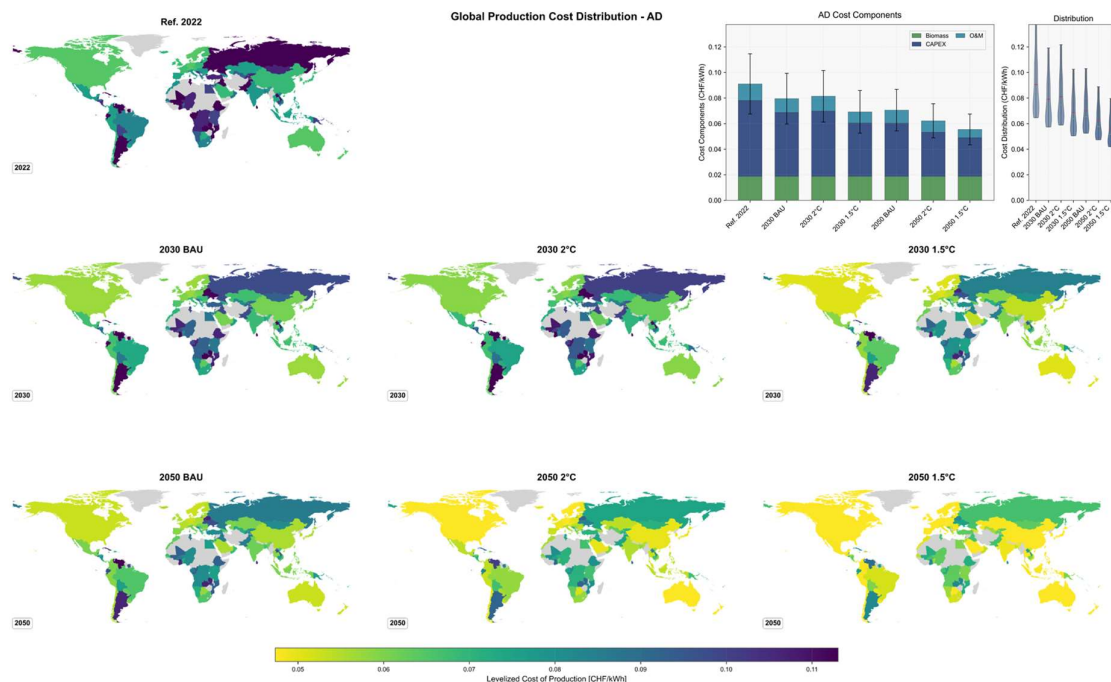


Figure 26: Global production cost distribution for biomethane production via anaerobic digestion (AD) under diverse decarbonization scenarios. The series of maps spans 2022 through BAU, 2 °C, and 1.5 °C scenarios in 2030 and 2050, using a color gradient from higher (purple) to lower (yellow/green) LCOF. The bar chart details major cost components, with error bars illustrating cross-country variation. The violin plot on the right illustrates the global spread of LCOF values, showing spreads within ± 2 SDs.

2.3.6. Aggregated fuel categories

A cross-cutting comparison of hydrogen production technologies—including green (water electrolysis: PEM, AE, SOEC), pink (nuclear-based: HTSE, CuCl), blue (natural gas- based with CCS: SMR+CCS, ATR+CCS, CLR), turquoise (methane pyrolysis), and dark green (biomass-based with CCS: TG-CCS)—reveals significant variation in cost structures and future projections. As shown in Figure 27, capital expenditures (CAPEX) and feedstock costs (electricity, natural gas, biomass) dominate total costs, with the relative contributions varying by pathway. In the reference year 2022, most technologies exceeded the indicative market price of 0.08 CHF/kWh for hydrogen (based on SMR of natural gas), reflecting early-stage deployment, limited scale, and resource constraints in many regions. Under climate mitigation scenarios (2°C and 1.5°C), progressive cost declines are observed across all routes. Green and pink hydrogen benefit from declining electricity prices and electrolyzer learning curves, while fossil-based routes with CCS maintain cost competitiveness in gas-rich regions. By 2050, several technologies—including AE, HTSE, SMR+CCS, and TG-CCS—approach or fall below the current reference benchmark, underscoring the potential for diverse low-carbon hydrogen options to achieve cost parity, contingent on regional energy conditions and sustained policy support.

Kerosene production pathways (Figure 28) span solar fuels (SR-FT, ST-FT), biomass-to-liquid (TG-FT), and power-to-liquid (PtX) approaches (RWGS-FT, RWGS-MeOH). Across all routes, CAPEX and feedstock inputs (e.g., natural gas, CO₂, hydrogen, or biomass) are the dominant contributors to total costs. In 2022, nearly all technologies lie above the indicative jet fuel price of 0.05 CHF/kWh, driven by high infrastructure costs, early-stage process integration, and volatile feedstock markets. Cost declines are most pronounced under the 1.5°C scenario, where technology learning and system scale-up reduce both capital intensity and input costs. Solar-based ST-FT remains the most expensive due to its comparatively low maturity and high-temperature solar reactor costs, while TG-FT and PtX-based RWGS pathways show more rapid convergence toward competitiveness. By 2050, multiple kerosene pathways



fall within or below the current reference range, suggesting that sustainable aviation fuels could become cost-viable in regions with supportive policy, renewable availability, and feedstock access.

Biodiesel production (Figure 29) includes FAME, HVO, and biomass pyrolysis. In 2022, all pathways exhibit production costs above fossil diesel benchmarks, primarily due to feedstock dependency (e.g., used vegetable oils, waste fats, or lignocellulosic biomass) and, in the case of HVO and pyrolysis, elevated capital costs. Over time, improvements in process efficiency, feedstock diversification, and reactor scaling contribute to progressive cost reductions. FAME and HVO generally achieve lower CAPEX and more stable production costs, whereas pyrolysis offers greater long-term potential due to its ability to utilize heterogeneous lignocellulosic inputs. By 2050, under climate-constrained scenarios, the cost gap narrows substantially, especially in biomass-rich regions. This trend highlights the increasing feasibility of biodiesel as a scalable and cost-effective contributor to future low-carbon fuel portfolios, particularly with continued investment and feedstock market development.

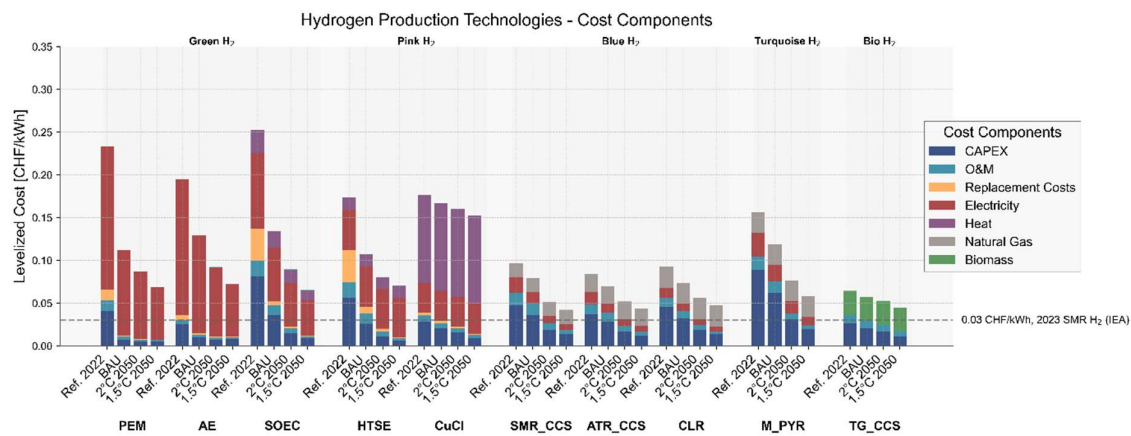


Figure 27: Cost component breakdown of hydrogen production pathways (green, pink, blue, turquoise, dark green) across selected reference years and scenarios. The red horizontal line (0.08 CHF/kWh) represents an indicative hydrogen market price in 2023. Bars are segmented into CAPEX, O&M, feedstock, and other cost categories.

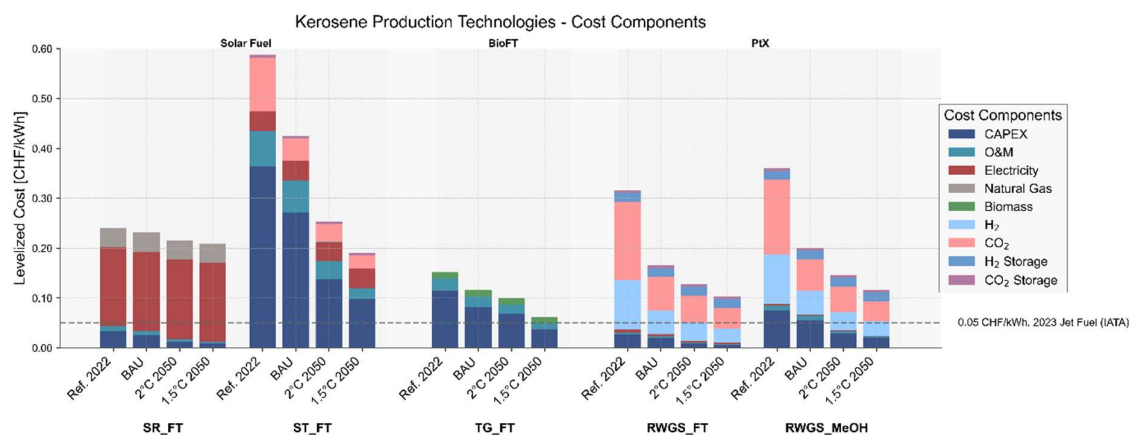


Figure 28: Cost component breakdown of kerosene production technologies (solar fuel, biofuel, PtX) for reference 2022, and three scenarios in 2050. The dashed horizontal line (0.05 CHF/kWh) indicates a 2023 market jet fuel price.

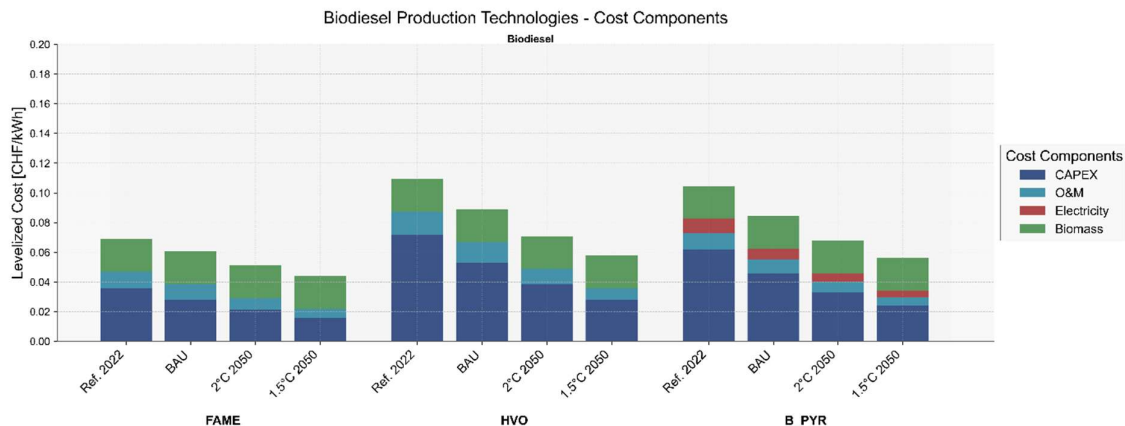


Figure 29: Cost component breakdown of biodiesel production (FAME, HVO, biomass pyrolysis) in the reference year and future decarbonization scenarios. Stacked bars highlight feedstock, capital, and operational contributions to total costs.

2.3.7. Global transport cost

Figure 30 illustrates hydrogen transport costs as a function of distance for various carriers and transport modes in 2022 and 2050. The y-intercepts represent the conversion and reconversion costs, while the slopes indicate the marginal cost per unit distance. Shipping-based modes (e.g., NH_3 , MeOH/LOHC) show relatively flat slopes, highlighting their cost-efficiency over long distances, while truck-based transport modes, especially for LH_2 and CH_2 , incur steep distance-related cost increases. Rail and pipeline options exhibit intermediate cost sensitivity.

Our comprehensive analysis of optimal hydrogen transport pathways to Switzerland reveals significant shifts in carrier preferences and infrastructure utilization in 2022 and 2050, as shown in Figure 31 and Figure 32. In the 2022 scenario without pipeline infrastructure, a clear pattern emerges with countries being serviced by distinct carrier-transport combinations. The visualization reveals three primary configurations: NH_3 -Ship (blue diamonds) for the most distant countries, NH_3 -Rail (blue squares) for some European countries, LOHC -Ship (gray triangles) for selected distant regions, and CH_2 -Truck (black circles) for neighboring countries. This distribution reflects the balance between conversion costs and transport efficiency, with ammonia emerging as the dominant (long-distance) carrier due to its favorable volumetric energy density and established shipping infrastructure. Transport costs exhibit a clear distance-dependent gradient, ranging from approximately 1.5 CHF/kg H_2 for European neighbors to more than 3.5 CHF/kg H_2 for remote locations in Asia, Africa, and the Americas. By 2050, with pipeline infrastructure available, the transport landscape will undergo a profound transformation. The map reveals a binary system dominated by CH_2 -Pipeline (black circles) for European countries and LOHC -Ship (gray triangles) for more distant regions. This shift reflects several technological and economic trends: (1) the implementation of dedicated hydrogen pipeline networks connecting Switzerland to neighboring countries, (2) projected improvements in LOHC technology that reduce conversion/reconversion costs, and (3) the overall maturation of hydrogen transport infrastructure. The European inset map clearly demonstrates the cost advantage of pipeline infrastructure, with connected countries enjoying significantly lower transport costs (0.5-1.0 CHF/kg H_2) compared to the 2022 scenario. Most notable is the dramatic reduction in transport costs across all pathways by 2050. The maximum costs decrease from above 3.5 CHF/kg H_2 in 2022 to below 2.5 CHF/kg H_2 in 2050, representing an approximately 30% reduction. This cost decline stems from technological learning curves, economies of scale, and infrastructure optimization, particularly the efficient pipeline network that eliminates costly conversion/reconversion steps for nearby European countries. The shift from a predominantly ammonia-based transport system in 2022 to one dominated by direct CH_2 pipeline transport and LOHC shipping in 2050 highlights how infrastructure development and carrier technology improvements can fundamentally reshape optimal hydrogen transport strategies. This transition has significant implications for



hydrogen market development, suggesting that proximity to pipeline networks will become a critical competitive advantage for hydrogen production in the European context.

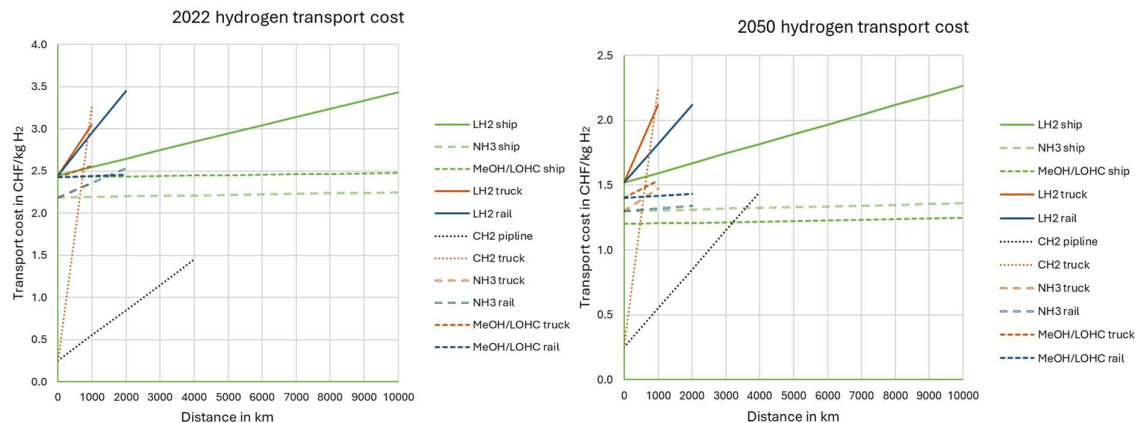


Figure 30: Hydrogen transport cost as a function of distance for various carriers and transport modes in 2022 and 2050. The y-intercepts represent the conversion and reconversion costs (CHF/kg H_2), while the slopes indicate the cost per unit distance (km).

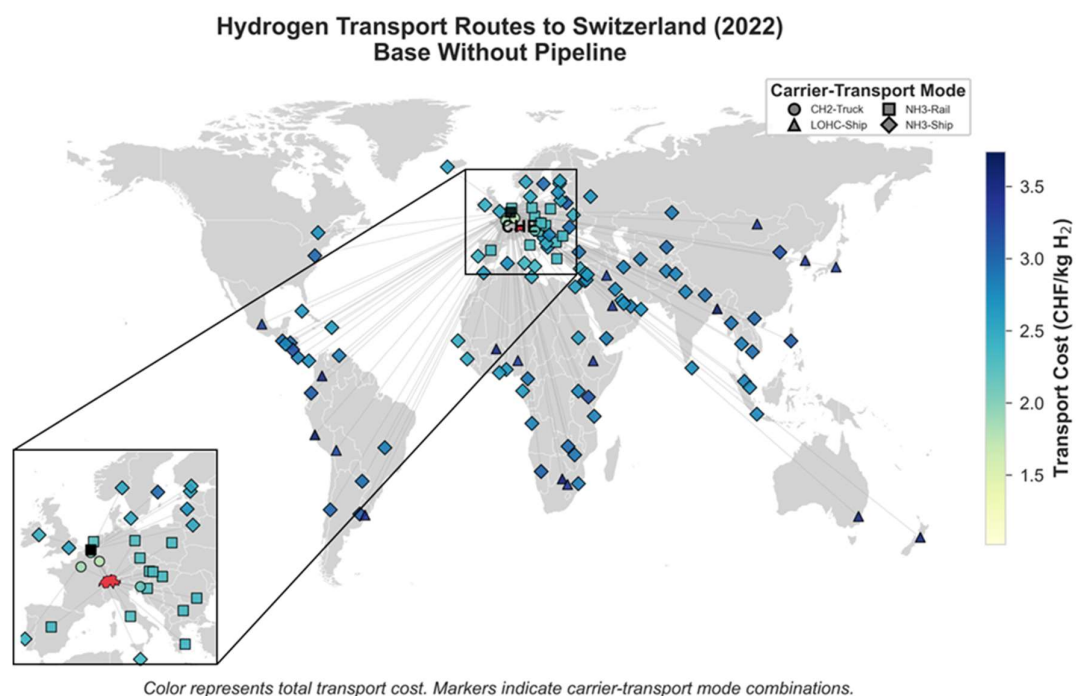


Figure 31: Cost-optimal transport routes for hydrogen delivery to Switzerland in 2022 under the base scenario without pipeline infrastructure. The map shows the optimal transport modes selected based on cost, where circles indicate shipping and triangles represent rail routes. NH_3 (ammonia) is the dominant hydrogen carrier, with 203 countries utilizing NH_3 shipping routes and 23 countries using compressed hydrogen (CH_2). The color scale indicates the transport cost in CHF/kg H_2 , with darker colors representing higher costs. Insets highlight transport connections within and around Europe.

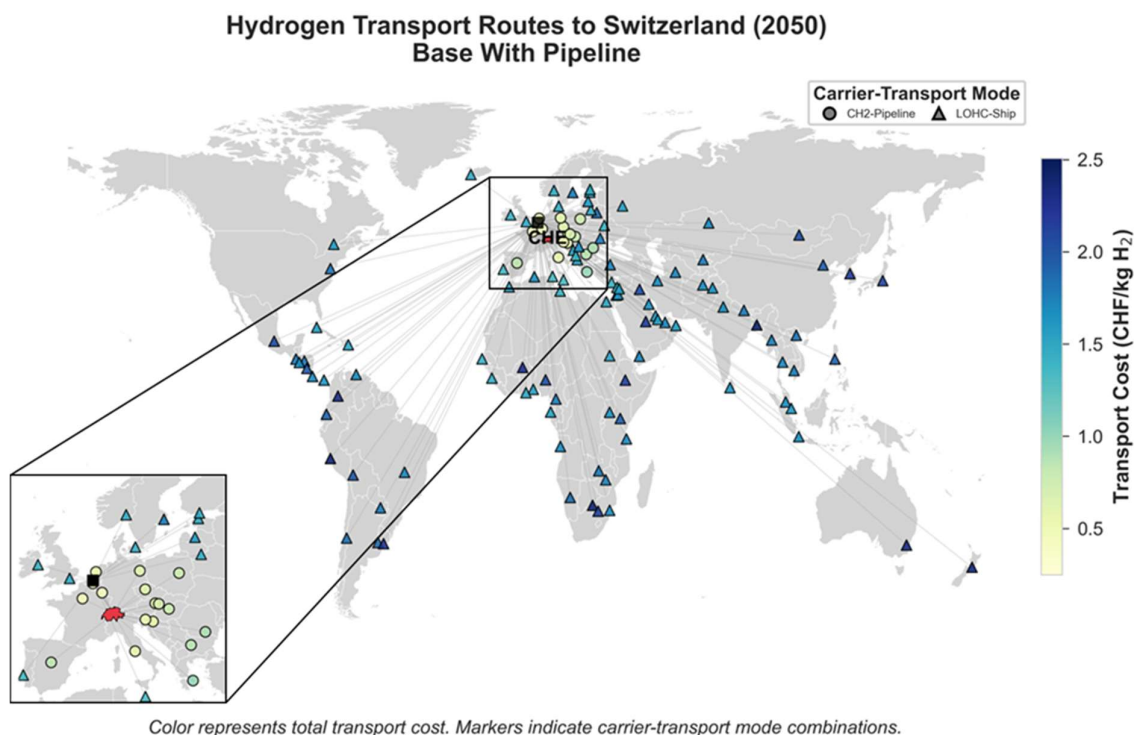


Figure 32: Cost-optimal transport routes for hydrogen delivery to Switzerland in 2050 under the base scenario with pipeline infrastructure enabled. In this future scenario, pipelines emerge as a key mode (diamonds), particularly within Europe. Shipping (circles) and rail (triangles) remain relevant for intercontinental and regional connections. Liquid Organic Hydrogen Carriers (LOHC) become the most frequently selected transport medium (201 countries), followed by CH₂ (25 countries). Insets zoom into the European region, emphasizing the expanded role of pipeline networks.

2.3.8. Sensitivity analysis

Figure 33, Figure 34 and Figure 35 present a multi-dimensional sensitivity analysis across fuel production technologies, highlighting the influence of cost components and financing conditions. Figure 33 shows that CAPEX is the dominant cost driver across nearly all pathways, particularly for early-stage or capital-intensive technologies such as PEM, AE, ST-FT, and HTSE. For electrolysis-based hydrogen and solar fuels, electricity and heat inputs also have a considerable impact (e.g., up to 38.5% for AE and 33.4% for ST-FT), while hydrogen and CO₂ costs significantly affect PtX pathways like RWGS-FT and RWGS-MeOH. In contrast, biofuel and CCS-based routes exhibit greater sensitivity to feedstock costs, notably biomass and natural gas, and assumed CCS costs.

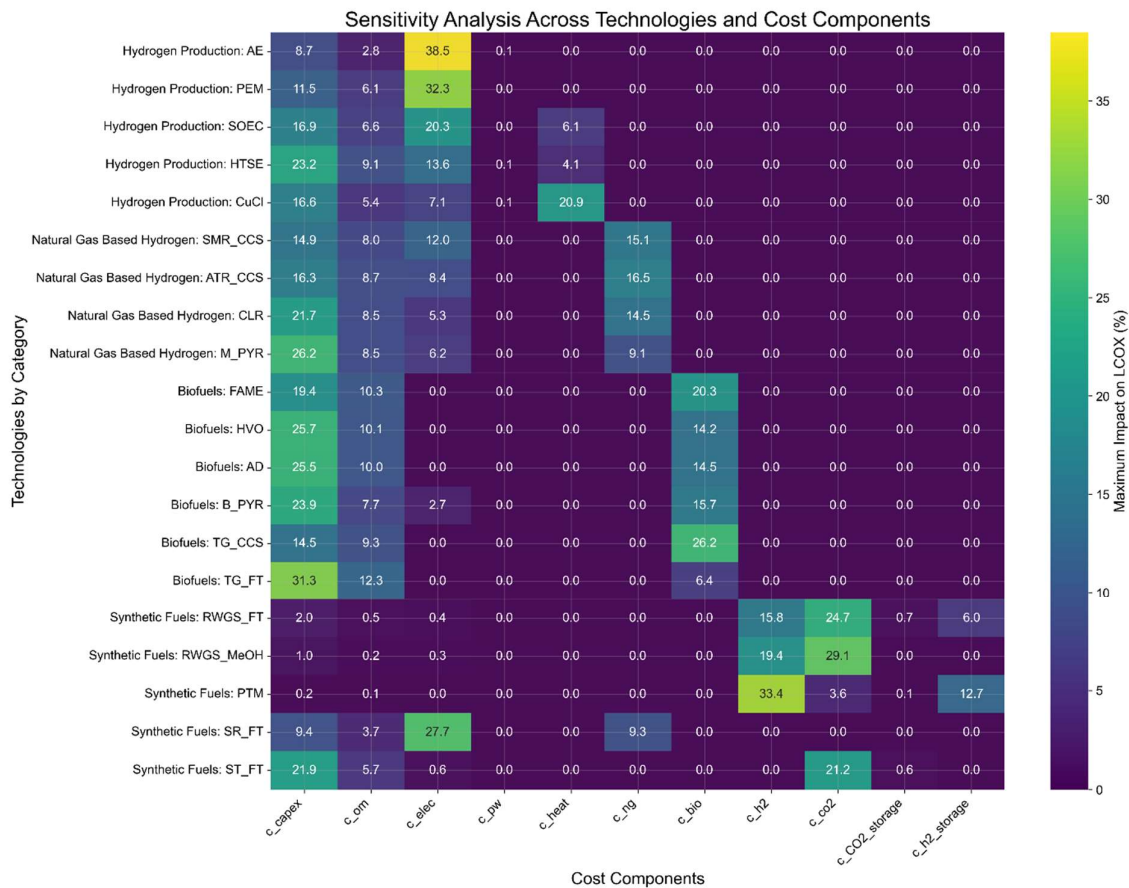


Figure 33: Sensitivity of levelized cost of output (LCOX) to individual cost components across all fuel production pathways. The heatmap displays the maximum percentage change in LCOX resulting from $\pm 20\%$ variation in each cost component for 22 representative technologies. Cost component abbreviations are: c_capex (capital expenditures), c_om (operation and maintenance), c_elec (electricity), c_ply (replacement costs), c_heat (thermal energy input), c_ng (natural gas), c_bio (biomass), c_h2 (hydrogen), c_co2 (carbon dioxide), c_CO2_storage (CO₂ storage), and c_h2_storage (hydrogen storage). Higher values indicate components with greater influence on LCOX, highlighting pathway-specific cost sensitivities.

Figure 34 reveals strong regional variability in sensitivity to the weighted average cost of capital (WACC). Technologies with high upfront investment requirements, such as HTSE, ST-FT, and B_PYR, exhibit the greatest WACC sensitivity, especially in capital-constrained regions like Africa and South America. In contrast, fossil-based technologies (e.g., SMR+CCS, ATR+CCS) and more mature options (e.g., FAME, AD) are less affected, particularly in developed economies with lower financing risks. This underscores the critical role of local financing conditions in shaping cost competitiveness.

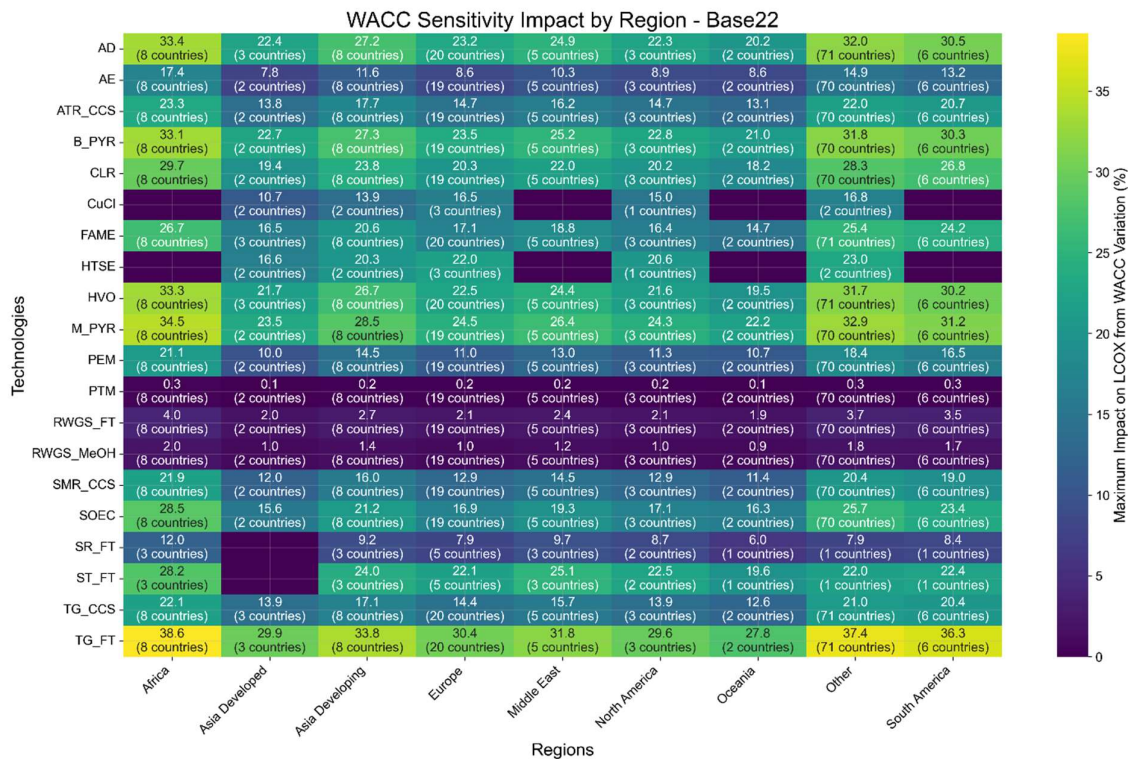


Figure 34: Regional sensitivity of LCOX to WACC variation across fuel production pathways (Base 2022). The matrix displays the maximum percentage impact on LCOX resulting from ± 4 percentage point changes in the weighted average cost of capital (WACC) across world regions. Values are averaged by region and pathway, with the number of countries represented shown in parentheses. Results emphasize regional disparities in financing sensitivity, particularly for CAPEX-intensive technologies.

Figure 35 illustrates the evolution of WACC sensitivity across future scenarios. Most technologies see a progressive reduction in WACC sensitivity under stringent decarbonization pathways, driven by improved capital efficiency, lower investment risk, and policy alignment. Notably, PEM, HTSE, and SOEC show the sharpest declines (e.g., >70% under 1.5°C in 2050), while methane pyrolysis and RWGS pathways remain moderately sensitive, reflecting continued CAPEX exposure. These results highlight the dual importance of learning about technology and financial de-risking to ensure long-term cost convergence and deployment viability.



Figure 35: Relative change in WACC sensitivity of LCOX across future scenarios (compared to Base 2022). This heatmap presents the percentage change in WACC sensitivity relative to the Base case, for each technology across six scenario-year combinations. Negative values indicate a decline in WACC dependence over time or under more ambitious climate targets, reflecting reduced financial risk or improved capital efficiency. (Base30: BAU 2030; 2deg30: 2°C 2030, etc.).

2.4 Conclusion: techno-economic analysis of LCF production and transport

Section 2 of this report provides a comprehensive, spatially explicit techno-economic assessment of global low-carbon fuel production pathways and transport options, with a focus on evaluating cost-effective import routes to Switzerland. The analysis reveals that the cost components of LCFs differ significantly across production technologies and feedstocks. Electrolysis-based hydrogen production (e.g., PEM, AE, SOEC) is primarily driven by electricity input costs, which can account for up to 70% of total production costs in grid-connected configurations, especially in regions with expensive fossil-dominated electricity mixes. In contrast, technologies such as high-temperature steam electrolysis (HTSE) and nuclear-based CuCl cycles exhibit high capital expenditures and nuclear thermal integration requirements, with conversion efficiency improvements and infrastructure coupling playing critical roles in cost reduction over time. Biofuel technologies such as HVO and FAME are more strongly influenced by feedstock availability and price, while processes like biomass gasification or pyrolysis involve high process energy input and sensitivity to regional biomass costs. For PtX-based kerosene production pathways, hydrogen and CO₂ input costs—particularly with CO₂ supplied by DAC—remain the most significant cost components, emphasizing the importance of upstream supply chain efficiency.

Geographic heterogeneity emerges as a key factor influencing global fuel economics. Renewable resource quality, investment risk profiles, and local energy costs jointly determine the competitiveness of



production sites. For example, countries with high solar irradiance and low WACC—such as Morocco, Chile, and Australia—consistently rank among the most competitive locations for green hydrogen and PtX production. Similarly, the availability of concentrated biomass resources in Brazil, Indonesia, and parts of sub-Saharan Africa favors biofuel production, although logistical constraints and land-use concerns must be considered. In Europe, while electricity prices and land availability limit the scalability of domestic LCF production, established industrial and transport infrastructure supports the import of intermediate carriers such as NH_3 , CH_3OH , and LOHC.

With respect to Switzerland, the findings indicate that the most viable import strategies will evolve over time. In the near term (up to 2030), maritime shipping of hydrogen in chemical carriers—particularly ammonia—offers the most cost-effective route, leveraging existing ammonia handling infrastructure and benefiting from lower transport and conversion costs compared to LOHC and LH_2 . Compressed hydrogen transported by rail emerges as a feasible mode for intra-European transport, particularly from neighboring countries such as Germany, France, and Austria. By 2050, under scenarios assuming pipeline infrastructure development, the landscape shifts: pipeline transport becomes a dominant mode, particularly within Europe, with the European Hydrogen Backbone (EHB) enabling direct import to Switzerland from up to 25 countries. LOHC, benefiting from moderate conversion and reconversion cost reductions, has become the most frequently selected transport medium in long-distance or high-volume routes under the 2050 scenario, signaling growing economic feasibility.

These results underscore the need for Swiss policymakers and infrastructure planners to evaluate hydrogen and synthetic fuel strategies not only from a technological or environmental standpoint but through a spatially resolved economic lens. Long-term infrastructure decisions—such as investments in ammonia cracking facilities, LOHC dehydrogenation units, or pipeline interconnectors—must align with evolving global fuel production cost dynamics and transport cost trajectories. Crucially, production site selection should be informed by both natural resource endowment and country-specific financial and political risk, captured in this study through differentiated WACC and learning rate assumptions. Supply contracts, bilateral agreements, and infrastructure development strategies should prioritize countries with a favorable combination of low LCOF, stable financing environments, and logistical proximity – e.g., Morocco, the Middle East, Australia, and South America.

In conclusion, this section contributes a globally consistent, data-rich foundation for designing future fuel import strategies for Switzerland. By integrating techno-economic modeling with spatial and infrastructure constraints, it enables the identification of not only cost-optimal fuel production sites but also credible and resilient transport corridors. The findings support a differentiated policy approach: in the short term, enhancing port and conversion infrastructure for ammonia and LOHC; in the long term, coordinating with European hydrogen network development; and throughout, promoting international cooperation to ensure access to scalable, low-carbon, and cost-effective fuel sources under future decarbonization scenarios.



3 Evaluation of the environmental performance of chemical low-carbon fuels

This section of the report provides an overview of the environmental performance of potential low-carbon fuels, with a clear focus on the impacts of climate change^{10,11}. We build upon the academic articles published within the context of the SHELTERED project (Boyce et al., 2024; Ingwersen et al., 2025; Liu et al., 2025; Saad et al., 2024; Sacchi et al., 2023; Terlouw et al., 2022, 2024a; Wei et al., 2024a). They present their main insights and outcomes and refer to those open-access publications for further details and background information. In general, climate impacts caused by the production and use of potential LCF and their broader environmental performance can only be evaluated by applying environmental Life Cycle Assessment (LCA) methodology, as environmental benefits and possible trade-offs most often depend on issues such as feedstock supply, type of energy carrier used for their production, production location and supply pathway, as well as end-use technologies (Borrill et al., 2024; Cabrera-Jiménez et al., 2025; Kurzawska-Pietrowicz, 2023; Osman et al., 2021a; Salas et al., 2024; Uddin & Wang, 2024; Wang et al., 2025).

3.1 Methodology

Environmental Life Cycle Assessment (LCA) is applied as a method of choice for the quantification of climate impacts and broader environmental burdens of LCF production and use (Hauschild et al., 2018; ISO, 2006b, 2006a). A future-oriented perspective (referred to as “prospective LCA”) is provided by applying the LCA software framework premise (Sacchi, Terlouw, et al., 2022b), developed at PSI. By applying LCA, all environmental burdens related to material and energy supply, process emissions, natural resource requirements, waste disposal, and transport activities associated with the production of LCA (and their use) are quantified. Prospective LCA considers technological progress in LCF production processes, future developments in end-use technologies, and the expected transformation of the economic background system according to specific climate goals (Sacchi, Terlouw, et al., 2022b).

3.2 Results

3.2.1. Hydrogen

Environmental burdens associated with hydrogen production (and to some extent its use) have been quantified by means of LCA in an extensive way (Ajeeb et al., 2024; Maniscalco et al., 2024; Osman et al., 2022; Wilkinson et al., 2023). Here, we show selected results of our own recent work, within and beyond the SHELTERED project. Among the many different methods for producing hydrogen, we limit the assessment to grey (steam methane reforming using natural gas), blue (steam methane reforming using natural gas with CCS), green (water electrolysis with electricity from renewables, including autonomous off-grid systems), water electrolysis using grid power, and biomass-based hydrogen (with and without CCS). As the use of hydrogen in most applications is not associated with major environmental burdens, the production stage is most relevant from an environmental perspective overall. The most important factor when it comes to GHG emissions of hydrogen production via water electrolysis is the GHG intensity of the electricity used to operate the electrolysis. Climate impacts of blue hydrogen production mostly depend on the CO₂ capture rate at the methane reforming unit and the methane emissions along the natural gas production and supply chain (Antonini et al., 2020, 2021; Bauer et al., 2022; Kleijne et al., 2024; Longden et al., 2021; Ueckerdt et al., 2022). These dependencies are visualized in Figure 36, which shows GHG emissions of grey, blue, and green hydrogen with several production configurations as a function of the CH₄ emission rate along the natural supply chain (Bauer et al., 2022).

¹⁰ Within this report, we use the terms “impacts on climate change”, “climate impacts”, “carbon footprint”, and “life cycle GHG emissions” as synonyms. These are – if not explicitly mentioned – quantified applying global warming potentials (GWP) for individual greenhouse gases for a time horizon of 100 years, i.e., “GWP100”.

¹¹ We refer to the cited publications for insights regarding other environmental burdens than impacts on climate change.

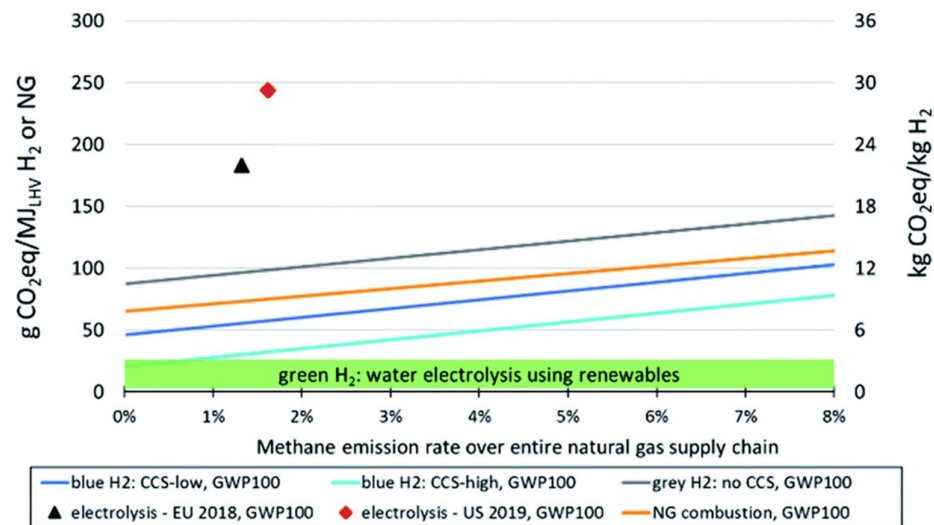


Figure 36: Life cycle GHG emissions of hydrogen production as a function of methane emissions along the natural gas supply chain, applying GWP100 factors for specific greenhouse gases (Bauer et al., 2022). The area shaded green represents hydrogen from water electrolysis using renewable power, which varies in its GHG intensity. The light blue line represents advanced methane reforming with a high CO₂ capture rate (93%), while the dark blue line represents methane reforming with a low CO₂ capture rate (56%). Using average grid electricity in Europe or the US (black and red markers) results in high GHG emissions from hydrogen production.

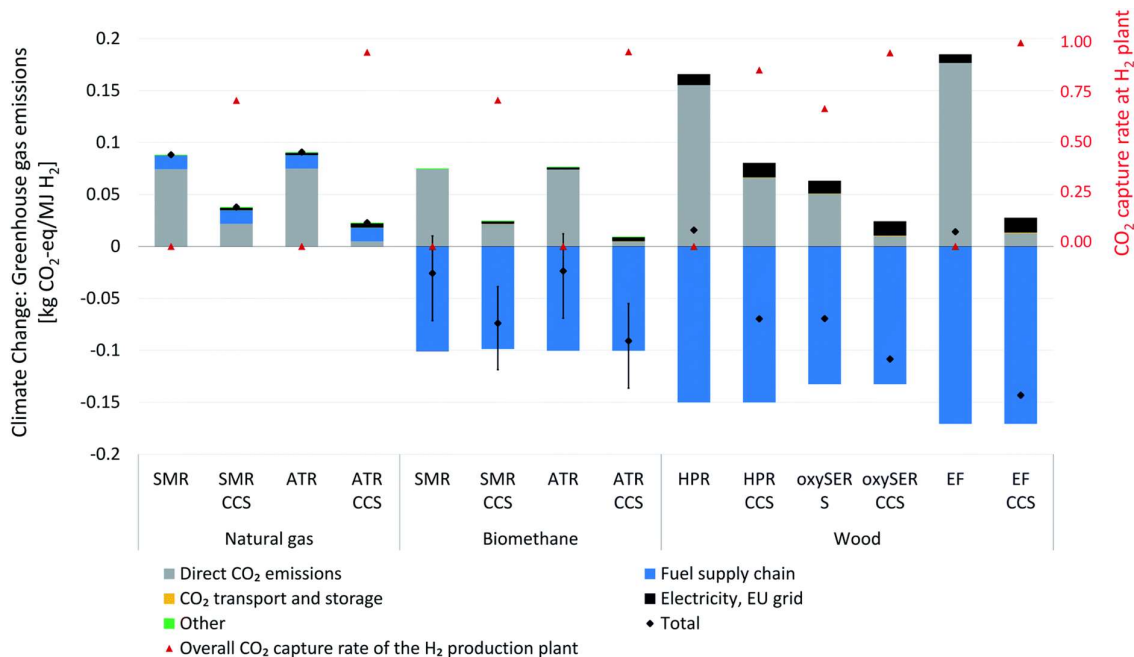
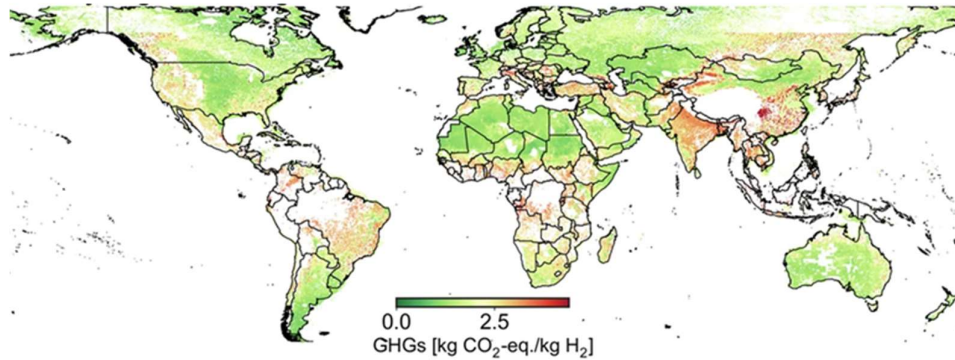


Figure 37: Life cycle GHG emissions of hydrogen production from biomass conversion (biomethane reforming and wood gasification), compared to natural gas reforming, all with and without CCS (Antonini et al., 2021). The right y-axis shows the overall CO₂ capture rate at the plant level. The category "Other" includes "Catalyst and Adsorbents", "Direct emissions from fuel combustion in furnace", "H₂ production unit infrastructure", and "Water supply". SMR = Steam Methane Reforming; ATR = Autothermal Reforming; HPR = Heat Pipe Reformer; oxySER = Sorption Enhanced Reforming gasifier; EF = Entrained flow gasifier.

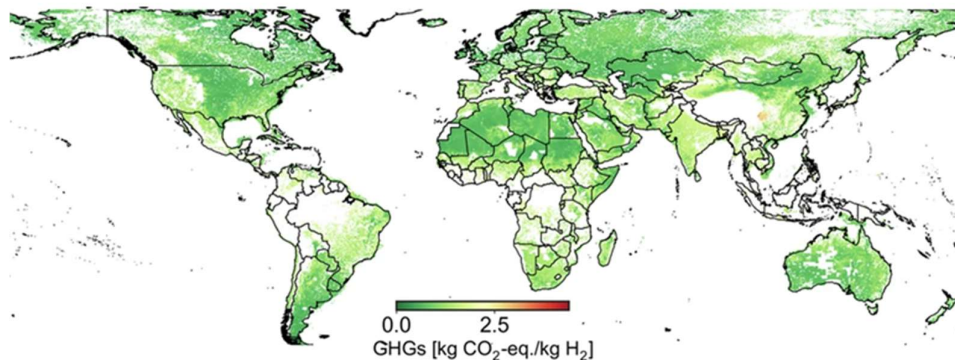


As Figure 37 shows, biomass conversion – biomethane reforming and wood gasification – can produce hydrogen with very low life cycle GHG emissions. And if combined with CCS, it can remove CO₂ from the atmosphere, i.e., result in negative GHG emissions (Antonini et al., 2020, 2021). It is the fact that the biomass feedstock must either come from residual material or from sustainable forestry, not leading to land use changes and associated climate impacts.

2022 - reference



2050 – business-as-usual



2050 – 2 degrees global warming

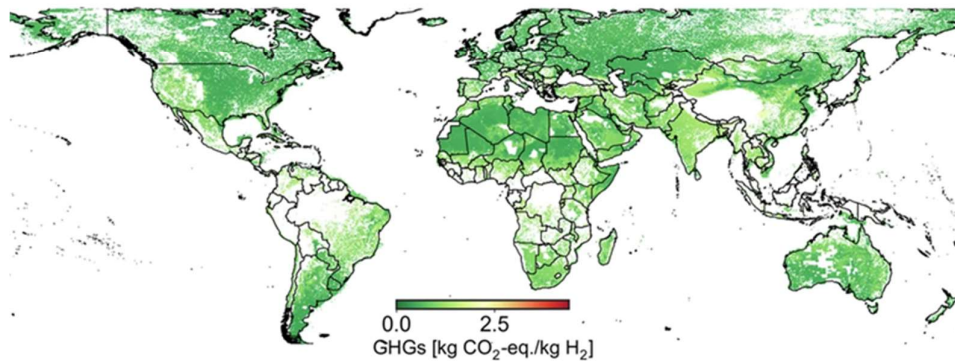


Figure 38: Life cycle GHG emissions of hydrogen production via water electrolysis with off-grid systems powered by photovoltaics and wind power for today and two future scenarios in 2050 (Terlouw et al., 2024a).

Climate impacts of green hydrogen production via water electrolysis crucially depend on the location-specific yields of photovoltaic modules and wind turbines installed to power the water electrolysis units, as shown in Figure 38. Today (“2022 – reference”), these GHG emissions amount to 1.1-5.6 kg



CO₂eq/kgH₂; by 2050, these emissions are expected to go down to 0.4-1.4 kg CO₂eq/kgH₂, as both electricity from PV panels and wind turbines will be less GHG intensive due to a decarbonized economy and also, electrolyzers are expected to become more efficient (Terlouw et al., 2024a).

Figure 39 reveals that today, the major contributions of overall life cycle GHG emissions of green hydrogen originate from the electrolyzer production chain and the infrastructure for electricity production, i.e., wind and PV installations (Terlouw et al., 2024a). Advanced methods for blue hydrogen production (“Autothermal reforming” with CCS in Figure 39, CO₂ capture rate of 93%) can produce hydrogen with GHG emission intensities like those of electrolysis with PV power.

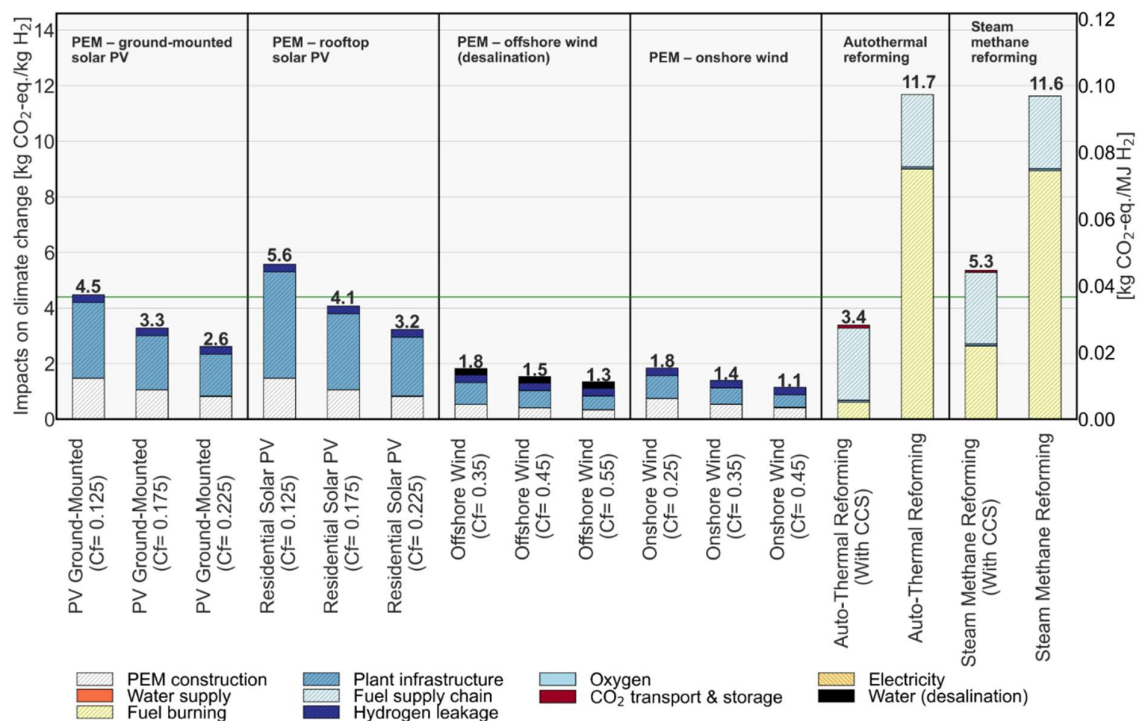


Figure 39: Contribution analysis for life cycle GHG emissions of hydrogen production via water electrolysis (reference scenario in 2022), compared to natural gas reforming with and without CCS (Terlouw et al., 2024a).

In general, these results are in line with those shown in Figure 40, calculated by (Wei et al., 2024b), who extended the technological scope in terms of hydrogen production pathways and quantified life cycle GHG emissions up to 2050 for IEA's net zero scenario up to 2050.

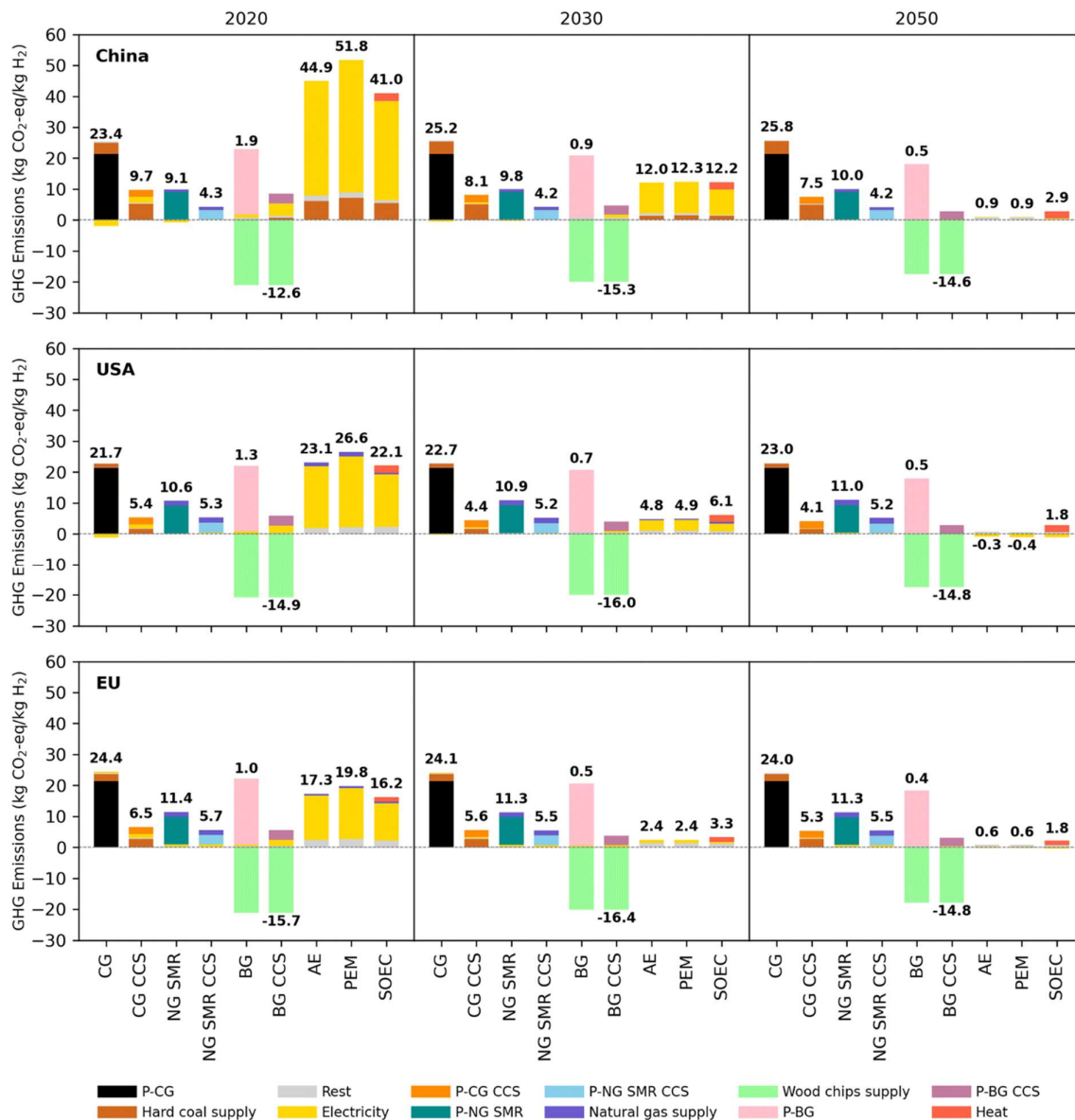


Figure 40: Contribution analysis of life cycle GHG emissions for IEA's net zero scenario (Wei et al., 2024b). The prefix P stands for the process itself, CG = coal gasification, NG SMR = steam methane reforming of natural gas, BG = biomass gasification, CCS = carbon capture (90% capture rate) and storage, AE = alkaline electrolyzer, PEM = proton exchange membrane electrolyzer, and SOEC = solid oxide electrolysis cell. In water electrolysis, the coal and natural gas supply are part of the electricity component. For CG and NG SMR, the negative GHG emissions can be generated by electricity co-produced in the H₂ production process when it is assumed to be delivered to the grid. For water electrolysis, the expansion of the bioenergy with CCS in the grid electricity can result in negative emissions.

Hydrogen can be transported by different means of transport and in different forms, as discussed in the section 2.2.4 from a technical and economic perspective. In Figure 41, life cycle GHG emissions of hydrogen production and transport to the point of delivery for different transport modes, using either wind or PV power for water electrolysis and compression/conversion of hydrogen, are shown as a function of transport distance (Kleijne et al., 2024). Up to a few hundred kilometers, pipeline transport generates the lowest GHG emissions; for hydrogen transport over longer distances, liquid hydrogen shipping generates the lowest GHG emissions among the three transport options shown here.

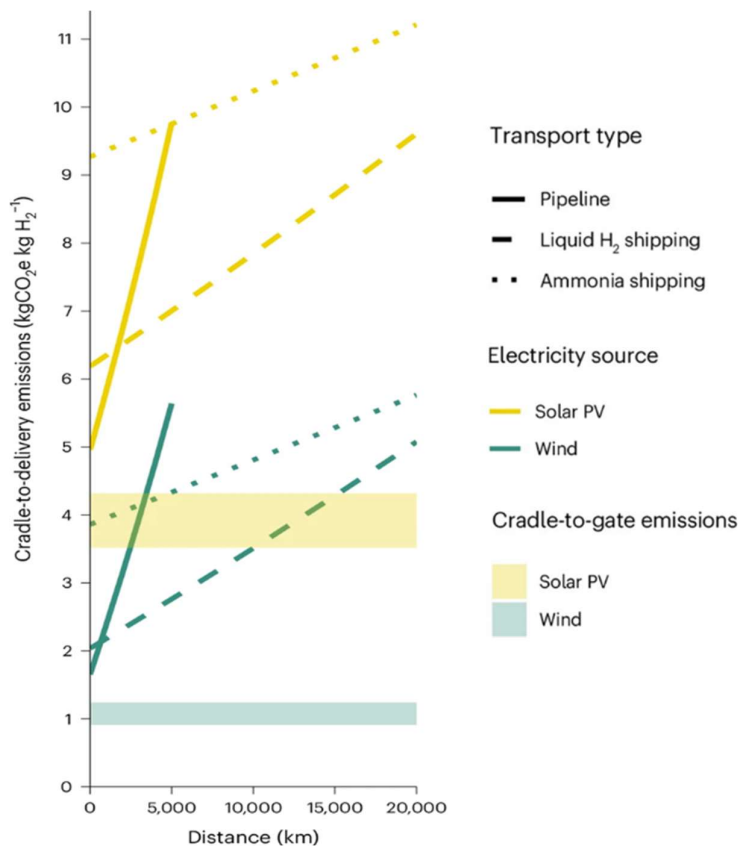


Figure 41: Life cycle GHG emissions of hydrogen production and transport to the point of delivery for different transport modes, using either wind or PV power for water electrolysis, as a function of transport distance (Kleijne et al., 2024).

3.2.2. Other low-carbon fuels: hydrocarbons and ammonia

Other LCF include hydrogen-based hydrocarbons like synthetic kerosene, methane, or methanol, as well as biomass-based fuels ("biofuels") and ammonia (Mohamed et al., 2024; Osman et al., 2021b; Patel & Singh, 2023; Prussi et al., 2021).

Regarding electricity-based hydrocarbons (so-called "e-fuels"), produced via water electrolysis and further conversion of hydrogen and CO₂, which can come from the atmosphere, biogenic or fossil sources, the overall energy efficiency needs to be considered. This energy efficiency from the primary energy resource to the energy service provided depends on the application of the e-fuels, but is, in general, much higher for direct use of electricity than for the e-fuel pathways, as shown in Figure 42. The comparatively low energy efficiency of e-fuel chains not only leads to high costs, but also potentially high GHG emissions, if the GHG intensity of electricity used for electrolysis is not close to zero, as shown in Figure 43, for the exemplary case of current and future passenger vehicles (battery electric vs. fossil petrol vs. synthetic e-petrol).

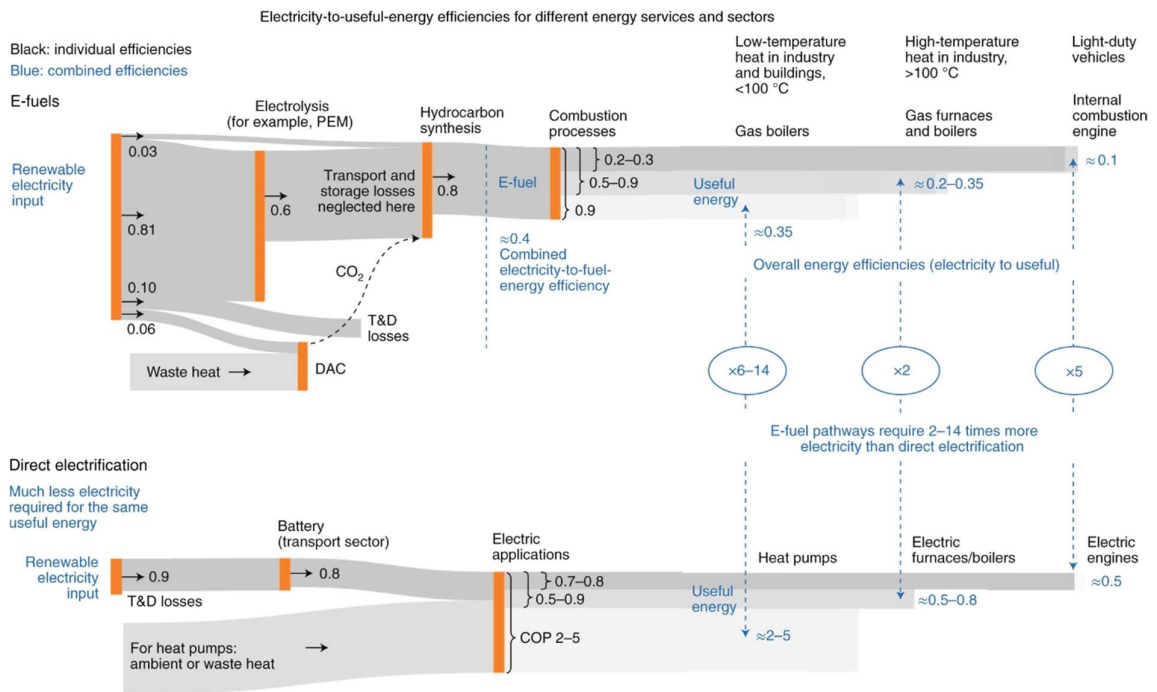


Figure 42: Energy efficiencies for major conversion steps from electricity input to useful energy, comparing e-fuel chains (top) with direct electrification (bottom) (Ueckerdt et al., 2021). Individual conversion efficiencies (black) and combined efficiencies (blue) are shown. The overall electricity-to-useful-energy efficiencies of e-fuels range from roughly 10% (e-gasoline in a light-duty vehicle) to 35% (e-methane boiler), which translates into (renewable) electricity generation requirements that are 2–14 times higher than for direct electrification alternatives.

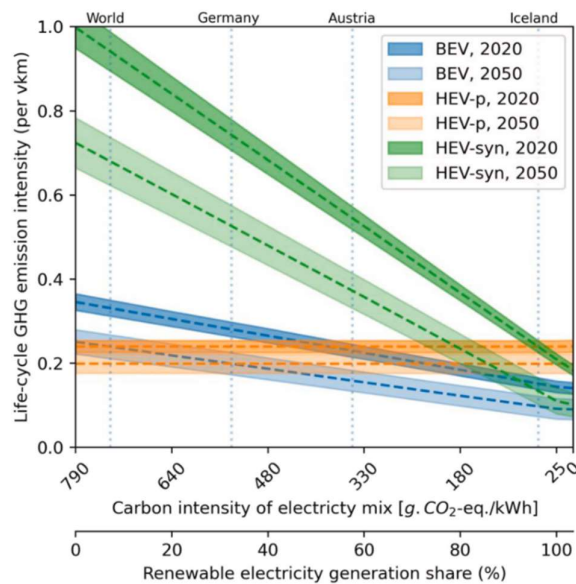


Figure 43: Life cycle GHG emissions of mid-size passenger vehicles (battery electric (BEV), e-petrol and petrol hybrid ICEVs) and the effect of the carbon intensity of the electricity mix used for charging the battery of a BEV as well as for producing the synthetic gasoline for the e-petrol ICEV (HEV-syn) (including the provision of heat via heat pumps), on their GHG emissions, compared to a petrol-fueled hybrid ICEV (HEV-p) (Sacchi, Bauer, et al., 2022).



Besides e-petrol and e-diesel, methanol, which can be used directly, for example as maritime shipping fuel, represents an alternative to crude oil-based fossil fuels. Methanol can also be further converted to synthetic jet fuel as an alternative to fossil kerosene. Methanol can be produced using electricity or biomass as a feedstock and primary energy source. We have analyzed three different production routes: CO₂-to-methanol via Electrochemical Reduction (“CO₂ER”), CO₂-to-methanol via Direct Hydrogenation (“CO₂HY”), and Biomass-to-methanol via Direct Hydrogenation (“BIOHY”) – the first two use CO₂ from direct air capture (DAC), the third one from biomass (Saad et al., 2024). Figure 44 shows cradle-to-gate (i.e., production-related) life cycle GHG emissions of these three different pathways as a function of the GHG intensity of the electricity used to produce methanol. Climate benefits compared to conventional methanol production via steam reforming of natural gas can only be achieved with low GHG intensities of electricity used in the electricity-based methanol production processes.

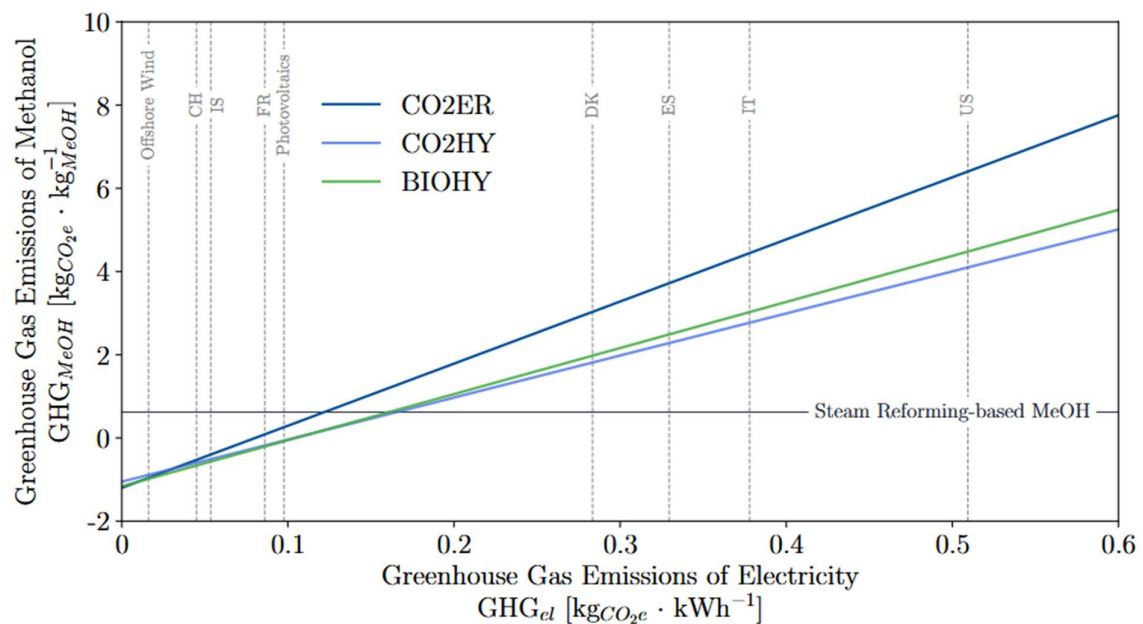


Figure 44: Cradle-to-gate life cycle GHG emissions of methanol, GHG_{MeOH} , as a function of the carbon intensity of electricity, GHG_{el} , for the three production processes (CO₂ER, CO₂HY, BIOHY) (Saad et al., 2024). The methanol emissions include the reduction in CO₂ emissions due to CO₂ capture from the atmosphere via direct air capture, which amounts to 1.375 kgCO₂ per kg methanol. Fossil fuel-based methanol GHG emissions are provided as a benchmark (horizontal line). The dashed vertical lines represent current low-voltage electricity supply in selected countries, such as Switzerland (CH), France (FR), Italy (IT), Spain (ES), Denmark (DK), and Iceland (IS), in addition to the carbon intensity of some renewable energy systems (utility-scale photovoltaics and offshore wind turbines in Germany).

Such methanol can be further converted to jet fuel and represents a potential low-carbon alternative to conventional kerosene produced from crude oil. Figure 45 shows life cycle GHG emissions of the three different methanol production pathways as a function of the GHG intensity of the electricity used to produce methanol and synthetic jet fuel. Again, a very low GHG intensity of the electricity used to produce synthetic jet fuel is key for the climate benefits provided compared to conventional kerosene.

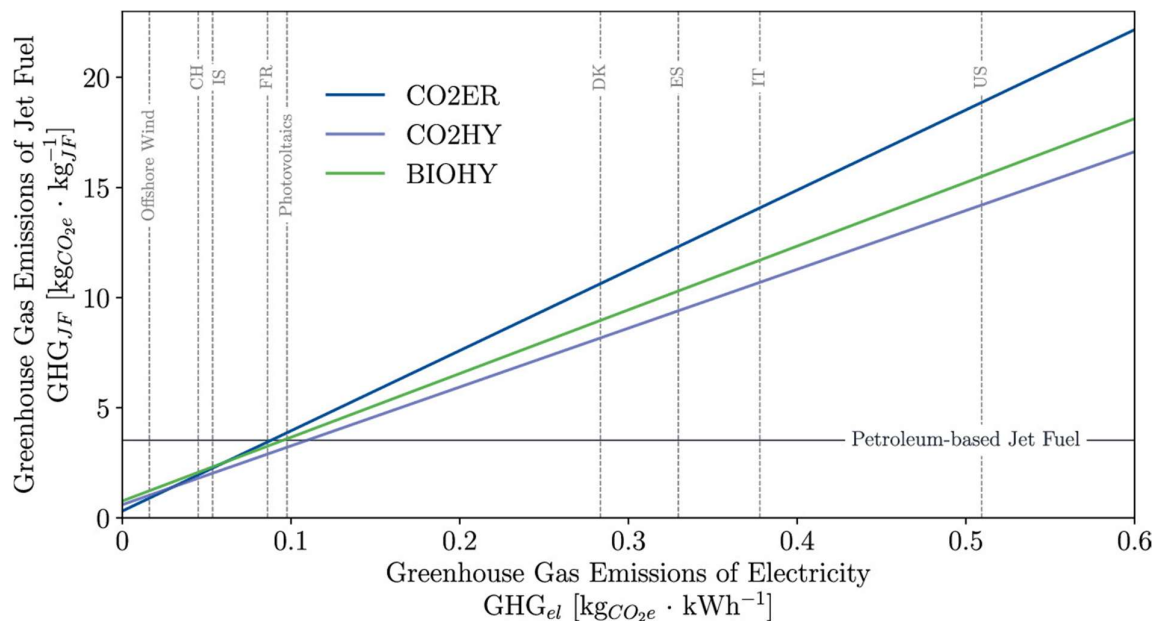


Figure 45: Life cycle GHG emissions of jet fuels, GHG_{JF} , as a function of the carbon intensity of electricity, GHG_{el} , for the three production processes (CO_2ER , CO_2HY , BIOHY) (Saad et al., 2024). Petroleum-based jet fuel GHG emissions are provided as a benchmark (horizontal line). The dashed vertical lines represent the current low-voltage electricity supply in selected countries such as Switzerland (CH), France (FR), Italy (IT), Spain (ES), Denmark (DK), and Iceland (IS), in addition to the carbon intensity of some renewable energy systems (utility-scale photovoltaics and offshore wind turbines in Germany).

Besides synthetic and biomass-based hydrocarbons, ammonia can represent a low-carbon fuel, most often discussed in the context of maritime shipping (Fullerton et al., 2025; Machaj et al., 2022). The Haber-Bosch process, using nitrogen and hydrogen, is the primary ammonia production method. Today, most hydrogen comes from fossil fuel sources, particularly from the steam reforming of natural gas, while nitrogen is taken directly from the air. Currently, SMR supplies hydrogen for more than 70% of global ammonia production, while most of the remainder is made with hydrogen from coal gasification – both processes being associated with substantial CO_2 emissions (Boyce et al., 2024). Low-carbon alternatives include so-called blue, turquoise, and yellow ammonia; blue being associated with adding CCS to fossil feedstock-based production, turquoise with hydrogen from methane pyrolysis, and yellow with hydrogen from water electrolysis.

Figure 46 shows life cycle GHG emissions of ammonia production with different technologies, in different regions, and according to different scenarios up to 2050 (Boyce et al., 2024). Water electrolysis is assumed to be grid-connected and to use average region-specific electricity. The three scenarios differ in terms of the expected development of the global economy, with the most ambitious decarbonization in the 1.5 degree scenario. It shows that if power generation is associated with very low (or even negative) GHG emissions, the ammonia production pathway via water electrolysis exhibits the lowest climate impacts. Also, methane pyrolysis and steam reforming natural gas with CCS can be considered as low-carbon production pathways, especially in the future.

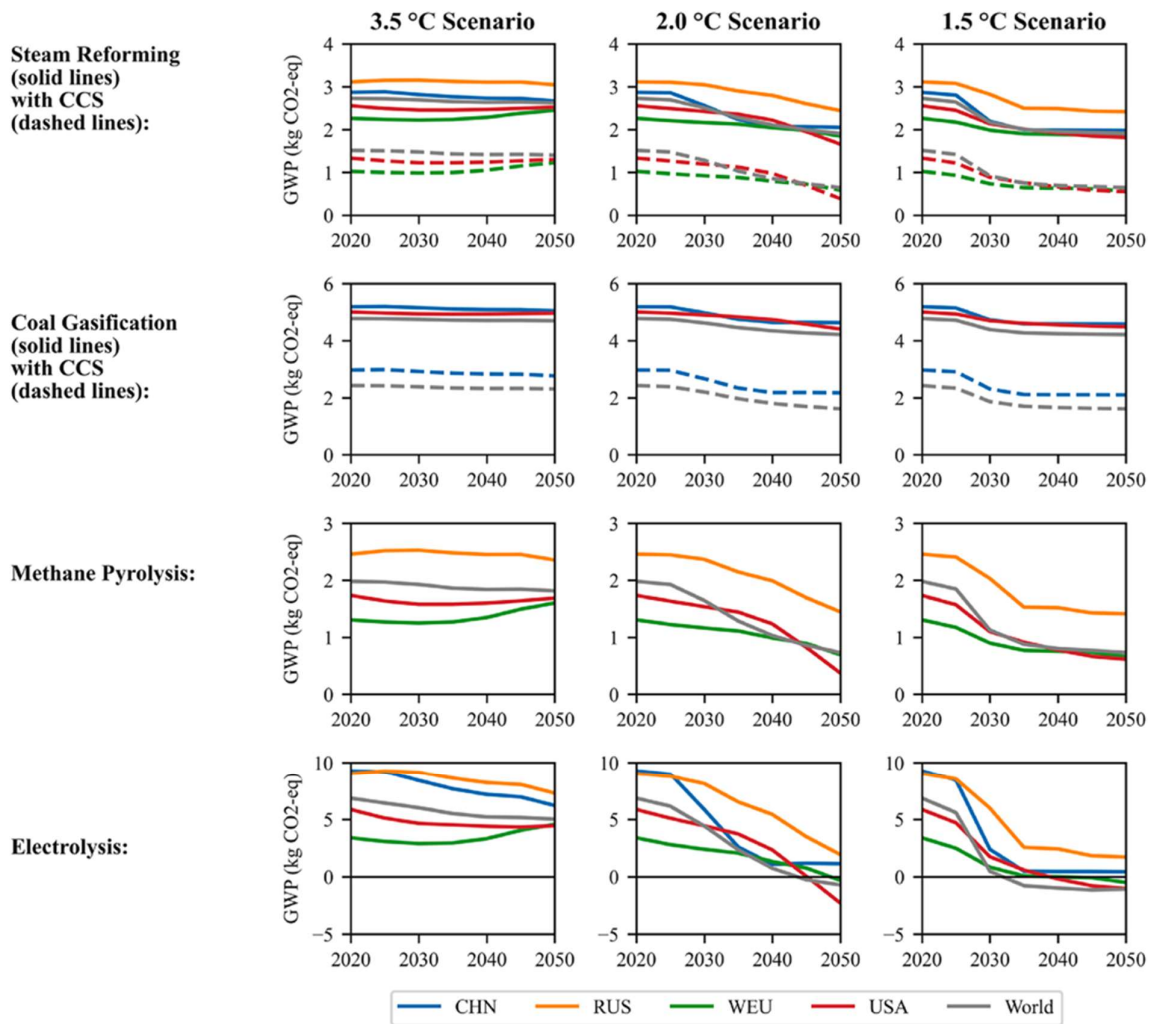


Figure 46: Life cycle GHG emissions of 1 kg ammonia produced per technology, region, and scenario. Negative values occur due to biogenic carbon sequestration (i.e., BECCS) in the background electricity scenarios (Boyce et al., 2024).

Besides ammonia, other LCFs can be used as maritime shipping fuels, for example, methanol and electricity-based liquefied methane. Ships can also be equipped with a CCS unit on board, which is supposed to reduce the GHG emissions of conventional fossil fuel use substantially. Figure 47 shows well-to-wake¹² GHG emissions per 1 GWh of marine propulsion energy using a range of fuels and propulsion technologies in 2050, with contribution breakdown for the main sub-processes (Ingwersen et al., 2025). Most substantial reductions of climate impacts compared to fossil shipping fuels (80-95%) are possible using electricity-based ammonia, e-Fischer-Tropsch fuel, and e-methanol. Carbon capture and storage systems on board do reduce GHG emissions, but only by about 40-60%. A key factor for electricity-based low-carbon fuels is a low-carbon electricity supply for water electrolysis to produce hydrogen as a precursor of these alternative shipping fuels. Here, a low-carbon electricity supply, mostly from renewables, nuclear, and fossil power with CCS, is assumed for 2050.

¹² Life cycle emissions excluding those associated with ship infrastructure production, maintenance, and end-of-life.

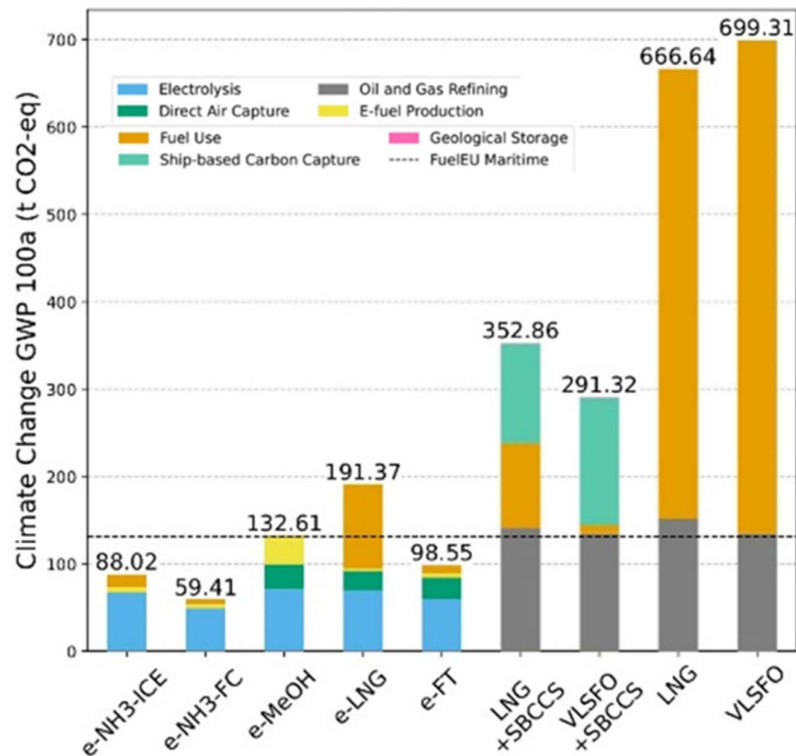


Figure 47: Well-to-wake GHG emissions per 1 GWh of marine propulsion energy using a range of fuels and propulsion technologies in 2050, with contribution breakdown for the main sub-processes (Ingwersen et al., 2025). The horizontal line represents the FuelEU maritime target for 2050. e-NH3-ICE = ammonia via water electrolysis burned in a combustion engine; e-NH3-FC = ammonia via water electrolysis converted in a fuel cell; e-MeOH = methanol via water electrolysis; e-LNG = liquefied methane via water electrolysis; e-FT = Fischer-Tropsch diesel via water electrolysis; LNG = Liquefied Natural Gas; VLSFO = Very Low Sulfur Fuel Oil; SBCCS = integrated ship-based carbon capture system.

Overall, the LCA-based results quantifying the climate impacts of LCF clearly indicate that electricity-based production pathways exhibit the highest potential for reduction of GHG emissions compared to fossil resource-based counterparts for all applications analyzed. And due to comparatively low overall energy efficiencies from primary energy source to LCF end-use, GHG emissions associated with the electricity used in the LCF production processes must be very low. As such, low-carbon electricity is and will further remain a limited resource in the foreseeable future; e-fuels must be used in applications that cannot be directly electrified, also for economic reasons. A categorization of e-fuel use options is shown in Figure 48 (Ueckerdt et al., 2021): Most meaningful e-fuel applications are aviation, maritime shipping, their use as feedstock in industry, and primary steel making due to the fact that direct electrification is impossible in those sectors.

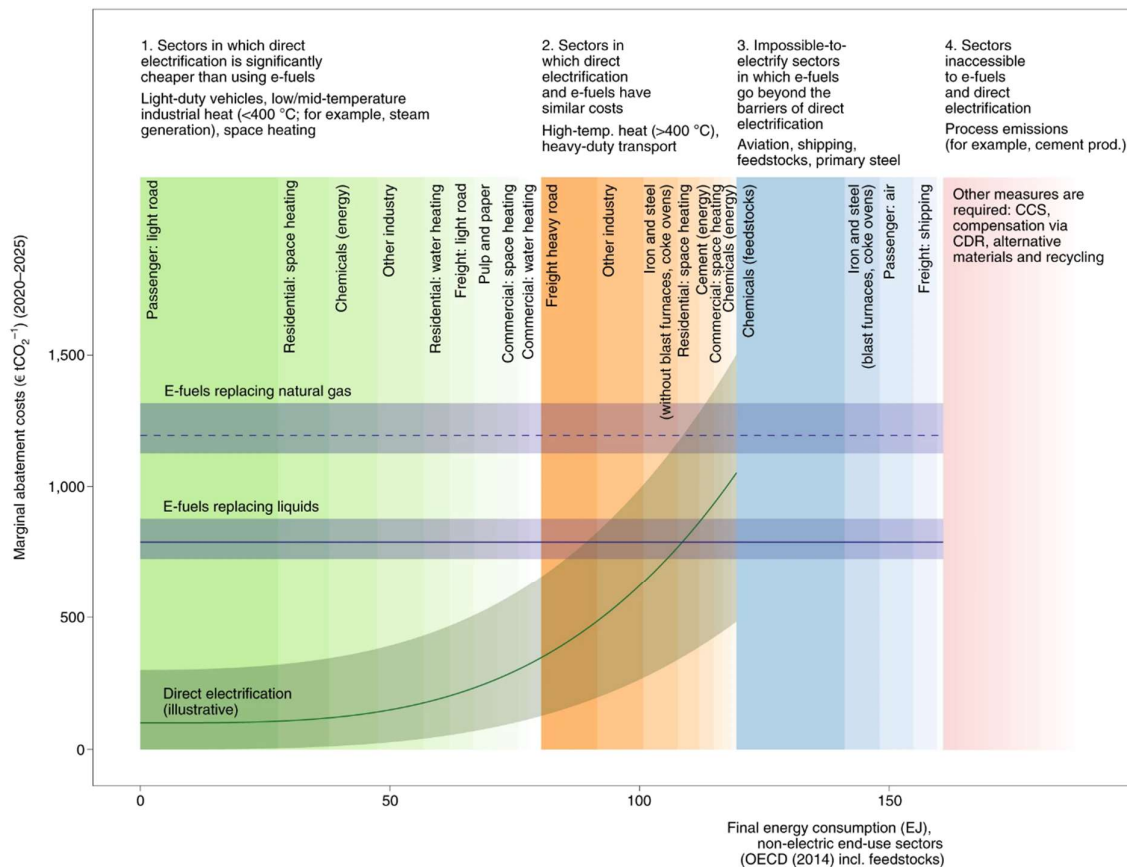


Figure 48: Marginal abatement cost curves (that is, fuel-switching CO₂ prices) and categorization of e-fuel end-use applications from an economic and climate impact perspective (Ueckerdt et al., 2021). The four categories of energy end uses are sorted according to the costs of directly electrifying the respective applications (horizontal sorting from low to high costs of direct electrification). Within each of the four categories, the sectors are sorted according to their size.

In the context of aviation, it is important that not only direct aircraft CO₂ emissions from fossil kerosene combustion determine climate impacts, but also short-lived so-called “non-CO₂ climate impacts” contribute to global warming and have been at least as relevant for global warming as direct aircraft CO₂ emissions in the past, as discussed in e.g. (D. S. Lee et al., 2021, 2023). Electricity-based synthetic jet fuel can substitute crude oil based kerosene and if produced with CO₂ sourced from the atmosphere and electricity for water electrolysis with a very low carbon footprint, it can substantially reduce climate impacts of aviation in two ways: First, aircraft using such synthetic jet fuel would be CO₂-neutral regarding direct CO₂ emissions; further life cycle GHG emissions, for example from aircraft construction and the fuel supply chain, play a minor role (Sacchi et al., 2023). Second, due to a slightly different chemical composition, synthetic jet fuel reduces non-CO₂ climate impacts to some extent. However, the projected growth (around 2% per year globally) of global aviation in the next decades represents a substantial challenge, as synthetic jet fuel production requires massive amounts of resources, and with a growing aviation sector, non-CO₂ climate impacts are likely to still grow despite using synthetic jet fuel.



We have attempted to analyze this for the European aviation sector and different scenarios (Figure 49)

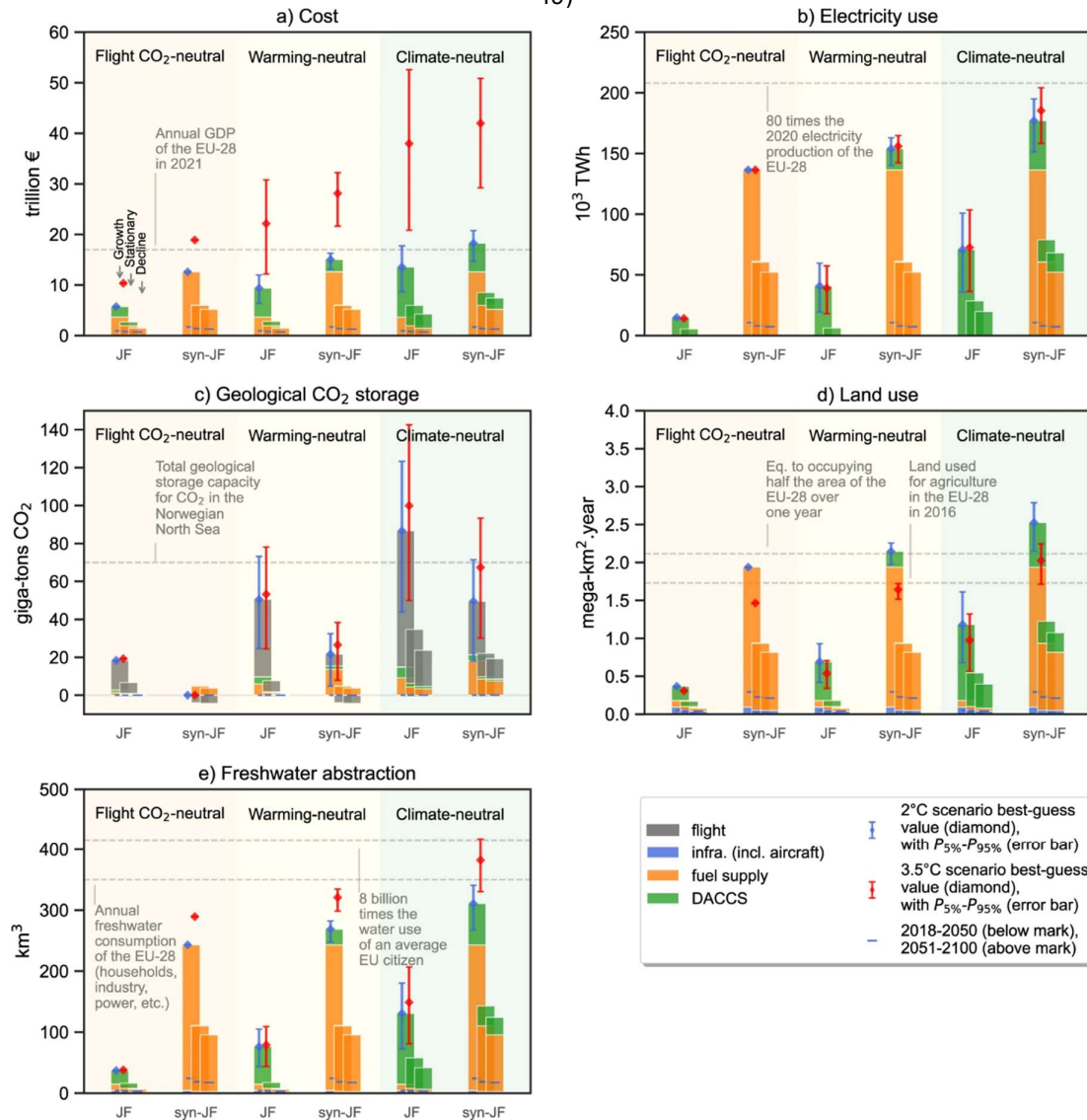


Figure 49(Sacchi et al., 2023): Quantified are costs, electricity consumption, geological CO₂ storage capacities needed, land use, and freshwater consumption – for “flight CO₂-neutral” (i.e., direct aircraft CO₂ emission), “warming neutral” (i.e., inducing no further warming from 2050 on), and “climate neutral” (i.e., no further warming from 2018 on) European aviation; using either fossil kerosene (JF) or electricity-based synthetic jet fuel (syn-JF); and for growing, stationary, or slightly declining aviation demand. CO₂-, warming, or climate-neutrality is achieved by (if needed) direct air capture of CO₂ with geological CO₂ storage (DACCS). As Figure 49 shows, further growing aviation represents a major challenge in terms of costs, electricity, and natural resource demand for an aviation sector in line with European net zero GHG emission (i.e., climate neutrality) goals in both cases, if using fossil kerosene in combination with DACCS to compensate climate impacts and also if using synthetic jet fuel (Sacchi et al., 2023). As these results depend on many assumptions and extrapolate certain developments over a long time horizon, the results should be carefully interpreted and not understood as forecasts, but rather as “what-if” scenarios.

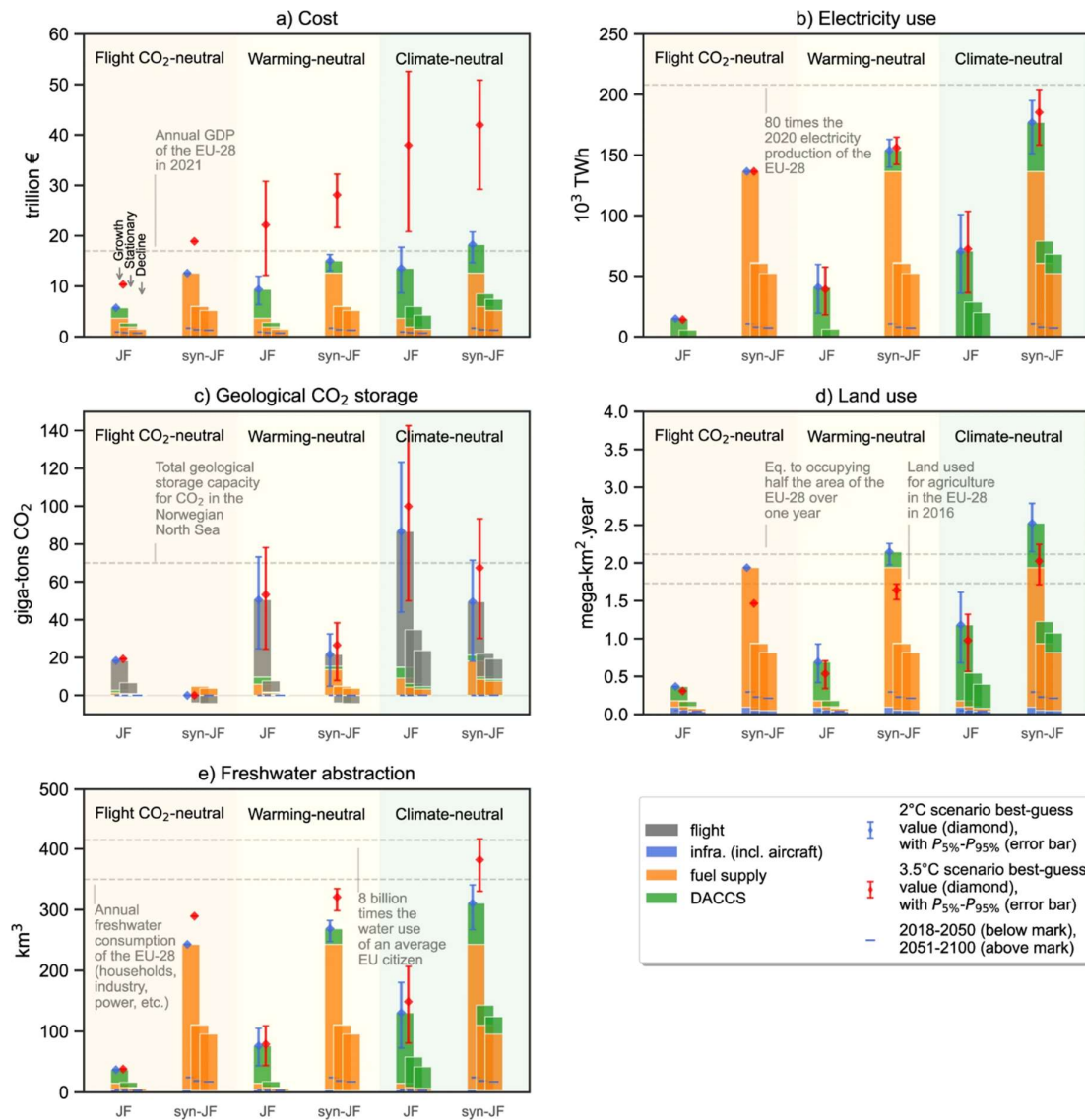


Figure 49: Cumulative resources required to achieve flight-CO₂, warming, and climate-neutrality for a growing (1.8%/a), stationary, and decreasing (0.8%/a for fossil jet fuel use, 0.2%/a for synthetic jet fuel use) European passengers' fleet activity over the 2018–2100 period, using jet fuel and syn-jet fuel complemented by direct air capture and carbon storage (DACCS), considering a 2°C (stacked bars and blue diamonds) and 3.5°C climate scenario (red diamonds) (Sacchi et al., 2023). Assumed yearly decrease of the fuel burn rate (in litres of jet fuel per passenger per km) of 1.2% between 2018 and 2050, with no further improvement afterwards.



4 Synfuels in Switzerland and the EU

The role of synfuels in the Swiss energy transition is assessed with a multi-regional European energy system model with Switzerland as one region. The model includes international aviation demand with a suite of different aircraft technologies and the supply of synthetic fuel. We analyse a net-zero scenario by 2050 and include the emissions from international aviation (non-CO₂ climate impacts excluded). In section 4.1, an outline of the modelling tool is provided. Section 4.2 provides insights from the analysis covering energy supply, emissions, and technology pathways.

4.1 Methods

A key task within this project was modelling the international aviation sector in the Swiss energy system. The Swiss TIMES energy system model (STEM) provides a detailed representation of the entire energy sector with full sector coupling. Although we developed the aviation sector within STEM, we found that it was not very insightful for assessing the aviation sector, particularly with the endogenous choice of aircraft.

While the aviation sector involves different market segments in terms of distance (domestic, inter-Europe, and intra-Europe), modelling this within a Swiss energy system model is challenging. Although the STEM model offers high intra-annual time resolution and detailed technology representation, it has limitations in modelling different aircraft sizes for various market segments. Therefore, we use the European energy system model to better represent different aviation demand scenarios by enhancing the aviation sector in the European model. For this project, we used the JRC-EU-TIMES model. While the EU model offers insight on energy exchange with the EU, a limitation of using a European model for Swiss policy analysis is the potential for sub-optimal solutions in smaller regions when compared to the rest of the EU countries (see limitations in section 4.1.5).

The modelling details, along with key technology representation, are outlined in the section 4.1.1. A detailed description and assumption of the model are included in the Annex. We assess net-zero scenarios, which are described in the section 4.1.4. The analytical results are presented and discussed in the section 4.2 and the discussion is focused on answering the key questions.

4.1.1. JRC-EU-TIMES model

The JRC-EU-TIMES energy systems model (EU, 2020) is an open-source (Nijs & Ruiz, 2019), bottom-up, partial equilibrium framework that minimises the total energy system cost. It is based on the TIMES model generator from the ETSAP Technology Collaboration Programme of the International Energy Agency, which combines a detailed technology specification with an optimisation approach. The model considers both the energy supply and demand side.

The model includes the following sectors:

- **Resources:** primary energy supply and cross-border trades
- **Energy conversion:** electricity generation, production of biofuels, hydrogen, synthetic fuels, as well as refineries.
- **End-use sector:** industry, residential, commercial, agriculture, and transport

JRC-EU-TIMES covers the energy sector's major greenhouse gas (GHG) emissions and related mitigation measures. The model solves for the cost-optimum investment portfolio of technologies and measures for the entire period (2020-2050), including supply chains, while fulfilling the energy-services demand. This implies simultaneously deciding on investments and operations, primary energy supply, and energy trade.



Regional scope

JRC-EU-TIMES includes 36 regions, each representing a country interconnected by energy and emissions flows as well as trade:

EU countries: Austria, Belgium, Bulgaria, Croatia, Cyprus, Czech Republic, Germany, Denmark, Estonia, Spain, Finland, France, Greece, Hungary, Ireland, Italy, Lithuania, Luxembourg, Latvia, Malta, the Netherlands, Poland, Portugal, Romania, Sweden, Slovenia, and Slovakia.

Non-EU countries: The United Kingdom, Switzerland, Iceland, Norway, Albania, Bosnia and Herzegovina, the Former Yugoslav Republic of Macedonia, Montenegro, and Serbia.

Through the endogenous trade of energy carriers and certificates, along with policy simulations, JRC-EU-TIMES captures the interdependencies between the energy systems of the modelled countries.

Time Horizon and Optimization: The model has a time horizon from 2015 to 2050, with optimization accounting for both annual and sub-annual operations. For every five-year time step (e.g., 2020, 2025, etc.), the model generates annual outputs from 2020 to 2050. Each year is divided into 12 intra-annual time slices, representing average day, night, and peak demand for each of the four seasons (e.g., summer day, summer night, summer peak, etc.).

Key Model Outputs: The most relevant outputs of JRC-EU-TIMES include annual technology stock and activity of energy supply and demand technologies for each region and period; energy and material flows, including emissions to air and fuel consumption, detailed for each energy carrier; economic outputs, such as operation and maintenance costs, investment costs for new technologies, and energy/material commodity prices (including emission prices if an emission cap is considered) for every time step.

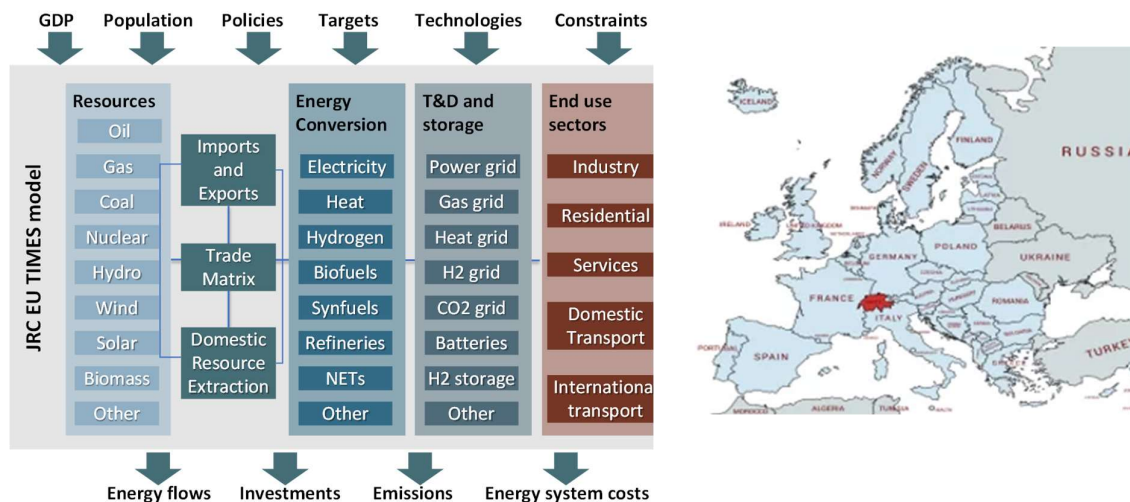


Figure 50: Sectoral coverage of the JRC-EU-TIMES model.

Policy Measures and Applications: JRC-EU-TIMES enables the analysis of various policy measures and packages, including:

- Eco-design and labelling regulations
- Efficiency and emission standards for buildings and vehicles
- Emissions Trading System (ETS) caps and national quota
- Renewable energy and biofuel targets and support mechanisms
- GHG effort-sharing policies
- Taxes, subsidies, and feed-in tariffs by technology or sector



- Emission ceilings per pollutant
- Research, Development, and Demonstration (R&D&D) support
- Green certificates
- Resource management policies, including water management and geological CO₂ storage
- Nuclear and coal phase-out policies
- Trade regulations on electricity and other energy carriers
- Energy security and market liberalisation policies

This model serves as a robust analytical tool for evaluating energy system transformations, emission reductions, and policy impacts across Europe and neighbouring regions.

4.1.2. Modelling of synfuel technologies

While the technology assessment, detailed in the section 2, covers a wide range of technologies, the JRC-EU-TIMES model has an aggregated representation of all broader categories of the synthetic fuel production technologies. The technologies represented in the JRC-EU-TIMES model and the assessment are mapped in Table 5.

Table 5: Mapping of details regarding the techno-economic characterization in the JRC-EU-TIMES model.

Fuel Type	LCF category	Feedstock	Technology Acronyms	Technology full names	TRL
Hydrogen	Green Hydrogen	Water, Renewable electricity	PEM	Proton exchange membrane electrolysis	8-9
	Green Hydrogen	Water, Renewable electricity	AE	Alkali electrolysis	8-9
	Green Hydrogen	Water, Renewable electricity	SOEC	Solid oxide electrolysis cell	6-7
	Pink Hydrogen	Nuclear Electricity/Heat	HTSE	high-temperature steam electrolysis	5-8
	H ₂ production				
	Blue Hydrogen	Natural gas	SMR+CCS	Steam methane reforming with CCS	8-9
	Blue Hydrogen	Natural gas	ATR+CCS	Autothermal reforming with CCS	8-9
					6-7
					4-6
	Biofuel/Green Hydrogen	Biomass/Fossil waste	BG+CCS	Biomass gasification with CCS	4-6
Synfuels	Solar Fuel	Solar, CO ₂ , Hydrogen	ST-FT	Pure solar thermochemical FT	4-6
	BioFT fuel	Lignocellulosic biomass/organic waste, Hydrogen	BG-FT	Biomass gasification FT	6-8
	Power to X	Hydrogen, CO ₂ , Renewable electricity	RWGS-FT	Reverse water gas shift FT	6-8
	Power to X	Hydrogen, CO ₂ , Renewable electricity	RWGS-MeOH	Reverse water gas shift MeOH	6-8
	Biofuel	Lignocellulosic biomass/organic waste, Hydrogen	FAME	Esterification	8-9
Biofuels	Other BTL	Biofuel	HVO	Hydrotreating	6-8
	Biofuel	Vegetable oils/waste cooking oils/animal fats	PYR	Biomass pyrolysis and hydroprocessing	4-6
	Biofuel	Vegetable oils/waste cooking oils/animal fats	PTM	Power to Methane	7-9
	Methane production	Hydrogen, CO ₂ , Renewable electricity			7-9
	Ammonia production	Ammonia	HB	Habor Bosch	8-9

4.1.3. Modelling of the aviation sector

Within this project, the aviation sector in the model was comprehensively overhauled and updated to include new aviation demand categories and a wide range of aircraft technologies. The model covers both personal and freight transport demands, featuring more than 25 types of aircraft serving for domestic, continental, and intercontinental flying ranges. In the JRC-EU-TIMES model, we include three categories of aviation market segments for personal and freight transport demands:

- Domestic: Flights within the country (including within Switzerland and other European countries).
- Intra-EU: Flights between two different European countries or between Switzerland and European countries (continental flights).
- Extra-EU: Flights between European and non-European countries or between Switzerland and non-European countries (intercontinental flights)

A mapping of different market segments, aircraft ranges, and types, along with details on their emissions and SAF blending, is provided in the Annex (see Figure 100).



The total aviation demand in Switzerland is expected to increase from 18 billion km in 2019 to 22 billion km by 2050 (EASA, 2024; EUROCONTROL, 2024). Figure 101 shows the development of the aviation demand by demand category. The intercontinental demand accounts for two-thirds of the demand. While the growth in intercontinental aviation is subtle (18% between 2019 and 2050), there is a significant growth in continental (intra-EU) demand (+33% between 2019 and 2050). The aviation demand assumption of other countries in Europe is given in the annex (see Figure 101).

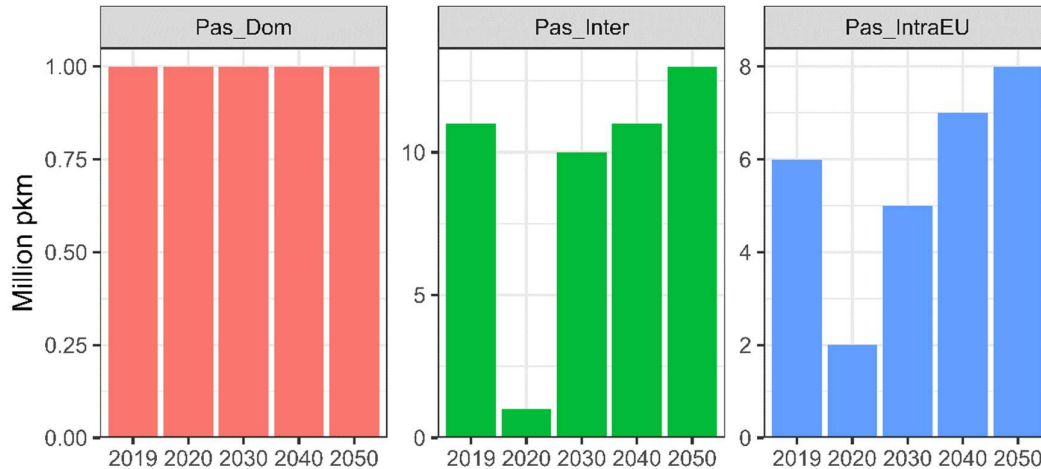


Figure 51: Development of Swiss aviation demand by modes.

The aircraft are broadly categorised into:

- conventional aircraft that use jet fuel (or SAF) for all flying ranges
- hydrogen fuel cell aircraft (for domestic and intercontinental EU flights)
- hybrid-electric aircraft (HEA)
- electric aircraft (for domestic and intra-continental EU flights).

Based on (ATAG, 2021) and (Der Bundesrat, 2024), we assume aircraft types under different categories. Table 6 adapted from ATAG (2021), outlines the aircraft types included in the model, their range classifications, and projected developments over the modelling horizon through 2050.



Table 6: Type of aircraft technology by fuel type and flying range (adapted from (ATAC 2021) and (Der Bundesrat 2024)).

	2020	2025	2030	2035	2040	2045	2050
Commuter » 9-19 seats » < 60 minute flights » <1% of industry CO ₂	SAF	Electric or Hydrogen fuel cell and/or SAF	Electric or Hydrogen fuel cell and/or SAF	Electric or Hydrogen fuel cell and/or SAF	Electric or Hydrogen fuel cell and/or SAF	Electric or Hydrogen fuel cell and/or SAF	Electric or Hydrogen fuel cell and/or SAF
Regional » 50-100 seats » 30-90 minute flights » ~3% of industry CO ₂	SAF	SAF	Electric or Hydrogen fuel cell and/or SAF	Electric or Hydrogen fuel cell and/or SAF	Electric or Hydrogen fuel cell and/or SAF	Electric or Hydrogen fuel cell and/or SAF	Electric or Hydrogen fuel cell and/or SAF
Short haul » 100-150 seats » 45-120 minute flights » ~24% of industry CO ₂	SAF	SAF	SAF	SAF potentially some Hydrogen	Hydrogen and/or SAF	Hydrogen and/or SAF	Hydrogen and/or SAF
Medium haul » 100-250 seats » 60-150 minute flights » ~43% of industry CO ₂	SAF	SAF	SAF	SAF	SAF potentially some Hydrogen	SAF potentially some Hydrogen	SAF potentially some Hydrogen
Long haul » 250+ seats » 150 minute + flights » ~30% of industry CO ₂	SAF	SAF	SAF	SAF	SAF	SAF	SAF

4.1.4.Scenario definition

The focus of the scenario analysis is to first assess the technology pathways to achieve net-zero emissions by 2050. The ultimate objective is to quantify the role of low-carbon and synthetic fuels in the Swiss energy system (and in Europe). While we have numerous energy scenarios (JASM, 2023; Panos et al., 2023b), in this project, we limit our results and discussion to answering the two specific questions:

- What is the role of low-carbon and synthetic fuels in the Swiss energy system to meet the net-zero emission goals?
- Which transportation modes (and other economic sectors) will have to rely (partially) on chemical fuels due to the lack of direct electrification options?

The net-zero goal in the model is implemented as a CO₂ cap for the EU and Switzerland, as outlined in the section 4.1.1. It is also worth noting that within EU member states, the announced national emissions reduction targets, including the year of achieving net-zero emissions, are also implemented. The scenarios are fully described in (Panos et al., 2024). Besides the CO₂ target, all available energy policies are implemented at the regional or national level. Other policies are energy efficiency measures as foreseen in the Energy Efficiency Directive, building performance standards, vehicle emission standards, technology-specific policies such as nuclear and coal phase-out, renewable energy targets, and so on. Similar to the EU, all policies and targets for Switzerland are included, such as the CO₂ law, participation in the EU-ETS, the Energy Act, renewable energy subsidies, vehicle emission and building performance standards, electricity grid expansion plans, etc. A summary of the EU and Swiss policies implemented in the scenario is shown in Table 7.



Table 7: List of policies included in the scenario in the EU and Swiss regions.

Scenario	EU-27	Switzerland
BAU (policies in the legislation until 1.1.2024)	- EED energy efficiency (EU2023/1791) - EPBD buildings performance standards (EU2018/844) - ETS (all revisions up to EU2023/959) - EU RED III renewable targets (up to EU2023/2413) - GHG effort sharing (up to EU2023/857) Vehicle emissions standards (EU2019/631, EU2023/851) Heavy vehicle emissions standards (EU2019/1242) - Coal phase out 2030 in DE, DK, FI, GR, HU, IE, IT, NL, PT, SI, SK, ES Intra-EEA aviation in EU-ETS - NTC electricity capacities as in ENTSO-E TYNDP 2022 plan - Reduction of nuclear share in France - New nuclear plants those under construction/advanced planning	- Lifetime of existing reactors 60yrs; no new reactors - Swiss ETS coupled with the EU-ETS Intra-EEA flights covered by the EU-ETS - SR 730.00 Energy Act (EnG) as of 1.1.2024 - SR 730.03 EnFV renewable subsidies as in 1.1.2024 - Buildings programme HFM 2015 - SR 641.71 CO2 Gesetz SR 641.61 MinStG fossil fuel taxes SR 641.81 on PSVA and LSVA for heavy vehicles - MuKen 2014 buildings performance standards - Electricity grid expansion plans of Swissgrid 2025 network
CLI (net-zero target scenario)	- GHG emissions from 1990: -55% in 2030, -90% in 2040 - Net-Zero GHG emissions in 2050 at the EU-level - Individual net-zero GHG emissions targets of the member states - GHG emissions reduction scope as in the EU Climate Law - includes LULUCF and 50% of the international transport Refuel aviation SAF mandates - EU-ETS-2 from 2030 (although incl. in 2023 revision of EU-ETS) + 8GW new nuclear power (BG, CZ, RO, SI, SK, FI, FR)	- GHG reductions from 1990: -35% in 2030 (domestic) - Net-Zero GHG emissions in 2050 - KiG sectoral emissions reduction targets - GHG emissions reduction scope includes LULUCF Carbon neutral international aviation - Mantelerlass targets for renewables & security of supply - Solarexpress and Windexpress - Energy savings targets (per capita consumption)

4.1.5. Model limitations

As a data-driven model, the main uncertainties are associated with the development of the techno-economic characterisation of technologies. We have made our efforts to have the best and latest data available and included. Since this analysis is based on an EU model, Switzerland may be operating under suboptimal conditions due to the significantly larger European market. Nevertheless, the analysis provides valuable insights and helps trace the origin of imported fuels—an aspect often overlooked in national models, which typically assume that low- or zero-carbon fuels can be imported without specifying their source or accounting for any limits in their availability, while usually the import price assumptions are not consistent with the context of the study in which they are used.

As a partial equilibrium model, JRC-EU-TIMES does not model economic interactions outside the energy sector. Additionally, it does not explicitly capture the mathematical formulation underlying demand curve functions or non-rational investment decisions in new and more efficient technologies. These aspects must be accounted for in the future through exogenous constraints representing non-rational decision-making.

4.2 Analytical results

As an energy system model, we cover almost all supply and end-use sectors of the European energy system. However, in this report, we limit the analytical results to developments in the aviation sector concerning energy use and emissions, the Swiss transport sector, and the overarching role of synthetic (bio)fuels in the Swiss energy system. Additional insights from a European perspective are included in the annex.

4.2.1. Development of the Swiss transport sector

Figure 52 presents the overall trend in final energy consumption in Switzerland's transport sector. The left panel displays total transport fuel consumption, including international aviation, while the right plot breaks down fuel usage by transportation type. Currently, transport fuel is predominantly fossil-based, with a small share of electricity and biofuel. Electricity is primarily used in railways, while fuel-blending mandates drive current biofuel demand. As the transition to a net-zero energy system progresses, fossil fuels are gradually replaced by electricity and bio- and synthetic fuels. The origins and primary sources of bio/synfuels are discussed in the subsection 4.2.3.

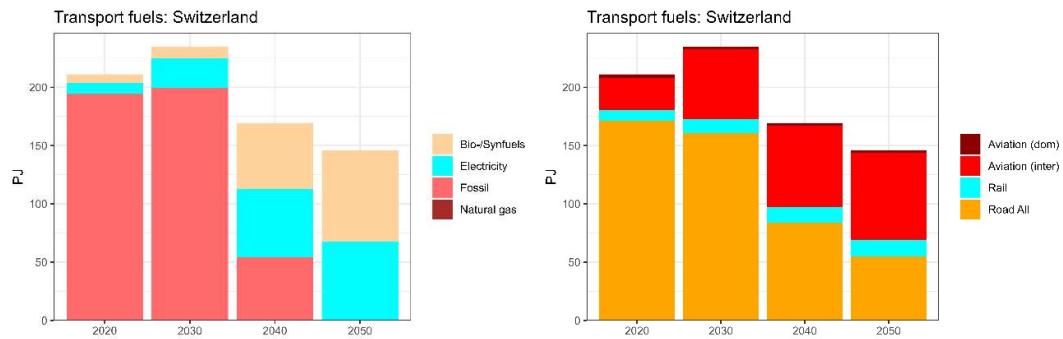


Figure 52: Final energy consumption in the Swiss transport sector (including international aviation), shown by fuel type (left) and by transport mode (right).

The aviation sector primarily relies on bio- or synthetic fuels to decarbonize, whereas road transport is highly electrified. Despite the increasing demand for personal mobility and freight transportation, overall energy demand in the transport sector is declining due to electrification, as electric vehicles are far more efficient than vehicles powered by ICEs. The breakdown of road transport fuel by fleet is shown in Figure 53 and should not be misinterpreted as a vehicle fleet composition, given the differing efficiencies of the drivetrains. The vehicle fleet composition is further detailed in Figure 54.

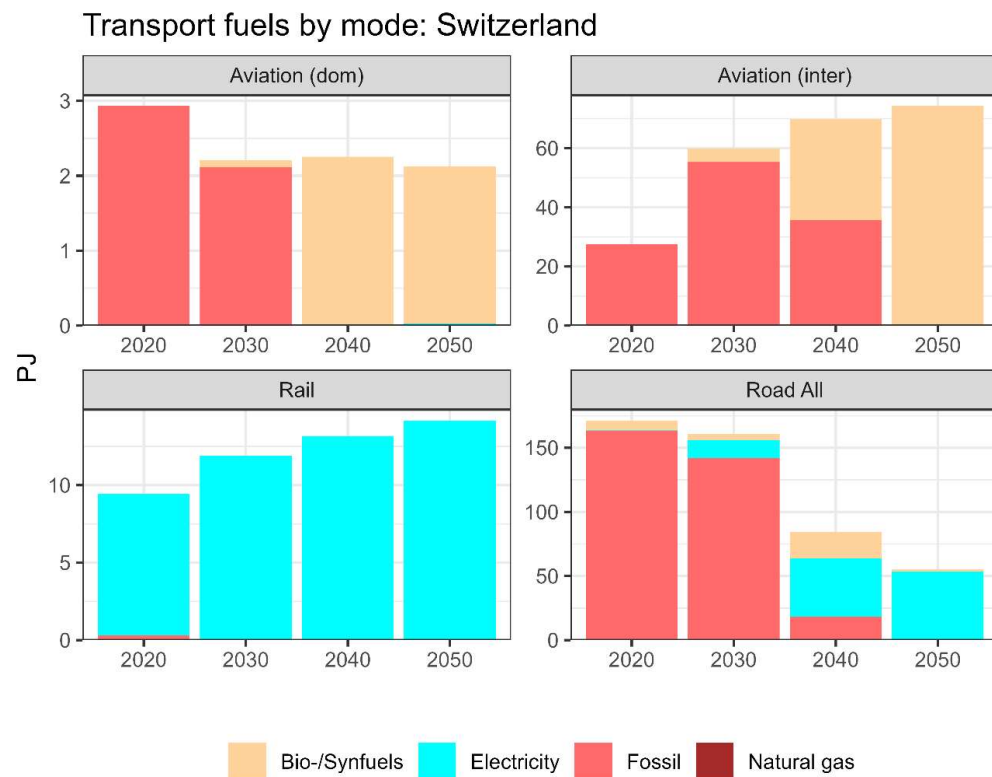


Figure 53: Final energy consumption of the Swiss transport sector by modes.

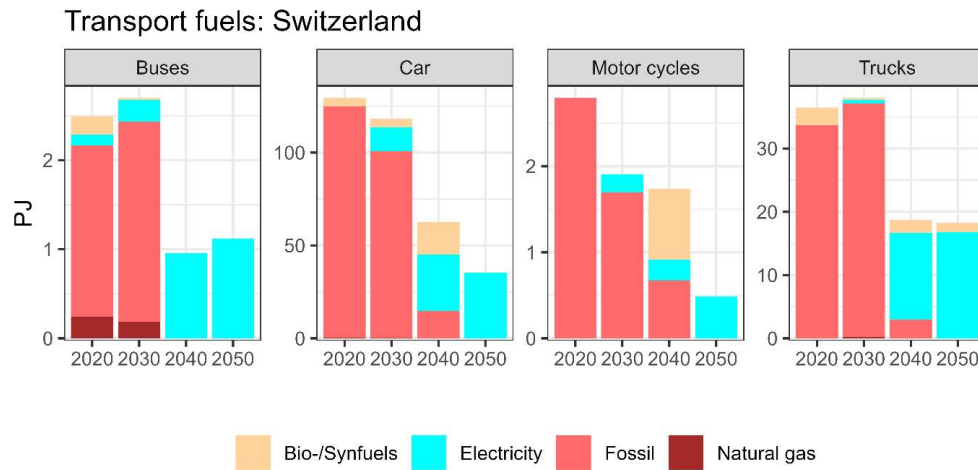


Figure 54: Road transport fuel consumption by modes in Switzerland.

Figure 54 illustrates the composition of road transport by vehicle type. In the car segment, ICE-based gasoline and diesel cars are gradually replaced by electric vehicles. By 2050, the entire Swiss car fleet will be electrified. The bus fleet undergoes rapid electrification, partly driven by stricter emission standards and the exceptionally high efficiency of electric buses in urban driving conditions. As a result, fuel demand for buses decreases substantially during the early transition period. In the truck segment, the electrification of light-duty trucks (Truck LGV in Figure 55) accelerates in the mid-term, outpacing the transition of heavy-duty trucks. By 2050, the entire LGV fleet is electrified, while some heavy-duty vehicles (HGV) retain ICE technology due to stock turnover from the 2040 period. Consequently, ICE trucks continue to operate but run on bio-/synthetic fuels.

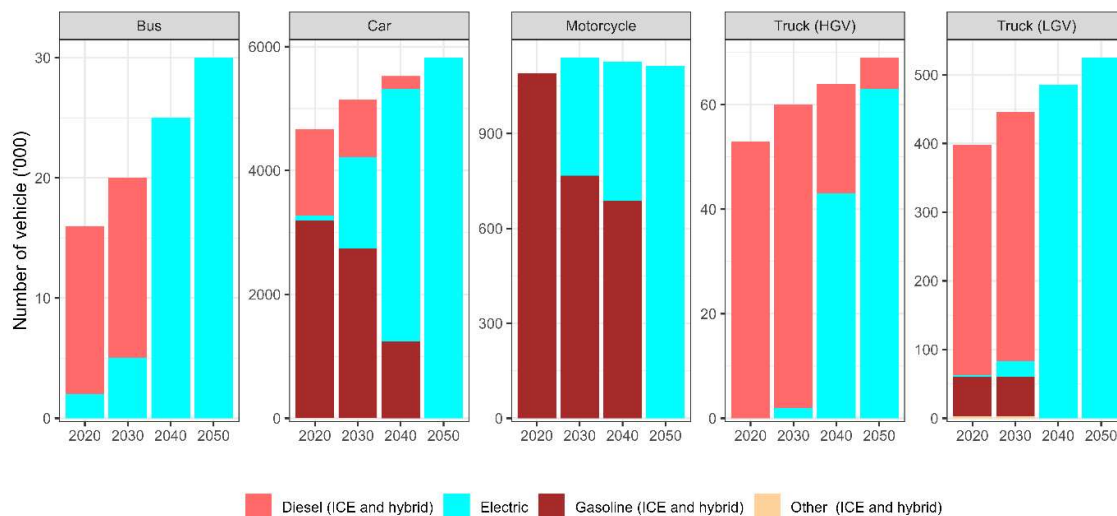


Figure 55: Evolution of the Swiss road transport fleet by vehicle drivetrain. The figure presents total stock per drivetrain category, and diesel ICE and hybrid vehicles transition to biofuel operation by 2050.

4.2.2. Fuel demand for the aviation sector

We present the development of aviation fuel demand till 2050 in Figure 56. As the aviation demand recovers from COVID 2019, the energy demand also increases. Biogenic and synthetic fuels begin to penetrate from 2030, and by 2050, the sector is fully decarbonised with biogenic and synthetic aviation fuels. The shift towards clean fuel in the early period is driven by the blending mandate (see Figure 102)



and later by the climate mitigation target. In terms of aircraft technology, mid-range aircraft transitioned to low-carbon jet fuel at a faster rate than long-range aircraft in the early period.

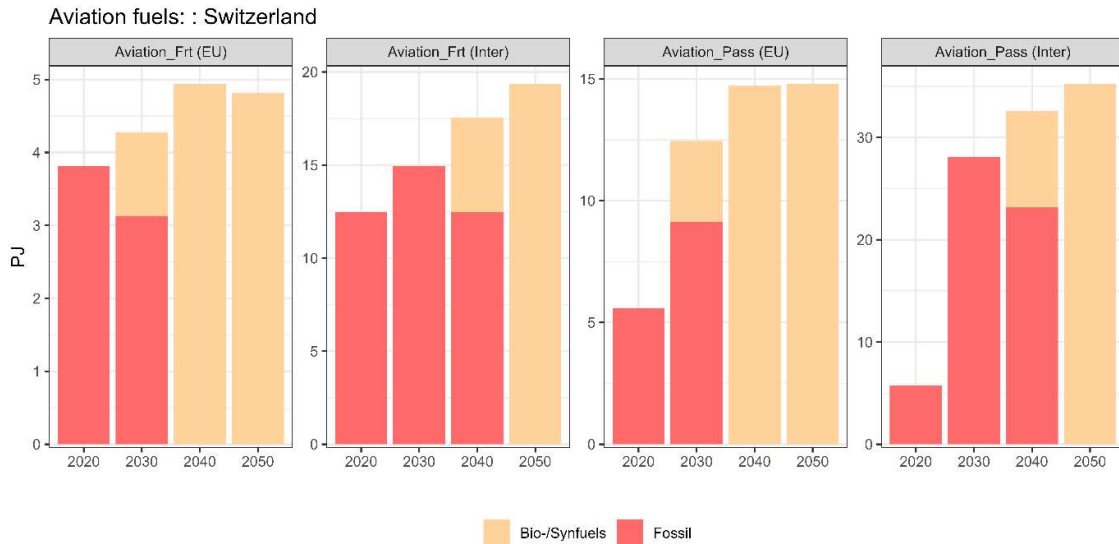


Figure 56: Aviation fuel demand in Switzerland by flight mode. “EU” represents intra-European flights, while “Inter” refers to international or intercontinental flights.

The insights from the aviation demand scenario variant are self-explanatory: higher demand leads to increased fuel consumption, and vice versa. However, to fully understand the impact on the energy system, one must also consider the supply side. Given that Swiss aviation relies heavily on imported jet fuel and synthetic aviation fuel, a higher demand is primarily met through increased fuel imports (see Figure 58).

4.2.3. Role of synthetic fuels beyond aviation

As seen in the transport sector, the international aviation sector is the primary demand driver for bio- and synthetic fuels, followed by a small quantity in the truck fleet. Additionally, they are used in other end-use sectors. Figure 57 illustrates the supply and demand of these fuels within the Swiss energy system (aviation excluded). In 2020, nonconventional fuels accounted for less than 1% of the Swiss end-use sector. However, the role of biogenic and electricity-based synthetic fuels is projected to grow from the current level of 8 PJ to 24 PJ by 2050. As decarbonization targets become more stringent, the industrial sector shifts away from fossil fuels, increasing demand for these alternative fuels.

In the mid-term, the transport sector consumes most of the bio- and synthetic fuels as a transitional solution to replace diesel and gasoline vehicles. In the long run, however, the industrial sector increasingly utilizes biofuels for heat and electricity production. Meanwhile, the services and residential sectors, to some extent, adopt synthetic methane for building heating as a substitute for natural gas. However, in relative terms and compared to the overall Swiss energy demand, these synthetic fuels remain at very low levels because, in the building sector, they are primarily used for heating systems where existing (stranded) assets must be utilized or where other constraints limit electrification.

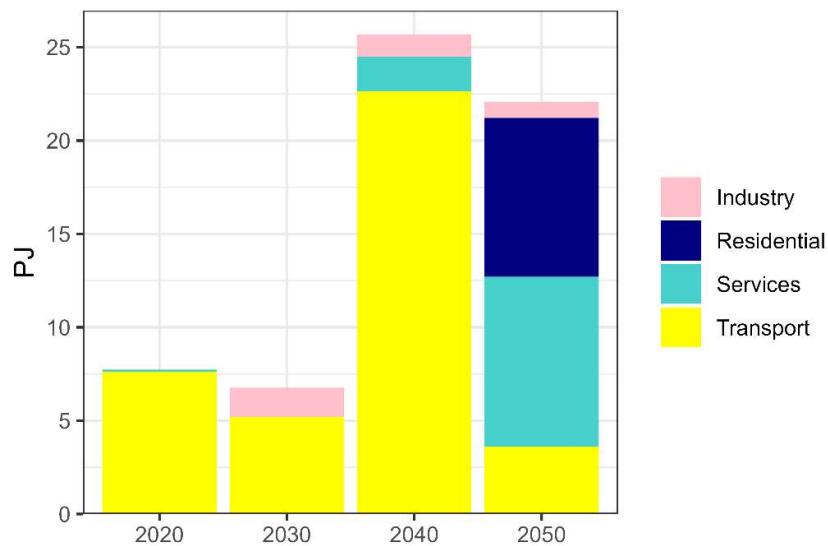


Figure 57: Synthetic and biogenic fuels supply and demand in Switzerland (aviation excluded).

As far as the source of bio-/synthetic fuel in Switzerland is concerned, by 2050, about 12 PJ would be domestically produced, while demand is expected to reach approximately 24 PJ in addition to the SAF demand of the aviation sector. The remaining supply will be met through imports. Figure 58 illustrates the domestic production and imported supply of hydrogen, bio-, and synthetic fuels. The primary sources of bio- and synthetic fuel in Switzerland are biogas and biofuel. Biofuel production is expected to become cost-effective by 2040, although it will remain constrained by feedstock limitations. Synthetic gas production, driven primarily by renewable electricity generation, is projected to become cost-effective from 2050 on. In addition to domestic synthetic fuel production, Switzerland will heavily rely on imports, mainly to meet aviation fuel demand (see Figure 58). As for the sources of imports, Figure 59 shows the overall production of biofuels and synthetic fuels across Europe. It is also worth noting that Europe as a whole imports biofuels.

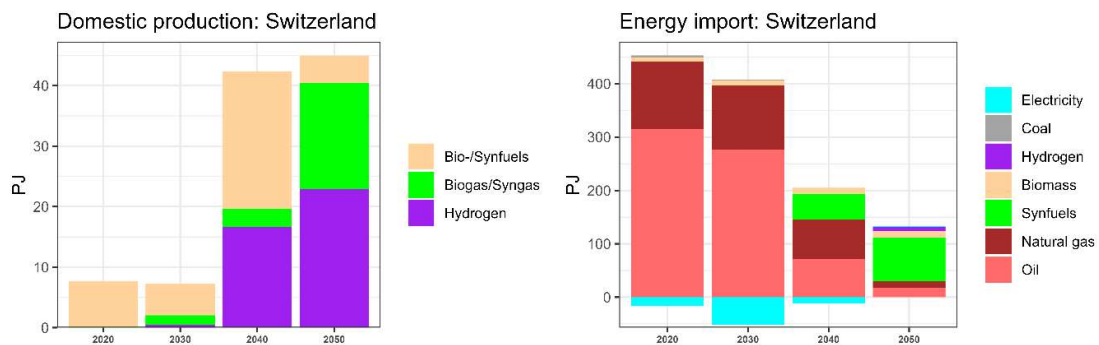


Figure 58: Sources of hydrogen, bio- and synfuel (domestic, left; imported, right) used in Switzerland (including aviation).

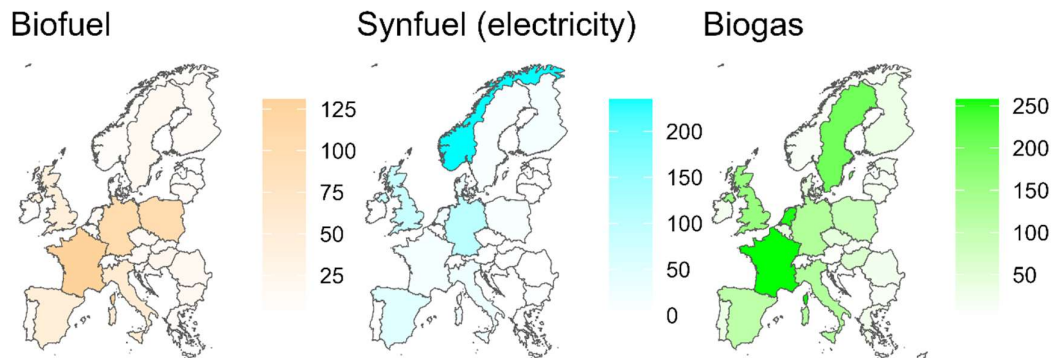


Figure 59: Bio- and synfuel production in PJ across Europe in the year 2050.

4.2.4. Electricity supply CO₂ emission trajectory

Today, the Swiss electricity system is primarily powered by nuclear and hydropower. However, following the nuclear phase-out, nearly all nuclear capacity has been replaced by renewable energy sources. Figure 110 illustrates the transition in the electricity supply sector. As shown, solar and wind become the dominant sources of electricity, while hydropower remains stable. Additionally, electricity supply from biomass is crucial, as biomass with carbon capture and storage (CCS) delivers negative emissions, thereby contributing to climate mitigation efforts.

In 2050, about one-third of domestically produced bio-/synthetic fuel is synthetic gas. On the one hand, there is a pull effect on synthetic gas production from the demand side to meet stringent net-zero goals. At the same time, strong renewable-based electricity generation drives a push toward synthetic gas production.

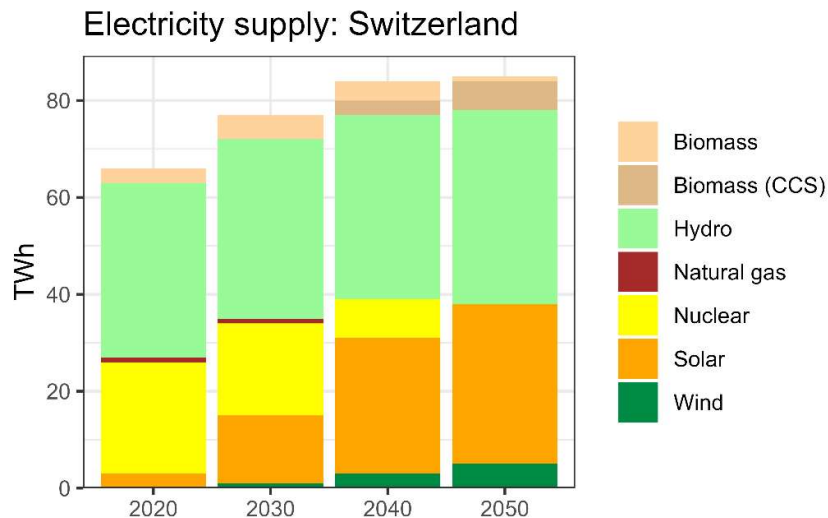


Figure 60: Swiss electricity supply.

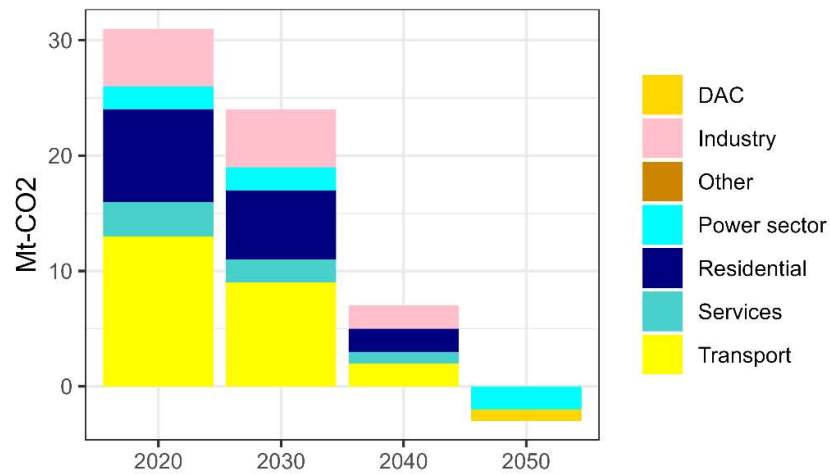


Figure 61: Swiss CO₂ emission trajectory by sectors (without aviation).

Figure 61 shows the CO₂ emission trajectory, without aviation. The transition of the Swiss energy system to net-zero is primarily driven by the decarbonization of end-use sectors through accelerated electrification. Limited biomass resources are primarily allocated to the electricity sector, where they are used with CCS to generate negative-emission credits, helping to offset emissions from some end-use sectors. In this context, biogenic and synthetic fuels play a minor role. However, the high share of renewable power generation increases the need for synthetic gas production, which, in turn, supports decarbonization in end-use sectors. The inclusion of international aviation results in higher carbon prices, which, in turn, enable the deployment of more expensive mitigation measures.

4.2.5. Sensitivity analysis: Aviation demand scenarios and associated electricity supply, energy imports, and hydrogen production

While the results presented so far focus on the *Base* scenario, we also performed sensitivity analyses on aviation demand across Europe. Figure 62 illustrates the key developments in aviation fuel consumption, electricity generation, and hydrogen production. As expected, aviation fuel demand increases proportionally to higher aviation activity. The additional aviation fuel requirements are predominantly met through imported synthetic fuels (bottom-left panel in Figure 62). Consequently, the system imports slightly more electricity to satisfy the overall import constraint. However, due to limits on imported fuels, the high-demand scenario shows a marginal change in domestic electricity supply. Specifically, a small shift from solar PV to wind power is observed, which ultimately reduces the need for hydrogen production under high aviation demand. This effect arises because a large share of hydrogen production in the base system is driven by the need to store surplus solar PV through seasonal storage.

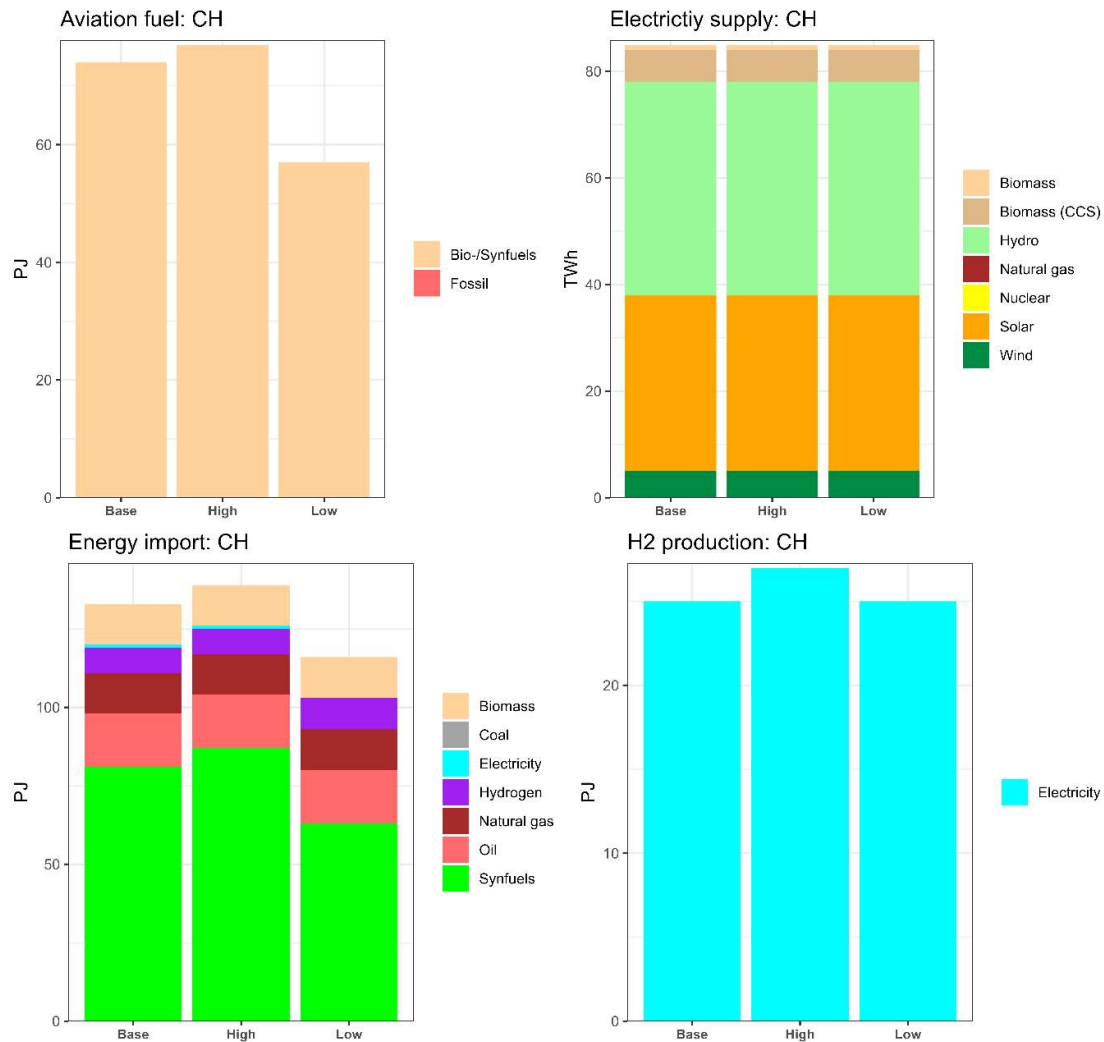


Figure 62: Scenario variants of Swiss aviation demand, showing aviation fuel demand, electricity supply, energy imports, and hydrogen production in the year 2050 under Base, high, and low aviation-demand trajectories.

4.3 Summary: Synfuels in Switzerland and the EU

Switzerland's transport sector is currently dominated by fossil fuels, with electricity primarily used for railways and biofuel demand driven by blending mandates. In transition pathways towards net-zero GHG emissions, fossil fuels are replaced by electricity and bio- or synthetic fuels. Road transport is undergoing rapid electrification, particularly for passenger cars and light-duty trucks, with nearly full electrification by 2050. Heavy-duty trucks are transitioning more slowly to battery-electric vehicles (BEVs), with a minor share of internal combustion engines (ICEs) operating on biofuels in 2050.

Despite increasing mobility demand, overall energy consumption in the transport sector declines due to efficiency gains from electrification. The shift to BEVs not only reduces direct CO₂ emissions but also significantly lowers energy consumption, as BEVs are more efficient than ICE vehicles.

Meanwhile, the aviation sector relies on bio- and synthetic fuels for decarbonization. By 2050, Switzerland's aviation sector, including international aviation, could be fully decarbonized through the adoption of biogenic and synthetic aviation fuels; however, non-CO₂ climate impacts are not quantified in our scenario analysis. The transition begins in 2030, initially driven by EU blending mandates and later by



climate mitigation targets. Mid-range aircraft adopt low-carbon jet fuel early. Given Switzerland's reliance on imported jet fuel, higher aviation demand increases fuel imports. While aviation emissions across Europe decline from 200 Mt in 2020 to 105 Mt by 2050, the 100% decarbonization of the Swiss international aviation segment is primarily driven by the national net-zero target, which requires the use of imported synthetic fuels at very high cost. However, if Switzerland aligns and cooperates with the EU under the EU ETS agreement, Swiss international aviation emissions could instead be reduced through EU ETS compliance rather than entirely through the use of imported synthetic fuels. In such a coordinated framework, aviation emissions would not be fully decarbonized by 2050.

The international aviation sector is the primary driver of demand for bio- and synthetic fuels, followed by other end-use sectors. The role of non-fossil fuels grows significantly, from almost negligible in 2020 to close to 100 PJ by 2050 (with ca. 70 PJ used in aviation). While transport dominates biofuel consumption in the mid-term, the industrial sector is increasingly using these fuels for heat and electricity generation. Additionally, synthetic methane partially replaces natural gas for heating in the residential and service sectors.

By 2050, Switzerland will produce about 12 PJ of bio-/synthetic fuel domestically, while demand will reach 24 PJ (excluding aviation), requiring substantial imports. Biogas and biofuel remain the primary domestic LCF, with biofuel becoming cost-effective by 2040, though limited by feedstock constraints. Synthetic methane, driven by renewable electricity, becomes viable at scale by 2050.

With the nuclear phase-out, solar and wind power will dominate electricity generation, while hydropower remains stable. Biomass with carbon capture and storage (CCS) will contribute negative emissions to support climate goals. Synthetic methane will account for one-third of domestic bio/synthetic fuel, driven by net-zero targets and strong renewable electricity production.

Outside international aviation, Switzerland's transition to net-zero is primarily driven by decarbonizing end-use sectors through accelerated electrification. Limited biomass resources are primarily allocated to the electricity sector, where they are used with CCS to generate negative-emission credits that offset emissions from some end-use sectors. In this context, biogenic and synthetic fuels play a minor role. However, the high share of intermittent renewable electricity increases the need for synthetic gas production, which, in turn, supports decarbonization in end-use sectors. The inclusion of international aviation raises carbon prices, enabling the deployment of more expensive mitigation measures.



5 Global low-carbon fuel supply analysis

5.1 Goal of global LCF supply analysis

In this part of the report, we evaluate market-optimal future production mixes of LCF in major export world regions from which the EU and Switzerland could import. The assumption of a market-driven development assumes that the world—at least on a macro-scale and for exporter regions (outside the EU)—allows global trade. Hence, for the quantitative analysis, we use a multi-regional global energy system model with a cost-effective allocation of resources, without political barriers on global energy trade, and without major policy guidelines outside of market factors (e.g., severe domestic production requirements). The major energy policy key assumption is a stringent climate mitigation, driven by increasing carbon costs for all world regions; hence, we do not assume a normative global net-zero target in the year 2050; indeed, for the EU31 region (EU+CH+NO+IS+UK), net zero is approximately reached in the year 2050 in our analysis. The employed energy system model tool is PSI's GMM model, the Global Multi-Regional Market Allocation Model, which is a bottom-up model with a focus on technology detail in all supply sectors and major demand sectors. GMM is used to analyse energy system configurations for LCF production under specific assumptions regarding regional resource potentials and regarding costs of resources and technologies. The main outputs for SHELTERED are the major LCF production pathways and the identification of the major export world regions of LCFs, under the assumption of a global free market of such energy carriers.

Because currently, LCF deployment is relatively small, global long-term results are subject to uncertainties. We address key uncertainties with sensitivity analyses, which are an important part of the analysis.

5.2 Methodology of the Global Supply Analysis

There is not yet a unique standard regarding the terminology used for alternative fuels; for example, the highly influential scenario study (IEA, 2024c) [Annex C, p. 357–370] lists quite generally “synthetic oil”, “liquid biofuels/energy”, and “low emission hydrogen (based liquid fuels)”.

We define the following two abbreviations for energy sources in this global modelling section of the report:

- “**ren**” = 100% of renewable electricity, or sustainable biomass (2nd generation)
- “**n-ren**” = negation of “ren” = “non-certified”, “grey” sources = any source of electricity, any biomass (i.e., can have parts or be entirely of 1st generation biomass)

We use the following notions (Table 8, with exceptions in some places):

Table 8: Low Carbon Fuel (LCF) terminology which is used throughout this section of the report.

LCF	Definition
Alternative liquid fuel	Liquid fuels, except conventional liquid fossil fuels (gasoline, diesel, fuel oils)
1st gen Biomass	Human-edible biomass
2nd gen Biomass	Ligno-cellulosic biomass: wood (waste and residues), stover; “sustainable”
Biofuel (conv)	Biodiesel, bioethanol, bio-methanol (via conventional processes as of today)
Hydrogen (ren)	Hydrogen from renewable electricity (wind, solar, hydro, geothermal) or from 2 nd gen biomass
Synfuels (ren)	Liquid fuels from Hydrogen (ren.), solar processes, or from 2 nd gen. biomass (via syngas or any other thermo-chemical conversion)
Hydrogen (fossil, n-ren)	Hydrogen from any source, for example, from grid electricity or from natural gas with CCS
Liquid e-fuels	Liquid fuels from hydrogen (requires a carbon source); are a subpart of Synfuels
Synfuels (fossil, n-ren)	Liquid e-fuels (from any hydrogen or carbon source); liquid biofuels from any (1 st and 2 nd) biomass or from domestic waste (via syngas or any other thermo-chemical conversion); bioethanol, Biodiesel, bio-methanol



5.2.1. The Global Multi-Regional Energy System Model (GMM)

The global energy pathways in SHELTERED are quantified using the Global Multi-Regional Market energy system model (GMM). GMM is a technologically detailed cost-optimization model that has been extended by the Energy Economics Group at the Paul Scherrer Institute (PSI) over two decades (Densing et al., 2012; Kober et al., 2020; Rafaj et al., 2006).

GMM is a bottom-up model having a detailed representation of energy supply, conversion, and energy end-use technologies to satisfy given sectoral useful energy demands. GMM includes more than 400 technologies per world region with their techno-economic characteristics, such as efficiency, current deployment, and costs. A simplified version of the so-called reference energy system, that is, the network energy flows and technologies, is given in Figure 63.

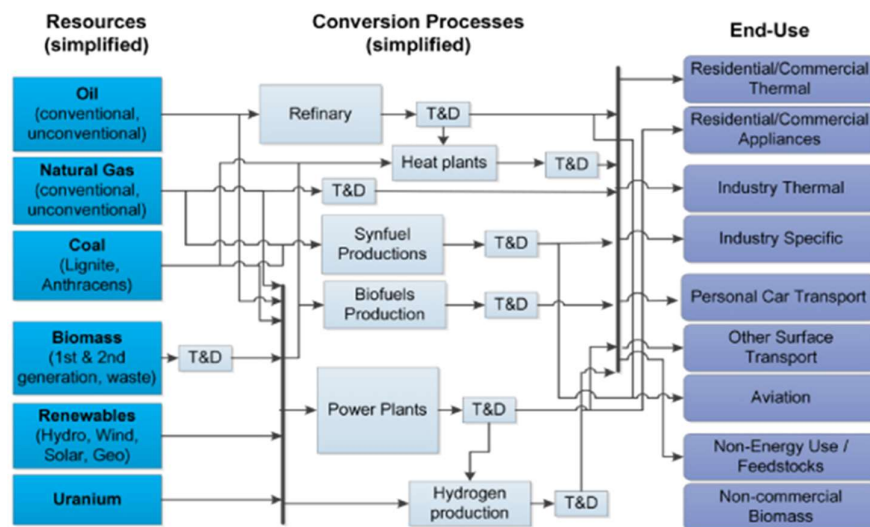


Figure 63: Reference energy system of the global multi-regional market-allocation model (GMM); simplified, for a single region. "T&D" = transport and distribution.

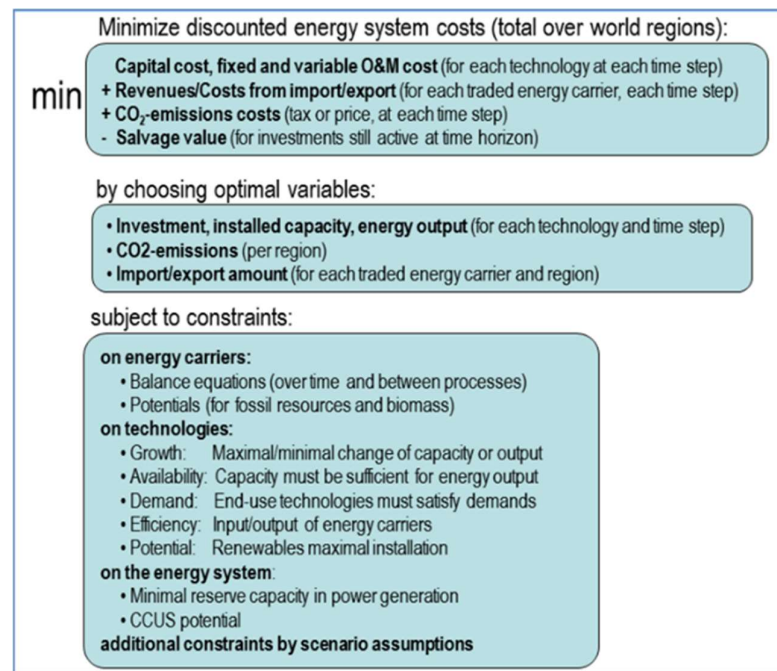


Figure 64: Minimization of system cost (= perfect-market allocation) of the energy system in the GMM model.

GMM optimizes for the least-cost combination of technology and fuel options to provide energy services; this is equivalent to the optimal market outcome under the assumption of a perfect market; a perfect market entails that all market participants do not exercise market power (i.e., they are price-takers) and receive a sufficient, undistorted price signal for every investment and operational decision. GMM simultaneously determines for each world region these investment and operating decisions together with primary energy supply decisions to establish an equilibrium between the cost of each energy carrier, the quantity supplied by producers, and the quantity demanded by consumers (Figure 64). This market equilibrium is assured at every conversion stage of the energy system (primary, secondary, end-use) and across time, representing a globally optimal allocation of society's energy resources and technologies given specific scenario assumptions. As usual in such bottom-up system modelling, GMM assumes perfect foresight of decisions. Future expenditures are discounted (5% p.a.) to account for time preferences and the cost of capital.

The reported time horizon of GMM covers the years 2020 – 2060 with a step length for investments of 10 years. However, internally, the optimisation is run until the year 2120 to address resource depletion and limit resource potentials. For system operation, GMM considers 6 time-slices per year for electricity: (Winter, Intermediate, Summer) x (Night, Day). Other energy carrier balances are performed on a yearly aggregated level.



Figure 65: The 17 world regions of GMM.

GMM has 17 world regions (see Figure 65). Large countries in terms of energy supply/demand are modelled as separate regions: China, Brazil, India, Russia, USA. Aggregated regions are: Eastern Europe¹³; South and Central Asia (excluding India); the developed Far East (Japan, South Korea, Taiwan(-China)); Australia & New Zealand; Latin America and the Caribbean (excluding Brazil and Mexico); Gulf Cooperation Council¹⁴ (GCC); Middle East (excluding GCC); North Africa; Sub-Saharan Africa; Canada and Mexico; Southeast Asia and the Pacific; EU31 (European Union, UK, Iceland, Norway, Switzerland). For each region, different availabilities, costs, efficiencies, and installed capacities influence the dynamics of demand and supply technologies. The combined regional and technology differentiation leads to a large-scale model with over 200'000 equations.

5.2.2. Power and demand sectors

The demand sectors in GMM are aggregated into industry, transport, and residential/commercial sectors. Within the industry and residential/commercial sector, GMM distinguishes useful energy demands between thermal and non-thermal ("specific", appliances) end uses (see Figure 63). In the transport sector, GMM has three subsectors: air transport, personal cars, and aggregated other-surface transport (= bus, truck, rail, ship). Useful energy in the demand sectors can be satisfied by different demand-technologies having different efficiencies, costs, and fuels; as an example, heating demand can be satisfied by: Furnaces (gas, oil, coal, hydrogen), heat pumps (electric, gas), district heating, hydrogen fuel cell, solar thermal, electric resistance, biomass, and (generic) alcohols. Car travel demand (vehicle-km/y) can be satisfied by ICEV, HEV, PHEV, BEV, and fuel cell vehicles using different (blends of) fuels. For the aggregated other-surface transport sector, GMM distinguishes by fuel and by engine type: liquid (combustion engine), gas (combustion engine, turbine), electricity (motor), hydrogen (fuel cell, ICEV), and coal (combustion engine).

GMM has various power supply options, for example, coal, gas, and oil fuelled technologies (e.g., steam-turbine, gas-turbine, combined-cycle turbine, coal-gasification, CHP (also hydrogen fuelled), nuclear, solar PV and thermal, on- and off-shore wind, hydropower, biomass/waste, geothermal (in total 33 power generation technologies). Fossil and bio power plants are in variants with and without CCUS. In GMM, the intermittency of solar and wind power is considered in that these types can only partially contribute to a peak-power constraint (of reserve capacity); solar PV is assumed to be partially stored

¹³ Albania, Armenia, Belarus, Bosnia and Herzegovina, Georgia, Macedonia, Moldavia, Serbia, Turkey, Ukraine

¹⁴ Bahrain, Kuwait, Oman, Qatar, Saudi Arabia, United Arab Emirates



in batteries, leading to a contribution also during nights. GMM has no grid topology but includes costs and losses of power transmission and distribution.

5.2.3. Liquid biofuel, hydrogen, and other synthetic fuel production

GMM's most important alternative fuel production options are shown in Table 9. Technologies in bold are specified as described in the section 2, with the technology parameters in GMM under the development scenario "Optimistic"; indeed, computational experiments showed that taking the pessimistic assumptions leads approximately to a linear scale-down of the activities of the alternative fuel pathways.

Table 9: Alternative fuel production options in GMM.

Fuel	Detail of technology	Output
Production from fossil fuels		
Natural gas	SMR-FT; ATR-FT	Liquid Fuel
Natural gas	SR-FT (solar reforming)	Liquid Fuel
Coal	FT	Liquid Fuel
Natural gas	conventional via syngas	Methanol
Production from biomass		
Sugar crops; Corn grains; Stover	conventional via Fermentation; Cellulosic dissection	Ethanol
Wood	Gasification	Bio-Methanol
Oil crops; Wood	Transesterification; Pyrolysis	Biodiesel, incl. FAME (fatty acid methyl esters)
Oil crops	Esterification	Liquid Biofuel, incl. FAEE (fatty acid ethyl esters)
Wood; Domestic waste	Anaerobic Domestic Waste Digestion (electricity co-generation)	Biogas, incl. DME (dimethyl ether)
2 nd generation biomass	BG-FT	(sustainable) Liquid Fuel
2 nd generation biomass	PYR	(sustainable) Liquid Fuel
Production from hydrogen or solar		
Hydrogen (renewable and non-renewable), any CO ₂ source	FT	Liquid Fuel
Hydrogen (renewable and non-renewable), any CO ₂ source	RWGS-MeOH	Methanol
Renewable hydrogen, DAC	RWGS-FT	Renewable liquid Fuel
Water, DAC	ST-FT (solar thermal)	Renewable liquid Fuel
Hydrogen production		
Grid electricity	PEM; AE	Grey hydrogen
Nuclear heat/electricity	HTSE; CuCl	Pink hydrogen
Natural gas	SMR; ATR; CLR ; with CCS	Blue hydrogen
Natural gas	PYR	Turquoise hydrogen
Renewable electricity	PEM; AE; SOEC	Green (sustainable) hydrogen
2 nd generation biomass	BG , with CCS	Green (sustainable) hydrogen
Methane production		
Hydrogen (from electrolyzers and other decentralised production options)	Methanation	Methane

Biomass resources in GMM are separated into 1st generation (human edible) biomass and 2nd generation. 1st generation has sub-categories (with separate potentials) of corn grains, sugar cane, oil crops,



and we consider as an additional sub-category also domestic waste, although it is roughly only 50% biogenic (2nd generation is lignocellulosic, that is, wood and stover). GMM considers pathways for liquid and for gaseous fuels from both 1st and 2nd generation biomass, leading to ethanol, methanol, biodiesel, and biogas. In GMM, these liquid and gaseous biofuels can serve both the stationary sectors and transport sectors. In the SHELTERED project, we also introduced (sustainable) biofuel pathways using exclusively 2nd generation biomass, dedicated to the transport sectors. Hence, results can distinguish the share of sustainable biofuel in total biofuels.

Table 9 shows also synthetic fuel production (incl. methanol) from hydrogen. Similar to biofuels, GMM has pathways from “generic” hydrogen (from any renewable or non-renewable source), which can also use any available CO₂ source. In addition, in SHELTERED, we introduced sustainable synfuel from sustainable hydrogen sources, or from pure solar-thermal processes. In the base case of SHELTERED, we assume that the renewable pathways require DAC as a carbon source.

For hydrogen production, apart from the fossil (“grey”) pathways, we consider “pink”, “blue”, and “turquoise” hydrogen. Moreover, we consider “green” (sustainable) hydrogen from renewable electricity or sustainable (i.e., 2nd generation) biomass. GMM also includes fossil alternative fuel pathways via natural gas and coal (see Table 9).

In GMM, we do consider the water consumption for any process. However, the cost of desalination in water-scarce regions relative to total hydrogen production costs is not more than 1%; (Terlouw et al., 2024b) and the references within.

5.2.4. Trade of energy carriers

In GMM, the trade of fuels across the 17 world regions is represented by a single global pool market for each fuel; transport costs and efficiency losses are identical between world regions. The following fuels are traded across world regions: “Green” (sustainable) hydrogen, Hydrogen (from any source), Liquid “green” (sustainable) synthetic fuel (mainly FT-type), Liquid synthetic fuel (from any source), Biodiesel, Biogas, Bioethanol, Methanol, Hard coal, Natural Gas (by average pipelines), LNG (with costs and capacity expansion of the terminal per region), Gasoline, and Diesel; bio-methanol is not traded between world regions. The long-distance hydrogen transport between the world regions is assumed in GMM to take place via ammonia. Indeed, the transport cost analysis in the section 2 shows that long-distance hydrogen transport is relatively more costly than other transport options (e.g., liquefied hydrogen); see also e.g. (IRENA, 2022). Ammonia allows the use of the existing LPG-tanker fleet (with minor modifications).

Inside world regions, energy carriers are associated with specific transport costs and efficiency losses. A special, more detailed case is hydrogen transportation, which has a variety of capacity expansion options (pipeline, truck, or no transport requirement because of decentralized production). In GMM, we assume that hydrogen transport infrastructure is newly built (i.e., no re-purposing of the methane infrastructure). Electricity (except between LAC and Brazil) and CO₂ are assumed not to be traded across the 17 world regions.

5.3 Key Data and Scenario Assumptions

The GMM model has time intervals of 10 years for capacity expansions (and phase-outs) until the internal time horizon of year 2110; the start year was newly calibrated in the SHELTERED project to 2019/2020 statistics; to avoid COVID effects, capacities are from the end of 2020, whereas production is from 2019. Major data sources include IEA’s extended energy balances, IRENA’s renewable power capacity statistics (IEA, 2020; IRENA, 2020), and the World Road Statistics (e.g., vehicle-km of personal cars) (IRF, 2022). In the following, we discuss two specific data assumptions: of geological CO₂ storage capacities for CCS and of biomass availability. These two assumptions were found, in hindsight, after obtaining first results, to be the key factors for the success of alternative fuel pathways.



5.3.1. Assumptions on CCS

Currently, the amount CCS is roughly 0.1% of global CO₂ emissions: 50 MtCO₂/y vs. 38 GtCO₂/y energy system emissions (Dziejarski et al., 2023; Global CCS Institute, 2023). As of the year 2024, operating since 2010, the largest CCS facility is still Brazil's offshore oil field «Santos Basin» (10.6 Mt/y CO₂ in the year 2022 for enhanced oil recovery) (Global CCS Institute, 2023). In Europe, Norway's «Northern Lights» facility started in the year 2024 with a capacity of 1.5 Mt CO₂/y. Future large-scale deployment is uncertain. In the base case scenario of SHELTERED, the assumed total CCS potential of all world regions is 2'146 Gt CO₂ (Hendriks et al., 2004; Turton et al., 2013). In GMM, the potential is the sum of on- and offshore locations and includes the categories: enhanced oil/gas recovery, depleted oil/gas fields, enhanced coal bed methane recovery (ECBM), and aquifers. The largest potential is expected to be in the Mideast and in Russia, mainly for enhanced recovery and in depleted gas fields. For China, most of the potential is ECBM (~150 GtCO₂). Table 10 shows that GMM's potential is relatively low compared with more recent studies (Global CCS Institute, 2023; Kearns et al., 2017).

Table 10: Global CCS Potentials (Unit: Gt CO₂). CCS Institute: Not all regions reported; sum of on- and offshore. Kearns: Shown is the "low estimate of practical potential" (water depth < 300 meters, < 200 miles of a major landmass, outside of Arctic/Antarctic); their upper estimate is 55'600 Gt globally. See Figure 65 for the names of world regions.

GMM world region	SHELTERED (base case)	Kearns et al. (low estimate)	CCS Institute
ASIAPAC	81	554	-
AUSNZL	55	595	502
BRAZIL	43	297	2'000
CANMEX	68	456	-
CENASIA	87	485	-
CHINAREG	185	403	2'400
EEUR	12	151	150
EU31	80	151	150
GCC	150	246	-
INDIA	64	99	50
JPKRTW	6	11	356
LAC	53	606	-
MIDEAST	150	246	-
NAFRICA	150	782	-
RUSSIA	295	1'234	-
SSAFRICA	138	782	150
USA	78	812	-
World	1'697	7'909	14'000

The estimated potentials are usually mostly technical potentials and may be considerably reduced by other factors: For example, by matching geographically CO₂ supply and sites (down to globally 290 Gt CO₂), and by considering limited injection rates based on limited growth of the injection industry (Grant et al., 2022), or by potential geological, geographical, and techno-economic limitations to growth (Zhang et al., 2024). Even considering such limitations, less than 10% of the CCS potential will be used over the next century in our results of the base case scenario of SHELTERED.

On the other hand, novel carbon storage and usages are not explicitly considered in GMM; concrete and other building materials as a storage medium may have a potential of up to 12 GtCO₂/y, which is even slightly above the total global carbon captured in the base case results of SHELTERED in the year 2060 (Lura et al., 2025).

There is also uncertainty about the cost of CCS: The common "rule-of-thumb" for transport and storage globally is 10\$/tCO₂ (Smith et al., 2021). In Switzerland, transport and storage costs are estimated to be an order of magnitude higher (BAK, 2023). Still, international cost ranges may be lower, in the range of 4-45 \$/tCO₂, which can lead to different cumulative stored amounts until 2100. In SHELTERED, the



base assumption for CO₂ transport and storage is 18\$(2024)/tCO₂, which is assumed to be constant over time. In Section 5.5.2, we consider a sensitivity analysis with reduced potential and higher cost.

5.3.2. Assumptions on biomass

The biomass potential in GMM is categorized into domestic waste, oil crops & corn grains, stover, sugar plants, and wood. In GMM, the 2nd generation (sustainable) biofuel production is from (lignocellulosic) stover and wood. Indeed, the figure shows that wood exceeds 50% of total biomass potential.

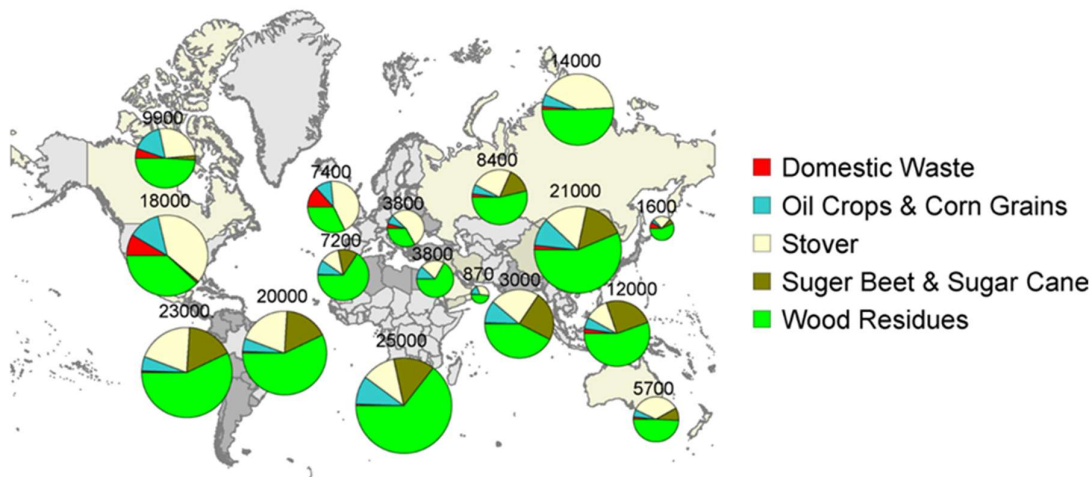


Figure 66: Assumed biomass potential in SHELTERED base case (PJ/y).

The assumption of the potential dates back to (Turton et al., 2013) and the references within, as in the previous case of CCS potential, more recent and globally consistent studies are scarce. In Table 11, we compare with (Slade et al., 2014; Smeets et al., 2007; Thrän et al., 2010).

Table 11: Global biomass potential (EJ/y) used within SHELTERED compared with recent review studies.

Category	SHELTERED	Slade		Thrän (year 2050)		Smeets (year 2050)	
		lower	upper	lower	upper	lower	upper
1 st gen	45	34	1'392	0	1'250	65	932
2 nd gen	150	73	331	90	340	150	340
1 st + 2 nd gen	195	107	1'723	90	1'590	215	1'272

These orders of magnitude are similar to those in a recent IRENA review (IRENA, 2016) [p. 25], which has average potentials above 100 EJ/y (visually read off from the figure).

The total potential in the base case of SHELTERED of 195 EJ/y (assumed to be constant over time) should be compared with today's extraction, which is approximately 60 EJ/y in the year 2020, that is, a tenth of the global primary energy supply of 606 EJ/y (GMM accounting of TPES). Because of the high uncertainty of the practical biomass potential, we consider a sensitivity analysis with a lower potential.

Studies on the regional costs of lignocellulosic biomass were recently reviewed by (Domingues et al., 2022), see Table 12. As an additional comparison, (IRENA, 2016)[p. 25] has similar price ranges of 2.5-13 \$(2024)/GJ. We vary the costs in a sensitivity analysis.



Table 12: Cost of lignocellulosic biomass. SHELTERED: Cost of wood (GMM has also stover). (Domingues et al., 2022): Lowest and highest median over all categories (Managed Forest, Wood Energy Crops, Grass Energy Crops, Agricultural residues, Forest residues); cost of land not included.

Region	SHELTERED (\$ ₂₀₂₄ /GJ)	(Domingues et al., 2022) (\$ ₂₀₂₄ /GJ)	
		low (median)	high (median)
AFRICA	2.05	2.14	4.01
LAC (incl. BRAZIL)	2.05	0.59	2.99
ASIA (incl. CHINA)	8.62	0.76	2.36
RUSSIA	2.51	3.15	4.46
EUROPE	4.67	3.82	5.93
USA	12.66	1.84	5.86

5.3.3.Scenario assumptions

As mentioned, one of the main goals of this part of the report is the quantification of international, market-driven alternative fuel production and deployment, especially in the exporting world regions. Market-driven means in our modelling a cost-effective deployment under given scenario constraints. Moreover, based on our results, EU31 will not be an exporting world region; the relatively strongly policy-driven EU31 region. As a prerequisite for the shift away from fossil fuels, we assume a strong decarbonization scenario. The scenario has the following main assumptions:

- Global population grows to 9.7 billion inhabitants in 2050, and to 10.2 billion in 2060, stabilizing thereafter (United Nations, 2020) [medium estimate].
- GDP growth continues according to short-term IMF forecasts in 2020-2030, and then globally at a rate of 2.6% p.a. (nominal, avg.) between 2030 and 2060, which can be considered as a “medium” global growth; wealth and living standards are considered to be rising in all world regions, especially in developing regions.
- We assume no crucial behavioural demand reduction: Useful energy demands in the demand sectors are still growing, especially in the developing world regions. Examples include:
 - o Demand for appliances in the residential & commercial sectors (i.e., non-heat demand specific for appliances, motors, etc., mostly served by electricity) rises globally by 2.4% p.a. between 2030 and 2060 on average.
 - o Fuel-use (in units of PJ) in aviation grows globally by 1.5% p.a. between 2030 and 2060 on average.
 - o Driven vehicle-km by personal cars continue to rise, by 0.7% p.a. in the developed world regions, and by 3.7% p.a. in the developing regions between 2030 and 2060 on average.
- We assume a strong decarbonization scenario globally, driven by a single proxy parameter in GMM, that is, a regional marginal cost of carbon, converging across world regions in 2050. Recent results using a variety of Integrated Assessment Models (IAM), which are used in the IPCC assessment process, show that attaining a global net-zero by 2050 is unlikely (Sognnaes et al., 2021), and IAMs were possibly too optimistic in the past (van Beek et al., 2022). Accordingly, we do not reach the normative target of net-zero globally in the year 2050 on a global scale, but still approximately for EU31 (see section 5.4.1).
- Further assumptions include:
 - o EU31: Aviation synfuel target (6%, 34%, 70% in the years 2030, 2040, 2050, respectively), and a maximal blending ratio of biofuels into total synthetic fuels
 - o Cost assumptions for wind and solar power at the lower end (interpretable alternatively as a subsidy)



- Growth constraints on coal & oil power plants (even if equipped with CCS), and on shale gas
- High allowed reduction rates for oil/gas in residential & commercial sector, and for oil use in transport
- Investment in CAPEX-intensive projects possible (if cost-effective): new nuclear and hydropower
- CCS accepted and cost-effectively deployed in all world regions (see also the sensitivity analysis of the section 5.5.2)

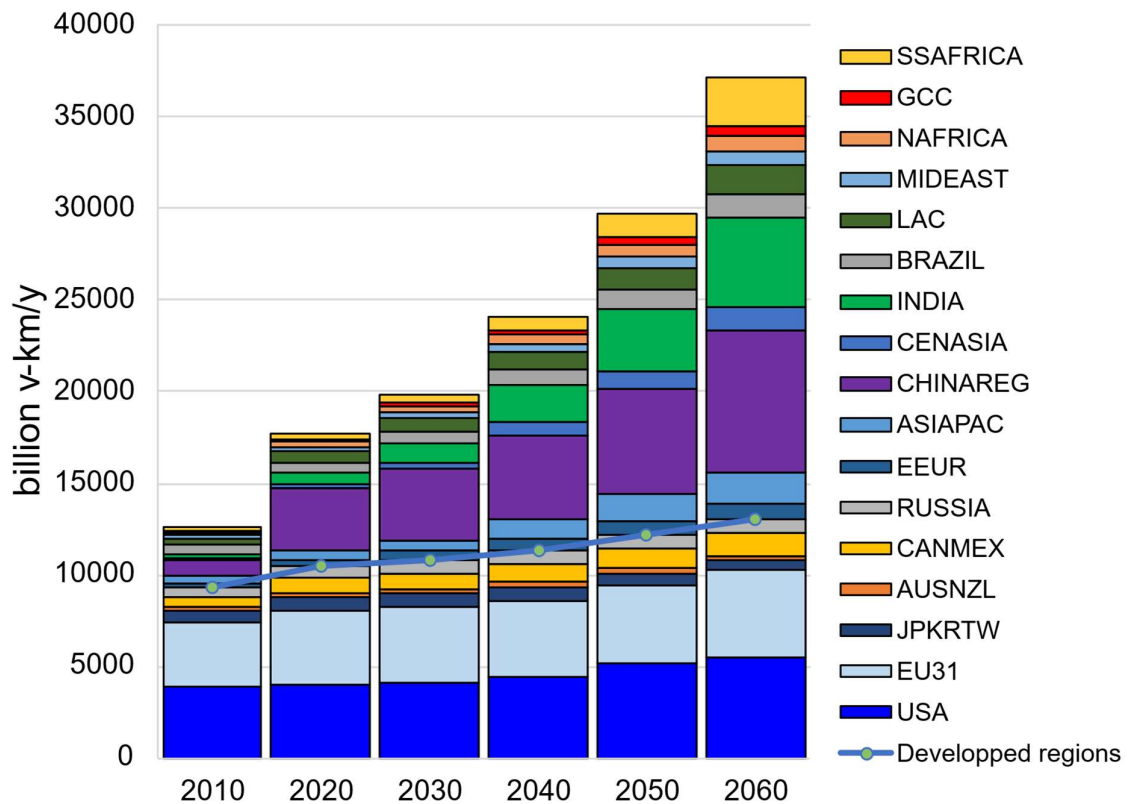


Figure 67: Useful energy demand of passenger cars (unit: billion vehicle-km/y). See Figure 65 for region names.

As a side note, Figure 67 and Figure 68 also show the past dynamic from 2010 to 2020 in the developing countries, for example, the relatively large increase of personal cars in China, which is assumed in our scenario to happen first in India and then later also in Sub-Saharan Africa.

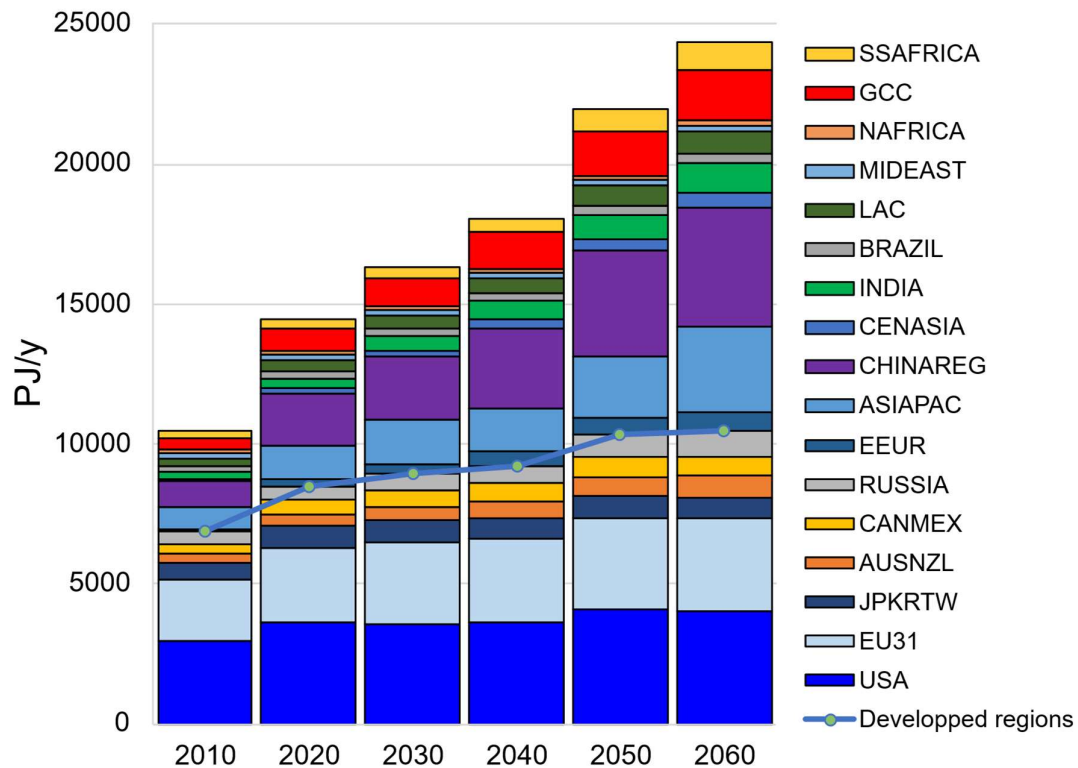


Figure 68: Useful energy demand of aviation (unit: PJ/y, in terms of today's technology efficiency). See Figure 65 for region names.

5.4 Results

5.4.1. GHG emissions

Figure 69 shows the global energy sector's CO₂ emissions of the SHELTERED strong-carbon reduction scenario and corresponding recent IPCC emissions bandwidths (IPCC, 2022). The modelled pathway is slightly above the median C2 emission of IPCC. In more detail, Figure 70 shows the energy sector's emissions of the 17 world regions, and Figure 71 show the energy sector's emissions in the small regions. For EU31, the energy system emissions go from 3.3 GtCO₂/y in the year 2020 down to 0.3 Gt/y in the year 2050. The figure shows GMM's start year of 2019/2020; in the meantime, global emissions have slightly increased from 36.3 Gt/y in 2019 to 37.4 Gt/y in 2023 (using IEA's accounting of combustion and industrial processes) (IEA, 2023a, 2024a).

The emission trajectory in Figure 69 shows that the modelling results in energy sectors' global emissions to be within IPCC's C2 and C3 bands. As outlined in the section 5.3.3, the normative net-zero goals of the year 2050 are not met, but emissions (after CCS) are considerably reduced to 11.5 GtCO₂/y in 2050 and to 4.5 GtCO₂/y in 2060. Generally, non-normative scenarios can currently be considered as more likely real-world outcomes. For example, (McKinsey, 2024) proposes three scenarios; the most ambitious scenario in terms of carbon emission reduction, "Sustainable Transformation", still yields 13 GtCO₂/y in 2050 if scaled down to energy-sector only emissions (McKinsey, 2024) (reports only total emissions, incl. non-energy).

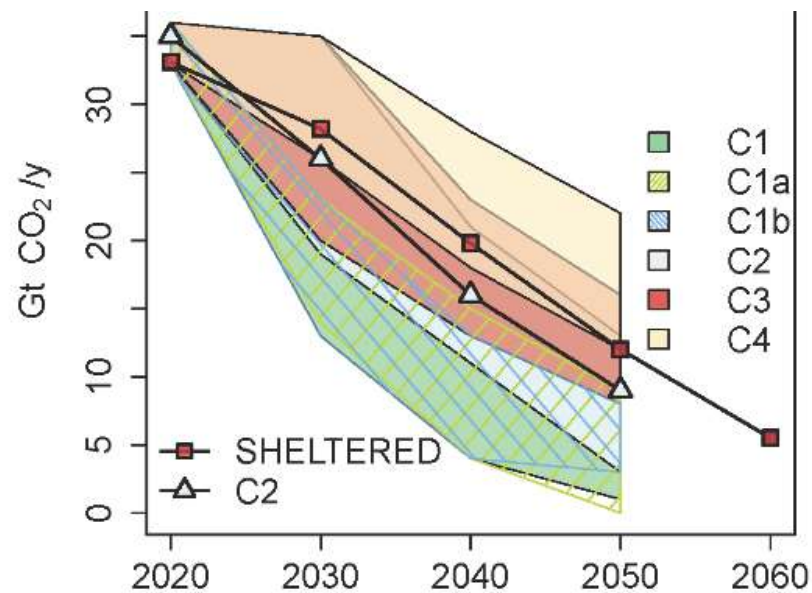


Figure 69: CO₂ energy system emissions in Gigatons per year, and IPCC emission bands, with C2 median pathway. IPCC Categories: C1: $\leq 1.5^{\circ}\text{C}$ ($> 50\%$) with no/limited overshoot; C1a: with net zero GHGs; C1b: without net zero GHGs; C2: $\leq 1.5^{\circ}\text{C}$ ($> 50\%$) with overshoot; C3: $\leq 2^{\circ}\text{C}$ ($> 67\%$); C4: $\leq 2^{\circ}\text{C}$ ($> 50\%$).

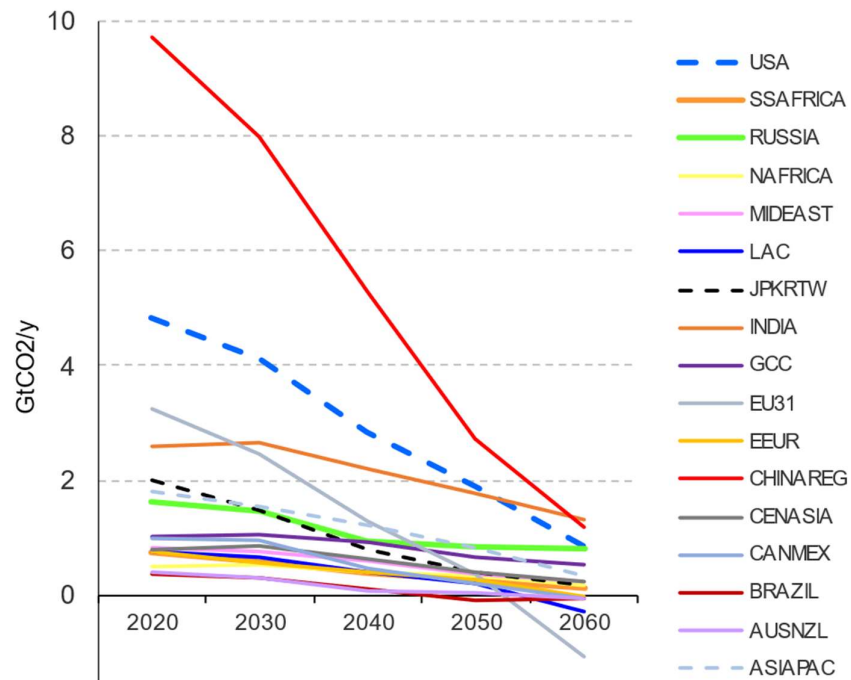


Figure 70: Carbon emissions of the energy system of the 17 world regions (See Figure 65 for region names).

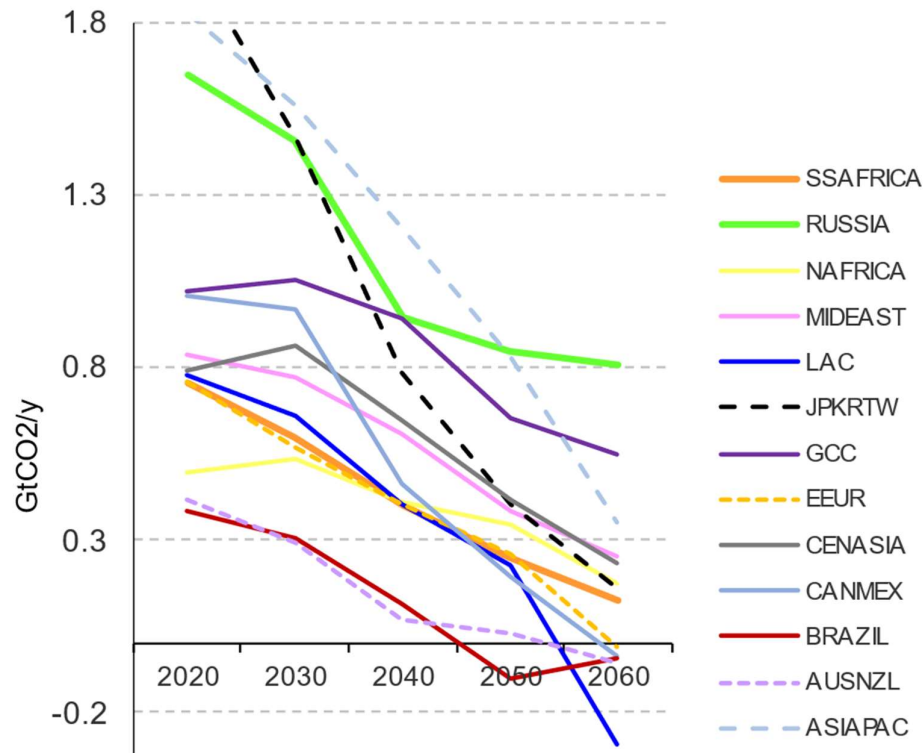


Figure 71: Carbon emission of the energy system of the smaller world regions.

5.4.2. Alternative liquid fuel production

Figure 72 shows the cost-effective global production sources of alternative fuel production in the year 2050 in the base case of SHELTERED.

Similarly, as is the case today, a large share of liquid alternative fuels in the future is from biomass in our base case scenario. Apart from the sustainable route from wood/stover (19 EJ/y in 2050, category "Biomass (2nd)"), a large share of it is also ethanol production (8 EJ/y in 2050) and conventional biodiesel from oil crops (3 EJ/y in 2050), inside category "Biomass" (22 EJ/y in 2050). FT-Liquids from hydrogen seem not to be cost-effective from a total energy system perspective. Nevertheless, there is a share of methanol production from hydrogen (6 EJ/y in 2050); this methanol is commercially traded and used in demand sectors (by contrast, on-site methanol production, which means conversion to other fuels on the production site, is not tracked separately in GMM). The solar-thermal technology is deployed on a large scale starting in 2050 (100 PJ/y in the year 2050). The cost-optimal production of liquid fuels from natural gas (gas-to-liquids, GtL) seems to be a system effect in the model, caused by the depletion of the cheapest oil resource category, and by the cheaper international long-distance trade of liquids than methane.

We compare with the World Energy Outlook; we will use the abbreviation WEO2024 for this IEA study for the rest of this report (IEA, 2024c). In WEO2024, liquid biofuels in the year 2050 are 8, 14, and 12 EJ/y in the STEPS, APS, and NZE scenarios, respectively; NZE is higher in the year 2040 (14 EJ/y) than in 2050. Hydrogen for liquid e-fuels in the year 2050 is 2, 10, and 13 EJ/y in the STEPS, APS, and NZE scenarios, respectively (with the assumption of the authors of 74% hydrogen-to-fuel efficiency). WEO2024 has also categorized "synthetic oil" of 1, 3, and 6 EJ/y in the STEPS, APS, and NZE scenarios, respectively. Hence, a comparison may be ambiguous: WEO2024 has more liquid e-fuels, whereas total liquid non-fossil fuels amounts seem to be lower in the year 2050. In WEO2024, biomass is used more in electricity for balancing, and also to drive the higher deployment of electrolyzers to produce liquid e-fuels; total electricity generation in WEO2024 is higher than in SHELTERED.

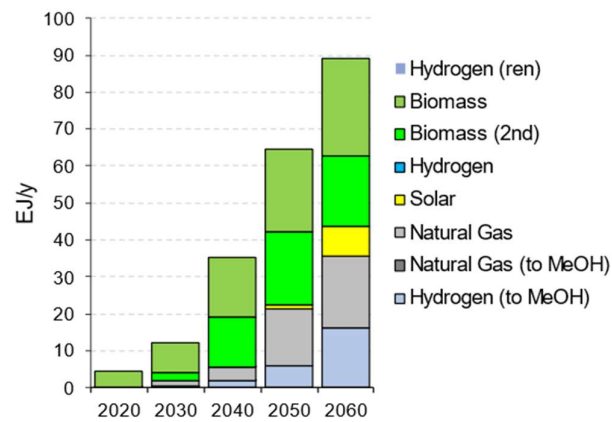


Figure 72: Global cost-minimal alternative liquid fuel production by source (base case of SHELTERED).

Comparing with (McKinsey, 2024), their category “sustainable liquid fuels” in the year 2050 is 8, 7, and 26 EJ/y in the SE, CM, and ST scenarios, respectively, whereas our study has 21 EJ/y for second-generation (“sustainable”) biomass and solar processes.

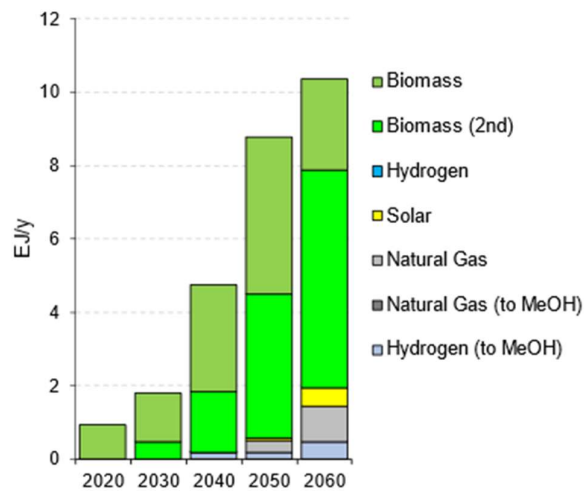


Figure 73: Brazil: Cost-minimal alternative liquid fuel production by source.

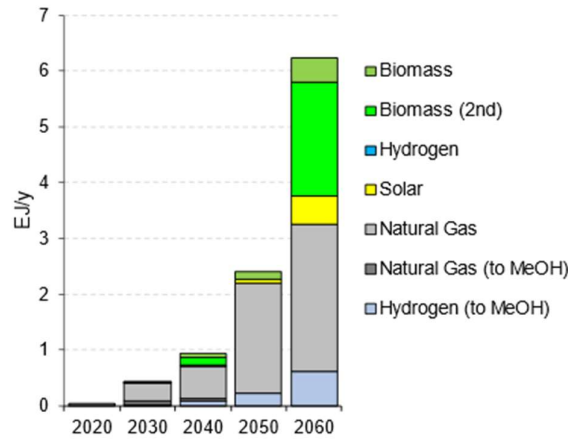


Figure 74: North Africa: Cost-minimal alternative liquid fuel production by source.

Cost-optimal deployment can vary from more emphasis on biomass, as in Brazil (Figure 73) towards emphasis on natural gas, hydrogen, and solar processes, as in North Africa (Figure 74).

As shown in Figure 75, the largest producers of alternative fuels in the year 2050 are: Brazil, USA, CANMEX (Canada & Mexico), and Sub-Saharan Africa. The largest shares of MeOH production from hydrogen are in LAC (Latin America & Caribbean) and in the Middle East.

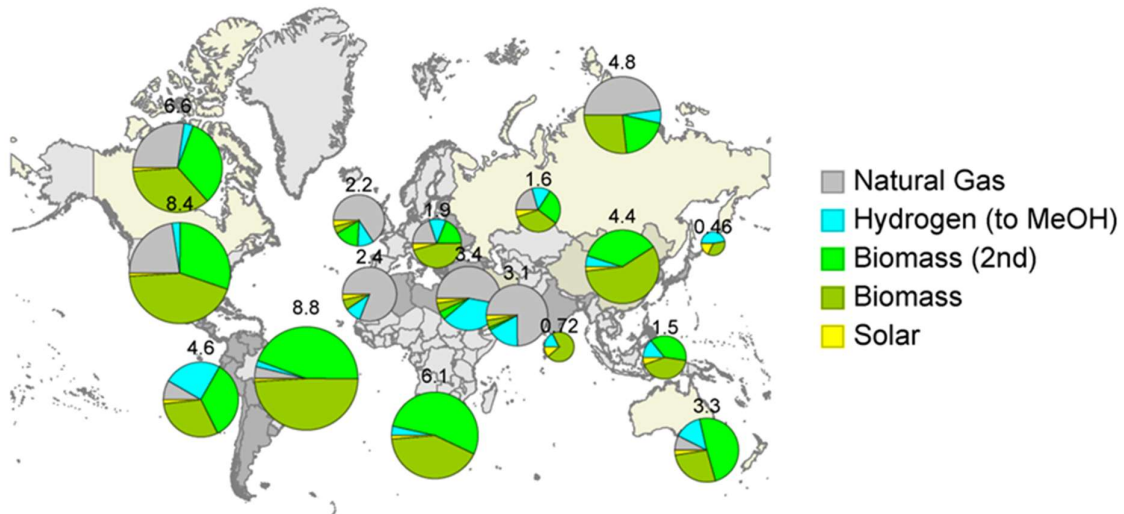


Figure 75: Global cost-minimal alternative liquid fuel production by source in 2050 (EJ/y).

It may come as a surprise that alternative liquid fuel production is heavily biofuel-based. First, we are broadening the scope compared to studies that analyse e-fuels exclusively (e.g. (IEA, 2024b)), or exclusively biofuels (e.g. (IRENA, 2021)). Second, there are other studies: (McKinsey, 2023) indirectly considers biofuels to be a large share of sustainable liquid fuels: In year 2050, the estimated financial investment is 76% in biofuels and only 24% in e-fuels (in scenario "Further Acceleration", the only reported scenario), where until year 2040 the world region with largest investment is Latin America, then surpassed in year 2050 by North America and EU. Third, in the section 5.4.5, we vary key parameters in sensitivity analyses.



Fuel use in the transport sector is shown Figure 76, which—by our results—will remain mostly on liquid fuels globally. Note that the figure shows final fuel consumption, and not service demand (e.g., electric motors are more efficient than combustion engines). Consequently, personal car energy demand decreases because of electrification, but total vehicle-km/y increases; whereas the efficiency gain in aviation is assumed to be limited in comparison with sectors such as passenger vehicles, which can be directly electrified.

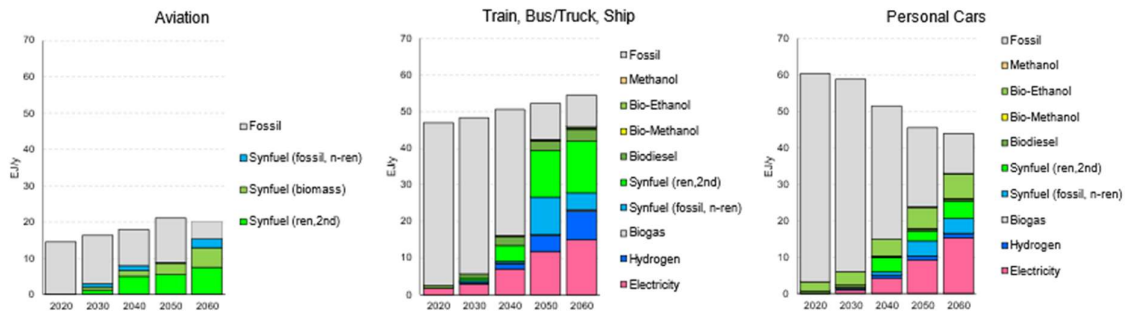


Figure 76: Transport sub-sectors: Global, cost-minimal alternative fuel use (liquid and gaseous). Fossil category: incl. coal-FT. Synfuel categories: see text.

As can be seen from Figure 76, while hydrogen is marginally used in personal cars, it may play a larger role starting in 2050/2060 in the Other Surface Transport sector, which is aggregated in GMM by differentiating into fuel/engine types, in the case of hydrogen, including combustion engines and fuel cells. The aggregation in GMM attempts to attenuate the relatively high technological uncertainty in this sector. Hence, hydrogen in surface transport is attributable to long-distance trucks and ships (also, e.g., as ammonia). By comparing with WEO2040, WEO2040's hydrogen in transport in the year 2050 is 2, 6, and 9 EJ/y in the STEPS, APS, and NZE scenarios, respectively; our Figure 76 has the same amount as APS (6 EJ/y).

In the following, we provide some more information on fuel and transport categories in Figure 76, which apply approximately to the alternative fuels in the international trade charts shown later on in the section 5.4.4:

- **Synfuel (fossil, n-ren)** is in this base case entirely "Steam Methane reforming FT".
- **Synfuel (ren, 2nd)** is in year 2030 entirely from 2nd generation biomass via "Biomass Pyrolysis and Hydroprocessing" (PYR) and via "Biomass Gasification FT". The biomass share declines to 94% in year 2050 and to 71% in year 2060 in terms of energy content, whereas solar thermochemical processes represent the remaining share, growing to 100% share in 2080 and after. From these two biomass processes, the pyrolysis has a share in total of 7% in the year 2030, then growing to 16% in the year 2060.
- **Methanol.** While MeOH has only small amounts in transport, methanol production in the whole energy system is strongly increasing to 1, 3, 6, and 16 EJ/y in the years 2030, 2040, 2050, and 2060, respectively. Methanol in the year 2050 and later is entirely produced by hydrogen ("Reverse Water Gas Shift" (RWGS-MeOH)), whereas in year 2040, this route represents only 69%, and the rest is from natural gas; in the year 2030, 12% of total methanol is from hydrogen, 81% from natural gas, and 7% from coal.

5.4.3. Hydrogen production

Figure 77 shows global hydrogen production. As a scenario assumption, the use of coal in any energy sector is not allowed to grow; hydrogen from coal is bound to stay low by assumption. The largest share is natural gas with CCS, followed by biomass. After 2050/2060, renewable electricity (wind, solar, hydropower, geothermal), together with a smaller share of general grid electricity, overtakes biomass.

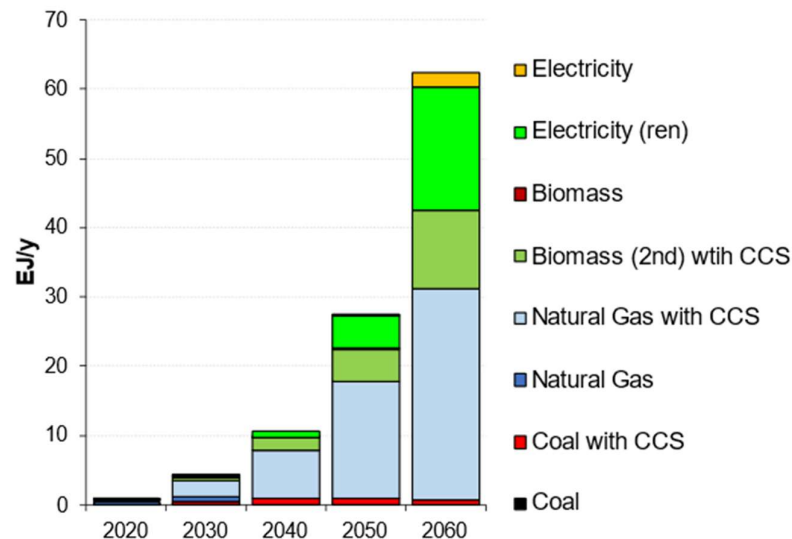


Figure 77: Global, cost-minimal hydrogen production.

In SHELTERED, the hydrogen from fossil sources is produced in detail as follows globally in the year 2050: The majority of 12 EJ/y is from steam methane reforming with CCS (“blue” hydrogen). 5 EJ/y is via methane pyrolysis (“turquoise” hydrogen), which is in Figure 77 part of the category “Natural Gas with CCS”, and which has a relatively high carbon capture rate. 1 EJ/y is from coal with CCS (“brown” hydrogen). The advanced “blue” hydrogen processes from natural gas, that is, autothermal reforming (ATR) and chemical looping reforming (CLR), are not used in our cost-optimal modelling.

Next, we compare with WEO2024 (IEA, 2024c). WEO2024 has 48 EJ/y of “low-emission” hydrogen in the NZE scenario, 31 EJ/y in APS, and 6 EJ/y in the STEPS scenario in the year 2050 (IEA, 2024c) [cf. Fig. 3.48]. Hence, the amounts of the NZE and APS scenarios in the year 2050 are surpassed in SHELTERED in the year 2060. Note that in the NZE scenario, (newly built) “low-emission” hydrogen production in year 2030 (5 years from now) is already at 8 EJ/y, which is the consumption of EU31 in the Other Surface Transport sector in 2020 (total of aviation, trucks, buses, trains). WEO2024 has larger amounts from electrolyzers: 39 EJ/y in NZE, 24 EJ/y in APS, 4 EJ/y in STEPS, in the year 2050. WEO2024 results are also partially driven by regional policies (and not solely by cost-effective emission reduction goals globally, as in this part of the report).

In our results for hydrogen production, 2nd generation biomass with CCS, that is, sustainable hydrogen via BECCS, is a valid option. This contrasts with WEO2024, where the hydrogen BECCS pathway is hardly used (0.12 EJ in the NZE scenario in the year 2050).

Regional results for some large producing regions are, in the following, shown for LAC, i.e., the Latin America & Caribbean, for the Mideast, and for Brazil. LAC is the largest producer, having large electrolyser shares; indeed, Chile has already, as of today, ongoing electrolyser projects in the GW range. The second largest region is the Mideast (and also GCC), having large natural gas shares. Brazil has a large biomass share (but a much smaller production volume than LAC). LAC, Mideast, and Brazil are also large hydrogen exporter regions, apart from Australia & New Zealand (see Section 5.4.4 below).

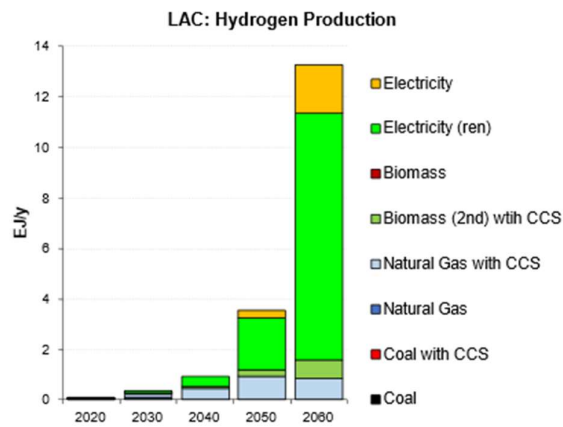


Figure 78: Hydrogen production by source in region LAC.

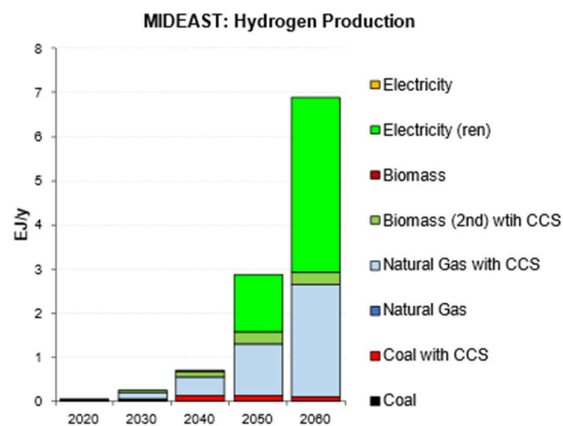


Figure 79: Hydrogen production by source in region MIDEAST.

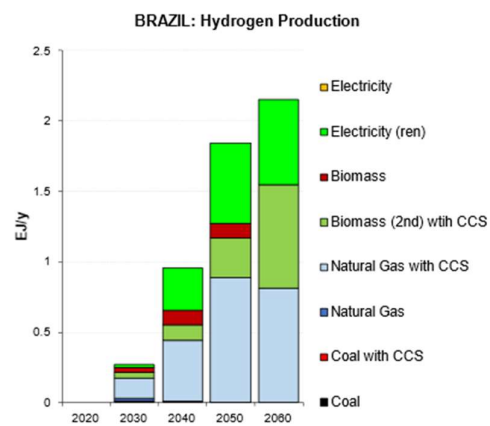


Figure 80: Hydrogen production by source in Brazil.

Figure 81 shows the hydrogen production per region in the year 2050 according to our model, and Figure 82 shows the production in the year 2060.

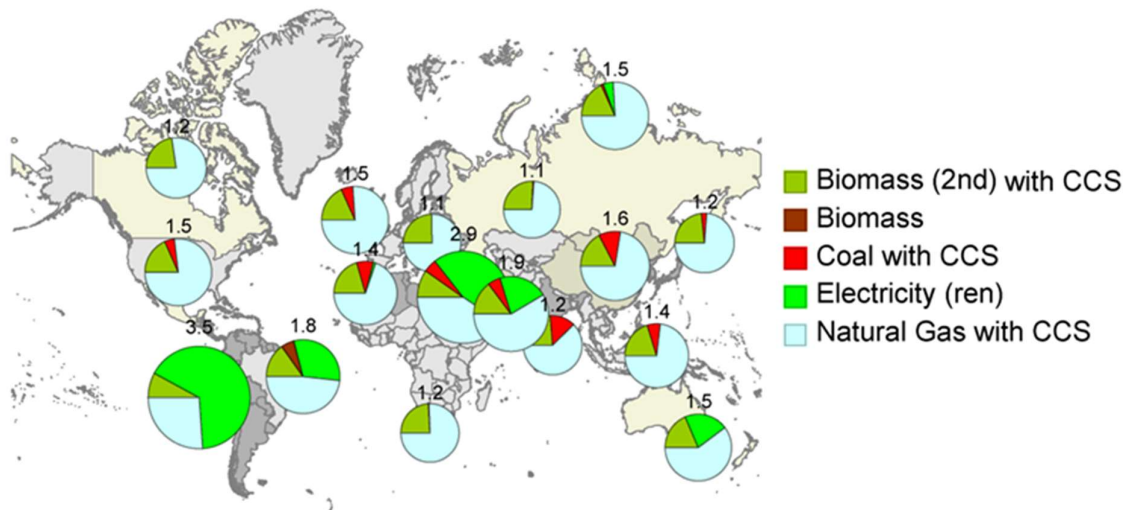


Figure 81: Global cost-minimal hydrogen production in 2050 (EJ/y).

As can be seen from the year 2050 to 2060, the trend of the large hydrogen producer regions continues to shift to electrolyzers, and total hydrogen production doubles globally from 28 GJ/y to 62 GJ/y.

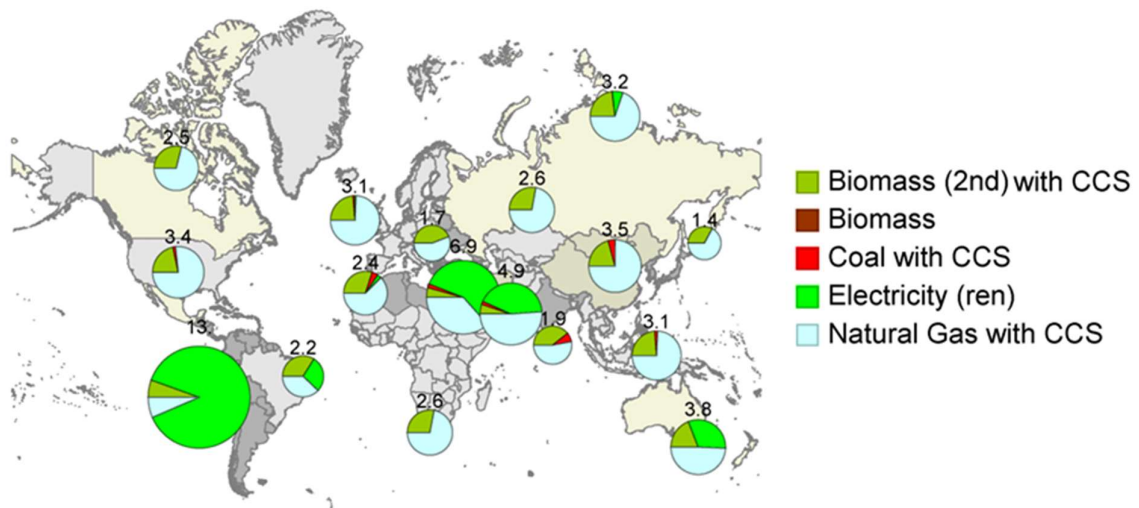


Figure 82: Global cost-minimal hydrogen production in 2060 (EJ/y). Note: Circle sizes are not proportional to Figure 81.

Figure 83 shows the direct end-use of transported hydrogen, that is, hydrogen that is not converted to other energy carriers. The largest category is «Fuel Cell Cogeneration Grid», which is mostly in the industry sector, and consists of combined-heat-and-power plants (fuel cell plants and combustion). The category «Other surface transport» is the (aggregated) transport sub-sector in GMM, consisting of ships, trucks, trains, and buses.

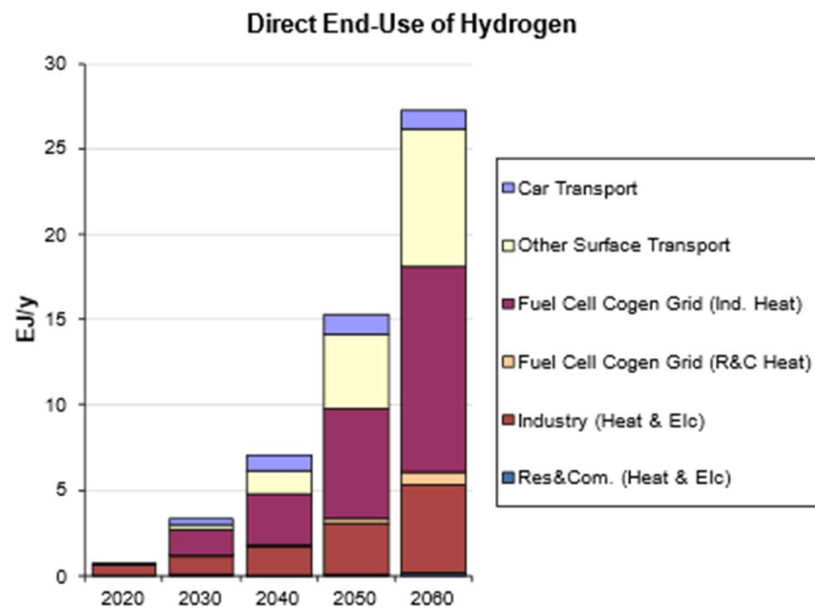


Figure 83: Global energy end-uses of hydrogen.

In our results, this direct use of transported hydrogen is the major part of commercial (wholesale) hydrogen production. Apart from transportation losses, a large part of hydrogen (stemming from electrolyzers) is also used for methanol production, amounting to 7.8 EJ(H₂)/y in 2050 globally, and also to a minor share for methanation, amounting to 2 EJ/y in 2050 (mainly 1.8 EJ/y in South America & Caribbean and 0.1 EJ/y in India). However, in our modelling, methanation grows significantly in 2060 and later, especially in South America & Caribbean, and it even starts in EU31 in the year 2070. For comparison, WEO2024 has a smaller amount of methanation (0.2 EJ/y only in the NZE scenario in the year 2050).

5.4.4. Alternative fuel trade

Figure 84 shows the large export regions of alternative liquid fuels and hydrogen (large in terms of total amount of energy). The largest exporter in 2050 is Brazil, followed by Canada & Mexico, and Russia and Australia & New Zealand.

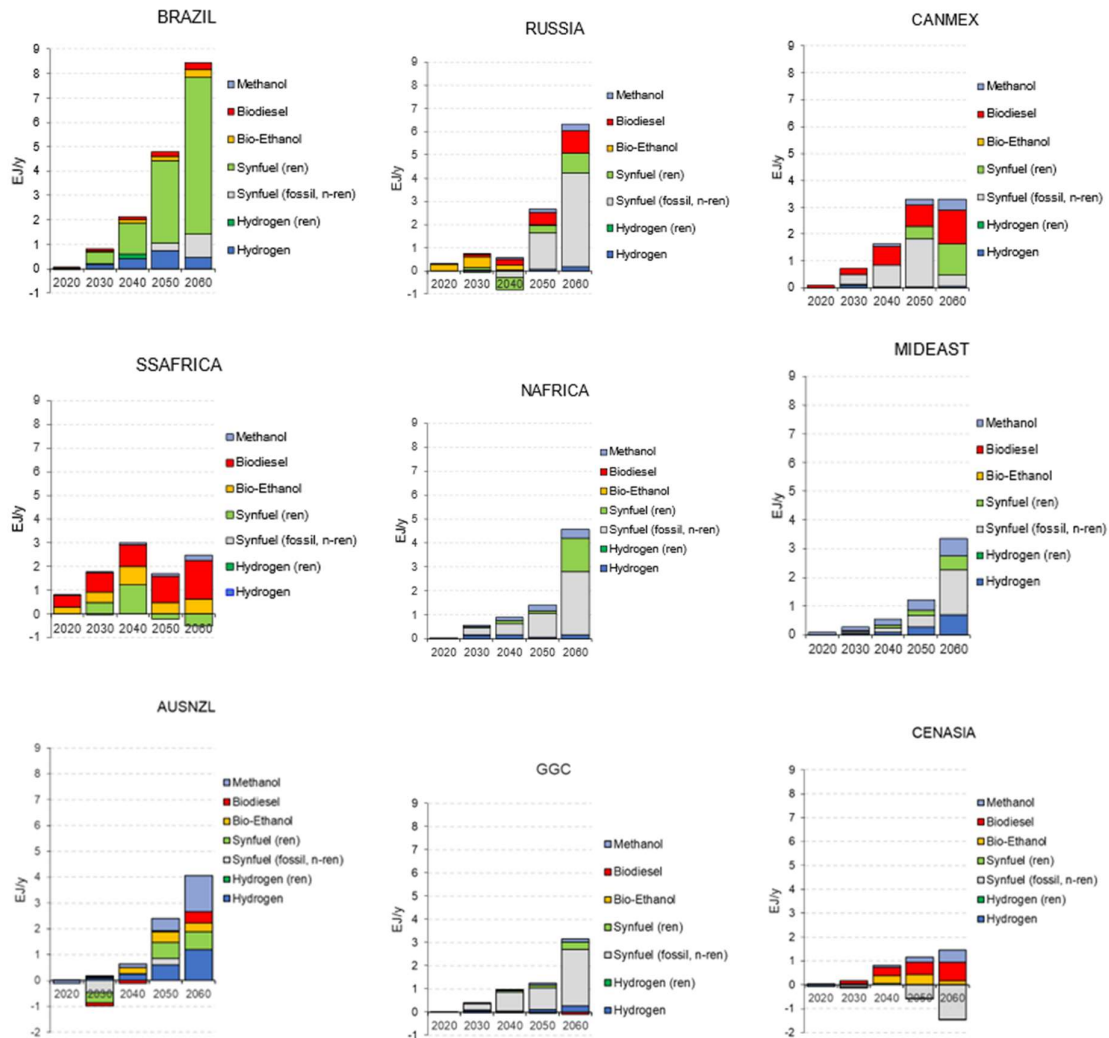


Figure 84: Major regions of alternative fuel export (sign: export > 0, import < 0). Categories “synfuel”: See text at the end of the section 5.4.2.

Figure 85 shows the world regions that are exporters in the year 2050. The gross trade of hydrogen across the 17 world regions in 2050 is 2 EJ/y; WEO2024 has 3, 7, and 9 EJ/y in the STEPS, APS, and NZE scenarios; note that WEO2024 has 27 world regions, and therefore more inter-regional trade opportunities.

The details of the categories “Synfuel (ren)” and “Synfuel (fossil, n-ren)” in the assumed global pool market of the fuels, that is, weighted by the export amounts of those fuels from the export regions only, were also calculated: They are approximately the same shares as in total liquid synfuel production (see end of section 5.4.2), e.g., the methanol is almost entirely from hydrogen, and green liquids are mostly from biomass.

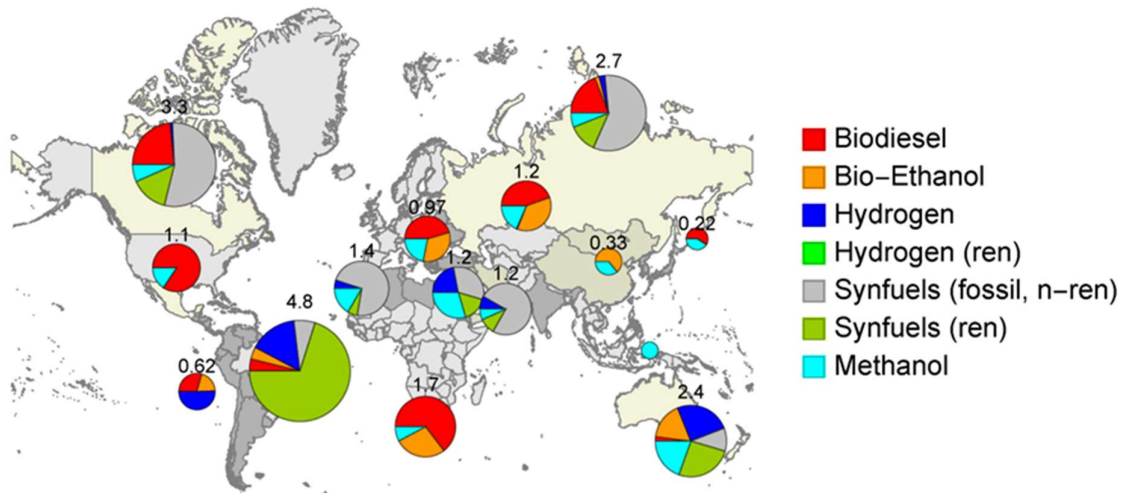


Figure 85: Alternative fuel export world regions in the year 2050 (EJ/y).

Figure 86 shows the export and the import regions in the year 2050 for alternative liquid fuels and for hydrogen. On the side of imports, the highest amount is for EU31 in all categories, second are the developing regions India, Asia Pacific, and China. In our cost-effective modelling, the region JPKRTW (Japan & South Korea & Taiwan), which has relatively low primary energy potentials, and is sometimes considered as a candidate for hydrogen import, continues to import LNG (7 EJ/y today, 5 EJ/y in the year 2050, and still 1 EJ/y in 2060), and JPKRTW hydrogen production will be mainly domestically from gas with CCS.

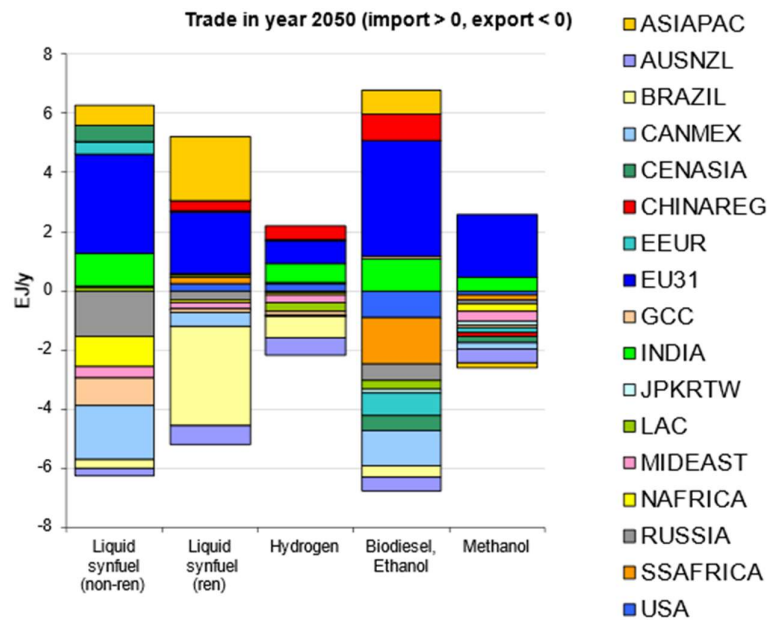


Figure 86: Export and import regions in the year 2050 of alternative liquids and of hydrogen (EJ/y).

As mentioned above, the largest exporters of non-renewable alternative liquid synthetic fuels are Canada & Mexico (1.8 EJ/y), followed by Russia (1.6 EJ/y), North Africa, and GCC (both 1 EJ/y). For green (renewable, 2nd generation biomass) alternative liquid fuels, the largest exporter is Brazil (3.4 EJ/y), followed by smaller fractions of Australia & New Zealand, Canada & Mexico.



In our result, in the year 2050, only generic hydrogen is traded long-distance between world regions; the “green” sustainable hydrogen from 2nd generation biomass and from renewable electricity is not traded anymore; in 2030 and 2040, India is the main importer of green hydrogen with a relatively low amount of up to 0.5 EJ/y. India, in general, is a region with exceptionally high absolute demand growth, such that exploitation of diverse domestic potentials and import options is necessary to yield a feasible solution in our modelling. As can be seen in Figure 86, the large export world regions of hydrogen are Brazil (0.7 EJ/y), Australia & New Zealand (0.6 EJ/y), the Middle East + GCC (0.4 EJ/y), and LAC (0.3 EJ/y).

Apart from alternative liquid fuels that use novel technology, traditional biodiesel and bioethanol have gross trade volumes of comparable size. The exporter world regions of biodiesel and bioethanol are diverse: The largest export region in the year 2050 is Sub-Saharan Africa (1.6 EJ/y), Canada & Mexico (1.2 EJ/y), USA (0.9 EJ/y), and Eastern Europe (0.8 EJ/y). Methanol for energy purposes seems to be traded less, but still slightly more than hydrogen; the largest export region is Australia & New Zealand (0.5 EJ/y in year 2050).

5.4.5. Additional Energy System Results

Figure 87 shows global electricity production in the base case scenario of SHELTERED. While electricity production roughly doubles between 2020 and 2050, this increase still falls short of WEO2024 (IEA, 2024c) [Fig. 3.21], which has an electricity production in the year 2050 of 58'352 TWh/y, 70'564 TWh/y, and 80'194 TWh/y in the STEPS, APS, and NZE scenarios, respectively. While IEA's investment levels in the power sector are assumed to be high (e.g., doubling until 2030 in NZE from 2023 level, [ibid., Fig. 3.27]), growth is assumed to be more limited in GMM, especially in the years 2025–2040 for wind and solar PV. In our modelling, intermittent wind and solar are partially balanced by gas-powered plants with CCS, whereas WEO2024 assumes mostly storage and flexible biomass power plants (IEA, 2024c) [ibid., Fig. 3.41]. In GMM, on a global level, biomass is used mostly cost-effectively in other sectors, for example, in biofuel production and heating. In terms of storage—as noted before—GMM has no explicit storage but implicitly accounts for some storage by spreading solar production to nights with increased costs.

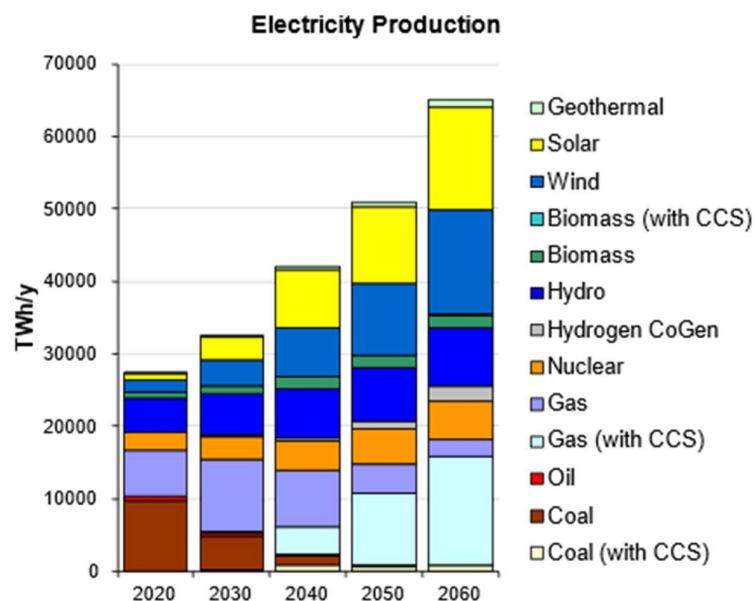


Figure 87: Global power generation by source. “Hydrogen CoGen”=District level CHPs; “Solar”=mostly Solar PV.

Hence, related, a further reason for the higher electricity production in WEO2024 is also the larger increase of electrolyser operation: Electricity for hydrogen increases from today's 5 TWh/y in the year



2050 up to 9'000 TWh/y in APS, and to nearly 15'000 TWh in the NZE scenario, which is more than half of today's electricity production) (IEA, 2024c) [ibid., p. 43].

Figure 88 shows the biomass extraction in the base case scenario of SHELTERED. The total biomass surpasses 140 EJ/y in the year 2050 but is still below the assumed potential of 195 EJ/y. For comparison, WEO2024, biomass use is less at approximately 100 EJ/y in the year 2050, both in their APS and NZE scenarios [ibid., p. 153]. As already mentioned above, biomass is used differently. Related, a reason for e-fuels in transport in the IEA's scenarios is provided in (IEA, 2024b) [p. 17/18]: Biomass has limited resource potential and will be required in road transport and for electricity and heat generation. By contrast, we may argue that the pathway from biomass over electricity generation to liquid e-fuels is not efficient, and heat generation as well as road transport is expected to be further electrified.

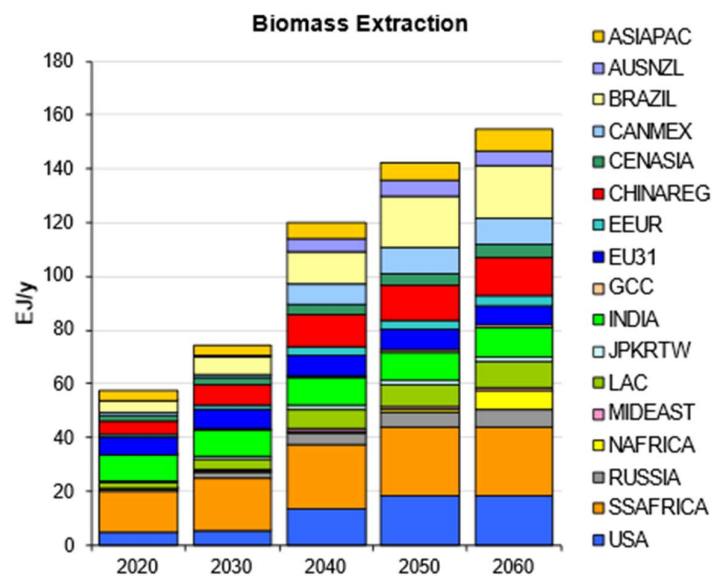


Figure 88: Biomass extraction of the 17 world regions.

Figure 89 shows the development of the personal car sector with the large trend towards electrification.

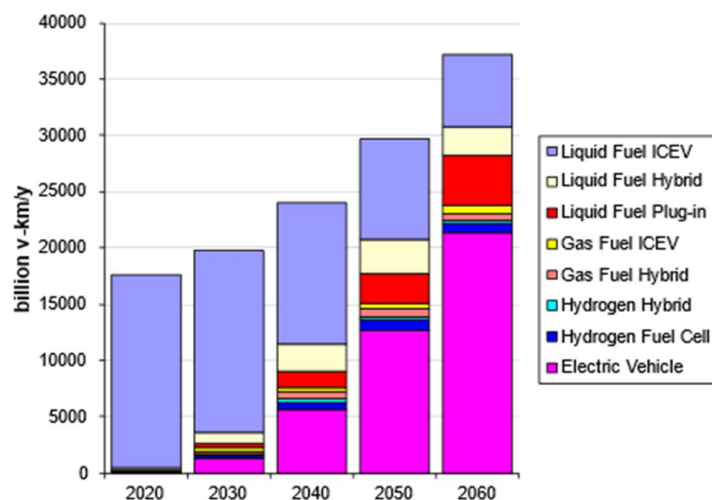


Figure 90: Global personal car sector.



We may compare with WEO2024 (IEA, 2024c) [ibid., p. 159, Fig. 3.46], which has shares of zero-emission vehicles in stock in the year 2035 of approximately 30%, 35%, and 45% in the STEPS, APS, and the NZE scenario (it seems that BEV, PHEV and hydrogen vehicles are counted as zero-emission); in SHELTERED, in year 2040, this share is 34%.

5.5 Sensitivity Analyses

By the previously shown results of our base case scenario, liquid biofuels are more cost-effective than liquid e-fuels. Some of the key factors are varied as follows in the sensitivity analyses.

5.5.1. Biomass: Reduced potential and doubled cost

In this sensitivity analysis on biomass, we reduce the biomass potential by 30% for each world region and each of GMM's biomass categories (cf. section 5.3.2). Exceptions are the regions India and EU31 with reduced potential of only 10% because a higher reduction leads to an infeasible optimization model; and based on our modelling experience, India and EU31 are the two world regions that generally have a high energy supply scarcity. In this sensitivity analysis, we also double the primary extraction cost of all biomass categories.

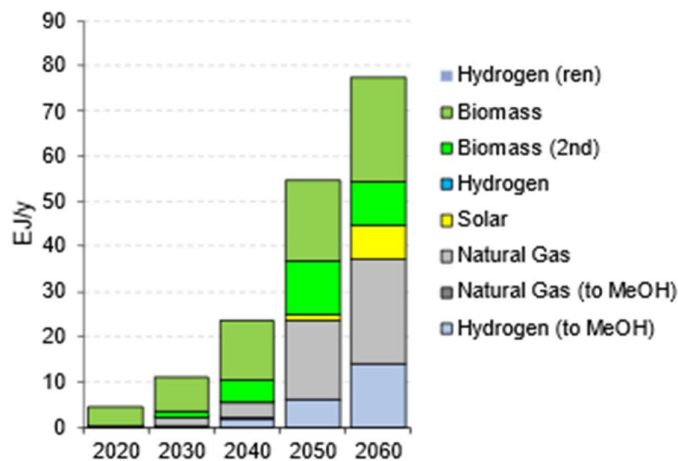


Figure 91: Global alternative liquid fuels production under reduced potential and doubled extraction cost of biomass.

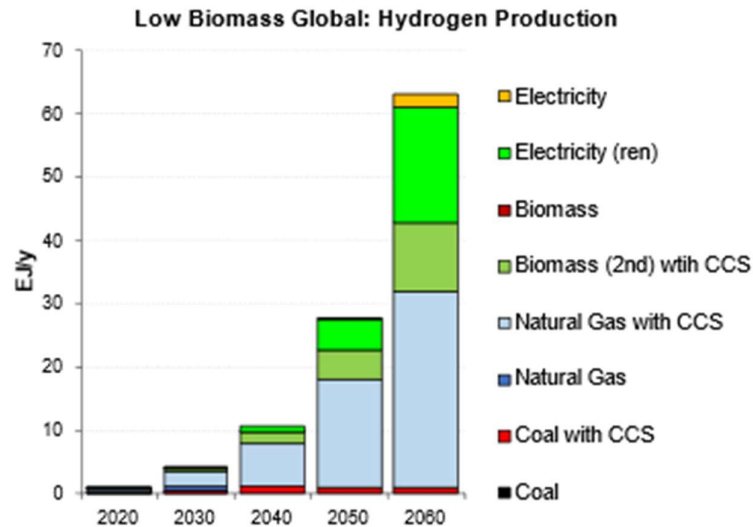


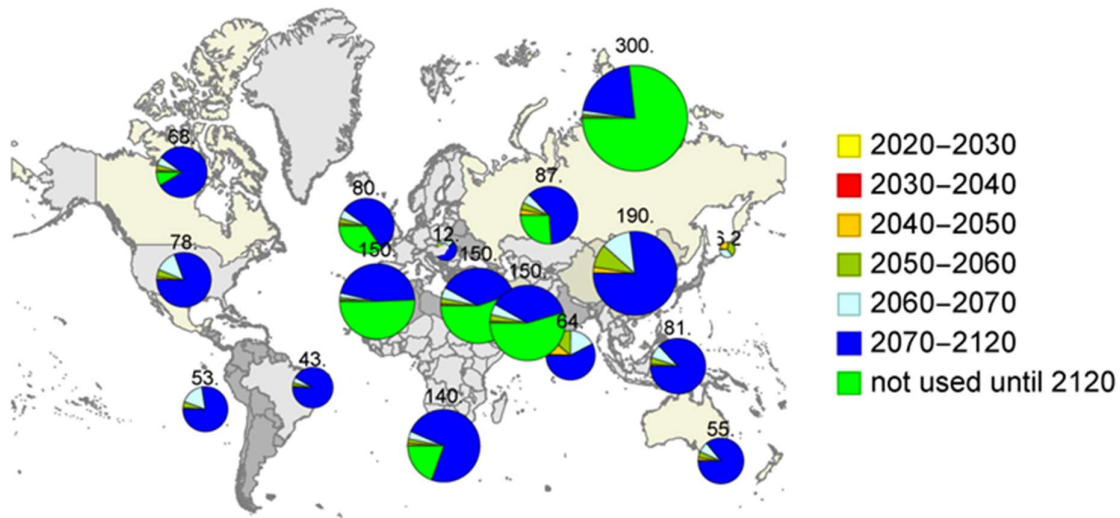
Figure 92: Global hydrogen production under reduced potential and doubled extraction cost of biomass.

As a result, because of the obviously reduced attractiveness of biomass, total biomass extraction in the year 2050 is reduced from 143 EJ/y in our previous base case scenario to 114 EJ/y (which is closer to WEO2040 of approximately 100 EJ/y). In terms of global alternative liquid fuel production, the change is merely a moderate scale-down of biomass use, and a slight scale-up of other pathways. For global hydrogen production, results are almost unchanged.

If biomass is less attractive, international trade also diminishes. For example, liquid sustainable fuels from biomass lose approximately 30% of their trading volume in the year 2050.

5.5.2. Carbon Capture and Storage: Reduced potential and higher costs

In our base case scenario (section 5.4), we assume that CC(U)S is socially accepted in the ranges of technical potentials and associated costs commonly reported in the literature (cf. section 5.3.1). Figure 93 shows the potential in each world region and its usage in the base case until 2120 (GMM runs internally for 100 years).



As can be seen in Figure 93, the storage potential is used up until the year 2070 only in the region JPKRTW (Japan + Korea + Taiwan-China); note that we allow no shipping of captured CO₂ across world regions. Most of the CCS happens after 2050. In a sensitivity analysis, we reduce the storage potential for each world region to 1%. The reduction may be due to low social acceptance, and we increase the cost of CCS from 18 to 73\$(2024)/tCO₂.

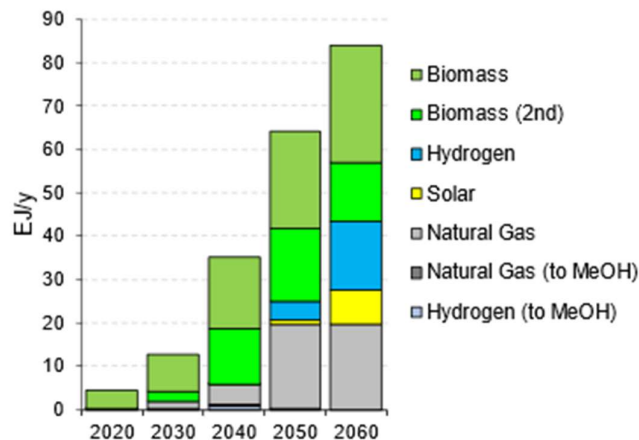


Figure 94: Global alternative liquid fuel production by source under reduced potential and higher costs of CCS.

As a result of the reduced attractiveness of CCS, in terms of global alternative liquid fuel production, the total amounts are roughly similar. If CCS is scarce, e-fuels from hydrogen start to be cost-effective in the year 2050, whereas commercial methanol production from hydrogen nearly vanishes. Hence, apart from this reshuffling, the change in CCS has a minor impact on liquid alternative fuel production.

By contrast, in terms of global hydrogen production, total production is roughly halved in all time steps in case CCS is scarce and more costly: The production from natural gas with CCS is heavily reduced. Hydrogen BECCS is replaced by generic biomass without CCS. Additionally, nuclear-based hydrogen starts to play a role in the years 2050/60.



With the reduced availability of CCS, the trade of alternative energy carriers also changes. For example, exported methanol (from hydrogen) nearly vanishes, whereas export of liquid fuels based on biomass pertains to their levels.

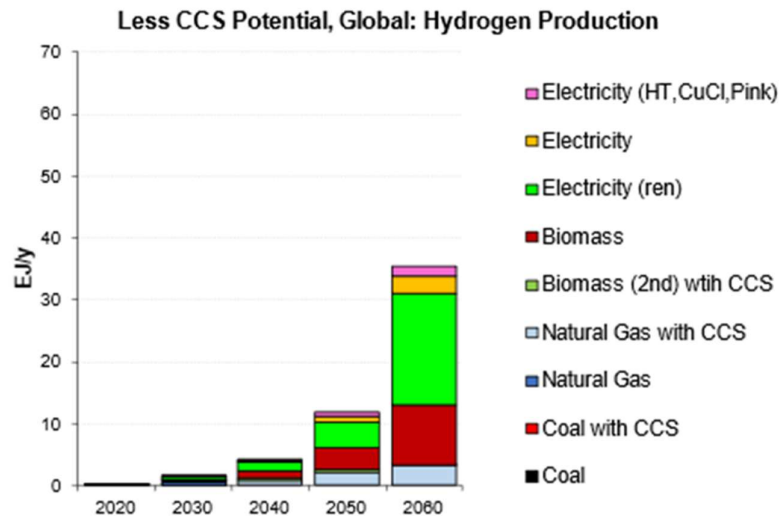


Figure 95: Global hydrogen production by source under reduced potential and higher costs of CCS.

5.5.3. DAC not required for hydrogen-based liquid fuels

In our base case scenario, liquid FT-type fuel production from renewable hydrogen sources must use DAC as a source for the required CO₂. In this sensitivity analysis, such liquid fuels can use any source of captured carbon. We assume the cost of 18\$(2024)/tCO₂ for the use of the carbon source (as for normal CCS).

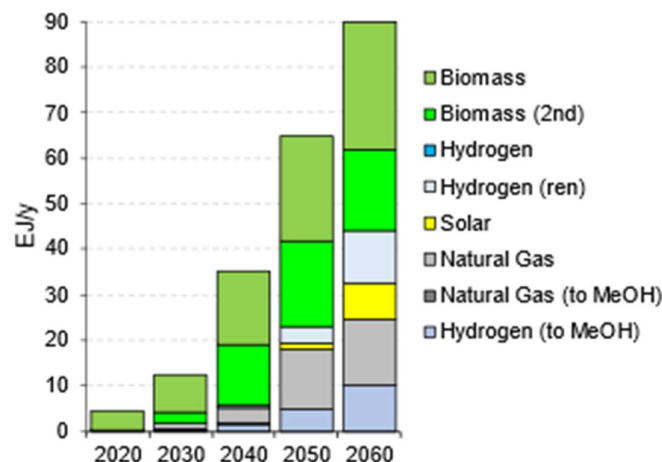


Figure 96: Global alternative liquid fuel production: No DAC required for e-fuels.

In terms of global alternative liquid fuel production, the most noticeable change is that hydrogen is now a cost-effective option for liquid fuels, but will not come in significantly before the year 2050 (see category "Hydrogen (ren)"). In terms of global hydrogen production, the relaxation of the DAC requirement for liquid e-fuels seems to have not much influence: the results are roughly the same.



If the DAC requirement is relaxed, then international trade of alternative energy carriers is less required. For example, total exported methanol (as in the previous sensitivity analysis on CCS) nearly vanishes, and liquid fuels based on biomass lose approximately one-third of the trading volume in the year 2050.

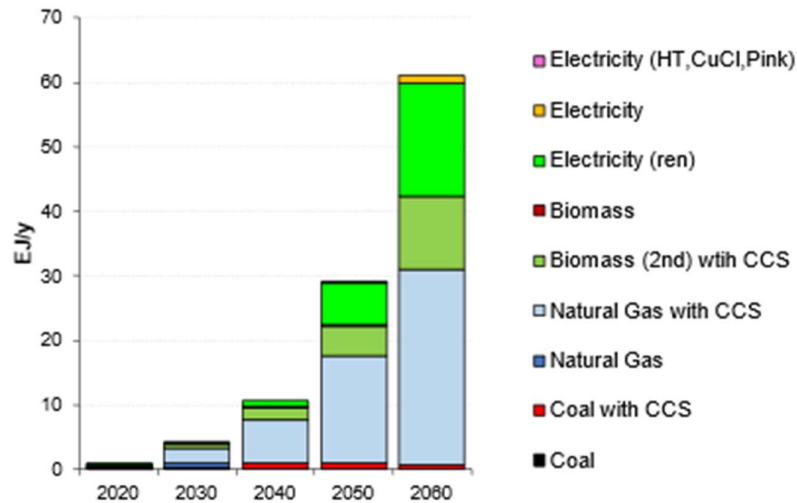


Figure 97: Global hydrogen production: No DAC required for e-fuels.

5.5.4. DAC not required, low CCS potential, biomass low potential & high costs

In this sensitivity analysis, we consider a combination of the previous sensitivity analyses. As in the section 5.5.1, we reduce the biomass potential by 30% (10% in EU31 and India), and we even quadruple the biomass extraction cost (previously in the section 5.5.1 they were just doubled). As in the section 5.5.2, we reduce the CCS potential to 1%. And as in the section 5.5.3 DAC is not required for liquid renewable e-fuels.

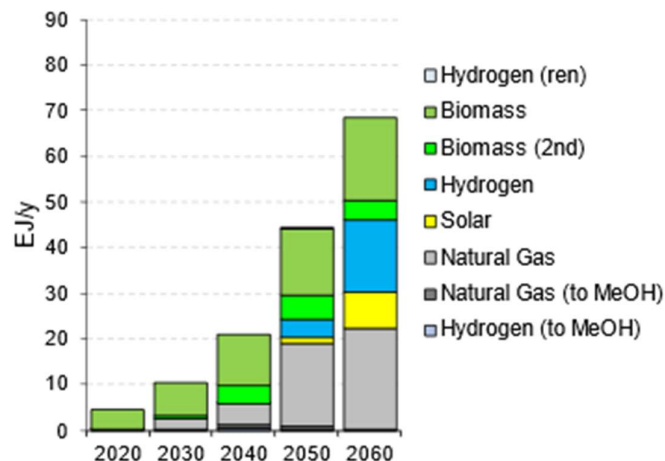


Figure 98: Global alternative liquid fuel production under: No DAC required, CCS low potential, and biomass low potential & high cost.

In terms of global alternative liquid fuel production, this combined case is similar to the case with reduced CCS potential, in combination with a reduced use of biomass. Hence, the stringency of the reduced CCS potential counteracts the relaxation of the DAC requirement for liquid e-fuels.



In terms of global hydrogen production, this combined case is also very similar to the case with reduced CCS potential. Hence, biomass is still used, even under four times the baseline extraction costs (just without CCS).

In this combined variation, international trade of alternative energy carriers is also partially reduced. While, for example, sustainable liquid biomass export globally is still on the same level as in the base case scenario in the year 2050 (despite the lesser attractiveness of biomass), methanol export (as in previous sensitivity analyses) nearly vanishes.

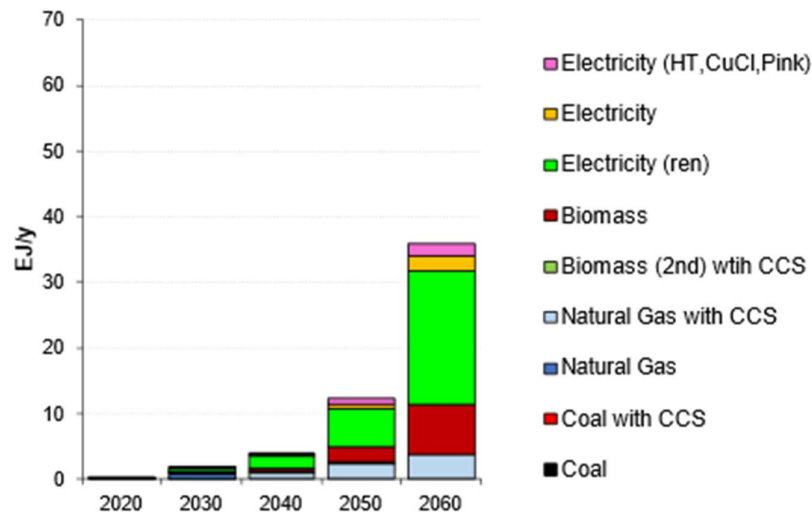


Figure 99: Global hydrogen production under: No DAC required, CCS low potential, and biomass low potential & high cost.

5.6 Conclusion

Under the assumption of a stringent, international climate policy towards net zero GHG emissions and of a market-oriented long-term cost-minimization of the global energy system with global trade options, the deployment of alternative fuels depends on three key aspects as follows:

- **How to use biomass.** Even in our sensitivity analysis of reduced biomass potential and increased biomass production and supply cost, biomass is still cost-effectively used globally for liquid alternative fuels (apart from conventional heating purposes). As a contrasting example, in IEA's World Energy Outlook 2024 (IEA, 2024c), the major share of biomass is used for electricity generation, and biomass power plants are used to balance solar and wind generation in all three scenarios. Biomass is therefore not much used for fuel production as an outcome; note that these outcomes are a mix of policy and cost-minimization assumptions, which are difficult to separate in results. Related is the fact that total biomass extraction in our base case scenario is higher than in (IEA, 2024c); also, in our modelling, electricity is cost-effectively balanced instead by gas power plants with CCS due to low CCS costs (in both studies, additionally also with batteries). Consequently, our total electricity generation is lower than in (IEA, 2024c); the higher electricity generation in (IEA, 2024c) is also used for higher hydrogen generation from electrolyzers, which in turn is used (partially) for liquid e-fuels. Our model tries to avoid the indirect pathway: Biomass → Electricity → Hydrogen → Liquid fuel. In summary, energy scenario models tend to favour either electricity production globally or high increases in biomass extraction (as our model tries first to a given limit).
- **Carbon capture and storage.** If CO₂ storage capacity is abundantly available, hydrogen from BECCS is a cost-effective option. On the other hand, liquid e-fuels are globally only cost-effective if CCS is limited; limitations can also be high costs, or limited availability of pipelines or



tanker ships (only trucks for compressed CO₂). Under limited CCS, also hydrogen from electrolysis can expand further, and is deployed at larger absolute amounts earlier globally (in the year 2040), but globally total hydrogen production is roughly reduced by 50%.

- Carbon source for liquid e-fuels. Our global results show that cost-effective liquid e-fuels require a cheap carbon source; DAC is likely too expensive. Hence, while liquid e-fuel deployment is reduced by large-scale CCS, some level of more conventional carbon capture is still required.

Other insights from this part of the report:

- In the base case scenario, large exporter regions of liquid alternative fuels are: Brazil, Canada & Mexico, Australia & New Zealand, and Russia. In the years 2030, 2040, and 2050, in the assumed international pool market, two of the main novel exported LCF, methanol from hydrogen and 2nd generation biomass fuels, are produced at approximately equal amounts: 1 EJ/y, 2.6 EJ/y, and 4.5 EJ/y export volume is reached in 2030, 2040, and 2050, respectively, for both fuel types.
- While our base case scenario results do not favour liquid e-fuels to substitute gasoline/kerosene, hydrogen is used to produce commercially traded methanol, which is used as an end-use fuel (also as a blend) and as feedstock.
- Hydrogen is only partially cost-effectively produced from electricity before 2050. Indeed, the global decarbonization scenario in SHELTERED assumes an internationally coordinated action to reduce CO₂ emissions, where all world regions show emission reductions. Three developments take place simultaneously: (i) the decarbonization of electricity generation, (ii) the electrification of demand sectors, and (iii) a high increase of useful energy in demand sectors in the developing and transitional countries (which can only partially be offset by higher efficiency). This leads to high marginal costs of electricity with respect to other energy carriers, such that large-scale global deployment of electrolyzers is delayed, and alternative hydrogen production routes are selected whenever possible.
- Solar processes for hydrogen and for liquid fuel production could be a cost-effective, large-scale deployment option starting in 2050.

5.7 Limitations and further research

- **Electrolyser operation.** The deployment of electricity-based hydrogen and further on of liquid e-fuels depends also on the cost-effective operation of the electrolyzers, which should preferably run as many full-load hours as possible. In current modelling, GMM has 6 time-slices for a year in the electricity sector. Day-night electricity storage is modelled only implicitly, for solar PV. Other supplies and demand in the energy system are balanced annually. Therefore, seasonal energy shifts and shifts between the day-hours and the night-hours are modelled implicitly. Generally, this level of aggregation in GMM may favour full-load operation. Nevertheless, a more detailed representation of dynamic electrolyser operation could be useful.
- **Feedstocks.** Future energy system modelling needs a more detailed representation of energy carrier pathways and detailed possibilities of substitution outside of the energy system (e.g., use in the chemical industry, feedstocks), especially for the new alternative energy carriers (hydrogen, methanol, etc.). Also, ammonia is not modelled separately.
- **CO₂ tracking in energy carriers.** In our global modelling, we differentiate between “green” pathways (from renewable electricity and 2nd generation biomass) and “generic” pathways. In more advanced energy system modelling of the future, life-cycle CO₂ emissions of each energy carrier shall be tracked endogenously. This allows us to consider life-cycle-based constraints (e.g., related to the EU’s Carbon Border Adjustment Mechanism) and a better accounting for trade. Indeed, as of today, an international low-carbon fuels certification is still lacking (IRENA, 2023a).



- **Long-distance hydrogen pipelines.** Although ammonia shipping seems to be a cost-effective long-distance trading option (see e.g., section 2.3.7 of this report or (IRENA, 2022), GMM does not consider re-purposed or newly built pipelines between the 17 world regions. Reasons are the high uncertainties in route choices and the uncertainty in the points of time for re-purposing.
- **Inelastic demand:** In the energy system modelling framework used in the analysis, energy service demands are treated as fixed, i.e., demand is effectively assumed to be inelastic, meaning it does not respond to changes in energy prices. Thus, the exogenously defined demand must be met at any cost, subject to technical or operational constraints. In reality, some demands are elastic —particularly in the aviation sector, where higher energy prices can translate into increased travel costs and, consequently, reduced demand. These behavioural and price-responsive effects are not captured in the current analysis.



6 Publications and other communications

Liu, Z., Terlouw, T., Frey, P., Bauer, C., McKenna, R. (2026). Global cost drivers and regional trade-offs for low-carbon fuels: a prospective techno-economic assessment. *Energy & Environmental Science*. doi: 10.1039/d5ee05591a

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8 Appendix

8.1 Techno-economic analysis of LCF production and transport

Table 13: Techno-economic data used for the LCOX calculation. capex [CHF/kW]: capital expenditure. om [%]: operational expenditure (percentage of capex). lt [hours]: lifetime of production equipment. eff [%]: energy efficiency (LHV). The capital expenditure includes all the production equipment and processes to reach the target fuel production (for FT fuels, including upgrading to Kerosene, and for MeOH pathway, including MeOH to Jet process).

technology	sub	Base_2022	Base_2030	2 de- gree_2030	1.5 de- gree_2030	Base_2050	2 de- gree_2050	1.5 de- gree_2050
PEM	capex	1200	512	462	359	371	270	240
	om	0.05	0.05	0.05	0.05	0.05	0.05	0.05
	lt	60000	71429	74286	78571	100000	110000	125000
	eff	58%	61%	62%	63%	70%	73%	75%
AE	capex	800	500	527	459	418	392	367
	om	3%	3%	3%	3%	3%	3%	3%
	lt	75000	82143	85000	89286	100000	110000	125000
	eff	61%	61%	64%	65%	61%	71%	75%
SOEC	capex	2500	1872	1156	580	1677	794	375
	om	5%	5%	5%	5%	5%	5%	5%
	lt	20000	37143	38571	40000	80000	85000	90000
	eff	88%	88%	89%	89%	88%	90%	90%
HTSE	capex	2500	1872	1156	580	1677	794	375
	om	5%	5%	5%	5%	5%	5%	5%
	lt	20000	37143	38571	40000	80000	85000	90000
	eff	88%	88%	89%	89%	88%	90%	90%
CuCl	capex	500	422	352	291	422	331	225
	om	5%	5%	5%	5%	5%	5%	5%
	lt	87600	87600	87600	87600	87600	87600	87600
	eff	43%	43%	43%	43%	43%	43%	43%
SMR_CCS	capex	1674	1624	1304	937	1528	1031	679
	om	5%	5%	5%	5%	5%	5%	5%
	lt	219000	219000	219000	219000	219000	219000	219000
	eff	70%	70%	74%	74%	70%	85%	85%
ATR_CCS	capex	1307	1268	1018	731	1193	805	530
	om	5%	5%	5%	5%	5%	5%	5%
	lt	219000	219000	219000	219000	219000	219000	219000
	eff	70%	70%	71%	71%	70%	75%	75%
CLR	capex	1200	1140	875	609	1029	651	419
	om	5%	5%	5%	5%	5%	5%	5%
	lt	219000	219000	219000	219000	219000	219000	219000
	eff	75%	75%	75%	75%	75%	75%	75%
M_PYR	capex	1500	1425	1094	762	1286	814	524
	om	5%	5%	5%	5%	5%	5%	5%
	lt	219000	219000	219000	219000	219000	219000	219000
	eff	60%	60%	63%	66%	60%	70%	80%
TG_CCS	capex	800	762	659	504	723	606	438
	om	6%	6%	6%	6%	6%	6%	6%
	lt	262800	262800	262800	262800	262800	262800	262800
	eff	60%	60%	60%	60%	60%	60%	60%
SR_FT	capex	1030	979	784	538	930	526	322
	om	5%	5%	5%	5%	5%	5%	5%
	lt	219000	219000	219000	219000	219000	219000	219000
	eff	64%	64%	64%	64%	64%	64%	64%
ST_FT	capex	2695	2560	2052	1407	2432	1377	843
	om	4%	4%	4%	4%	4%	4%	4%
	lt	219000	219000	219000	219000	219000	219000	219000
	eff	19%	19%	19%	19%	19%	19%	19%
TG_FT	capex	1787	1648	1399	1041	1507	1259	885
	om	5%	5%	5%	5%	5%	5%	5%
	lt	219000	219000	219000	219000	219000	219000	219000
	eff	45%	45%	45%	46%	45%	45%	50%
RWGS_FT	capex	606	576	462	316	547	310	190
	om	3%	3%	3%	3%	3%	3%	3%



technology	sub	Base_2022	Base_2030	2 de- gree_2030	1.5 de- gree_2030	Base_2050	2 de- gree_2050	1.5 de- gree_2050
RWGS_MeOH	lt	219000	219000	219000	219000	219000	219000	219000
	eff	65%	65%	68%	68%	65%	74%	74%
	capex	2029	1928	1545	1059	1831	1037	635
	om	3%	3%	3%	3%	3%	3%	3%
FAME	lt	219000	219000	219000	219000	219000	219000	219000
	eff	78%	78%	78%	78%	78%	78%	78%
	capex	1660	1592	1336	1039	1530	1184	925
	om	5%	5%	5%	5%	5%	5%	5%
HVO	lt	219000	219000	219000	219000	219000	219000	219000
	eff	92%	92%	92%	92%	92%	92%	92%
	capex	2000	1863	1520	1157	1743	1304	1010
	om	5%	5%	5%	5%	5%	5%	5%
B_PYR	lt	219000	219000	219000	219000	219000	219000	219000
	eff	80%	80%	80%	80%	80%	80%	80%
	capex	973	906	739	563	848	635	492
	om	5%	5%	5%	5%	5%	5%	5%
PTM	lt	219000	219000	219000	219000	219000	219000	219000
	eff	56%	56%	56%	56%	56%	56%	56%
	capex	320	304	244	167	289	163	100
	om	10%	10%	10%	10%	10%	10%	10%
AD	lt	219000	219000	219000	219000	219000	219000	219000
	eff	85%	85%	85%	85%	85%	85%	85%
	capex	1200	1009	1080	808	950	829	597
	om	5%	5%	5%	5%	5%	5%	5%
HB	lt	219000	219000	219000	219000	219000	219000	219000
	eff	58%	58%	58%	58%	58%	58%	58%
	capex	515	500	415	295	485	303	190
	om	3%	3%	3%	3%	3%	3%	3%
DAC	lt	219000	219000	219000	219000	219000	219000	219000
	eff	70%	70%	70%	70%	70%	70%	70%
	capex	1384	1109	965	493	789	555	301
	om	12%	12%	12%	12%	12%	12%	12%
	lt	219000	219000	219000	219000	219000	219000	219000
	eff	50%	58%	58%	58%	78%	78%	78%

Table 14: Technology learning rate, TRL, and accumulated capacity data used for calculation.

Scenarios	2 degree									1.5 degree									BAU								
Variables	Learning rate			TRL			Scale (Mt H2 equivalent)			Learning rate			TRL			Scale (Mt H2 equivalent)			Learning rate			TRL			Scale (Mt H2 equivalent)		
Tech.	2022	2030	2050	2022	2030	2050	2022	2030	2050	2022	2030	2050	2022	2030	2050	2022	2030	2050	2022	2030	2050	2022	2030	2050	2022	2030	2050
PEM	14%	8	9	9	0.2	16	189			14%	8	9	9	0.2	51	327			14%	0.2	9	9	0.1	5	22		
AE	8%	8	9	9	0.5	16	189			8%	8	9	9	0.5	51	327			8%	0.5	9	9	0.1	5	22		
SOEC	10%	7	8	9	0.1	16	189			15%	7	9	9	0.1	51	327			5%	0.1	8	9	0.1	5	22		
HTSE	10%	6	8	9	0.1	16	189			15%	6	9	9	0.1	51	327			5%	5	8	9	0.1	5	22		
CuCl	10%	5	7	9	0.1	1	1.5			15%	5	9	9	0.1	1	3			5%	6	8	9	0.1	1	1		
SMR_CCS	8%	8	9	9	1	8	56			13%	8	9	9	1	18	89			3%	8	9	9	1	2	8		
ATR_CCS	8%	8	9	9	1	8	56			13%	8	9	9	1	18	89			3%	8	9	9	1	2	8		
CLR	10%	6	8	9	1	8	56			15%	6	9	9	1	18	89			5%	6	8	9	1	2	8		
PYR	10%	5	8	9	1	8	56			15%	5	9	9	1	18	89			5%	5	8	9	1	2	8		
TG_CCS	8%	8	9	9	0.1	0.5	1			13%	8	9	9	0.1	1	2			3%	8	9	9	0.1	0.1	1		
SR_FT	10%	6	8	9	1	6	83			15%	6	9	9	1	16	142			5%	6	8	9	1	2	4		
ST_FT	10%	5	7	9	1	6	83			15%	5	9	9	1	16	142			5%	5	7	9	1	2	4		
TG_FT	10%	7	8	9	0.1	0.1	1			15%	7	9	9	0.1	1	2			5%	6	8	9	0.1	0.1	2		
RWGS_FT	10%	7	8	9	1	6	83			15%	7	9	9	1	16	142			5%	6	8	9	1	2	4		
RWGS_MeOH	10%	7	8	9	1	6	83			15%	7	9	9	1	16	142			5%	6	8	9	1	2	4		
FAME	8%	8	9	9	0.23	1.4	3.83			13%	8	9	9	0.23	2.37	4.23			3%	8	9	9	0.23	0.6	1.47		



Scenarios	2 degree							1.5 degree							BAU						
HVO	10%	7	8	9	0.23	1.4	3.83	15%	7	9	9	0.23	2.37	4.23	5%	6	8	9	0.23	0.6	1.47
PYR	10%	5	8	9	0.23	1.4	3.83	15%	5	9	9	0.23	2.37	4.23	5%	4	7	9	0.23	0.6	1.47
PTM	10%	7	8	9	1	6	83	15%	7	9	9	1	16	142	5%	7	8	9	1	2	4
AD	10%	7	8	9	12.5	25	142.5	15%	7	9	9	12.5	67.5	245	5%	7	8	9	12.5	130	295
HB	8%	9	9	9	1	6	83	13%	9	9	9	1	16	142	3%	9	9	9	1	2	4
DAC	8%	5	8	9	0.5	10	1000	13%	5	8	9	0.5	10	1000	5%	5	8	9	0.5	10	1000

Table 15: Input energy and material balance data for each technology's 1 kWh target fuel production.

tech	Target fuel	Pure water [kg/kWh]	Biomass [kg/kWh]	Industry water [kg/kWh]	CO ₂ [kg/kWh]	CH ₄ [kg/kWh]	H ₂ [kg/kWh]	Elec [kWh/kWh]	Heat [kWh/kWh]
PEM	Hydrogen	0.405	0.000	0.000	0.000	0.000	0.000	1.000	0.000
AE	Hydrogen	0.405	0.000	0.000	0.000	0.000	0.000	1.000	0.000
SOEC	Hydrogen	0.405	0.000	0.012	0.000	0.000	0.000	0.800	0.200
HTSE	Hydrogen	0.405	0.000	0.000	0.000	0.000	0.000	0.800	0.200
CuCl	Hydrogen	0.405	0.000	0.000	0.000	0.000	0.000	0.290	0.710
SMR_CCS	Hydrogen	0.000	0.000	0.201	0.000	0.072	0.000	0.133	0.000
ATR_CCS	Hydrogen	0.000	0.000	0.201	0.000	0.090	0.000	0.107	0.000
CLR	Hydrogen	0.000	0.000	0.000	0.000	0.108	0.000	0.092	0.000
M_PYR	Hydrogen	0.000	0.000	0.000	0.000	0.106	0.000	0.168	0.000
TG_CCS	Hydrogen	0.000	0.392	0.000	0.000	0.000	0.000	0.000	0.000
SR_FT	Kerosene	0.000	0.000	0.000	0.000	0.160	0.000	0.614	0.000
ST_FT	Kerosene	0.106	0.000	0.000	0.262	0.000	0.000	0.045	0.000
TG_FT	Kerosene	0.000	0.181	0.000	0.000	0.000	0.000	0.000	0.000
RWGS_FT	Kerosene	0.000	0.000	0.000	0.262	0.000	0.013	0.045	0.000
RWGS_MeOH	MeOH-Kerosene	0.000	0.000	0.000	0.251	0.000	0.013	0.025	0.000
FAME	Diesel	0.000	0.307	0.000	0.000	0.000	0.000	0.000	0.000
HVO	Diesel	0.000	0.307	0.000	0.000	0.000	0.000	0.000	0.000
B_PYR	Diesel	0.000	0.307	0.000	0.000	0.000	0.000	0.056	0.000
PTM	Methane	0.000	0.000	0.000	0.200	0.000	0.038	0.010	0.000
AD	Methane	0.000	0.260	0.000	0.000	0.000	0.000	0.000	0.000
HB	Ammonia	0.000	0.000	0.000	0.000	0.000	0.035	0.096	0.000

Table 16: Fuel property data used in the calculation (Bertoli et al., 2016).

Fuel	Boiling point (°C)	Energy density (kWh/L)	Lower heating value (LHV, kWh/kg)	Higher heating value (HHV, kWh/kg)	Lower heating value (LHV, MJ/kg)
Ammonia	-33.34	3.53	5.22	6.25	18.79
Methanol	64.70	4.67	5.60	6.40	20.16
Kerosene	150-300	10.70	11.90	12.70	42.84
Diesel	163-357	10.70	11.90	12.70	42.84
Methane	-161.60	0.01	12.70	14.75	45.72
Liquid hydrogen	-252.9	2.50	33.30	39.40	119.88



Table 17: WACC technology and scenario specific factor $f_{x,t}^{tech}(x,t)$ data used in the calculation in each scenario and year.

Technology	Base_2022	Base_2030	2 de-gree_2030	1.5 de-gree_2030	Base_2050	2 de-gree_2050	1.5 de-gree_2050
PEM	1	1	0.72	0.76	0.66	0.60	0.75
AE	1	1	0.77	0.81	0.71	0.64	0.81
SOEC	1.5	1.5	1.03	1.10	0.95	0.86	1.08
HTSE	1.5	1.5	1.03	1.11	0.95	0.86	1.08
CuCl	1.875	1.875	1.58	1.40	1.58	1.53	1.34
SMR_CCS	1	1	0.86	0.86	0.81	0.74	0.85
ATR_CCS	1	1	0.86	0.86	0.81	0.74	0.85
CLR	1.5	1.5	1.29	1.31	1.21	1.11	1.27
M_PYR	1.875	1.875	1.61	1.66	1.51	1.39	1.59
TG_CCS	1	1	0.89	0.72	0.84	0.84	0.72
SR_FT	1.5	1.5	1.31	1.31	1.22	1.08	1.27
ST_FT	1.875	1.875	1.64	1.66	1.53	1.35	1.59
TG_FT	1.5	1.5	1.50	1.10	1.27	1.27	1.08
RWGS_FT	1.5	1.5	1.31	1.30	1.22	1.08	1.27
RWGS_MeOH	1.5	1.5	1.31	1.30	1.22	1.08	1.27
FAME	1	1	0.87	0.77	0.84	0.81	0.76
HVO	1.5	1.5	1.31	1.16	1.26	1.22	1.14
B_PYR	1.875	1.875	1.64	1.49	1.58	1.52	1.43
PTM	1.5	1.5	1.31	1.30	1.22	1.08	1.27
AD	1.5	1.5	1.43	1.57	1.32	1.25	1.54
HB	1	1	0.87	0.77	0.84	0.81	0.76
DAC	1.875	1.875	1.61	1.66	1.51	1.39	1.59

Table 18: WACC country specific factor used in the calculation $f_y^{country}(y)$, and country risk premium data (Calcaterra et al., 2024; Polzin et al., 2021).

Country Name	ISO_A3_EH	Country Risk Premium	$f_y^{country}(y)$
Albania	ALB	0.08	1.97
Algeria	DZA		
Angola	AGO	0.11	2.40
Argentina	ARG	0.21	3.59
Armenia	ARM	0.06	1.78
Australia	AUS	0.00	1.00
Austria	AUT	0.01	1.09
Azerbaijan	AZE	0.04	1.54
Bangladesh	BGD	0.06	1.78
Belarus	BLR	0.21	3.59
Belgium	BEL	0.01	1.13
Belize	BLZ	0.16	2.94
Benin	BEN	0.08	1.97
Bolivia	BOL	0.09	2.19
Bosnia and Herzegovina	BIH	0.11	2.40
Botswana	BWA	0.02	1.26
Brazil	BRA	0.05	1.65
Bulgaria	BGR	0.03	1.34
Burkina Faso	BFA	0.13	2.62
Cambodia	KHM	0.09	2.19
Canada	CAN	0.00	1.00
Chile	CHL	0.01	1.18
Colombia	COL	0.03	1.41
Costa Rica	CRI	0.09	2.19



Country Name	ISO_A3_EH	Country Risk Premium	$f_y^{country}(y)$
Croatia	HRV	0.03	1.41
Cuba	CUB	0.21	3.59
Cyprus	CYP	0.04	1.54
Czech Republic	CZE	0.01	1.13
Democratic Republic of the Congo	COD	0.11	2.40
Denmark	DNK	0.00	1.00
Djibouti	DJI		
Dominican Republic	DOM	0.06	1.78
Ecuador	ECU	0.17	3.16
Egypt	EGY	0.09	2.19
El Salvador	SLV	0.17	3.16
Equatorial Guinea	GNQ		
Eritrea	ERI		
Estonia	EST	0.01	1.15
Ethiopia	ETH	0.16	2.94
Fiji	FJI	0.08	1.97
Finland	FIN	0.01	1.09
France	FRA	0.01	1.11
Gabon	GAB	0.13	2.62
Georgia	GEO	0.05	1.65
Germany	DEU	0.00	1.00
Ghana	GHA	0.21	3.59
Greece	GRC	0.06	1.78
Guatemala	GTM	0.04	1.54
Honduras	HND	0.08	1.97
Hungary	HUN	0.03	1.41
Iceland	ISL	0.01	1.18
India	IND	0.04	1.47
Indonesia	IDN	0.03	1.41
Iran	IRN		
Iraq	IRQ	0.13	2.62
Ireland	IRL	0.01	1.15
Israel	ISR	0.01	1.15
Italy	ITA	0.04	1.47
Jamaica	JAM	0.09	2.19
Japan	JPN	0.01	1.15
Jordan	JOR	0.08	1.97
Kazakhstan	KAZ	0.03	1.41
Kenya	KEN	0.09	2.19
Kuwait	KWT	0.01	1.15
Kyrgyzstan	KGZ	0.11	2.40
Laos	LAO	0.17	3.16
Latvia	LVA	0.02	1.26
Lebanon	LBN	0.25	4.09
Liberia	LBR		
Libya	LBY		
Lithuania	LTU	0.01	1.18
Luxembourg	LUX	0.00	1.00
Madagascar	MDG		
Malawi	MWI		
Malaysia	MYS	0.02	1.26
Mali	MLI	0.16	2.94
Mauritania	MRT		
Mexico	MEX	0.03	1.41
Moldova	MDA	0.11	2.40
Mongolia	MNG	0.11	2.40
Montenegro	MNE	0.08	1.97
Morocco	MAR	0.04	1.54
Mozambique	MOZ	0.16	2.94
Myanmar	MMR		
Namibia	NAM	0.08	1.97
Nepal	NPL		
Netherlands	NLD	0.00	1.00
New Caledonia	NCL		
New Zealand	NZL	0.00	1.00
Nicaragua	NIC	0.11	2.40



Country Name	ISO_A3_EH	Country Risk Premium	$f_y^{country}(y)$
Niger	NER	0.11	2.40
Nigeria	NGA	0.11	2.40
North Korea	PRK		
Norway	NOR	0.00	1.00
Oman	OMN	0.06	1.78
Pakistan	PAK	0.13	2.62
Palestine	PSE		
Panama	PAN	0.03	1.41
Papua New Guinea	PNG	0.09	2.19
Paraguay	PRY	0.04	1.54
People's Republic of China	CHN	0.01	1.15
Peru	PER	0.03	1.34
Philippines	PHL	0.03	1.41
Poland	POL	0.01	1.18
Portugal	PRT	0.03	1.41
Puerto Rico	PRI		
Qatar	QAT	0.01	1.13
Republic of the Congo	COG	0.16	2.94
Romania	ROU	0.04	1.47
Russia	RUS	0.13	2.62
Rwanda	RWA	0.09	2.19
Saudi Arabia	SAU	0.01	1.15
Senegal	SEN	0.06	1.78
Serbia	SRB	0.05	1.65
Sierra Leone	SLE		
Slovakia	SVK	0.01	1.18
Slovenia	SVN	0.02	1.26
Solomon Islands	SLB	0.13	2.62
Somalia	SOM		
South Africa	ZAF	0.05	1.65
South Korea	KOR	0.01	1.11
South Sudan	SSD		
Spain	ESP	0.03	1.34
Sri Lanka	LKA	0.21	3.59
Sudan	SDN		
Suriname	SUR	0.17	3.16
Sweden	SWE	0.00	1.00
Switzerland	CHE	0.00	1.00
Syria	SYR		
Tajikistan	TJK	0.11	2.40
Tanzania	TZA	0.09	2.19
Thailand	THA	0.03	1.34
Togo	TGO	0.11	2.40
Trinidad and Tobago	TTO	0.05	1.65
Tunisia	TUN	0.13	2.62
Turkey	TUR	0.11	2.40
Uganda	UGA	0.09	2.19
Ukraine	UKR	0.17	3.16
United Arab Emirates	ARE	0.01	1.11
United Kingdom	GBR	0.01	1.13
United States of America	USA	0.00	1.00
Uruguay	URY	0.03	1.41
Uzbekistan	UZB	0.08	1.97
Venezuela	VEN	0.25	4.09
Vietnam	VNM	0.05	1.65
Yemen	YEM		
Zambia	ZMB	0.21	3.59



Table 19: Aggregated country specific onshore wind and PV capacity factor (CF) based on pixel level optimization and the calculated country specific grid electricity LCOE in different scenarios.

NAME_EN	ISO_A 3_EH	Country aggregated CF		Country specific grid electricity LCOE (CHF/kW)						
		mean_cf_on shore_wind	mean_cf _pv	Base_ 2022	Base_ 2030	2 de- gree_20 30	1.5 de- gree_203 0	Base_ 2050	2 de- gree_20 50	1.5 de- gree_205 0
Afghanistan	AFG	0.211	0.209	0.069	0.048	0.040	0.031	0.048	0.040	0.031
Albania	ALB	0.181	0.168	0.082	0.058	0.048	0.037	0.058	0.048	0.037
Algeria	DZA	0.371	0.205	0.078	0.053	0.043	0.033	0.053	0.043	0.033
Angola	AGO	0.094	0.194	0.116	0.086	0.073	0.059	0.086	0.073	0.059
Argentina	ARG	0.358	0.192	0.097	0.065	0.053	0.040	0.065	0.053	0.040
Armenia	ARM	0.148	0.171	0.091	0.065	0.054	0.043	0.065	0.054	0.043
Australia	AUS	0.309	0.196	0.047	0.032	0.026	0.020	0.032	0.026	0.020
Austria	AUT	0.220	0.136	0.068	0.046	0.038	0.029	0.046	0.038	0.029
Azerbaijan	AZE	0.144	0.159	0.106	0.076	0.063	0.050	0.076	0.063	0.050
Bangladesh	BGD	0.128	0.162	0.111	0.080	0.067	0.054	0.080	0.067	0.054
Belarus	BLR	0.331	0.123	0.105	0.069	0.055	0.041	0.069	0.055	0.041
Belgium	BEL	0.386	0.122	0.055	0.037	0.029	0.022	0.037	0.029	0.022
Belize	BLZ	0.084	0.174	0.129	0.096	0.081	0.066	0.096	0.081	0.066
Benin	BEN	0.127	0.175	0.099	0.071	0.059	0.047	0.071	0.059	0.047
Bhutan	BTN	0.045	0.163	0.210	0.159	0.136	0.113	0.159	0.136	0.113
Bolivia	BOL	0.144	0.206	0.108	0.078	0.065	0.053	0.078	0.065	0.053
Bosnia and Herze- govina	BIH	0.172	0.149	0.126	0.088	0.072	0.057	0.088	0.072	0.057
Botswana	BWA	0.210	0.213	0.068	0.048	0.040	0.031	0.048	0.040	0.031
Brazil	BRA	0.108	0.184	0.107	0.078	0.065	0.053	0.078	0.065	0.053
Brunei	BRN	0.033	0.163	0.273	0.210	0.181	0.151	0.210	0.181	0.151
Bulgaria	BGR	0.186	0.154	0.077	0.054	0.044	0.034	0.054	0.044	0.034
Burkina Faso	BFA	0.202	0.190	0.082	0.059	0.049	0.039	0.059	0.049	0.039
Burundi	BDI	0.056	0.174	0.175	0.132	0.112	0.093	0.132	0.112	0.093
Cambodia	KHM	0.112	0.172	0.108	0.078	0.065	0.053	0.078	0.065	0.053
Cameroon	CMR	0.056	0.178	0.175	0.132	0.113	0.094	0.132	0.113	0.094
Canada	CAN	0.334	0.159	0.056	0.037	0.030	0.023	0.037	0.030	0.023
Central African Re- public	CAF	0.063	0.186	0.158	0.119	0.101	0.084	0.119	0.101	0.084
Chad	TCD	0.347	0.202	0.056	0.038	0.031	0.023	0.038	0.031	0.023
Chile	CHL	0.334	0.224	0.046	0.032	0.026	0.020	0.032	0.026	0.020
Colombia	COL	0.056	0.169	0.179	0.135	0.115	0.096	0.135	0.115	0.096
Costa Rica	CRI	0.115	0.171	0.109	0.079	0.066	0.054	0.079	0.066	0.054
Croatia	HRV	0.208	0.151	0.078	0.054	0.044	0.035	0.054	0.044	0.035
Cuba	CUB	0.217	0.189	0.107	0.075	0.061	0.048	0.075	0.061	0.048
Cyprus	CYP	0.151	0.196	0.079	0.057	0.048	0.038	0.057	0.048	0.038
Czech Republic	CZE	0.264	0.127	0.072	0.049	0.040	0.030	0.049	0.040	0.030
Democratic Republic of the Congo	COD	0.038	0.177	0.238	0.183	0.157	0.131	0.183	0.157	0.131
Denmark	DNK	0.504	0.118	0.051	0.033	0.026	0.019	0.033	0.026	0.019
Djibouti	DJI	0.352	0.200	0.056	0.038	0.030	0.023	0.038	0.030	0.023
Dominican Republic	DOM	0.160	0.190	0.089	0.064	0.054	0.043	0.064	0.054	0.043
East Timor	TLS	0.116	0.181	0.103	0.075	0.063	0.051	0.075	0.063	0.051
Ecuador	ECU	0.053	0.142	0.301	0.226	0.192	0.159	0.226	0.192	0.159
Egypt	EGY	0.363	0.219	0.065	0.044	0.036	0.028	0.044	0.036	0.028
El Salvador	SLV	0.113	0.201	0.123	0.091	0.077	0.063	0.091	0.077	0.063
Equatorial Guinea	GNQ	0.027	0.153	0.325	0.251	0.217	0.182	0.251	0.217	0.182
Eritrea	ERI	0.230	0.204	0.066	0.047	0.038	0.030	0.047	0.038	0.030
Estonia	EST	0.358	0.118	0.073	0.048	0.038	0.028	0.048	0.038	0.028
Eswatini	SWZ	0.182	0.180	0.080	0.056	0.046	0.036	0.056	0.046	0.036
Ethiopia	ETH	0.145	0.196	0.096	0.069	0.057	0.045	0.069	0.057	0.045
Falkland Islands	FLK	0.661								
Fiji	FJI	0.190	0.159	0.083	0.058	0.047	0.037	0.058	0.047	0.037
Finland	FIN	0.296		0.071	0.047	0.037	0.028	0.047	0.037	0.028
France	FRA	0.287	0.141	0.053	0.036	0.029	0.022	0.036	0.029	0.022
Gabon	GAB	0.030	0.150	0.301	0.232	0.200	0.167	0.232	0.200	0.167
Georgia	GEO	0.155	0.155	0.093	0.066	0.054	0.043	0.066	0.054	0.043
Germany	DEU	0.337	0.123	0.052	0.035	0.028	0.021	0.035	0.028	0.021
Ghana	GHA	0.101	0.168	0.154	0.113	0.095	0.077	0.113	0.095	0.077



Country aggregated		Country specific grid electricity LCOE (CHF/kW)								
CF										
Greece	GRC	0.186	0.173	0.071	0.050	0.042	0.033	0.050	0.042	0.033
Greenland	GRL	0.590								
Guatemala	GTM	0.088	0.183	0.131	0.098	0.083	0.068	0.098	0.083	0.068
Guinea	GIN	0.077	0.185	0.135	0.101	0.085	0.070	0.101	0.085	0.070
Guinea-Bissau	GNB	0.119	0.186	0.101	0.073	0.061	0.049	0.073	0.061	0.049
Guyana	GUY	0.058	0.175	0.170	0.128	0.109	0.090	0.128	0.109	0.090
Haiti	HTI	0.159	0.195	0.083	0.059	0.049	0.039	0.059	0.049	0.039
Honduras	HND	0.117	0.178	0.103	0.076	0.064	0.052	0.076	0.064	0.052
Hungary	HUN	0.258	0.143	0.065	0.044	0.036	0.028	0.044	0.036	0.028
Iceland	ISL	0.449								
India	IND	0.138	0.180	0.095	0.069	0.058	0.046	0.069	0.058	0.046
Indonesia	IDN	0.044	0.157	0.227	0.173	0.148	0.124	0.173	0.148	0.124
Iran	IRN	0.228	0.205	0.099	0.070	0.057	0.045	0.070	0.057	0.045
Iraq	IRQ	0.318	0.195	0.078	0.053	0.043	0.033	0.053	0.043	0.033
Ireland	IRL	0.517	0.105	0.073	0.047	0.036	0.026	0.047	0.036	0.026
Israel	ISR	0.186	0.212	0.066	0.048	0.040	0.032	0.048	0.040	0.032
Italy	ITA	0.177	0.166	0.069	0.049	0.040	0.032	0.049	0.040	0.032
Ivory Coast	CIV	0.091	0.167	0.125	0.092	0.077	0.063	0.092	0.077	0.063
Jamaica	JAM	0.174	0.183	0.091	0.065	0.054	0.043	0.065	0.054	0.043
Japan	JPN	0.236	0.144	0.065	0.045	0.037	0.029	0.045	0.037	0.029
Jordan	JOR	0.285	0.221	0.069	0.048	0.039	0.031	0.048	0.039	0.031
Kazakhstan	KAZ	0.376	0.154	0.067	0.044	0.035	0.027	0.044	0.035	0.027
Kenya	KEN	0.205	0.188	0.082	0.057	0.046	0.036	0.057	0.046	0.036
Kuwait	KWT	0.429	0.201	0.049	0.033	0.027	0.020	0.033	0.027	0.020
Kyrgyzstan	KGZ	0.150	0.171	0.090	0.064	0.053	0.042	0.064	0.053	0.042
Laos	LAO	0.130	0.161	0.101	0.072	0.060	0.048	0.072	0.060	0.048
Latvia	LVA	0.359	0.119	0.076	0.050	0.039	0.029	0.050	0.039	0.029
Lebanon	LBN	0.159	0.201	0.197	0.141	0.117	0.094	0.141	0.117	0.094
Lesotho	LSO	0.214	0.214	0.067	0.048	0.039	0.031	0.048	0.039	0.031
Liberia	LBR	0.047	0.162	0.203	0.154	0.131	0.109	0.154	0.131	0.109
Libya	LBY	0.382	0.214	0.052	0.035	0.028	0.022	0.035	0.028	0.022
Lithuania	LTU	0.376	0.120	0.071	0.046	0.036	0.026	0.046	0.036	0.026
Luxembourg	LUX	0.322	0.123	0.062	0.042	0.033	0.025	0.042	0.033	0.025
Madagascar	MDG	0.186	0.198	0.075	0.053	0.044	0.035	0.053	0.044	0.035
Malawi	MWI	0.176	0.192	0.079	0.056	0.046	0.037	0.056	0.046	0.037
Malaysia	MYS	0.032	0.156	0.284	0.219	0.188	0.158	0.219	0.188	0.158
Mali	MLI	0.325	0.195	0.058	0.040	0.032	0.025	0.040	0.032	0.025
Mauritania	MRT	0.453	0.198	0.051	0.034	0.027	0.020	0.034	0.027	0.020
Mexico	MEX	0.143	0.205	0.084	0.060	0.050	0.040	0.060	0.050	0.040
Moldova	MDA	0.302	0.144	0.073	0.049	0.039	0.029	0.049	0.039	0.029
Mongolia	MNG	0.302	0.198	0.068	0.046	0.038	0.029	0.046	0.038	0.029
Montenegro	MNE	0.183	0.159	0.095	0.066	0.054	0.042	0.066	0.054	0.042
Morocco	MAR	0.349	0.209	0.057	0.039	0.032	0.024	0.039	0.032	0.024
Mozambique	MOZ	0.134	0.185	0.094	0.068	0.056	0.045	0.068	0.056	0.045
Myanmar	MMR	0.080	0.173	0.179	0.133	0.113	0.092	0.133	0.113	0.092
Namibia	NAM	0.219	0.224	0.065	0.047	0.039	0.031	0.047	0.039	0.031
Nepal	NPL	0.072	0.167	0.147	0.110	0.093	0.076	0.110	0.093	0.076
Netherlands	NLD	0.461	0.119	0.050	0.033	0.026	0.019	0.033	0.026	0.019
New Caledonia	NCL	0.257	0.166	0.071	0.048	0.039	0.030	0.048	0.039	0.030
New Zealand	NZL	0.364	0.153	0.056	0.037	0.030	0.022	0.037	0.030	0.022
Nicaragua	NIC	0.184	0.171	0.095	0.066	0.054	0.042	0.066	0.054	0.042
Niger	NER	0.339	0.202	0.056	0.038	0.031	0.024	0.038	0.031	0.024
Nigeria	NGA	0.154	0.179	0.088	0.062	0.052	0.041	0.062	0.052	0.041
North Korea	PRK	0.204	0.163	0.079	0.055	0.045	0.035	0.055	0.045	0.035
North Macedonia	MKD	0.150	0.162	0.093	0.066	0.054	0.043	0.066	0.054	0.043
Norway	NOR	0.355	0.115	0.071	0.047	0.037	0.028	0.047	0.037	0.028
Oman	OMN	0.297	0.215	0.057	0.039	0.032	0.025	0.039	0.032	0.025
Pakistan	PAK	0.174	0.196	0.101	0.072	0.060	0.048	0.072	0.060	0.048
Palestine	PSE	0.188	0.206	0.074	0.052	0.043	0.034	0.052	0.043	0.034
Panama	PAN	0.116	0.165	0.097	0.071	0.059	0.048	0.071	0.059	0.048
Papua New Guinea	PNG	0.056	0.154	0.181	0.136	0.116	0.095	0.136	0.116	0.095
Paraguay	PRY	0.255	0.178	0.068	0.047	0.038	0.029	0.047	0.038	0.029
People's Republic of China	CHN	0.239	0.162	0.057	0.039	0.032	0.025	0.039	0.032	0.025
Peru	PER	0.054	0.204	0.173	0.132	0.113	0.095	0.132	0.113	0.095
Philippines	PHL	0.152	0.164	0.092	0.066	0.055	0.043	0.066	0.055	0.043



		Country aggregated CF		Country specific grid electricity LCOE (CHF/kW)						
Poland	POL	0.350	0.124	0.064	0.042	0.033	0.025	0.042	0.033	0.025
Portugal	PRT	0.245	0.180	0.059	0.041	0.033	0.026	0.041	0.033	0.026
Puerto Rico	PRI	0.169	0.183	0.082	0.058	0.048	0.038	0.058	0.048	0.038
Qatar	QAT	0.321	0.205	0.057	0.039	0.032	0.024	0.039	0.032	0.024
Republic of the Congo	COG	0.037	0.157	0.248	0.190	0.163	0.136	0.190	0.163	0.136
Romania	ROU	0.205	0.147	0.081	0.056	0.046	0.036	0.056	0.046	0.036
Russia	RUS	0.278	0.140	0.079	0.053	0.043	0.033	0.053	0.043	0.033
Rwanda	RWA	0.045	0.171	0.251	0.193	0.166	0.139	0.193	0.166	0.139
Saudi Arabia	SAU	0.292	0.215	0.060	0.041	0.034	0.026	0.041	0.034	0.026
Senegal	SEN	0.217	0.191	0.070	0.050	0.042	0.033	0.050	0.042	0.033
Serbia	SRB	0.215	0.147	0.082	0.056	0.046	0.035	0.056	0.046	0.035
Sierra Leone	SLE	0.063	0.170	0.162	0.121	0.103	0.085	0.121	0.103	0.085
Slovakia	SVK	0.221	0.136	0.075	0.052	0.042	0.033	0.052	0.042	0.033
Slovenia	SVN	0.183	0.143	0.083	0.058	0.048	0.038	0.058	0.048	0.038
Solomon Islands	SLB	0.107	0.154	0.115	0.083	0.070	0.056	0.083	0.070	0.056
Somalia	SOM	0.336	0.198	0.057	0.039	0.031	0.024	0.039	0.031	0.024
South Africa	ZAF	0.231	0.208	0.066	0.047	0.039	0.031	0.047	0.039	0.031
South Korea	KOR	0.210	0.159	0.079	0.055	0.045	0.035	0.055	0.045	0.035
South Sudan	SSD	0.116	0.186	0.102	0.074	0.062	0.050	0.074	0.062	0.050
Spain	ESP	0.228	0.184	0.058	0.041	0.034	0.026	0.041	0.034	0.026
Sri Lanka	LKA	0.258	0.175	0.094	0.065	0.053	0.041	0.065	0.053	0.041
Sudan	SDN	0.368	0.206	0.054	0.036	0.029	0.022	0.036	0.029	0.022
Suriname	SUR	0.051	0.178	0.187	0.142	0.121	0.101	0.142	0.121	0.101
Sweden	SWE	0.300	0.118	0.067	0.044	0.036	0.027	0.044	0.036	0.027
Switzerland	CHE	0.185	0.140	0.072	0.051	0.042	0.034	0.051	0.042	0.034
Syria	SYR	0.296	0.202	0.059	0.041	0.033	0.026	0.041	0.033	0.026
Tajikistan	TJK	0.170	0.181	0.082	0.058	0.048	0.038	0.058	0.048	0.038
Tanzania	TZA	0.119	0.188	0.100	0.073	0.061	0.049	0.073	0.061	0.049
Thailand	THA	0.130	0.169	0.096	0.070	0.059	0.047	0.070	0.059	0.047
The Bahamas	BHS	0.246	0.190	0.067	0.046	0.038	0.029	0.046	0.038	0.029
The Gambia	GMB	0.181	0.190	0.078	0.055	0.045	0.036	0.055	0.045	0.036
Togo	TGO	0.104	0.172	0.113	0.082	0.069	0.056	0.082	0.069	0.056
Trinidad and Tobago	TTO	0.162	0.181	0.084	0.060	0.050	0.039	0.060	0.050	0.039
Tunisia	TUN	0.349	0.198	0.073	0.049	0.040	0.030	0.049	0.040	0.030
Turkey	TUR	0.179	0.180	0.092	0.065	0.054	0.043	0.065	0.054	0.043
Turkmenistan	TKM	0.358	0.182	0.059	0.039	0.032	0.024	0.039	0.032	0.024
Uganda	UGA	0.065	0.186	0.185	0.140	0.120	0.099	0.140	0.120	0.099
Ukraine	UKR	0.338	0.137	0.096	0.064	0.051	0.038	0.064	0.051	0.038
United Arab Emirates	ARE	0.258	0.209	0.062	0.043	0.035	0.028	0.043	0.035	0.028
United Kingdom	GBR	0.467	0.109	0.056	0.036	0.029	0.021	0.036	0.029	0.021
United States of America	USA	0.302	0.182	0.053	0.036	0.029	0.023	0.036	0.029	0.023
Uruguay	URY	0.370	0.179	0.049	0.033	0.027	0.020	0.033	0.027	0.020
Uzbekistan	UZB	0.339	0.178	0.061	0.041	0.033	0.025	0.041	0.033	0.025
Vanuatu	VUT	0.155	0.147	0.095	0.067	0.055	0.043	0.067	0.055	0.043
Venezuela	VEN	0.113	0.181	0.229	0.167	0.140	0.113	0.167	0.140	0.113
Vietnam	VNM	0.160	0.148	0.093	0.065	0.054	0.042	0.065	0.054	0.042
Yemen	YEM	0.234	0.217	0.141	0.100	0.082	0.065	0.100	0.082	0.065
Zambia	ZMB	0.127	0.201	0.094	0.068	0.057	0.046	0.068	0.057	0.046
Zimbabwe	ZWE	0.153	0.203	0.083	0.060	0.050	0.040	0.060	0.050	0.040



Table 20: Transport distances (data from CERDI-sea distance database (Bertoli et al., 2016)). For coastal countries: The port is chosen based on the coastal area with the highest number of shipping lines intersecting major roads. For landlocked countries: The port is selected based on the shortest road distance from the country's capital to a foreign port. The Exporter and Importer (Switzerland) are ISO alpha-3 code of countries and regions. Sea distance is the bilateral sea distance in km. capitalport1 is the road distance between the capital of the exporter country and the relevant port in km. capitalport2 is the road distance between the capital of Switzerland to its nearest foreign port (Port of Antwerp considered in this case). Road distance is the bilateral road transport distance between two capitals in km. short is a variable which is equal to 1 if road distance is lower than capitalport1+capitalport2, and 0 otherwise.

Exporter	Importer	Sea distance	capitalport1	capitalport2	capitalport12	road distance	short
ABW	CHE	7685		581	581		0
AFG	CHE	7725	1471	581	2052	6450	0
AGO	CHE	8723	1184	581	1765		0
AIA	CHE	6785		581	581		0
ALB	CHE	1398	248	581	829		0
AND	CHE	0	453	581	1034	890	1
ANT	CHE	6777		581	581		0
ARE	CHE	7584	229	581	810		0
ARG	CHE	13197	1738	581	2319		0
ARM	CHE	3529	818	581	1399	3923	0
ASM	CHE	19072		581	581		0
ATG	CHE	6688		581	581		0
AUS	CHE	16856	638	581	1218		0
AUT	CHE	1976	468	581	1049	843	1
AZE	CHE	3529	1197	581	1778	4196	0
BDI	CHE	8046	1365	581	1946	9732	0
BEL	CHE	3514	132	581	712	490	1
BEN	CHE	6733	80	581	661		0
BFA	CHE	6649	971	581	1552	10129	0
BGD	CHE	10613	996	581	1577		0
BGR	CHE	2582	451	581	1032	1300	1
BHR	CHE	8046	0	581	581		0
BHS	CHE	7861		581	581		0
BIH	CHE	1643	197	581	777		0
BLR	CHE	5157	530	581	1110	1930	0
BLZ	CHE	9238	78	581	658		0
BMU	CHE	6399	0	581	581		0
BOL	CHE	14329	2520	581	3101		0
BRA	CHE	9896	1121	581	1702		0
BRB	CHE	6652	0	581	581		0
BRN	CHE	12257	42	581	622		0
BTN	CHE	10611	1072	581	1652	12033	0
BWA	CHE	10912	947	581	1528	13018	0
CAF	CHE	7382	1273	581	1854	9288	0
CAN	CHE	6159	1102	581	1683		0
CHL	CHE	14329	116	581	696		0
CHN	CHE	15426	1449	581	2029		0
CIV	CHE	6085	251	581	831		0
CMR	CHE	7382	283	581	864		0
COD	CHE	8205		581	581		0
COG	CHE	8102	438	581	1018		0
COK	CHE	17993		581	581		0
COL	CHE	8355	934	581	1515		0
COM	CHE	8561		581	581		0
CPV	CHE	3783		581	581		0
CRI	CHE	9100	142	581	722		0
CUB	CHE	8717		581	581		0
CYM	CHE	8494	0	581	581		0
CYP	CHE	2404	43	581	623		0
CZE	CHE	3768	693	581	1273	773	1
DEU	CHE	3770	391	581	971	750	1
DJI	CHE	4502	297	581	878		0
DMA	CHE	6718	0	581	581		0
DNK	CHE	4571	0	581	581		0
DOM	CHE	7357		581	581		0
DZA	CHE	865	386	581	967		0



Exporter	Importer	Sea distance	capitalport1	capitalport2	capitalport12	road distance	short
ECU	CHE	10101	347	581	927		0
EGY	CHE	2026	175	581	756		0
ERI	CHE	4390	592	581	1173		0
ESP	CHE	1070	655	581	1236	1250	1
EST	CHE	5187	23	581	603		0
ETH	CHE	4388	864	581	1445	7871	0
FIN	CHE	5203	0	581	581		0
FJI	CHE	19335		581	581		0
FLK	CHE	13264	0	581	581		0
FRA	CHE	0	757	581	1338	430	1
FRO	CHE	4462	0	581	581		0
FSM	CHE	15786		581	581		0
GAB	CHE	7581	14	581	594		0
GBR	CHE	3226	95	581	676		0
GEO	CHE	3616	436	581	1016		0
GHA	CHE	6506	14	581	595		0
GIB	CHE	1063		581	581		0
GIN	CHE	4691	0	581	581		0
GLP	CHE	6690		581	581		0
GMB	CHE	4035	0	581	581		0
GNB	CHE	4312	38	581	619		0
GNQ	CHE	7561		581	581		0
GRC	CHE	1600	28	581	608	1600	1
GRD	CHE	6875		581	581		0
GRL	CHE	4925		581	581		0
GTM	CHE	10592	198	581	779		0
GUF	CHE	6379	0	581	581		0
GUM	CHE	15720		581	581		0
GUY	CHE	6818	45	581	625		0
HKG	CHE	14055		581	581		0
HND	CHE	9254	275	581	856		0
HRV	CHE	1904	264	581	844	690	1
HTI	CHE	7620		581	581		0
HUN	CHE	1976	569	581	1150	1097	1
IDN	CHE	11695	0	581	581		0
IND	CHE	7847	1312	581	1893		0
IRL	CHE	3481	0	581	581		0
IRN	CHE	7623	1533	581	2114		0
IRQ	CHE	8280	640	581	1221		0
ISL	CHE	4583	52	581	633		0
ISR	CHE	2284	53	581	634		0
ITA	CHE	516	14	581	595	700	1
JAM	CHE	8108	59	581	639		0
JOR	CHE	2817	321	581	902		0
JPN	CHE	16455	378	581	958		0
KAZ	CHE	3529	3085	581	3665	5290	0
KEN	CHE	7738	515	581	1095		0
KGZ	CHE	7725	3209	581	3790	6031	0
KHM	CHE	12190	139	581	720		0
KIR	CHE	17080		581	581		0
KNA	CHE	6779		581	581		0
KOR	CHE	16167	423	581	1004		0
KWT	CHE	8248	118	581	699		0
LAO	CHE	12690	669	581	1250	14718	0
LBN	CHE	2438	91	581	671		0
LBR	CHE	5665	640	581	1220		0
LBY	CHE	1264	111	581	692		0
LCA	CHE	6760		581	581		0
LIE	CHE	1976	684	581	1265	216	1
LKA	CHE	8395	100	581	681		0
LSO	CHE	10912	579	581	1159	13572	0
LTU	CHE	5156		581	581		0
LUX	CHE	3456	325	581	905	401	1
LVA	CHE	5031	177	581	758		0
MAC	CHE	14034		581	581		0
MAR	CHE	1106	257	581	837		0



Exporter	Importer	Sea distance	capitalport1	capitalport2	capitalport12	road distance	short
MCO	CHE	208	0	581	581		0
MDA	CHE	2857	501	581	1081	2050	0
MDG	CHE	9070	283	581	864		0
MDV	CHE	7817		581	581		0
MEX	CHE	11767	502	581	1083		0
MHL	CHE	18213		581	581		0
MKD	CHE	1638	329	581	909	1810	0
MLI	CHE	4691	855	581	1436	10904	0
MLT	CHE	905		581	581		0
MMR	CHE	10280	1372	581	1952		0
MNE	CHE	1639	53	581	633		0
MNG	CHE	15425	2849	581	3430	8362	0
MNP	CHE	15903		581	581		0
MOZ	CHE	10559	100	581	681		0
MRT	CHE	3083	503	581	1083		0
MSR	CHE	6745		581	581		0
MTQ	CHE	6748	0	581	581		0
MUS	CHE	9558	0	581	581		0
MWI	CHE	8046	1680	581	2261	11336	0
MYS	CHE	10657	65	581	646		0
MYT	CHE	8592		581	581		0
NAM	CHE	9636	334	581	914		0
NCL	CHE	18316	142	581	722		0
NER	CHE	6732	1016	581	1597	9566	0
NFK	CHE	18801		581	581		0
NGA	CHE	6865	667	581	1247		0
NIC	CHE	8932	486	581	1067		0
NIU	CHE	19112		581	581		0
NLD	CHE	3456	167	581	748	610	1
NOR	CHE	4221	54	581	634		0
NPL	CHE	10611	1662	581	2242	11258	0
NRU	CHE	18000		581	581		0
NZL	CHE	19819	597	581	1178		0
OMN	CHE	5857	1053	581	1634		0
PAK	CHE	7725	1449	581	2030		0
PAN	CHE	8825	56	581	637		0
PER	CHE	10735	974	581	1555		0
PHL	CHE	13612	230	581	811		0
PLW	CHE	14578		581	581		0
PNG	CHE	15880	0	581	581		0
POL	CHE	5014	446	581	1027	1080	1
PRI	CHE	6960		581	581		0
PRK	CHE	16862	529	581	1109		0
PRT	CHE	1730	2	581	583		0
PRY	CHE	11778	1350	581	1930		0
PSE	CHE	2258		581	581		0
PYF	CHE	17097		581	581		0
QAT	CHE	8008	29	581	610		0
REU	CHE	9580		581	581		0
ROU	CHE	2858	203	581	783	1400	1
RUS	CHE	3530	1512	581	2093		0
RWA	CHE	8046	1331	581	1912	9523	0
SAU	CHE	3365	973	581	1553		0
SDN	CHE	3189	1139	581	1720		0
SEN	CHE	3849	0	581	581		0
SGP	CHE	10995	0	581	581		0
SHN	CHE	10485		581	581		0
SLB	CHE	16976		581	581		0
SLE	CHE	4911	183	581	764		0
SLV	CHE	10306	44	581	625		0
SMR	CHE	513	359	581	939	820	1
SOM	CHE	6287	550	581	1131		0
SPM	CHE	5566	0	581	581		0
SRB	CHE	1642	404	581	985	1416	0
STP	CHE	7335		581	581		0
SUR	CHE	6476	0	581	581		0



Exporter	Importer	Sea distance	capitalport1	capitalport2	capitalport12	road distance	short
SVK	CHE	1976	527	581	1107	911	1
SVN	CHE	1978	111	581	691	520	1
SWE	CHE	4178	472	581	1052		0
SWZ	CHE	10558	317	581	898	13255	0
SYC	CHE	7456	0	581	581		0
SYR	CHE	2475	210	581	790		0
TCA	CHE	7518		581	581		0
TCD	CHE	7382	1529	581	2109	8245	0
TGO	CHE	6649	0	581	581		0
THA	CHE	12690	19	581	599		0
TJK	CHE	7725	2104	581	2684	6036	0
TKL	CHE	18966		581	581		0
TKM	CHE	7622	1948	581	2528	5538	0
TLS	CHE	13839	205	581	785		0
TON	CHE	19501		581	581		0
TTO	CHE	6959		581	581		0
TUN	CHE	756	7	581	588		0
TUR	CHE	2433	476	581	1056		0
TUV	CHE	19204		581	581		0
TWN	CHE	14324	347	581	927		0
TZA	CHE	8047	194	581	775		0
UGA	CHE	7737	1137	581	1718	9078	0
UKR	CHE	3171		581	581		0
URY	CHE	11778	749	581	1330		0
USA	CHE	9673	2242	581	2823		0
UZB	CHE	7725	2633	581	3214	5721	0
VCT	CHE	6838		581	581		0
VEN	CHE	7584	205	581	786		0
VGB	CHE	6900	0	581	581		0
VIR	CHE	6931	0	581	581		0
VNM	CHE	12350	1514	581	2094		0
VUT	CHE	18329	0	581	581		0
WLF	CHE	19583		581	581		0
WSM	CHE	19141		581	581		0
YEM	CHE	4675	345	581	926		0
ZAF	CHE	10913	630	581	1210		0
ZMB	CHE	10558	1757	581	2337	11566	0
ZWE	CHE	10558	1301	581	1882	12037	0

8.2 The JRC-EU TIMES model

8.3 Overview and selective features of JRC-EU TIMES

JRC-EU-TIMES (Da Camara et al., 2013; EU, 2020; Nijs & Ruiz, 2019) includes seven industrial sectors: Iron and Steel, Chemicals (Ammonia production, Chlorine production, and other chemicals), Paper and Pulp (High- and Low-quality paper production), Non-Ferrous Metals (Aluminium production, Copper production, other non-ferrous metals), Non-metallic Minerals (Cement production, Lime demand, Glass (Hollow- and Flat-) demand, other non-metallic minerals), Other Industries (including the Construction sector) and Non-Energy Uses. In each sector, a detailed Material Flow representation is also included.

In the residential sector, the model distinguishes between single- and multi-family buildings with a detailed representation of their vintage (construction year). The model can endogenously decide to demolish or build new buildings to meet household demand. For each building type, several energy end-uses are included: space and water heating, cooking, cooling, lighting, refrigerators, dishwashing, clothes washing, and other electrical appliances and uses.

The services sector distinguishes between buildings for Hospitals, Hotels and restaurants, Sports and recreation, large and small shops, and offices (including Schools, Universities, Museums, etc.). Like the Residential sector, several energy end uses are identified for each building type: space and water



heating, cooking, cooling, lighting, ICT, refrigeration, and ventilation. Also, street lighting is included in the services sector.

In transport, the model considers different modes for passenger and freight transport. Domestic passenger transport is divided into private, public, rail, and aviation. Freight transport is divided into road and rail transport. There is also explicit accounting for the international aviation sector (intra-EU and extra-EU flights).

On the supply side, the model is very detailed in the electricity, hydrogen, synfuel, and biofuel production sectors. In the electricity sector, the vintages of the power plants are explicitly considered, while nuclear power is modelled at the reactor level. In the hydrogen sector, the model explicitly considers the green hydrogen production routes and distinguishes the different colours of hydrogen for tracking and certification purposes. In the synfuel production sector, there is a clear distinction between sustainable and non-sustainable fuels, with the former being tracked that green electricity and C-atoms from biogenic or direct air capture sources are used for their production. Finally, the biofuel production sector is extensive, as one of the main uses of the JRC-EU-TIMES model in the past was to assess the role of biofuels in the EU energy system's decarbonisation.

8.4 Analytical results for Europe

This section includes the development in Europe analogous to the key metrics presented for Switzerland in the main report (section 4.2).

Feature / Category	Domestic Aviation	Intra-EU Aviation	Extra-EU Aviation
Definition	Within the same EU country	Between two EU countries	Between EU and non-EU countries
Example	Rome → Milan	Madrid → Berlin	Paris → New York
Flight Distance	Short	Medium	Long
Demand Scope	National	Regional (EU internal)	International (partially EU-bound)
Model Representation	Internal air transport demand	EU-wide transport flows	EU-to-World or World-to-EU transport
Emissions Accounting	Included in national inventories	Counted in EU inventory, under EU ETS	Only departing flights may be regulated
SAF Blending (RefuelEU)	Yes (applies)	Yes (applies)	Only outbound flights from EU airports apply
EU ETS Coverage	Yes	Yes	Partially (only within EU airspace or outbound)
Typical Aircraft	Regional jets / turboprops	Narrow-body aircraft	Wide-body / long-haul aircraft

Figure 100: Mapping of aviation market segment, aircraft type in JRC-EU-TIMES.



Figure 101: Development of aviation demand in Europe.

Year	Minimum SAF Share	Synthetic Aviation Fuel Share (within SAF)
2025	2%	0%
2030	6%	1.2%
2035	20%	5%
2040	34%	8%
2045	42%	11%
2050	70%	35%

Figure 102: Aviation blend mandate implemented in JRC-EU-TIMES model.

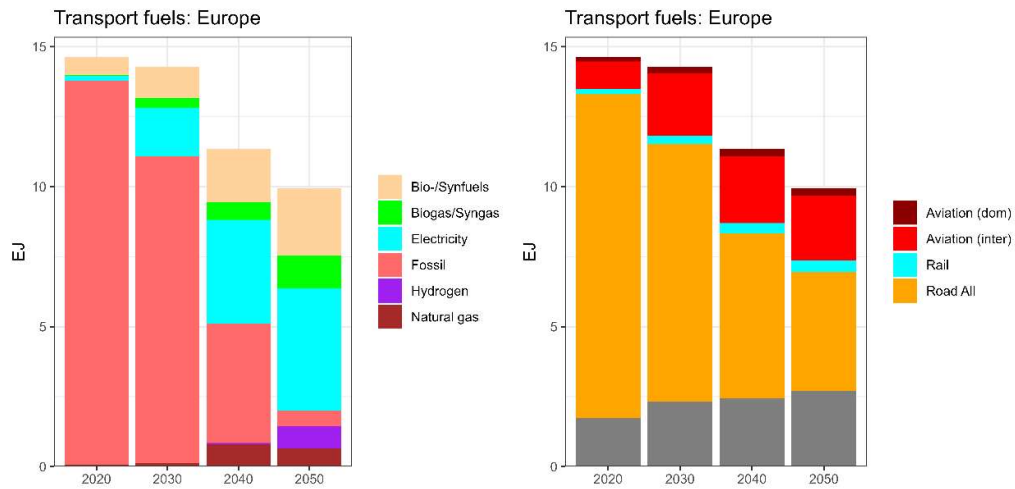


Figure 103: Transport sector final energy demand in Europe by fuel and mode of transport.

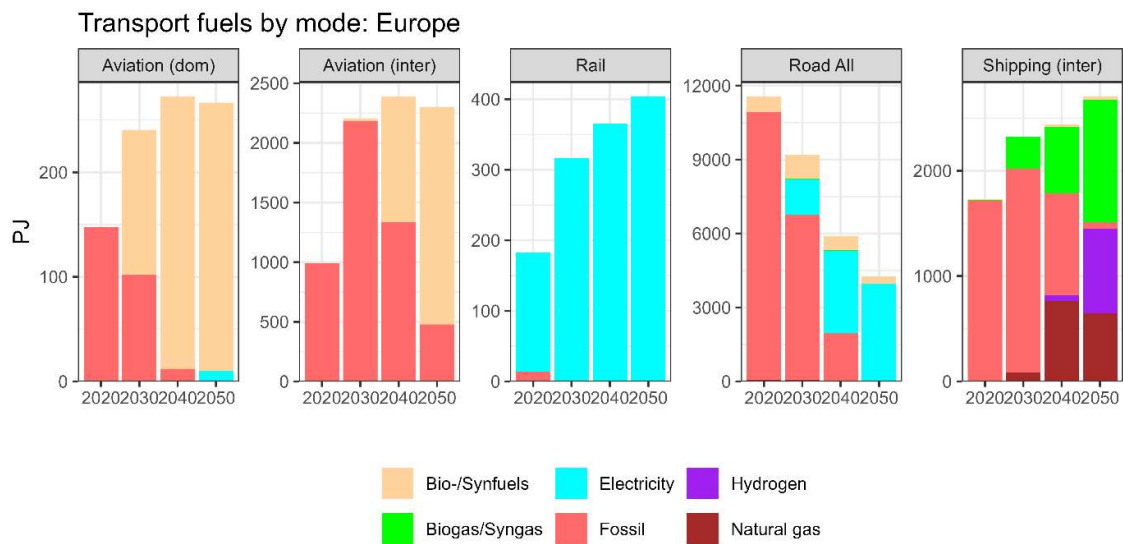


Figure 104: Transport fuel demand in Europe by sub-sectoral modes.



Transport fuels: Europe

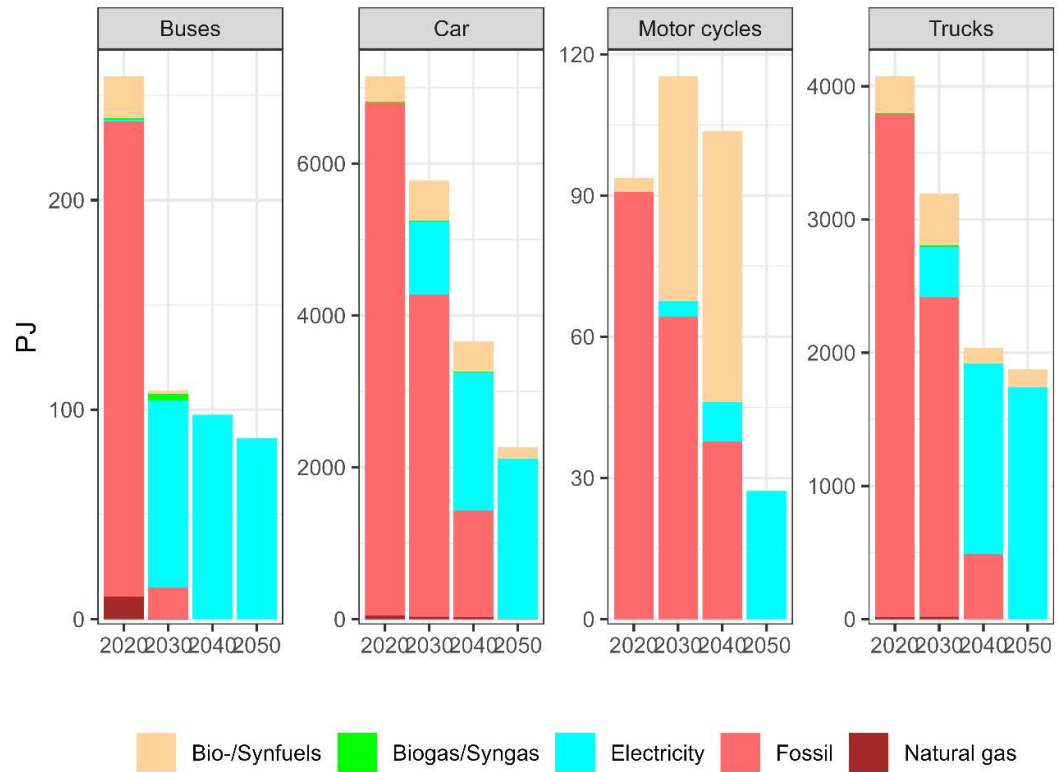


Figure 105: Road transport fuel consumption by modes in Europe.

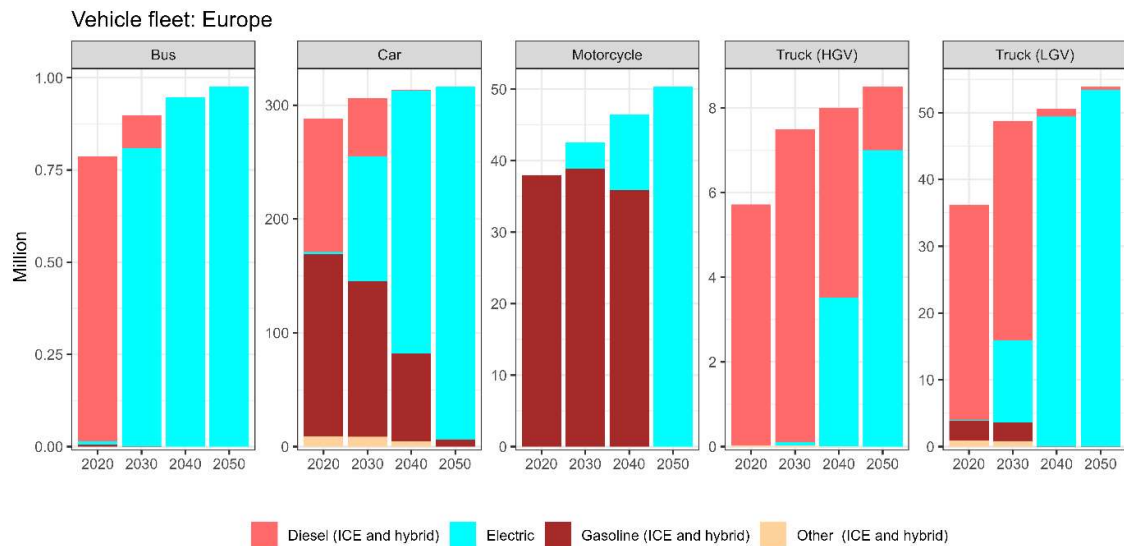


Figure 106: Road transport vehicle types in Europe.

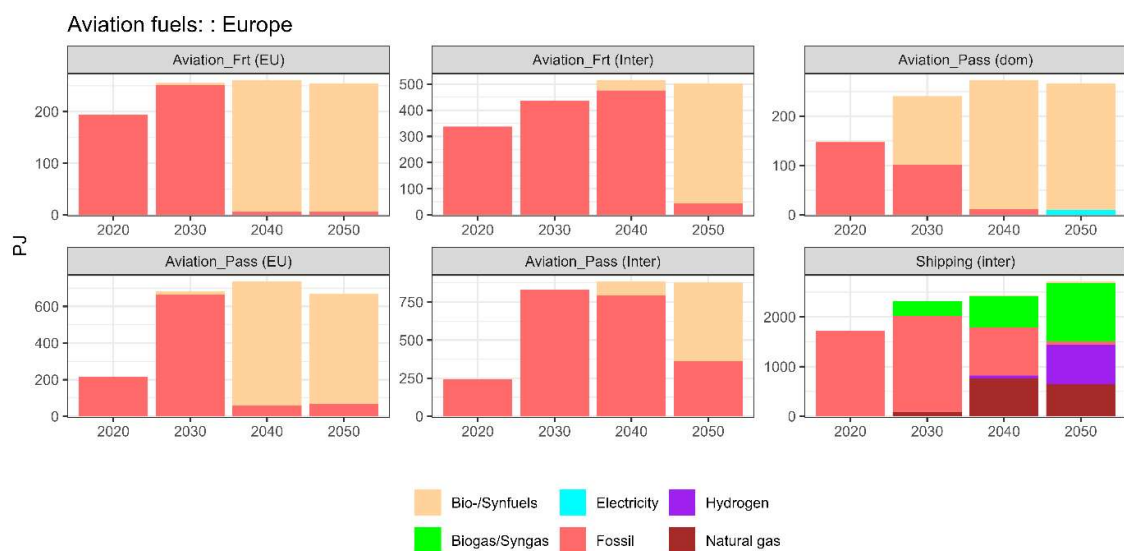


Figure 107: Aviation fuel demand in Europe.

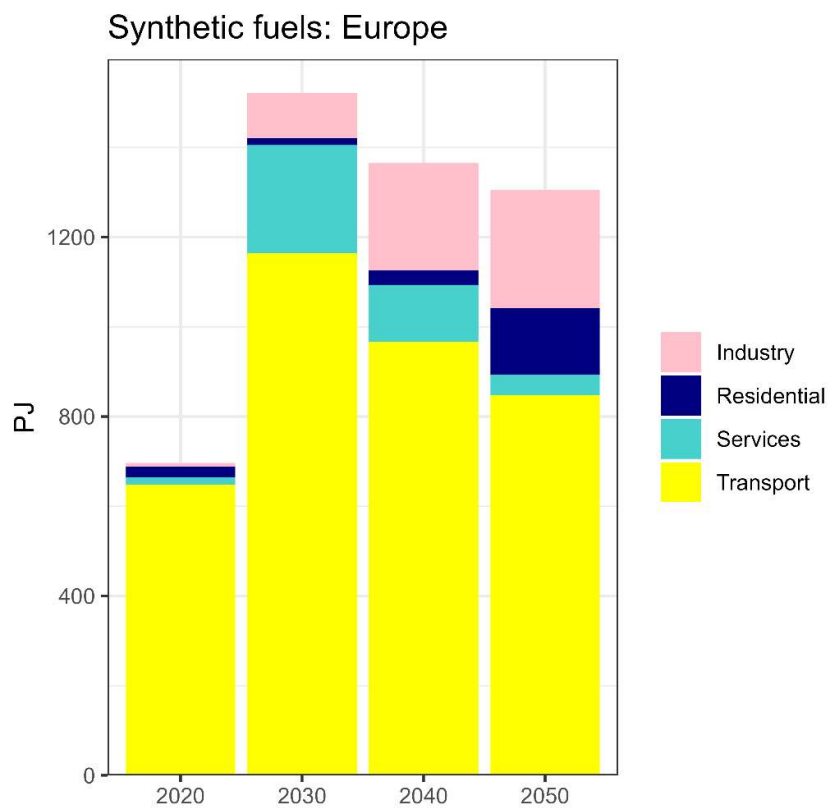


Figure 108: Synthetic and biogenic fuel consumption by end-use sector in Europe.

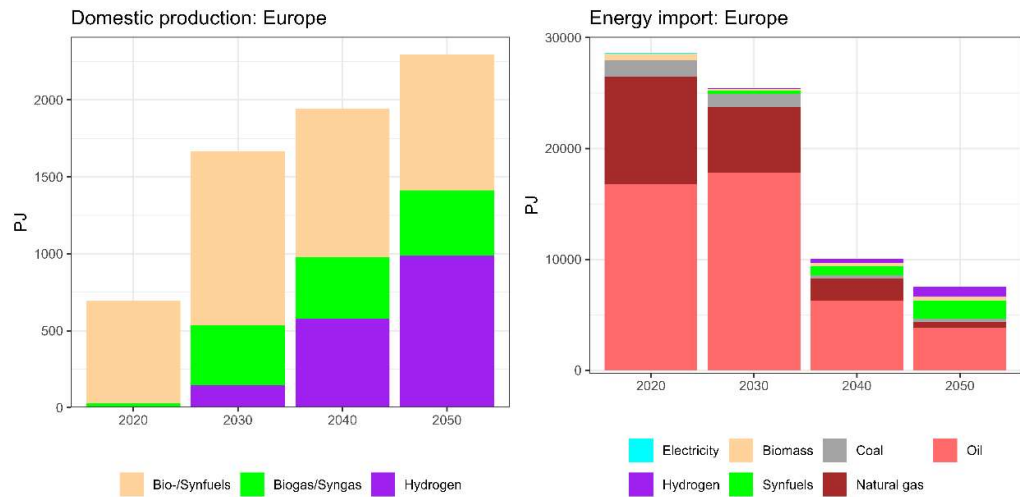


Figure 109: Sources of bio- and synfuel (domestic and imported).

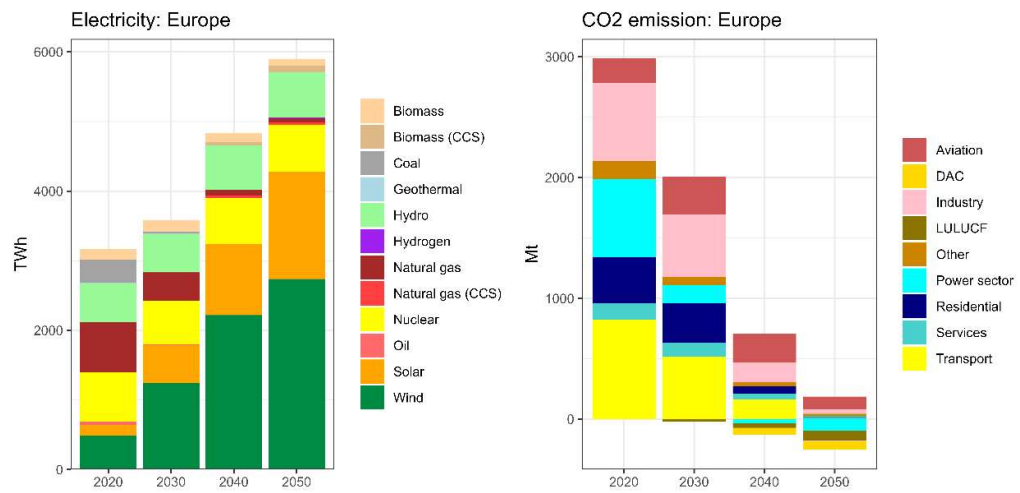


Figure 110: European electricity supply and CO₂ emission trajectories.

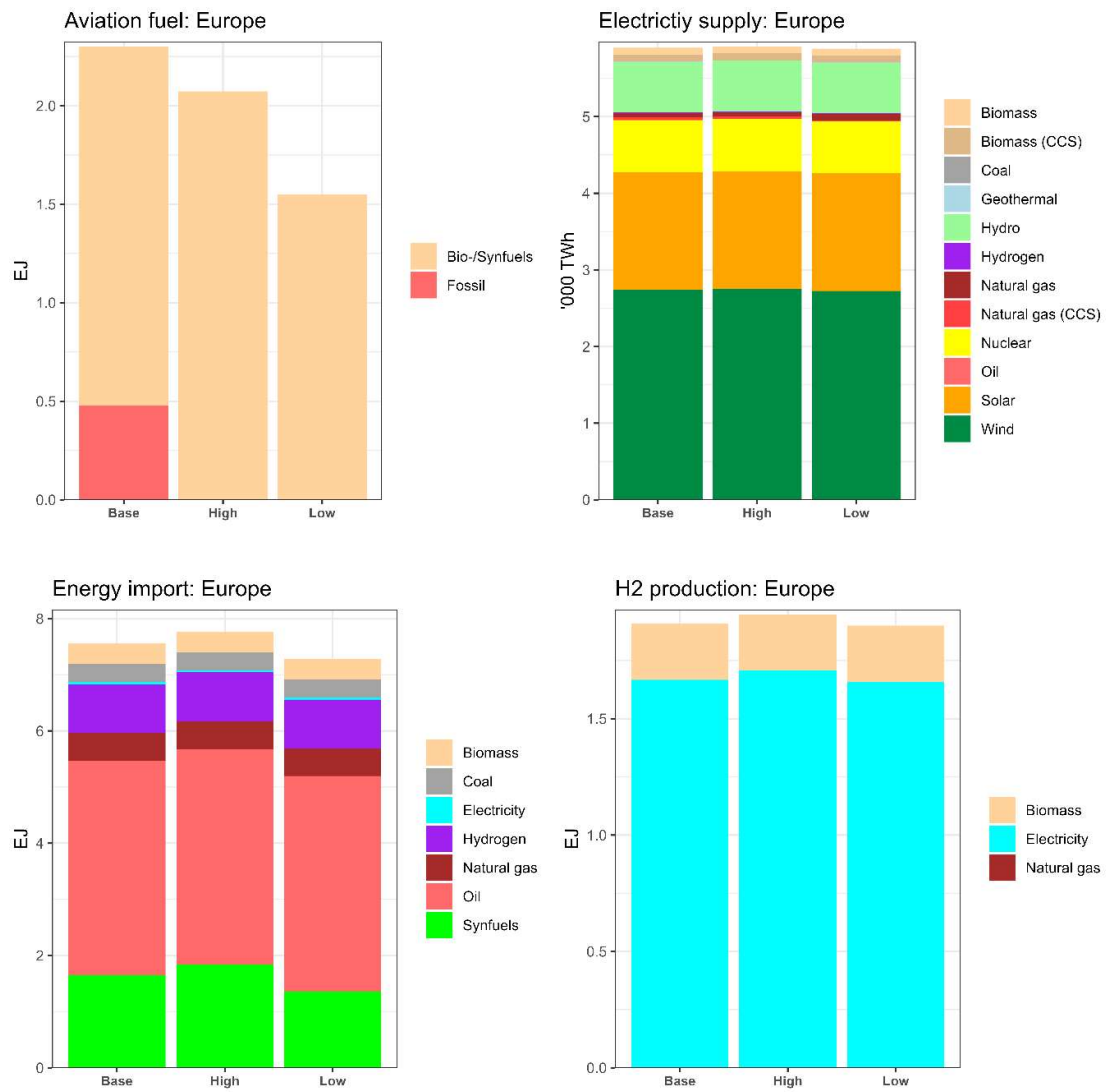


Figure 111: Aviation fuel demand, electricity supply composition, imported fuels, and domestic hydrogen production pathways in the year 2050 across the aviation-demand variant scenarios.