Core Model Proposal #415: Updated Energy System Techno-Economic Data

Product: Global Change Analysis Model (GCAM)

Institution: Joint Global Change Research Institute (JGCRI)

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Related sector: Energy

Type of development: data, code

Purpose: This proposal updates structures and techno-economic assumptions for hydrogen, electricity, US road transport, US buildings, and industry. Hydrogen-specific updates are a follow-up to Core Model Proposal 359 and Core Model Proposal 386.

Description of changes

This proposal complements the recent Base Year Update to 2021, which updated the calibration year but for the most part not the model's techno-economic assumptions (i.e., energy intensities, non-energy costs). It also includes a merge of the pull request from CMP 407: Add Small Modular Reactors, in order to not have multiple revisions to the same assumptions occurring simultaneously. Many of GCAM's techno-economic assumptions are sourced from data sets that are themselves updated somewhat regularly; in such cases this proposal just updates the data and makes minor revisions to the processing code in gcamdata, as needed. Other updates are sourced from new literature altogether. Incorporating revised data in support of this proposal did involve some restructuring, both of the processing code in gcamdata and in the names and inter-relations of the sectors and technologies in the XML input files. The hydrogen sector is re-structured to better capture the commodity differentiation for end users, as well as the switch in the underlying source data (H2A) from representing stand-alone wind and solar electrolysis technologies to hybrid facilities that use both. The proposal also overhauls the data processing of the Electricity Annual Technology Baseline (ATB) data set regularly published by the National Renewable Energy Laboratory, in order to improve the historical time series, match exactly the ATB's published values, and simplify the processing code. One additional significant change is that the default global buildings XML file now replaces the simple global default representation (heating/cooling/other) with the more detailed representation in the USA region that heretofore was only used when GCAM-USA was run (11 commercial services; 18 residential services, split by income decile). A few deprecated XML files have been removed, and some technology sensitivity scenario XML files have been added. Ultimately, no XML files used by the committed configuration (and batch) files to run any standard scenarios have been added, deleted, or renamed.

Transport

Vehicle survival curves

In order to improve GCAM's projected energy consumption and vehicle stocks and sales, the core/default vehicle survival curves for several vehicle classes were modified (including for light duty vehicles, medium trucks and heavy trucks). Figure 1 shows the default and the modified survival curves for light duty vehicles (LDVs). The specific data used for this revision is the Transportation Energy Data Book (Davis et al. 2022); prior to this revision, GCAM's estimated near-term vehicle sales were far higher than present-day data, and this elevated stock turnover rate caused significantly greater emissions mitigation in the baseline scenario to 2030.

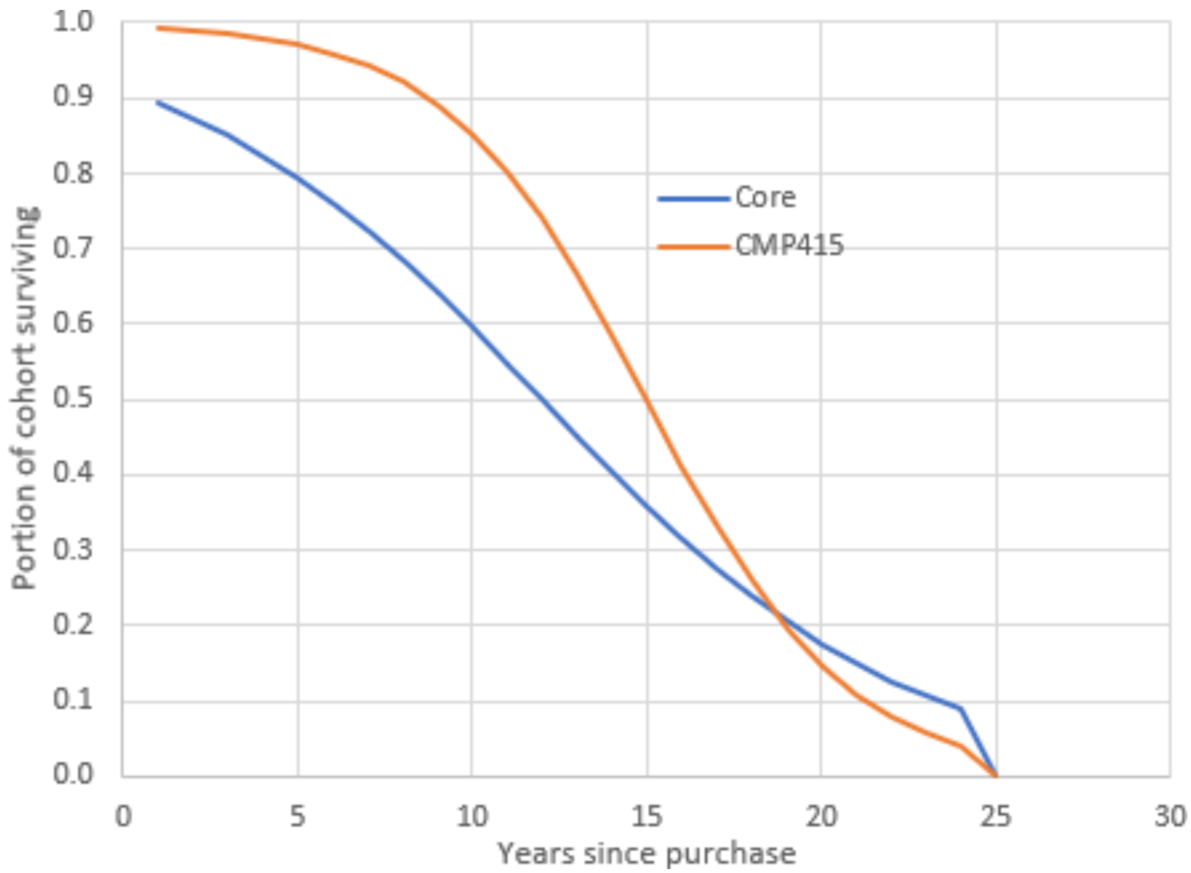


Figure 1. Light-duty vehicle survival curves in GCAM, showing the default trajectory ("Core") and the revised ("CMP415") trajectory.

US LDV capital costs and energy intensities

Transportation vehicle techno-economic assumptions in the USA region are now based on Autonomie (Islam et al., 2023), a detailed, physics-based vehicle simulation model developed by Argonne National Laboratory. Medium- and heavy-duty trucks were updated with Autonomie data in CMP 386, and here we extend this approach to light-duty vehicles (LDVs). Autonomie estimates vehicle performance and cost using detailed engineering and economic data at the component level (e.g., batteries, motors), also considering operational aspects such as vehicle duty cycles and speeds. The assumptions in GCAM's Reference scenario are based on Autonomie's low-technology-progress scenario (and we use the base-vehicle, not the premium vehicle, data). Advanced-technology assumptions are also processed and written to a separate XML file. The advanced technology file adjusts assumptions in all regions, applying the same adv:ref cost and intensity multipliers as in the USA. The mapping between powertrains in Autonomie and vehicle technologies in GCAM is shown in Table 1; similarly, vehicle size class assignments are shown in Table 2. The weighting from the more resolved "Compact" and "Midsize" car size classes in Autonomie to the final ones used in GCAM follows the UCD transportation database, described in CMP 304. GCAM's "Large Car and Truck" characteristics are a simple unweighted average of the three Autonomie vehicle classes indicated. A subset of LDV technologies and size classes is shown in Figure 2. Note that the conventional technologies increase in costs from 2020 to 2035. This is due to assumed improvements in combustion and engine technologies aimed at improving vehicle fuel economy; their adoption is explained in the documentation as "business as usual regulatory and market environments" (Islam et al. 2022). Note that the use of "Conventional SI Turbo" as the base vehicle technology is consistent with the approach in TEMPO, and reflects the increasing market shares of turbo-charged vehicles in recent years (Honeywell 2019; DOE FOTW 2020). Compared with the "Conventional SI" vehicle, the Turbo technology generally has about 4% higher price and 9% higher fuel economy.

Table 1. Vehicle drivetrain mapping between Autonomie and GCAM. BEV300 = battery electric vehicle with 300-mile range; CNG = compressed natural gas; SI = spark-ignited; FCEV = fuel cell electric vehicle; FCHEV = fuel cell hybrid electric vehicle; NG = natural gas; MD = medium duty; HD = heavy duty.

Autonomie		**GCAM**	
Category	**Vehicle Powertrain**	**Sector**	**Technology**
Light Duty	BEV300	Passenger	BEV
	Conventional CNG		NG
	Conventional SI Turbo		Liquids
	FCEV		FCEV
	SplitHEV		Hybrid Liquids
MD HD Truck	Conv	Freight	Liquids
	BEV		BEV
	FCHEV		FCEV

Table 2. Vehicle size class mapping between Autonomie and GCAM. GCAM Large Car and Truck is calculated as an unweighted average of the three Autonomie size classes indicated. SUV = sports utility vehicle; MD = medium duty; HD = heavy duty.

Autonomie		**GCAM**	
Category	**Vehicle class**	**Sector**	**Size class**
	Compact		Car
	Midsize		Car
	Small SUV		Large Car and Truck

Light duty	Midsize SUV	Passenger	Large Car and Truck
	Pickup		Large Car and Truck
MD HD Truck	Class 2 Van	Freight	Light Truck
	Class 6 Box Truck		Medium Truck
	Class 8 Longhaul Sleeper		Heavy Truck

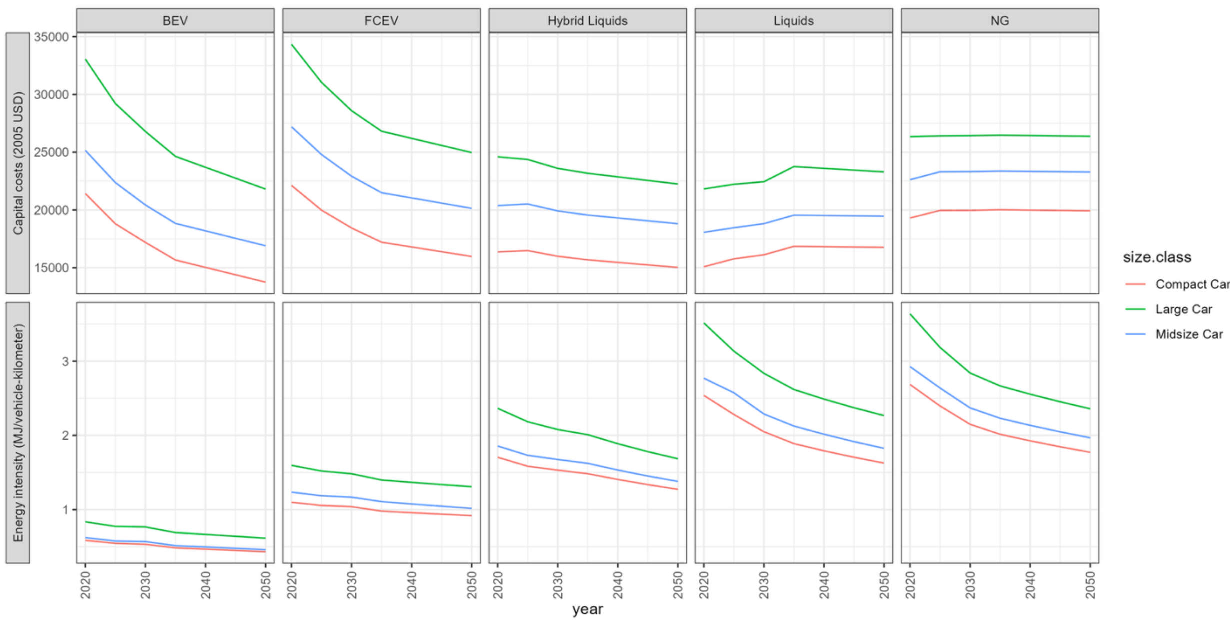


Figure 2. Time series for different light-duty vehicle powertrains and size classes in Autonomie, showing capital cost (2005 USD, top row) and energy intensity (MJ/vehicle-kilometers, bottom row). The "Large Car" size class is calculated as an unweighted average of Small SUV, Midsize SUV, and Pickup.

The processing of Autonomie data is mostly handled in a separate repository: https://stash.pnnl.gov/scm/~wolf184/autonomie_cost.git which selectively over-writes assumptions in the `energy/OTAQ_trn_data_EMF37.csv` file. The existing transportation data processing code is not changed. An additional `trn_tech_scenarios.csv` file is added, to produce the advanced technology sensitivity scenario, with the processing code in two new code files: `zenergy_xml_elec_tech_scenarios.R` and `zgcamusa_xml_elec_tech_scenarios.R`.

Annual Travel per Vehicle

The annual travel per vehicle is an assumption in UCD_trn_data_CORE, used in the gcamdata code for levelizing LDV capital and fixed annual operating expenses. These values are updated to more recent data; where the core model was assuming LDVs travel 12,000 miles per vehicle per year (with light trucks going 10,300), the more recent FHWA data puts this at 10,775 in 2021, with no remarkable differentiation by vehicle size. This figure is somewhat less than the pre-Covid values (about 11,540 in 2018-2019), but is more than 2020 (10,143), and slightly less than 2022-2023 (about 11,000). This proposal updates this assumption, which has the net effect of modestly increasing levelized vehicle non-fuel costs. As the same assumption is used in post processing estimation of the vehicle stocks implied in any scenario, this revision will also change the estimated vehicle stocks.

Hydrogen production

Hybrid PEM electrolysis

The H2A development team at NREL no longer maintains separate techno-economic data for stand-alone wind and solar electrolysis technologies, basing the revision on optimization modeling results showing that some level of hybrid (co-located wind and solar) electricity generation was always optimal. This is consistent with the observation that most if not all gigawatt-scale electrolysis projects globally will be using hybrid (wind and solar) energy sources. Within the US, for example, even a site in California with the highest possible PV output in the U.S. could still benefit from some wind capacity to provide power for electrolyzers at night. We are thus replacing the stand-alone wind and solar electrolysis technologies with hybrid solar–wind PEM electrolysis to GCAM. Hybrid solar–wind PEM electrolysis is a process that uses electricity generated from solar and/or wind power to drive a proton exchange membrane (PEM) electrolyzer, which splits water into hydrogen and oxygen to produce clean hydrogen fuel. The main data source is H2A-Lite (NREL 2025), which defines key techno-economic cost and performance data, indicated per kg of hydrogen produced, for a set of technologies under 3 technology progress scenarios in 5-year timesteps between 2025 and 2050. The specific workbooks used to produce the data in the gcamdata inputs are available at https://doi.org/10.5281/zenodo.18746607. Table 3 shows the parameters used and unit conversions applied in translating from H2A-Lite to GCAM. In GCAM, the producer prices of each production technology are the sum of the non-energy cost, and each input-output coefficient times the (endogenous) price of each input. The non-energy cost is in USD per GJ of hydrogen produced (assuming LHV energy density of 120 GJ per tonne of hydrogen), and the input-output coefficients are unitless, derived as GJ of each input per GJ of hydrogen produced.

Table 3. Conversions from parameters in H2A-Lite to GCAM.

H2A-Lite parameter	GCAM parameter	Factor	Conversions
Energy-free levelized cost [2022$/kg]	non-energy-input: "non-energy" input-cost	1.96	dollar year; kg H_2 to GJ H_2 (LHV)

Energy use Electricity (Solar) [kWh/kg]	energy-input: "global solar resource" coefficient	0.0299	kWh to GJ; kg H_2 to GJ H_2 (LHV)
Energy use Electricity (On-shore wind) [kWh/kg]	energy-input: "onshore wind resource" coefficient	0.0299	kWh to GJ; kg H_2 to GJ H_2 (LHV)

Parameters for the USA region in the standard configuration of GCAM apply the "US Average" data from H2A-Lite to the "USA" model region. In the GCAM-USA configuration, each state's hybrid (wind and solar) electrolysis technology is parameterized specifically, based on the H2A-Lite data, which is provided for each of the 48 coterminous states. In filling out data for all states in GCAM-USA, the characteristics of hybrid electrolysis in Alaska are inherited from New Hampshire, and Hawaii uses the data from Florida. Both of these states have comparatively high costs of production, with New Hampshire having the lowest solar capacity factors in the data set, and Florida having greater reliance on solar energy.

For estimating the techno-economic parameters of hybrid electrolysis outside of the USA, we use the variation between states in three key H2A-Lite parameters (Energy-free levelized cost, Energy use Electricity (Solar), and Energy use Electricity (Wind)) in order to build two numerical models (Figure 3) that predict these parameters in any model region, based on the capacity factors of wind and solar electricity, which are assumptions in GCAM's electricity sector. The first linear model (Figure 3, top) predicts energy intensities by global region and uses the following three inputs:

- Wind and solar energy intensities for hydrogen production by U.S. state,
- Wind and solar capacity factors by GCAM region, and
- Wind and solar capacity factors by U.S. state.

The model is a simple linear regression relating hydrogen energy intensity (*H2_sol_wind*) to capacity factors (*CF_sol_wind*):

$$H2\_sol\_wind = -0.30464+1.28865\ CF\_sol\_wind$$

where *H2_sol_wind* is the predicted hydrogen energy intensity.

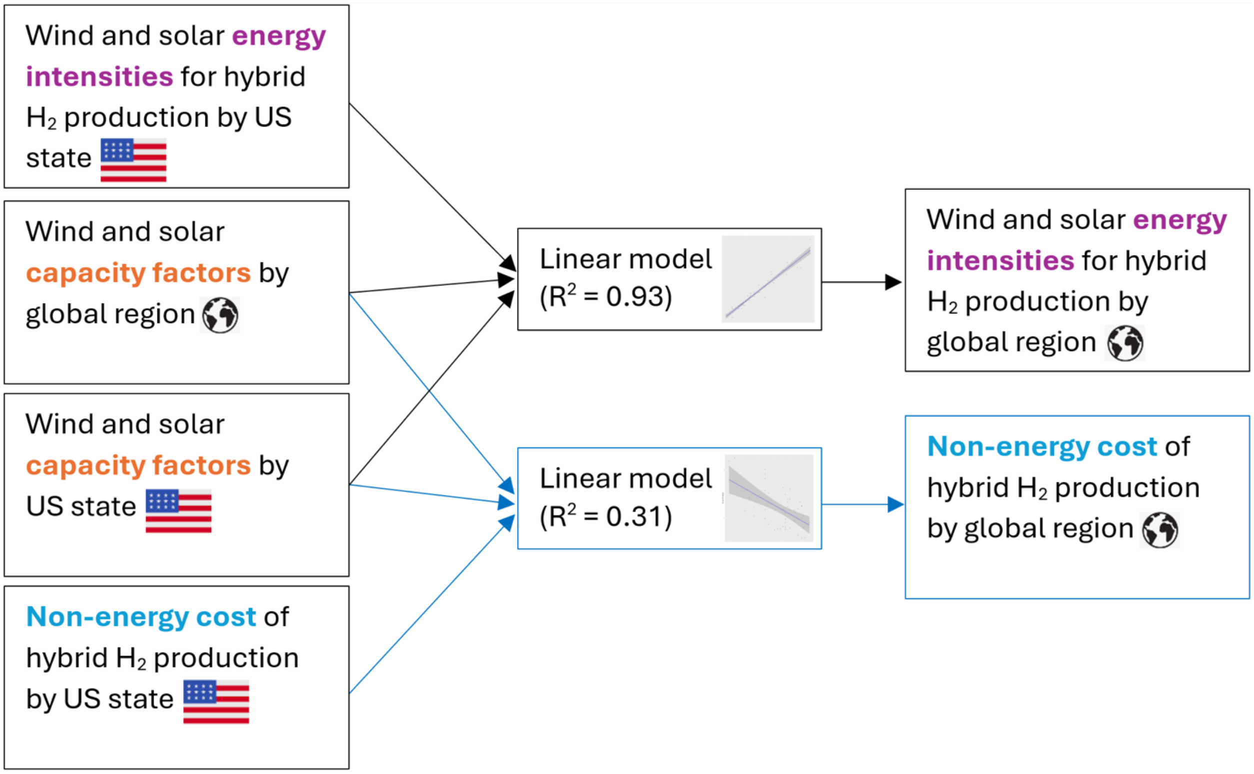


Figure 3. Schematic illustrating the estimation of energy intensities and energy-free costs for hybrid solar–wind hydrogen production across global GCAM regions. The next figure presents enlarged charts of the linear models.

Specifically, we use the ratio of solar to wind energy intensity for hydrogen production by U.S. state and relate it to the ratio of solar to wind capacity factors by U.S. state. This model achieves a high explanatory power ($R^2 = 0.93$, left side of Figure 4), indicating that the renewable-electric capacity factors generally are a good predictor of the respective shares of wind and solar energy in hybrid electrolysis. In this model, the "actuals" being explained are the state-level solar and wind energy-intensity values for hybrid electrolysis reported directly in the H2A-Lite dataset, which serve as the dependent variables.

To estimate non-energy costs of hybrid electrolysis in each GCAM region, a second linear model is used (Figure 4, bottom). This model relates:

- Sum of wind and solar capacity factors by global region
- Sum of wind and solar capacity factors by U.S. state
- Non-energy cost of hydrogen production from hybrid solar-wind by U.S. state

The model is a simple linear regression relating the 2040 levelized hydrogen cost (*NE_cost_2040_transform*) to the summed capacity factors (*sum_CF_transform*):

$$NE\_cost\_2040\_transfrom = 0.9774 - 0.8176\ sum\_CF\_transform$$

where NE_cost_2040_transfrom is the projected hydrogen cost.

The logic behind this model is that the energy-free levelized cost of electrolysis should scale inversely with the annual production of hydrogen; and, annual hydrogen production quantities should scale with the sum of wind and solar capacity factors.

However, it should be noted that the energy-free levelized costs in H2A-Lite do not only scale with hydrogen output; the estimated costs also take into consideration state-specific geologic hydrogen storage resources. As such, the non-energy cost regression has less explanatory power than the first; GCAM does not carry any information about geologic hydrogen storage potentials in the different regions. The goal of this second regression is to represent the non-energy costs only as a function only of renewable resource capacity factors. We evaluate several data transformations to improve model fit, and ultimately adopt the following: the reciprocal of the logarithm (1/log) of the sum of wind and solar capacity factors by U.S. state (*sum_CF_transform*), and the reciprocal of the logarithm (1/log) of the energy-free levelized cost of hydrogen production by U.S. state in 2040 (*NE_cost_2040_transform*). We also test the impact of excluding outlier regions on model fit, but observe no improvement. This second model, despite lower explanatory power ($R^2 = 0.31$, right side of Figure 4), nevertheless enables estimation of non-energy costs of hydrogen production for each GCAM region that is better than the default approach of simply assuming the same cost in all regions. Here, the "actuals" are the state-level non-energy costs of hybrid electrolysis from H2A-Lite, which constitute the dependent variable in the regression and against which the model's explanatory power is evaluated.

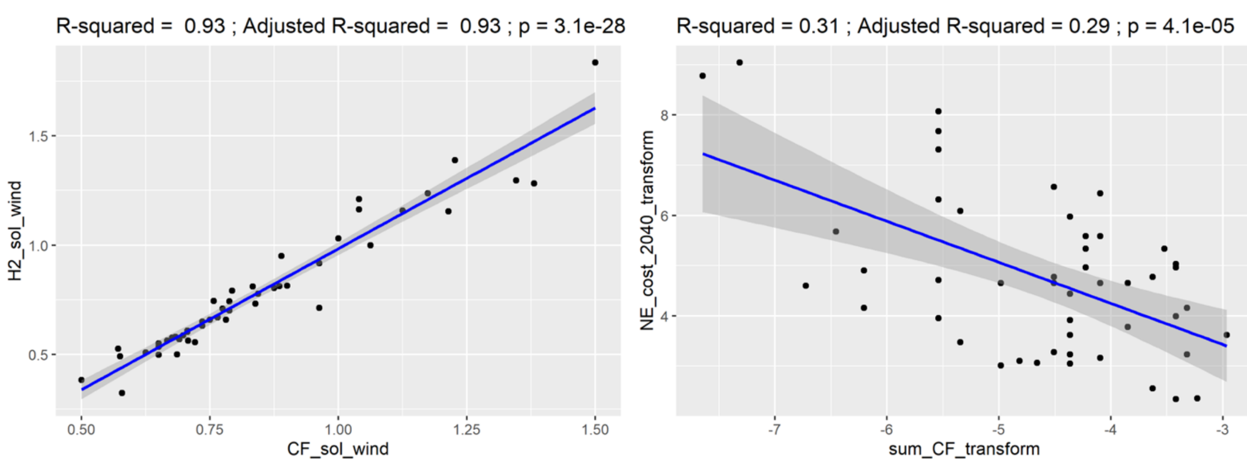


Figure 4. Linear models of the energy intensity of hydrogen production (left) and non-energy costs of hydrogen production (right) as a function of solar and wind capacity factors. *H2_sol_wind* = ratio of solar to wind energy intensity for hydrogen production by U.S.

state; *CF_sol_wind* = ratio of solar to wind capacity factors by U.S. state; *NE_cost_2040_transform* = transformed non-energy costs for hydrogen production by U.S. state; *sum_CF_transform* = transformed sum of solar and wind capacity factors by U.S. state.

For estimating energy-free levelized costs of hybrid electrolysis in the non-US regions, a final bias correction step is performed, to approximate the siting approach in H2A-Lite. Solar capacity factors in the electricity generation sectors of GCAM regions are intended to reflect weighted averages over the entire geographic area, not necessarily what would be observed at an optimal or near-optimal site for producing such energy within a region. However the "US Average" hybrid technology's energy-free levelized in H2A-Lite is quite close to the minimum observed across all 48 states, indicating that H2A-Lite applied at the national level tends towards optimal geographic siting. The cost model's estimate of the USA's renewable electrolysis non-energy cost (using GCAM's assumptions of USA electricity sector solar and wind capacity factors) is about 20% higher than what H2A-Lite reports as the US Average. This bias correction is calculated for each scenario and time period, and applied to the estimated energy-free levelized costs in all non-US regions.

Table 4 shows the key non-energy cost (in 2022$/kg, the unit used by H2A-Lite) and energy intensity assumptions for the 32 GCAM regions, excerpted for year 2040 in the reference ("med") scenario. Most regions have reasonably similar energy-free levelized cost; within the data shown in Table 4, from the least costly (Northern Africa; $1.17/kg) to the most expensive (European Free Trade Association: Iceland, Switzerland, and Norway; $1.46/kg) only spans $0.29 per kg. In contrast, the relative use of wind vs. solar electricity in producing hydrogen is quite heterogeneous, with the solar share of the electricity input around 10% in boreal regions (Russia, Canada, European Free Trade Association), and more than 40% in sunnier regions (Africa, the Middle East, and the USA).

Table 4. Cost ("energy-free levelized cost"), in 2022$/kg, and energy intensity assumptions by GCAM region for the year 2040 in the reference scenario.

Region	Cost 2022$/kg	Solar kWh/kg	Wind kWh/kg
Africa_Eastern	1.21	22.7	29.6
Africa_Northern	1.17	21.0	31.3
Africa_Southern	1.32	25.6	26.6
Africa_Western	1.22	22.1	30.2
Argentina	1.26	18.1	34.2
Australia_NZ	1.18	20.5	31.8
Brazil	1.27	20.2	32.1

Canada	1.42	6.7	45.6
Central America and Caribbean	1.21	19.0	33.3
Central Asia	1.30	17.1	35.2
China	1.23	18.1	34.1
Colombia	1.35	19.1	33.2
EU-12	1.37	11.7	40.6
EU-15	1.32	13.1	39.2
Europe_Non_EU	1.28	16.6	35.7
European Free Trade Association	1.46	3.8	48.5
India	1.25	19.7	32.5
Indonesia	1.29	19.1	33.2
Japan	1.31	13.7	38.6
Mexico	1.18	20.2	32.1
Middle East	1.21	21.6	30.7
Pakistan	1.23	20.6	31.7
Russia	1.42	6.8	45.5
South Africa	1.19	21.2	31.0
South America_Northern	1.25	19.4	32.9
South America_Southern	1.24	18.7	33.6
South Asia	1.24	20.3	32.0
South Korea	1.42	20.1	32.2
Southeast Asia	1.26	19.0	33.3
Taiwan	1.38	17.4	34.8
Ukraine	1.40	12.9	39.4
USA	1.29	24.2	28.1

The total producer price of hydrogen from hybrid renewable electrolysis technologies in any scenario and year is equal to the sum of the levelized non-energy cost shown in Table 4, plus the solar and wind electricity inputs times their respective electricity generation costs, plus the water intensity times the endogenous price of water to the industrial sector. The costs of solar and wind electricity generation are estimated from exogenous and scenario-specific capital costs, fixed charge rates, capacity factors, and operating costs. GCAM maintains 3 different cost scenarios for each of these electricity generation technologies, from the 2024 Electricity Annual Technology Baseline (NREL 2024). Note however that GCAM uses different fixed charge rates and capacity factor assumptions for these technologies than the ATB, so even within the USA model region, the levelized costs of hydrogen production do not exactly match the corresponding levelized costs of hydrogen production estimated by H2A-Lite.

This proposal also includes revisions to the hydrogen transmission and distribution (T&D) representation, including: an update to techno-economic parameterizations from a more recent version of the Hydrogen Delivery Scenario Analysis Model (HDSAM; v4.1), and more product differentiation to end users in the transportation sector. Where the core model has all hydrogen delivered to transportation under a single commodity with a single price in any given scenario, region, and year ("H2 retail dispensing", parameterized based on LDV service stations in HDSAM v3), this proposal disaggregates three commodities, defined as follows.

- H2 LDV: hydrogen for light duty vehicles
- H2 MHDV: hydrogen for medium and heavy duty vehicles and rail
- LH2: liquefied hydrogen for aviation and maritime shipping

This differentiation allows H2 MHDV to have lower prices than H2 LDV, due to higher assumed daily dispensing volumes of the former, whereas LH2 is generally the most expensive of the three due to the liquefaction step. Specific settings used in HDSAM are shown in Table 5. Note that LH2 costs are estimated from hydrogen purchased from H2 pipeline, with additional costs from the liquefier portion of the H2 liquid truck pathway.

	H2 liquid truck	**H2 pipeline**	**H2 LDV (via liquid truck)**	**H2 LDV (via pipeline)**	**H2 MHDV (via liquid truck)**	**H2 MHDV (via pipeline)**
Description of HDSAM output used within GCAM	Delivering liquid H2 by truck.	Delivering gaseous H2 by pipeline.	Dispensing H2 to LDV vehicles when delivered as liquid hydrogen.	Dispensing H2 to LDV vehicles when delivered by gaseous pipelines or produced onsite.	Dispensing H2 to M/HDV vehicles when delivered as liquid hydrogen.	Dispensing H2 to M/HDV vehicles when delivered by gaseous pipelines or produced onsite.

1. H2 market	Medium / Heavy-Duty Market Demand (50 tpd)	Medium / Heavy-Duty Market Demand (50 tpd)	Combined Urban / Rural	Combined Urban / Rural	Medium / Heavy-Duty Market Demand (16 tpd)	Medium / Heavy-Duty Market Demand (16 tpd)
2. Transmission mode	Liquid H2 truck	Pipeline	Liquid H2 truck	Pipeline	Liquid H2 truck	Pipeline
3. Distribution mode	Liquid H2 truck	Pipeline	Liquid H2 truck	Pipeline	Liquid H2 truck	Pipeline
4. Dispensing options to vehicle tank	700 bar gas via pump	700 bar cascade dispensing	700 bar gas via pump	700 bar cascade dispensing	700 bar gas via pump	700 bar cascade dispensing
5. Component for plant outage + summer peak	Liquefier and liquid storage	Geologic/gaseous storage	Liquefier and liquid storage	Geologic / Gaseous Storage	Liquefier and liquid storage	Geologic / Gaseous Storage
6. Production volume	Mid	High	Low	Low	Mid	Mid
7. Pipeline region	n/a	Great Lakes	n/a	n/a	n/a	Great Lakes
8. Transmission pipeline length	n/a	100 km	n/a	100 km	n/a	100 km
9. Distribution pipeline length	n/a	2.7 km	n/a	n/a	n/a	2.7 km
10. Refueling lifetime	20 years	20 years	20 years	20 years	n/a	20 years
11. Station type	Medium/ Heavy-Duty	Medium/ Heavy-Duty	Light-Duty	Light-Duty	Medium/ Heavy-Duty	Medium/ Heavy-Duty
12. City Selection	n/a	n/a	Columbus OH	Columbus OH	n/a	n/a
13. Dispensing rate	n/a	n/a	1600 kg / day	1600kg / day	n/a	n/a
14. Local market penetration	n/a	n/a	50%	50%	n/a	n/a

15. Fleet size	30	30	n/a	n/a	200	200
16. Station daily operation hours	8	8	24	24	18	18

New files in gcamdata:

- H2ALite_TEA_mapping.csv
- H2ALite_TEAdata.csv
- H2ALite_wind_solar_CF.csv
- gcam-usa/A225.structure.csv

Water demand

Water demand intensities of all hydrogen production technologies (hybrid electrolysis and other as defined in CMP 386) are also tracked using input-output coefficients, whose values equal to the median values from Melaina et al. (2025, unpublished), converted from gallons of water per kg of hydrogen to cubic meters of water per GJ of hydrogen. These values are shown in Table 6. Hybrid renewable technologies' water intensities are based on the weighted average of wind and solar electrolysis in each region, time period, and scenario (described above). Biomass-based hydrogen production uses the corresponding values from natural gas based production, and grid electrolysis uses the values from wind electrolysis. No distinction is made between water withdrawals and consumption for hydrogen production technologies.

Table 6. Water use intensities of various technologies of hydrogen production. Source: Melaina et al. (2025, unpublished).

Technology	gal H_2O/kg H_2	m^3 H_2O/GJ H_2 (LHV)
Conventional SMR (natural-gas based)	2.2	0.069
SMR with CCS (natural-gas based)	6	0.189
Nuclear electrolysis	35	1.102
Solar PV electrolysis	15.5	0.488
Wind electrolysis	7	0.220

New file in gcamdata:

- Melaina_h2_water.csv

NO_x emissions factors

General industrial energy use of hydrogen is assumed to entail combustion; as such, emissions factors of nitrogen oxides (NO_x) are assigned. Specifically, industrial energy use of hydrogen is assigned a NO_x emission factor of 0.074 kg NO_x per GJ of hydrogen, corresponding to the European Monitoring and Evaluation Programme's Tier 1 NO_x emission factor for industrial combustion of natural gas (European Environment Agency 2023).

New file in gcamdata:

- A41.H2_globaltech_input_driver.csv

Industry

Ammonia

GCAM has included a nitrogen fertilizer module since the 4.0 release in 2014, with updates in 2022 to include a technology that uses hydrogen from the modeled hydrogen market (CMP 359), and in 2024 to improve the representation of international trade of ammonia, and also switch the accounting convention from nitrogen (N) to ammonia (NH3) for supply and trade (CMP 386). This section provides documentation of the ammonia supply module, focusing on its interactions with the hydrogen module.

While ammonia production via Haber-Bosch synthesis involves hydrogen production as an intermediate feedstock, this transformation is not represented explicitly in GCAM's default fossil energy based technologies, which include natural-gas based steam methane reforming (SMR), and some non-US countries also have production from partial oil oxidation (India, Eastern Europe), and coal chemical transformation (China; IEA 2021). Technologies with CO2 capture and storage (CCS) also compete for market share in future model time periods that have greenhouse gas emissions mitigation policies. These technologies are characterized by exogenous energy intensities (GJ of energy per tonne of NH3 produced), and non-energy cost ($ per tonne), which is calculated for the natural-gas based SMR technology as US farmgate ammonia prices minus estimated natural gas costs. As such, the non-energy costs of ammonia production technologies also include costs of distribution.

In order to integrate the modeled hydrogen market into the ammonia production sector, the model also includes an ammonia production technology starting in the first future time period (2025), that takes inputs of centrally produced hydrogen and natural gas. This technology is intended to be consistent with the existing natural gas based ammonia synthesis technology, in terms of its costs and system-wide energy intensities. The purpose of the technology is to allow the full suite of alternate hydrogen production technologies to compete for market share in the ammonia production sector.

The purchased hydrogen technology has two input-output coefficients, for hydrogen and natural gas (IO_H and IO_{NG}, respectively, indicated in GJ per tonne of NH_3 produced). These coefficients are derived as follows, for the 2025 model time period:

$$IO_H = 3\ t\ H_2 / 17\ t\ NH_3 * 120.2\ GJ_{LHV\ H2} / 1\ t\ H_2 = 21.2\ GJ\ H_2 / t\ NH_3$$

$$IO_{NG} = 36.9\ GJ\ NG / 1\ t\ NH_3 - (21.2\ GJ\ H_2 / t\ NH_3 * 1.39\ GJ\ NG / 1\ GJ\ H_2) = 7.5\ GJ\ NG / 1\ t\ NH_3$$

The hydrogen input-output coefficient (IO_H) is calculated from the stoichiometric mass portion of ammonia that is hydrogen (3/17), multiplied by the lower heating value energy density of hydrogen (IEA 2007). This input-output coefficient is held constant over time as it is not subject to technological improvement. The natural gas energy (i.e., non-feedstock) input, IO_{NG}, is calculated from the assumed total energy intensity of natural-gas-based ammonia synthesis in 2025 (36.9 GJ/t) minus the amount of natural gas used for hydrogen production, which itself is equal to the hydrogen feedstock input (21.2 GJ / t NH_3) times the input-output coefficient of natural-gas based SMR from H2A-Lite (1.39, converted from 0.1749 mmbtu per kg). This energy-use natural gas input-output coefficient IO_{NG} is assumed to decrease over time, which declines from 36.9 to 32.4 GJ of natural gas per tonne of ammonia between 2025 and 2050, for newly constructed facilities. This value is the gross energy intensity of the best available technology identified in IEA (2021). This calculation results in a value of purchased natural gas per tonne of ammonia produced (IO ng) of 2.9 GJ for new hydrogen technology starting in 2050.

Unlike other end uses of hydrogen, ammonia synthesis is structurally represented as taking place at the same physical site as hydrogen production; the hydrogen input to the production technology ("H2 central production") is upstream of the modeled hydrogen transmission and distribution system. This representation reflects (1) current industry practices, (2) that transportation of ammonia is less costly than that of hydrogen, and (3) that the hydrogen consumption rates of ammonia production facilities are similar to the assumed production capacities of central hydrogen production facilities in H2A-Lite. In fact, the natural-gas based hydrogen production technology in H2A-Lite (SMR) assumes a production capacity of 483 tonnes of hydrogen per day, or 176,000 tonnes per year, which is equivalent to the hydrogen feedstock needs of a 1 million tonne per year ammonia production facility (based on the 3/17 mass ratio). The 5 largest ammonia production facilities in the USA have production capacities of 3.9, 1.2, 1.1, 1.0, and 0.9 million tons per year.

Non-energy costs of the purchased-hydrogen-based ammonia production technology are set equal to those of the natural gas ammonia technology, minus the estimated non-energy cost of the natural-gas based SMR process itself. This approach results in an assumed non-energy cost of $305/tNH3 for natural gas SMR based ammonia production, and $244/t NH3 for purchased hydrogen based ammonia production. As noted above, these costs implicitly include ammonia distribution costs, not represented explicitly in GCAM.

Ammonia trade can effectively allow inter-regional hydrogen trade, in the absence of structural representation of hydrogen trade. For instance, a region with low hydrogen producer prices can use its domestic hydrogen to produce and export ammonia into the global ammonia market.

While ammonia trade has been in GCAM since CMP389 in 2023, based on net flows of ammonia in each region, in this proposal ammonia trade is recalibrated based on the pairwise trade of nitrogenous fertilizers between all countries, using the Chatham House (2024) bilateral trade matrix of nitrogenous fertilizers to partition each model region's net trade of nitrogen in fertilizers (from FAOSTAT; FAO 2025) into gross imports and exports. Each of the 9 nitrogenous fertilizer commodities in the Chatham House (2024) matrix is converted to a nitrogen quantity, based on the reported weight of the commodity traded times its stoichiometric nitrogen mass fraction (e.g., urea is 46.7% nitrogen based on its chemical formula, and the atomic mass of each constituent element). Because GCAM does not distinguish between the different types of nitrogenous fertilizers, and because the nitrogen in these synthetic fertilizers is derived from ammonia, the model represents the traded nitrogen fertilizer commodities as the mass of ammonia that was required to produce them. For purposes of calibration of trade in GCAM, trade between countries that are within the same GCAM region is not considered (e.g., trade between France and Germany is dropped from the bilateral trade matrix).

The theoretical basis of the method for modeling trade is described in Zhao et al. (2022). The method represents a hybrid modeling approach between Heckscher-Ohlin trade, which posits that export patterns follow exactly from producer price discrepancies, and Armington-based bilateral trade, which represents each pair of trading partners individually, and anchors future trade to the historical data. In GCAM, the base year calibration does influence trade patterns in all future periods, but there is a greater degree of fungibility in inter-regional trade than the Armington approach would yield. In future model years, the degree of price-driven changes to calibrated trade patterns depends on several assumed logit exponents (in the "traded ammonia" and "regional ammonia" sectors, both -3), which are not revised in this proposal.

New files in gcamdata for ammonia revisions:

- Rt_Nfert_bilateral_trade.csv
- Rt_Nfert_commodities.csv

Steel sector IO coefficients

GCAM includes a technology-based representation of iron and steel production, featuring a variety of production technologies shown in Table 7, and inter-regional trade (JGCRI 2023c; JGCRI 2025b). The energy intensities of each production technology are shown for the 2025 and 2100 model time periods in Table 7. Assumed energy intensities of new investment are assumed to improve over time; specifically, energy intensities are linearly reduced from their 2025 base values to the "world best practice levels" reported in Worrell et al. (2007). The hydrogen-based DRI technology (H_2-DRI) is assigned the energy intensity values from the 75% EAF–DRI H_2 technology in Zang et al. (2023), and others are from Durga et al. (2024) unless otherwise noted. Table 8 tabulates the file modifications made in gcamdata to facilitate these changes.

Table 7. Assumed energy intensities of iron and steel production technologies for the 2025 and 2100 model time periods.

Technologies		2025 value (GJ/t)	Source/notes	2100 value (GJ/t)	Source/notes
Conventional	BF-BOF (Conventional BLASTFUR)	25.4	Durga et al. (2024), Worrell et al. (2007)	14.8	Worrell et al. (2007)
	EAF-DRI coal	25.6	Nduagu et al (2022)	19.1	CSTEP (2013)
	EAF-DRI gas	21.9	Durga et al. (2024), Worrell et al. (2007)	16.9	Worrell et al. (2007)
	EAF-scrap	6	Durga et al. (2024)	2	Worrell et al. (2007)
Advanced	H_2-DRI	16.2	Zang et al. (2023)	15.1	Worrell et al. (2007)
	Biomass-based BLASTFUR	25.4	Durga et al. (2024), Worrell et al. (2007)	14.8	Aperam SA
	BLASTFUR CCS	26.1	IEA (2013)	14.8	43% CCS penalty on electricity consumption
	BLASTFUR with hydrogen	26.7	20 kg H_2/t steel injection (1 kg H_2 replaces ~2 kg pulverized coal)	14.8	Worrell et al. (2007)
	BLASTFUR CCS with hydrogen	27.4	43% CCS penalty on electricity consumption	14.8	Worrell et al. (2007)
	EAF-DRI coal - CCS	27.1	43% CCS penalty on electricity consumption	19.1	43% CCS penalty on electricity consumption
	EAF-DRI gas CCS	23.4	Durga et al. (2024), Worrell et al. (2007)	16.9	43% CCS penalty on electricity consumption

GCAM regions are classified as either coal-intensive or gas-intensive producers of conventional steel (compare with section 4.2 in CMP 374). Note that even in gas-intensive regions, several technologies require significant amounts of coal as a source of process fuel (Figure 5). For instance, blast furnaces (BLASTFUR) rely on coal as the chemical reductant to convert iron ore into iron. EAF with DRI in coal-intensive regions exhibits a higher overall energy intensity compared to EAF with DRI in gas-intensive regions, reflecting fundamentally different process configurations (compare "EAF with DRI" in Figure 5 to "EAF with DRI" in Figure 6). Figure 7 shows technologies that are common across all GCAM regions.

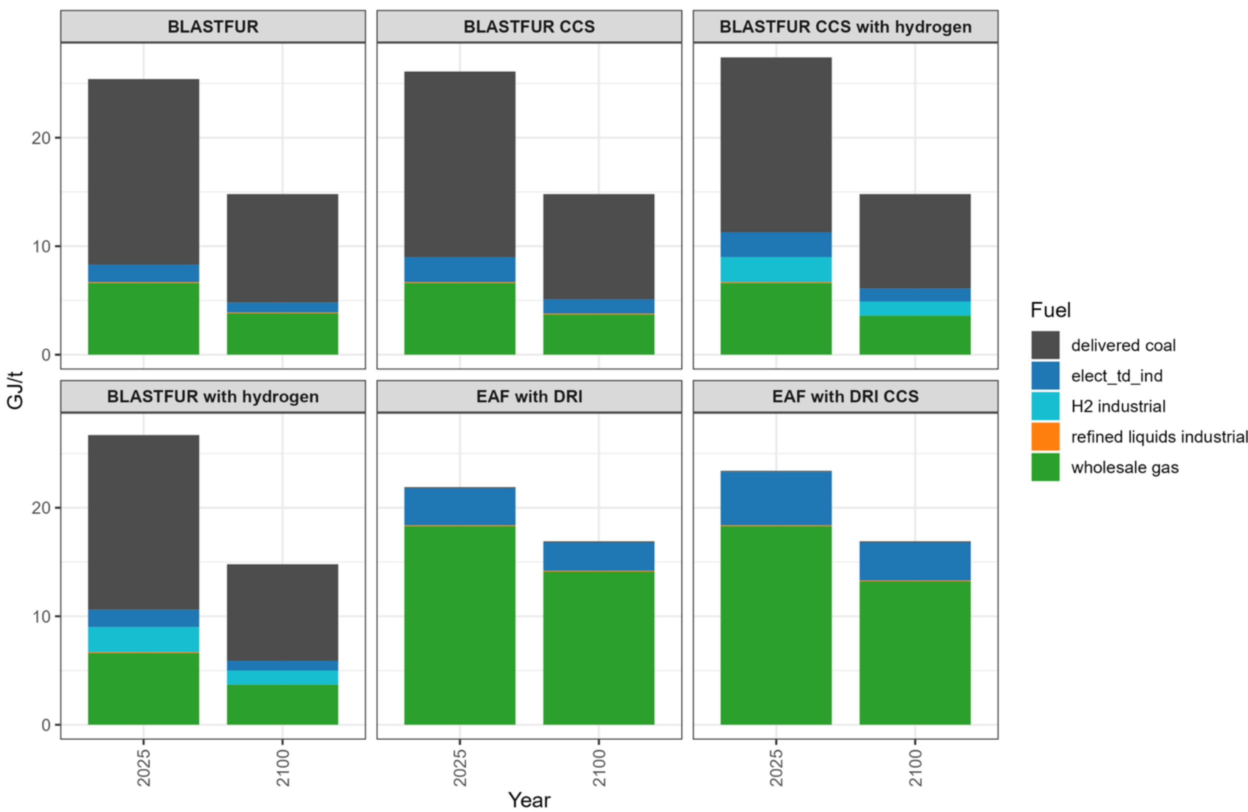


Figure 5. Steel production energy intensity by technology in gas-intensive GCAM regions.

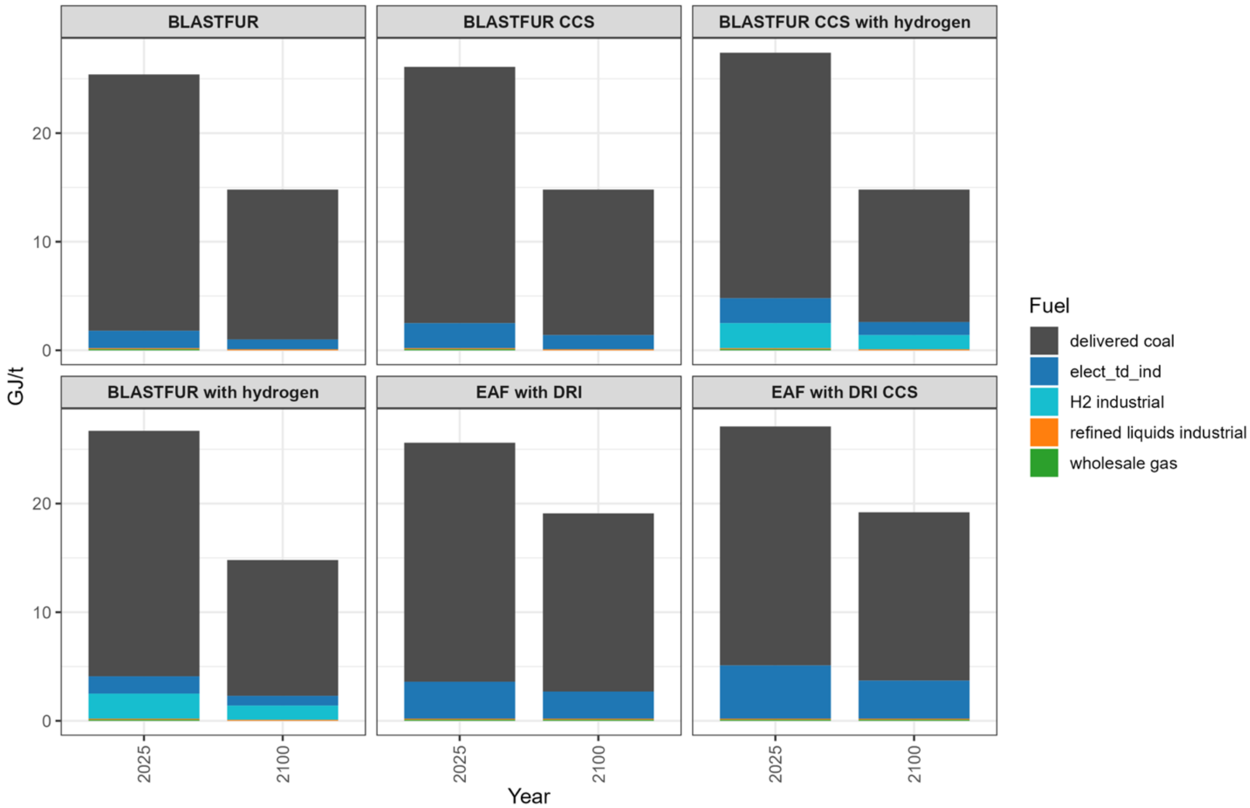


Figure 6. Steel production energy intensity by technology in coal-intensive GCAM regions.

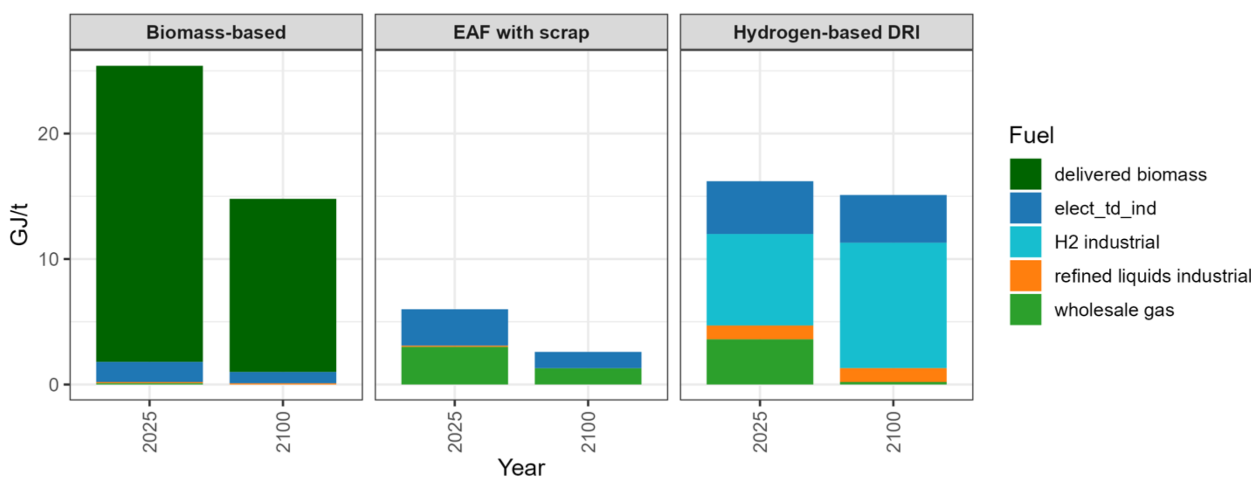


Figure 7. Steel production energy intensity by technology, applied across all GCAM regions.

Table 8. Deprecated and updated files for the iron and steel sector in GCAM.

Old Files	Modified Files
energy/IO_IRONSTL_scaled.csv	energy/A_regions.csv
energy/steel_intensity.csv	energy/A323.globaltech_coef.csv
	R/zenergy_L1092.iron_steel_GrossTrade.R
	R/zenergy_L2323.iron_steel.R
	R/zenergy_L1323.iron_steel.R

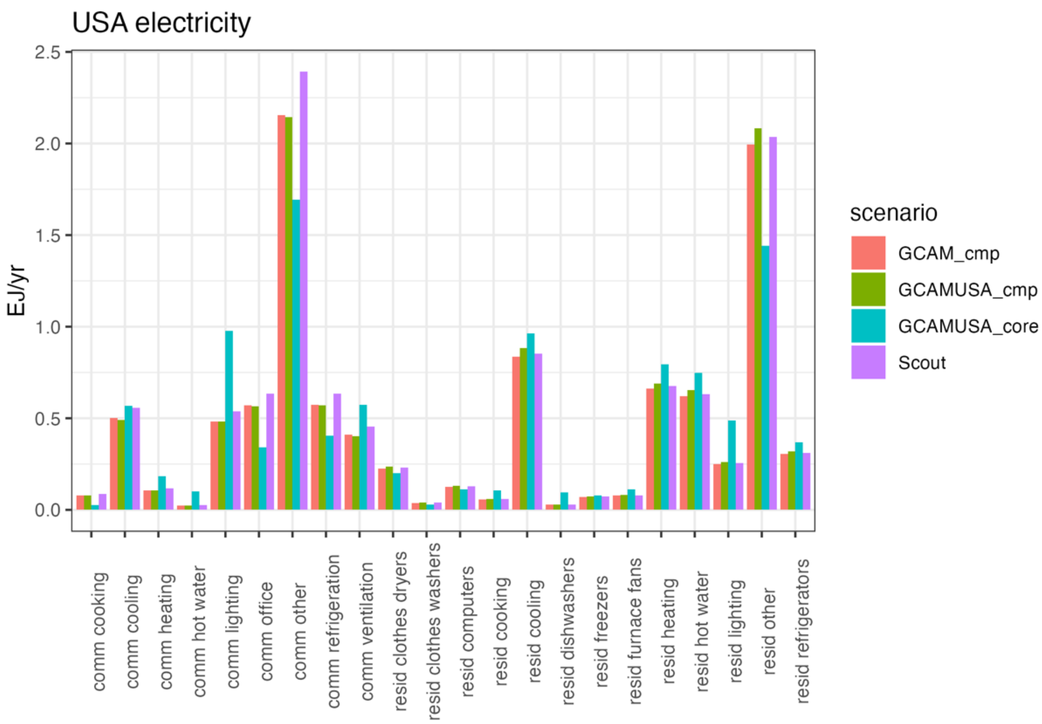
US buildings

Since CMP 271 Consolidated GCAM-USA Updates, GCAM has included two different versions of buildings in the United States. When running in the standard configuration, the building sector in the United States has the same structure as all other regions: residential and commercial sectors; heating, cooling, and other services. When running in the GCAM-USA configuration, a much more detailed version of the building sector is used, which has 11 commercial and 14 residential services (similar to the NEMS Commercial Demand and Residential Demand Modules). Several projects have developed detailed versions of USA buildings that run in the USA region of the standard configuration, but none have ever been merged to the core model. This proposal does that, and it uses the detailed USA buildings module to supersede the default global representation that had been used. The revisions take place within the processing pipelines that build the global buildings XML file (building_det.xml), so no new XML files are created as a result, and no changes to the configuration files are necessary. The logic behind this approach is that there is no reason to be running a US building sector model with only three services disaggregated; the first version of detailed buildings in the USA region was published more than 15 years ago (Kyle et al. 2010), and most US buildings models today have greater service-level detail (e.g., see Table 2 of Browning et al. 2023). There is no meaningful increase to the computation burden on the solver as this additional detail does not make any new solved markets.

This new detailed US buildings module still disaggregates all residential services to the 10 income deciles, applying the portional shares of "resid other" to all of the new residential services. In doing this model development, care was taken to ensure no dependency on any “module_gcamusa” code within gcamdata. This is necessary to maintain the capability to disable the gcamusa module. All additional data processing necessary to create the detailed USA buildings module for the standard configuration takes place in “module_energy” code files.

In addition to including detailed buildings in the USA region, this proposal also revises the base year calibration of detailed buildings, in both the USA region of the standard configuration, as well as the state level representation in the GCAM-USA configuration. The prior data sources and processing code are left intact, but for the 2021 time period this proposal switches the data source to the Scout buildings model, a publicly available model of the United States building sector, that is intended to be consistent with NEMS at the national level, but that has state- and technology-level detail. The Scout dataset also properly downscales space heating/electricity energy consumption to our modeled heat pump and furnace technologies, at the state level. The mapping between technologies in Scout and GCAM was documented in Binsted et al. 2022.

The figures below show the reallocation of electricity to end-use services in the residential and commercial sector, comparing the allocations in the USA region of this proposal (GCAM_cmp), the sum of the states in this proposal (GCAMUSA_cmp), the sum of the states in the core model (GCAMUSA_core), and the underlying source data from Scout. The USA region in the core model is not shown in these figures because it only has three services. GCAM_cmp and aggregated GCAMUSA_cmp differ slightly in the USA figures, as the latter need to be fit into each state's energy balances (i.e., total electricity/gas by sector and fuel), which differ between GCAM-USA and Scout. As shown, the reallocations of energy between services are not especially dramatic, though the revised (cmp) quantities are closer to the Scout quantities for all services, and we do see more divergence from the core GCAM-USA allocations at the state level (Texas shown as an example).


USA electricity
EJ/yr
2.5
2.0
1.5
1.0
0.5
0.0
comm cooking
comm cooling
comm heating
comm hot water
comm lighting
comm office
comm other
comm refrigeration
comm ventilation
resid clothes dryers
resid clothes washers
resid computers
resid cooking
resid cooling
resid dishwashers
resid freezers
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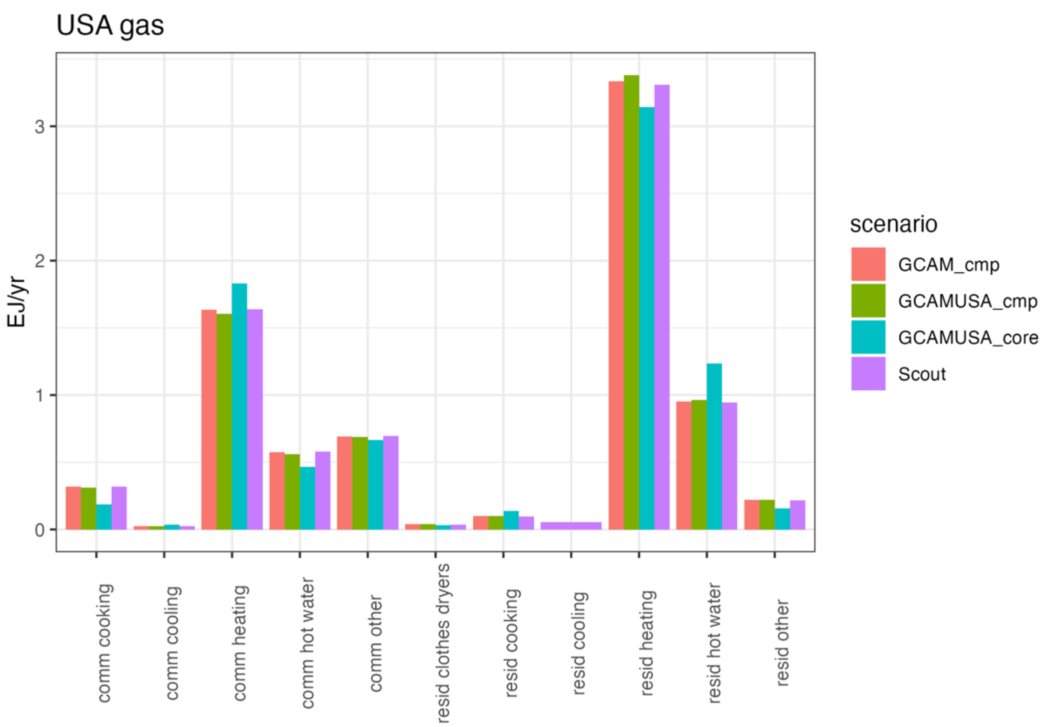
resid lighting
resid other
resid refrigerators
scenario
GCAM_cmp
GCAMUSA_cmp
GCAMUSA_core
Scout


USA gas
EJ/yr
3
2
1
0
comm cooking
comm cooling
comm heating
comm hot water
comm other
resid clothes dryers
resid cooking
resid cooling
resid heating
resid hot water
resid other
scenario
GCAM_cmp
GCAMUSA_cmp
GCAMUSA_core
Scout

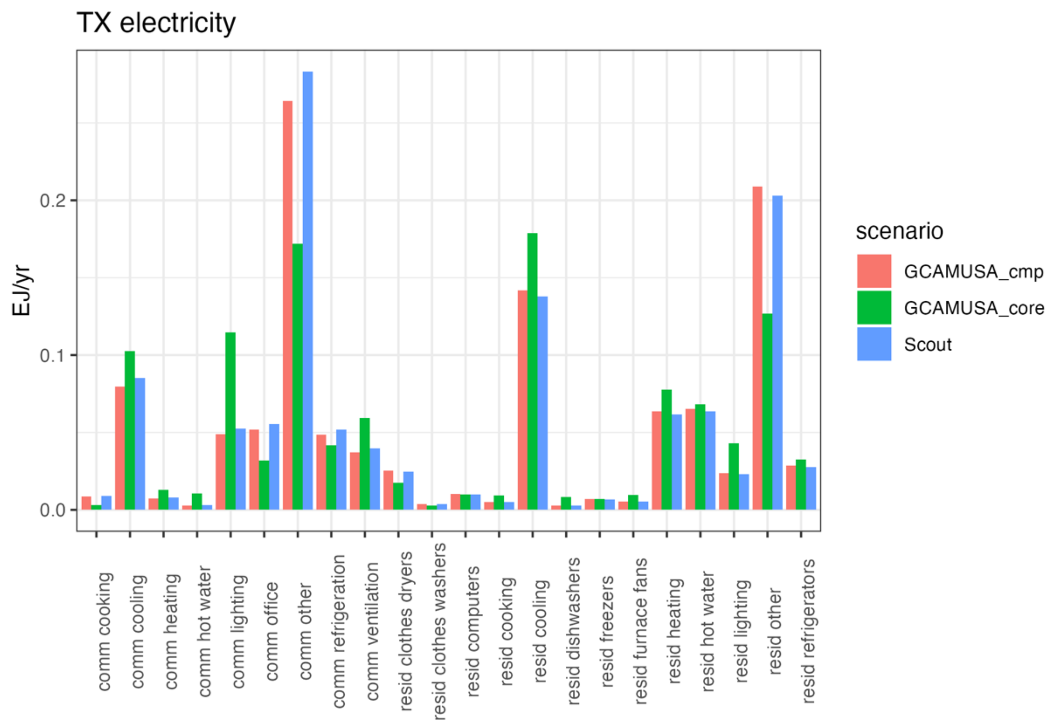


Figure 8. Comparison of energy service allocations between models and source data. Panels show U.S. electricity (left side), U.S. natural gas (center), and Texas electricity (right side).

New files:

- A44.fuelprefElasticity_USA.csv
- zenergy_L1441.building_det_en_USA.R
- Scout_bld_calibration.csv
- USAbld_emission_mapping.csv

Electricity

Different versions of NREL's Annual Technology Baseline (ATB) data have previously been used to estimate electricity generation costs in GCAM. For the electricity sector, all historical ATB versions have now been removed and replaced with a single continuous time series file primarily based on the ReEDS model and ATB 2024 data. Most technology cost trajectories are drawn directly from ReEDS; when technologies are not available in ReEDS, ATB 2024 data are used instead. For technologies represented in both ReEDS and ATB 2024, costs are identical across all common years and scenarios. The consolidated file includes all previously modeled GCAM technologies, as well as small modular reactors, using the parameterizations described in CMP 407: Add Small Modular Reactors. The merge of this core model proposal was implemented manually, copying changes from the relevant pull request, as an automatic merge would not have worked given the significant differences between the two branches' processing of electric sector data in general. The previous GCAM data code, which stitched together multiple files using the *fill_exp_decay_extrapolate* function, is no longer needed because a complete historical dataset is now available through 2050. Beyond 2050, cost data are extrapolated using an assumed tech-change rate, user-modifiable for each technology, for the three different scenarios maintained (low, default, and adv; Table 9). This consolidation also renders certain files obsolete, as summarized in Table 10.

Table 9. Extrapolation rates for different electricity cost cases in the 2050 to 2100 time range.

Case	Cost extrapolation rate
Low	-0.05%/year
Default	-0.10%/year
Adv	-0.20%/year

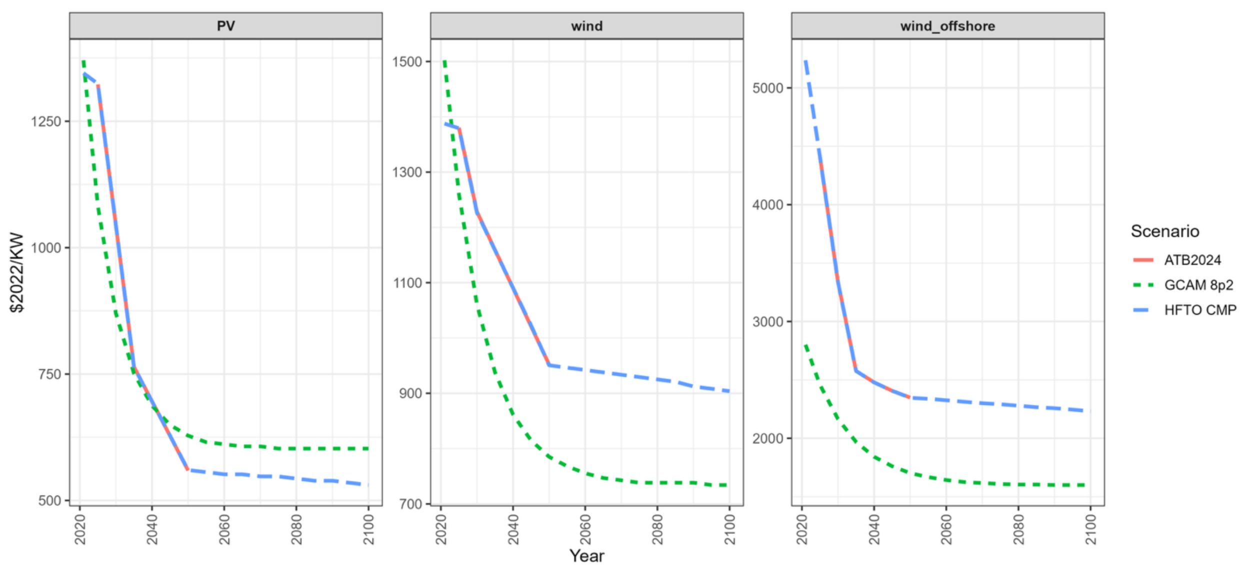


Figure 9. Comparison of overnight capital costs of variable power generation technologies. HFTO CMP=CMP415, GCAM 8p2=Core.

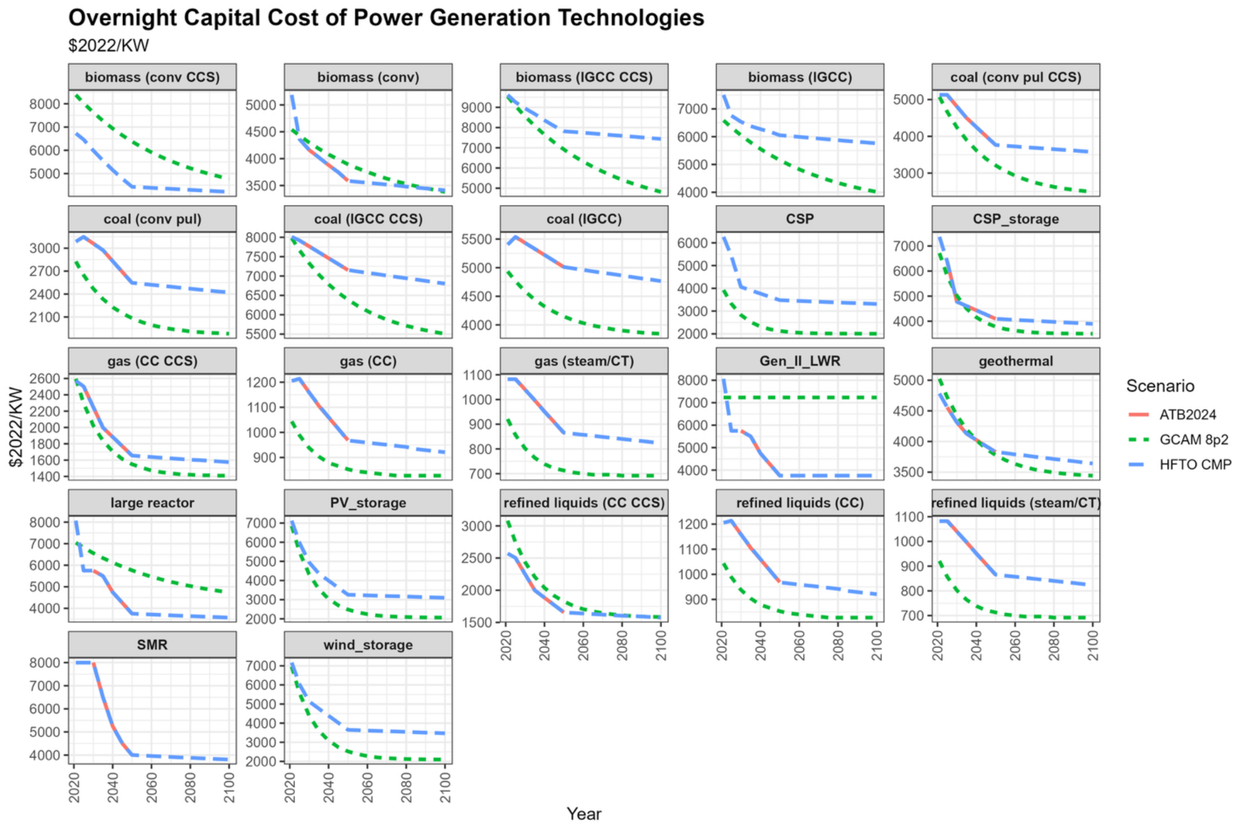


Figure 10. Comparison of overnight capital costs of other power generation technologies. HFTO CMP=CMP415, GCAM 8p2=Core.

Figure 9 shows a comparison of overnight capital costs for variable power generation technologies, comparing ATB 2024 data with GCAM Core (which is based on ATB 2022) and the current CMP. While the rooftop PV technology is not shown in Figure 9, because the assumptions in the model are read in as a pre-levelized cost, it should be noted that the technology's costs did increase between the 2022 ATB and the 2024 ATB. In the 2035 year, which is the one year that the Core model's assumption is directly sourced from the ATB (i.e., ATB2022), the CMP415 value (i.e., sourced from ATB2024) is 17% higher than the Core. Due to aggressive 2035-2050 technological change assumed in the Core, this cost discrepancy reaches 60% by 2050. Note that the value in this proposal is sourced directly from ATB2024, whereas the 2050 value in the core model is based on a projection from 2035 using the *fill_exp_decay_extrapolate* function.

Table 10. List of files removed (left panel) and added (right panel) in gcamdata, for the updates to the electricity technology data processing.

Old files	New files
• Muratori_globaltech_capital_adv.csv • Muratori_globaltech_capital_low.csv • Muratori_globaltech_capital.csv • Muratori_globaltech_OMfixed.csv • Muratori_globaltech_OMvar.csv • NREL_ATB_capital_2017.csv • NREL_ATB_capital_2019.csv • NREL_ATB_capital_2021.csv • NREL_ATB_capital_2022.csv • NREL_ATB_OMfixed_2017.csv • NREL_ATB_OMfixed_2019.csv • NREL_ATB_OMfixed_2021.csv • NREL_ATB_OMfixed_2022.csv • NREL_ATB_OMvar_2017.csv • NREL_ATB_OMvar_2019.csv • NREL_ATB_OMvar_2021.csv • NREL_ATB_OMvar_2022.csv	▪ ReEDS_power_plant_costs.csv ▪ NREL_ATB_capital_2024.csv ▪ NREL_ATB_OMfixed_2024.csv ▪ NREL_ATB_OMvar_2024.csv
• atb_gcam_mapping.csv • ATB_tech_mapping.csv	▪ atb_gcam_elec_tech_mapping.csv
▪ A23.globaltech_capital_adv.csv ▪ A23.globaltech_capital_low.csv ▪ A23.globaltech_capital.csv ▪ A23.globaltech_OMfixed.csv ▪ A23.globaltech_OMvar.csv	▪ A23.globaltech_cost_tc.csv ▪ A23.globaltech_cost_tfcr.csv
▪ zenergy_L113.atb_cost.R ▪ zgcamusa_L114.wind.R	• zenergy_L1233.elec_cost_data.R
• zenergy_xml_elec_bio_low.R • zenergy_xml_elec_geo_low.R • zenergy_xml_elec_geo_tech_adv.R • zenergy_xml_elec_nuclear_adv.R • zenergy_xml_elec_nuclear_low.R • zenergy_xml_elec_solar_adv.R • zenergy_xml_elec_solar_low.R • zenergy_xml_elec_wind_adv.R • zenergy_xml_elec_wind_low.R	• zenergy_xml_elec_tech_scenarios.R • zgcamusa_xml_elec_tech_scenarios.R

Other new file in gcamdata:

- gcam-usa/us_nuclear_legacy.csv: used for updating the characteristics and anticipated retirement of the existing stock of nuclear power plants. Documented in CMP 407: Add Small Modular Reactors.

In general this proposal does not update capacity factors, consistent with the prior updates to new editions of the ATB. The ATB does provide year- and scenario-specific assumptions of capacity factors for each generation technology, but for the most part these are not used in gcamdata. The one technology whose capacity factor assumptions are revised in this proposal however is utility PV, where the baseline default assumption for the United States was 20%, and all other regions' capacity factors were estimated from this starting point. A recent LBNL report estimated the weighted average capacity factor of solar in the United states to be already 24%, and going into the future this proposal further revises the assumptions to follow one of the mid-class resources in the ATB (Class 5, of 10, in the Moderate case). There are two reasons why the capacity factors are significantly higher than estimated 10 years ago, when 20% was a reasonable assumption. The first is the implementation of axis tracking at utility PV projects, which allows solar panels to partially track the sun, improving the average angle of incidence as compared with a fixed panel. The second is that because PV module prices have come down, there has been a practice of oversizing the PV module to the inverter. Because the capacity factor is computed with reference to the AC electricity coming out of the combined unit, the net effect of this over sizing is to increase the measured capacity factor. Looking ahead, R&D advances could further increase PV energy yield through bifacial modules, improved ground albedo, better soiling removal, reduced cell temperatures, lower system losses, O&M practices that improve uptime, and reductions in degradation rates. ATB future scenarios reflect these possibilities, with assumed energy-yield gains ranging from 0% up to 18.8%, depending on the scenario (NREL 2024). The specific assumptions, from A23.globaltech_capacity_factor.csv, are shown in Table 11. Note that the 2021 assumption applies to the stock of utility PV operating in 2021 (and thereafter), whereas the assumptions for 2025 and thereafter refer to new investment.

Note that the proposal does not revise the capacity factors of rooftop PV, which (unlike utility PV) are assumed constant over time. This is because the core model assumption for the USA (17%) is already quite close to the ATB assumptions in the base year, and unlike utility PV, do not increase much over time in the ATB. Where mid-grade utility PV sites increase from 26% to 30% from 2022 to 2050, the corresponding capacity factors for commercial are 16% to 17%, and for residential are 15% to 16%.

Table 11. Assumed utility PV capacity factors over time in the USA. The corresponding values in the core model are 0.2 in all years.

year	CF
1971	0.2
2021	0.24

2025	0.27
2050	0.3
2100	0.3

Other Miscellaneous Revisions

This proposal makes several other minor revisions to gcamdata, to resolve issues that were just noticed in the course of doing the model development documented above. These are documented here in the order that they occur in the pull request.

- data-raw/generate_package_data.R, and mi_headers/ModelInterface_headers.txt: add capability to parse a base-value for an uncalibrated absolute-cost-logit. Not otherwise used in this proposal; it's useful for representing e-fuels in GCAM-USA.
- inst/extdata/energy/A22.globaltech_cost_low.csv, R/zenergy_L222.en_transformation.R, R/zenergy_xml_en_transformation_low.R: remove deprecated inputs and processing code to create en_transformation_low.xml, whose cost assumptions (and calculation methods) had not been revised alongside the standard en_transformation.xml. According to the comments, this was intended to be a low-tech and therefore high-cost scenario, but the costs in most years and for most technologies were lower than the reference, and did not use the fill_exp_decay_extrapolate() function.
- inst/extdata/gcam-usa/Macknick_elec_water_m3MWh.csv: removal of duplicate file also found in inst/extdata/water/ folder
- R/module-helpers.R: revision to fill_exp_decay_extrapolate() to allow fully qualified technology names (supplysector/subsector/technology, instead of just technology). The former approach works for sectors or groups thereof where each technology has a unique name, but this isn't always the case; in GCAM the fully qualified (unique) name of a technology is the supplysector, subsector, and technology name.
- R/utils.R: revision to load_csv_files() to avoid re-setting global options when the function fails, e.g. when a column type is incorrectly specified. In the prior version, such an error would set the global options to crash upon a warning, and right now gcamdata has known/expected warnings.
- R/utils.R: revision to inputs_of() and outputs_of() to allow more than one module/chunk call. Explained more fully in 573e00dfdfa
- R/zenergy_L210.resources.R: reset hard-wired "capital" to named object used elsewhere socioeconomics.EN_CAPITAL_MARKET_NAME
- R/zenergy_L226.en_distribution.R: slight revisions to make code work for technologies with multiple energy and/or non-energy inputs

Validation

High-level results

This proposal changes the techno-economic assumptions of a large number of technologies in the model, but for the most part the changes themselves do not cause dramatically different results at regional or global scales. The exception is the update to the power sector technology costs and solar PV capacity factors, which reduce the levelized costs of solar and nuclear electricity generation; this sector's update is largely responsible for all high-level divergence between the Core and CMP415 scenario outcomes. That revision is mostly attributable to the difference in estimated costs in the 2024 ATB as compared with the 2022 ATB which is used in the current core model.

However, even though this proposal reduces the levelized costs of renewable electricity (as compared with the core model), GCAM's renewable electricity producer prices are still significantly higher than the corresponding estimates in the ATB. For example, in the Reference Scenario, USA region, year 2040, the producer price of PV is \$4.11/GJ (1975\$), equal to \$63/MWh, in 2022\$. In the ATB's Class 5 resource (basis of GCAM's capacity factor), this same value is \$24/MWh in the Moderate scenario. This difference is mostly attributable to different financing assumptions (GCAM having much higher fixed charge rates).

The CMP415 revision reduces atmospheric CO_2 concentrations in all baseline scenarios (Figure 11, left side), and consistent with this, also the CO_2 price in the mitigation scenarios with an end-of-century radiative forcing target (Figure 11, right side).

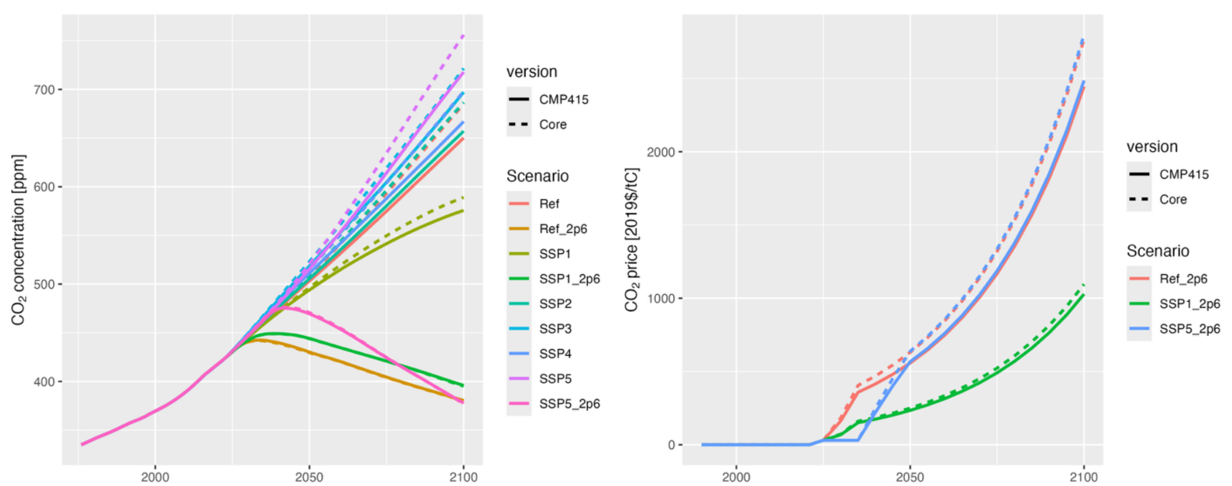


Figure 11. CO_2 concentration by scenario (left) and CO_2 prices by scenario (right).

Overall global energy consumption is slightly reduced from the core model in 7 of the 9 global validation scenarios, with differences being at most 2% (Figure 12, left). By fuel type, electricity demands are higher, while demand for gas, and refined liquids are reduced by the end of the century in the reference scenario. In the mitigation scenario "Ref_2p6", a similar pattern emerges, except that hydrogen demand is lower (Figure 12, right side). Further explanation is provided below.

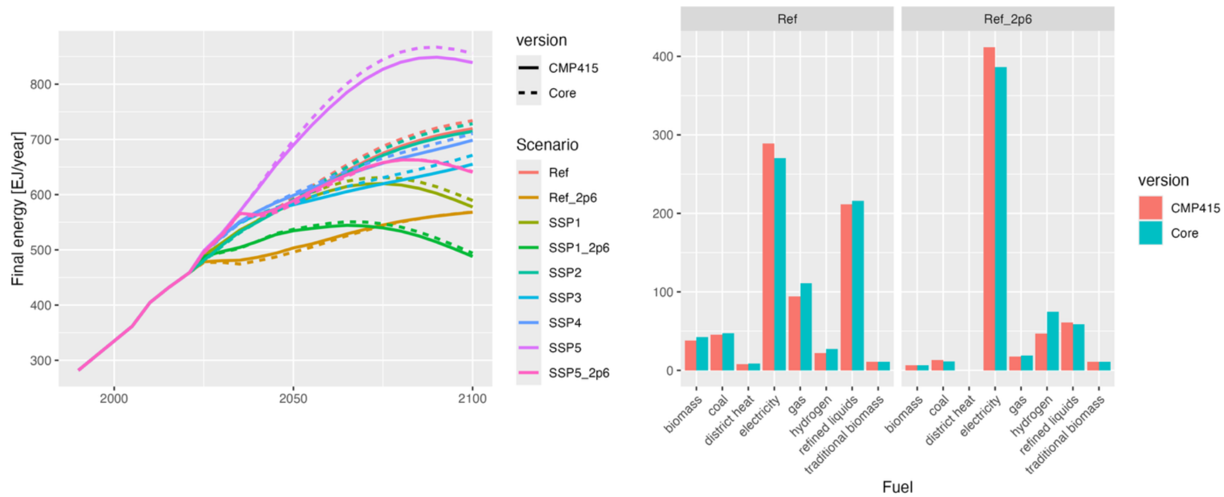


Figure 12. Final energy use by scenario (left) and final energy use by fuel in 2100, scenario "Ref" versus "Ref_2p6" (right).

Transport

In the transportation sector, global differences in total final energy demand are less than 2% across the whole scenario set (not shown), which is not surprising because the techno-economic assumptions were only updated in the USA region. Figure 13 focuses on the United States, where the revised scenarios have generally less total final energy—between 13% and 20% reduction from 2050 to 2100 (Figure 13, left panel). This is because even in the "low" technology progress scenario of Autonomie, the future efficiency levels are significantly higher than the core model's prior assumptions, both for the standard ICEV technologies and particularly electric vehicles. Electric vehicles gain more of the market share than before (see Figure 15), both due to the assumed improved efficiencies as well as lower costs. Still the main difference between the two model versions in the Reference and mitigation scenarios is the reduction in total energy demand. Due to lower future vehicle costs, passenger service demand growth in the USA is slightly higher in the revised scenarios; where the Core Reference scenario has 21% growth from 2021 to 2050, the CMP415 scenario has 25%.

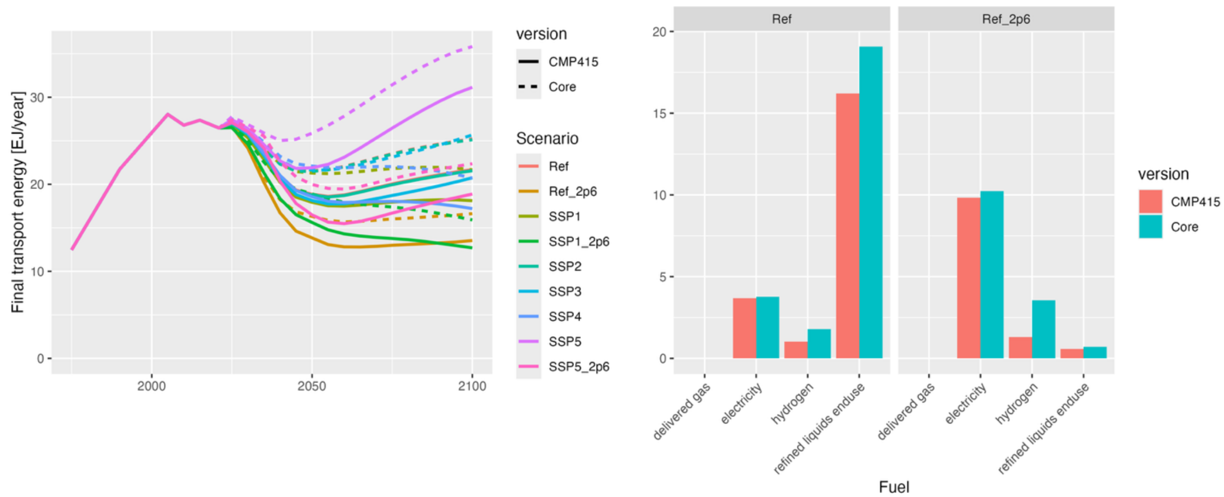


Figure 13. U.S. final transport energy use by scenario (left) and U.S. final transport energy use by fuel in 2100, scenario "Ref" versus "Ref_2p6" (right).

Figure 14 focuses on the light duty vehicles (LDVs) that are largely responsible for the differences between model revisions shown in Figure 13. The left panel shows vehicle transportation costs by a set of regions, confirming that no changes were made in the non-US regions; any differences in non-US regions are simply due to different fuel prices. Within the United States, all LDV technologies are less expensive than before, and in the revised scenarios, BEVs offer the lowest levelized costs of driving among all options, even in the reference scenario.

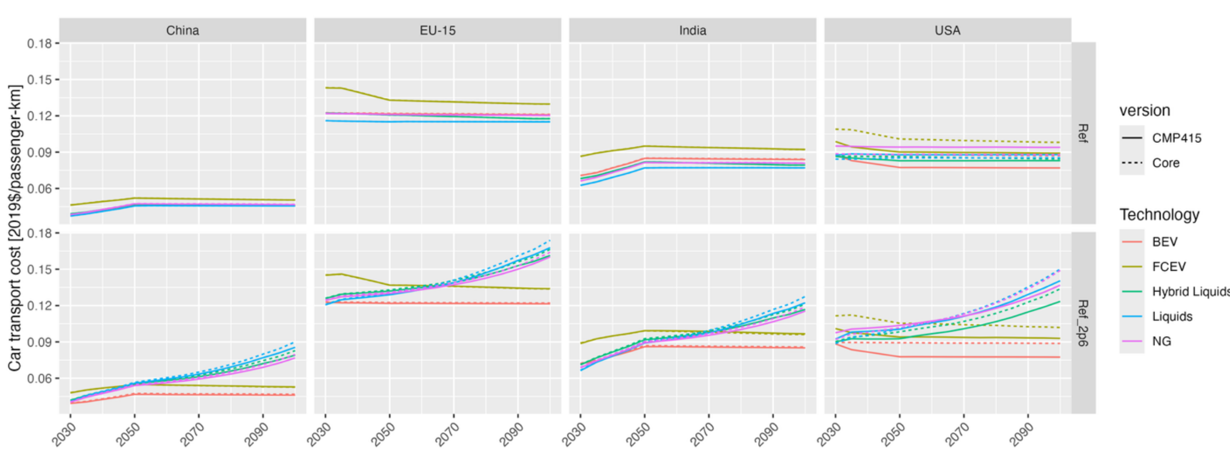
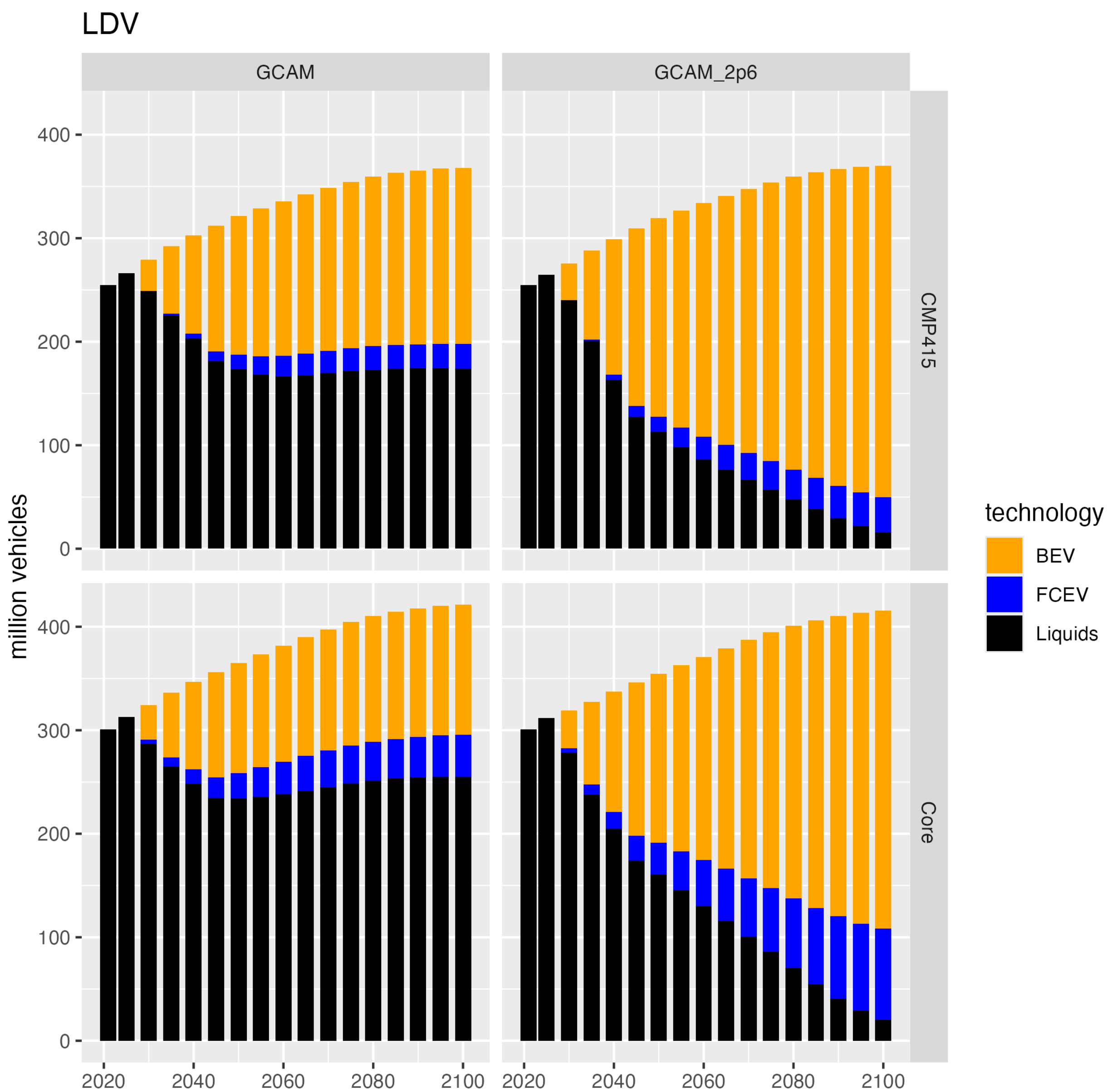


Figure 14. Car transport cost by technology and for four regions, scenario "Ref" versus "Ref_2p6 (left) and U.S. light-duty vehicle energy use by energy source in 2100, scenario "Ref" versus "Ref_2p6 (right).

Combining the calibrated vehicle service outputs (calculated from calibrated energy consumption quantities and assumed energy intensities) with the assumed annual travel per vehicle, in the core model the LDV stock in 2021 is 300 million vehicles (Figure 15). By updating the energy intensities in this proposal for the calibration year, and by updating the assumed travel per vehicle per year, the derived LDV stock is decreased significantly. At 255 million vehicles (including motorcycles), the CMP415 estimated vehicle stock in 2021 is almost identical to the FHWA estimate of 257 million vehicles.

Figure 15 shows the evolution to 2100 in the United States vehicle stocks, across the reference and 2.6 scenarios. The future growth rates in the vehicle stocks are similar, as are the general patterns of future fuel choice. In the reference scenario ("GCAM") in 2050, the shares of alternative-fueled vehicles increase from 29% BEV and 7% FCEV in the Core to 42% BEV and 4% FCEV in the CMP revision. In the 2.6 mitigation scenario ("GCAM_2p6"), the CMP415 and Core versions see similar levels of fuel-switching away from Liquids (about 5% in 2100), though in CMP415 the BEVs take a greater share of the market (87% vs. 74%, respectively).

For the medium and heavy duty vehicles, the revised scenarios would see greater uptake of hydrogen fuel cell vehicles in the baseline, but for a downward revision to the share-weights that keeps the FCEV share more or less similar to what it was in the Core. The issue is that Autonomie's baseline ("low") scenario estimates that hydrogen powered trucks (FCHEV drivetrain) will have lower vehicle purchase prices and levelized costs of driving than conventional diesel trucks by 2050, so without any secondary considerations, this technology would take a significant portion of the market. Prior to the updates in this proposal, such uptake was limited by high hydrogen prices. In the revisions to hydrogen T&D implemented in this proposal, the cost of hydrogen delivered to trucks drops from about $7.50/kg in the Core to just over $5/kg in the CMP415 revision, in the post-2040 timeframe. Note that $5/kg of hydrogen is similar to the assumed hydrogen price in Autonomie. It is also worth noting that the 2025 Annual Energy Outlook, which also uses Autonomie's techno-economic estimates in this sector, also has about 15% of heavy freight trucking provided by this FCHEV technology in 2050 (AEO 2025 Table 49). In any case, it is expected that future updates to Autonomie will include less aggressive technological improvement in the FCHEV technology, at which point the share-weights might be reset to 1.



LDV
GCAM
GCAM_2p6
CMP415
Core
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100
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2040
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2080
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technology
BEV
FCEV
Liquids

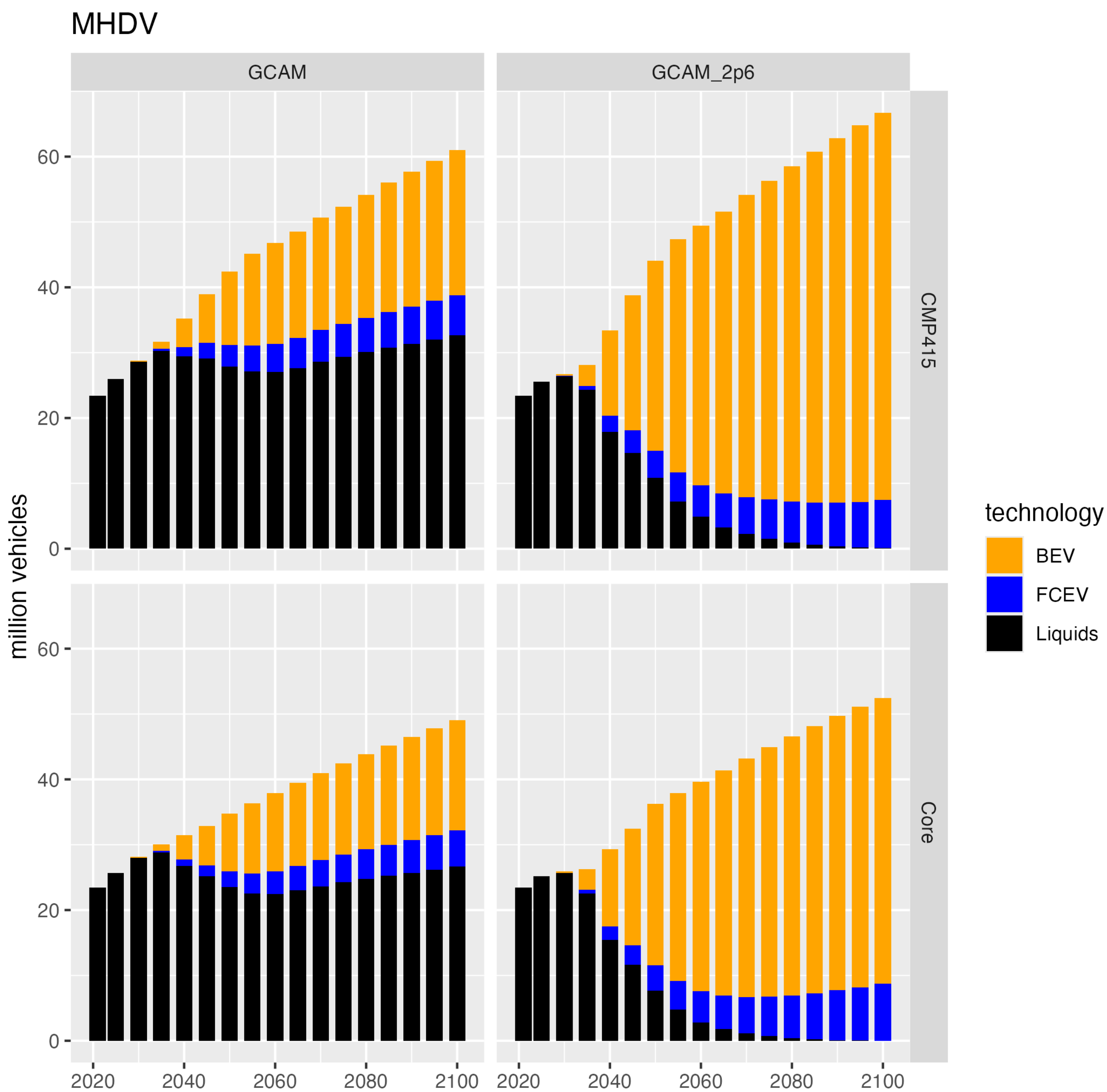


Figure 15. US light-duty vehicle (LDV; left) and medium and heavy duty vehicle (MHDV; right) stocks by scenario.

Hydrogen

The update to the techno economic data throughout the hydrogen module causes hydrogen production and demand to decrease slightly in the Ref and more significantly in the Ref_2.6 scenario; note that this Ref reduction is sensitive to the share-weights assumed for fuel cell vehicles, described above. In studies allowing the fuel cell trucks to compete evenly, the hydrogen demand would increase compared to the Core. The reduction in demand in the Ref_2.6 scenario is largely due to the costs of liquefied hydrogen; where the core model's hydrogen commodity to aviation and maritime end users was gaseous, in the revised scenarios these uses can only take liquefied hydrogen, which is less price-competitive against biofuels for these end uses.

Comparing against the literature, these CMP415 scenarios are still within the bounds of future estimated hydrogen deployment, for both baseline and mitigation scenarios (Zare et el. 2025). In the USA, the scenarios have between 10 Mt (Ref) and 12.5 Mt (Ref_2p6) of hydrogen in 2050, as compared with the 12 Mt/yr in the 2025 Annual Energy Outlook (Table 71), and the 50 Mt/yr target for 2050 in the U.S. National Clean Hydrogen Strategy and Roadmap. Globally, the CMP415 scenarios have between 83 and 117 Mt in 2050, and between 186 and 392 Mt/yr in 2100, for the Ref and Ref_2p6 scenarios, respectively. Note that the definitional boundaries in GCAM still exclude conventional hydrogen use in petroleum refining and ammonia production. As such, even with the reduction from the core model, the scenarios still imply a significant build-out of novel hydrogen production and use to 2050.

Shifting focus to the production technologies, the hybrid option delivers far less output than the original standalone wind and solar technologies (Figure 16, right). In small part this result is predictable from the red-bus-blue-bus issue in logit choice modeling, because in this proposed revision, two subsectors (wind, solar) are collapsed into one (hybrid). However the reduction in renewable electrolysis in the scenarios is overwhelmingly due to comparatively higher producer prices (Figure 17), which themselves are mostly due to incorporation of a more realistic characterization of the technologies, to include the costs of electricity curtailment. In the core model, the renewable hydrogen costs are based on electrolysis costs from H2A, and the costs of producing renewable electricity, with no assumed electricity curtailment, even though the technologies are parameterized around an approximate 5:3 capacity sizing ratio that comes from the optimization literature and current industry practice (i.e., a renewable hydrogen production facility has 5 MW of electricity generating capacity for every 3 MW of electrolyzer capacity). In the revised representation, the renewable electrolysis ("hybrid") technology curtails about 12% of electricity generated due to this oversizing, which increases the costs of this technology as compared with the prior representation which did not consider these losses.

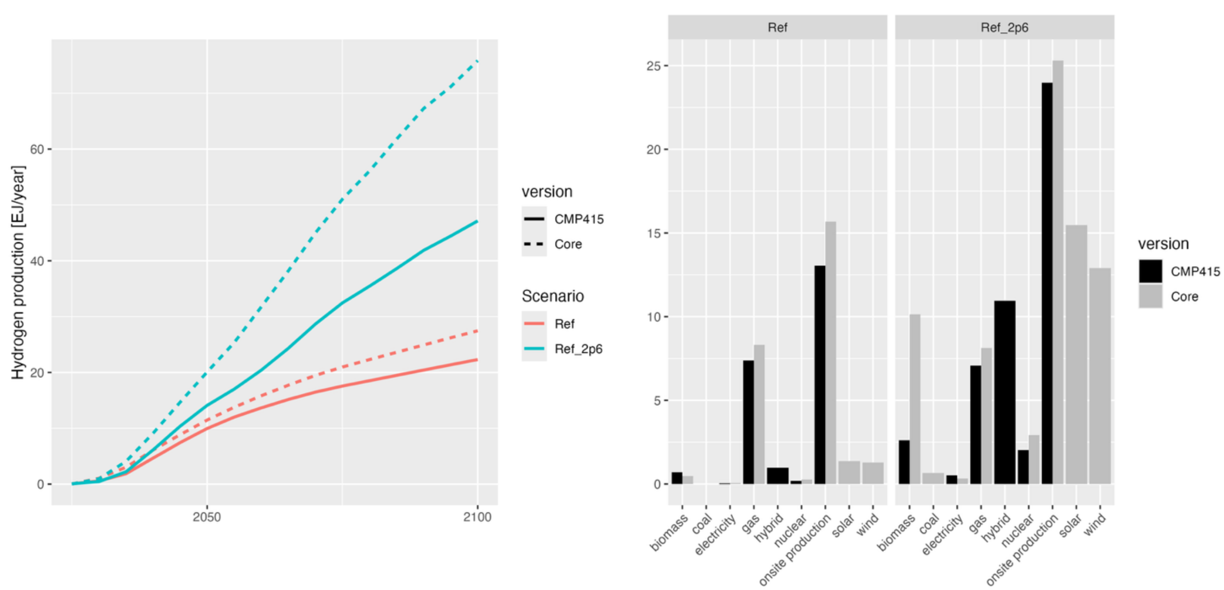


Figure 16. Hydrogen production over time under scenarios "Ref" and "Ref_2p6" (left side) and hydrogen production in 2100 by subsector under scenarios "Ref" and "Ref_2p6" (right side).

Updating the techno-economic data generally did not make renewable hydrogen comparatively cheaper than gas-based hydrogen via steam methane reforming (SMR), in any of the GCAM regions in the Reference scenario (Figure 17). The main driver of GCAM's divergence from H2A-Lite on the costs of renewable hydrogen is financing assumptions for producing renewable electricity, which are inherited from GCAM's power sector. Under H2A-Lite's assumptions (which are consistent with the Electricity ATB), PV producer prices for electricity supplying electrolysis fall below two cents per kWh starting around 2035, resulting in hydrogen producer prices that fall below $3 per kg. In GCAM, the PV and wind electricity producer prices are between 2 and 3 times higher in all years than what is seen for the levelized cost of electricity in ATB or H2A-Lite. Even still, in H2A-Lite, the natural-gas based technology remains cheaper than hybrid electrolysis, in most regions, scenarios, and years. Note also that GCAM has higher natural gas prices than are assumed in H2A-Lite, so the costs of natural-gas based production in GCAM are higher than in H2A-Lite.

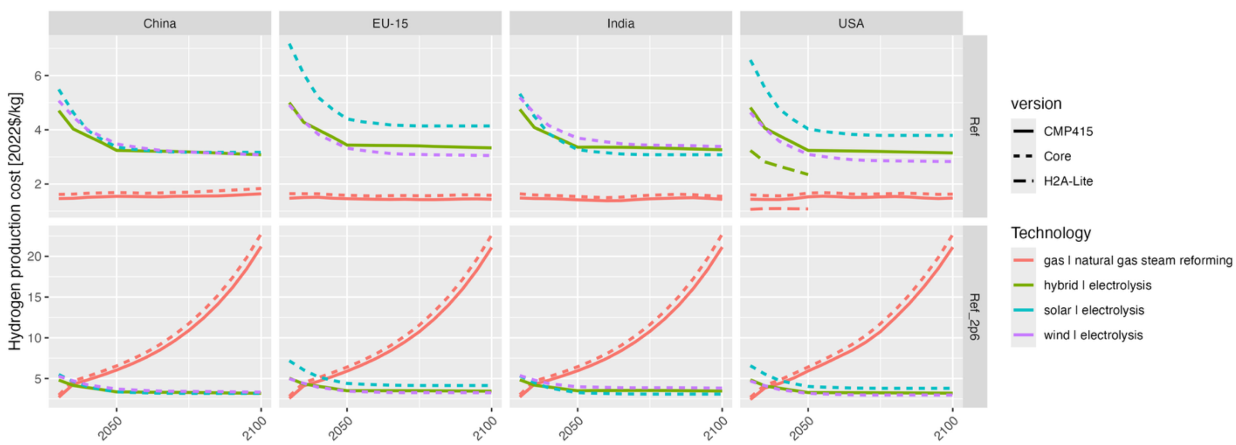


Figure 17. Production costs of select hydrogen production pathways in four GCAM regions, scenario "Ref" versus "Ref_2p6".

The global water demand in the Reference scenario is pretty similar between versions, though the "Ref_2p6" scenario sees a reduction in water (Figure 18, left), consistent with the global production volumes shown in Figure 16. Due to updated NO_x emission intensities and increased natural gas-based hydrogen production, total NO_x emissions in the hydrogen sector are higher in CMP415 than in the current core model (Figure 18, right).

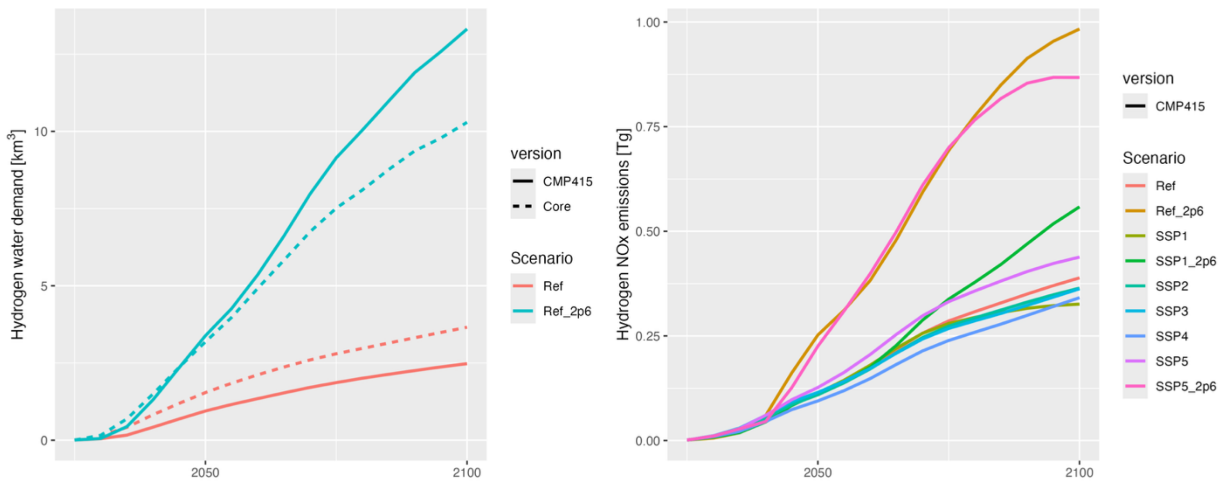


Figure 18. Global water demand of hydrogen production by scenario (left side) and NO_x emissions from industrial hydrogen combustion by scenario (right side). Note that NOx emissions from industrial hydrogen use was not represented in the Core version.

Industry

Across the industrial sector, the differences are generally minor but can be traced to different fuel prices, for the most part. The CMP415 revision scenarios have more electricity use due to lower electricity prices, and less natural gas and refined liquids (Figure 19, right panel). Given the assumed efficiency differences between these fuel options, this switch results in lower total final energy (Figure 19, left panel). Because the proposal only updates techno-economic assumptions in the ammonia and iron and steel subsectors, the following sections will address these industries specifically.

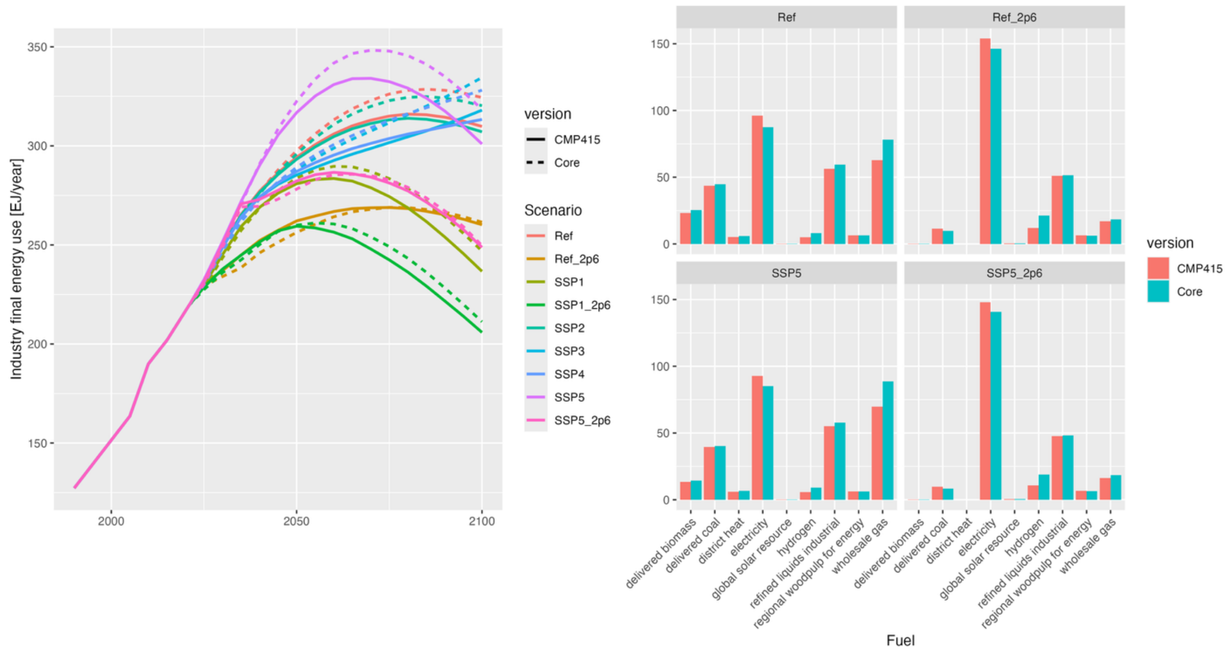


Figure 19. Final industry energy use by scenario (left) and final transport energy use by fuel in 2100, scenario "Ref" versus "Ref_2p6" and "SSP5" versus "SSP5_2p6" (right).

Ammonia

Ammonia production costs are slightly lower in CMP415, reflecting changes in non-energy production costs and potential shifts in input energy prices, including gas and hydrogen (Figure 20, left). A key driver of the reduced natural gas consumption in the industry sector (as seen above) is the strong shift from gas to hydrogen in ammonia fertilizer production (Figure 20, right), resulting from the updated integration of hydrogen into the ammonia market. Note that in the reference scenario most of the purchased hydrogen is itself produced from natural gas (see producer prices in Figure 17), so backed out to primary energy, this switch doesn't really entail a switch in fuels, in the reference scenario.

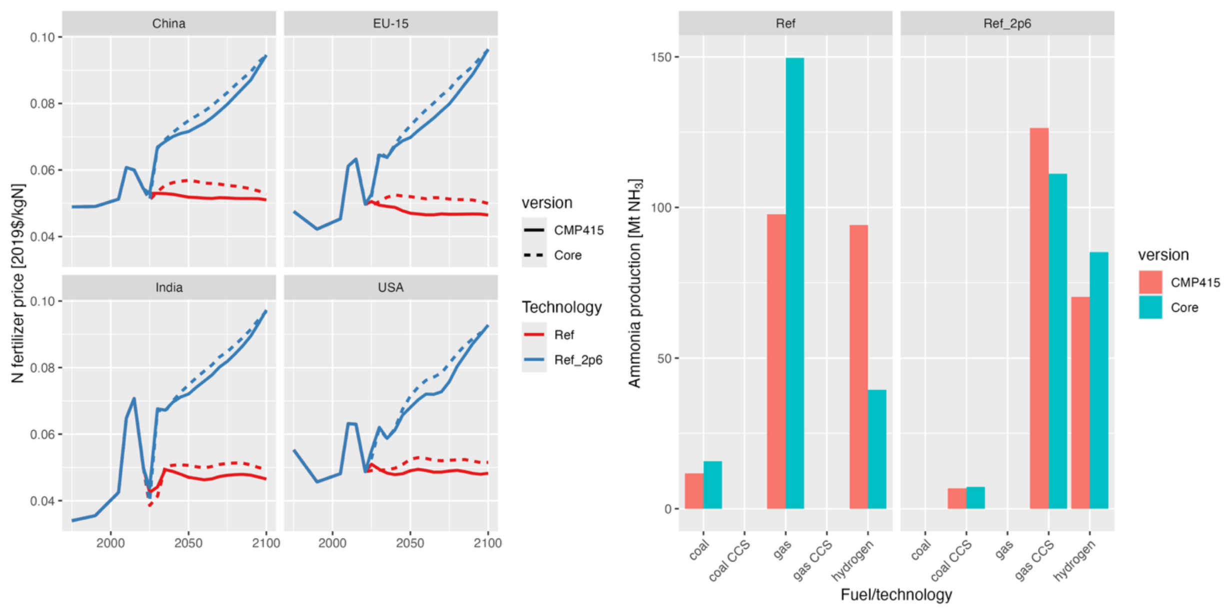


Figure 20. Nitrogen fertilizer price in four select GCAM regions, scenario "Ref" versus "Ref_2p6" (left side) and ammonia production by fuel/technology in 2100, scenario "Ref" versus "Ref_2p6" (right side).

Iron and steel

Iron and steel production overall is only slightly affected by the proposed changes relative to the core model (Figure 21, left). The distribution of production does show some differences, most notably a reduction in EAF with DRI in favor of BLASTFUR and EAF with scrap by 2100 in both the "Ref" and "Ref_2p6" scenarios (Figure 19, central panel). Energy inputs are generally lower (Figure 21, right), reflecting updated energy intensities in line with Table 7 above as well as shifts in production compared to the core model.

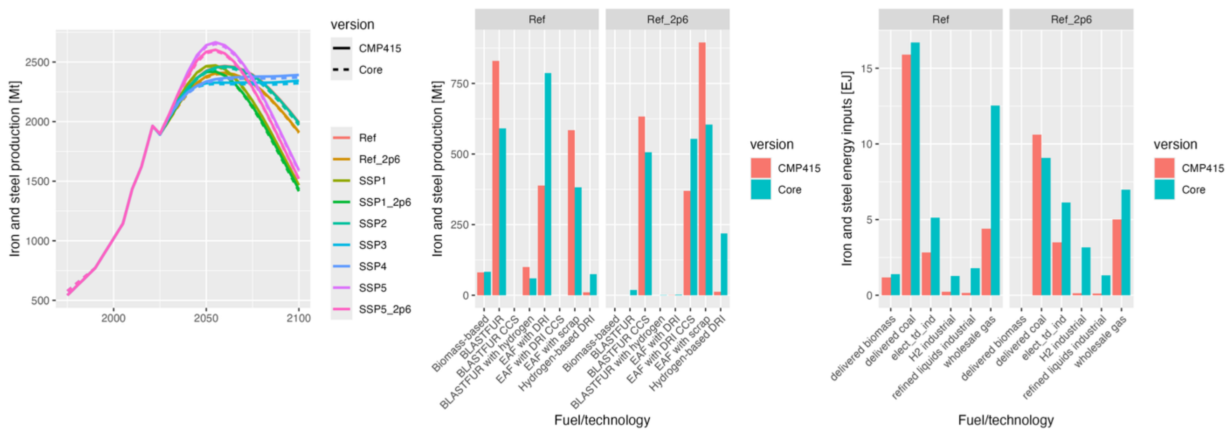


Figure 21. Iron and steel production production by scenario (left side), iron and steel production by fuel/technology in 2100, scenario "Ref" versus "Ref_2p6" (center) and inputs into iron and steel production by fuel in 2100, scenario "Ref" versus "Ref_2p6" (right side).

US Buildings

The high-level results from the US building sector show a general reduction in total final energy in the CMP416 revision, despite identical floorspace quantities between the revisions (not shown). In a policy scenario, the revised scenarios have similar amounts of fuel-switching, away from natural gas and refined liquids towards electricity. This proposal does remove hydrogen as an end-use fuel in the US building sector, which is consistent with the current DOE literature (e.g., it isn't in the 2025 Annual Energy Outlook's residential or commercial sector's energy demands in Tables 4 and 5, and the Hydrogen Roadmap does not include buildings among 18 potential hydrogen end uses shown in Figure 41). If the outlook changes on this fuel option, it could be re-added at a later date, but right now there doesn't appear to be much reason to represent hydrogen as an end-use fuel in the US building sector. To the extent that hydrogen blending into natural gas pipelines will be modeled, this would be implemented upstream of the building sector (e.g., in the "delivered gas" sector). As there is some interest in this option outside of the United States (e.g., IEA 2019), this proposal does not remove it as a technology option for the non-US regions.

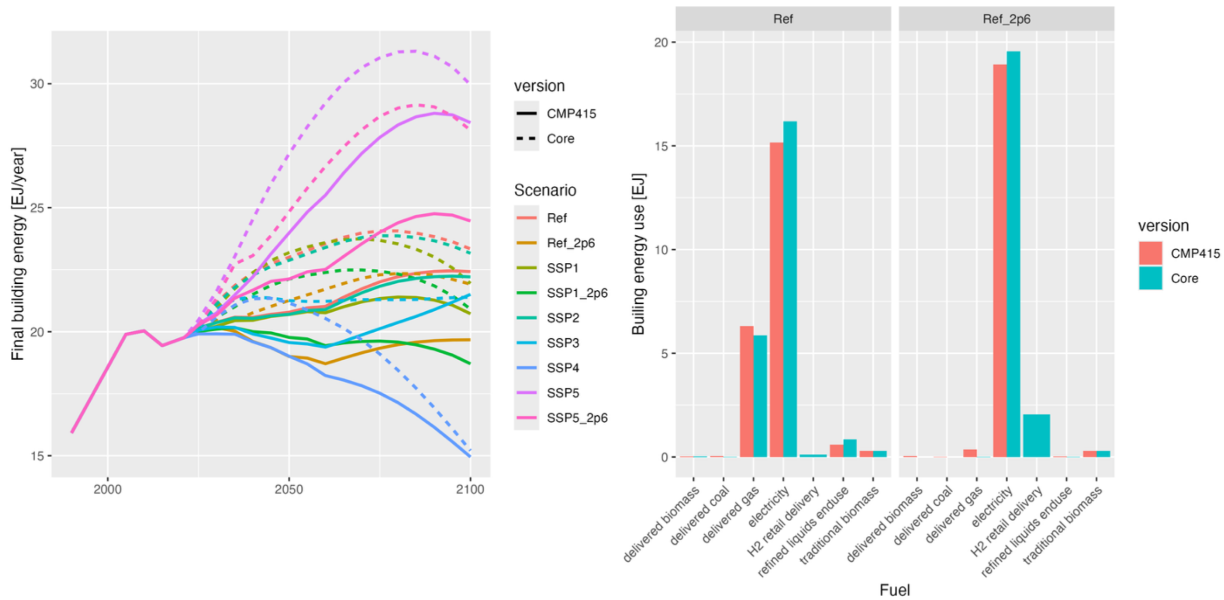
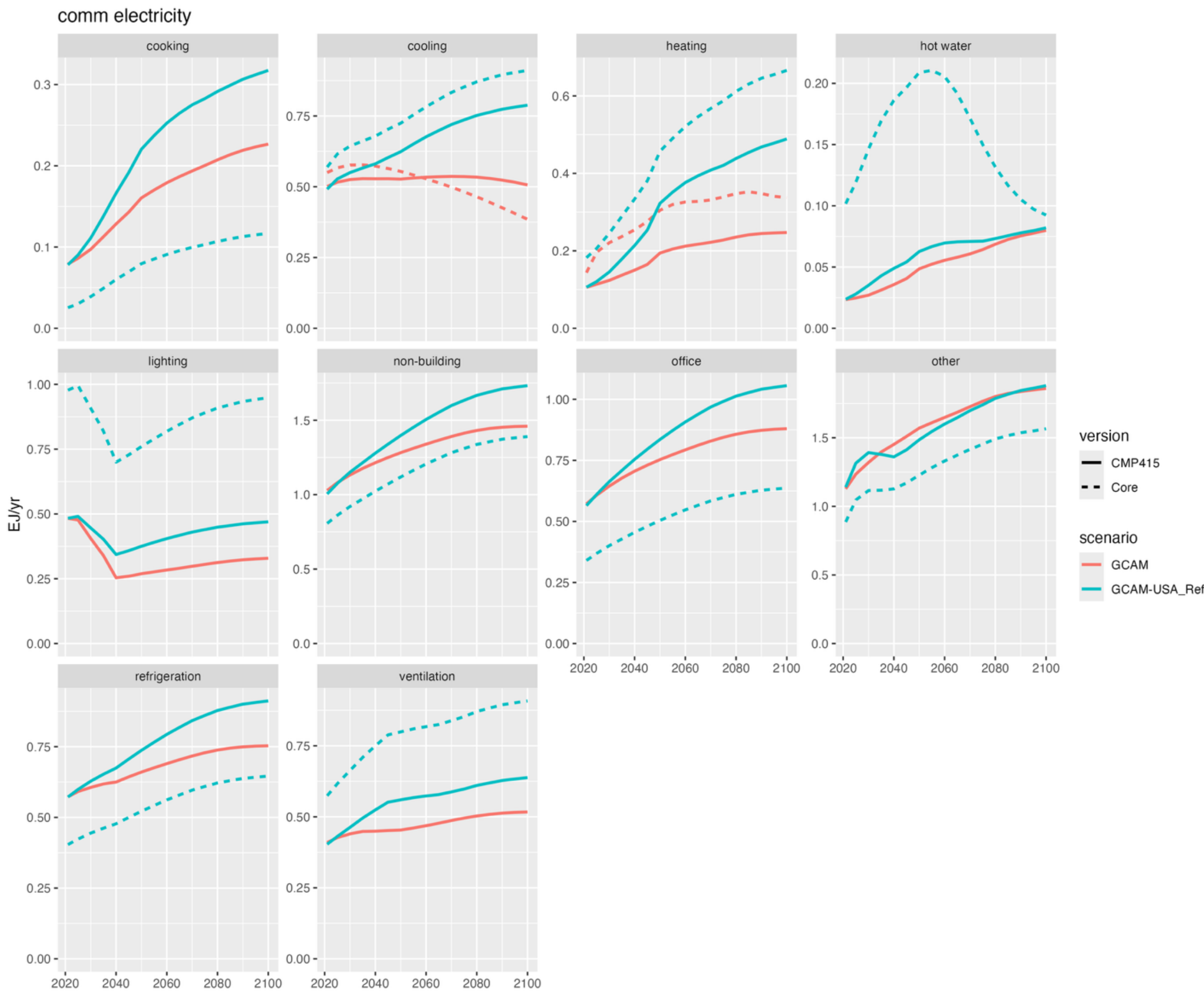


Figure 22. U.S. building energy use by scenario (left side). U.S. building energy use by fuel, "Ref" versus "Ref_2p6" in 2100 (right side).

Figure 23 presents energy use by each sector (residential, commercial) and main fuel (electricity, natural gas), showing the trajectories of energy use by each individual service over time. From the Core version, “GCAM” scenario, only the heating and cooling energy demands are shown; “others” from this scenario are not included as this category includes the sum of all other services. The figures show a number of points of divergence between the USA region in the standard configuration (red), and the sum of 50 states and Washington DC in GCAM-USA (blue). This proposal does not set out to harmonize these two model configurations, or address these points of divergence, which were already present for the heating and cooling services in the core model. In fact, within these services (where such a comparison can be made), the CMP415 scenarios have less divergence than the core. The sources of the divergence could be different assumptions about heating and cooling degree days, building shell conductance, building floorspace, building technology costs and performance, or even exogenous assumptions such as population and GDP. GCAM-USA is not intended as a downscaling of the USA region of the standard configuration; it is its own separate representation, and as such, many of the basic variables governing future energy demand differ between these two configurations.

Regarding the differences shown in Figure 23, comparing GCAM-USA between the two model versions (blue series, solid vs. dotted lines), the biggest differences simply relate to different base year calibration. Future trajectories are generally the same, with the exception of electricity used for commercial water heating, which has a peak and decline pathway in the core model that is not replicated in the CMP415 runs. Many of the fuel and service pathways are characterized by non-monotonic trends, often with sharp declines in energy consumption to 2030 or 2040. In general these are driven by the assumptions in gcam-usa/A44.globaltech_eff.csv, which are not revised in this proposal.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cooking
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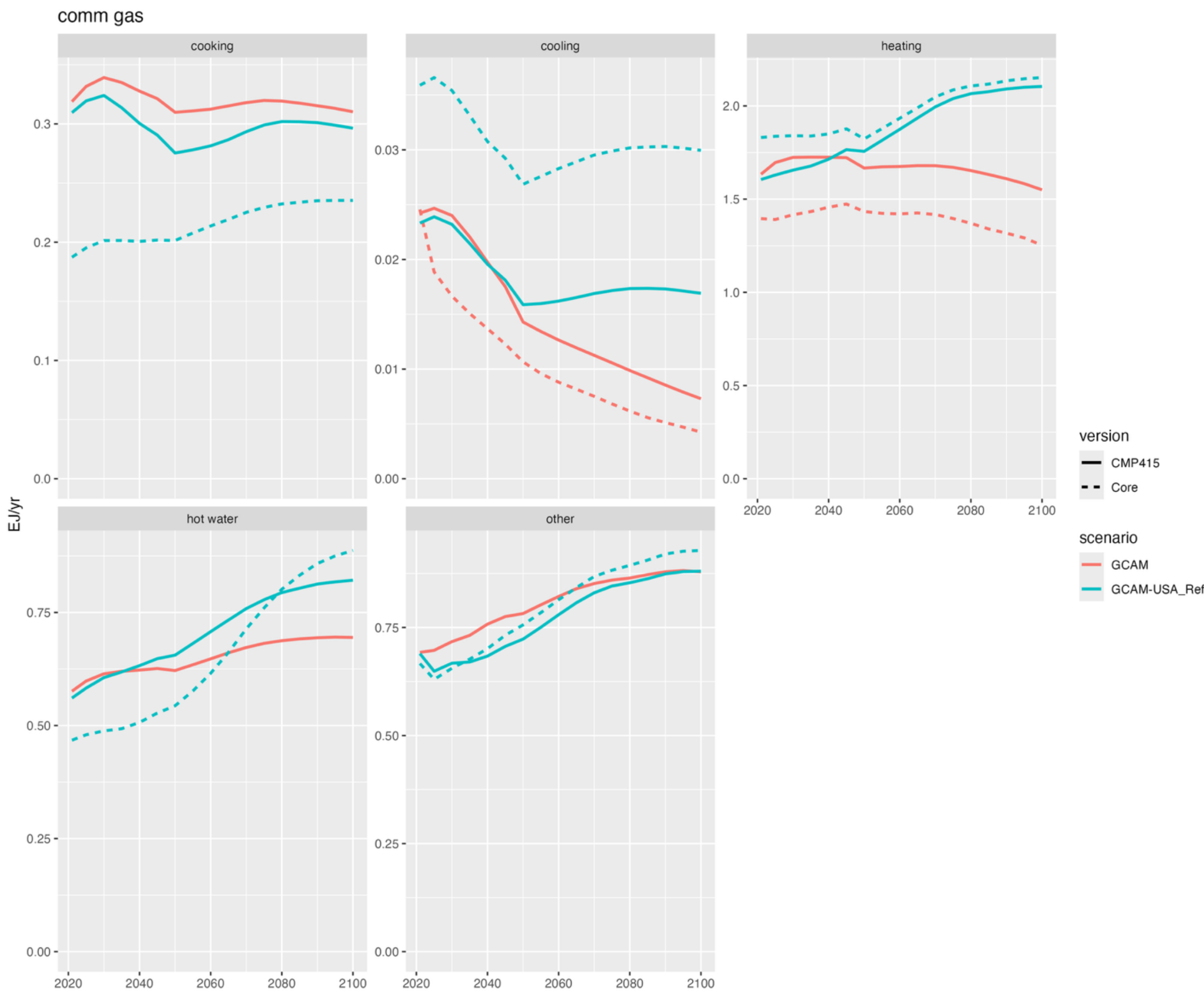
GCAM
GCAM-USA_Ref



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cooking
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other
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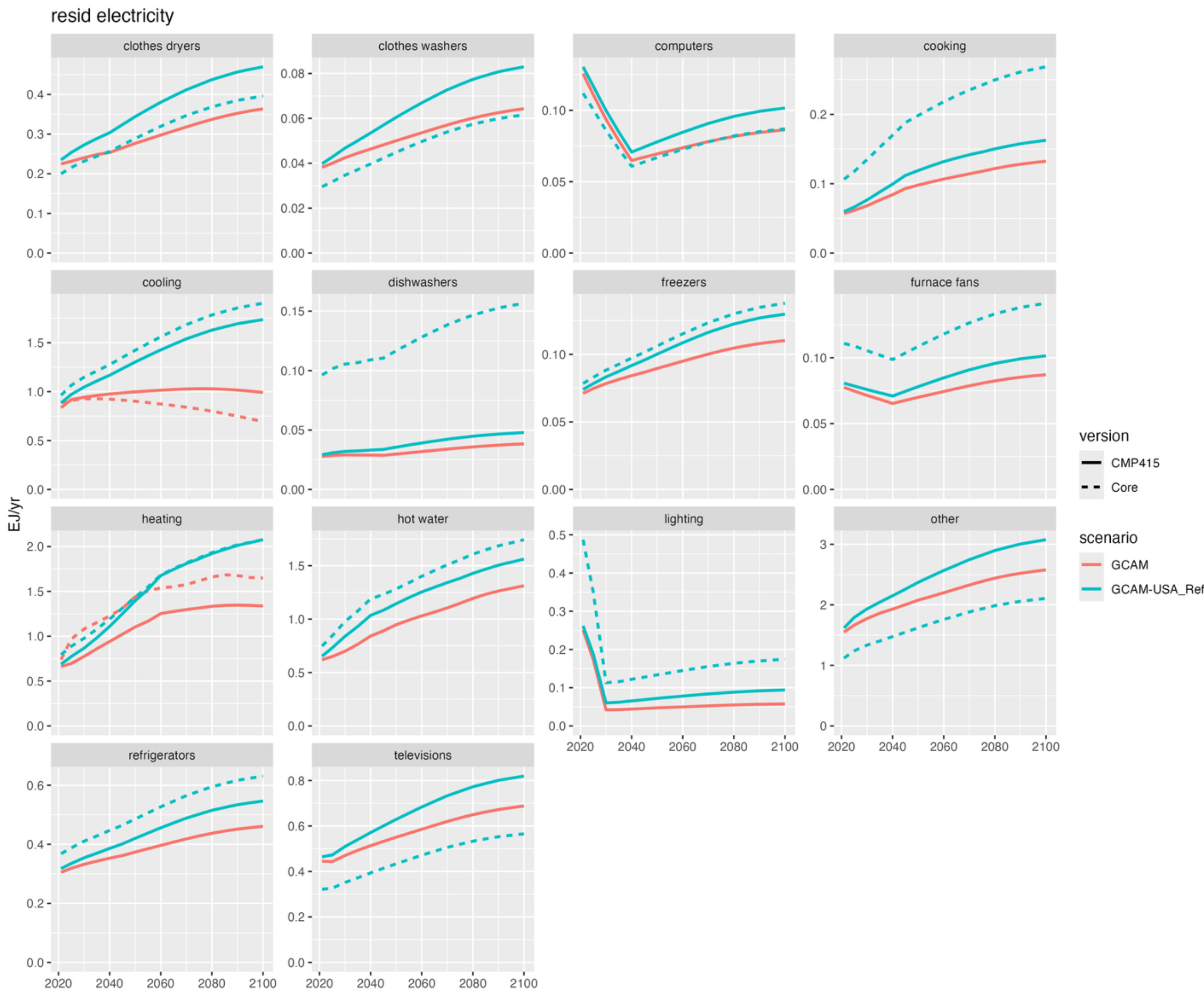
GCAM-USA_Ref


resid electricity
clothes dryers
clothes washers
computers
cooking
cooling
dishwashers
freezers
furnace fans
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refrigerators
televisions
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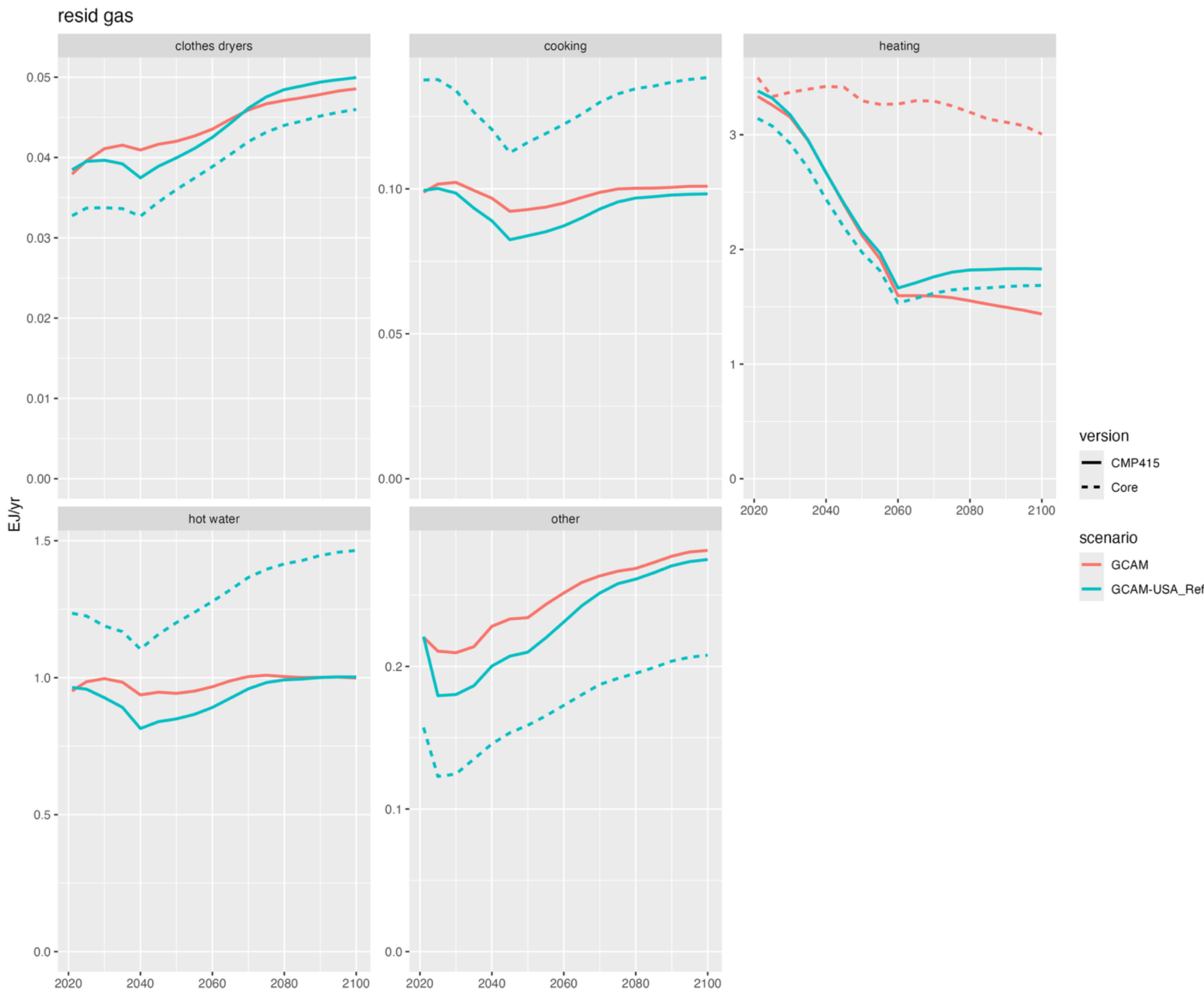


Figure 23. U.S. building energy use by sector (commercial, residential), main fuel (electricity, gas), and service (individual panels of each plot)

GCAM-USA

Total final energy in the standard testing scenarios for GCAM-USA follows generally the same trends as before (Figure 24), with the most significant exception being the transportation sector, where the LDV efficiencies are higher so energy demand is lower than the corresponding Core scenario in all future periods. Within buildings, even though there were significant changes to the allocation of energy to the services in calibration, which resulted in different long-term energy consumption quantities by service in some cases, the whole sector's consumption of energy is reasonably similar to before. The net ~3% increase in total final energy that is seen across the whole sector (in going from Core to CMP415 scenarios, in 2100) is largely attributable to the shift of electricity towards “commercial other” (including "commercial non-building") in the calibration data. That is, having an increased amount of energy allocated to this fast-growing and large service in the base year results in a long term increase in energy demand for the whole sector. Industry does not have any noteworthy differences at this scale.

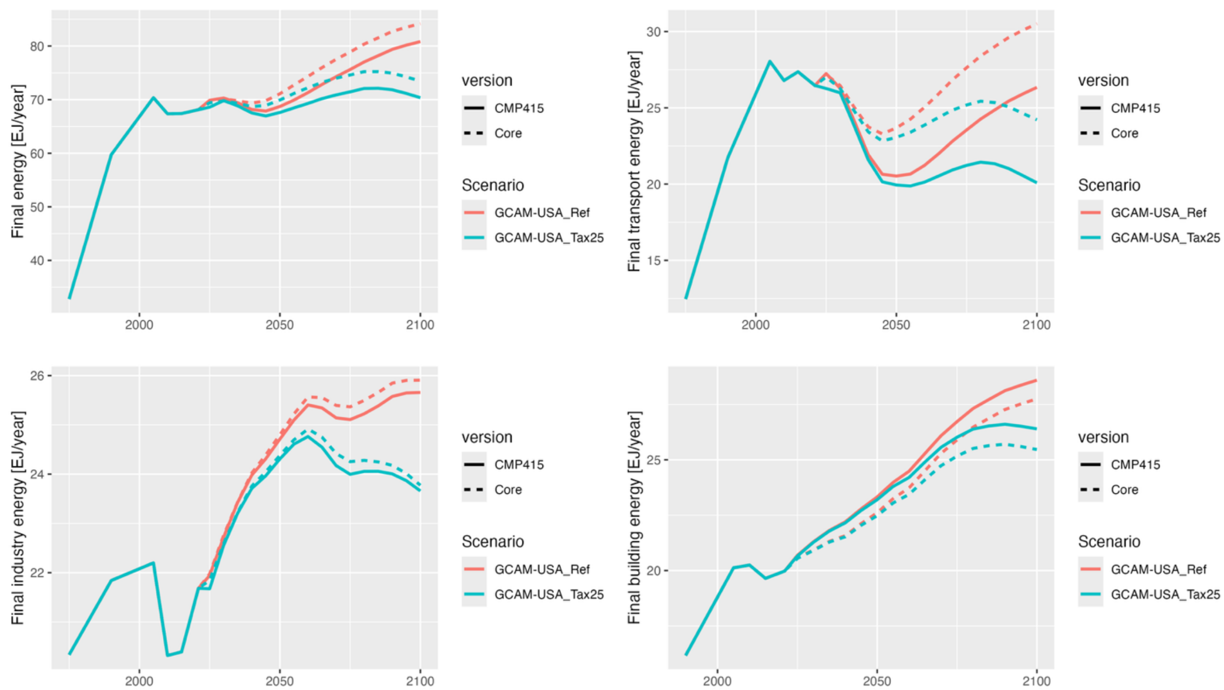


Figure 24. Energy demand in the U.S. region (sum of all states) by scenario, modeled with GCAM-USA, shown as total (top left) and by aggregated end-use sector (transport, industry, and buildings).

Electricity

Figure 25 shows the global electricity generation by technology, across the standard testing scenarios. Several major differences from the core model are worth highlighting up front. First, the proposal involves an approximate doubling in utility solar (range: +50% to +120% in 2100), while also reducing rooftop PV by about 90% (range: -84% to -92% in 2100). The increase in utility solar is entirely driven by utility PV, whose costs are decreased largely because of the capacity factor update (see Figure 9 for the capital cost difference, and Table 11 for the capacity factor revision). The reduction in rooftop PV is because of (1) the increase in estimated costs of this technology, due to higher costs in the 2024 ATB than the 2022 ATB, and because the CMP415 set uses the ATB assumptions to 2050 rather than an internal projection; and (2) reduced prices of centrally produced electricity in general make rooftop PV less cost-competitive in the elect_td_bld sector. The net impact is an increase in total solar electricity generation (sum of rooftop PV, utility PV, and CSP) by between 11% (SSP1_2p6) and 49% (Reference).
Due to the revisions in nuclear reactor costs in the 2024 ATB, as well as the inclusion of small modular reactors in GCAM, the standard validation scenario set also sees significant increases in

nuclear power generation in all scenarios. In 2100, increases range between 14% (SSP1_2p6) and 76% (SSP5), with one scenario (SSP4) that sees a factor of 4.5 increase.

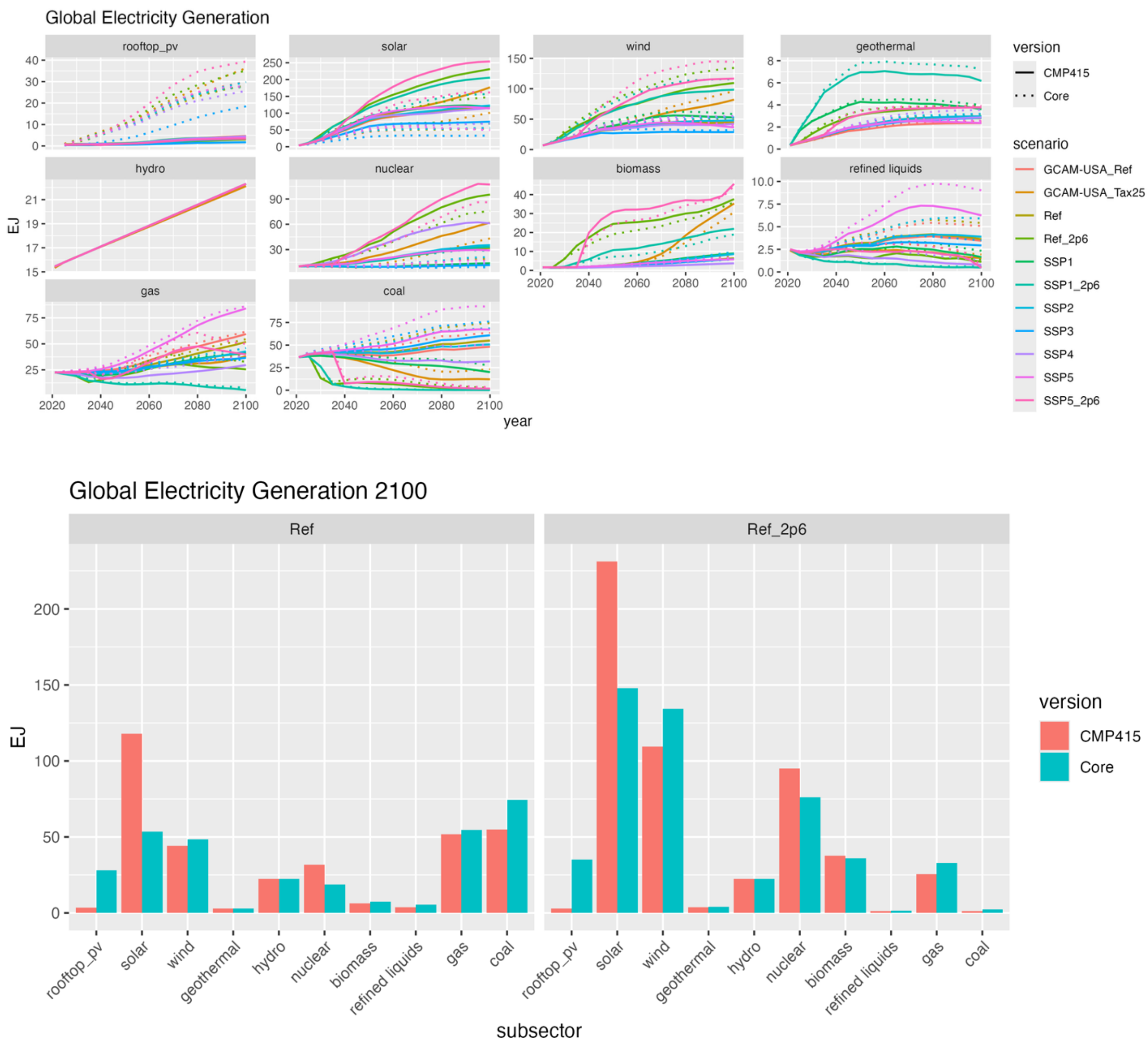
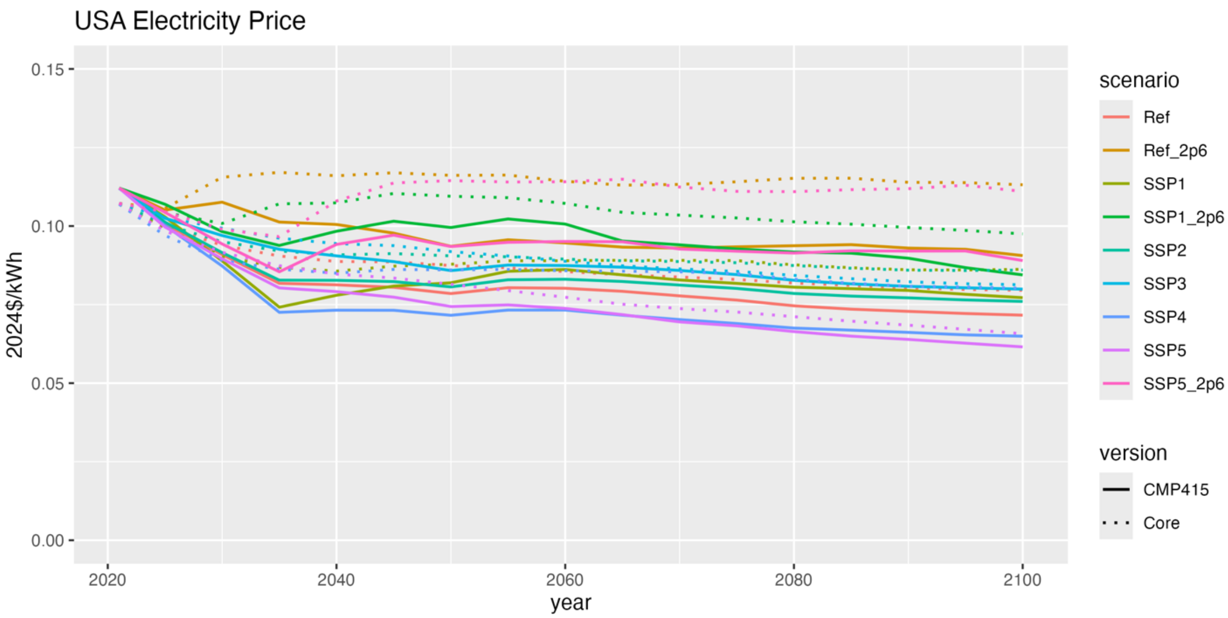


Figure 25. Global electricity generation by year, technology, and scenario (top panel), and by technology in 2100 in the Ref and Ref_2p6 scenarios (bottom panel).

The Core-to-CMP415 increases in generation by solar PV and nuclear are complemented by modest reductions in coal, gas, and wind, but all CMP415 scenarios have more total electricity generation than their corresponding Core scenarios. Specifically, in 2100, the increases in total electricity generation range from 1% (SSP1_2p6) to 10% (SSP4). These increases are driven by an overall reduction in average costs of electricity generation, which induces an increase in demand from all end-use sectors. Electricity producer prices are shown in Figure 26 for the USA, China, and India. All of the CMP415 revision scenarios are characterized by a decrease from the corresponding Core scenario, by between 5% and 20% in 2050.


USA Electricity Price
0.15
0.10
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0.00
2024$/kWh
2020
2040
2060
2080
2100
year
scenario
Ref
Ref_2p6
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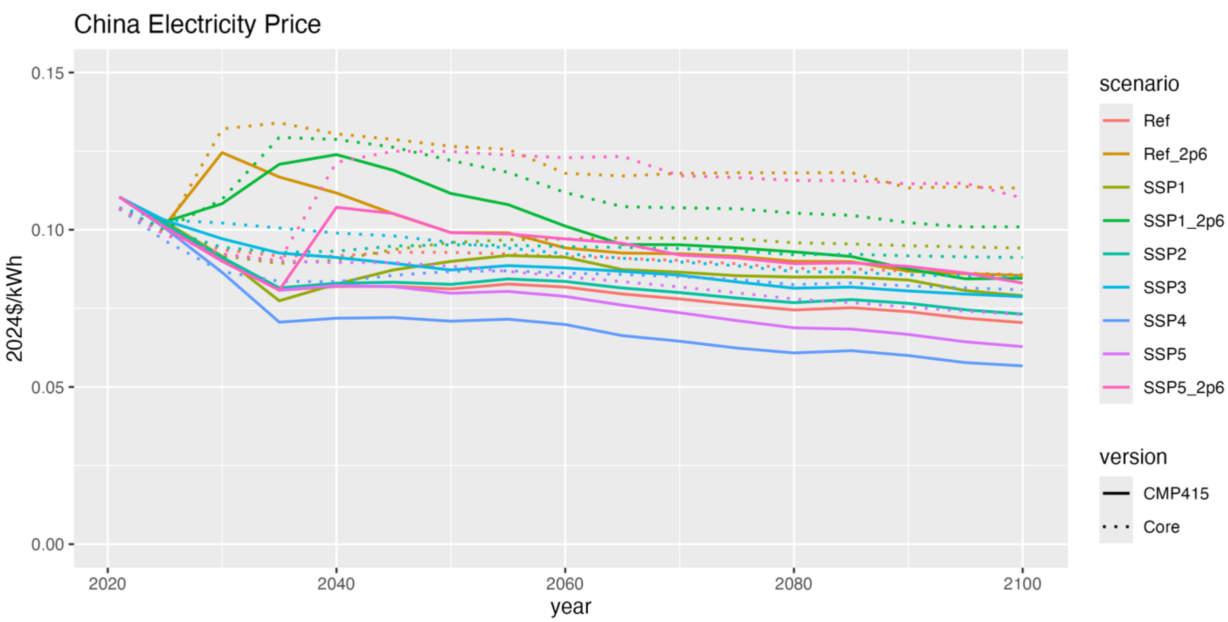
version
CMP415
Core


China Electricity Price
0.15
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2024$/kWh
2020
2040
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2080
2100
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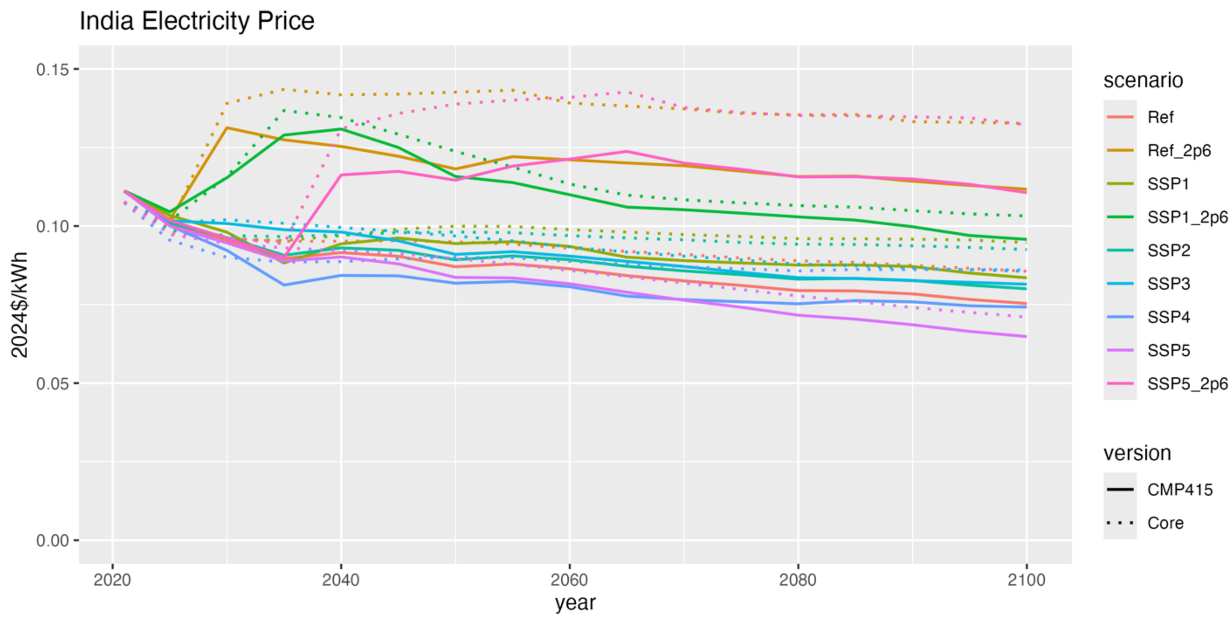

Figure 26. Electricity producer prices ("electricity" sector in the model) in selected regions, 2021 to 2100, across the testing suite

Because so much of the behavior regarding electricity in the model is anchored to calibration-derived share-weights, it is also worth paying attention to the change in electricity prices from the model base year. That is, future fuel choices in most sectors of the model are responsive to fuel price changes from the calibration year. Figure 27 focuses on the 2050 time period, because it is the final year of the ATB dataset, and because the price changes in the post 2050 years are comparatively minimal to the 2021-2050 changes. Figure 27 isolates these changes, for the three regions shown above. In general, the regions see similar patterns in their differences between scenarios (e.g., highest prices in Ref_2p6, greatest reductions in SSP4 and SSP5), and between model versions (CMP415 is always lower than Core). For the most part, the decrease from Core to CMP415 is driven by the reduced levelized costs of solar PV. While this reduction in electricity producer prices as compared with the Core scenarios is significant, it is nevertheless mitigated by GCAM's fixed charge rates. Had the scenarios harmonized to the levelized cost of electricity rather than the capital and O&M costs of the 2024 ATB, these changes would have been far more dramatic.

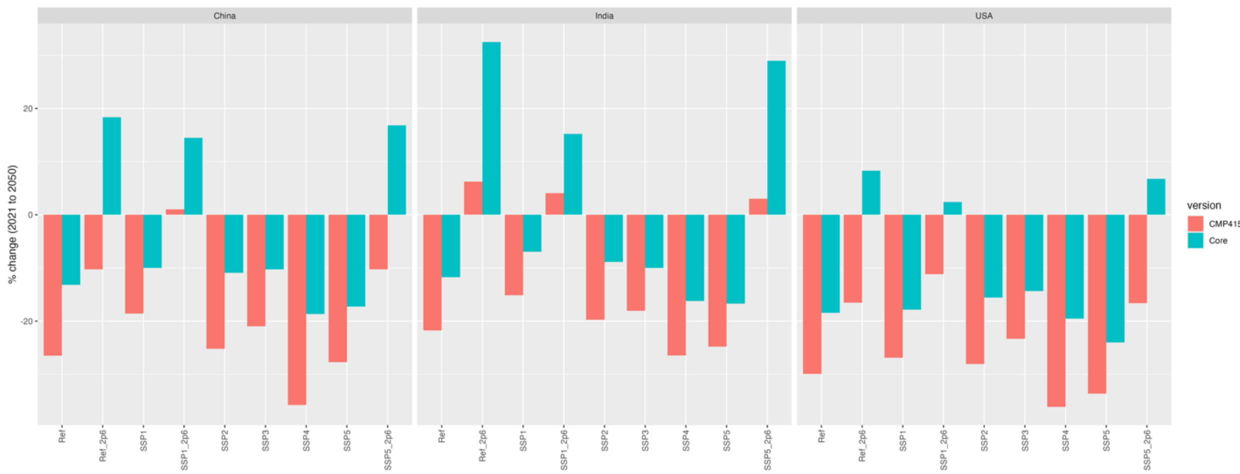

Figure 27. 2021 to 2050 electricity price differences by scenario in China, India, and the USA.

Figure 28 shows one final comparison: global PV installed capacity in these CMP415 scenarios (rooftop PV plus utility PV), compared with 3 external projections: the IEA's Net Zero by 2050 scenario, the IRENA REMAP scenario, and the 25th, 50th, and 75th percentile of the scenarios in the AR6 database. Rather than comparing against the current core model, the purpose of this last figure is to check, given the increase in global PV electricity production, that the GCAM scenarios are reasonable in the context of scenarios published in the literature. Interestingly, in 2050 the GCAM Ref scenario is pretty similar to the AR6 median, and by 2100 it is slightly below the 25th percentile. The GCAM Ref_2p6 scenario tracks the AR6 75th percentile to 2050, and by 2100 is more or less on par with the median in the database. There does not seem to be any issue with the values projected from this core model proposal being too high compared to the literature.

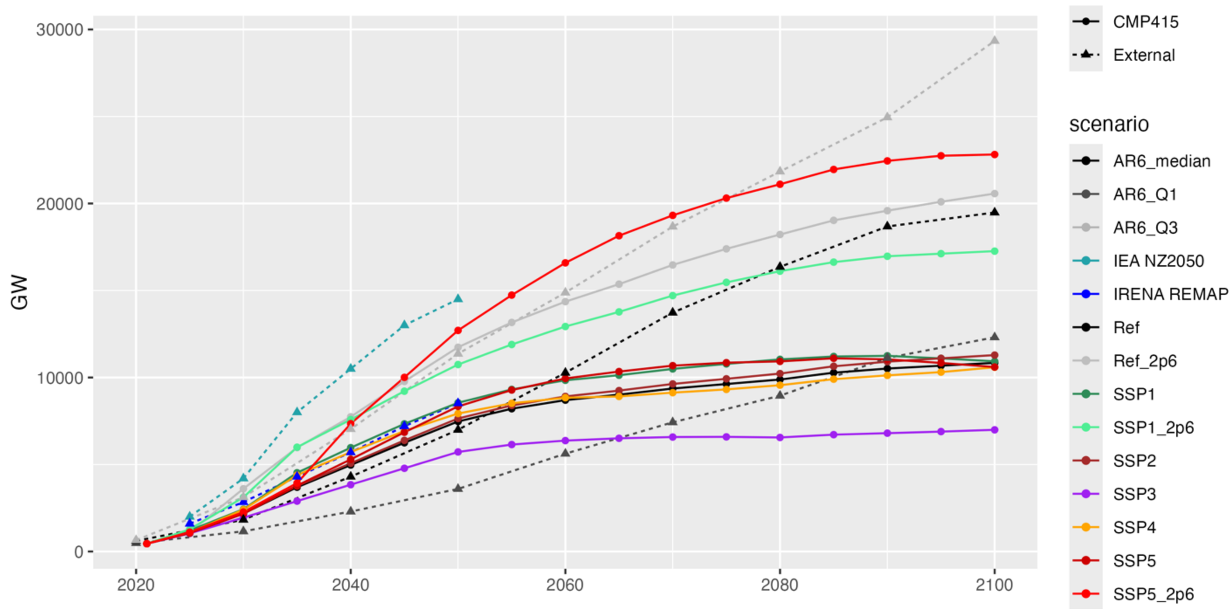

Figure 28. Global PV installed capacity, comparing the CMP415 scenarios (solid lines, circles) to various literature projections (dotted lines, triangles)

Conclusions

This proposal implements a large number of changes to the techno-economic assumptions of key energy system technologies throughout the model. However, at a global level the changes in capacity factors of utility PV, along with a modest reduction in utility PV capital costs, are by far the most impactful. These changes result in a reduction in electricity producer prices of about 10% from the core model in most regions and scenarios between 2050 and 2100 (Figure 26). These significant reductions in costs are seen despite PV in GCAM (CMP415 scenarios) having about 2.5x higher levelized costs than the 2024 ATB, due to GCAM's higher fixed charge rates.