Minimizing emissions from grid-based hydrogen production in the United States: Supplementary Information

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1. Supplementary Note 1: Model Input and Results Data

All GenX input and results data relevant to this work are available in a repository https://doi.org/10.5281/zenodo.7141069. Data for each modeled scenario is contained within a folder in the main directory, using the naming convention [Clean Energy Matching Regime]_[Model Year]_[Electrolyzer Zone]_[Electrolyzer Capacity]_[Hydrogen Sales Revenue]kg_[Additional Descriptors]. Clean energy matching regime tags include 'BaseCase' (the No Policy regime), '100AM' (the 100% Annual Matching regime), '100WM' (the 100% Weekly Matching regime), '100CFE' (the 100% Hourly Matching regime), and '100SRME' (the Net-Zero SRME regime). The 'BaseCase_2030_noload' folder contains the baseline system without any added electrolysis demand. The 'Scripts' folder contains plotting scripts and copies of all figures used in this work. The 'SRME Iterations' folder contains intermediate runs used to calculate short-run marginal emissions time-series for each SRME case. Each case folder in the main repository contains 'Inputs' and 'Settings' folders, which contain GenX inputs and are described further in the GenX GitHub repository: https://github.com/GenXProject/GenX. All model outputs are contained in the 'Results' folder and are also described in detail in the GenX documentation. Input and results files marked 'tfs' are part of the 24/7 Carbon-Free Electricity GenX module, which will be included in an upcoming open-source release of GenX.

2. Supplementary Note 2: LCOH Calculation

We calculate the levelized cost of hydrogen in this study via the following equation:

$$LCOH = \left(\frac{CAPEX \times (FOM + CRF) + C_{grid}}{CF \times 8760} \right) / Eff_{el}^{H_2} + \frac{C_{el}^{Tot}}{H_2^{Tot}} \tag{1}$$

where $CAPEX$ is the total installed capital expenditure per kW of the electrolyzer system, FOM is the total fixed O&M costs given as an annual percentage of CAPEX, CRF is the capital recovery factor, C_{grid} is the cost of a transmission-level grid connection, CF is the electrolyzer capacity factor, C_{el}^{Tot} is the total cost of sourcing input electricity, and $Eff_{el}^{H_2}$ is the electrolyzer efficiency. Values for these and other input parameters are provided in Table 1 in the main text. We calculate the cost of input electricity for hydrogen producers as:

$$C_{el}^{Tot} = \sum_{t}(L_t^{H_2} \times P_t) + (C_{NE} + C_{TL} - R_C + C_{ESR} + C_{Bat} + C_{CFE}) \tag{2}$$

where P_t is the local price of bulk electricity (including generation and capacity costs) at timestep t, C_{NE}, C_{TL}, R_C, and C_{ESR} are the hydrogen producer's shares of the local cost of network expansion, transmission loss cost, congestion revenue, and cost of compliance with state energy share requirement policies, respectively, C_{Bat} is the cost of onsite battery storage, and C_{CFE} is the cost of purchasing EACs to meet any hydrogen-specific policy requirements. This cost formula assumes that all clean energy purchases are in the form of EACs. Costs with long-term PPAs will be less than or equal to the costs with EACs, as procurers may be able to capture excess generator rents in the form of lower PPA prices or secure lower average purchase price by providing generators with greater revenue certainty.

3. Supplementary Note 3: SRME Calculation

Short-run marginal emissions (SRMEs) reflect the impact of an incremental change in electricity demand at a given point in space and time on total electricity system emissions. They reflect only short-run impacts, i.e. on the electricity system as it exists at a given point in time. In the long-run, consistent marginal changes in demand may also have impacts on capacity investment and retirement decisions, leading to an often different long-run marginal emission rate. Because long-run marginal emissions cannot be measured in the real world, we focus only on SRME accounting as a possible means of mitigating hydrogen's embodied emissions in this paper.

SRMEs can be calculated via multiple methodological approaches, some of which can provide very different results.‡ In the real world, SRMEs are often calculated empirically using the emission rate of the 'marginal generator,' the specific unit that would need to increase its output to supply a marginal increase in load. In this work we calculate SRME time series for each case by measuring the change in hourly system-level emissions between pairs of GenX runs. In the initial run, the system is allowed to optimize electrolysis operations and energy procurements given an initial assumed SRME time series. We then conduct a 'perturbed' run, in which all technology capacities are fixed at their final values from the initial run and the load in the target zone is increased by 1 GW (a similar order of magnitude to the impact of electrolysis operational decisions). We calculated updated hourly SRMEs as the difference in system-level

‡ Ryan NA, Johnson JX, Keoleian GA. Comparative Assessment of Models and Methods To Calculate Grid Electricity Emissions. Environ Sci Technol. 2016 Sep 6;50(17):8937-53. doi: 10.1021/acs.est.5b05216.

emissions between the initial and perturbed cases, divided by the total increase in load. Because the updated SRME time series could incentivize different behaviors from the hydrogen producer, thereby changing the SRME values, we iterate through this process several times until the average standard deviation of all hourly SRMEs between the final run and the previous run is less than 0.015 $kgCO_2/kWh$. Convergence was typically achieved after roughly three iterations. It should be noted that while our SRME calculation process will likely not give identical results to other methods in the literature, it is fully consistent with the GenX model framework and provides accurate signals for Net-Zero SRME optimization within that context.

4. Supplementary Tables

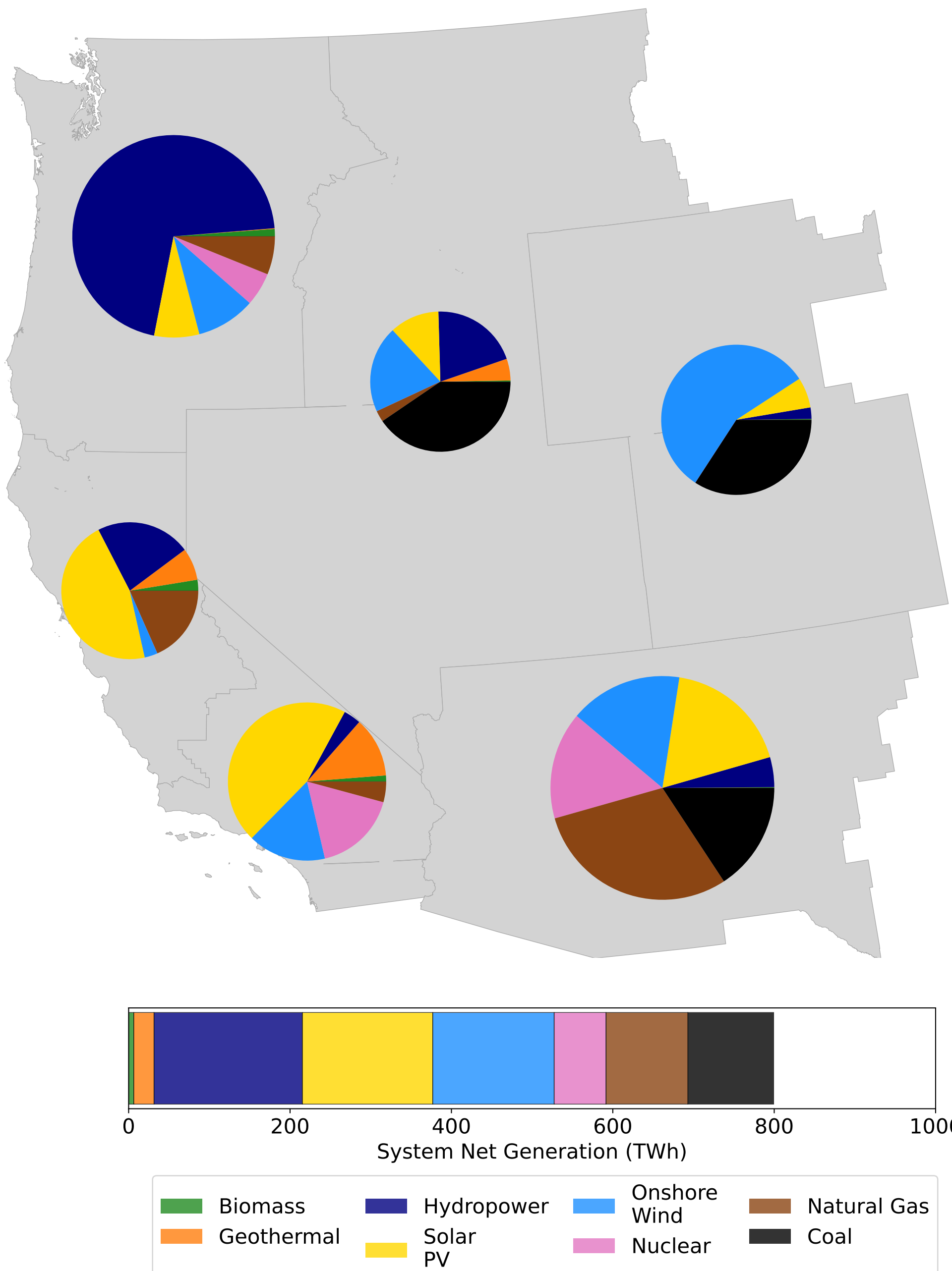
Technology	**Power CAPEX** ($/kW)	**Energy CAPEX** ($/kWh)	**Fixed O&M** ($/kWyr)	**Variable O&M** ($/kWh)	**Round-trip Efficiency** %	**Heat Rate** (MMBTU/ MWh)
Solar	1090	N/A	20.2	-8.75	N/A	N/A
Onshore Wind	1185	N/A	41.3	-9.53	N/A	N/A
Offshore Wind	2946	N/A	73.0	0	N/A	N/A
Geothermal	3953	N/A	133.3	0	N/A	N/A
LI Battery	151	143	5.4	0.15	85	N/A
NGCC	1036	N/A	27.6	1.76	N/A	6.36
NGCT	894	N/A	21.2	5.00	N/A	9.72

Supplementary Table 1. Primary economic parameters used in this work for new-build technologies. All costs are average values over the model planning period and include any applicable IRA tax credits. Quoted capital costs do not include regional cost adjustment factors applied to individual technologies in each GenX zone.

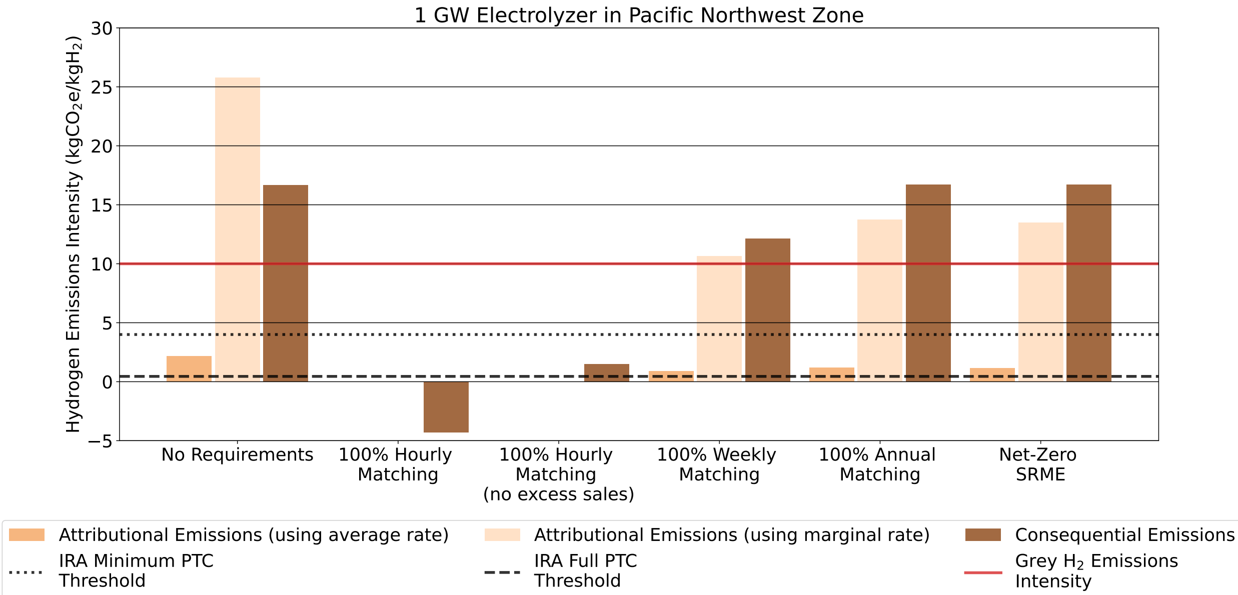
Fuel	**Cost** ($/MMBTU)	**Emissions Rate** ($kgCO_2e$/MMBTU)
Pacific Natural Gas	3.3	53.1
Mountain Natural Gas	3.41	53.1
Mountain Coal	1.53	95.5

Supplementary Table 2. Costs and emissions rates for fossil fuels used in this work. The ‘Pacific’ fuel zone contains the CA and PNW GenX model zones, while the ‘Mountain’ fuel zone contains all other GenX zones.

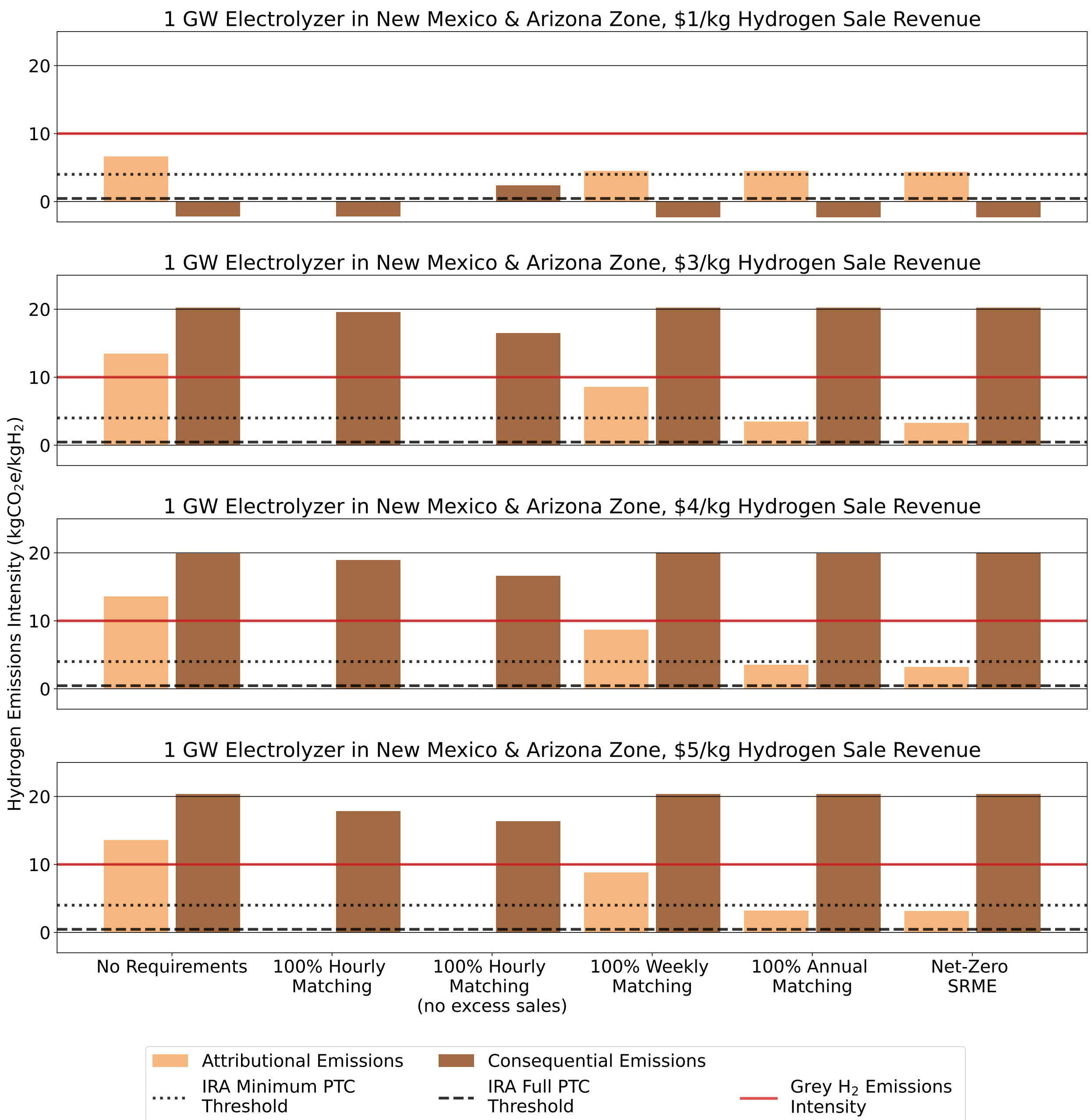
5. Supplementary Figures



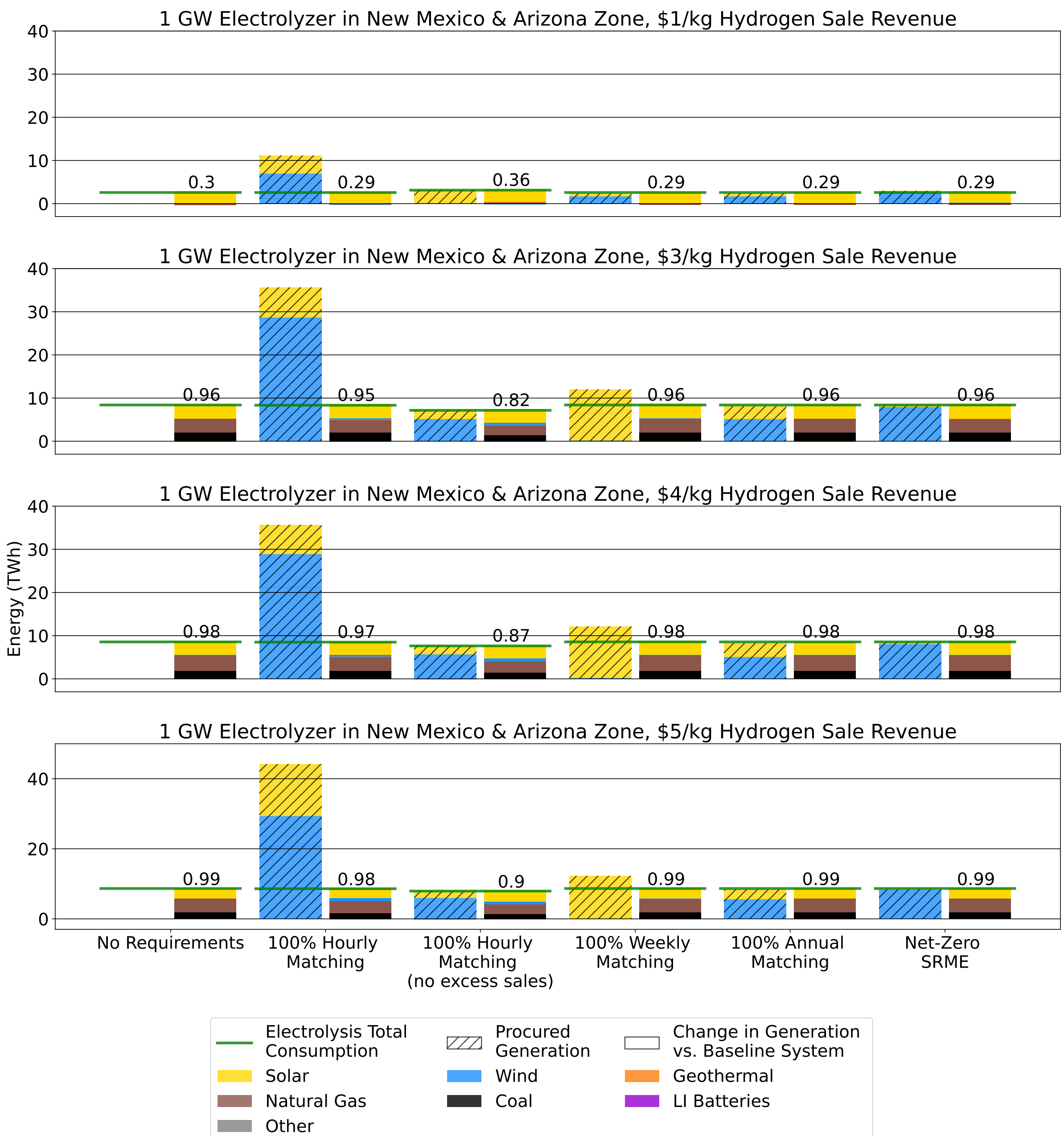
Supplementary Figure 1. Total annual generation by technology and model zone in 2030 in the baseline system.



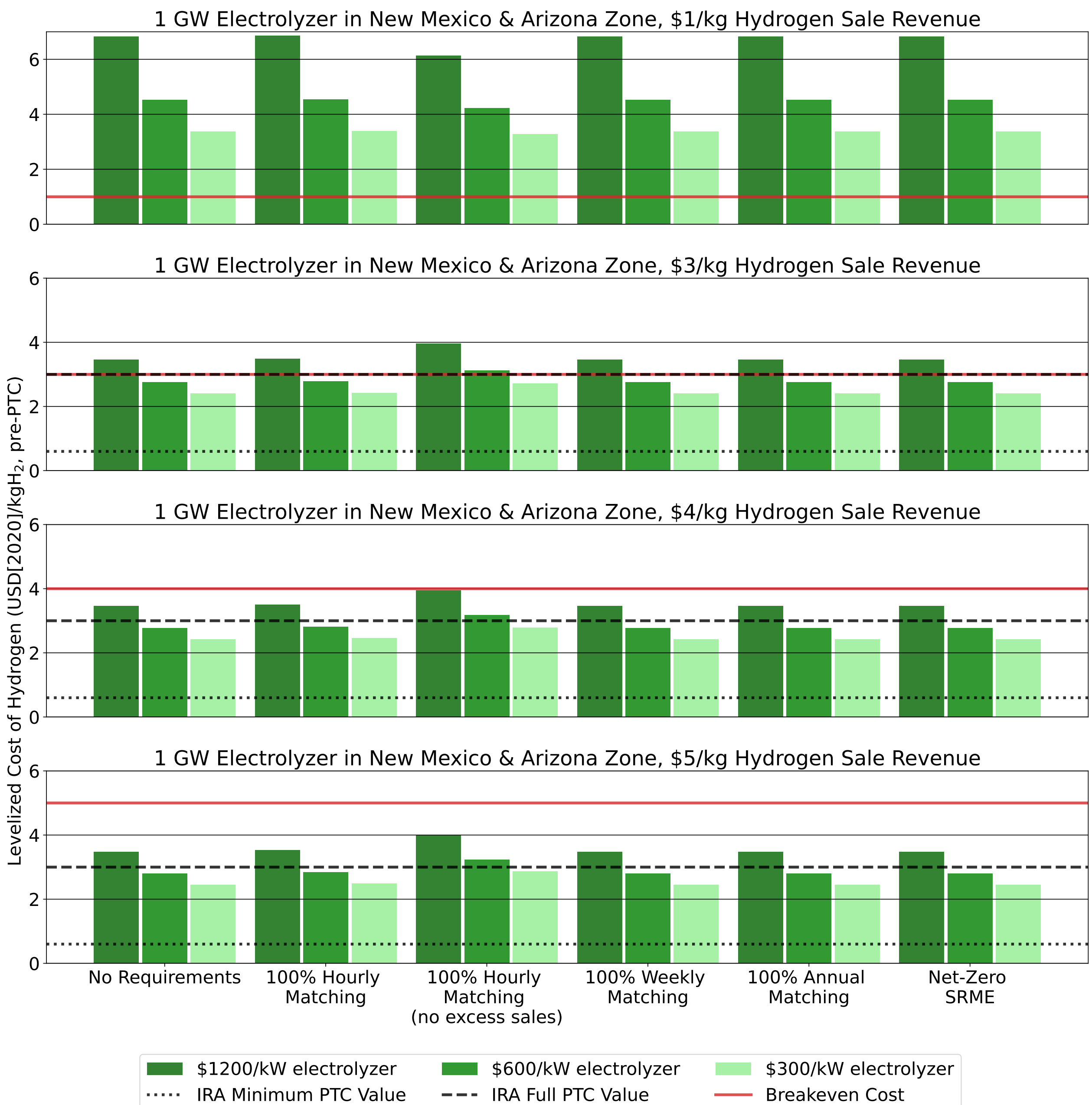
Supplementary Figure 2. Same as row five of Figure 2 in the main text, showing an additional alternative attributional accounting approach reliant on SRMEs rather than average emissions. The marginal accounting methodology penalizes grid electricity consumption in a manner better reflecting true consequential emissions outcomes.



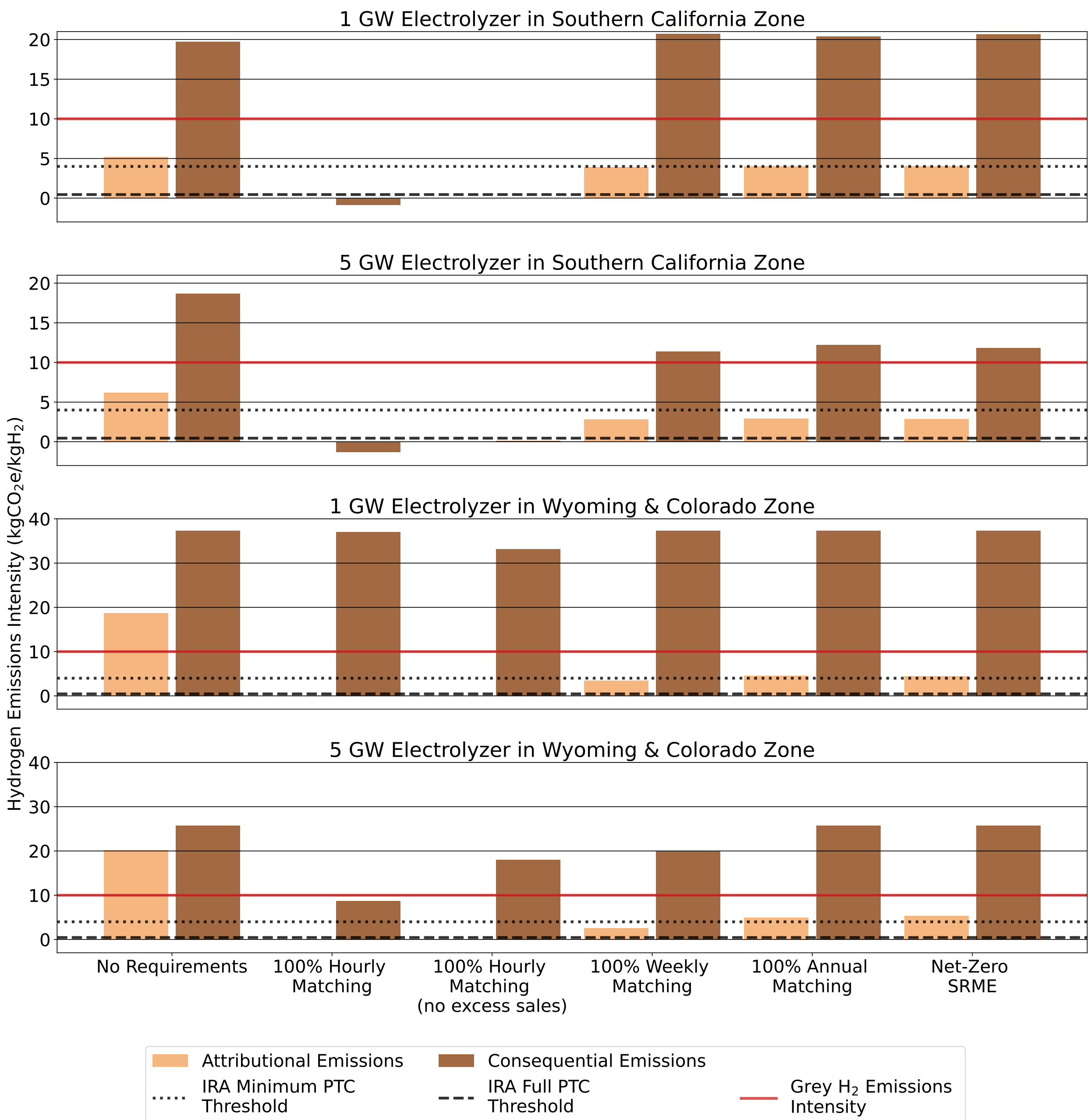
Supplementary Figure 3. Same as Figure 2 in the main text, showing the impact of varying the hydrogen sales revenue on outcomes in the New Mexico & Arizona model zone.



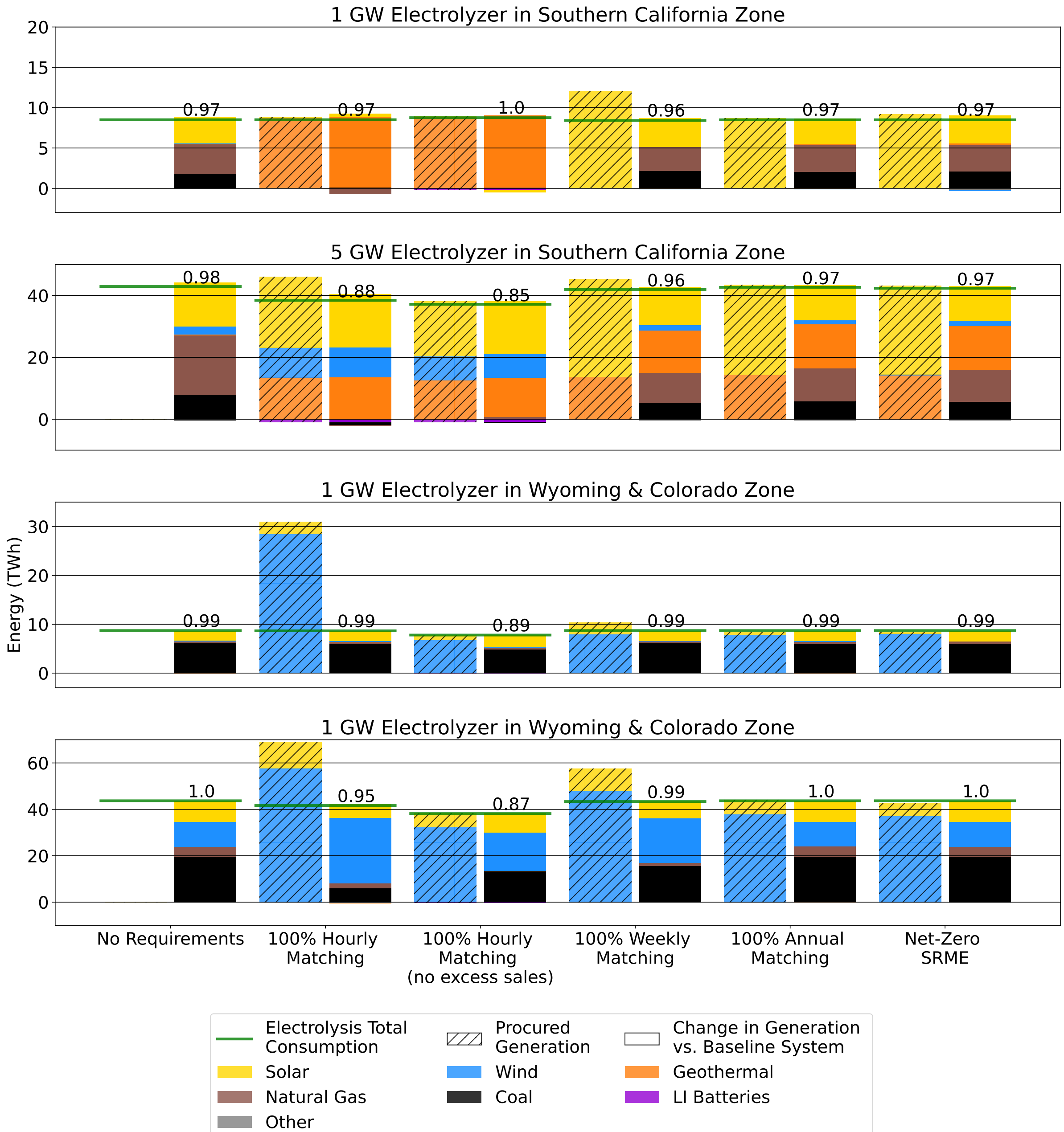
Supplementary Figure 4. Same as Figure 3 in the main text, showing the impact of varying the hydrogen sales revenue on outcomes in the New Mexico & Arizona model zone.



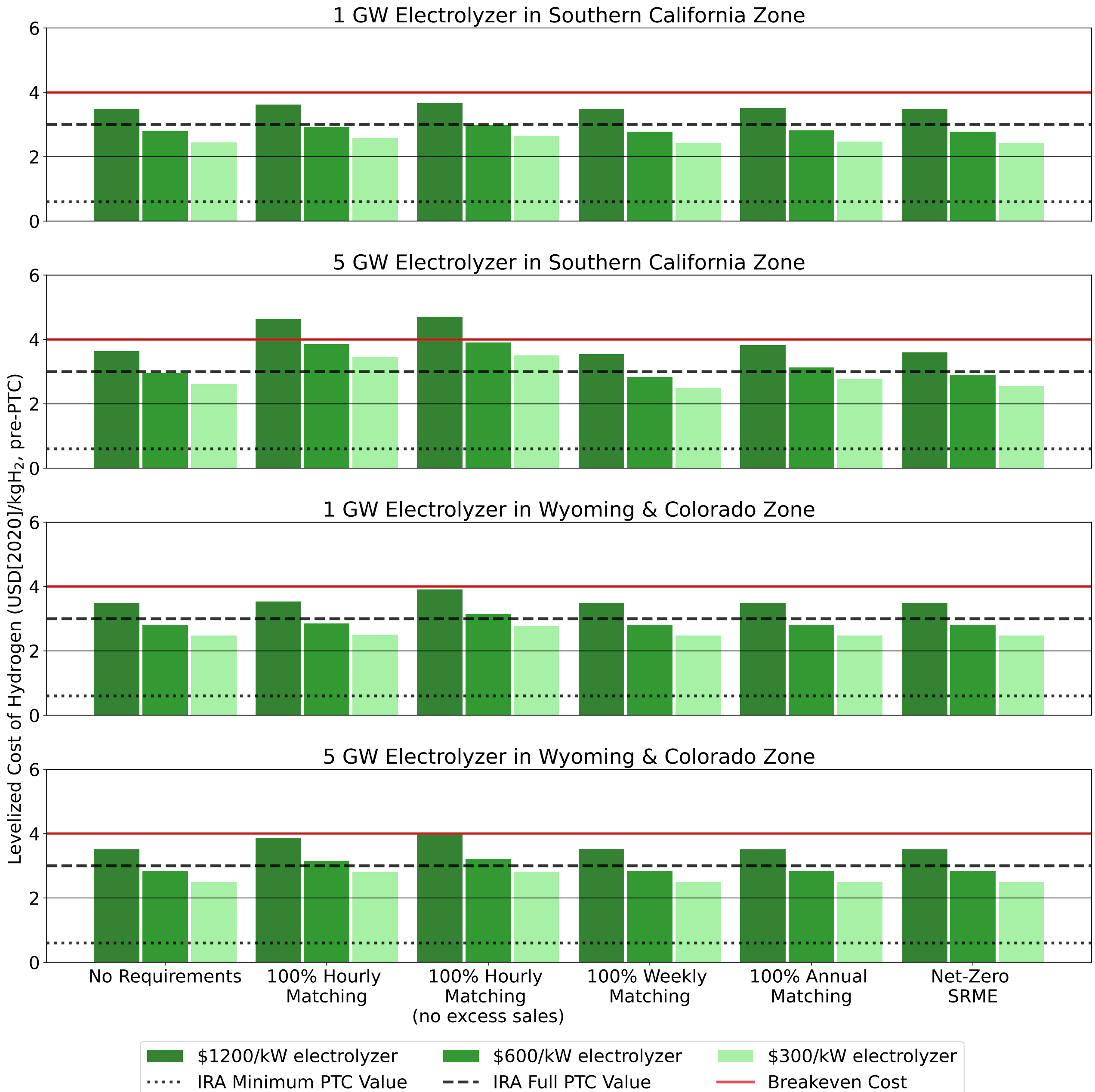
Supplementary Figure 5. Same as Figure 5 in the main text, showing the impact of varying the hydrogen sales revenue on outcomes in the New Mexico & Arizona model zone.



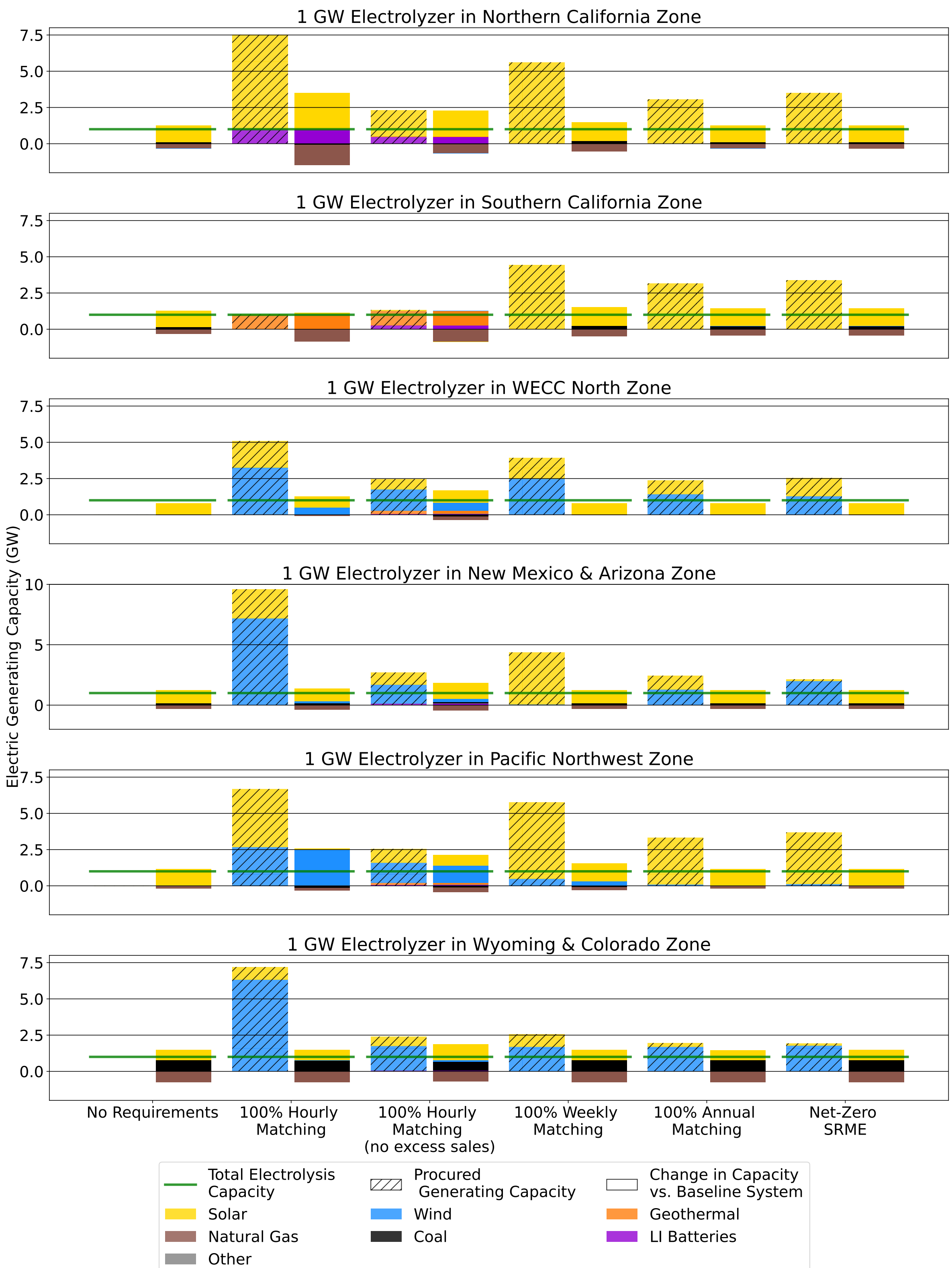
Supplementary Figure 6. Same as Figure 2 in the main text, showing the impact of increasing electrolyzer capacity 5x in two of the model zones.



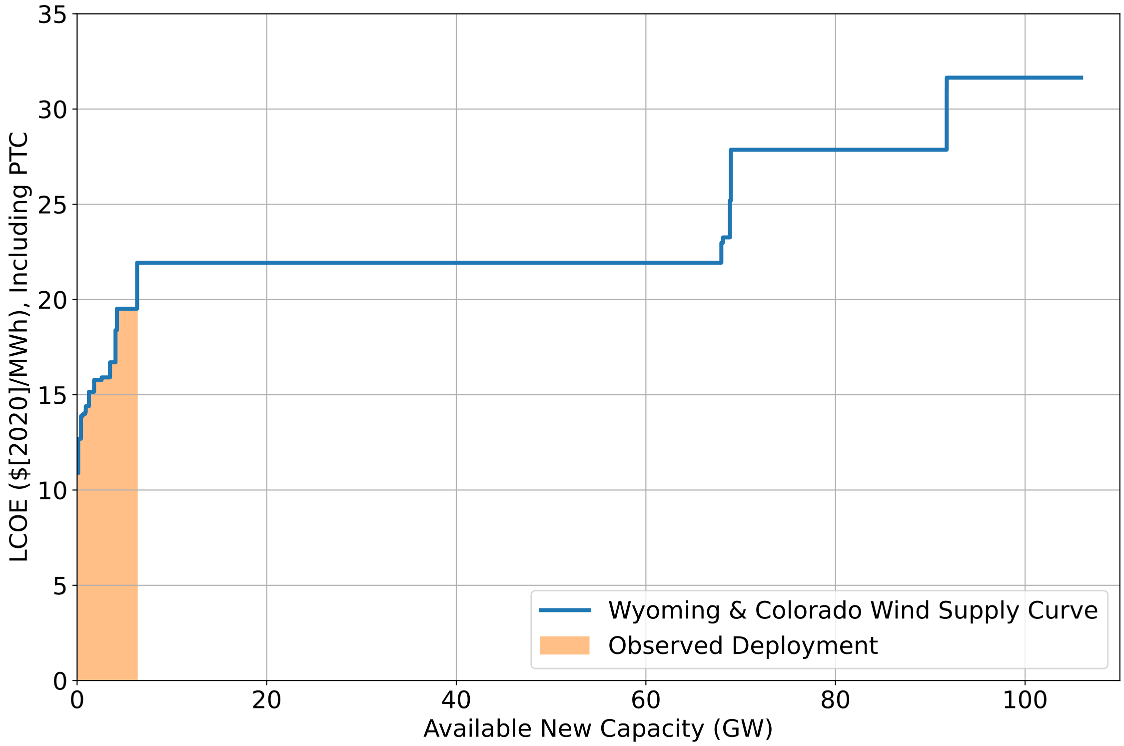
Supplementary Figure 7. Same as Figure 3 in the main text, showing the impact of increasing electrolyzer capacity 5x in two of the model zones.



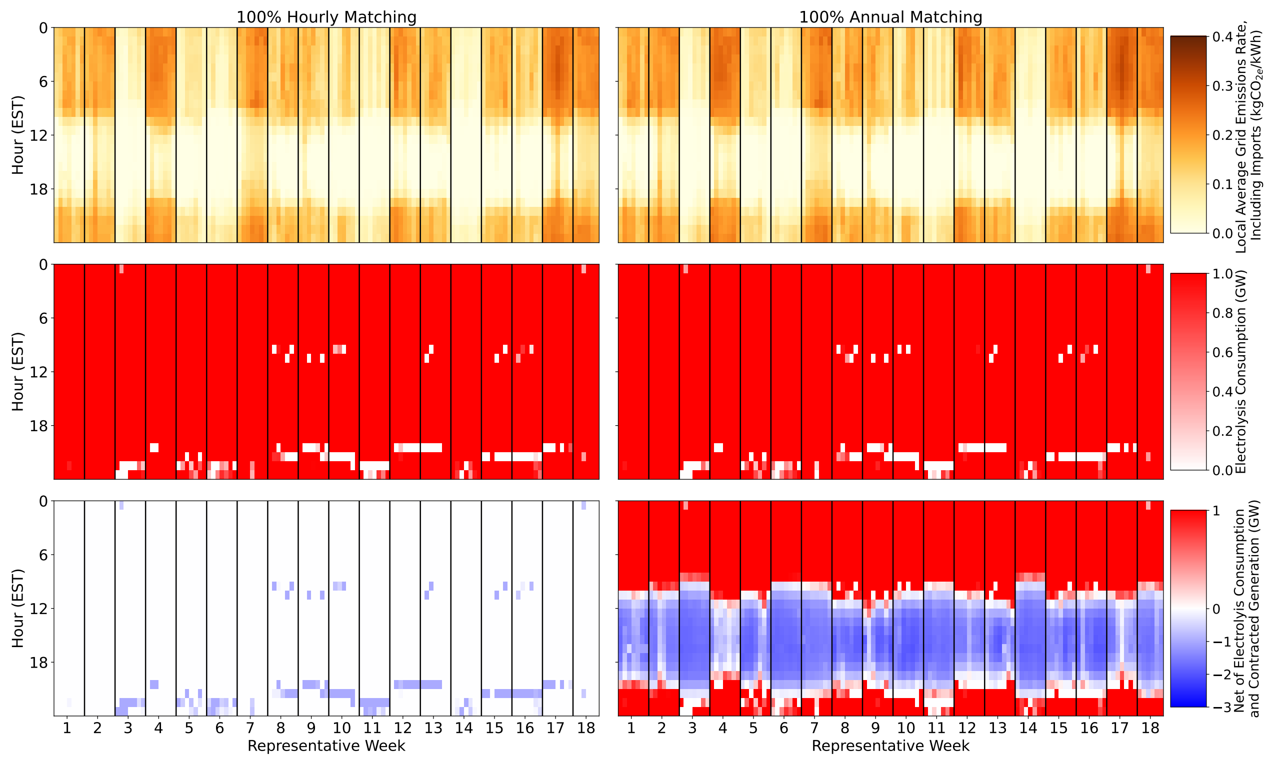
Supplementary Figure 8. Same as Figure 5 in the main text, showing the impact of increasing electrolyzer capacity 5x in two of the model zones.



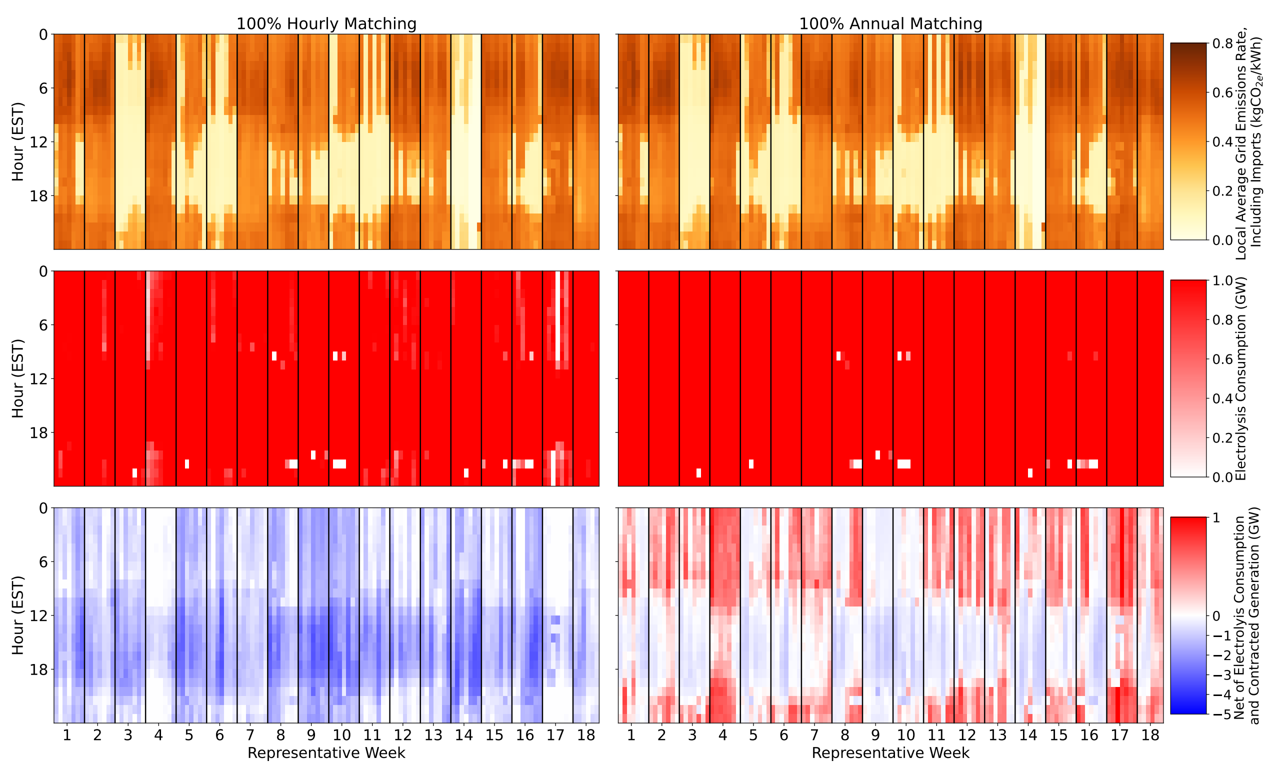
Supplementary Figure 9. Installed electrolyzer capacity (green lines), compared with procured generating capacity (left) and the actual observed changes in capacity resulting from the addition of electrolysis demand to the system (right), under the same scenarios shown in Figures 2, 3 and 5 in the main text.



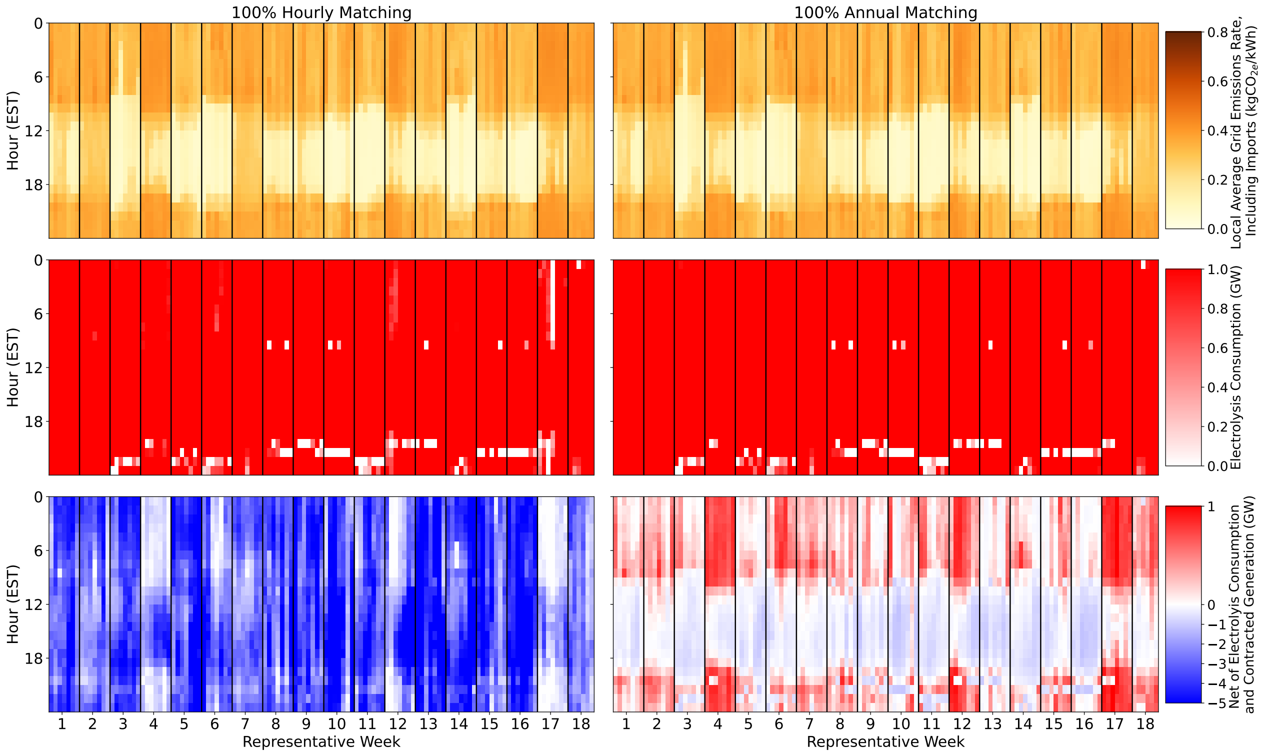
Supplementary Figure 10. The full supply curve for wind resources in the Wyoming & Colorado model zone, given in terms of levelized cost of electricity. The orange highlighted region shows the total wind resource deployed in both the base case and cases with 1 GW of added electrolysis load. Resources higher on the supply curve are not deployed even when some lower-cost resources are procured for hydrogen production, presumably because they are not cost-competitive with existing coal power.



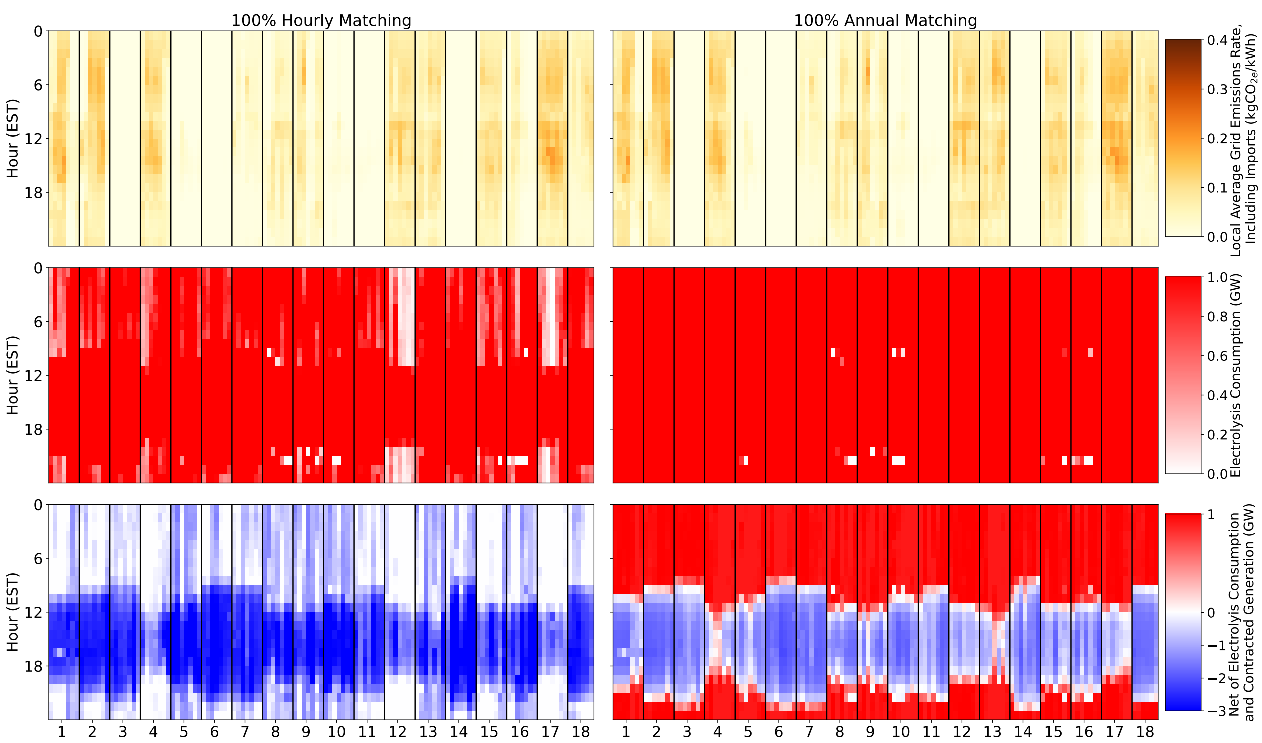
Supplementary Figure 11. Same as Figure 4 in the main text, for hydrogen production in the Southern California model zone.



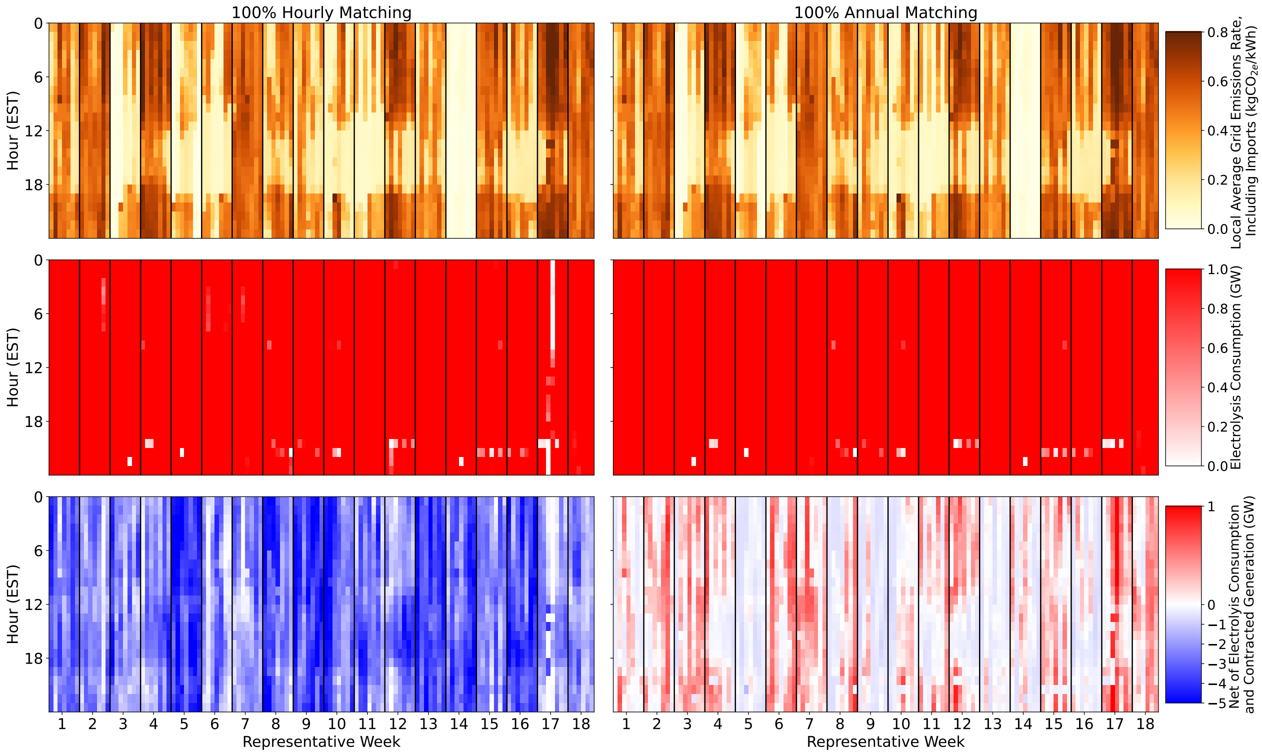
Supplementary Figure 12. Same as Figure 4 in the main text, for hydrogen production in the WECC North model zone.



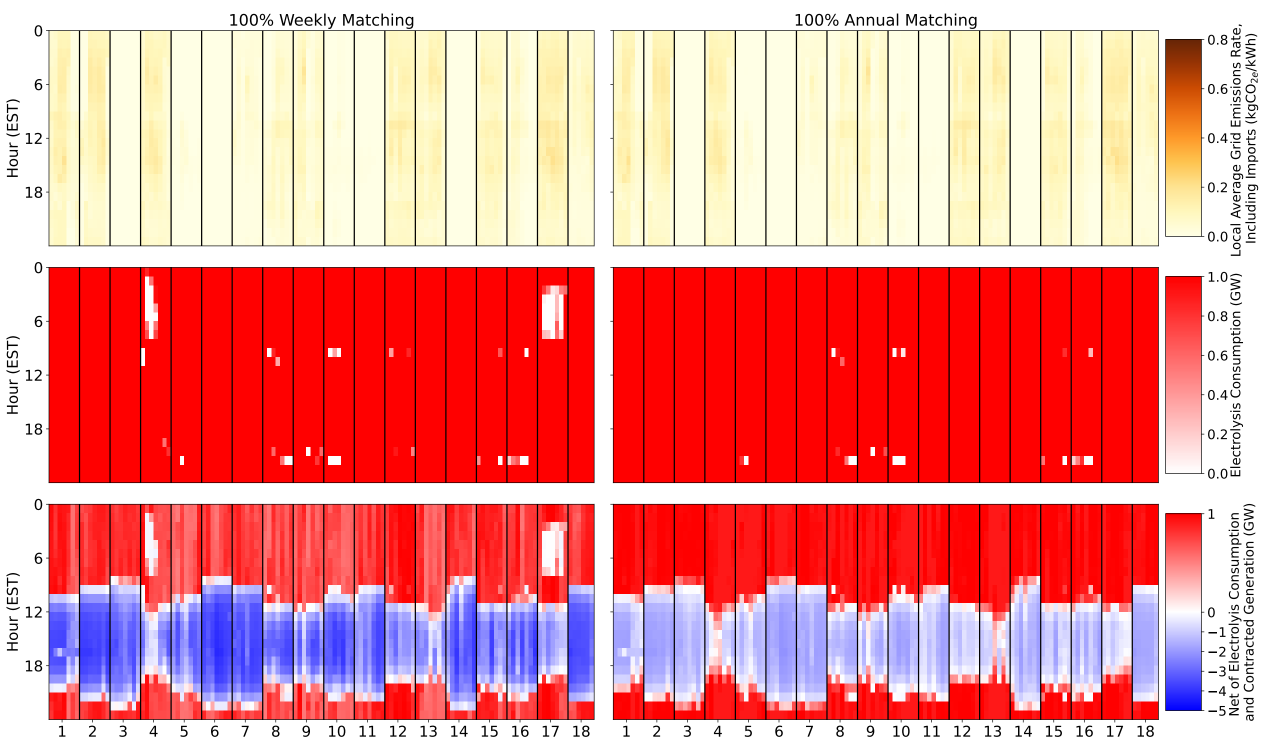
Supplementary Figure 13. Same as Figure 4 in the main text, for hydrogen production in the New Mexico & Arizona model zone.



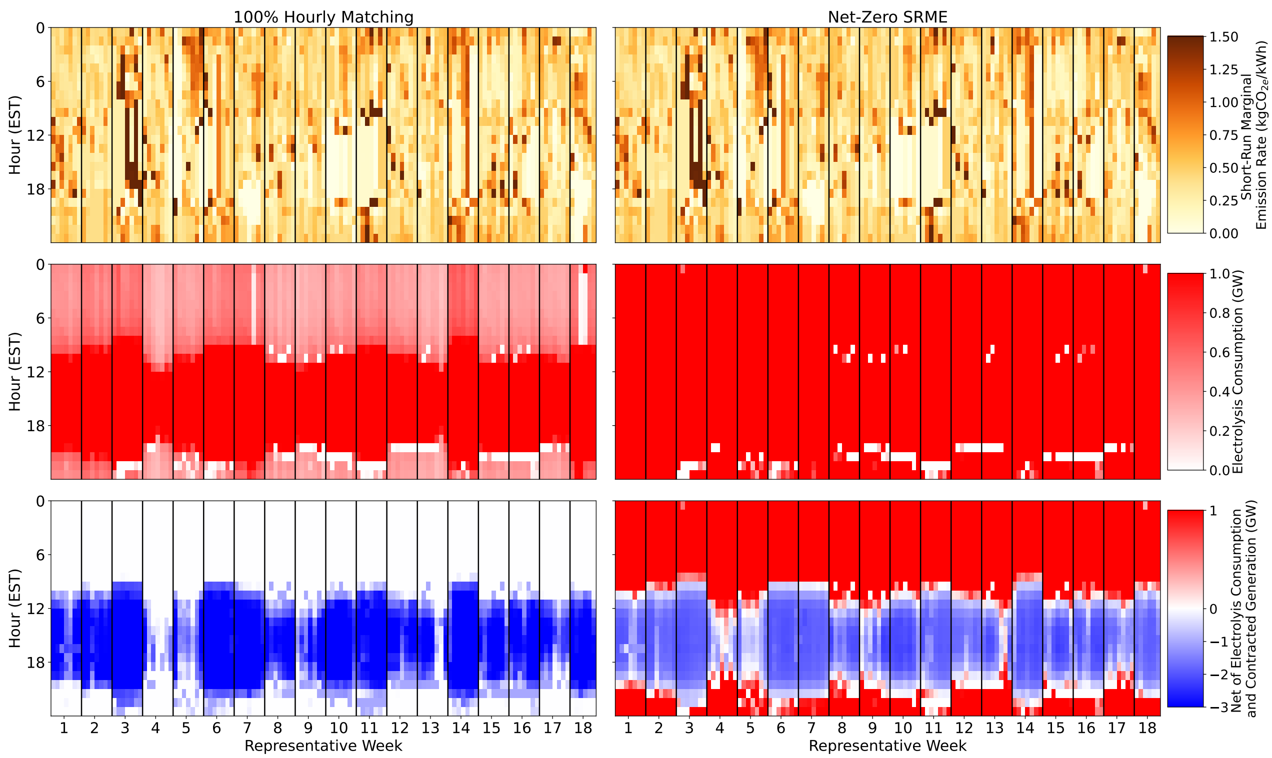
Supplementary Figure 14. Same as Figure 4 in the main text, for hydrogen production in the Pacific Northwest model zone.



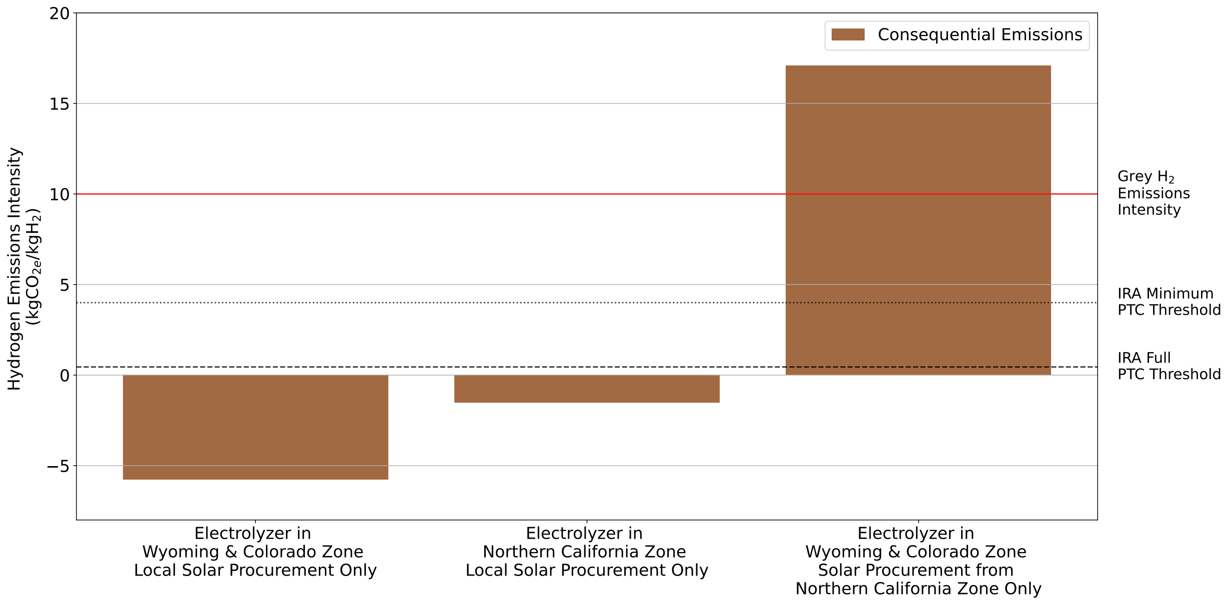
Supplementary Figure 15. Same as Figure 4 in the main text, for hydrogen production in the Wyoming & Colorado model zone.



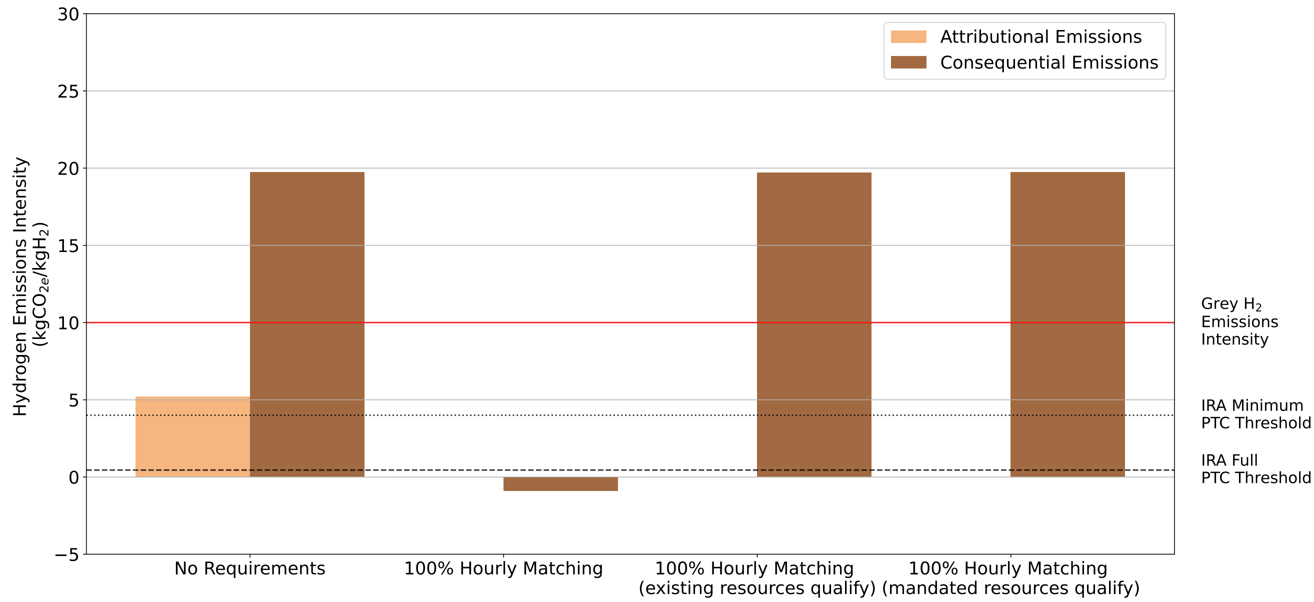
Supplementary Figure 16. Same as Figure 4 in the main text, showing a comparison between outcomes under 100% Weekly Matching (left) and 100% Annual Matching (right) policies in the Pacific Northwest model zone.



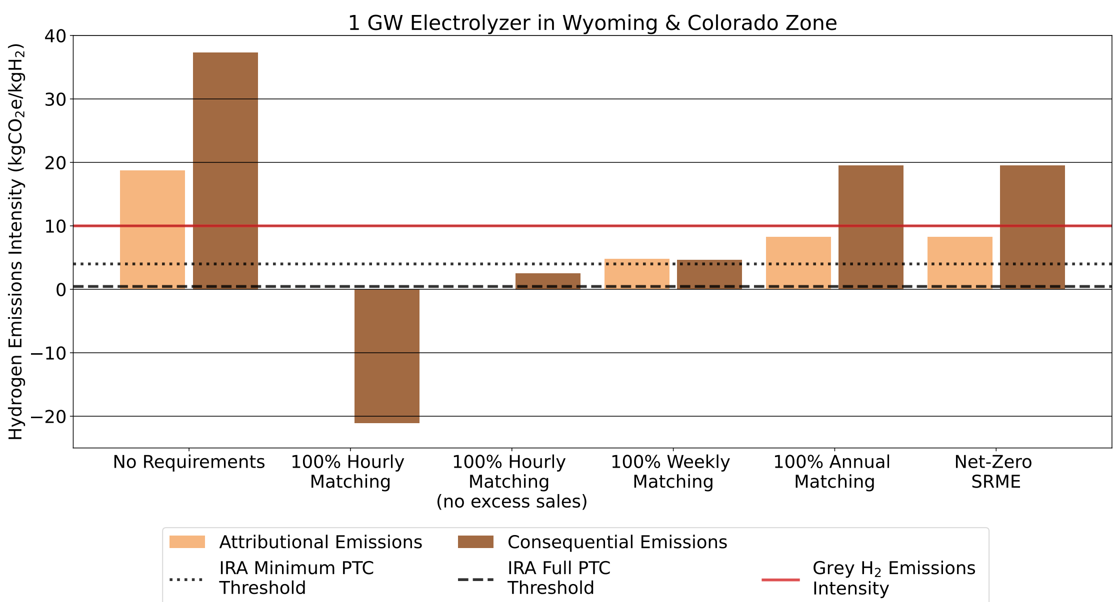
Supplementary Figure 17. Similar to Figure 4 in the main text, showing a comparison between outcomes under 100% Hourly Matching (left) and Net-Zero SRME (right) policies in the Northern California model zone. The top row in this plot shows hourly short-run marginal emissions rather than average emissions.



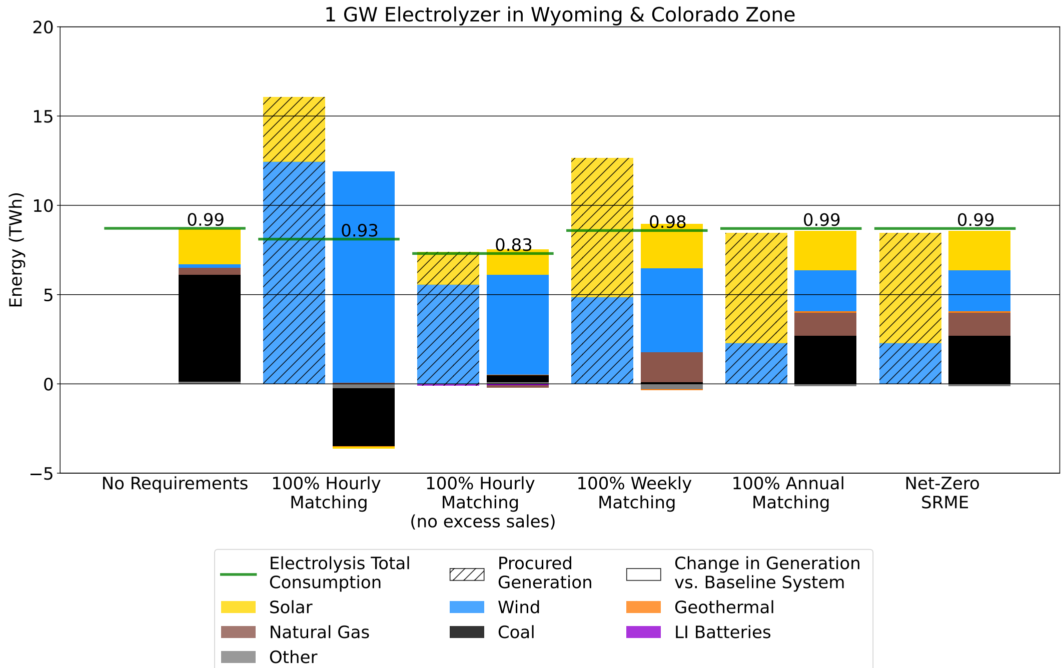
Supplementary Figure 18. Changes in consequential emissions from hydrogen production as a result of relaxing the deliverability requirements under a 100% Hourly Matching policy. In the left column, hydrogen production is located in the Wyoming & Colorado zone and clean energy procurements are required to come from solar resources in the same zone. In the middle column, hydrogen production is located in the Northern California zone and clean energy procurements are required to come from solar resources in the same zone. In the right column, hydrogen production is located in the Wyoming & Colorado zone but clean energy procurements are required to come from solar resources in the Northern California zone. Transmission constraints lead to much larger consequential emissions in the third case.



Supplementary Figure 19. Changes in attributional and consequential emissions from hydrogen production as a result of relaxing additionality requirements, for the case with 1 GW electrolyzer capacity in the Southern California zone and a 100% Hourly Matching procurement requirement. Columns three and four illustrate cases where existing resources and mandated resources, respectively, are allowed to qualify for procurement under a 100% Hourly Matching policy.



Supplementary Figure 20. Same as Figure 2 in the main text, showing outcomes for the Wyoming & Colorado zone when wind resources built in the No Requirements case are not allowed to be procured by hydrogen producers to meet policy requirements in other cases. Without hydrogen competing for these high-quality resources, consequential emissions are much lower than those shown in Figure 2.



Supplementary Figure 21. Same as Figure 3 in the main text, showing outcomes for the Wyoming & Colorado zone when wind resources built in the No Requirements case are not allowed to be procured by hydrogen producers to meet policy requirements in other cases.