Core Model Proposal #359: Hydrogen and transportation technology update

Product: Global Change Assessment Model (GCAM)

Institution: Joint Global Change Research Institute (JGCRI)

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Purpose: This core model proposal updates modeling structures, key technology assumptions, and data sources for a detailed representation of hydrogen in GCAM's energy system, including production, transmission and distribution, and consumption in hydrogen end-use sectors (buildings, transportation, industry).

Background

In the ongoing search for alternative low-carbon and zero-carbon energy carriers, interest in hydrogen is renewed. However, it remains highly debated to what extent hydrogen may be deployed in a future energy system where it competes with demand for liquid fuels and electric energy, and what costs may be incurred by large-scale hydrogen deployment. Here we update the Global Change Analysis Model (GCAM) to include hydrogen technology in all supply and demand sectors.

Description of Changes

Overview

In the core model, hydrogen is represented as an energy commodity that can be produced centrally and distributed to end users, or produced on-site. No energy losses are tracked in the distribution, though there is a cost mark-up in the distribution, a portion of which is understood to be energy costs. A single "H2 enduse" commodity is represented as an input to production technologies in the transportation (LDV) and industry (generic industrial energy use, iron and steel) sectors. As such, there's no differentiation in the prices of hydrogen between different end-use applications. In this proposal, we update the assumptions of hydrogen production technologies, add a number of hydrogen end-use technologies throughout the energy and industrial system, and overhaul the structural representation of distribution so as to better estimate the heterogeneous prices paid by various end-use purposes, which are largely a function of the temperatures and pressures at which hydrogen is transported and stored. The details of the new hydrogen module are detailed in the sections that follow.

Figure 1 shows the general schematic for the flows of H2, from the point of production from primary fuels at the top of the figure, through the transmission and distribution network, to a wide variety of end use applications at the bottom of the figure. Note that forecourt natural gas steam reforming and electrolysis are also available as pathways.

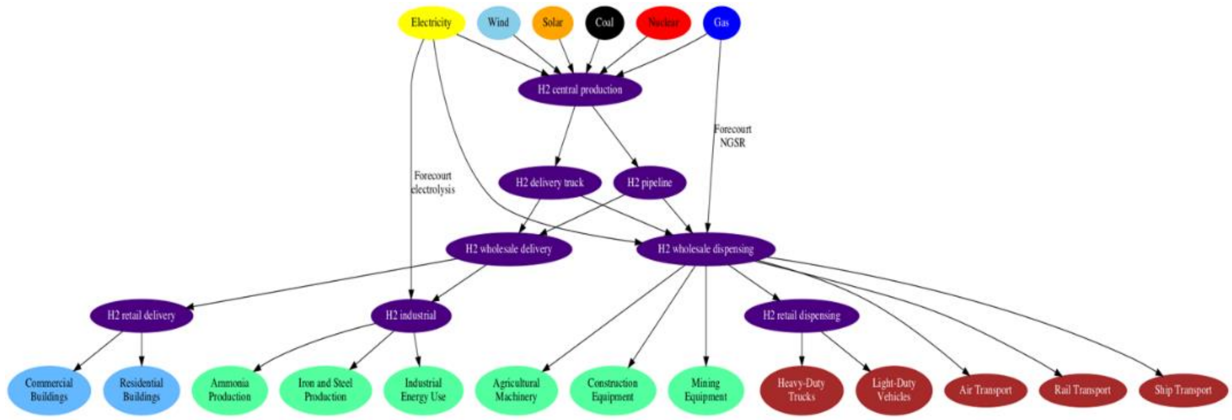

Figure 1. Representation of H2 in GCAM.

Update to H2 production technologies

GCAM H2 production assumptions are updated with the latest NREL Hydrogen Analysis Model (H2A) data (version 3) (NREL, 2018). The key parameters used by GCAM for any hydrogen production technology are the energy intensity of production (i.e., GJ of input fuel per kg of hydrogen produced), and the average levelized non-energy costs of production. These costs include all amortized capital, and fixed and variable operations and maintenance costs excluding purchased energy. Annual technological improvement rates were calculated from 2020 to return the estimated 2040 values in H2A, with an additional 10% improvement allowed through 2100. Figure 2 illustrates the updated costs of H2 production technologies for 2030 in a reference scenario.

In contrast to prior modeling of hydrogen production in GCAM, technologies are allowed multiple energy inputs, as appropriate. In addition to the technologies included in the latest version of NREL H2A, GCAM now also includes:

- bio + CCS
- coal without CCS
- coal + CCS (future)
- nuclear hydrogen production (through thermal splitting)
- solar electrolysis
- wind electrolysis

Base year bio + CCS and coal without CCS assumptions were created by applying the ratio between comparable IGCC technologies in GCAM's power sector. Coal without CCS was given the same improvement rate as the H2A biomass without CCS technology. The differences between the costs and energy intensities of corresponding "CCS" and "no CCS" technology pairs for coal and biomass were then reduced over time, consistent with the assumptions of similar IGCC technologies in GCAM's power sector. Wind and solar electrolysis costs are estimated by adding the cost of solar panels1 and wind turbines2 to the H2A electrolysis plant using NREL Annual Technology Baseline (ATB) data (2019) (NREL, 2019). Nuclear thermal splitting utilized an earlier version of H2A data (version 2.1) (NREL, 2018a). This data was updated by modifying H2A reactor costs to be consistent with NREL ATB's 2019 data. Long-term improvements in costs are consistent with nuclear reactor cost improvement rates assumed in the GCAM power sector.

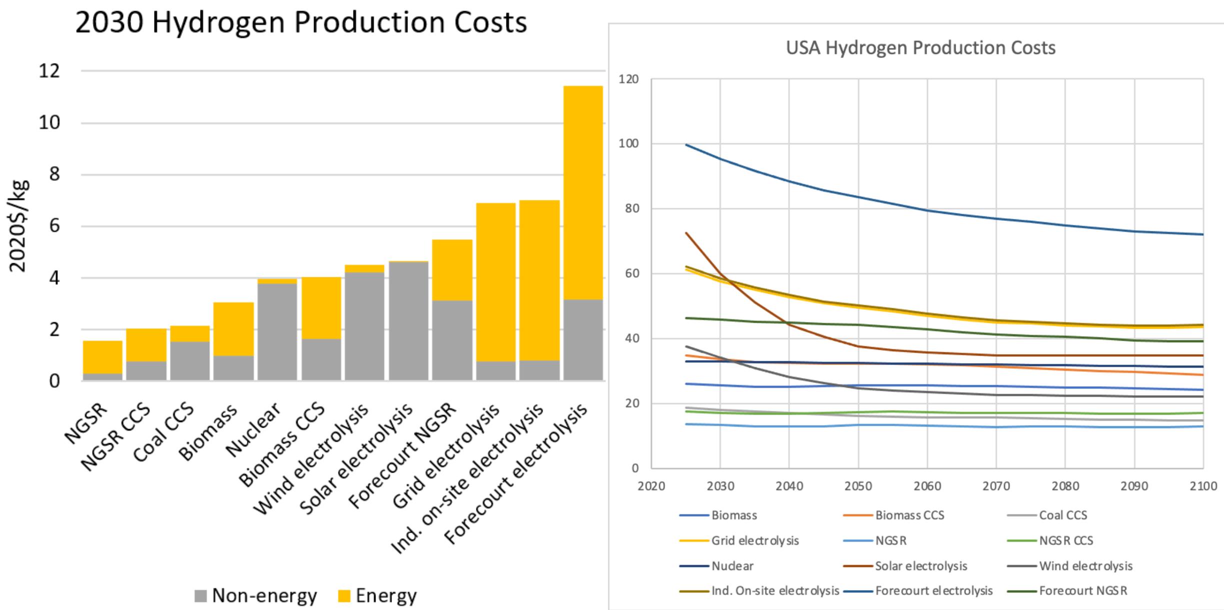

Figure 2. Hydrogen production costs in GCAM in model year 2030 (2020 $ per kg; left panel), and the cost trajectory from 2025 to 2100 for all technologies (right panel). Energy costs shown are for a reference scenario with a nominal CO2 price so that the CCS technology costs print correctly. Forecourt non-energy costs include additional energy and non-energy costs for hydrogen compression and refrigeration.

The approach for direct renewable electrolysis has also been revised from the prior methods, which took H2A's information literally and had generally the same costs of direct renewable hydrogen production in all regions. In this proposal, the costs of direct wind and solar electrolysis are estimated as the sum of levelized costs of electricity generation from wind or solar, and the sum of the levelized costs of the electrolysis process which converts electricity into hydrogen. The levelized costs of producing wind or solar electricity in each region and time period come from the global technology assumptions for the costs of PV panels and wind turbines, and region-specific capacity factors from the power sector. Levelized costs of the electrolyzers are also estimated on a region-specific basis, determined by the power output from the renewable generation equipment. That is, all regions are assumed to see the same capital costs of electrolyzers, but the annual output depends on the renewable capacity factors, so the levelized costs are region-specific. The input-output coefficients for converting electricity into hydrogen are from the corresponding grid-electrolysis technology in the hydrogen sector. One important assumption in the cost calculation is the capacity of the electrolyzers compared to the capacity of the renewable generation equipment, given that the renewable capacity factors tend to be less than 50%, whether from wind or solar. Sizing the two equally (i.e., for each MW of solar panels, installing 1 MW of electrolyzers) implies >50% idling of the electrolysis equipment; conversely, sizing the electrolyzers to the expected average renewable power production implies that the facility will produce excess electricity during times of high renewable output. This is a question that has been addressed in the literature both because of the techno-economic implications (what is the cost-optimal ratio) as well as from the standpoint of estimating the environmental footprint of the hydrogen production. For example, a facility that intends to keep its electrolyzers running at full capacity by purchasing power from the grid during times of low on-site renewable power output, and selling power during times of excess electric generation, wouldn't be considered "green" hydrogen by some definitions, due to the carbon intensity of the purchased electricity.

Our representative direct renewable electrolysis technology does not export or import any electricity to/from the surrounding grid. For estimating the levelized cost of electrolyzers at direct renewable facilities, we use a electrolyzer:renewable capacity ratio of 0.618, based on correspondence with researchers at NREL and EERE who note that in their estimates the cost-optimal ratio tends to be around 0.66, and the characteristics of a large planned renewable electrolysis plant in Namibia, which will feature 5 GW of wind and solar power capacity and 3 GW of hydrogen electrolysis capacity (ratio of 0.6). The Namibia plant will not use purchased electricity to supplement its on-site generation. There is likely some sort of backup system that will be installed, but the details of such a system are not publicly available at this time. GCAM's representation can be revised as needed if more information becomes available (e.g., if the information about the on-site electricity storage system at the Namibia facility becomes publicly available), but for now the costs are estimated in a way that is as true as possible to the available knowledge on direct renewable hydrogen electrolysis facilities.

Figure 3 illustrates the performance of each H2 production pathway in 2030 in a reference scenario. Note that in this figure, "forecourt electrolysis" refers to hydrogen produced on-site for mobile applications (transportation equipment, off-road industrial machinery), where higher pressures and lower temperatures for hydrogen storage and dispensing are required than for the other technologies. Because this all happens at the same facility, this technology is assigned some electricity that would only be assigned downstream of the generation technology for the others in the figure. For this reason it has an apparently higher electricity input-output coefficient than other technologies, even though the electrolysis input-output coefficient is the same as the other electrolysis technologies.

The market share of competing technology options in GCAM is determined by a logit choice competition that allocates share based on the relative costs of each technology (Calvin et al., 2019), calculated in each period as the sum of exogenous non-energy costs and energy costs; the latter depend on the exogenous energy intensity, and endogenous energy commodity prices. Market shares of competing options in the model are also modified by an exogenous “share-weight” parameter assigned to each technology in each year. The share-weight can be used to increase or decrease market share of specific technologies, due to aspects that aren’t reflected in the estimated costs. In general, all hydrogen production technologies are allowed to compete evenly (i.e., with all subsector and technology share-weights set to 1) in 2025, with no exogenous preference for any technologies assumed in any regions or time periods. However, CCS technologies (natural gas, coal, and biomass) are assigned low share-weights in 2025, effectively delaying their potential deployment until the 2030 model time period, consistent with the assumptions of CCS technologies in all other sectors.

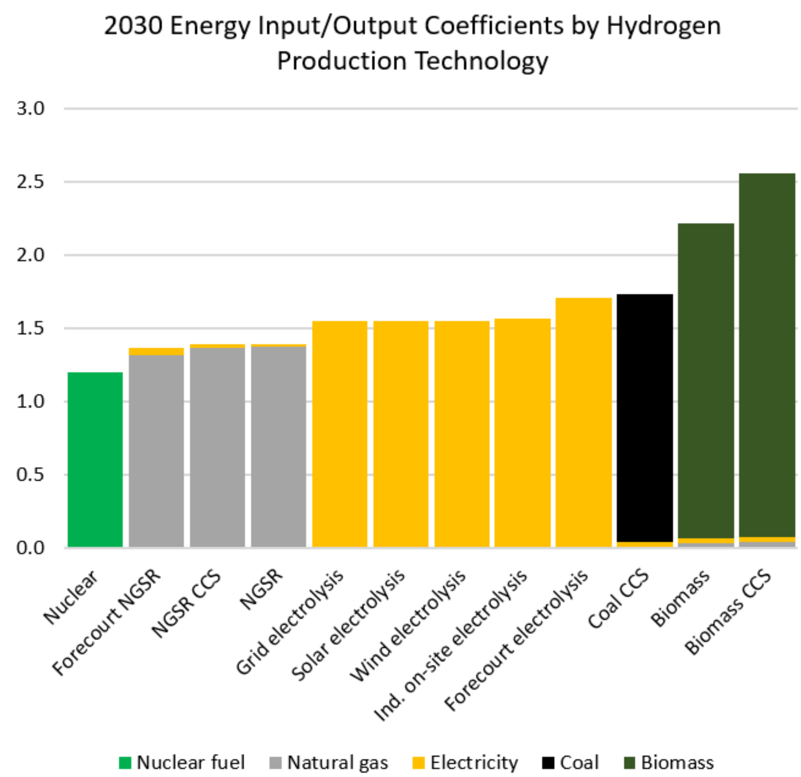

Figure 3. Hydrogen production input-output coefficients in GCAM in model year 2030 (GJ in /GJ H2).

Transmission and distribution technologies

GCAM hydrogen transmission and distribution assumptions are updated with the latest Argonne Hydrogen Delivery Scenario Analysis Model (HDSAM) data (version 3) (ANL, 2015). The specific configurations of HDSAM used to derive the input assumptions to GCAM are shown in Tables 1, 2, and 3. These assumptions are important in HDSAM for returning estimated levelized costs of hydrogen distribution by different pathways (we analyzed pipeline-based distribution, and liquid hydrogen truck based distribution). The data we pull from HDSAM include the total costs and electricity input-output requirements for the following 5 stages of pipeline-based distribution: transmission pipeline, distribution pipeline, central compressor, geologic storage, and gaseous refueling station. The first 4 cost components are assigned to the H2 pipeline technology, while the latter is assigned to the pipeline-based wholesale dispensing technology, which compresses and stores the hydrogen at high pressures (higher than the pipeline), incurring both capital and energy-related costs. In all aspects of hydrogen distribution, we keep the non-energy and energy-related costs separate, in order to ensure that the electricity requirements of a hydrogen transmission and distribution system are appropriately accounted. For the liquid truck pathway, the following cost components are taken from HDSAM: liquefier, terminal, tractor-trailer, and liquid refueling station. Here, the tractor trailer costs are not read to the model as a levelized cost and energy input-output coefficient, but rather we use an explicit input of trn_freight_road that is calculated from the assumed transit distance and the load factor of the truck, both of which are available in HDSAM.

Table 1. Settings for the methods of transmission and distribution of hydrogen.

Category	Specific setting
H2 market	Combined urban/rural
Region selection	Columbus, OH
Dispensing rate	1600 kg/day
Local market penetration	50%
Refueling lifetime	20 yrs.

Table 2. Settings for liquid truck transmission and distribution.

Category	Specific setting
Dispensing options to vehicle tank	700 bar gas via pump
Storage	Liquefier and liquid storage
Production volume	Mid

Table 3. Settings for gaseous hydrogen pipeline assumptions.

Category	Specific setting
Dispensing options to vehicle tank	700 bar cascade dispensing
Storage	Geologic/gaseous storage
Production volume	High

The representation documented here departs from the prior GCAM hydrogen structures and assumptions in several ways. First, the updated representation of hydrogen transmission and distribution explicitly competes different technology pathways on the basis of relative costs, in similar fashion to the hydrogen production technologies described above. Specifically, the three pathways are: central production to hydrogen pipelines, central production to liquid hydrogen trucks, and forecourt (i.e., on-site) production at service stations and industrial manufacturing facilities. Second, an additional cost mark-up for compression and refrigeration is assigned to refueling stations, for all hydrogen used by transportation technologies and mobile industrial equipment, thus increasing the costs paid by these end users. Third, the representation documented here explicitly tracks the energy used by each stage of hydrogen transmission, distribution, and on-site storage. Energy, mostly electricity, is used for hydrogen compression, refrigeration, liquefaction, and trucking. Figure 4 shows a restructured version of Figure 1, with a focus on the hydrogen distribution technologies, including all of the distribution-related input-output coefficients.

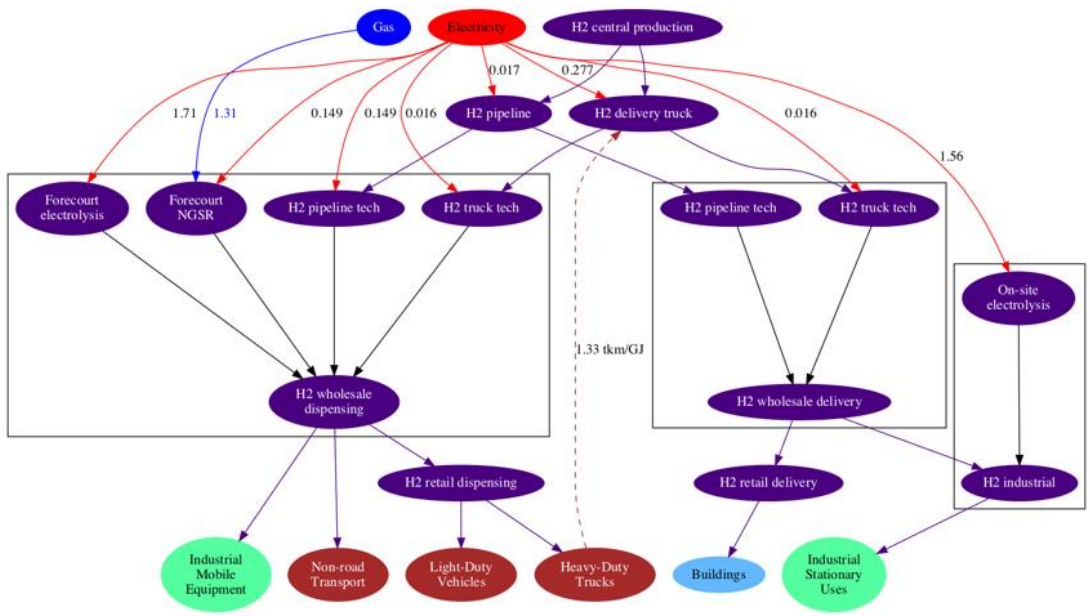

Figure 4. Hydrogen commodity flows, with input-output requirements shown. Arrows are color-coded by fuel. Boxes indicate hydrogen commodities that can be produced from multiple production technologies.

Note that the hydrogen trucking technology consumes some of the output of the heavy-duty trucking sector; in this way, there is no specific fuel type that is assigned to power the trucks used for hydrogen distribution. Rather, the energy intensity and fuel mix of this stage of hydrogen distribution is endogenous, and will reflect whatever technology changes are occurring in freight trucking in any given scenario.

HDSAM does not incorporate cost reductions overtime, thus an improvement rate was set to achieve an assumed 25% reduction in distribution costs by 2100 for both types of transmission and distribution. Liquid refueling stations were given a 10% total improvement in refueling costs by 2100, while gaseous refueling stations were allowed a 20% decrease in total costs by the end of the century. Hydrogen pipeline transmission and distribution is allowed starting in 2030. Most of the input-output coefficients are held constant over time, as e.g. gas compression is considered a mature technology. However, the liquefaction coefficient, which as shown in Figure 4 is 0.277 (Electricity -> H2 delivery truck), corresponds to about 9.2 kWh of electricity per kg of hydrogen liquefied, which is the assumption in ANL's HDSAM model. Based on correspondence with ANL, we reduce this to 8 kWh/kg by 2040 and 7 kWh/kg by 2060.

End-use technologies

Buildings

The core model does not have any building technologies that use hydrogen, so this is a new demand sector in this proposal. The buildings sector in GCAM is sub-divided into two sectors (residential and commercial), each of which has three building services (space heating, cooling, and other services). Hydrogen is allowed to compete for market share in space heating and other services, with the technical parameters based on the corresponding natural gas technologies (Table 4). Specifically, hydrogen technologies are assigned the same energy intensities and 10% higher capital costs than corresponding natural gas technologies. The 10% markup on capital costs is assumed given there could be increased costs to account for hydrogen being a smaller molecule than natural gas, therefore likely requiring tighter fitting to avoid leakage. Leakage detection may also be needed.

In the structural implementation, the hydrogen technologies are nested with the natural gas technologies in all regions. In this way, hydrogen competes directly with natural gas for market share for services provided by gaseous fuels as a whole, and the competition between gaseous fuels and all others is calibrated, with the calibration parameters determined by each region's costs and market shares in the base year. Regions with zero natural gas in buildings in the base year are assumed to remain as such in GCAM, and similarly such regions will also never have any hydrogen consumption in buildings.

Table 4: Cost and efficiency parameters of heating and other energy use provided by natural gas and hydrogen.

Demand sector	Technology	Installed cost (2005$/unit)	Lifetime (years)	O&M cost (2005$/yr/unit)	Efficiency (out/in)
Resid. heating	Natural gas	1500	20	50	.8
Resid. other	Natural gas	1500	10	20	.6
Comm. heating	Natural gas	5000	25	200	.8
Comm. other	Natural gas	3000	10	100	.6
Resid. heating	H2	1650	20	50	.8
Resid. other	H2	1650	10	20	.6
Comm. heating	H2	5500	25	200	.8
Comm. other	H2	3300	10	100	.6

Transportation

The development of cost and performance assumptions for hydrogen transportation technologies coincides with a broader update to the existing GCAM database of transportation technologies in all global regions; the existing database assumptions are documented in Mishra et al., 2013. Because no other documentation of the transportation data in general exists, this section also provides a description of the approach and data sources used for the updates of all transportation technologies, including those that do not use hydrogen.

Natural gas vehicle (NGV) share-weights

In addition to the specific transportation technology cost and performance updates, and new technologies added, this proposal also modifies the approach for representing natural gas vehicles (NGVs), replacing the current approach of allowing NGVs to compete in all regions starting in the first future time period, with NGV share-weights that interpolate from their base-year value in 2015 (usually 0) to 1 in 2100. In this proposal we assign "fixed" interpolation to NGVs, which carries the base-year share-weights forward to all future periods. In the core model reference scenario, NGVs account for 19% of global transportation final energy consumption in 2100, growing from less than 1% in 2015. This is generally understood to be a very aggressive growth level; the issue came up in Core Model Proposal 316, which for reasons mostly related to timing ultimately ended up not revising the approach. The justifications for revising the NGV deployment and for using fixed interpolation rather than just lowering the default end-of-century share-weights are as follows:

- Technology maturity. Unlike BEVs or FCEVs, NGVs are a mature technology, that has been available for decades, and unlike BEVs, we have reasonably reliable estimates of base-year energy consumption of NGVs in all regions, in the IEA Energy Balances. As such, the calibrated share-weights do contain meaningful information that can be expected to carry forward into future years.
- Maintaining inter-regional heterogeneity: There are a number of regions that have large-scale use of NGVs, such as Argentina, where the historical policy and infrastructural environments have been favorable for these technologies. There are others such as Japan where NGVs would probably never make sense due to the liquefaction stage of its imported natural gas. Assigning the same share-weights to all regions ignores these real sources of heterogeneity that would reasonably carry forward in a business-as-usual scenario.
- Lack of motivation for fuel-switching to NG: NGVs do not help with reducing total greenhouse gas emissions, nor energy security in regions that import all or most of their natural gas, and many regions do not have extensive gas pipeline networks, so would require significant infrastructural build-out to enable the fuel to be used for transportation.

In the future, if this technology becomes of interest and we want a greater level of reference scenario deployment, we will likely want to set region-specific share-weights for the technology, such that regions that are self-sufficient for natural gas start to deploy the technology in some future year. Regions that operate gas-to-liquids plants seem especially likely, as this indicates the presence of abundant and cheap natural gas. For example, Africa_Western doesn't have any

NGVs in the base year, so the fixed share-weight interpolation used in this proposal keeps the deployment at zero in all future periods. However the region has significant natural gas resources, and a large GTL plant, so it could reasonably be expected to see NGVs in a reference scenario. Regardless, setting region-specific NGV share-weights is beyond the scope of the present proposal.

Light-duty vehicles

Conventional (i.e., liquids) and natural gas vehicle purchase prices are unchanged from the standard GCAM assumptions (Mishra et al., 2013). The costs of batteries, fuel cells, and hydrogen storage tanks have been updated, which translates into updated cost assumptions for hybrid-electric vehicles (HEVs), battery-electric vehicles (BEVs), and fuel cell electric vehicles (FCEVs) in all regions, as the total purchase prices of these vehicles are estimated bottom-up. Specifically, the size of the fuel cell in each vehicle is computed from the vehicle mass and power, and the size of the hydrogen storage tank is calculated from the range of the vehicle and the fuel economy, generally assuming a 400 km range, roughly corresponding to the sales-weighted average range of BEVs in the US in 2019 (Wolfram and Hertwich, 2020). Meanwhile sales-weighted average battery capacity of US BEVs was just under 75 kWh (Ambrose et al., 2020). The amount of batteries required in any BEV is similarly computed from the assumed maximum range and vehicle fuel economy, but the range assumptions are tuned to return approximate battery capacities seen in marketed BEVs in each global region. The specific assumptions of the capacities of the battery packs per region and vehicle size class are shown in Figure 5.

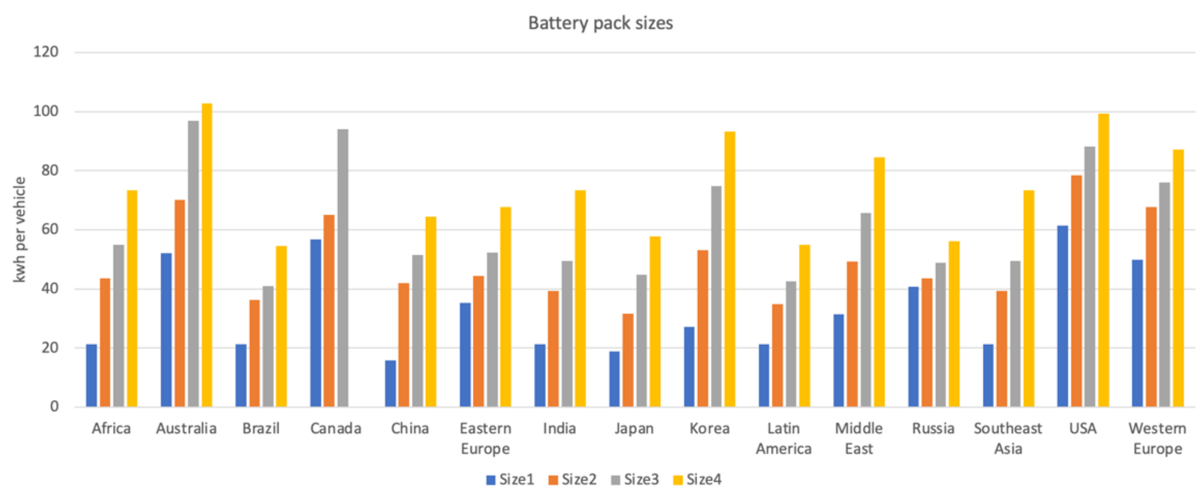

Figure 5. Battery capacities assumed by region and LDV size class, based on a survey of vehicles manufactured in eight vehicle markets globally (Australia, China, Eastern Europe, Western Europe, India, Japan, South Korea, and the USA). The physical meaning of each size class is specific to each region; for example, “Size1” in India is mini cars (cars < 1000 kg), whereas in the USA it refers to compact cars (e.g., Honda Civic).

BEV battery pack costs come from the 2020 BNEF Electric Vehicle Outlook (BNEF, 2021) estimated OEM pack prices and projected pack prices for 2025 and 2030 (held constant thereafter), plus a 50% markup to represent the cost of vehicle OEMs integrating the battery pack into finished vehicles. This cost mark-up is what NREL ADOPT assumes. Fuel cell stack costs are taken from NREL's most recent technoeconomic data, presented in the 2020 Transportation Annual Technology Baseline (NREL, 2020). The specific battery and fuel cell costs used in estimating the vehicle purchase price costs are shown in Table 5. Note that these costs are the costs paid by vehicle purchasers, not the prices paid by automobile manufacturers.

Table 5: Key cost assumptions for HEVs, BEVs, and FCEVs.

Variable	Unit	2015	2020	2035	2050
Battery cost	2015$/kWh	530	198	70	70
Fuel cell cost	2015$/kW	NA	232	73	42
Hydrogen tank cost	2015$/kWh	NA	30	30	30

Vehicle energy intensities of all drivetrains and size classes in the USA have also been updated; the update was performed by EPA's Office of Transportation and Air Quality, as well as EPA's Office of Research and Development. The revisions incorporate current CAFE standards into the projected energy intensities of gasoline vehicles (Liquids and Hybrid Liquids).

Buses & medium-/heavy-freight trucks

Purchase capital costs and fuel intensities for all technology types are taken from NREL FASTSim modeling results (Brooker, 2015). BEV charging infrastructure costs are taken from estimates developed by the California Air Resources Board (CARB, 2019). For translating the capital costs into a levelized cost per vehicle kilometer travelled, we assume that medium and heavy trucks travel 45,000 miles per year (72,400 km/yr), for a lifetime of 15 years, with a 10% discount rate. As the capital cost of the truck only accounts for a portion of the total freight costs, these remaining costs are estimated for the standard technology and applied equally to all of the new technologies being introduced. Table 6 shows the capital costs, assumed non-energy costs in the model, and assumed energy intensities for several size classes of trucks in the USA, for the 2030 model time period. We assume that distribution, storage, and fueling infrastructure costs for petroleum, biofuels, and hydrogen will be embedded within the modeled/assumed cost of fuel, and as such we do not assign refueling costs to the assumed vehicle costs. Note that there is also a smaller size class of freight trucks represented, corresponding to Classes 1 and 2 in the USA's classification system. The technical parameterizations of the BEV, hybrid, and hydrogen technologies are taken from the corresponding light trucks represented in the passenger sector.

Table 6: Key cost assumptions for medium and heavy freight trucks.

Size class	Drivetrain	Capital cost (2018$ per vehicle)	Non-energy cost (2018$/vkm)			Energy intensity (MJ/vkm)
			Truck capital	Balance of costs	Total	
Class 3-6	BEV	139,310	0.27	0.28	0.54	3.1
Class 3-6	FCEV	120,104	0.23	0.28	0.51	4.1
Class 3-6	Hybrid Liquids	94,400	0.18	0.28	0.46	6.8
Class 3-6	Liquids	89,800	0.17	0.28	0.44	8.6
Class 7-8	BEV	503,675	0.91	0.12	1.04	6.5
Class 7-8	FCEV	289,068	0.52	0.12	0.65	8.3
Class 7-8	Hybrid Liquids	182,000	0.33	0.12	0.45	10.7
Class 7-8	Liquids	170,000	0.21	0.12	0.33	11.5

Rail

The representation of freight rail transportation is expanded to include three new drivetrain technologies: battery electric, hydrogen fuel cell, and hybrid, where the hybrid technology is understood to be a technology with higher capital costs and lower energy intensities than the corresponding standard liquid fuel based technology in each region. Note that some regions already have electric freight rail in the historical years, which is grid-connected. The representation of this grid-connected technology is not modified in the present revision. For the new technologies, we first estimate the locomotive capital costs, based on the rail technology assessment (CARB, 2016), supplemented by conversations between staff from EPA OTAQ and CARB.

In general, non-energy costs of freight transportation technologies in GCAM are intended to reflect all costs of moving goods, such that model's estimated total costs of each service, indicated in dollars per tonne-km, is reasonably consistent with published freight transportation costs (e.g BTS, 2021 for the USA). In order to estimate the additional costs of the alternative rail technologies, we first estimate the locomotive-only costs of each technology, by translating locomotive capital costs into a dollars per vehicle-km, using the assumed capital costs of the locomotives, a travel distance of 90,000 km per year, a lifetime of 25 years, and a discount rate of 10%. The balance of the system costs are estimated from the assumed total costs in the base year minus the levelized costs of the standard locomotive, and are applied equally to all rail technologies. The full set of assumptions for model time period 2030 is shown in Table 7.

Table 7: Key assumptio**ns for rail technology costs in model time period 2030.**

Rail technology	**Capital cost (2018$ per locomotive)**	**Non-energy costs (2018$/vkm)**			**Energy Intensity (MJ/vkm)**
		Locomotive	**Non-locomotive**	**Total**	
BEV	14,000,000	10.65	34.81	45.46	360
FCEV	7,400,000	5.63	34.81	40.44	479
Hybrid Liquids	3,500,000	2.66	34.81	37.47	575
Liquids	3,250,000	2.47	34.81	37.28	719

Hybrid locomotives are assumed to be 1.25x more efficient than conventional diesel-electric locomotives. Fuel cell locomotives are assumed to be 1.5x more efficient, and battery electric locomotives are assumed to be 2x more efficient. Note that, due to the nascence of the technology and lack of active pilots, fuel cell freight locomotives are assumed to be unavailable before 2025.

All assumptions for high-speed rail are taken from the current GCAM core database (as documented in (Mishra et al., 2013).

Aviation

Battery electric purchase capital costs and non-fuel operation and maintenance costs for aircrafts are taken from Shafer et al. 2018 (Schäfer et al., 2019). Fuel intensity is assumed to be 2x more efficient than the equivalent conventional jet engine aircraft.

Hydrogen-powered aircraft costs and assumed efficiencies are taken from the Destination 2050 report (van der Sman et al., 2020). Explicitly associated to the switch to hydrogen technology, aircraft capital expenditures (cost of the tank structure, fuel distribution and larger fuselage) are expected to increase by 31% and maintenance cost will be up by 47%. Longer refueling times are likely to cause 7% less flight cycles. In addition, the reduced seating capacity decreases productivity by approximately 12% (Table 8).

Table 8: Key assumptions for domestic aviation technology costs in 2030 and 2050.

Year	Fuel	Non-energy costs (2018$/vkm)			Energy Intensity (MJ/vkm)
		Capital	Other	Total	
2030	Electricity	7.07	10.05	17.12	148
2030	Hydrogen	n/a	n/a	n/a	n/a
2030	Liquids	4.64	7.78	12.42	297
2050	Electricity	5.68	9.40	15.08	140
2050	Hydrogen	5.38	7.40	12.78	182
2050	Liquids	4.78	8.01	12.80	280

Marine transportation

Costs and energy intensities for hybrid, battery electric, and fuel cell electric vessels are estimated in similar fashion to the locomotive assumptions, due to the similarities of these drivetrains and the lack of literature on advanced technologies for marine freight vessels. Costs have been estimated by applying the ratios between conventional and advanced locomotive technology costs to conventional marine vessel costs. The availability of hydrogen technologies for marine vessels is delayed to 2030; all others are assumed to be available in 2025, though their costs ensure that their market share will be limited in this time period. Table 9 shows the cost assumptions in 2030 and 2050.

Table 9: Key assumptions for international ship technology costs in 2030 and 2050.

Technology	2030		2050	
	Non-energy costs (2018$/vkm)	Energy Intensity (MJ/vkm)	Non-energy costs (2018$/vkm)	Energy Intensity (MJ/vkm)
Electricity	190.32	1036	93.11	1015
Hydrogen	60.90	1381	39.35	1354
Hybrid Liquids	28.55	1658	23.28	1625
Liquids	22.84	2072	22.84	2031

Industry

This proposal adds some hydrogen-consuming technologies to the recently committed detailed industrial module (Core Model Proposal 326). In addition to cement and fertilizer, the following industrial groups are disaggregated: iron and steel, bulk chemicals, and the following non-manufacturing industries: agriculture, construction, and mining. This section provides an overview of the industry groups that include specific hydrogen-based production technologies.

Iron and steel production

In general, the assumptions for iron and steel technologies are based on (Ren et al., 2021) and the International Energy Agency (IEA, 2020), and documented in full in (Yu et al., 2021). As part of this project, we added one additional technology: hydrogen blast furnace with CCS (Table 10), which would combine the abatement benefits of both CCS and hydrogen to make its deployment potentially more attractive under emissions policy. Table 10 reports the cost and input coefficients for the hydrogen-using iron and steel production technologies, and the parameterization of the hydrogen blast furnace + CCS technology is detailed in the text below. We scaled the electricity consumption of vented (non-CCS) hydrogen blast furnace technology by a factor of 1.9, consistent with the standard blast furnace with CCS (without hydrogen). Hydrogen input is assumed the same as that of vented hydrogen blast furnace (3.3 GJ/t). The coal input coefficient for hydrogen blast furnace CCS is calculated by subtracting 3.12 GJ/t from the coal input of blast furnace + CCS technology. The small required inputs of natural gas and refined liquids are assumed equal to that of hydrogen blast furnace without CCS.
To derive the non-energy costs (i.e., the sum of all levelized capital, fixed, and variable O&M costs) for hydrogen blast furnace + CCS, we added the difference in assumed non-energy costs between non-hydrogen blast furnace and non-hydrogen blast furnace CCS, to the non-energy cost of hydrogen blast furnace without CCS.

Table 10: Input assumptions for hydrogen-using iron and steel technologies.

	Input coefficients (GJ/tonne)					**Non-energy costs (2020 USD/tonne)**		
Technology	**hydrogen**	**electricity**	**coal**	**natural gas**	**refined liquids**	**2020**	**2050**	**2100**
Hydrogen-based DRI	14.37	1.24	-	-	-	$ 328	$ 237	$142
BLASTFUR with hydrogen	3.30	0.55	13.66	0.01	0.01	$ 125	$ 110	$ 90
BLASTFUR with hydrogen CCS	3.30	1.06	10.90	0.01	0.01	$ 129	$ 114	$ 93

Cement

For producing process heat for cement, an additional technology was added that uses hydrogen as the heat source. The use of hydrogen for cement process heat could enable the elimination of combustion emissions from carbon-based fuels, but not limestone calcination; these emissions can still be abated with a CCS technology that is represented within GCAM's cement sector. Because hydrogen is not currently used for cement process heat, a share-weight phase-in was assumed, starting at zero in 2020, increasing linearly to 1 by 2050, in which year it competes against the current dominant technology on the basis of costs alone. This share-weight phase-in is intended both to represent limited technology availability in the upcoming decade, as well as the long-lived nature of capital in this sector, limiting the extent to which a new technology option can gain market share over time.

Ammonia fertilizer

While ammonia fertilizer production involves hydrogen production as an intermediate feedstock, this transformation is not represented explicitly in the model; rather, the standard natural gas steam reforming technology has an input of natural gas, and an output of N fertilizer. However, there may be capability in the future to substitute away from hydrogen produced on-site from natural gas to centrally produced and distributed hydrogen, or hydrogen produced on-site from electrolysis, potentially reducing carbon emissions from this industrial process. As such, this project allows a new technology to deploy starting in 2025 that has generally the same characteristics as the standard natural gas based technology, but that uses gas for process heat, but not hydrogen production (Figure 6). Non-energy costs for fertilizer production using direct hydrogen input (as opposed to on-site steam methane reforming (STM) of natural gas to produce the hydrogen required for the ammonia) are set equal to those of the natural gas process, less the non-energy cost of natural gas SMR hydrogen production from H2A. This approach results in an assumed production plant non-energy cost of 0.49 $2016/kgN for natural gas SMR, and 0.43 $2016/kgN for direct hydrogen input.[3] Additional non-energy cost associated with hydrogen production via other pathways, as well as hydrogen distribution are documented separately. The hydrogen input coefficient (GJ H2/kg N) is assumed to remain constant over time and is assumed to satisfy the stoichiometric hydrogen requirement for ammonium-based fertilizer production. Any remaining thermal energy requirement is then assumed be supplied by natural gas, which is calculated by subtracting out the natural gas that would have been required to produce the hydrogen in the natural gas-based process, using input coefficient assumptions from H2A.

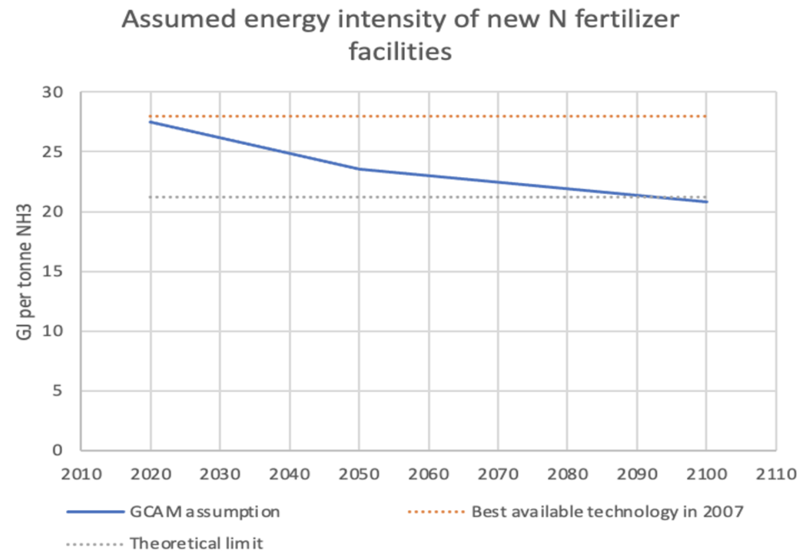

Figure 6: Input coefficients in the current release of GCAM compared to best available technology and theoretical limit.

Note that for the natural gas fertilizer production technology, the public version of the model has input-output coefficients that dip below what is thermodynamically possible; as shown in Figure 7, both the gas and gas CCS technologies' input-output coefficients dip below the feedstock-only requirements of natural gas for fertilizer manufacturing (dashed lines in Figure 7), as the coefficients were parameterized around "best practices" in terms of GJ per tonne NH3, failing to consider that our technology and N fertilizer commodity are represented in terms of tonnes of N, not NH3. These have been updated more generally in this exercise, as shown in the solid lines in Figure 7.

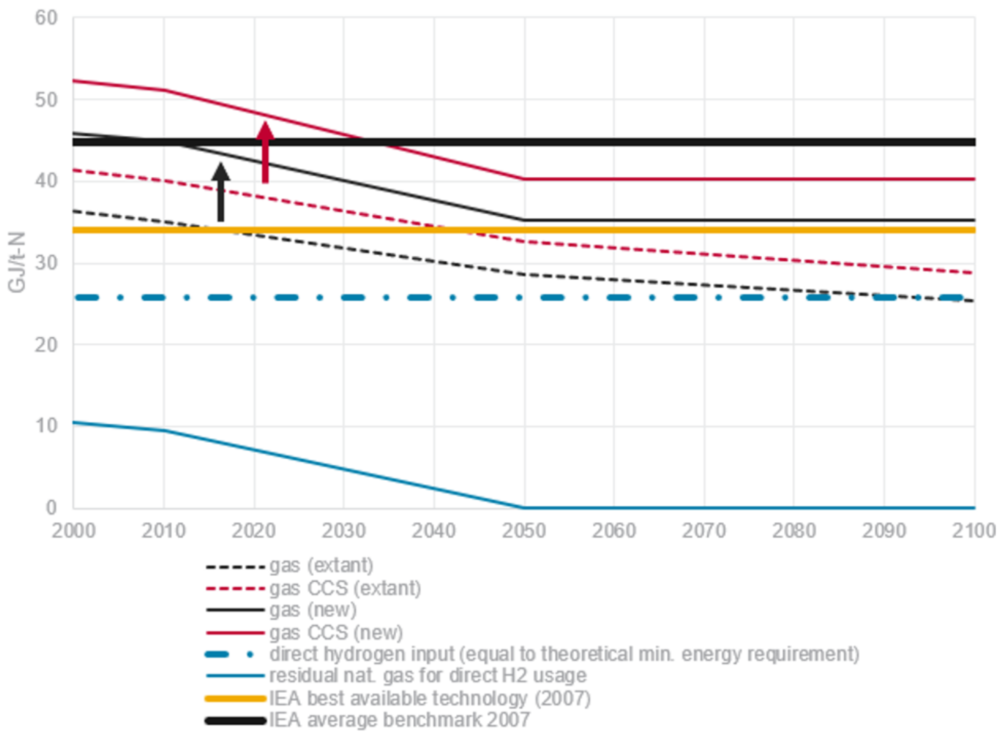

Figure 7. Input coefficient assumptions for natural gas and natural gas CCS **(corrected)** and direct hydrogen usage (new) fertilizer production technologies. The black and red arrows represent upward adjustments to the natural gas and natural gas CCS technologies.

Using method above to calculate the residual natural gas input for direct hydrogen fertilizer production, if the input natural gas requirement for the "baseline" natural gas steam reforming technology drops below ~35.2 GJ/t-N (25.7 theoretical minimum energy requirement/0.73 efficiency), this results in a negative calculated coefficient for residual natural gas input. We therefore assume zero natural gas input requirement from 2050 onward, when the natural gas based process is assumed to exactly equal the 35.2 GJ/t-N required to produce the hydrogen with the assumed 73% natural gas SMR conversion efficiency. This assumed value in 2050 is slightly higher than the IEA's best available fertilizer production technology as of 2007, which combines partial oxidation and steam reforming technology.

The changes made to the natural gas fertilizer production technology described above result in the natural gas + CCS production technology having lower input coefficients than natural gas without CCS. To address this, we derived new natural gas + CCS input coefficients by scaling the "new" natural gas without CCS input assumptions by the 1.14 ratio between the two technologies from the previous version (Figure 7).

Off-road vehicles and non-manufacturing

In the core model, the non-manufacturing sectors (agriculture/forestry, construction, and mining) are represented under a general category of "offroad" industrial activities. Still, the representation within each sector allows some substitution between different fuels which tend to be used for very different purposes. For example, the agricultural sector uses electricity for irrigation and facilities, diesel fuel for tractors and other off-road equipment, and natural gas for post-harvest drying. To best represent the technologies for hydrogen use and decarbonization more broadly, we have disaggregated the energy use for these off-road non-manufacturing sectors into "mobile" and "stationary" uses, which are represented as non-substitutable inputs to production functions. The reason for doing this is that the mobile equipment relies 100% on liquid hydrocarbon fuels at present, with no options for substitution, whereas the stationary uses rely on a variety of fuels whose relative shares can be expected to be price-elastic. Representing these sectors' energy demands without this disaggregation could allow an unrealistic degree of switching out of liquid fuels and into other options. Fuel-switching in the future is nevertheless allowed in the mobile sector, but with electric- and hydrogen-based technology costs and performance measures estimated in detailed fashion, described below.

These industries are characterized by many different energy-consuming technologies performing a wide array of services, which to our knowledge have not been characterized in detail in energy statistics or energy models to this point. However, all three sectors are significant users of liquid hydrocarbon fuels, with limited capabilities for price-driven fuel-switching, as much of the energy is used by mobile equipment that can't directly connect to the electric grid or pipelines carrying gaseous fuels. As such, these industrial sectors may be important in the context of emissions mitigation; technologies facilitating emissions reductions here can lower the costs of mitigation for the system as a whole. For this reason we have expanded the detail with which these processes are represented, in order to capture the potential future fuel-switching capabilities and costs, while keeping the output units of these sectors generic, not in physical units (e.g., tonnes of ore processed).

To perform the stationary/mobile disaggregation, we revise the sector/subsector/technology structure; where in the core model, the subsectors are fuels and the technology nest doesn't have any competition, here we assign two subsectors, "stationary" and "mobile", each of which has multiple fuel options. In the historical periods, 80% of liquid fuel consumption is allocated to mobile subsector / refined liquids technology, with the remainder allocated to stationary / refined liquids. The representative mobile/hydrogen and mobile/electricity technologies are assigned zero output in the historical periods. Shareweights for hydrogen and battery powered off-road vehicles are linearly interpolated from zero in 2020 to 1 by 2050, reflecting assumed technology availability over time and capital carryover. The derivations of non-energy cost and efficiency parameters for off-road vehicles are detailed below.

Efficiency: Because the output of these sectors is not represented in physical units, the efficiencies, which describe the ratio between output and input for any technology, are also not physically meaningful. As such, we have set the liquid fuel technology to an index efficiency of 1, and for the electric and hydrogen technologies we use the efficiency ratios between these technologies and the corresponding standard "Liquids" technology for freight rail, as shown in Table 7. These efficiency estimates—1 for liquid fuels, 1.5 for fuel cell vehicles, and 2 for battery electric vehicles—were applied to mobile equipment of all three off-road industries, and increased at a modest rate of 0.1% per year in future periods.

Levelized non-energy costs. Technologies in GCAM compete on the basis of levelized costs of service provision, where the costs are equal to the sum of fuel costs and levelized non-energy costs. Because the outputs of off-road technologies are not in physical units, we adopt an approach that estimates the non-fuel costs based on the ratio of fuel to non-fuel costs in the historical years. In this way, the method accurately captures the economic trade-offs between the different technology options, even though the specific cost numbers are arbitrary, and depend on what was assumed for the efficiency of the liquid fuel technology described above. Fuel costs are equal to fuel prices divided by efficiency. The derivation of the non-fuel costs for liquid fueled offroad vehicles is described in detail below. We then used ratios of non-energy costs for BEV and FCEV heavy freight trucks relative to the liquid-fueled technology (Table 11) to scale to the corresponding non-energy cost.

Table 11: Non-energy costs for BEV and FCEV heavy freight trucks relative to the liquid-fueled technology.

	2025	**2030**	**2035**	**2040**	**2045**	**2050**	**2100**
BEV	1.58	1.49	1.41	1.32	1.23	1.15	1.15
FCEV	1.2	1.18	1.16	1.14	1.12	1.1	1.1

Agriculture - non-energy cost

Costs for liquid-fueled tractors, which are assumed to be representative of agricultural off-road vehicles, were obtained from Iowa State University's "Ag Decision Maker" Machinery Cost Calculator (Edwards, 2015). The fuel and non-fuel costs were disaggregated and used to calculate a ratio of fuel to non-fuel costs for liquid fueled tractors. Based on a known GCAM fuel cost for refined liquid fuels, and an indexed efficiency of 1 for internal combustion engines, this can be used to derive a fuel cost per unit of output for liquid-fueled vehicles. This is then multiplied by the ratio of non-fuel fuel to fuel costs to calculate a non-energy cost that is harmonized for input into GCAM. The resulting non-energy cost is assumed to remain constant over time. Note that the non-energy cost ratios are different from the capital cost ratios, as many of the cost components were assumed equal between the different drivetrain technologies.

Mining - non-energy use

Costs for mining equipment were obtained from the U.S. Department of Interior "Cost Estimation Handbook for Small Placer Mines" (Stebbins, 1987, p. 30). Bulldozers are assumed to be representative of mining vehicle energy use.

Construction - non-energy use

Costs for liquid-fueled construction vehicles were obtained from (Gransberg and Rueda-Benavides, 2006[4]). The U.S. Army Corps of Engineers cost estimation method (Table 2.7 in the book) for calculating the cost of a 150 ton truck crane, which is assumed to be representative of construction equipment energy usage. The non-energy cost was normalized to GCAM input format using the same method as for mining and agricultural equipment.

Energy conversion

H2-enhanced biomass-to-liquid

We include a new energy-conversion pathway for the production of liquid vehicle fuels from biomass and hydrogen. Following Hennig and Haase (Hennig and Haase, 2021), we estimate that in order to produce one energetic unit of liquid fuel, 1.032 units of biomass and 0.816 units of hydrogen are needed as inputs (Table 15). We assume that surplus electrical energy can be reused for electrolysis, i.e. converting electrical energy to hydrogen (compare with Figure 3 (middle) in Hennig and Haase).

Table 15: Assumed energetic inputs for the production of one energetic unit of liquid vehicle fuel.

Fuel	Input	System efficiency
Biomass	1.032	
Hydrogen	0.816	
Sum	1.848	54%

Hennig and Haase also provide cost estimates for this pathway. The authors estimate total production costs are 3.24 euro/kg fuel. From that we deduct the costs for feedstocks (straw and hydrogen) to arrive at an estimated non-energy cost of 0.80 euro/kg fuel (compare with Figure 4 in Hennig and Haase). For use in GCAM we convert this number to US$/GJ. Therefore, we estimate a "composite" lower heating value of 12.30 kWh/kg for the two fuel product outputs (gasoline and LPG). The reason therefore is that the output masses of each fuel and their individual lower heating values differ. We then convert 2021 euro to 2021 US$ using an exchange rate of 1.16 US$/euro.

GCAM-USA

In the core model, GCAM-USA doesn't have a hydrogen module at the state level; hydrogen is represented in the "USA" region, and the electrolysis technologies are disabled because in the GCAM-USA configuration the relevant electricity markets (elect_td_ind, elect_td_trn) don't exist in the USA region. Light-duty-vehicle transportation and other industrial energy use have technologies that consume hydrogen, at the state level, from this USA hydrogen market. This proposal makes a simple modification to that approach, copying the full representation of hydrogen production and T&D down to each state. The way it is structured in this proposal, each state's hydrogen market is closed; i.e. there is no hydrogen trade between states. There are still fuel price differences from one state to another, such that the technology choices and hydrogen prices will vary from state to state, but there's no capability for the emergence of hydrogen production "hubs" that supply hydrogen to neighboring states.

Because this proposal doesn't do any development on the end-use sectors of GCAM-USA, only some of the hydrogen demand technologies described above are available in GCAM-USA in this proposal. All hydrogen demand technologies in the transportation sector are carried to the 51 states, because the structural representation in the USA region is simply replicated at the state level. In the industrial sector, hydrogen technologies are available in the following: other industrial energy use, cement, and N fertilizer. Because GCAM-USA doesn't have detailed industry at this time, it doesn't have a place for the hydrogen technologies in iron and steel, chemicals, or off-road non-manufacturing industries. Finally, no new technologies were added to the buildings module, as GCAM-USA uses a customized representation with more services than the USA region of GCAM in its default configuration.

Future Work

The following areas are known to benefit from future work:

- GCAM-USA Buildings: while the GCAM-USA Industry sector is currently under development, the buildings sector could be assigned hydrogen demand technologies, following the same approach used for the global buildings module.
- GCAM-USA Inter-state T&D: In this proposal, state markets are closed and there is no capability for inter-state trade of hydrogen. This should be represented, with scale-dependent average levelized costs for the pipeline sector, that capture that states with large markets and low production costs can gain the comparative advantage to become hydrogen exporters to surrounding states.
- Include a liquid hydrogen commodity. The existing suite of hydrogen commodities available to different end-use consumers reflect several levels of temperatures and pressures of hydrogen, but we don't currently represent the markets for liquefied hydrogen for end-use purposes as a distinct commodity from gaseous hydrogen. The current representation includes hydrogen that is liquefied for T&D purposes ("H2 liquid truck"), but not hydrogen that is liquefied for end-use consumption. The net impact of this omission is that the hydrogen fuel price paid by aviation and shipping (which would require liquid hydrogen) is slightly lower than it would be if the existing costs and electricity requirements of hydrogen pressurization and storage for wholesale dispensing (at about 10,000 psi, were replaced with the corresponding costs and electricity coefficients of liquefaction.

Footnotes:

[1] Utilizes the overnight capital cost of ATB’s Solar Utility PV technology, mid case.
[2] Utilizes the overnight capital cost of ATB’s Land based Wind - TRG 1, mid case.

[3] Note that the commodity represented in GCAM, “N fertilizer”, is indicated as the nitrogen mass only of ammonia, and is an input to crop production. This convention follows standard practices in agricultural modeling. The stoichiometric mass conversion is 14 kg N is equal to 17 kg of NH_3.

[4]Gransberg, Douglas D, Calin Popescu, and Richard C Ryan. Construction Equipment Management for Engineers, Estimators, and Owners. Civil and Environmental Engineering, 21. Boca Raton, FL: CRC Taylor & Francis, 2006.

Validation

At a high level, the changes in this proposal generally increase baseline emissions and radiative forcing slightly for SSPs 1, 3, 4, and 5 (Figure 8, left panel), and decrease radiative forcing slightly in the Reference and SSP2 scenarios. The biggest difference in the reference scenario is that the H2 revision sees less natural gas demand (for transportation), and in the SSP5 scenario this seems to be mostly counter-balanced with increases in oil and coal. Across all mitigation scenarios, the H2 Revision decreases the carbon prices required to hit any emissions mitigation target (Figure 8, right panel), because the availability of low-carbon technological options throughout the transportation sector--particularly for ship and air--allows more mitigation from this sector, which is otherwise quite important for determining whole-system mitigation costs. As shown in Figure 9, left panel, the mitigation scenarios in the H2 revision also have more total primary energy, which is a consequence of having lower carbon prices (Figure 8).

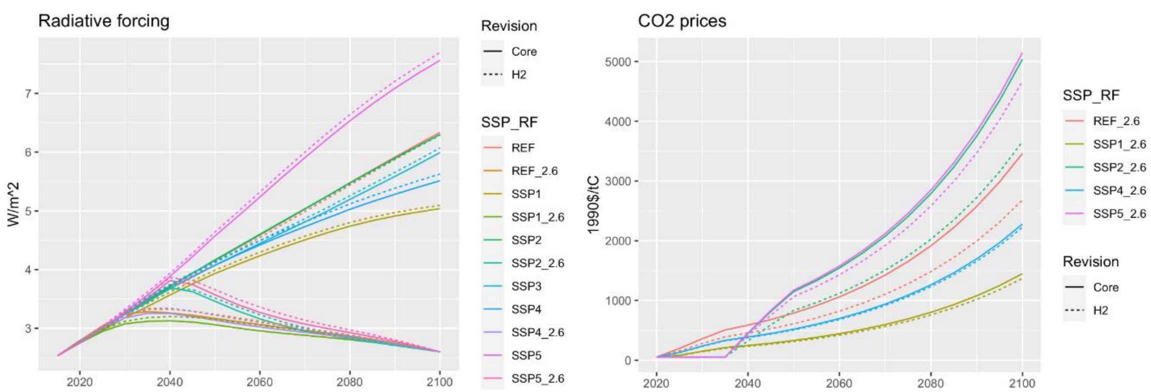

Figure 8. Radiative forcing and CO2 prices in the validation scenarios.

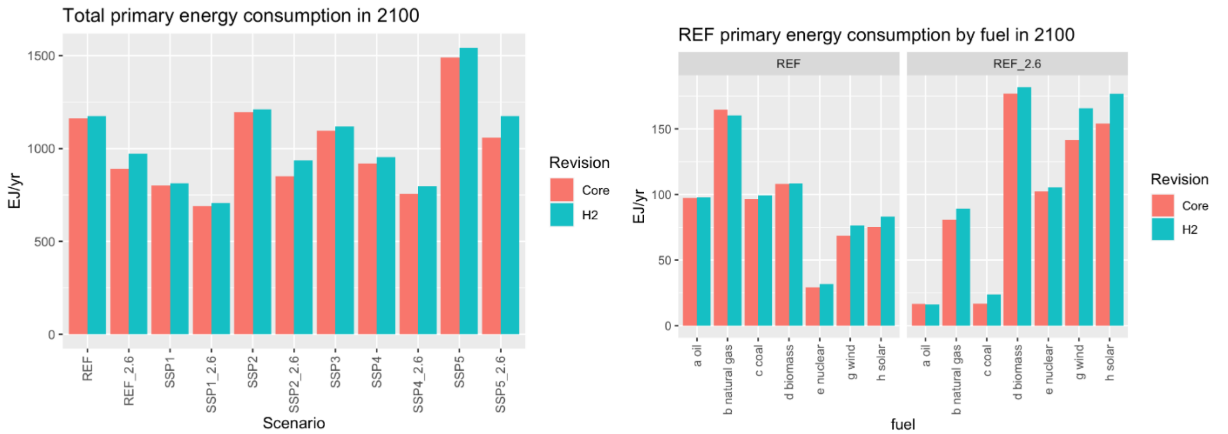

Figure 9. Total primary energy consumption in the scenarios in 2100 (left panel), and Reference and Reference_2.6 scenario primary energy consumption by fuel in 2100.

The right panel of Figure 9 indicates that in specific fuels, the largest increases that we see are in wind and solar, with lesser increases seen in nuclear and coal. Oil and biomass are similar, and there is a slight decrease in natural gas, due primarily to the NGV share-weight modification, which reduces Reference scenario natural gas consumption for transportation in 2100 from about 45 EJ/yr in the Core to less than 1 EJ in the H2 Revision. In Reference_2.6, we see increases in all fuels except for oil, which is consistent with the statement above that the transportation sector in the H2 Revision has more electric and hydrogen options that allow it to rely on feedstocks other than oil.

Figure 10 shows that across all scenarios in the validation suite, the hydrogen markets are significantly larger than the core model. This is a direct consequence of having many more potential demands; where the core model has only LDV transport and generic industrial energy use, the revision has dozens of technologies throughout the energy system that use hydrogen. The specific inter-sectoral allocation of hydrogen demands are addressed below. Another interesting dynamic shown in Figure 10 is that while the technological composition of hydrogen production in the reference scenario is similar between the core model and the proposed revision, in the policy we see quite different results. In the core model's Reference_2.6 scenario, the dominant technology is nuclear thermal splitting, while in the revision that technology is barely part of the mix at all, due to the costs in the revised H2A data. Instead, in the revision there is a mix of electrolysis (mostly direct renewable electrolysis), natural gas with CCS, and biomass with CCS. This marks a significant increase in direct renewable electrolysis from the core model, which is the consequence of harmonizing our technological assumptions for renewable-electric-hydrogen production with the assumption in the power sector for renewable-electric power production.

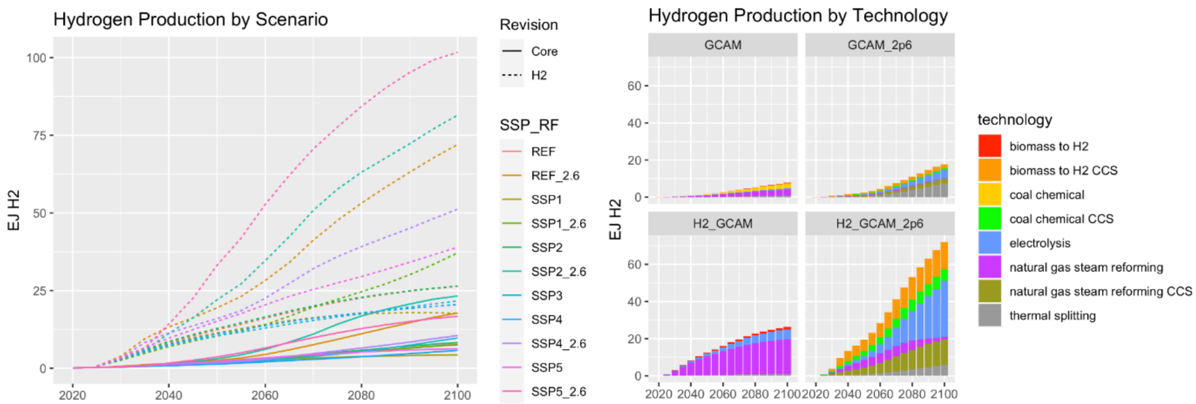

Figure 10. Global hydrogen production by scenario (left panel), and by technology for the Reference and Reference_2.6 scenarios (right panel).

The transmission and distribution of centrally produced hydrogen in the H2 Revision scenarios, shown in Figure 11, tends to be mostly by pipeline, which is the lower-cost option in both reference and policy scenarios. Where the reference scenario sees about 35% of hydrogen produced on-site ("forecourt production"), in the policy scenario the market share of forecourt production drops to about 10%, because of the favorable economics of the technology choices in the central production sector. Forecourt production is only allowed for natural gas without CCS and grid-based electrolysis. The right panel of Figure 11 shows the electricity and freight road transport requirements of the hydrogen T&D system globally (these inputs had been ignored in the Core model; the costs of purchased energy were folded into the assumed T&D costs).

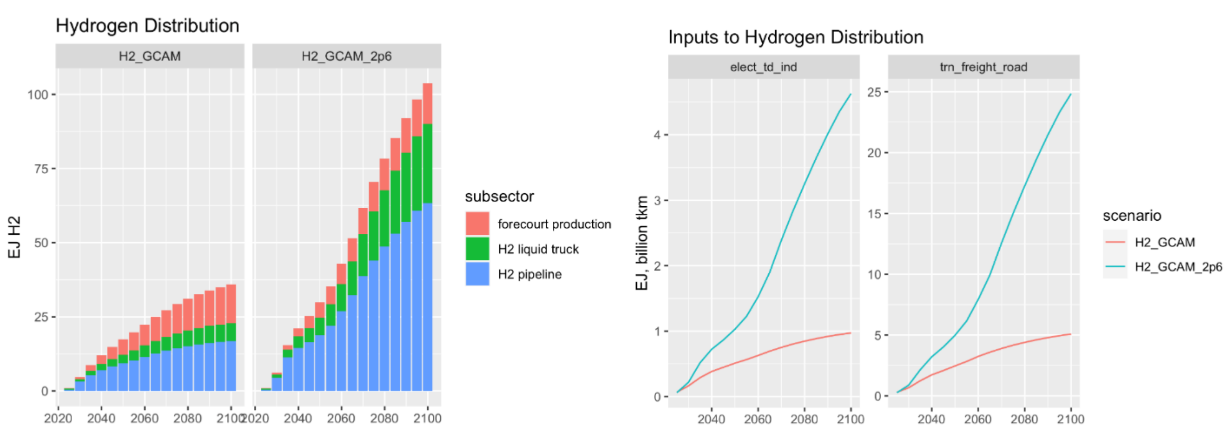

Figure 11. Hydrogen transmission and distribution by technology (left panel), and the energy input requirements thereof (right panel).

Figure 12 shows the transportation sector's fuel choices across the full scenario set, in 2100. The largest change across the scenario set is the reduction in natural gas used for transportation, which tends to be a minor fuel in the Core 2.6 scenarios, but is a pretty major fuel across the full set of reference scenarios. Setting NGV share-weights to use "fixed" interpolation removes the

NGV technology set entirely from a number of regions, and of the regions where it is available, the share-weights tend to be pretty low, so their deployment levels are similarly reduced compared with the Core scenarios. The H2 Revision scenarios see more hydrogen and electricity in all scenarios, particularly the 2.6 scenarios, and interestingly most of the 2.6 scenarios see an increase in total energy consumption compared with the Core; given the efficiency differences between the technologies, this indicates increased service demand, explored further in Figure 13.

Transportation

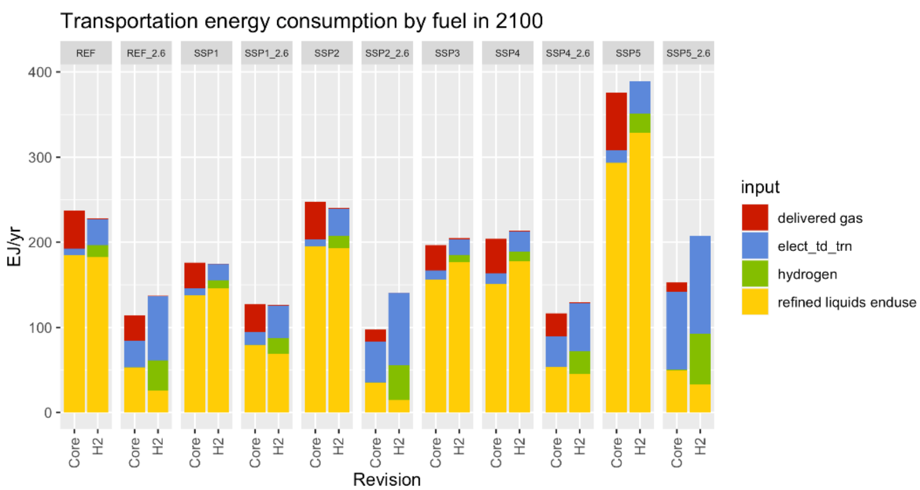

Figure 12. Transportation sector energy consumption by fuel and scenario in 2100

As shown in Figure 13, transportation total service output levels by mode do not differ dramatically in the reference scenarios, but in mitigation scenarios, having low-carbon technologies allows service demand levels to remain closer to their reference levels. This is especially noticeable in maritime shipping and aviation, which in the core model are limited to liquid fuels, so the mitigation scenario response is to cut service demand in response to increasing prices. In the H2 Revision scenarios, the mitigation response differs significantly across modes, due to the different costs of fuel-switching. Maritime shipping tends to switch to hydrogen, whereas aviation and trucking switch to mostly battery-electric vehicles. Within aviation, battery electric aircraft account for the vast majority, 85%, of the passenger-km of the "Domestic Aviation" (defined as flights < 2000km) in the year 2100 in the REF_2.6 scenario, but only 12% of the International Aviation sector, where liquid fuels remain the dominant technology (57% of pkm), with the remaining 30% going to hydrogen aircraft.

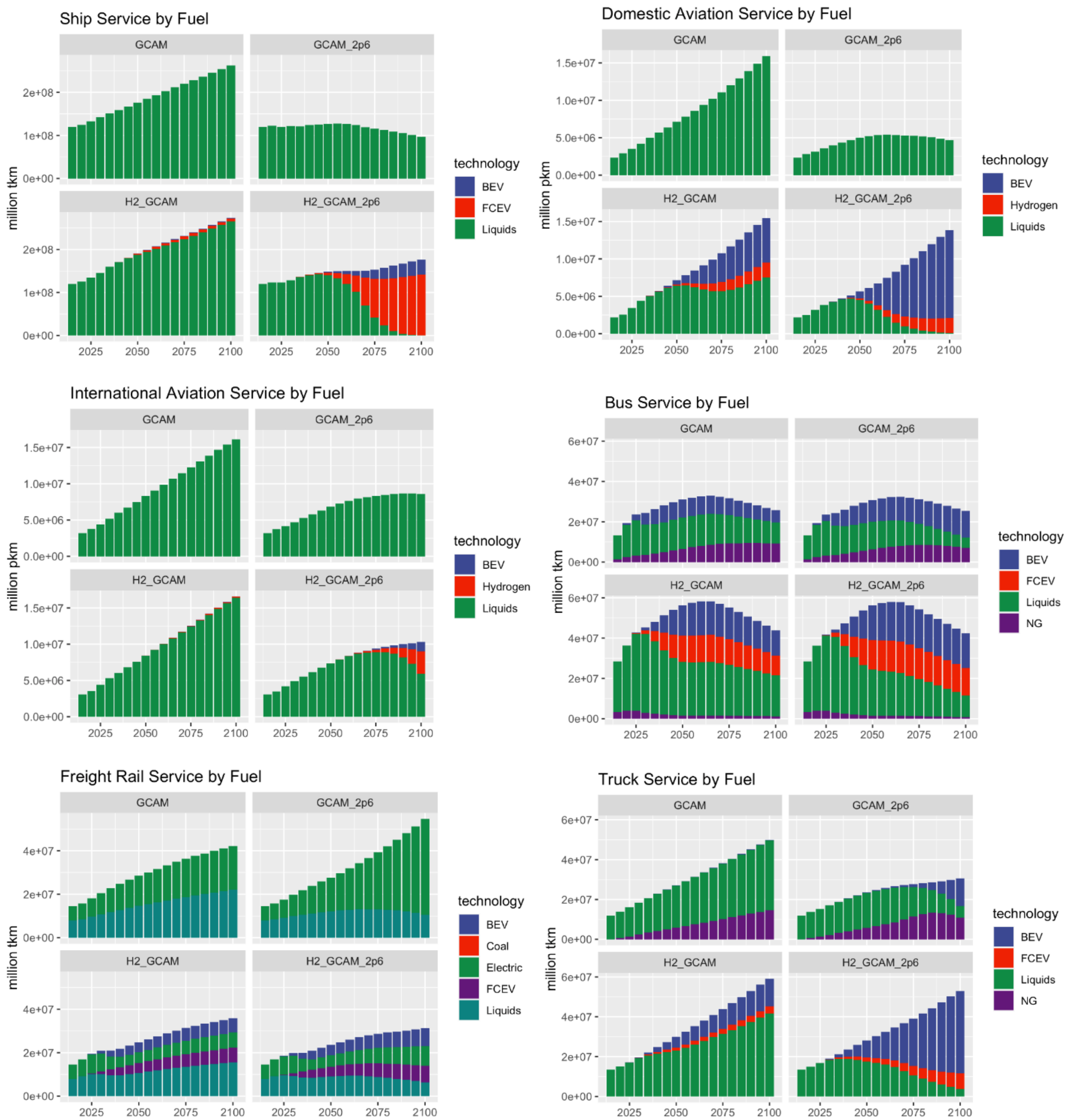

Figure 13. Transportation service output by selected mode, technology, and scenario. Aviation and bus service output are indicated in million passenger-km whereas the remainder are indicated in million tonne-km of freight.

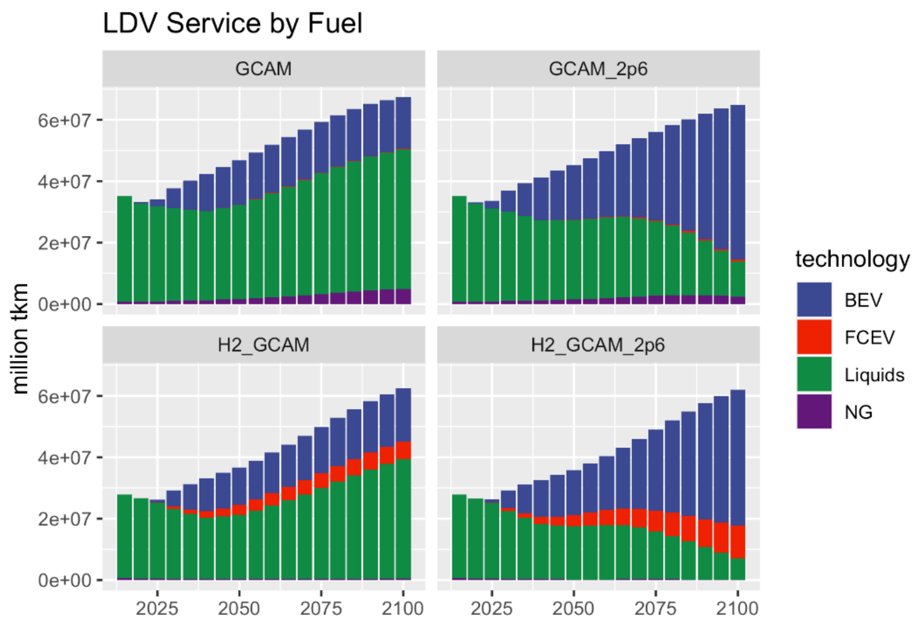

Figure 13 (continued). Transportation service output by selected mode, technology, and scenario. Aviation and bus service output are indicated in million passenger-km whereas the remainder are indicated in million tonne-km of freight.

This result for shipping market shares are fundamentally because BEV ships would need to have enormous battery banks in order to be able to cover the necessary travel distances, so the costs of this option are comparatively higher than the liquid hydrogen technology option. Both electricity and hydrogen are significantly cheaper than the liquid fuels technology, because of the large increase in the prices of liquid fuels, and the large portion of total service costs that are from fuel for this market segment. In aviation, the long-distance ("international") market segment remains reliant mostly on liquid fuels in the scenarios, with significant contributions from hydrogen; BEV market shares are low largely due to the assumed share-weights, given the speculative nature of the electric technology in this market segment. However, the shorter-haul ("domestic") market segment that accounts for the majority of the passenger travel is more amenable to electrification, and the costs of the BEVs in 2100 in the 2.6 scenario are far lower than the corresponding liquid fuel option. In the light-duty vehicle market, electric cars are the least-cost option for many time periods in the reference scenario, due to assumed cost reductions that are consistent with present-day projections (e.g., Bloomberg New Energy Finance). This sort of result is actually already in the core model, where the transportation technologies were updated in 2021. For this reason, the cost responses in the USA region are pretty similar between the core and the H2 Revision, with the exception that the H2 Revision incorporates also reduced costs of fuel cells, consistent with current DOE ATB projections. Still, the fuel cell vehicles are more expensive than electric vehicles in all years, and more expensive than liquid fuel vehicles in most scenarios and years.

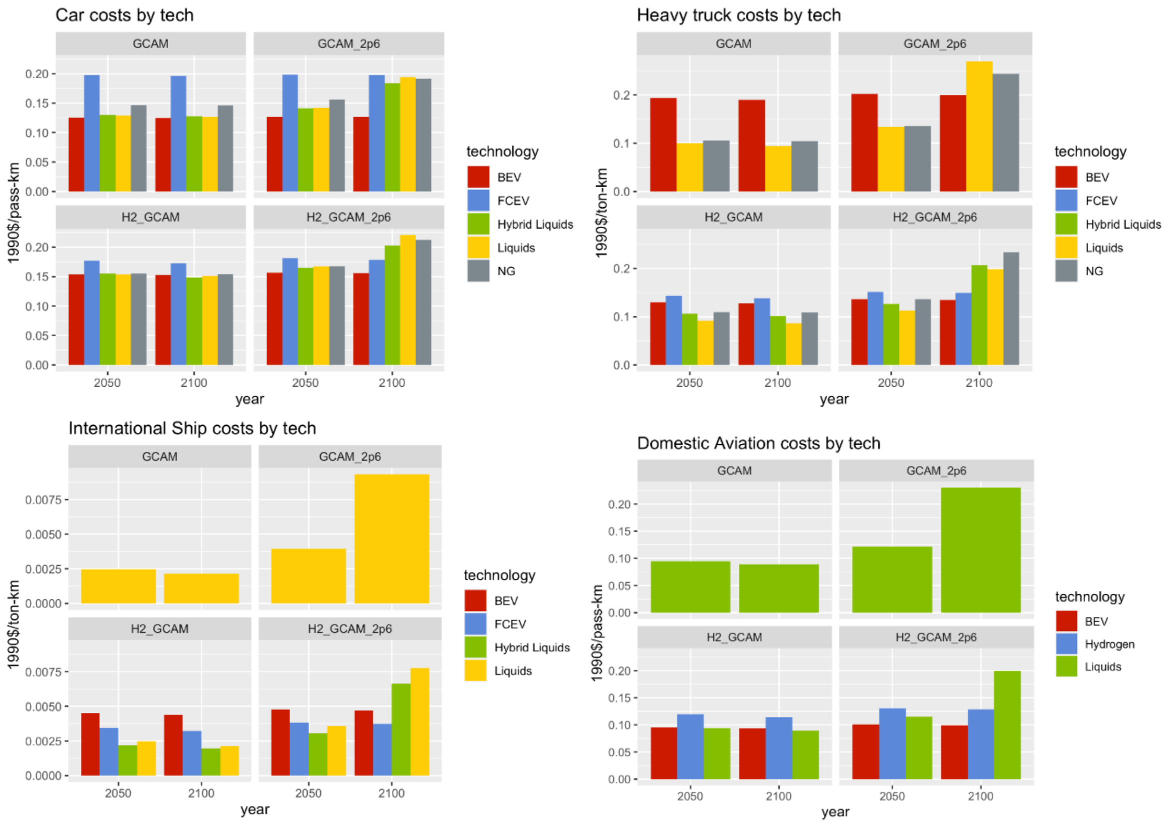

Figure 14. Transportation technology costs by selected modes, technologies, and scenarios, for the 2050 and 2100 model time periods.

Industry

Industrial energy consumption by sector, fuel, and selected scenarios are shown in Figure 15. In the industrial sector, this proposal re-structures the agriculture, construction, and mining sectors so as to disaggregate mobile from stationary applications, and adds in FCEV and BEV technologies to the mobile segment. Despite this structural change, the broad patterns of energy use in these sectors are largely similar to the core model, though with less fuel-switching away from liquid fuels in the reference (no-mitigation) scenarios, and a lesser role for hydrogen in the construction and mining industries. In the iron and steel sector, the H2 Revision does involve some technology shifting, shown in Figure 16, but the fuel use patterns shown in Figure 15 are strikingly similar. The cement sector in the H2 Revision scenario has an option to use hydrogen as kiln fuel; despite not having any efficiency advantage over the other competing options, this option gets pretty significant utilization in the 2.6 scenario. This implies a role for hydrogen in the scenarios for high-temperature industrial heat, where electricity is understood to not be an option, and the use of any carbon-based fuels would presumably need to source their carbon from limited bioenergy resources.

Industrial Final Energy by Fuel

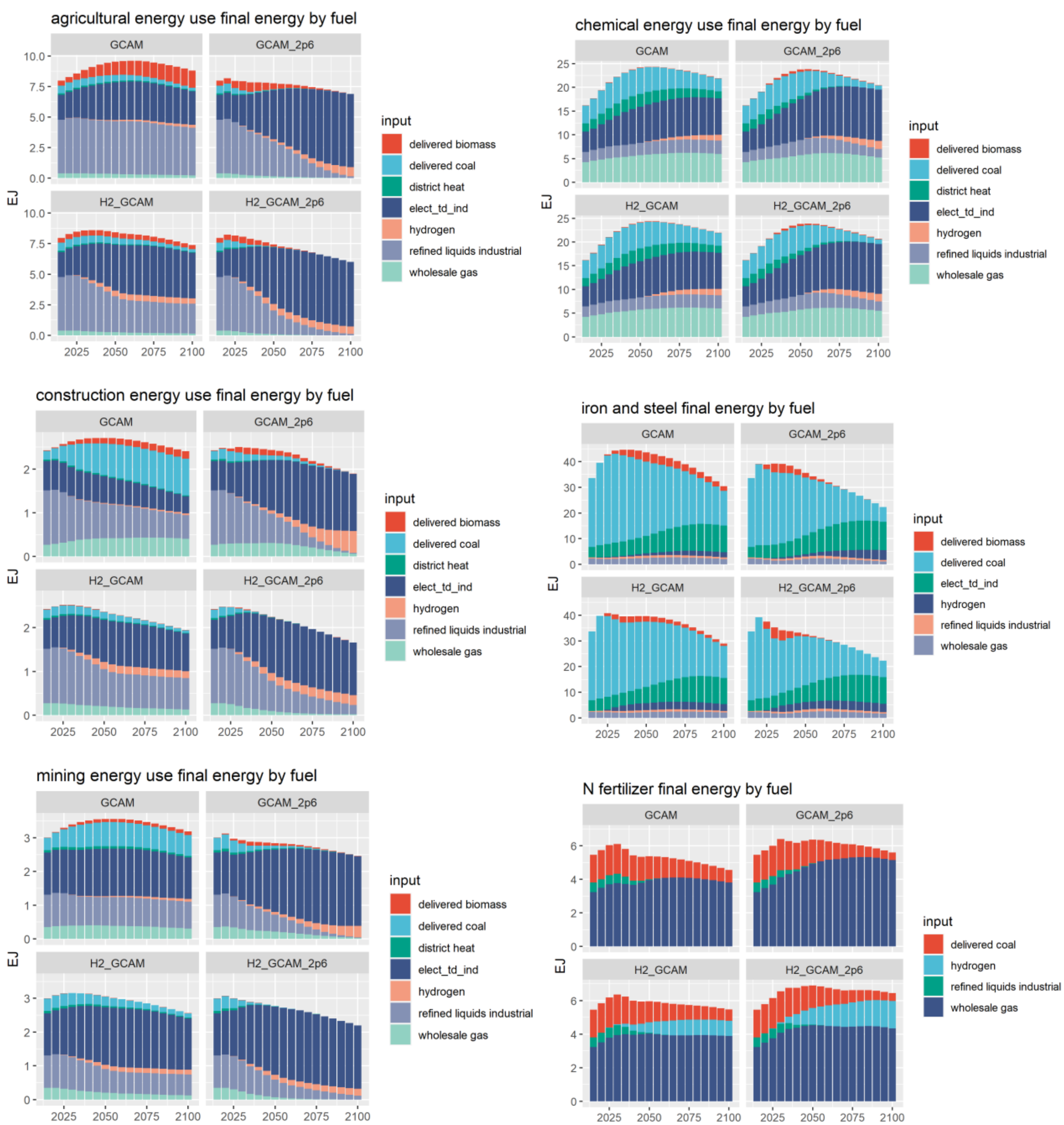

Figure 15. Energy consumption by year (2015-2100), scenario (Reference, Reference_2.6), industrial subsector, and fuel.

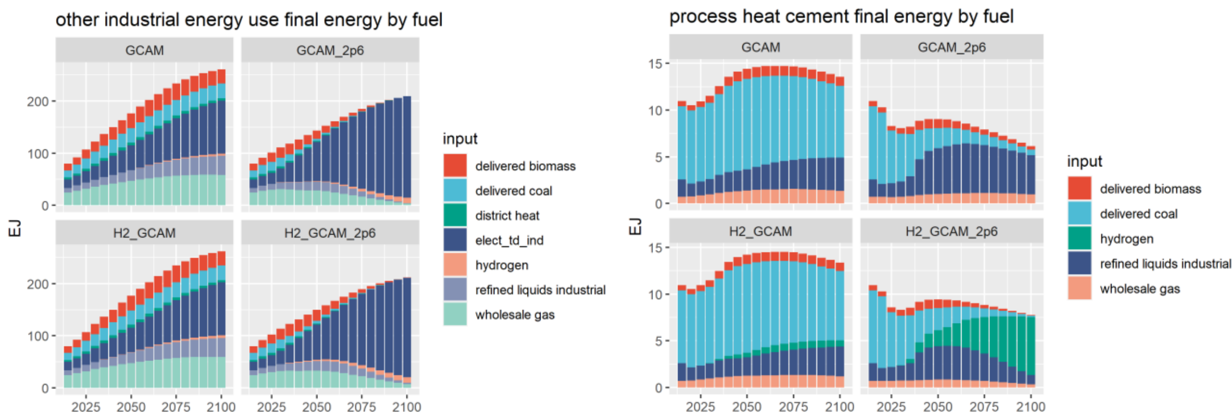

Figure 15 (continued). Energy consumption by year (2015-2100), scenario (Reference, Reference_2.6), industrial subsector, and fuel.

These fuel-level results are shown from the standpoint of industrial output in Figure 16; for sectors such as chemicals and other industrial energy use, the figures convey basically the same information as Figure 15 due to the similarities in efficiencies from one fuel to the next. The iron and steel figure is quite different, as each of the detailed production technologies consumes a specified fuel blend, so the technology shares can't be estimated from Figure 15. Here we see that in the H2 revision, in the 2.6 scenario, the Blast furnace technology with CCS and hydrogen becomes an important option in some years; note that this technology only uses a small amount of hydrogen, in contrast to the Hydrogen-based DRI technology which remains more expensive than other options in all scenarios, and only accounts for a small portion of the steel production. In the fertilizer sector, we see some deployment of the technology that uses purchased hydrogen; in the reference scenario this doesn't really modify the primary energy footprint of ammonia production, because the hydrogen is mostly produced from natural gas anyways. Still in the 2.6 scenario, this does indirectly allow some ammonia production from direct renewable electrolysis and biomass with CCS, technology pathways that are technically feasible but not allowed in the Core model representation.

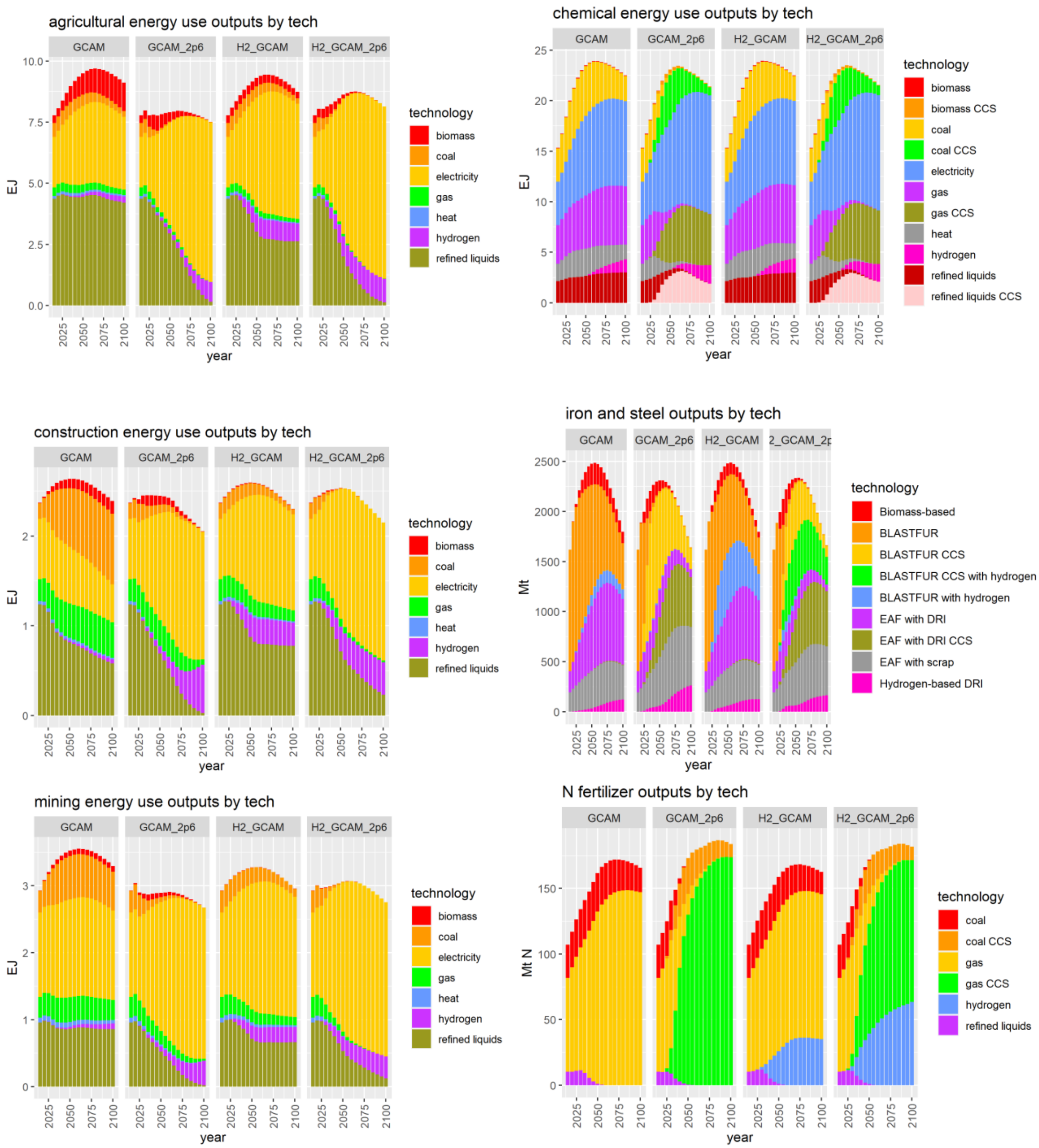

Figure 16. Industrial output by technology and industrial subsector, Reference and Reference_2.6, Core and H2 Revision.

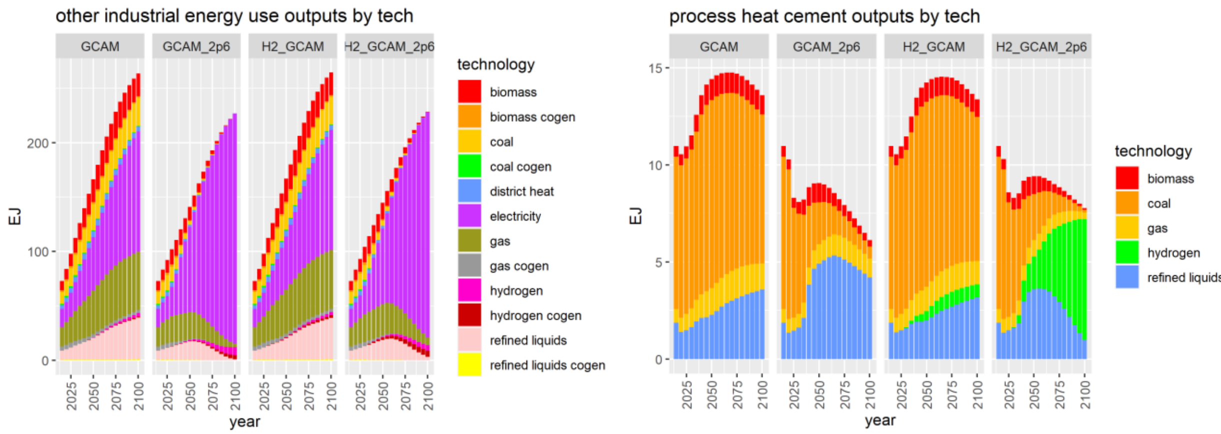

Figure 16 (continued). Industrial output by technology and industrial subsector, Reference and Reference_2.6, Core and H2 Revision.

Figure 17 explores the costs of these different industrial technologies, that are behind the shares shown in Figure 16, for the representative 2035 and 2070 time periods in the USA region. As shown, the hydrogen-based technologies tend to be more expensive than all other options in the Reference scenarios, but their cost increases in the policy scenarios are buffered by the low-carbon options for production (NGSR with CCS, BECCS, direct renewable electrolysis), so their price increases are less severe than the other options that use carbon-based fuels.

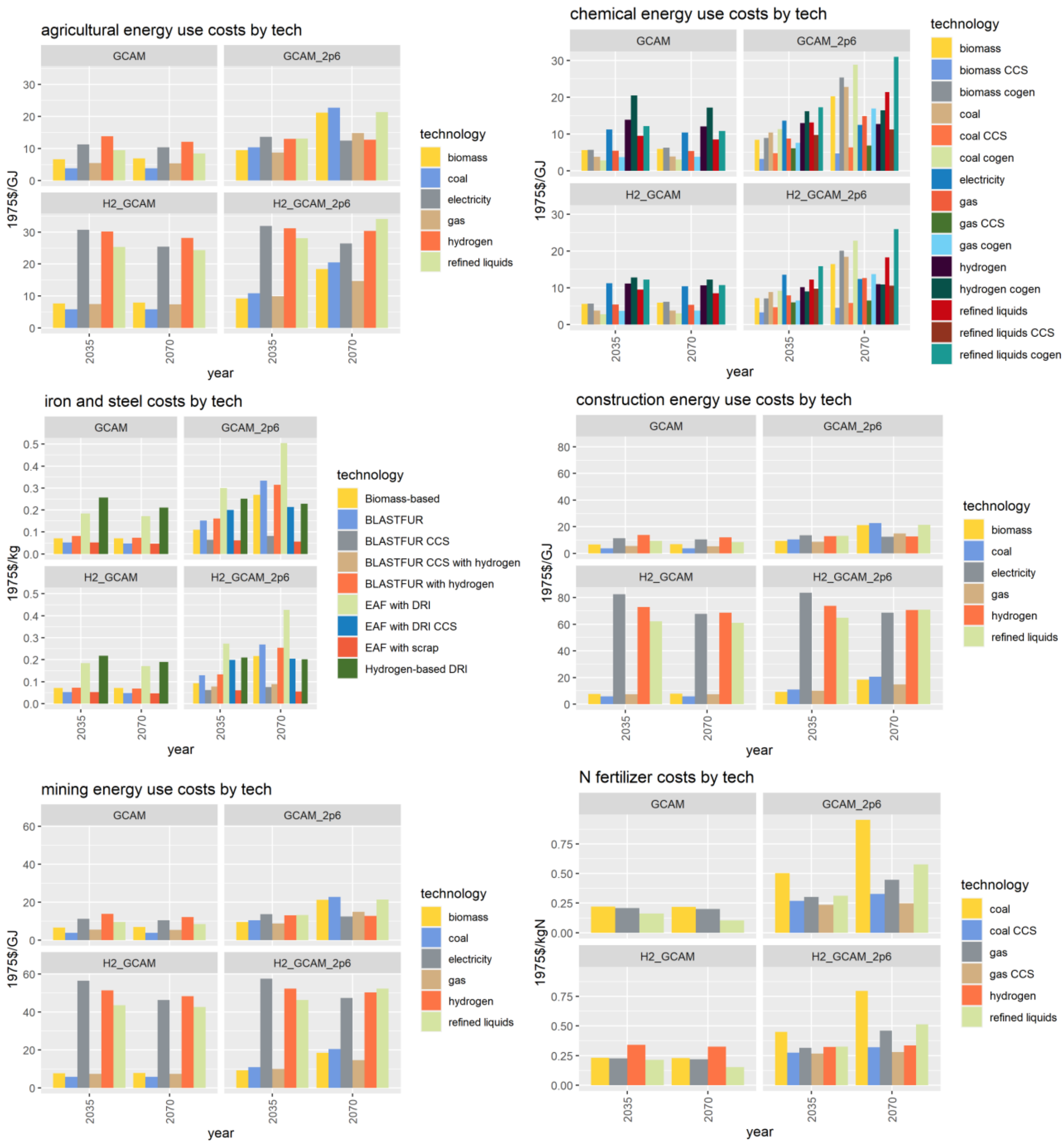

Figure 17. Technology-level costs of industrial production, by industry, scenario (Reference, Reference_2.6), and Revision (Core, H2 Revision). Only 2035 and 2070 years are shown for simplicity.

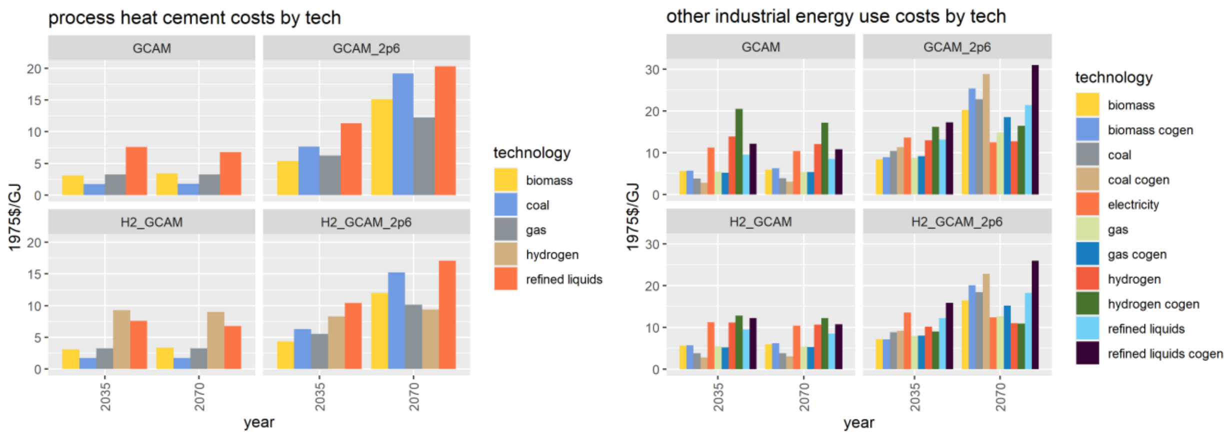

Figure 17 (continued). Technology-level costs of industrial production, by industry, scenario (Reference, Reference_2.6), and Revision (Core, H2 Revision). Only 2035 and 2070 years are shown for simplicity.

Building energy use

In the building sector, hydrogen is allowed to compete directly with natural gas for buildings services (heating and other); it is structured within the same subsector as natural gas. It does not deploy anywhere in the reference scenarios, as it is more expensive than natural gas, and the technology-level logit exponent is higher than most subsector logit exponents in the model. Because most regions globally don't use piped natural gas to buildings, the share of hydrogen in buildings total final energy is low in 2.6 scenarios at the global level, but the shares are higher when focusing on temperate regions that use piped natural gas, such as the USA (right panel of Figure 18). This 2.6 scenario sees a general phase-out of natural gas use in buildings in the USA, with partial replacement by hydrogen. The end-use technology stocks are tracked, but the infrastructure capital is not, so the result can be interpreted to mean that existing pipelines are carrying increasing amounts of hydrogen over time, and appliances are modified over time to accommodate the greater portions of hydrogen, or it could imply altogether different hydrogen infrastructures are constructed for hydrogen distribution. Regardless of the interpretation, the costs of the hydrogen commodity delivered to buildings is estimated from the costs of hydrogen T&D; it doesn't get a "free ride" through existing natural gas pipelines.

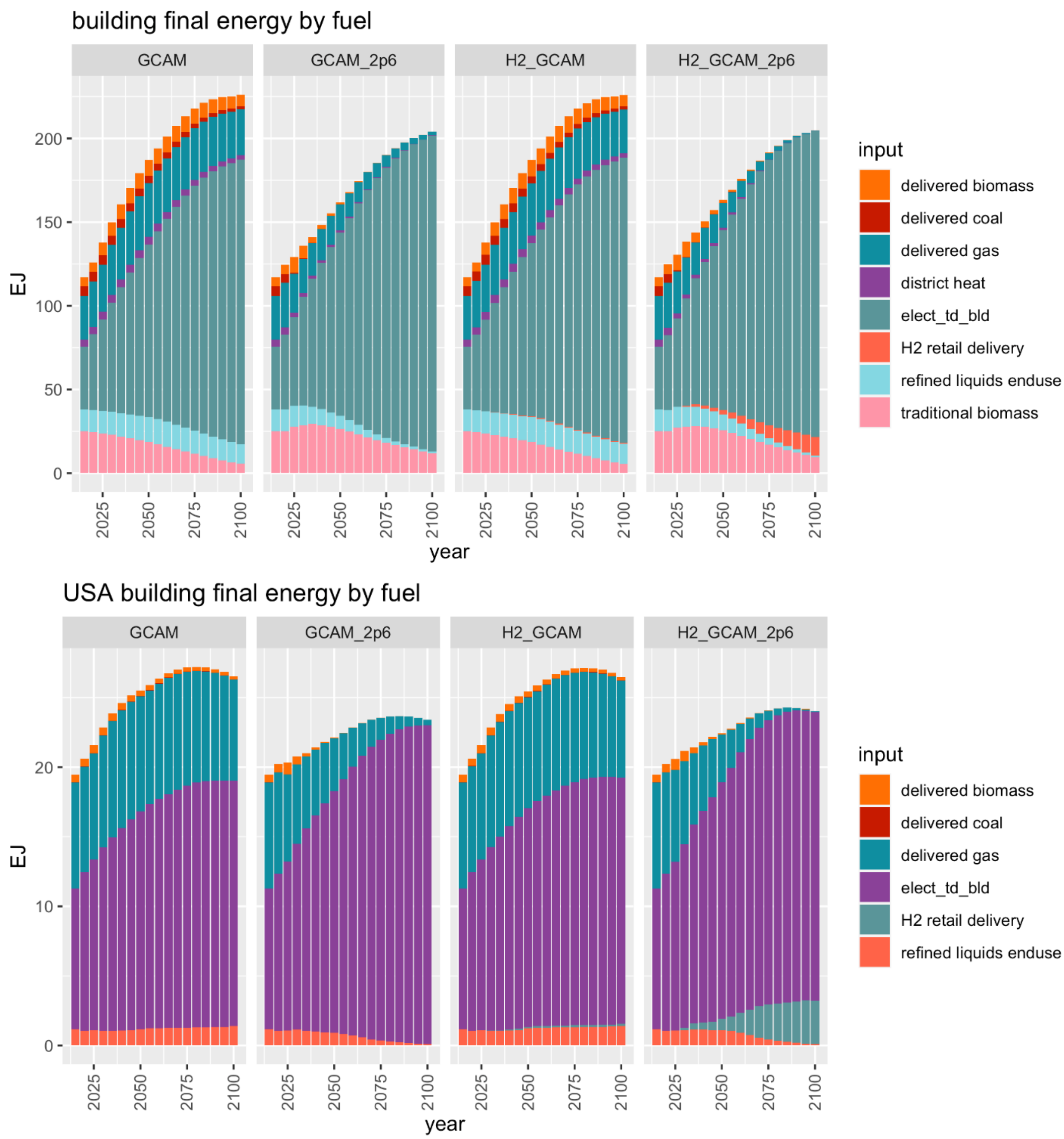

Figure 18. Buildings sector final energy by fuel, Reference and Reference_2.6, Core and H2 Revision, globally (top panel) and in the USA (bottom panel).

GCAM-USA

In general, the revisions make hydrogen deployment much higher in the states in GCAM-USA; the Core GCAM-USA has consistent with what was shown in Figure 10. For example, in GCAM-USA in 2050, the Core scenario has a combined total of 0.04 EJ/yr of hydrogen consumption in 2050 across all states, whereas the H2 Revision has 1.4 EJ. Note that even though this constitutes a many-fold increase from the Core, the actual production volume isn't unreasonable; the USA currently produces about 1 EJ per year of hydrogen, mostly in petroleum refineries and ammonia factories. The volumes are shown by state in the left panel of Figure 19; in addition to a different distribution of hydrogen among states, the key difference between the Revision and Core scenarios is the x-axis of the figure.

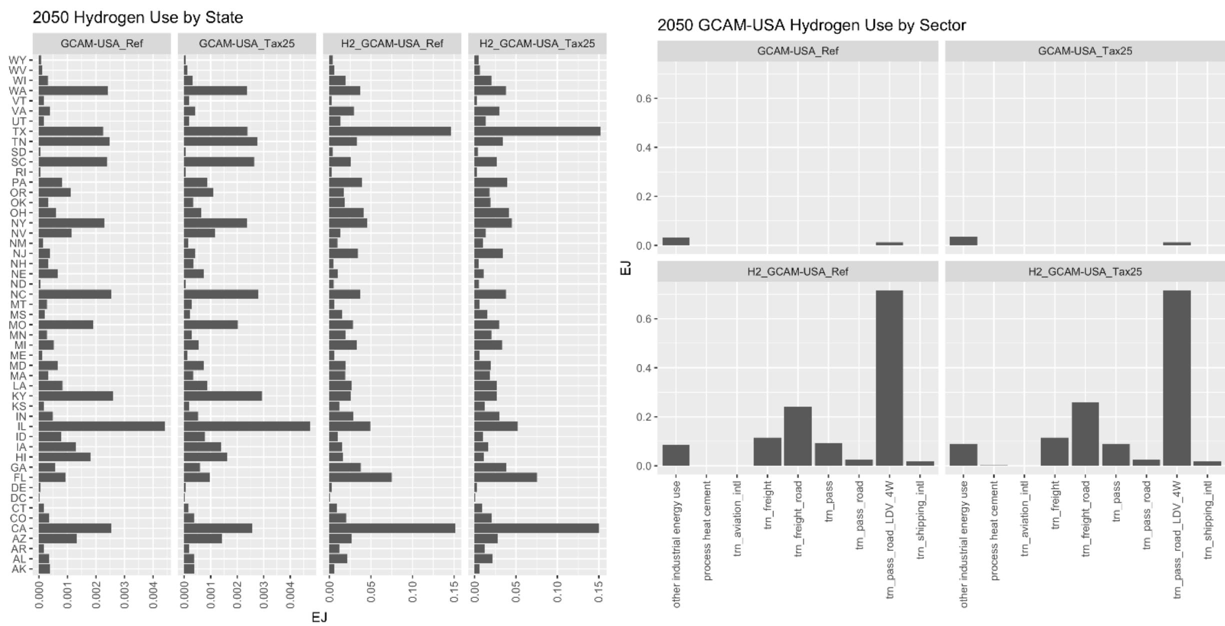

Figure 19. Hydrogen consumption by state (left panel) and sector (right panel), comparing the Core and H2 Revision scenarios for GCAM-USA, reference and 25-tax policy.

The right panel of Figure 19 shows that the increase in "other industrial energy use" demand of hydrogen is not especially dramatic from Core to the Revision, but that the new technologies/sectors where hydrogen is allowed account for the vast majority of the increase. Interestingly, LDV vehicles increase significantly from the Core to the H2 Revision, due to the assumed cost reductions in FCEVs from adopting the ATB assumptions for future fuel cell and hydrogen tank costs.

Finally, Figure 20 shows the breakdown of hydrogen production at the state level, in selected states that have distinct fuel prices and have different renewable and carbon-storage resource supply curves: California, Hawaii, Maine, North Dakota, and Texas. As shown, for the policy scenario, natural gas steam reforming without CCS remains the dominant technology in most states, but Hawaii sees some deployment of nuclear in both reference and policy scenarios due to all other energy forms being comparatively expensive, Maine sees the least coal with CCS due to high coal prices, and North Dakota sees more wind than California, in both reference and policy scenarios. In any case, the figure is only presented to demonstrate the capability to represent state-level hydrogen production, and to interpret the results as a function of state-specific fuel price dynamics. This capability is not in the Core scenarios, which represents hydrogen production at the USA region level only, and with electrolysis and renewable-based production technologies turned off.

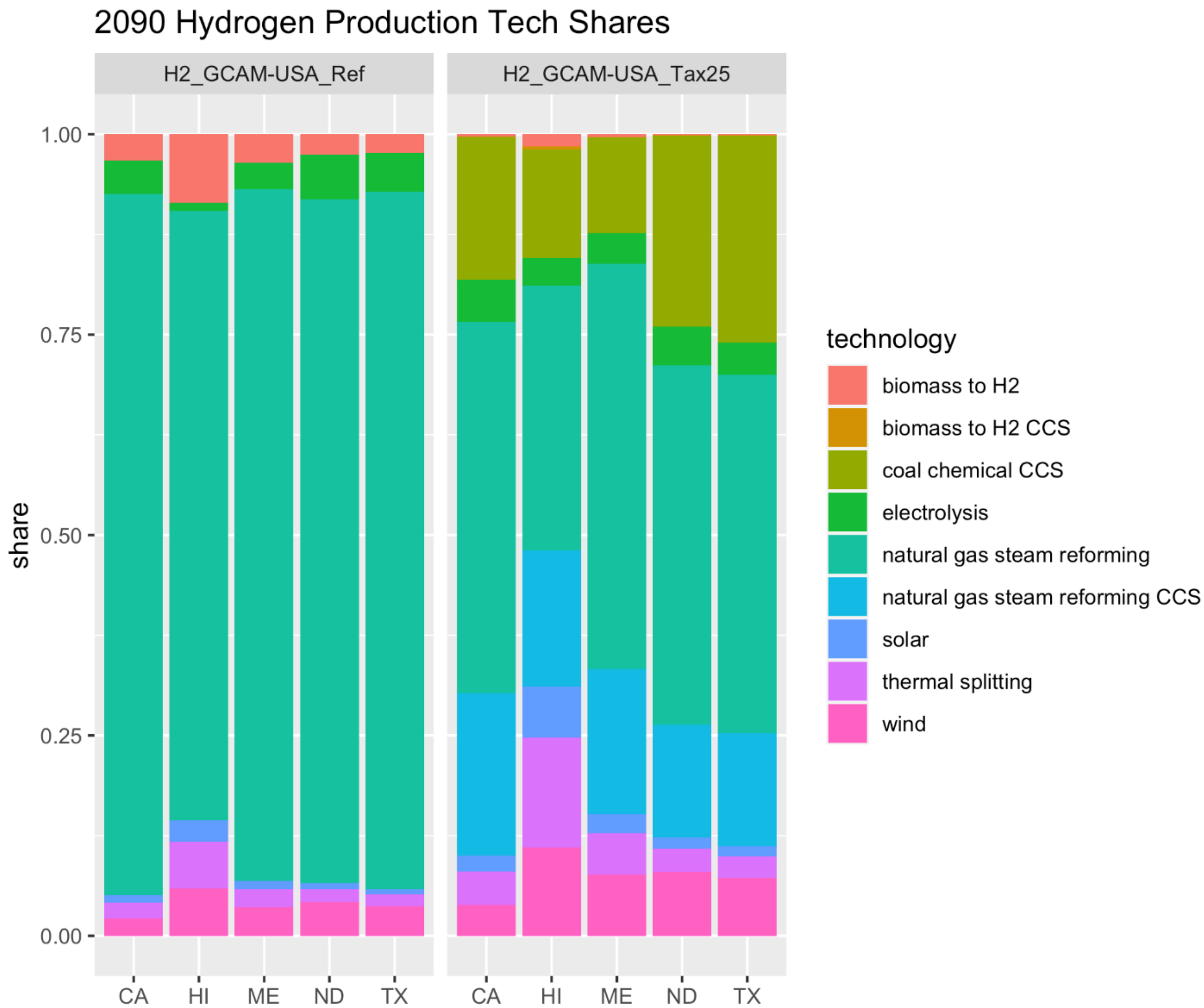

Figure 20. Hydrogen production technology shares in 2090 in selected states, in the H2 Revision scenarios (GCAM-USA_Ref and GCAM-USA_Tax25).

Figure 21 shows freight (left) and passenger (right) road transportation service output by fuel in GCAM-USA, for the extant core and H2 update. The transportation and hydrogen production updates result in substantially increased BEV and FCEV shares for freight in both the reference and Tax25 scenarios, and reduces natural gas trucking to near-zero levels. Similar results are seen for passenger transport, with the H2 update scenarios showing increased FCEV, and drastically decreased natural gas vehicle use.

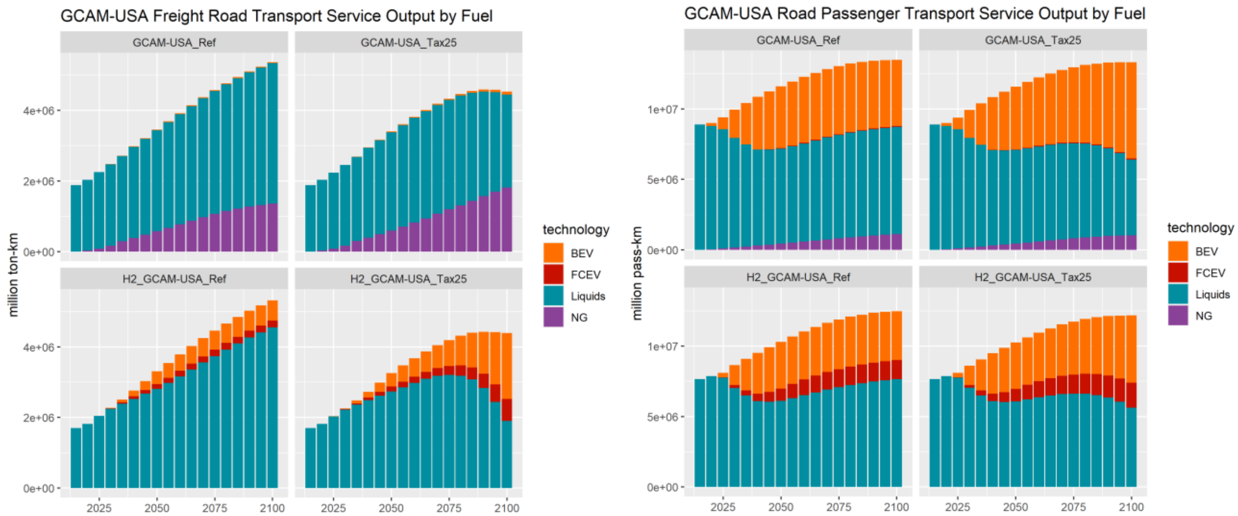

Figure 21. Passenger and freight service output by fuel, in the core and H2 revision scenarios

Figure 22 compares electricity generation by fuel for the extant core and H2 revision scenarios for all states in GCAM-USA. The hydrogen revisions do not substantially change the electricity generation mix

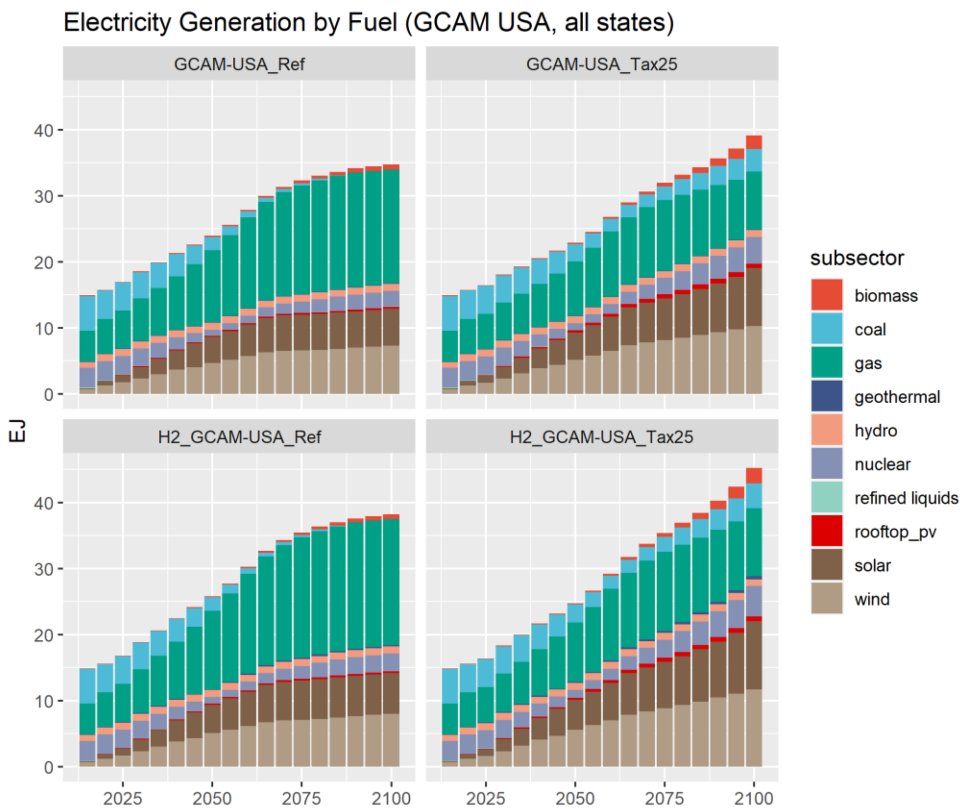

Figure 22. Electricity generation by fuel in the core and H2 revision scenarios

Figure 23 compares industrial final energy by fuel for the extant core and H2 revision scenarios for all states in GCAM-USA. The included industrial sectors are process heat cement, N fertilizer, and other industrial energy use in all scenarios, as the remaining detailed industry sectors have not yet been added to GCAM-USA. The H2 revision scenarios have slightly increased hydrogen use in industry.

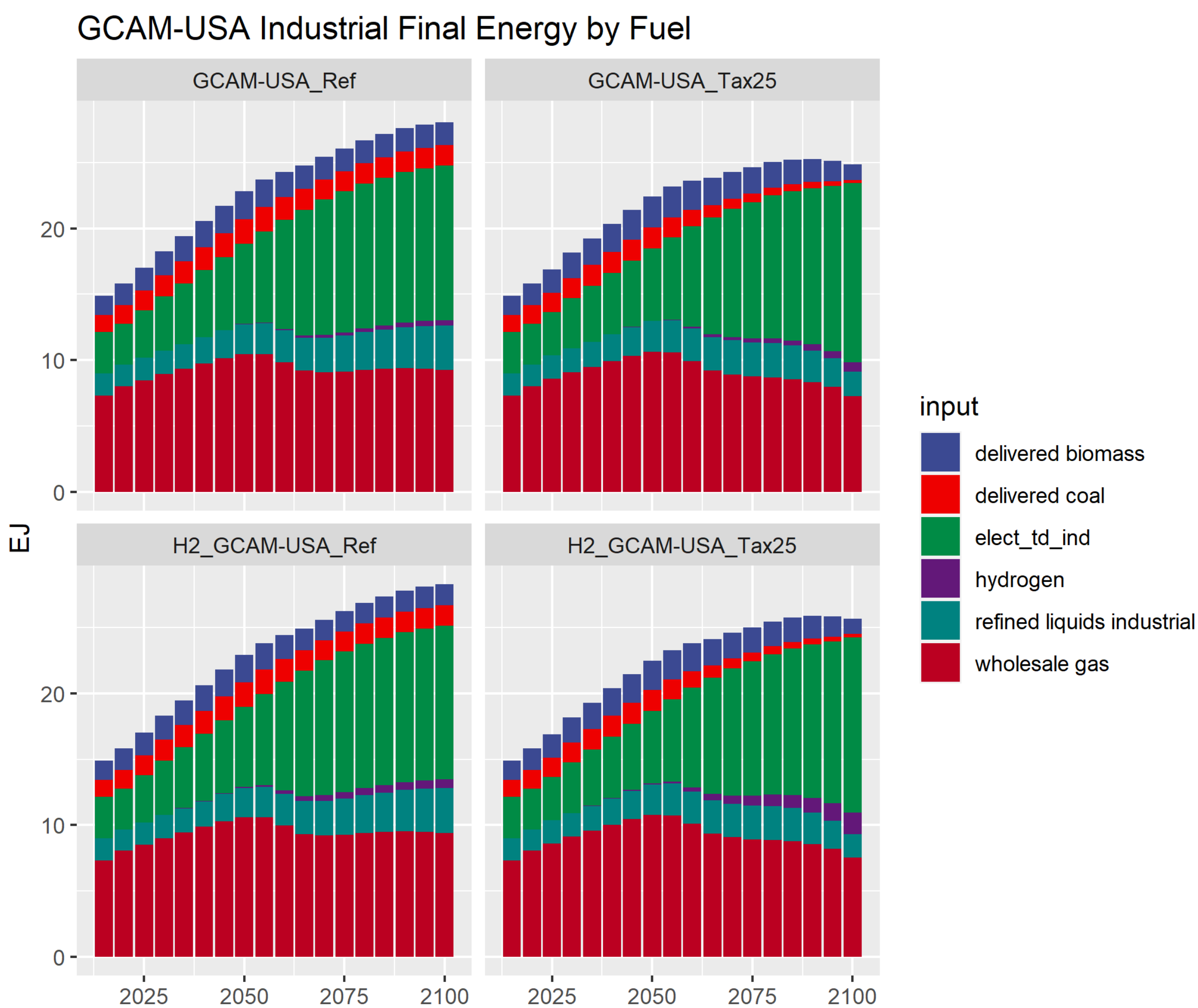

Figure 23. Industrial final energy by fuel in the core and H2 revision scenarios for all GCAM-USA states

Figure 24 compares final energy use by fuel for freight and passenger transport, plus international aviation and shipping in GCAM-USA. The transport and H2 production and distribution revisions increase both hydrogen and electric vehicle use, and virtually eliminate natural gas use in the transport sector.

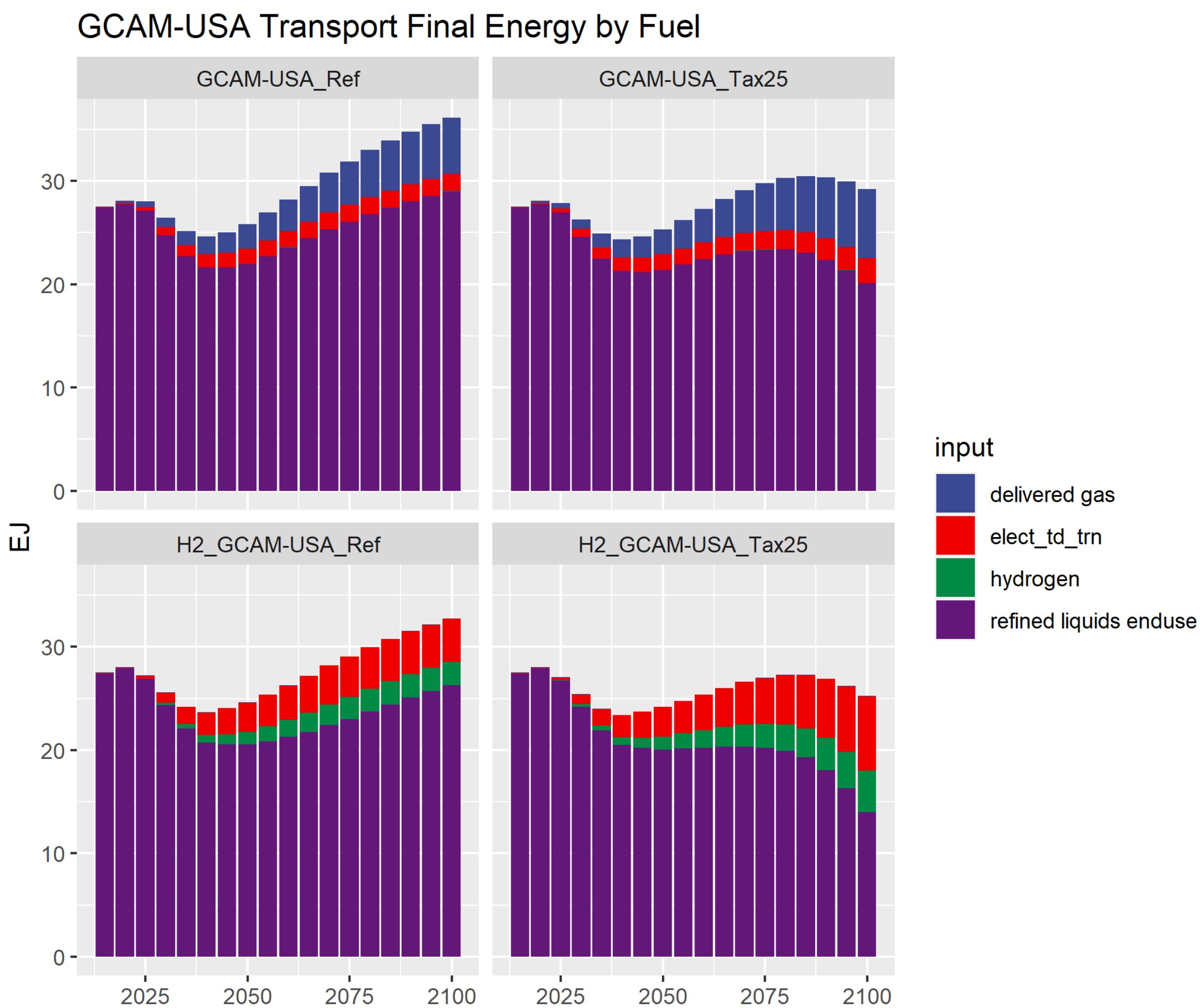

Figure 24. Transport final energy by fuel in the core and H2 revision scenarios for all GCAM-USA states