Supplemental Information:

The Use of Carbon Capture in Decarbonizing the Power Sector Increases Health Costs and Perpetuates Inequities

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1 Supplementary Results

This section of the Supplemental Information provides additional results, including those related to emissions, health damages, installed capacity, dispatched generation, system costs, test cases, and sensitivity analyses.

Emissions & Related Health Damages

The following section provides supplemental results related to annual emissions and related health damages for each scenario.

Annual Health Damage Totals

For reference, Table S1 shows the InMAP and COBRA (low and high) estimates of total annual health damages for 2035 based on the full range of EF assumptions. We assume the same Value of Statistical Life (VSL) for all results, which is from COBRA's incidence input file and equals \$13.25 billion (\$2024). Note the term "exported" in Table S1 refers to $PM_{2.5}$ exposure from air pollution that is generated in the WECC but transported outside of the WECC to other regions of the U.S., according to InMAP and COBRA calculations of atmostpheric chemistry and air transport. The reason the Net-Zero scenario has the same damages no matter the EF assumption is because all damages in the Net-Zero scenario are from biomass generation, and we do not assume a range of EFs for biomass. COBRA's low and high estimates are derived from two different sets of assumptions about the sensitivity of adult mortality and heart-related health issues to changes in ambient $PM_{2.5}$ levels. These values are dramatically higher than the InMAP estimates. We have more confidence in the InMAP estimates, since the geographical resolution of the InMAP model is higher than COBRA, and the calculations are based on more complex reduced-order air quality modeling methods than the S-R matrix used in COBRA [1, 2].

Per Capita Health Damages for Negatively Affected Census Blocks

In Figure 3(a) of the main manuscript we show the probability distribution of the change in 2035 annual health damages per capita (\$2024) between the representative CCS scenario and the Net Zero scenario for negatively affected U.S. census blocks in the WECC (blocks with higher per capita damages in the representative CCS scenario than in the Net Zero scenario) by income group. Each census block is assigned to an income group based on the percentage of its population that is considered low- to moderate- income. The most affluent income group is 0-25% and the least affluent is 75-100%. Table S2 shows a summary of the statistical analysis conducted on the 2035 annual health damages per capita (\$2024) between the Net Zero and representative CCS scenario by income group. The average increase in per capita health damages is 1.6 times higher for the poorest census blocks compared to the most affluent blocks. The 95th percentile increases are 1.2 times higher for the poorest blocks compared to the most affluent. The skew in these results across negatively affected census blocks increases from most affluent to least affluent.

Due to the high skews, we conduct the Shapiro Wilk test to analyze normality of the distributions for each income group, finding that all of the distributions of 2035 change in per capita health damages for negatively affected census blocks in the WECC are not normal (Table S3). Since each p-value is well below 0.05, we conclude that the distribution of these values is not normal. This is consistent with the high skew values for each income group shown in Table S2. Therefore, the median becomes an important metric to evaluate, since it is less sensitive to skewness and outliers

Table S1: Total 2035 health damages (billions $2024 annually) by scenario and assumed emission factors (EFs).

		InMAP (Billions $2024)			**COBRA (low estimate)** (Billions $2024)			**COBRA (high estimate)** (Billions $2024)		
Scenario	EFs	WECC	Exported	Total	WECC	Exported	Total	WECC	Exported	Total
NET ZERO	N/A	**1.90**	**0.06**	**1.96**	**5.25**	**0.06**	**5.31**	**11.84**	**0.15**	**11.99**
RET + NTT	low	2.96	0.28	3.24	10.11	0.19	10.30	22.84	0.44	23.28
	avg.	**5.13**	**0.54**	**5.66**	**11.66**	**0.29**	**11.95**	**26.35**	**0.65**	**27.00**
	high	7.35	0.79	8.14	13.17	0.37	13.54	29.77	0.84	30.61
NO RET + NO NTT	low	3.55	0.29	3.84	11.48	0.23	11.71	25.94	0.53	26.47
	avg.	**5.99**	**0.56**	**6.54**	**13.18**	**0.42**	**13.60**	**29.82**	**0.93**	**30.75**
	high	8.50	0.84	9.33	14.96	0.73	15.69	33.84	1.63	35.47
NO RET + NTT	low	3.49	0.28	3.77	11.33	0.19	11.52	25.59	0.45	26.04
	avg.	**5.72**	**0.51**	**6.23**	**12.91**	**0.28**	**13.19**	**29.20**	**0.62**	**29.82**
	high	8.02	0.76	8.78	14.47	0.36	14.83	32.72	0.81	33.53
NO RET	low	3.42	0.31	3.72	10.51	0.21	10.72	23.74	0.48	24.22
+ NTT	avg.	**5.78**	**0.58**	**6.36**	**12.14**	**0.32**	**12.46**	**27.45**	**0.71**	**28.16**
+ MIN 45Q	high	8.23	0.87	9.10	13.76	0.43	14.19	31.10	0.98	32.08
NO RET	low	3.54	0.38	3.92	10.79	0.25	11.04	24.38	0.58	24.96
+ NTT	avg.	**6.38**	**0.76**	**7.14**	**12.57**	**0.37**	**12.94**	**28.40**	**0.86**	**29.26**
+ MID 45Q	high	9.31	1.17	10.47	14.28	0.50	14.78	32.29	1.13	33.42
NO RET	low	3.55	0.39	3.94	10.81	0.27	11.08	24.43	0.61	25.04
+ NTT	avg.	**6.47**	**0.79**	**7.26**	**12.62**	**0.40**	**13.02**	**28.53**	**0.89**	**29.42**
+ MAX 45Q	high	9.47	1.21	10.68	14.36	0.53	14.89	32.48	1.19	33.67

Table S2: Summary statistics of 2035 change in annual monetized health damages per capita ($2024/person) between Net Zero and representative CCS scenarios (NO RET + NTT + midpoint 45Q) by income group across negatively affected U.S. census blocks (CCS scenario values - Net Zero values > 0).

Income Group (% of Block Pop. with Low-Mod. Income)	Mean ± CI (95%)	Median	Std. Dev.	Skew	75th Percentile	95th Percentile	Number of Blocks
0–25%	41.88 [40.54, 43.21]	16.34	64.65	2.87	44.72	177.39	9208
25–50%	44.43 [43.46, 45.41]	17.07	64.65	2.47	49.33	186.69	17221
50–75%	51.65 [50.54, 52.80]	20.30	67.15	1.91	69.45	197.27	13296
75–100%	65.69 [63.84, 67.57]	28.10	70.79	1.32	118.78	205.73	5611

than the mean. Table S4 shows results of the Mood's Median Test with False Discovery Rate (FDR) correction (Benjamini–Hochberg procedure [3]) applied to the change in 2035 per capita health damages for negatively affected census blocks in the WECC for each income group. Since all p-values are well below 0.05, we conclude that all possible pairs of income groups have statistically significant differences in their median values.

Weighted $PM_{2.5}$ Exposure for Negatively Affected Census Blocks

In Figure 3(b) of the main manuscript we present the probability distribution of the difference in 2035 population-weighted $PM_{2.5}$ concentration ($\mu g/m^3$) between the representative CCS scenario

Table S3: Shapiro-Wilk test results for 2035 change in population-weighted $PM_{2.5}$ exposure ($\mu g/m^3$) by income group between the Net Zero and representative CCS scenarios (NO RET + NTT + midpoint 45Q) across negatively affected U.S. census blocks.

Income Group (% of Block Pop. with Low-Mod. Income)	Shapiro–Wilk Statistic	p-value
0–25%	0.62	5.16e-89
25–50%	0.67	1.15e-101
50–75%	0.73	6.51e-90
75–100%	0.82	6.66e-62

Table S4: Significant pairwise Mood's median test differences after FDR correction across income groups. All pairs shown are statistically significant.

Income Groups (% of Block Pop. with Low-Mod. Income)						
Group 1	Group 2	Group 1 Median	Group 2 Median	Mood's Median Statistic	p-value	p-adj (FDR)
0–25%	25–50%	16.34	17.07	4.99	$2.54e-02$	$2.54e-02$
0–25%	50–75%	16.34	20.30	116.76	$3.24e-27$	$6.48e-27$
0–25%	75–100%	16.34	28.10	292.81	$1.22e-65$	$7.30e-65$
25–50%	50–75%	17.07	20.30	92.58	$6.47e-22$	$7.77e-22$
25–50%	75–100%	17.07	28.10	283.84	$1.10e-63$	$3.29e-63$
50–75%	75–100%	20.30	28.10	109.36	$1.36e-25$	$2.03e-25$

and Net-Zero scenario for negatively affected United States (U.S.) census blocks in the WECC by demographic group (meaning the demographic group is worse off in the CCS scenario than in the Net-Zero scenario). We test this to see is any demographic groups are disproportionately affected by the deployment of large-scale CCS. Figure S1 shows the spatial distribution of the difference in 2035 population-weighted $PM_{2.5}$ concentration ($\mu g/m^3$) between the representative CCS scenario and the Net-Zero scenario for U.S. census blocks in the WECC for the general population. Similar to the spatial distribution of differences in per capita health damages across the WECC, the differences in 2035 population-weighted $PM_{2.5}$ concentration are overwhelmingly positive values, meaning that there are higher population-weighted $PM_{2.5}$ concentrations in most census blocks in the representative CCS scenario than in the Net-Zero scenario. Also, the most affected blocks tend to reside in the South WECC, especially near Southern California and the Bay Area. A small number of blocks near Northern California and Southern Oregon experience lower population-weighted $PM_{2.5}$ concentrations in the representative CCS scenario compared to the Net Zero scenario, but the values are at most -0.3 $\mu g/m^3$, compared to increases in population-weighted $PM_{2.5}$ concentrations as high as 101.5 $\mu g/m^3$ in other regions of the WECC.

Table S5 shows a summary of the statistical analysis conducted on the 2035 change in population-weighted $PM_{2.5}$ exposure between the Net Zero and representative CCS scenario by demographic group. The average increase in population-weighted $PM_{2.5}$ exposure between the Net Zero and representative CCS scenario is 2.6 times higher for Asian populations and 2.5 times higher for Black populations compared to White (Non-Latino) populations. The 95th percentile increases

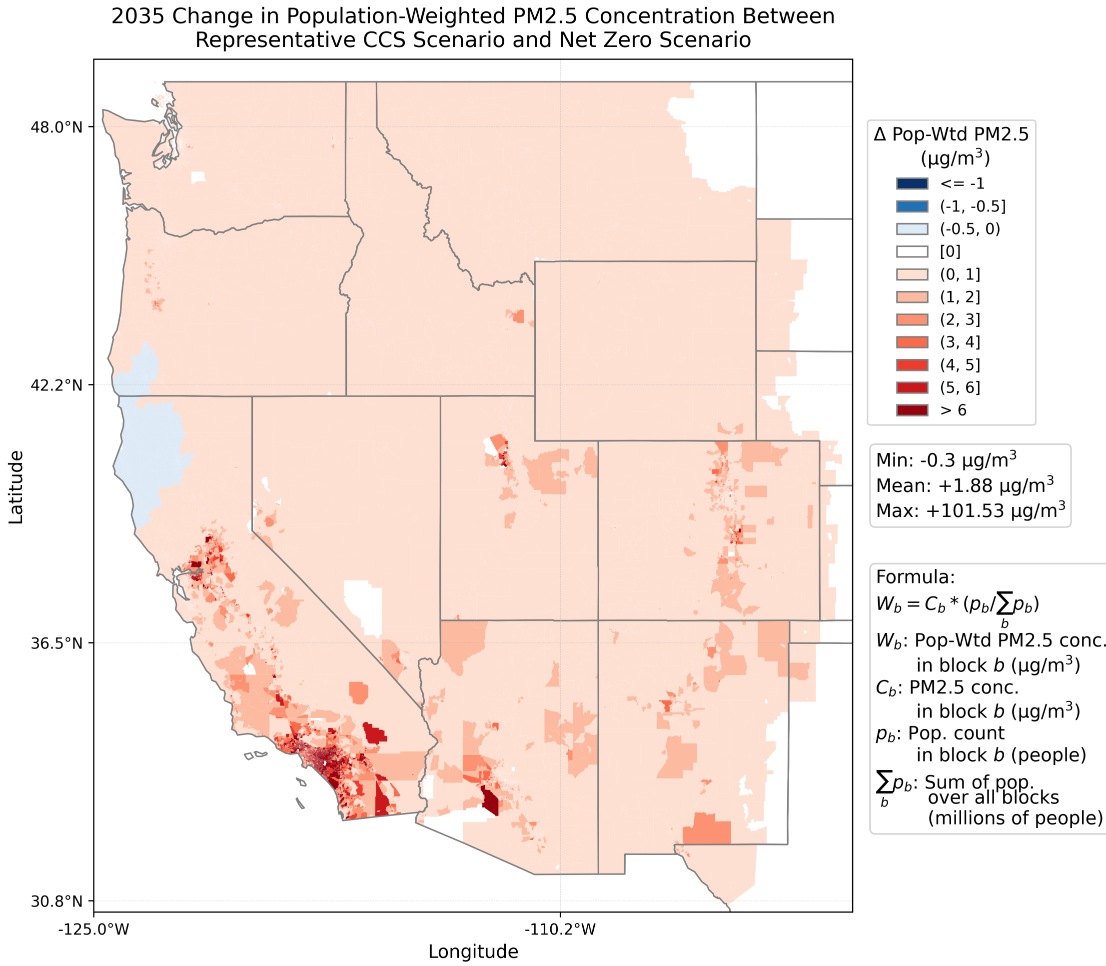

Figure S1: Map of 2035 change in population-weighted $PM_{2.5}$ concentration ($\mu g/m^3$) between the representative CCS scenario and the Net Zero scenario for U.S. census blocks in the WECC. Positive values (red) indicate census blocks that have higher population-weighted $PM_{2.5}$ concentration values than in the Net Zero scenario, and negative values (blue) indicate census blocks that have lower population-weighted $PM_{2.5}$ concentration values than in the Net Zero scenario.

are 2.9 times higher for Asian populations and 3.0 times higher for Black populations than White populations. The skew in these results across negatively affected census blocks is highest for Asian, Black, Latino, Native American, then White populations, in that order.

Due to the high skews, we conduct the Shapiro Wilk test to analyze normality of the distributions for each demographic group, finding that all of the distributions of 2035 change in population-weighted $PM_{2.5}$ concentrations ($\mu g/m^3$) for negatively affected census blocks in the WECC are not normal (Table S6). Since each p-value is well below 0.05, we conclude that the distribution of these values is not normal. This is consistent with the high skew values for each demographic group shown in Table S5. Therefore, the median becomes an important metric to evaluate, since it is less sensitive to skewness and outliers than the mean. Table S7 shows results of the Mood's Median Test with False Discovery Rate (FDR) correction (Benjamini–Hochberg procedure [3]) applied to the 2035 population-weighted $PM_{2.5}$ concentrations ($\mu g/m^3$) for negatively affected census blocks in the WECC for each demographic group. Since all p-values are well below 0.05, we conclude that all possible pairs of demographic groups have statistically significant differences in their median

Table S5: Summary statistics of 2035 change in population-weighted $PM_{2.5}$ exposure ($\mu g/m^3$) between Net Zero and representative CCS scenarios (NO RET + NTT + mid 45Q) by demographic group across negatively affected U.S. census blocks (CCS scenario values - Net Zero values > 0).

Demographic Group	Mean ± CI (95%)	Median	Std. Dev.	Skew	75th Percentile	95th Percentile	Number of Blocks
Asian	3.61 [3.48, 3.74]	0.37	11.67	9.84	2.04	17.58	33687
Black	3.54 [3.43, 3.65]	0.56	9.16	7.41	2.54	17.88	27907
Latino	2.69 [2.63, 2.75]	0.41	6.29	4.84	1.92	14.62	43665
Native American	2.60 [2.47, 2.73]	0.49	8.03	8.55	1.72	10.96	13960
White (Non-Latino)	1.40 [1.38, 1.43]	0.48	2.67	6.03	1.41	5.94	44701

values.

Table S6: Shapiro-Wilk test results for 2035 change in population-weighted $PM_{2.5}$ exposure ($\mu g/m^3$) by demographic group between the Net Zero and representative CCS scenarios (NO RET + NTT + midpoint 45Q) across negatively affected U.S. census blocks. All groups reject the null hypothesis of normality.

Demographic Group	Shapiro–Wilk Statistic	p-value
Asian	0.56	2.11e-24
Black	0.69	5.89e-18
Latino	0.70	1.25e-26
Native American	0.27	5.90e-33
White (Non-Latino)	0.87	8.23e-19

Table S7: Significant pairwise Mood's median test differences after FDR correction across racial/ethnic groups. All pairs shown are statistically significant.

Group 1	Group 2	Group 1 Median	Group 2 Median	Mood's Median Statistic	p-value	p-adj (FDR)
Asian	Black	0.37	0.56	311.94	$8.25e-70$	$8.25e-69$
Asian	Latino	0.37	0.41	31.83	$1.68e-08$	$2.10e-08$
Asian	Native American	0.37	0.49	148.66	$3.41e-34$	$8.52e-34$
Asian	White (Non-Latino)	0.37	0.48	210.73	$9.52e-48$	$4.76e-47$
Black	Latino	0.56	0.41	176.60	$2.68e-40$	$8.92e-40$
Black	Native American	0.56	0.49	21.83	$2.98e-06$	$3.32e-06$
Black	White (Non-Latino)	0.56	0.48	56.13	$6.79e-14$	$1.13e-13$
Latino	Native American	0.41	0.49	52.79	$3.72e-13$	$5.31e-13$
Latino	White (Non-Latino)	0.41	0.48	74.87	$5.02e-18$	$1.00e-17$

Per Capita Health Damages for Positively Affected Census Blocks

Figure S2 shows the probability distribution of the 2035 change in annual monetized health damages per capita for positively affected U.S. census blocks in the WECC (blocks with lower per capita damages in the representative CCS scenario than in the Net Zero scenario) by income group. The reason we separate the presentation of these distributions is because the x-axis is on a log-scale, which is incompatible with negative and zero values. Hence, we show the log distribution of the magnitude of negative values in Figure S2. We observe that the benefits of CCS deployment are not concentrated within any particular income group. In contrast, the negative impacts are disproportionately borne by low-income communities, as detailed in the main manuscript.

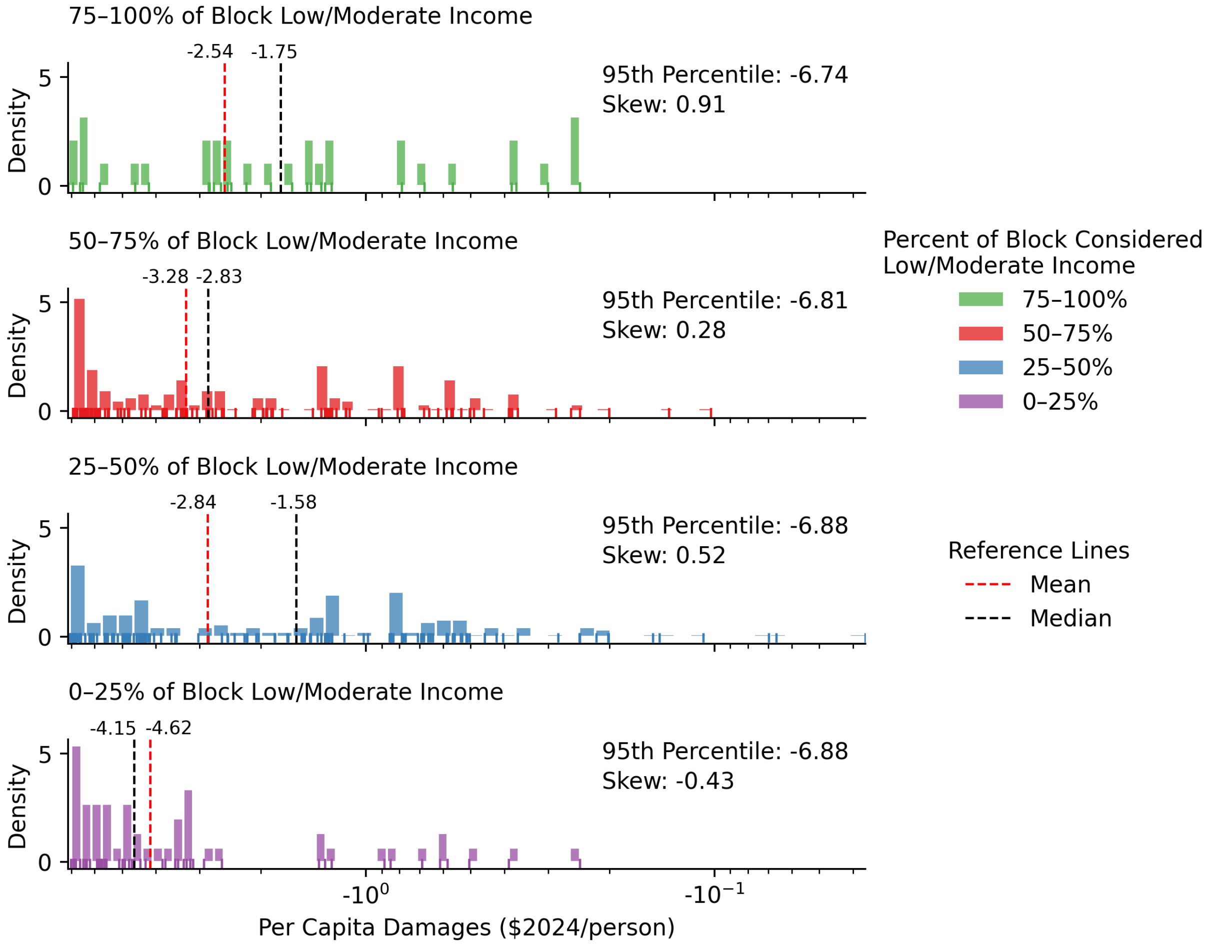

Figure S2: Probability distribution of 2035 change in annual health damages per capita ($2024/person) between the representative CCS scenario and the Net Zero scenario for positively affected U.S. census blocks in the WECC (blocks with lower per capita damages in the representative CCS scenario than in the Net Zero scenario) by income group.

Weighted $PM_{2.5}$ Exposure for Positively Affected Census Blocks

We further our analysis of CCS beneficiaries by segmenting impacted populations by racial and ethnic groups with the results shown in Figure S3. On average, the most positively affected groups are Native Americans, followed by White people. This is likely attributable to the fact that the region that benefits slightly in the representative CCS scenario compared to the Net Zero scenario from a slight decrease in biomass emissions has a slightly higher Native American population (3.8-12.6%, [1]) than the U.S. average (0.6% according to InMAP default population file).

Per Capita Health Damages Across Total Population

We also show the log-scale distribution of the 2035 change in annual health damages per capita ($2024/person) between the representative CCS scenario and the Net Zero scenario for the general population in all U.S. WECC census blocks with non-zero values in Figure S4. This distribution

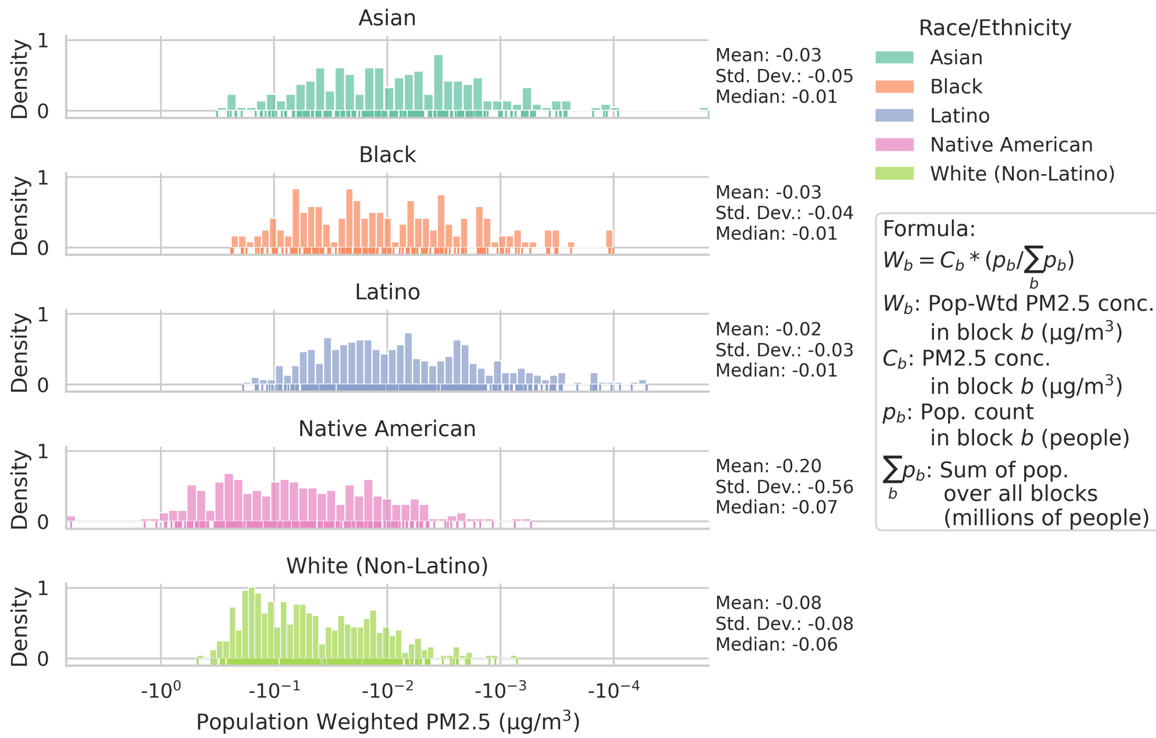

Figure S3: Probability distribution of 2035 change in population-weighted $PM_{2.5}$ concentration ($\mu g/m^3$) between the representative CCS scenario and the Net Zero scenario for positively affected U.S. census blocks in the WECC (blocks with lower population-weighted $PM_{2.5}$ concentration in the representative CCS scenario than in the Net Zero scenario) by demographic group.

further demonstrates how the majority of census blocks in the WECC have higher per capita damages in the representative CCS scenario than in the Net Zero scenario. The log-distribution reveals a pronounced concentration of census blocks with relatively high per capita damages. We infer to be those in the Los Angeles region that experience dramatically higher per capita damages than most of the rest of the WECC.

Non-Weighted $PM_{2.5}$ Exposure Map for All Census Blocks

The spatial distribution of differences in non-weighted $PM_{2.5}$ concentrations ($\mu g/m^3$) between the representative CCS scenario and the Net Zero scenario for U.S. census blocks in the WECC follow a similar distribution to differences in population-weighted values, as seen in Figure S5. Note non-weighted $PM_{2.5}$ concentration values are not as useful as population-weighted $PM_{2.5}$ concentration values because they do not capture how many people are exposed to those concentrations. Regardless, we include a visualization of the non-weighted $PM_{2.5}$ concentrations here (Figure S5) for reference.

Installed Capacity and Generation

Figure S6 shows the CCS mix in each CCS scenario. The majority of installed CCS is gas with post-combustion captures. The subplots with thin lines in the pie are attempting to show negligible amounts of gas with oxyfuel capture (0.032 or less kW) built in all of the no retrofit scenarios.

We take the CCS scenarios and analyze the 2035 build out of coal and gas (with and without CCS) capacity to see if each scenario builds capacities that are comparable in magnitude to typical

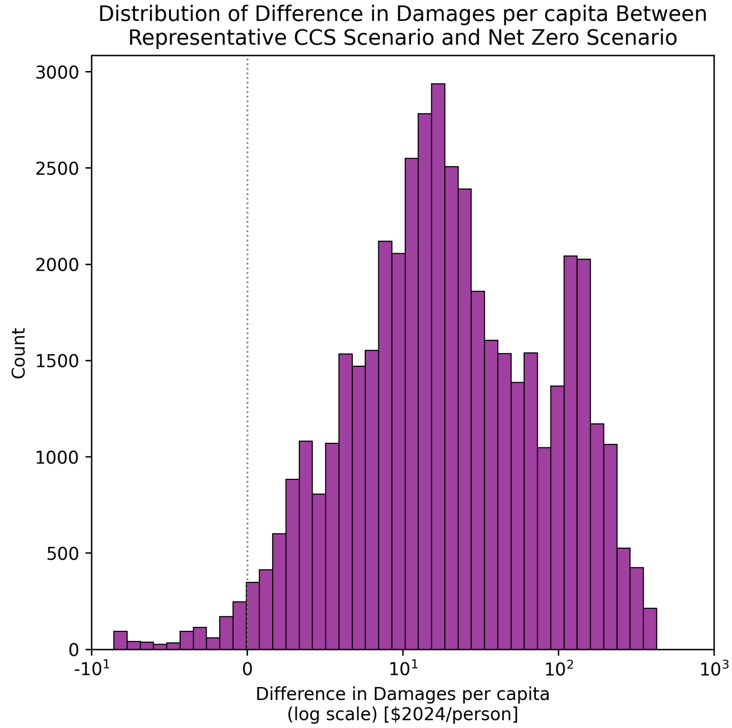

Figure S4: Log-scale distribution of 2035 change in annual health damages per capita ($2024/person) between the representative CCS scenario and the Net Zero scenario for all U.S. census blocks in the WECC.

thermal plants in operation today. We calculate the ratio of 2035 installed coal and gas capacity (with and without CCS) to existing coal and gas capacity for each load zone. We find the minimum, average, and maximum ratio to be 1.56E-8, 5.94, and 326.75, respectively. We believe an average increase in coal and gas capacity of about 6 times per load zone is not unreasonable for high-CCS futures considering electricity demand is expected to continue rising with population and GDP growth, electrification is an important aspect of decarbonization that will further increase demand, and additional thermal capacity needs to be installed if CCS is used in order to compensate for the energy penalty. Table S8 shows the existing and 2035 installed coal and gas capacity values, as well as the ratio of these values and the capacity of the single largest plant in the load zone, for load zones with 2035 coal and gas capacity ratios that exceed 5.94 (average ratio) the existing installed capacity. We observe that there are 3 load zones with significantly large increases in coal and gas capacity (14-327 times existing capacity). However, the single largest plant built in any of these load zones for any of these scenarios, if we distribute newly built capacity proportionally to existing sites, is 1.8 GW in size. As a reminder, this assumption is required for emissions accounting purposes, since newly built fossil fuel generators need a location assigned to them to have their impact be evaluated with InMAP. Hence, we are assuming new coal and gas plants will be installed at the same location or very nearby to existing coal and gas plants. Note the largest existing natural gas plant in the U.S. (as of 2022) is 3.777 GW and is located in Florida [2]. No single natural gas plant built in 2035 in any of the scenarios exceeds the size of the current largest U.S. natural gas plant. Furthermore, since each of these scenarios build 86-105 GW of total coal and gas capacity in 2035, the largest installed plant makes up at most only about 2% of the fraction of the total system coal and gas capacity. Hence, we infer that allowing unlimited amounts of CCS to be installed in any load zone that has existing coal or gas capacity, overall, does not lead to build out values that far exceed the magnitude of existing coal and gas plants.

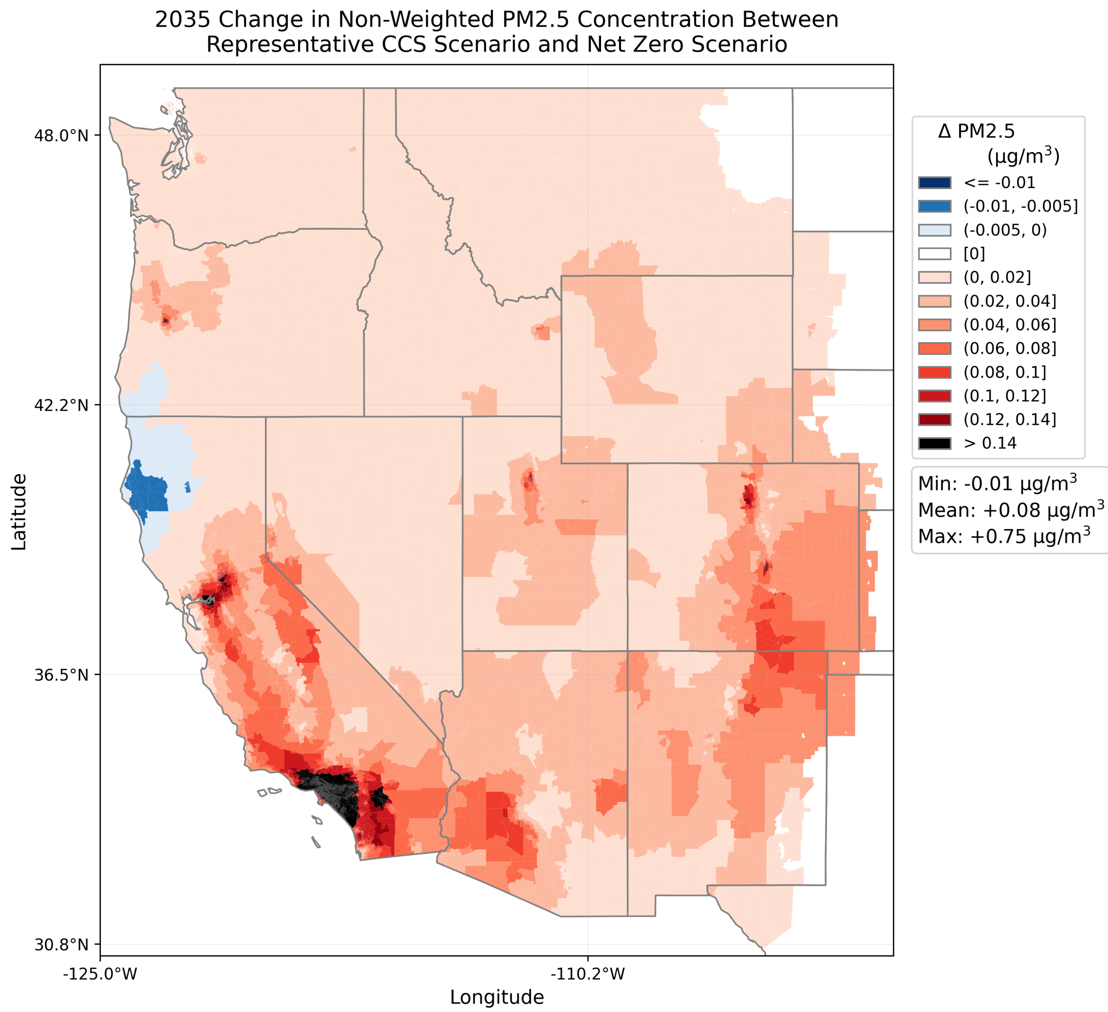

Figure S5: Map of 2035 change in non-weighted $PM_{2.5}$ concentration ($\mu g/m^3$) between the representative CCS scenario and the Net Zero scenario for U.S. census blocks in the WECC. Positive values (red) indicate census blocks that have higher non-weighted $PM_{2.5}$ concentration values than in the Net Zero scenario, and negative values (blue) indicate census blocks that have lower non-weighted $PM_{2.5}$ concentration values than in the Net Zero scenario.

For reference, we show 2035 total installed capacity values (GW) by technology and CCS scenario in Table S9 and 2035 total annual generation values (TWh) by technology and CCS scenario in Table S10.

LCOE & System Costs

Table S11 shows the levelized cost of electricity (LCOE) for the various coal and gas technologies with and without CCS in our model. We use the simple LCOE formula from the National Renewable Energy Lab's (NREL) LCOE calculator documentation [4], which is shown in Eq. 1. OC is the overnight cost (\$/MW), FOM is the fixed operation and maintenance (O&M) costs (\$/MW-yr), 8760 is the number of hours in a year, CF is the capacity factor of each technology (1 - annual outage rate) (unitless), FC is the fuel cost (\$/MMBtu), HR is the heat rate (MMBtu/MWh), and VOM is the variable O&M cost (\$/MWh). CRF is the capital recovery factor, and the equation

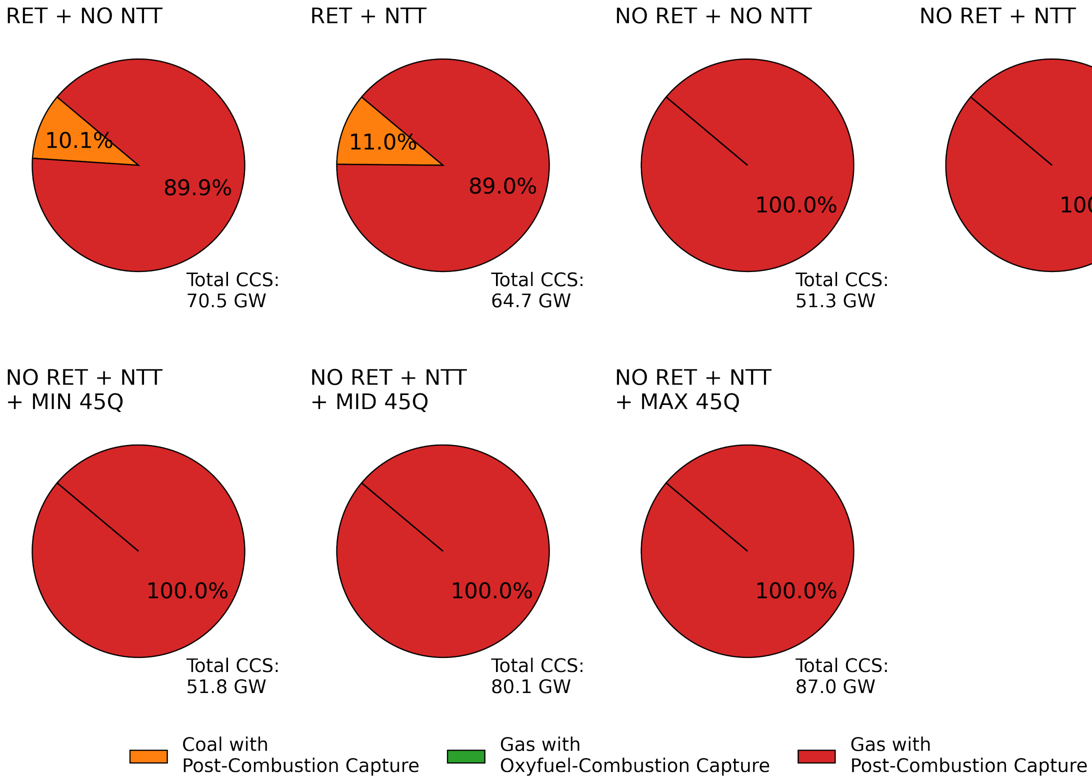

Figure S6: 2035 installed CCS mix for CCS scenarios with unlimited CCS capacity (only in load zones with existing coal/gas capacity). CCS scenarios are the same as those in the main manuscript.

Table S8: Load zones with a ratio of 2035 coal and gas capacity (with and without CCS) to existing coal and gas capacity larger than the average ratio (outliers).

Scenario	Load Zone	Existing Coal & Gas (MW)	2035 Coal & Gas (MW)	Ratio of 2035 to Existing Capacity	2035 Capacity of Largest Plant (MW) (for emissions accounting)
RET + NO NTT	CA_SCE_VLY	64.0	910.8	14.2	861.0
RET + NO NTT	ID_E	5.6	1,829.8	326.8	1,829.8
RET + NO NTT	OR_W	17.5	412.0	23.5	259.0
RET + NTT	CA_SCE_VLY	64.0	892.2	13.9	843.4
RET + NTT	ID_E	5.6	509.4	91.0	509.4
RET + NTT	OR_W	17.5	287.0	16.4	180.4
NO RET + NO NTT	CA_SCE_VLY	64.0	930.5	14.5	879.6
NO RET + NO NTT	ID_E	5.6	825.9	147.5	825.9
NO RET + NO NTT	OR_W	17.5	822.0	47.0	516.7
NO RET + NTT	CA_SCE_VLY	64.0	893.3	14.0	844.4
NO RET + NTT	ID_E	5.6	716.4	127.9	716.4
NO RET + NTT	OR_W	17.5	1,091.0	62.3	685.8

for CRF is shown in Eq. 2 (unitless), where i is the assumed interest rate and n is the number of finance years or number of annuities paid. We assume an interest rate of 5% and 40 years for the lifetime of all coal and gas technologies in Table S11. The CRF is used to annualize the overnight cost. The final LCOE values are reported in \$/MWh.

$$\mathrm{LCOE} = \frac{\mathrm{OC} * \mathrm{CRF} + \mathrm{FOM}}{8760 * \mathrm{CF}} + \mathrm{FC} * \mathrm{HR} + \mathrm{VOM} \tag{1}$$

Table S9: Total 2035 installed capacity (GW) by technology for each CCS scenario.

Technology	Scenario							
	NET ZERO	RET + NO NTT	RET + NTT	NO RET + NO NTT	NO RET + NTT	NO RET + NTT + MIN 45Q	NO RET + NTT + MID 45Q	NO RET + NTT + MAX 45Q
Biomass	2.1	1.4	1.5	1.5	1.5	1.4	1.3	1.3
Coal	0.0	0.0	0.0	7.1	7.1	7.1	1.5E-3	1.5E-3
Coal with CCS	0.0	7.1	7.1	0.0	0.0	0.0	0.0	0.0
Gas	0.1	15.3	39.3	33.4	52.6	49.2	32.5	25.2
Gas with CCS	0.0	63.4	57.6	51.3	45.7	51.8	80.1	87.0
Geothermal	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Hydro	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9
Nuclear	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Oil	0.0	0.2	0.2	0.2	0.2	0.2	0.02	0.02
Waste	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Offshore Wind	26.1	2.5	2.2	2.2	1.9	0.6	0.3	0.6
Wind	53.7	30.6	39.4	33.8	42.7	32.7	20.8	19.0
Storage	82.1	23.8	5.5	12.9	5.0E-6	1.2E-5	0.0	2.3
Solar	241.7	113.1	97.1	104.3	91.1	88.6	82.4	82.8
Total	465.4	317.6	308.1	312.2	307.6	286.4	276.2	277.8

Table S10: Total 2035 generation (TWh) by technology for each CCS scenario.

Technology	Scenario							
	NET ZERO	RET + NO NTT	RET + NTT	NO RET + NO NTT	NO RET + NTT	NO RET + NTT + MIN 45Q	NO RET + NTT + MID 45Q	NO RET + NTT + MAX 45Q
Biomass	7.9	9.3	9.5	9.5	9.4	9.1	9.1	9.1
Coal	0.0	0.0	0.0	12.1	0.3	1.7	0.0	0.0
Coal with CCS	0.0	6.8	4.3	0.0	0.0	0.0	0.0	0.0
Gas	0.3	33.7	71.6	25.0	66.9	60.9	7.6	3.5
Gas with CCS	0.0	269.0	243.7	280.9	257.1	302.4	423.1	432.1
Geothermal	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Hydro	178.8	178.8	178.8	178.8	178.8	178.8	178.8	178.8
Nuclear	42.8	39.3	38.4	39.0	38.4	40.0	40.8	41.4
Oil	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0
Waste	0.1	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Offshore Wind	116.4	10.7	9.6	9.6	8.5	2.9	1.5	2.8
Wind	126.6	101.5	129.2	112.1	138.5	109.3	69.6	63.2
Storage	235.6	34.0	8.2	18.5	0.0	0.0	0.0	2.7
Solar	549.4	316.1	268.9	290.7	251.6	248.2	233.6	234.9
Total	1260.2	1001.9	1164.9	979.0	951.9	955.9	966.8	970.2

$$\mathrm{CRF} = \frac{i * (1+1)^n}{(1+i)^n - 1} \tag{2}$$

Figure S7 shows the 2035 system-wide itemized investment and operation costs by CCS scenario in Billions of USD (NPV) with 2018 as the base year, including the 45Q tax-credit in the 3 core cases that consider it. Figure S7 does not include annual health damage costs.

Table S11: Levelized cost of electricity (LCOE) components for new coal/gas technologies.

Technology	Investment costs ($/MWh)	Fixed O&M costs ($/MWh)	Variable O&M costs ($/MWh)	Fuel costs ($/MWh)	Total LCOE ($2024/MWh)
Coal steam turbine	22.49	3.07	4.57	19.74	61.84
Coal steam turbine + post-CCS	26.93	12.27	12.01	37.60	110.12
Coal steam turbine + oxy-CCS	31.91	21.90	13.24	28.20	118.11
IGCC	32.56	4.33	7.34	17.44	76.48
IGCC + pre-CCS	46.72	23.90	19.98	20.04	137.20
NGCC	6.69	1.53	4.50	35.05	59.23
NGCC + post-CCS	11.29	5.11	3.35	39.38	73.33
NGCC + oxy-CCS	11.86	8.14	5.08	43.81	85.42

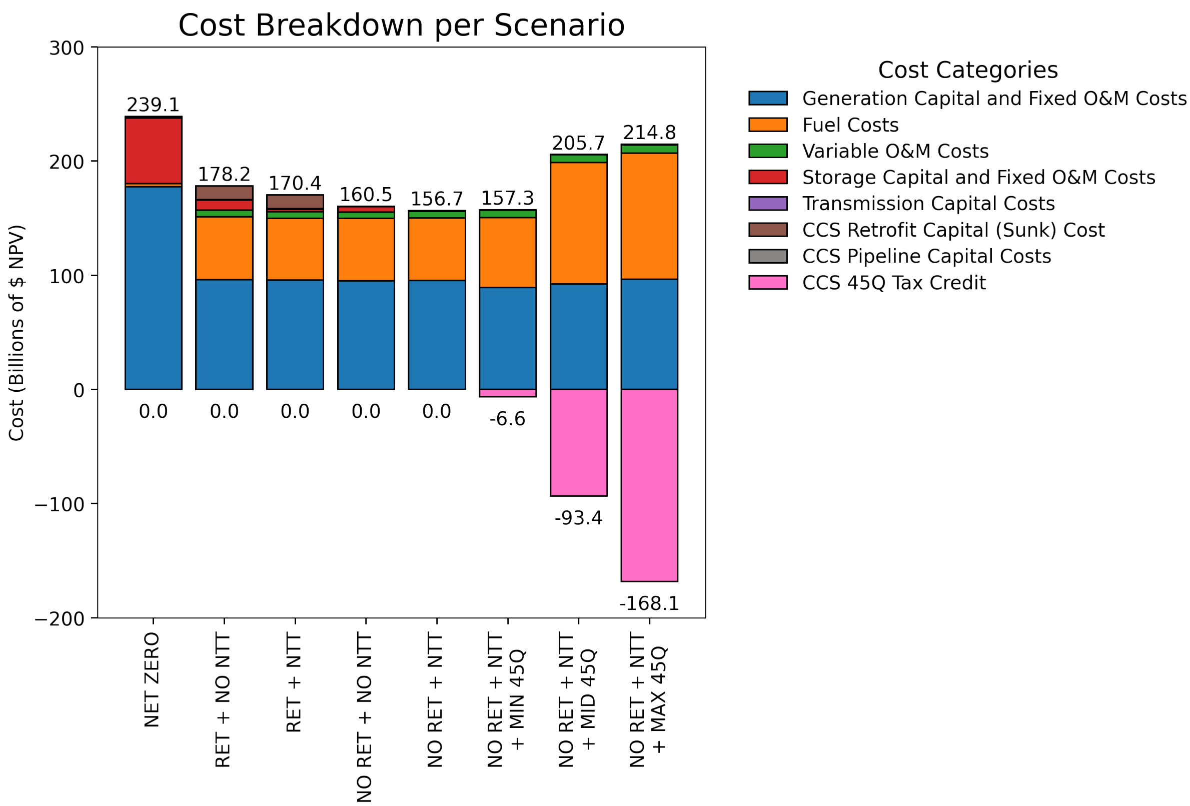

Figure S7: 2035 system-wide itemized costs by CCS scenario in billions of USD (NPV) with 2018 as the base year. Note “CCS Retrofit Capital Costs” are sunk costs that are not included in the objective function. They are included for demonstration purposes.

Daily and Annual Dispatch

We show the system-wide optimal daily dispatch for a summer day (Figure S8) and a winter day (Figure S9) in 2035. As expected, gas with CCS is dispatched mostly in the early mornings and evenings when solar energy is unavailable. Compared to the Net Zero scenario, the CCS scenarios have very little (if any) battery dispatch. The solar peak also appears smaller in the CCS scenarios relative to the Net Zero scenario. In the winter when wind energy is high, we observe even smaller solar peaks in the CCS scenarios, but the shape of dispatch for gas with CCS retains the same shape with most deployment in the early mornings and evenings. In both seasons, the case with the most battery dispatch is the most restrictive one, i.e. the one that enforces retrofit and does not allow new traditional thermal to be built. Figure S10 shows the average system-wide optimal annual dispatch for all of 2035, revealing that the dispatch of gas with CCS follows the load shape, which peaks mid-summer and mid-winter. The mid-summer peak in gas and gas with CCS seems to be exacerbated by a slight reduction in wind generation in the summer.

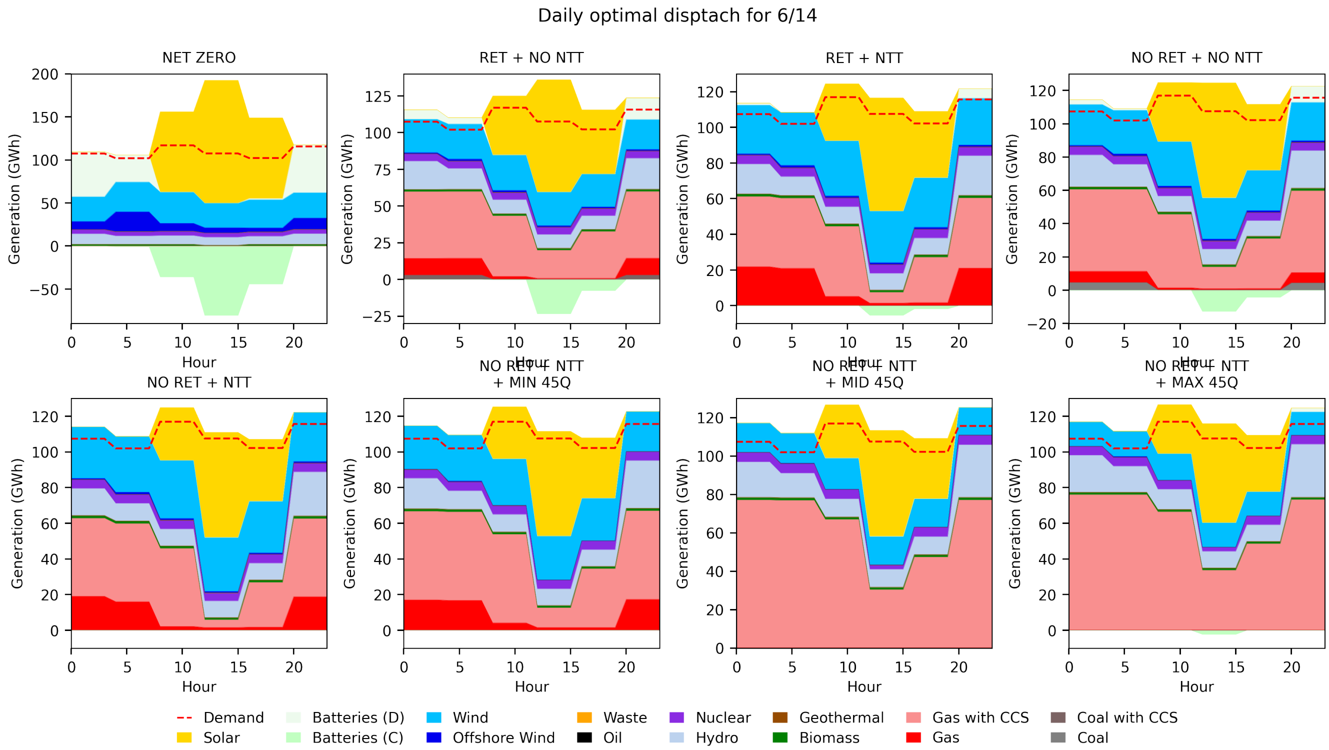

Figure S8: 2035 system-wide optimal dispatch for a summer day by CCS scenario in GWh.

Additional Test Scenarios and Sensitivity Analyses

This section describes additional scenarios used to test various alternative outcomes, including sensitivity analysus on CCS costs, CCS energy penalties, assumed VSL, and choice of retrofit technology.

Limited CCS Scenarios

As mentioned in the main manuscript, candidate CCS-equipped generators are based on existing compatible coal and gas generators, with the power capacity of each candidate CCS-equipped generator limited by the capacity of the corresponding existing generator. However, each load zone also has the option to build as much additional capacity of each type of CCS as desired, as long as the load zone has existing NGCC or coal plants. The reason we restrict new CCS builds to load zones that have existing coal and gas plants is because emissions accounting requires a geographical assumption— this "extra" installed capacity is assigned to the location of existing CCS-compatible generators, proportional to the current capacity of existing plants. It would not be possible to use this assumption if the load zone had no existing coal or gas capacity. Furthermore, it is unlikely that regions that currently have no polluting fossil fuel generators will want to build these generators in the coming decades, especially as decarbonization increasingly becomes a priority.

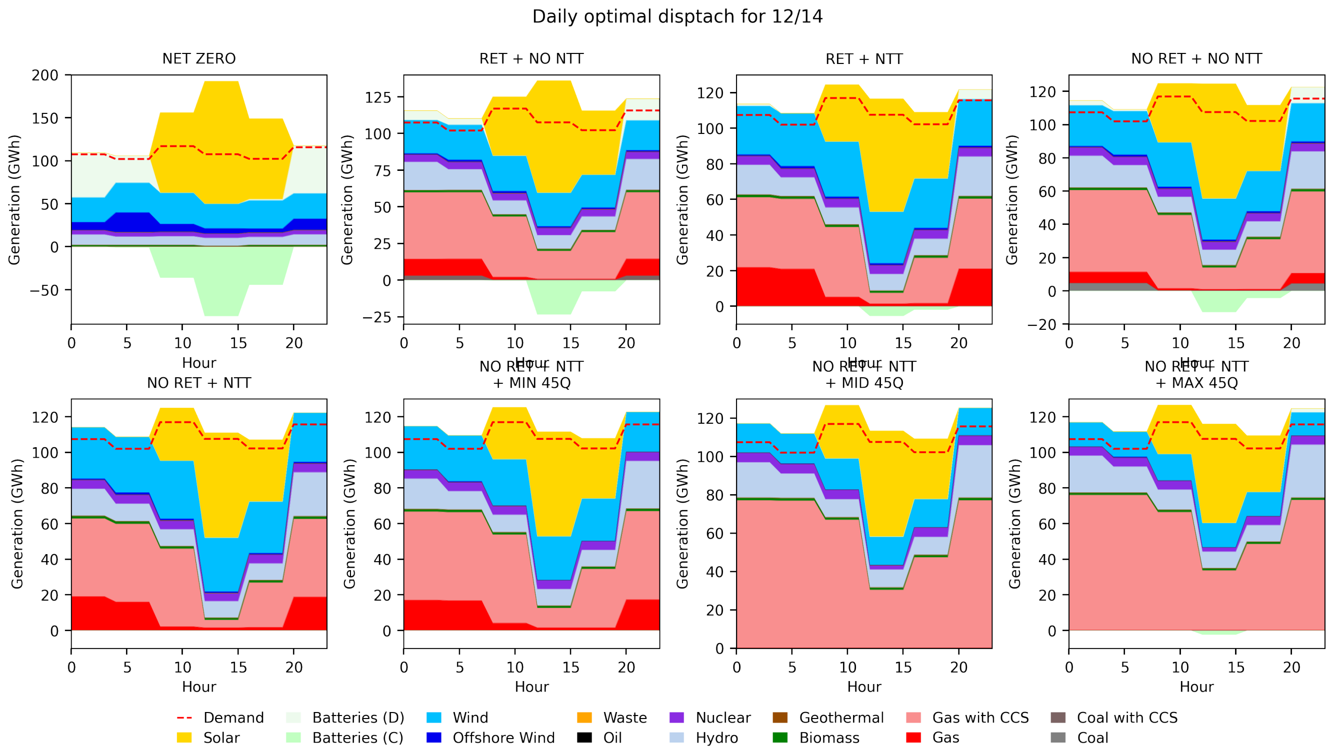

Figure S9: 2035 system-wide optimal dispatch for a winter day by CCS scenario in GWh.

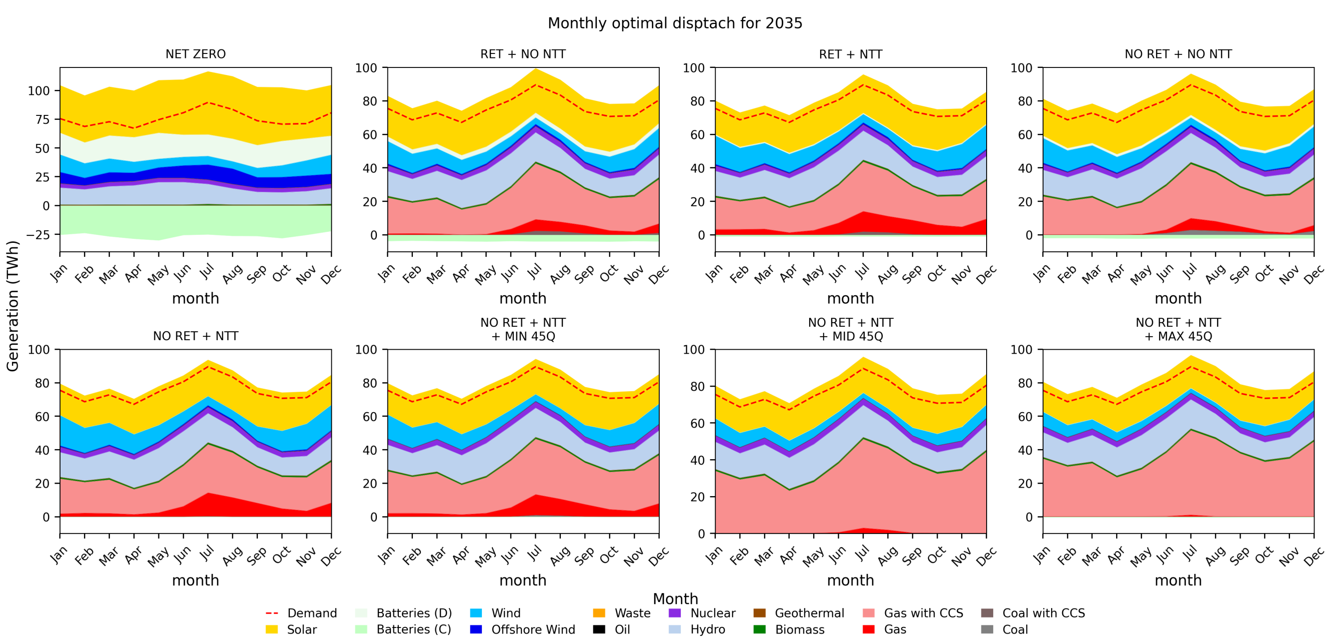

Figure S10: 2035 system-wide optimal annual dispatch by CCS scenario in GWh.

Due to local zoning laws, permitting requirements, and public perceptions, we infer that new fossil fuel generators will likely be located near existing ones rather than in areas where these technologies have not already been established. However, we test limiting each load zone to building 6 times the power capacity of existing coal steam turbines and/or NGCC turbines for each compatible type of CCS to test how limiting the amount of CCS capacity per load zone affects the results. We enforce this by limiting the expansion of each existing coal and gas generators by 6 times its current capacity for each corresponding candidate CCS type. Currently, there are no operational IGCC plants in the WECC, so we allow up to 6 GW of IGCC with pre-combustion CCS per load zone for the test cases that limit newly built CCS per load zone. Similarly, for these test cases, we allow up to 6 GW of each type of new traditional thermal per load zone for the scenarios that allow it. Although we allow California load zones to build up to 6 GW of IGCC with pre-combustion CCS (since most CO_2 emissions would be captured by those plants), they are restricted from building any new traditional coal, in line with the State's policies against coal [5]. Furthermore, for the emissions accounting reasons described previously, we also restrict any new thermal (with or without CCS) from being built in load zones that do not currently have any coal or gas capacity. Table S12 summarizes the system-wide capacity per coal/gas technology for the CCS limited test scenarios according to the restrictions described above.

Table S12: Maximum system-wide capacity (GW) by technology and scenario policy for limited CCS capacity test scenarios.

Technology	**Capture Technology**	**Capacity per Scenario Policy (GW)**	
		NTT	**NO NTT**
NGCC	none	222.0	0.0
Coal Steam Turbine	none	156.0	0.0
IGCC	none	156.0	0.0
NGCC	oxyfuel-combustion	344.5	344.5
NGCC	post-combustion	344.5	344.5
Coal Steam Turbine	oxyfuel-combustion	142.7	142.7
Coal Steam Turbine	post-combustion	142.7	142.7
IGCC	pre-combustion	222.0	222.0

Figure S11 shows the optimal installed capacity and annual generation for the CCS scenarios with limited CCS capacity. We observe that in general, the capacity and generation mixes in the limited CCS scenarios are very similar to those of the unlimited CCS scenarios, besides the lower amounts of generation from gas with CCS. Because we limit by CCS type, NGCC with post-combustion capture gets maxed-out in most load zones, leaving only the other types of CCS that proved to be uncompetitive (given the assumed parameters) in the unlimited CCS scenarios available for installation. This is a limitation of the limited capacity formulation, because investments are not limited by technology type in reality. However, to enforce CCS limits in the model, this is necessary. Future work could benefit from limiting CCS technologies based on an in-depth sitting analysis that takes into account suitable land. Then, all coal and gas plants (with or without CCS) may be constrained by a single, technology agnostic capacity limit that corresponds to the maximum about amount thermal technologies than can be built in each load zone.

Figure S12 reveals that because NGCC with post-combustion capture is maxed-out, we see more generation from other types of CCS, namely coal with post-combustion capture and NGCC with oxyfuel-combustion capture. However, coal with post-combustion capture is only optimal to dispatch in the cases that enforce retrofit, hence installed coal retrofits are considered sunk costs and thus are "free" to install, and the cases with the two highest 45Q tax credits. There is a very small amount of generation (0.4-6.7%) from NGCC with oxyfuel-combustion capture in every limited CCS scenario, which varies from the unlimited CCS scenarios that did not install any NGCC with oxyfuel-combustion capture.

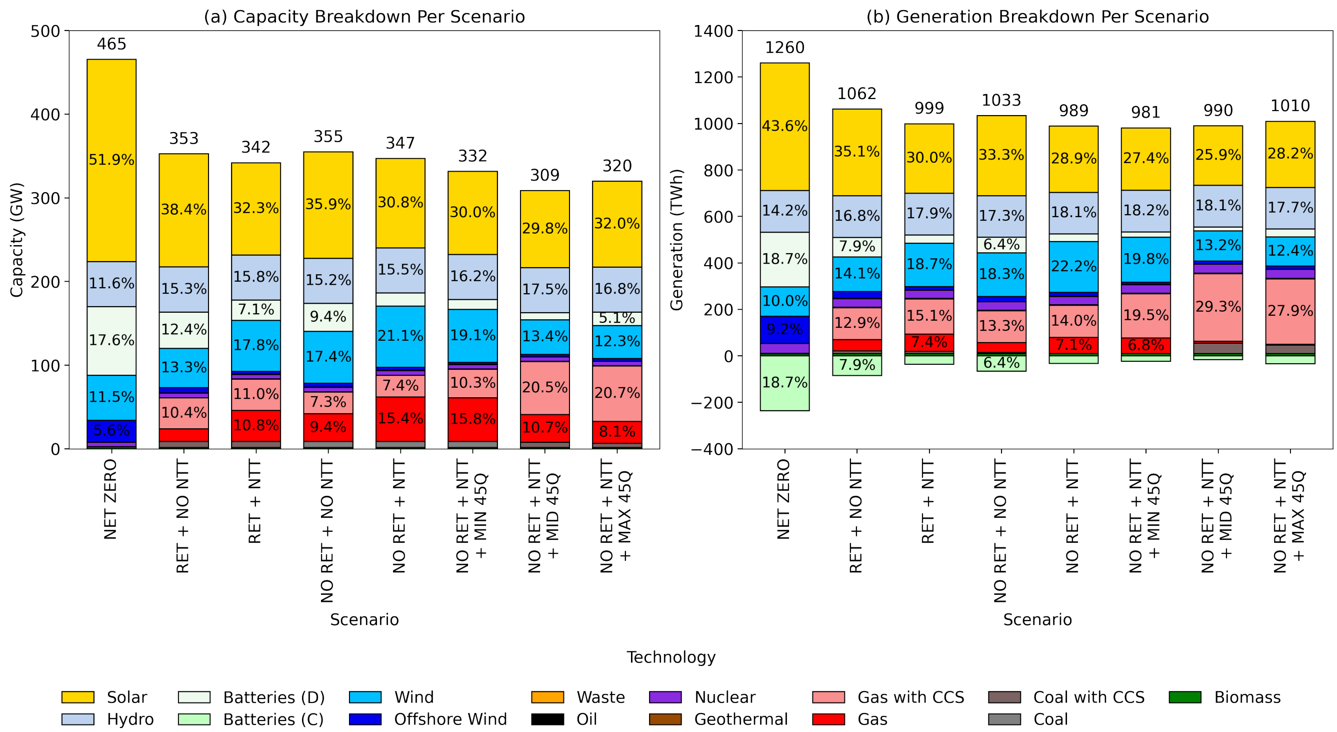

Figure S11: 2035 optimal installed capacity (GW) and annual generation (TWh) for CCS scenarios with limited CCS capacity (6X existing coal/gas capacity per CCS type, only in load zones with existing coal/gas capacity). CCS scenarios are the same as those in the main manuscript, but CCS capacity is limited by CCS type for each load zone.

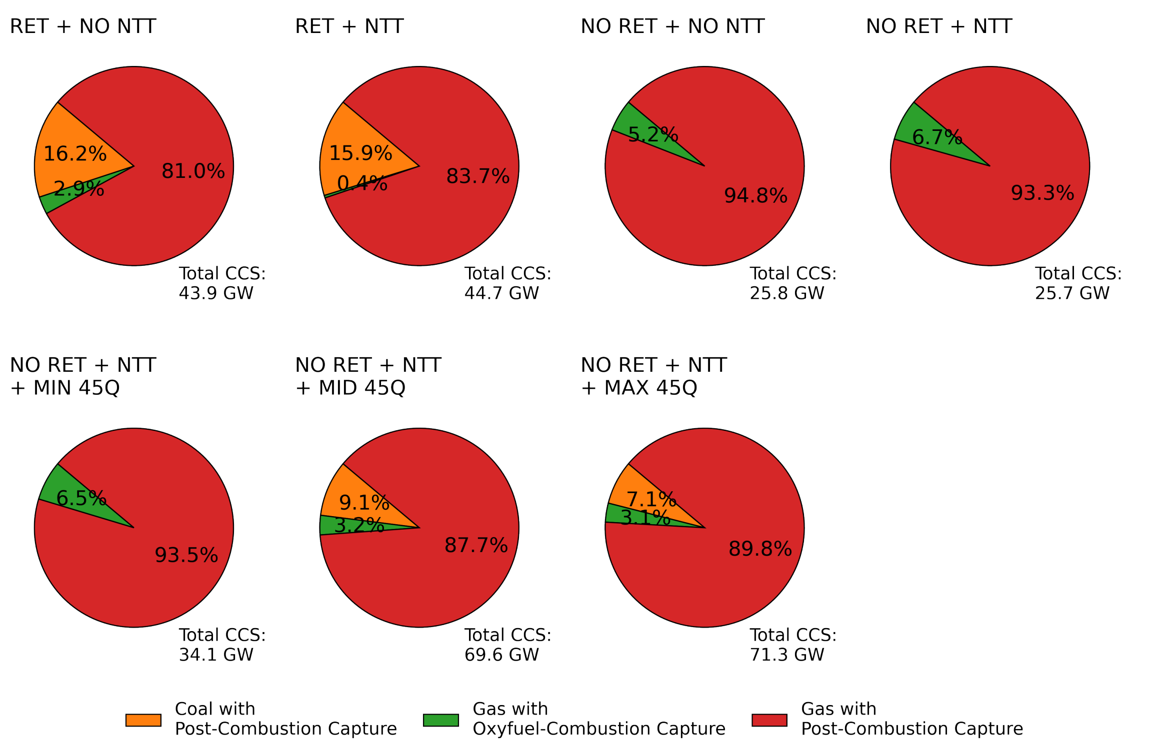

Figure S12: 2035 installed CCS mix for CCS scenarios with limited CCS capacity (6X existing coal/gas capacity per CCS type, only in load zones with existing coal/gas capacity). CCS scenarios are the same as those in the main manuscript, but CCS capacity is limited by CCS type for each load zone.

We observe that, just as with the unlimited CCS scenarios, emissions for all CAPs and CAP precursors are higher in all CCS scenarios than in the Net Zero scenario. The top row of Figure S13 shows the full range of likely emissions for these pollutants in all CCS scenarios with limited CCS capacity. The bottom row shows emissions totals for average emissions factors (EFs) broken down by source. Just as with the unlimited CCS scenarios, NH_3, NO_X, and SO_2 emissions are dominated by gas with CCS. One difference we notice between the limited and unlimited CCS scenarios is that more coal with CCS is dispatched in the retrofit cases and mid- and high-45Q cases in the limited CCS scenarios than in the unlimited CCS scenarios. This is likely a consequence of the fact that more NGCC with post-combustion capture was not available to invest in, so the model had to resort to other types of CCS, including coal with post-combustion capture and a small amount of NGCC with oxyfuel-combustion CCS. We observe that those cases that produce even a small amount of generation from coal or coal with CCS have notably higher emissions of each CAP or CAP precursor. Because the representative CCS scenario (NO RET + NTT + mid 45Q) with limited CCS has comparable emissions quantities to the same case with unlimited CCS, we infer that health impacts are likely comparable between the two versions of the representative CCS scenario.

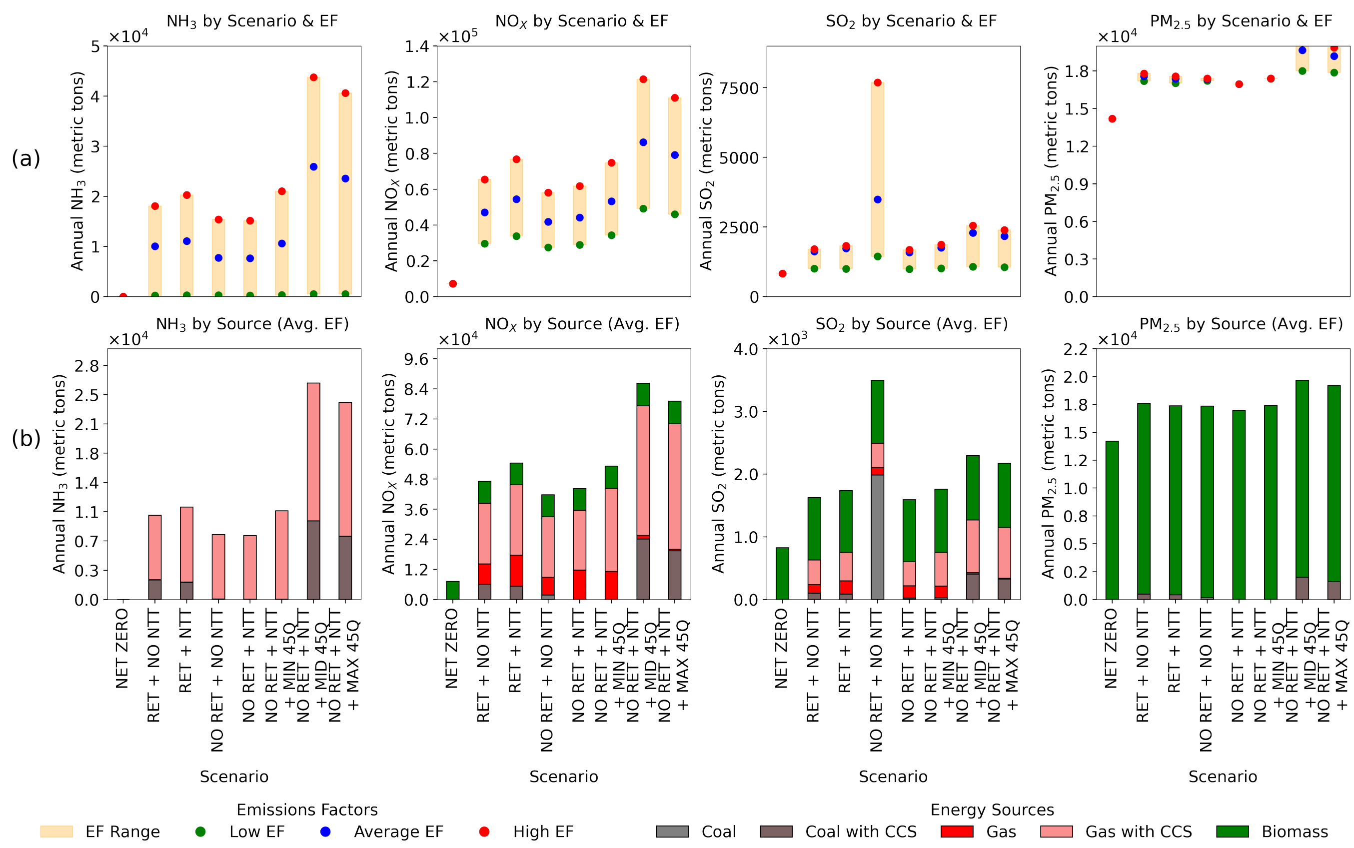

Figure S13: 2035 total system-wide emissions and their sources by limited-CCS scenario. Row (a) shows emissions for full EF range and row (b) shows emission totals and their sources for average EFs.

CCS Cost Sensitivity

Figure S14 shows the installed capacity and generation mixes for the no retrofit + new traditional thermal allowed scenario and each of the reduced CCS cost cases (-5% to -20% CCS costs in 2035) based on the same scenario. Recall that the percent decreases in CCS costs are applied uniformly to all CCS technology options for the sensitivity analysis. Gas with CCS only experiences an increase of 2.5% in its share of the installed capacity mix and an increase of 3.7% in its share of the annual generation mix between the nominal CCS cost case and the -20% CCS cost case, which corresponds to a capacity increase of only about 7 GW out of the ∼300 GW total in the system and a generation increase of only about 36 TWh out of the ∼954 TWh total in the year. The slight uptick in gas with CCS mostly affects land-based wind energy deployment, but it only reduces land-based wind's share of the capacity and generation mixes by about 3.3% and 3.4%, respectively. There is no coal with CCS built and NGCC with post-combustion capture continues to be the only type of gas with CCS built in all cases of the CCS costs sensitivity analysis. Since the generation profiles are very similar across all cases of the CCS costs sensitivity analysis and health impacts from emissions are dependent on the annual generation mix, we infer that the outcomes of our study are not highly sensitive to the assumed CCS costs.

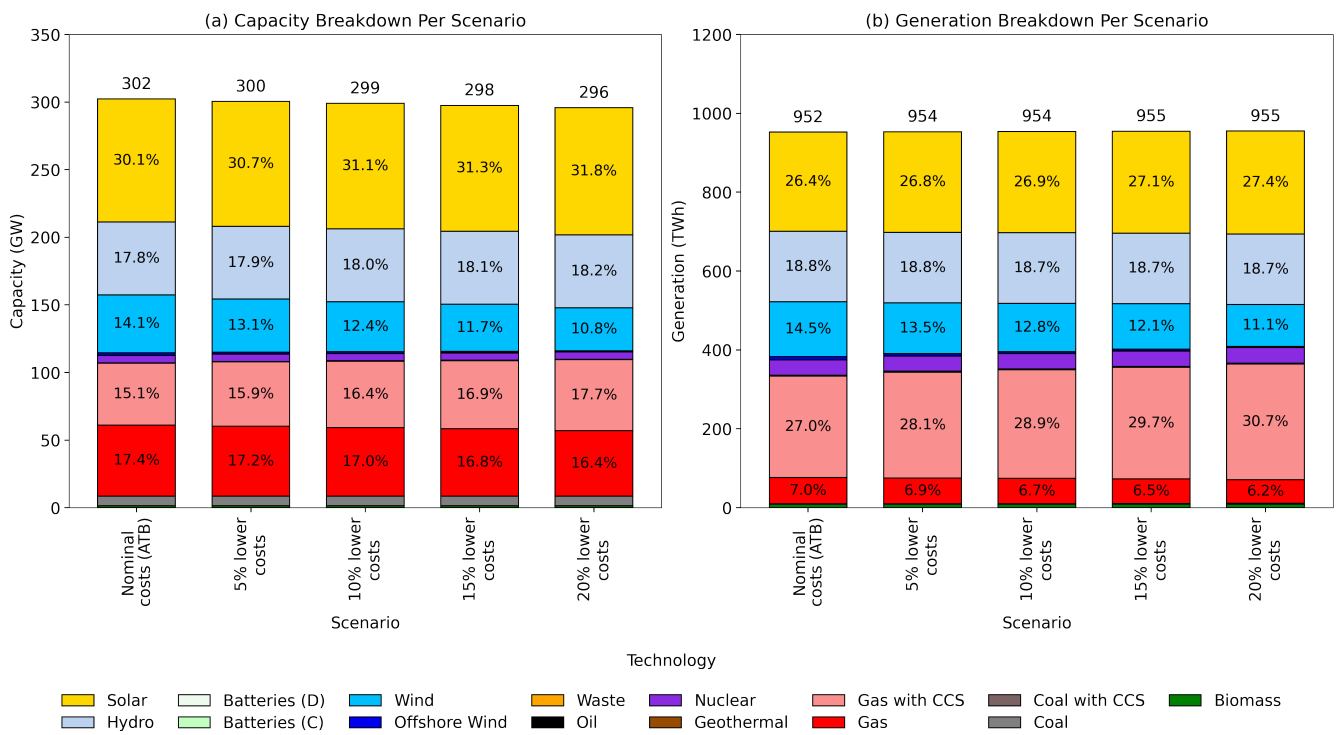

Figure S14: 2035 optimal installed capacity and annual generation by CCS cost scenario. Scenarios test various CCS cost assumptions used for no retrofit + new traditional thermal allowed scenario. Installed capacity (GW) and generation (TWh) mixes are not significantly affected by CCS costs if all types of CCS experience the same percent decreases in cost.

CCS Energy Penalty Sensitivity

Figure S15 shows the installed capacity and generation mixes for the no retrofit + new traditional thermal allowed scenario with nominal energy penalties and each of the reduced CCS energy penalty cases (-1% to -5% energy penalties) based on the same scenario. The percent decreases in CCS energy penalties are applied uniformly to all CCS technology options for the sensitivity analysis. Gas with CCS only experiences increases of 1% and 1.7% in its share of the installed capacity and annual generation mixes, respectively, between the nominal energy penalty case and the -5% energy penalty case, which corresponds to a capacity increase of only about 1.6 GW out of the ∼300 GW total in the system and a generation increase of only about 12.8 TWh out of the ∼950 TWh total in the year. Similar to the CCS cost sensitivity analysis, the slight increase in gas with CCS mostly affects land-based wind energy deployment, but it only reduces land-based wind's share of the capacity and generation mixes by about 2.1%. Since the decreased energy penalties are synonymous to increases in overall efficiency, we also observe a slight decrease in total installed capacity (-9 GW) and total generation (-12 TWh) as the energy penalties decrease from nominal to -5%. There is no coal with CCS built and NGCC with post-combustion capture continues to be the only type of gas with CCS built in all cases of the energy penalty sensitivity analysis. Since the generation profiles are very similar across all cases of the energy penalty sensitivity analysis and health impacts from emissions are dependent on the annual generation mix, we infer that the outcomes of our study are not highly sensitive to the assumed CCS energy penalties.

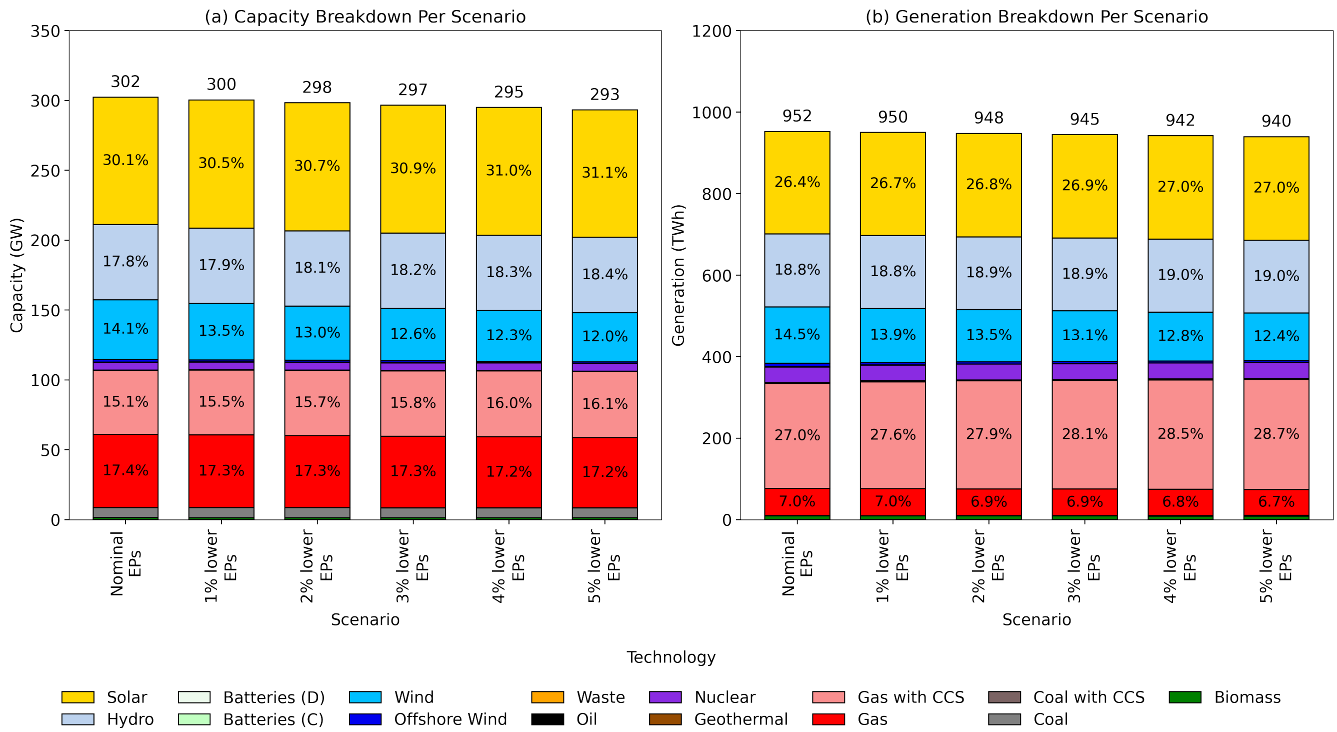

Figure S15: 2035 optimal installed capacity and annual generation by energy penalty scenario. Scenarios capture various CCS energy penalty assumptions used for no retrofit + new traditional thermal allowed scenario. Installed capacity (GW) and generation (TWh) mixes are not significantly affected by CCS energy penalties if all types of CCS experience the same percent decreases in energy penalties.

Assumed VSL Sensitivity

Table S13 shows the total annual health damages from InMAP for 2035 based on each Value of Statistical Life (VSL) for each CCS scenario with Average EFs in Billion \$2024. "COBRA VSL" refers to the VSL used in the U.S. Environmental Protection Agency's (EPA's) COBRA model. The low, mid, and high VSLs refer to the VSL range in \$2024 recommended by the U.S. Office of the Secretary of Transportation [6].

Oxyfuel-Combustion Retrofits

In theory, oxyfuel-combustion capture has the potential to emit significantly less CAPs than other types of CCS [6]. Horssen et al. state that "oxyfuel-combustion capture from coal-fired plants can achieve more than 90% reduction in NO_X, SO_X and dust emissions per unit output compared to

Table S13: Total annual health damages from InMAP for 2035 based on various VSLs with Average EFs (Billion $2024).

Scenario	Assumed VSL ($2024)			
	Low VSL = $7,146,831.66	Mid VSL = $12,705,478.51	COBRA VSL = $13,249,840.97	High VSL = $17,734,730.42
NET ZERO	1.06	1.88	1.96	2.63
RET + NO NTT	3.08	5.48	5.71	7.65
RET + NTT	3.05	5.43	5.66	7.58
NO RET + NO NTT	3.53	6.27	6.54	8.76
NO RET + NTT	3.36	5.97	6.23	8.33
NO RET + NTT + MIN 45Q	3.43	6.10	6.36	8.52
NO RET + NTT + MID 45Q	3.85	6.85	7.14	9.56
NO RET + NTT + MAX 45Q	3.91	6.96	7.26	9.71

emissions from conventional coal-fired plants without CO_2 capture" due to pure oxygen being used in the combustion stage and a CO_2 purification and compression step before transport [7]. Despite the slowly growing pool of literature that explores CAP emissions factors for coal with oxyfuel-combustion capture, emissions factors for natural gas plants with oxyfuel-combustion capture are generally unknown. It is important to note that although the emissions factors assumed for NGCC plants with oxyfuel-combustion capture are nearly 0 for all CAPs, these values are missing in most literature that reports CAPs emissions from CCS-equipped plants, with only one or two sources estimating 0 emissions for NO_X, SO_2, and particulate matter [6, 7, 8]. Oxyfuel-combustion capture is still a relatively nascent and expensive technology compared to post-combustion capture, so it is unlikely to be used for large-scale retrofitting of the existing thermal fleet within the next decade. Furthermore, we have seen that even small amounts of generation from coal plants (with or without CCS) leads to notable increases in emissions that are harmful to human health. Hence, we recommend that efforts to bring oxyfuel-combustion capture to market should focus on NGCC plants.

Figure S16 shows the installed capacity and generation mixes for the scenarios that enforce system-wide retrofits (retrofit + new traditional thermal allowed/not allowed), testing both post- and oxyfuel-combustion capture as the retrofit technologies. The left two bars in each plot represent the scenario that does not allow new traditional thermal to be built (with post-combustion capture on the left and oxyfuel-combustion capture on the right), and the right two bars in each plot represent the scenario that does allow new traditional thermal to be built (also with post-combustion capture on the left and oxyfuel-combustion capture on the right). In general, retrofitting with post-combustion capture vs. oxyfuel-combustion capture does not affect the rest of the installed capacity mix by a notable amount. Even in the scenarios where the existing fleet of coal and gas generators is retrofitted with oxyfuel-combustion capture rather than post-combustion capture, all new CCS additions are still made up entirely of NGCC with post-combustion capture. The generation mix is slightly more affected by the retrofit technology than the installed capacity mix, but it still experiences few, relatively small differences between the post- and oxyfuel-combustion retrofitting cases based on the same scenario. For example, retrofitting with oxyfuel-combustion capture rather than post-combustion capture lowers the percent of annual generation made up by gas with CCS by only 0.5-0.8%. There are also very slight increases in total 2035 generation (2-3 TWh more annually) between the post-combustion capture retrofit cases and the oxyfuel-combustion capture retrofit cases, likely due to the higher energy penalties associated with oxyfuel-combustion capture.

The most notable difference, although it is not visible in Figure S16, in generation between the post- and oxyfuel-combustion capture cases is that generation from coal with CCS increases from 6.8 TWh to 21.9 TWh (222% increase) and from 4.3 TWh to 15.2 TWh (253% increase) between post- and oxyfuel-combustion retrofit cases that don't and do allow new traditional thermal, respectively. This can be seen in Figure S17, which shows the full range of likely emissions outcomes of each scenario. In the cases that use oxyfuel, the increase in generation from coal with CCS leads to notably higher SO_2 emissions and slightly higher NO_X and NH_3 emissions, although generation from coal with CCS only makes up less than 2.2% of total generation in those cases. The uptick in generation from coal generators retrofitted with oxyfuel-combustion capture is likely a consequence of the lower energy penalty assumed for coal with oxyfuel-combustion capture compared to post-combustion capture. This increase in overall efficiency makes it more competitive for dispatch.

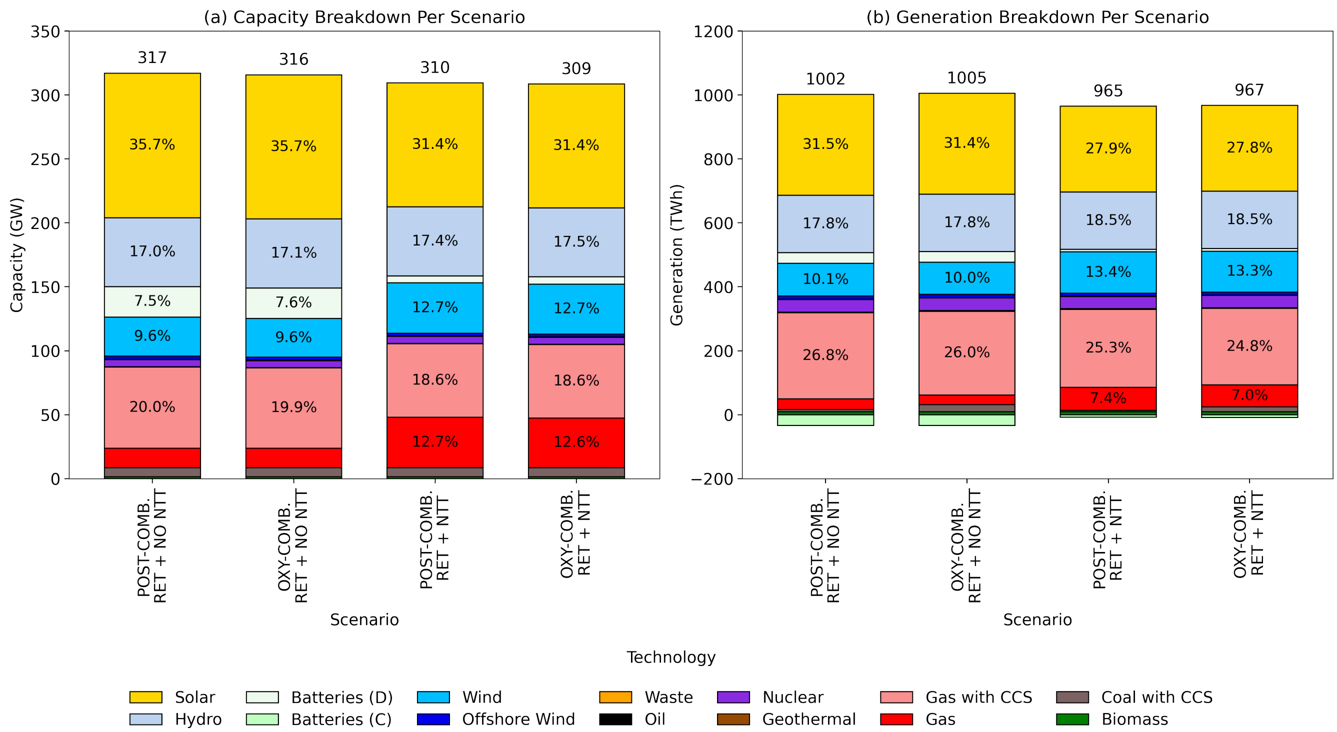

Figure S16: 2035 optimal installed capacity and annual generation by retrofit scenario. Scenarios test retrofitting with post-combustion capture vs. retrofitting with oxyfuel-combustion capture. Installed capacity (GW) and generation (TWh) mixes are nearly unaffected by choice of retrofit technology for the parameters assumed in this study.

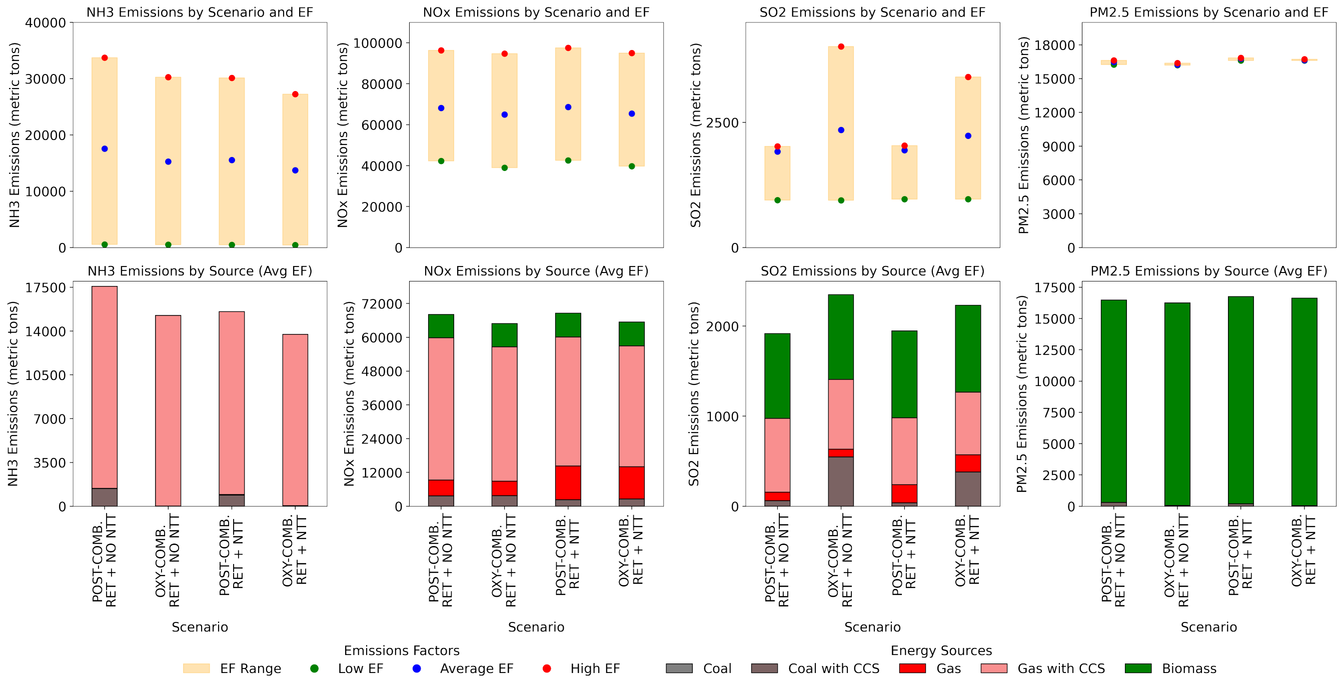

Figure S17: 2035 optimal installed capacity and annual generation by retrofit scenario. Scenarios test retrofitting with post-combustion capture vs. retrofitting with oxyfuel-combustion capture. Installed capacity (GW) and generation (TWh) mixes are nearly unaffected by choice of retrofit technology for the parameters assumed in this study.

2 Supplementary Model Information: SWITCH Data

This section of the Supplemental Information contains information about the data used in the SWITCH model, including geographic and temporal data, generator data, transmission data, costs, load data, and policies. We describe the data used in the CCS scenarios from the main manuscript (with unlimited CCS). All additional test scenarios and sensitivity analysis scenarios shown in this Supplemental Information document use the same underlying data, besides the specific inputs adjusted for each analysis, as described previously.

To optimize long-term energy system buildout under the cost target scenarios of this study, we use the capacity expansion model SWITCH. SWITCH is an open-source model with high spatial and temporal resolution designed to plan a system with high levels of renewable resources [9], and has been used to evaluate system expansion in several case studies of the Western U.S. [10], [11], [12]. We build on the SWITCH 2.0 (Python) version from a recent study [9], and use an academic license of the Gurobi solver version 11.0.1 build v11.0.1rc0 [13], to evaluate the optimal generation and transmission capacity expansion decisions for the U.S. portion of the Western Interconnect or Western Electricity Coordinating Council (WECC) region out to 2035. SWITCH makes investment and operations decisions for four time periods and a sample of hours per period between 2020 and 2050. More specifically, we use SWITCH-WECC by the REAM Laboratory at University of California San Diego v2.0.6 [14] with Gurobi settings MIPGapAbs = 1E5 (up to ~0.000065% optimality error), Crossover = 0, Parameter Method = 2 using a AMD EPYC 7313 16-Core Processor with 32 physical cores, 64 logical processors, and up to 32 threads. The objective function minimizes the expected value of the total net present value of generation and transmission operations and investment. We provide a detailed description and full mathematical formulation of the SWITCH model in section 3.

Geographic and Temporal Resolution

The U.S. WECC study area of this analysis is divided up into 47 "load zone" regions (Figure S18), covering all or of parts of Washington, Oregon, California, Arizona, Nevada, New Mexico, Utah, Idaho, Montana, Wyoming, Colorado, and Texas. Load zone boundaries were used from prior SWITCH-WECC analyses [9], which constructed the regions based on state lines, North American Electric Reliability Corporation (NERC) control areas, utility service territory boundaries, and high-population metropolitan areas (Figure S18). Some utility service territories were divided into multiple zones if there was a large amount of high-voltage transmission connectivity existing within the same service territory (i.e. CA_PGE_BAY, CA_PGE_CEN, CA_PGE_S, CA_PGE_N for PG&E). The boundaries were also constructed to represent zones that are unlikely to have transmission congestion within the zone (since only transmission between zones is included), and between which there has historically been transmission congestion (reflecting pathways where additional transmission may be needed). The temporal resolution of the study includes one investment period covering one 11-year duration: 2035 (covering 2030-2040). The duration of this investment period reflects the planning horizons typically used in the long-term planning process of a utility, and the length of time often needed to plan and build generation and transmission infrastructure. To represent the investment period as an 11-year timespan, we sample every day of 2035, every four hours per day (365 days x 6 hour/day = 2,190 hours). Each timepoint represents 4 hours of the corresponding day. This is the default temporal resolution used in this study, although it is altered in the temporal resolution sensitivity analysis.

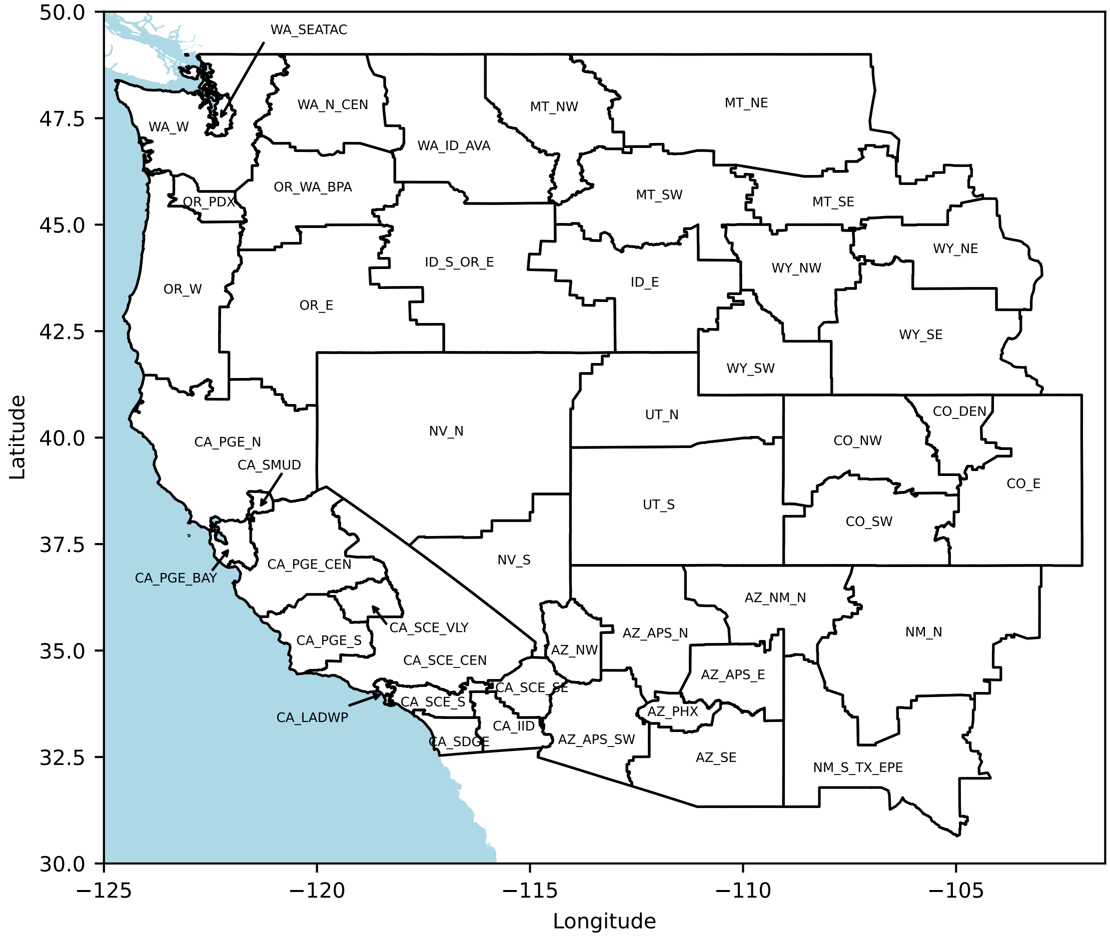

Figure S18: SWITCH-WECC U.S. load zone boundaries.

Generators

Existing Generation Data

As inputs into SWITCH, we include the list of individual generators that are existing and/or are planned for the WECC region. For the US portion of WECC, we extract the list of generators and their characteristics (such as location, fuel source, generating technology, online year, and planned retirement year if any) from the Energy Information Administration (EIA) Form 860 [15]. At the time of the data collection (in late 2019/early 2020), the latest complete year of data was the 2018 EIA Form 860. We include generators from this form that are flagged with any of these statuses: operating, standby/backup, new unit under construction, cold standby, out of service but will be returned to service, construction complete but not yet in commercial operation, not under construction but site prep underway, and under construction, under the assumption that all generators in construction or planning phases are brought online by 2035. Generators are assigned to load zones based on their latitude and longitude.

The EIA Form 860 also includes planned retirement years for generators, if known. Generators are not allowed to operate beyond their expected lifetime, therefore planned retirement years are used to calculate the lifetime of the plant to be included in the SWITCH runs. Monthly data was used from more recent Form 860 data to confirm that there were no additional planned retirements. For generators with no known retirement years, we assign a maximum lifetime based on the generating technology.

For thermal generators, we join the list of generators from Form 860 with the monthly generation and fuel use from the EIA Form 923, for the available years 2004 – 2018 [16]. We use the historical monthly generation and fuel use from Form 923 to calculate the second-best (or second-lowest) heat rate (MMBtu/MWh) for each generator, avoiding any outliers from the best heat rate. The heat rate is used in the SWITCH dispatch optimization to calculate the fuel use and associated variable cost and emissions from dispatching thermal generators. Existing thermal generators in the WECC are shown in Figure S19.

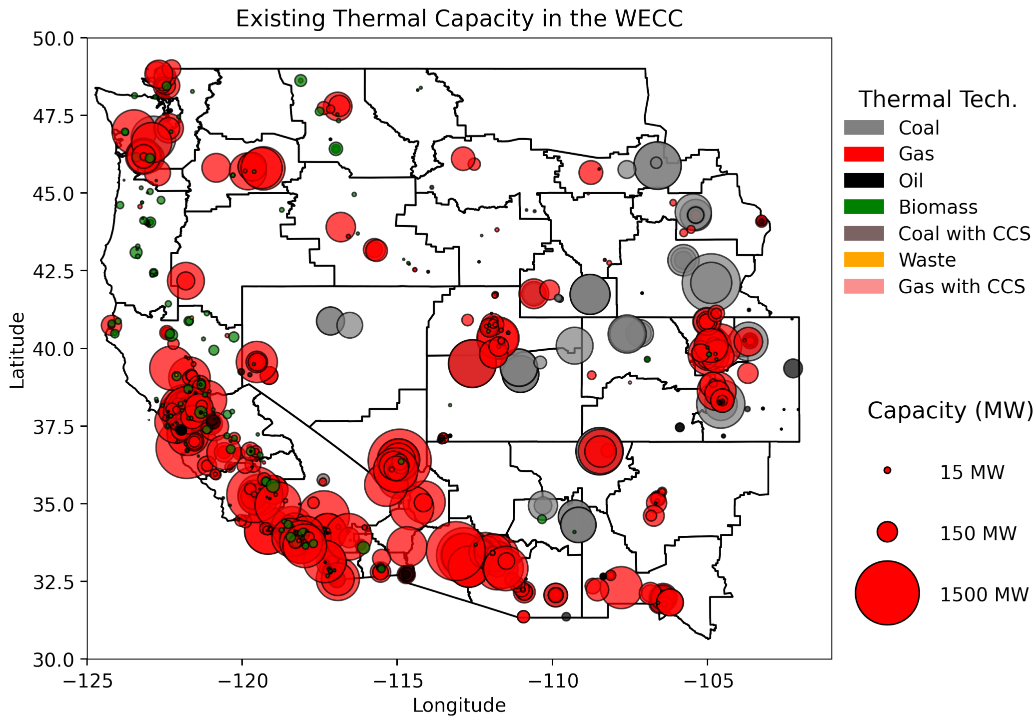

Figure S19: Map of existing thermal generation capacity in the U.S. WECC according to data from the EIA-860 [15].

Hydropower generators are constrained to generate at their average historical monthly capacity factor [11]. We extract the monthly generation by generator from 2004 – 2018 (the most recent complete data at the time of the analysis) from the Form 923. For each generator, we calculate the average power for each month (monthly generation/hours in month) and estimate that the proxy for minimum flows for each generator is the power generated at half the average monthly level. For each generator we calculate the average monthly power (and minimum flow power) over the years 2004 – 2018.

Candidate Generators

One of the key decision variables in SWITCH is the capacity investment of generation, out of a set of candidate generators with specific generating technologies and fuel sources, load zone locations, and other physical and financial generating characteristics. We use the dataset of candidate generators that was previously compiled in prior SWITCH-WECC analyses [10], [11], [12].

Candidate onshore and offshore wind generators were derived based on wind power output from a gridded 3TIER Western Wind and Solar Integration Study dataset [17] and a gridded Canadian wind developer dataset, and a selection of prime sites based on criteria including high wind energy density, and proximity to transmission [11]. A portion of candidate generators were screened out in California if they were in "Category 3, high environmental risk" locations, which include areas legally excluded for development, protected areas with ecological or social value, conservation regions, and prime agricultural land [18]. We add 39 additional candidate offshore wind generators based on the fixed-bottom candidate projects and projects based on offshore wind Call Areas in a recent SWITCH marine energy study [19]. Candidate solar generators include Residential PV (rooftop PV on homes), Commercial PV (rooftop PV on commercial buildings), Central PV (utility-scale), and Concentrating Solar Power with and without storage (solar thermal trough systems with or without thermal energy storage). Distributed Residential and Commercial PV candidate generation had been derived based on a gridded population density dataset, solar insolation data from NREL's (now deprecated) Solar Prospector tool, and assumptions on rooftop area and solar cell characteristics [11]. Available land and capacity for Central PV and Concentrating Solar Power candidate generators were screened based on land exclusion criteria (including national parks, wildlife areas, and steep terrain), solar insolation from the System Advisor Model from the National Renewable Energy Laboratory [20], and assumptions on the solar technology characteristics [11].

To simulate the dispatch of wind and solar generators, we use an exogenous dataset of hourly capacity factors by generator that had been constructed in prior SWITCH analyses [6, 8]. For wind generators, hourly capacity factors for the candidate generator set were calculated from the 3TIER Western Wind and Solar Integration Study wind speed dataset [17] using idealized turbine power curves. Capacity factors for the additional offshore wind candidates from [17] are based on the NREL Offshore NW Pacific Dataset [21], using the power curve of the 2020 ATB Reference 15 Wind Turbine [22]. For solar generators, hourly capacity factors for the candidate generator set are calculated from the System Advisor, using data from 2006 (consistent with the base weather year underlying the load profiles) [20]. Central PV and onshore wind generators with capacity-weighted average capacity factors below the 75th percentile for their technology were screened out to only have the candidate set among a computationally tractable, and commercially viable, set of higher-quality resource sites [11]. For existing solar and wind generators, we average the hourly capacity factors for all solar and wind generators, respectively, in each load zone, and assign all the generators in that load zone the average capacity factor for the given technology.

Biogas (from landfill, wastewater treatment plants, and manure) candidate generator availability is derived from an assessment of the technical resource/feed stock availability [23]. Bioliquid generators are allowed to be reinstalled in their current locations but no new bioliquid plants are assumed. No new biomass (bio solid) candidate generators are assumed, but cogeneration bio solid generation is allowed to be reinstalled at the end of its lifetime [11]. Candidate geothermal generators are based on the current locations and capacity of existing plants that may be reinstalled after retirement [11]. We assume there is no candidate hydropower generation. Natural gas combined cycle generators and combustion turbines do not have imposed maximum capacity limits. Coal generators, including IGCC, are not allowed to be installed in California but are otherwise allowed to expand without capacity limits. All types of CCS, including coal with CCS, can be built in any load zone that has existing coal or gas capacity, including those in California, in all CCS scenarios since most CO_2 emissions would be captured. Load zones with no existing coal or gas capacity are excluded from building any new coal or gas capacity (with or without CCS). Only the limited-CCS test scenarios described previously impose limits on how much of each type CCS can be built in each load zone. Cogeneration plants (with gas combined cycle or combustion turbine plants) are given the option to be reinstalled at current locations after reaching their maximum age, at current capacity limits. We assume that there is no nuclear generation available for new, candidate generation. Battery storage is available for installation in all load zones and investment periods, without capacity limits. An AC-DC-AC storage efficiency of 85%, a lifetime of 10 years, and a variable O&M cost of 0 is assumed, consistent with prior SWITCH analyses [24].

Table S14 summarizes the maximum capacity available for the set of candidate generators, and the capacity installed for existing generators for the least restrictive CCS scenario (no retrofit + new traditional thermal allowed). The no retrofit + no new traditional thermal allowed case has the same existing generators as those listed in Table S14, and the candidate generator list is the same besides there are no candidate coal or gas generators of any type. Table S15 shows the amount of coal and gas capacity retrofitted with post-combustion capture (considered to be existing capacity) in the retrofit CCS scenarios. The retrofit + new traditional thermal allowed scenario has the same capacity of existing generators shown in Table S14, besides the coal and natural gas capacity replaced by retrofitted CCS from Table S15. The retrofit + no new traditional thermal allowed case has the same existing generators as those listed in Table S14, besides the coal and natural gas capacity replaced by retrofitted CCS from Table S15, and the candidate generator list is the same besides there are no candidate coal or gas generators of any type.

Table S14: WECC total available capacity of existing and candidate generation.

Existing or Candidate Generator	Energy Source	Generation Technology	Capacity Limit (GW)
Existing Generators	Biogas	Biogas Combustion Turbine	0.1
		Biogas Combustion Turbine Cogen	0.01
		Biogas Internal Combustion Engine	0.2
		Biogas Internal Combustion Engine Cogen	0.1
		Biogas Steam Turbine	0.1
		Other Turbine	0.0002
	Bio Liquid	Bio Liquid Steam Turbine	0.013
		Bio Liquid Steam Turbine Cogen	0.3
	Bio Solid	Bio Solid Steam Turbine	0.7
		Bio Solid Steam Turbine Cogen	0.5
		Other Turbine	0.008
	Coal	Coal Steam Turbine	23.7
		Coal Steam Turbine Cogen	0.1
	Distillate Fuel Oil	Distillate Fuel Oil Combustion Turbine	0.4
		Distillate Fuel Oil Internal Combustion Engine	0.4
		Distillate Fuel Oil Internal Combustion Engine Cogen	0.005
	Electricity	Battery Storage	1.1
	Gas	NGCC	51.1
		NGCC Cogen	6.3
		Gas Combustion Turbine	24.8
		Gas Combustion Turbine Cogen	3.0
		Gas Internal Combustion Engine	1.5
		Gas Internal Combustion Engine Cogen	0.3
		Gas Steam Turbine	7
		Gas Steam Turbine Cogen	0.1
		Other Turbine	0.012
	Geothermal	Geothermal	3.8
	Solar	Central PV	22.0
		Concentrating Solar Power Trough, No Storage	0.4
		Steam Turbine	1.4
	Uranium	Nuclear	7.7

Table S14: (continued)

Existing or Candidate Generator	Energy Source	Generation Technology	Capacity Limit (GW)
	Waste Heat	Steam Turbine	0.7
	Water	Hydropower	49.5
		Pumped Storage	4.3
	Wind	Onshore Wind	26.2
	Total		**237.6**
Candidate Generators	Biogas	Biogas Combustion Turbine	0.006
		Biogas Internal Combustion Engine	0.0069
		Biogas Internal Combustion Engine Cogen	0.024
	Bio Liquid	Bio Liquid Steam Turbine	0.013
		Bio Liquid Steam Turbine Cogen	0.2
	Bio Solid	Bio Solid Steam Turbine	0.5
		Bio Solid Steam Turbine Cogen	0.3
	Coal	Coal Integrated Gasification Combined Cycle (IGCC)	Not limited, except not allowed in CA
		Coal Steam Turbine	Not limited, except not allowed in CA
		Coal Steam Turbine Cogen	0.071
		Coal Steam Turbine with Post CCS	Not limited
		Coal Steam Turbine with Oxyfuel CCS	Not limited
		IGCC with Pre CCS	Not limited
	Electricity	Battery Storage	Not limited
	Gas	Natural Gas Combined Cycle (NGCC)	Not limited
		NGCC Cogen	6.2
		Gas Combustion Turbine	Not limited
		Gas Combustion Turbine Cogen	2.9
		Gas Internal Combustion Engine Cogen	0.026
		Gas Steam Turbine Cogen	0.092
		NGCC with Post CCS	Not limited
		NGCC with Oxyfuel CCS	Not limited
	Geothermal	Geothermal	9.7
	Solar	Central PV	3104.9
		Commercial PV	52.7
		Concentrating Solar Power Trough, 6 hours storage	3508.8
		Concentrating Solar Power Trough, No Storage	5068.7
		Residential PV	124.3
	Wind	Offshore Wind	43.6
		Onshore Wind	436.3
	Total		**12,359.5**

Table S15: WECC total available capacity of existing coal and natural gas capacity retrofitted with post-combustion capture for retrofit CCS scenarios (unlimited CCS).

Fuel Source	Capture Technology	Capacity (GW)
Coal	Coal Steam Turbine with Post CCS	57.4
Natural Gas	NGCC with Post CCS	23.8

Technology Assumptions on Lifetime, Capacity Factors, Efficiencies, and UC Parameters

For all existing generators and candidate generators, we assume the following default technology assumptions based on the generating technology and fuel source (Table S16), primarily based on the technology and cost assumptions from Black & Veatch [25], NREL's 2024 Annual Technology Baseline (ATB) definitions page [26], and a CEC Cost of Generation Report collected in the prior SWITCH analyses [24] and converted to $2018. Some technology values (battery, wind, solar PV, solar CSP, and geothermal) were previously updated based on NREL's 2020 ATB [27]. Since this study focuses heavily on thermal generation, technology values for thermal generators were updated more recently with NREL's 2023 ATB [28]. For existing generators with known planned retirement years, a specific lifetime is calculated.

Table S16: Technology assumptions for existing and candidate generators.

Fuel Source	Generating Technology	Lifetime (Years)	Forced Outage Rate (%)	Scheduled Outage Rate (%)
Biogas	Biogas	45	4%	6%
	Biogas Internal Combustion Engine	45	4%	6%
	Biogas Internal Combustion Engine Cogen	45	11%	4%
	Biogas Steam Turbine	45	13%	9%
Bio Liquid	Bio Liquid Steam Turbine Cogen	45	13%	9%
Bio Solid	Bio Solid Steam Turbine	45	4%	6%
	Bio Solid Steam Turbine Cogen	45	13%	9%
Coal	Coal IGCC	40	8%	12%
	Coal IGCC with Pre- CCS	40	8%	12%
	Coal Steam Turbine	40	4%	6%
	Coal Steam Turbine Cogen	30	8%	12%
	Coal Steam Turbine with Post- CCS	40	8%	12%
	Coal Steam Turbine with Retrofitted Post- CCS	30	8%	12%

Table S16: (continued)

Fuel Source	Generating Technology	Lifetime (Years)	Forced Outage Rate (%)	Scheduled Outage Rate (%)
	Coal Steam Turbine with Oxyfuel- CCS	40	8%	12%
	Coal Steam Turbine with Retrofitted Oxyfuel- CCS	30	8%	12%
Distillate Fuel Oil	Distillate Fuel Oil Combustion Turbine	30	5%	7%
	Distillate Fuel Oil Steam Turbine	30	5%	7%
	Distillate Fuel Oil Internal Combustion Engine	30	5%	7%
	Distillate Fuel Oil Internal Combustion Engine Cogen	30	5%	7%
Electricity	Battery Storage	10	2%	1%
Gas	NGCC	40	4%	6%
	NGCC Cogen	30	5%	10%
	NGCC with Post- CCS	40	5%	10%
	NGCC with Retrofitted Post- CCS	30	5%	10%
	NGCC with Oxyfuel- CCS	40	5%	10%
	NGCC with Retrofitted Oxyfuel- CCS	30	5%	10%
	Gas Combustion Turbine	30	5%	7%
	Gas Combustion Turbine Cogen	30	5%	7%
	Gas Internal Combustion Engine	30	5%	7%
	Gas Internal Combustion Engine Cogen	30	5%	7%
	Gas Steam Turbine	30	5%	7%
	Gas Steam Turbine Cogen	30	5%	7%
	Other Turbine	30	5%	7%
Geothermal	Geothermal	20	0%	0%
Solar	Central PV	20	0%	0%
	Commercial PV	20	0%	0%
	Concentrating Solar Power Trough 6h Storage	20	6%	0%

Table S16: (continued)

Fuel Source	Generating Technology	Lifetime (Years)	Forced Outage Rate (%)	Scheduled Outage Rate (%)
	Concentrating Solar Power Trough No Storage	20	0%	0%
	Residential PV	20	0%	0%
	Steam Turbine	20	4%	6%
Uranium	Nuclear	80	4%	6%
Waste Heat	Steam Turbine	40	4%	6%
Water	Hydropower	200	5%	5%
	Pumped Storage	200	5%	5%
Wind	Offshore Wind	30	5%	1%
	Onshore Wind	20	0%	0%

SWITCH represents unit commitment (UC) constraints for minimum and up- and down-time, minimum load fraction, and startup costs. UC is an important modeling feature when the system has a large amount of thermal generation technologies, and it is often omitted from large-scale capacity expansion models. The optional UC module creates a decision variable that decides how much capacity (MW) from each project to commit in each timepoint. We choose to operate in continuous mode rather than discrete in order to reduce computational complexity. Since this study focuses on thermal technologies with CCS, which have operational characteristics that limit their flexibility, we enable UC for all runs that allow CCS. The minimum load fraction describes the minimum loading level of a project as a fraction of committed capacity. All nuclear, geothermal, and co-generation plants are treated as base-load technologies with a minimum load fraction of 1 [19]. For existing thermal generators, the minimum load fraction is assigned uniquely to each generator from data reported in the U.S. EIA Form 923 (EIA-923) [16]. For generators which EIA-923 does not report a minimum operational load, we use data from [29, 30]. Start-up operation and maintenance (O&M) costs describe costs incurred from starting up additional generation capacity expressed in units of $2018/MW. The minimum up- and down-time describe the minimum time that a generator can be committed (turned on) or uncommitted (turned off), in hours. Table S17 shows the parameters from [29, 30, 16] used in the UC formulation of the model. The Technology Assumptions on Lifetime, Capacity Factors, Efficiencies, and UC Parameters Section of this Supplemental Information contains details about the parameters used in the UC formulation of the model.

Table S17: Unit commitment parameters for various generator types. Coal and gas plants with CCS are assumed to have the same UC parameters as traditional coal and gas plants, given that the addition of CCS is not expected to affect flexibility of the plants [30]. *Note: "Custom" indicates that the minimum load fraction is customized to the particular generator based on minimum operational loads reported by EIA Form 923. Data sources: [16, 29, 30]

Generator Type	Minimum Load Fraction [fraction of capacity]	Startup O&M Cost [$2018/MW]	Minimum Uptime [h]	Minimum Downtime [h]
Nuclear	0.30	59	168	168
Hydropower (pumped)	0.33	401.2	-	-
Hydropower (non-pumped)	-	401.2	-	-
Geothermal	1	0	-	-
Concentrated Solar Power	0.25	0	1	1
Gas	*Custom (0.20-1)	35.4	4	3
Gas (Cogen)	1	35.4	4	3
Coal	*Custom (0.07-0.30)	94.4	8	4
Coal (Cogen)	1	94.4	8	4
IGCC	0.7	21.24	14	7
Biomass	*Custom (0.26-0.76)	35.4	8	4
Biomass (Cogen)	1	35.4	8	4

Transmission

Existing and Candidate Transmission

The SWITCH optimization includes the construction of new transmission lines and the operations of existing and new transmission as decision variables. The model includes a set of 116 existing aggregated transmission lines between load areas within the WECC (Figure S20), based on a prior SWITCH analyses that aggregated the thermal limits of individual high-voltage lines between load areas from a Ventyx purchased dataset and Federal Energy Regulatory Commission (FERC) data [11]. New transmission capacity may be added to existing transmission. The line length assumed is 1.3 times the straight-line distance between the largest substations in each load zone, based on a prior analysis that calculated this as the average ratio between line length and straight-line distance between transmission substations in WECC [11]. For every 100 miles of distance, a 1% efficiency loss is assumed, based on typical losses for high-voltage transmission [31]. For both existing and newly constructed transmission lines, the maximum power transfer on each line is the thermal limit multiplied by a derating factor. The derating factor is 0.95 and comes from a prior SWITCH analysis and is meant to capture the combined effect of stability concerns, loop flows, voltage concerns, power factors less than unity, and overloading of individual transmission lines within the bundle, that are difficult to model in detail in the linear model [11].

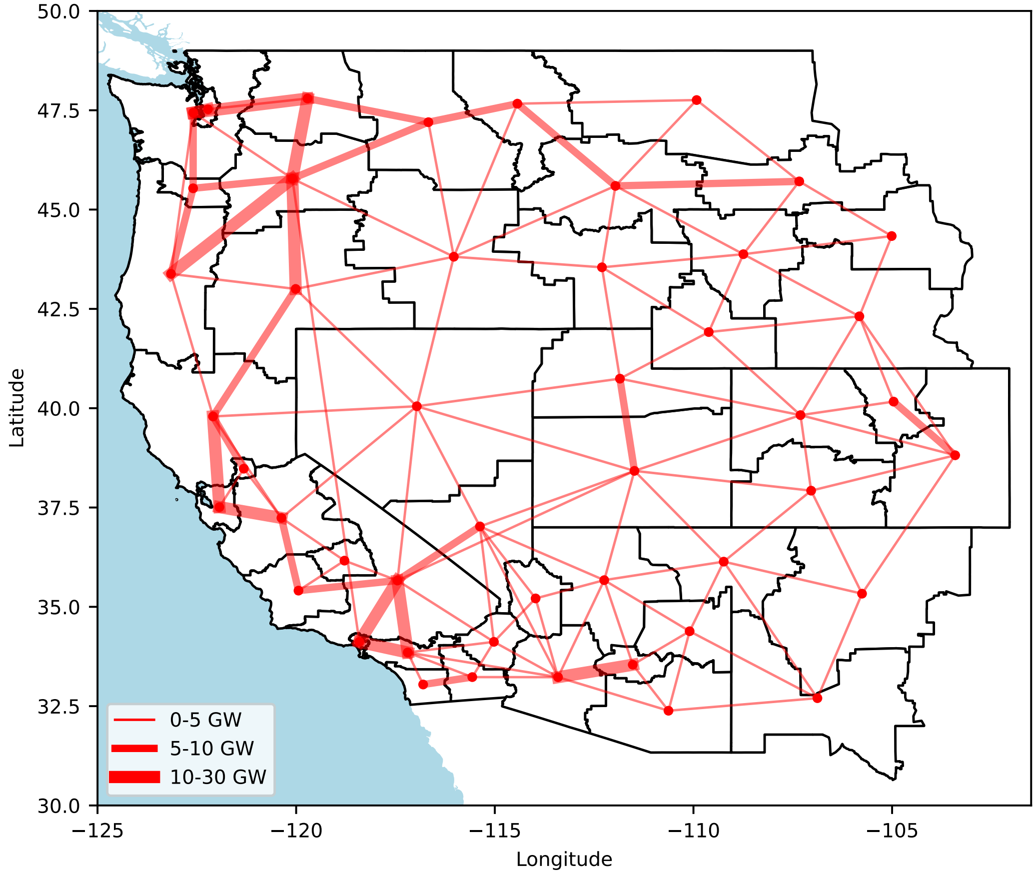

Figure S20: Transmission topology and transmission rating category considered in 47 load zones for the U.S. WECC region used in the SWITCH-WECC model. Transmission lines are categorized as follows: 5 GW - (0-5], 10 GW - (5-10], and 30 GW (10-30].

Costs

CCS Costs

Costs for installing CCS-equipped generators are defined in terms of overnight costs ($/MW), fixed O&M costs ($/MW), and variable O&M costs ($/MWh). These costs are shown in Section 2 of the Supplemental Information. Cost projections from now until 2035 for post- and pre-combustion capture are from the National Renewable Energy Laboratory (NREL) 2023 ATB [32]. As the 2023 ATB does not include oxyfuel-combustion capture cost projections, we derive these by taking the upper end of the 2020 oxyfuel-combustion capture cost range reported in Table 10.2 of [33], and we assume the same percent cost decline between now and 2035 as those reported in the 2023 ATB for post- and pre-combustion capture. Variable O&M costs of retrofitted plants are included for post-combustion capture retrofits, but they are omitted for pre-combustion capture (WECC has no existing IGCC plants) and for oxyfuel-combustion capture (data not available) retrofits. We assume plants retrofitted with oxyfuel-combustion capture have the same variable O&M costs as newly built plants equipped with oxyfuel-combustion capture. Investment costs required to retrofit coal and gas plants are also included, but only for demonstration purposes. Those additional investment costs associated with retrofitting existing plants are considered sunk costs that are excluded from the least-cost optimization. However, all investments for new plants are optimized.

Table S18: Overnight [$/MW], retrofit overnight [$/MW], fixed O&M [$/MW], and variable O&M [$/MWh] costs for CCS technologies. Sources for CCS costs: [32, 33]. Note Additional Overnight Cost to Retrofit describes investment costs associated with retrofitting existing coal and gas plants, which are included here for demonstration purposes but are omitted from the objective function.

Energy Conversion Technology	Capture Technology	Overnight Cost New Build [$2018/MW]	Additional Overnight Cost to Retrofit [$2018/MW]	Fixed O&M Cost [$2018/MW]	Variable O&M Cost New Build (Retrofit) [$2018/MWh]
NGCC	Post-combustion	1,612,530	765,900	42,540	3.35 (3.66)
NGCC	Oxyfuel-combustion	1,693,000	804,130	67,720	5.08
IGCC	Pre-combustion	6,461,510	2,646,830	192,590	19.98
PC	Post-combustion	3,723,950	1,441,440	98,890	7.42 (13.96)
PC	Oxyfuel-combustion	4,412,460	1,707,950	176,500	13.24

Overnight Capital Cost, Variable O&M Cost, Fixed O&M Cost

The SWITCH optimization includes several types of costs in the decision to invest in and/or operate generation. Costs for candidate generators include overnight capital cost (applied to the built capacity), fixed O&M costs per MW-year of operations, and variable O&M costs per MWh of operation. Mature technologies (biogas, bioliquid, biosolid, coal, gas cogeneration, gas steam turbine) are assumed to have their real costs stay constant over time, whereas other technologies are assumed to decrease costs over time with technology improvements and economies of scale. Capital, fixed O&M, and variable O&M costs by generator technology type originate primarily from Black & Veatch estimates for the mature technologies [25]. For technologies with changing costs over time (battery, solar PV, solar CSP, wind, geothermal, NGCC, gas CT), we compile cost data from NREL's 2020 ATB database using the "Moderate Scenario" which is based on the of median projections from the literature [27]. For wind and central solar PV, we also account for lower overnight costs in the first investment period from the Production Tax Credit and Investment Tax Credit, respectively [34, 18]. For battery storage, we separate out the capital costs into $/MW (balance of system battery cost) and $/MWh (battery pack cost which would be multiplied by the storage duration hours) costs [27]. The costs we use assume a four-hour duration battery. The average costs by energy source and technology for 2035 are in Table S19. Capital costs for existing generators and retrofitted generators are considered sunk costs and we do not include them in the total system costs; they do not affect future investment decisions. Variable O&M costs for existing generators are set to be the same as for candidate generators. Costs for generators with CCS are included in the Methods section of the main manuscript.

Table S19: Average capital, fixed O&M, and variable O&M costs for candidate generators built in investment period 2035 (2018$).

Energy Source	Generation Technology	Overnight Capital Cost ($/MW)	Fixed O&M Cost ($/MW-year)	Variable O&M Cost ($/MWh)
Biogas	Biogas Combustion Turbine	2,118,354	64,380	4.69
	Biogas Internal Combustion Engine	1,588,766	48,285	4.69
	Biogas Internal Combustion Engine Cogen	1,588,766	48,285	4.69

Table S19: (continued)

Energy Source	Generation Technology	Overnight Capital Cost ($/MW)	Fixed O&M Cost ($/MW-year)	Variable O&M Cost ($/MWh)
Bio Liquid	Bio-Liquid Steam Turbine Cogen	3,225,737	80,012	4.69
Bio Solid	Bio-Solid Steam Turbine	3,593,381	146,215	4.69
	Bio-Solid Steam Turbine Cogen	3,225,737	80,012	4.69
Coal	Coal IGCC	4,503,135	34,924	7.34
	Coal Steam Turbine	3,245,403	25,828	4.57
	Coal Steam Turbine Cogen	2,434,058	19,371	7.42
Electricity	Battery Storage	136,955	19,154	0.00
Gas	NGCC	964,875	12,863	4.50
	NGCC Cogen	1,035,945	5,314	1.64
	Gas Combustion Turbine	880,443	11,395	2.16
	Gas Combustion Turbine Cogen	548,292	4,430	5.97
	Gas Internal Combustion Engine Cogen	565,136	4,430	5.97
	Gas Steam Turbine Cogen	418,841	26,717	5.97
Geothermal	Geothermal	7,440,234	173,105	0.00
Solar	Central PV	799,236	9,360	0.00
	Commercial PV	976,987	7,005	0.00
	CSP Trough 6h Storage	4,495,540	52,447	3.59
	CSP Trough No Storage	4,476,076	56,148	0.00
	Residential PV	1,057,875	7,934	0.00
Wind	Offshore Wind	2,538,600	112,298	0.00
	Onshore Wind	1,176,891	37,489	0.00

Connection Costs

In addition to capital costs for the construction of a generator itself, for candidate generators we also add a connection cost to reflect the expense of connecting to the grid. This connection cost originally derived from EIA data and compiled in a prior SWITCH analysis [11] is either a "generic" cost if the generator is not located at a specific site (for gas, coal, biosolid, biogas, or battery storage), or is calculated for a specific site (for onshore wind, offshore wind, geothermal, central PV, and CSP with and without storage). Underwater transmission lines for offshore wind projects are assumed to cost $10,332/MW/km. The "generic" cost includes the cost of building a substation ($80,000/MW in $2018) and either a small transmission line to the substation ($31,000 in $2018). Site specific connection costs include a transmission line cost of $1,200 per MW per km based on the distance from the site to the substation, and the cost of the substation. There is no connection cost applied for existing generation.

Fuel Costs and Emissions

Fuel costs are applied to non-renewable generators (natural gas, coal, fuel oil, uranium) and originate from the EIA's Annual Energy Outlook (AEO) compiled from a prior WECC analysis [12]. Gas costs differ by load zone based differences in regional market prices and the wellhead price [11]. Table S20 shows the average 2035 costs for each fuel across all load zones, in $2018. The fuel costs for bio solid generators are based on supply curves derived based on estimates of the economically feasible volumes of biomass feedstock available by load zone and different fuel price tiers [11].

Table S20: Average fuel costs across load zones for investment period 2035 ($/MMBtu in $2018).

Fuel Source	2035
Bio Liquid	0.0105
Coal	2.21
Distillate Fuel Oil	24.21
Gas	5.23
Uranium	0.99

Transmission Costs

The cost of building new transmission lines is calculated as the product of a line length, a base $/MW/km cost, a terrain multiplier that reflects the topography differences that make a line more expensive to construct, and an economic multiplier that represents differences in labor, permitting, and other "soft" costs between WECC load zones. We assume a base $960/MW-km cost, which is the cost for constructing a 500 kV line in the WECC from the ReEDS capacity expansion model database ($1,347/MW-mile in $2010 dollars, converted to $/MW-km and $2018 dollars) [31]. For the economic multiplier, for all lines within California we use a factor of 2.25, between California and other WECC load zones we use a factor of 1.125, and within other WECC load zones we use a factor of 1 (keeping the base cost as it is) from the ReEDS documentation [31]. Steeper terrain and urban land area increase transmission construction costs. Terrain multipliers come from a prior SWITCH GIS analysis that overlaid the transmission line paths over a gridded dataset of terrain-dependent transmission costs, that had been derived from the slope and the land cover in the WECC region [11]. The multipliers range from 0.7 to 3.4. Transmission lines also have a fixed O&M cost applied to reflect upkeep costs for lines, which is assumed to be 3% of capital costs from the prior SWITCH analysis.

Load

The future load assumed in this analysis was developed in a prior study and represents a case of high energy efficiency and building electrification, as well as increased adoption of Zero Emissions Vehicles (ZEVs), primarily from electric vehicles [12]. The load forecast achieves a doubling of the rate of energy efficiency by 2030 in California, compliant with the state's SB 350 legislative targets, aggressive building electrification starting in 2020, growing industry electrification, and approximately 125,000 GWh in electricity demand from transportation. Hourly demand profiles from 2006 (consistent with the weather-year used for calculating solar and wind capacity factors) from FERC Form 714 and a dataset procured from ITRON were used as a base from which demand projects (residential, commercial, industrial, transportation) were created and scaled by sector to meet states' policy targets and reflect population growth [35]. Where detailed state/province-level load forecasts with state efficiency, electrification, and population estimates were available (including California, Washington, Oregon) load zone forecasts were scaled to those projections; otherwise forecasts were scaled to the EIA's Annual Energy Outlook projections in the prior SWITCH analysis [36, 17]. In the 2017 Annual Energy Outlook Electric projections used, population growth across the U.S. is on average 0.6% annually, based on the U.S. Census Bureau's mid-case projections at the time [37]. Electric vehicles are assumed to charge in an "unmanaged" way (without smart charging or time-of-use rates), based on charging profiles developed with an agent-based mobility model BEAM [38].

Planning Reserves

We assume that the load zones in the WECC region must meet a planning reserve margin of 15%, that is, the model is required to build capacity to meet 115% of the peak load in each reserve area. The reserve requirement is applied by reserve area; utilities like Southern California Edison (SCE) and Pacific Gas & Electric (PG&E) that span multiple load zones have a combined reserve requirement across their total region. All generator technologies are assumed to be eligible to provide capacity towards meeting the planning reserve requirement. Thermal generators contribute their nameplate capacity, solar and wind generators contribute as much as their capacity factor during the peak hour, hydropower generators contribute as much as their monthly capacity factors for all hours of that month, battery storage contributes as much as it discharges during the peak hour, and net transmission imports contribute as much as the flows during the peak hour.

Carbon Cap Policy

A constraint on carbon emissions from generators can be imposed in SWITCH by load zone and investment period. In this analysis, the carbon cap that is enforced is zero-emissions by 2035 in the entire U.S. WECC for the Net Zero scenario, and 90% reduction (relative to 1990 levels) in CO_2 by 2035 for the CCS scenarios. The values for these constraints are shown in Table S21.

Table S21: WECC-wide and California carbon cap average by investment period.

Scenario	Investment Period	Percent Decarbonization (relative to 1990 levels)	Carbon cap (tons CO_2 per year)
Net Zero	2035	100	0
All CCS Scenarios	2035	90	28,480,000

To measure compliance with this constraint, SWITCH tracks the emissions from each generator and aggregates to the load zone, based on emissions intensity for each fuel source (Table S22) [39]. We assume biomass has a net-zero CO_2 intensity due to the natural CO_2 sequestration that happens during the life of the feedstock. For CCS-equipped generators, the capture efficiency of each CCS type is outlined in the Methods section of the main manuscript. A capture efficiency of 90% implies that 90% of the CO_2 emissions related to the emissions intensities in Table S22 would be captured and sequestered.

Table S22: Emissions intensity of fuel-based energy sources (tons CO_2/BTU).

Fuel	CO_2 Intensity of Fuel (tons CO_2/BTU)
Biogas	0
Bio Liquid	0
Bio Solid	0
Coal	0.09552
Distillate Fuel Oil	0.07315
Gas	0.05306
Residual Fuel Oil	0.0788
Uranium	0

3 Supplementary SWITCH Mathematical Formulation

This section of the Supplemental Information contains the objective function, variables, parameters, and constraints for the modules that were implemented for the SWITCH Western Electricity Coordinating Council (WECC) model we use in this paper. For a full description of the SWITCH model refer to [40]. This document was adapted and synthesized from the Supplemental Information in [40], courtesy of J. Johnston, R. Henriquez-Auba, B. Maluenda and M. Fripp.

Objective Function

The objective function minimizes the total cost of investments and operations (as net present value):

$$\min \sum_{p\in\mathcal{P}} d_p \left\{ \sum_{c^{\mathrm{f}}\in\mathcal{C}^{\mathrm{fixed}}} c^{\mathrm{f}}_p + \sum_{t\in\mathcal{T}_p} w^{\mathrm{year}}_t \sum_{c^{\mathrm{v}}\in\mathcal{C}^{\mathrm{var}}} c^{\mathrm{v}}_t \right\} \tag{3}$$

Where $\mathcal{P}$ is the set of periods in the optimization, $\mathcal{C}^{\mathrm{fixed}}$ is the set of fixed costs, $\mathcal{C}^{\mathrm{var}}$ is the set of variable costs, $\mathcal{T}_p$ is the set of timepoints in the optimization, and p, c^{f}, t and c^{v} are respective elements in those sets. The term c^{f}_p is the fixed cost that occurs during period p, c^{v}_t is the variable cost per timepoint t, w^{year}_t scales costs from a sampled timepoint to an annualized value, and d_p is the discount factor that converts the costs to net present value.

Operational Constraints

Power balance

Power injection and withdrawal must be equal in each load zone for all timepoints.

$$\sum_{p^{\mathrm{i}}\in\mathcal{P}^{\mathrm{inject}}} p^{\mathrm{i}}_{z,t} = \sum_{p^{\mathrm{w}}\in\mathcal{P}^{\mathrm{withdraw}}} p^{\mathrm{w}}_{z,t}, \qquad \forall z\in\mathcal{Z}, \forall t\in\mathcal{T} \tag{4}$$

Depending on the SWITCH modules used, power injection $\mathcal{P}^{\mathrm{inject}}$ includes power output $P_{g,t}$ for every generation project g located in load zone z and incoming transmission flows to the load zone z, $F_{\ell^{\mathrm{in}}_z,t}$. Power withdrawal $\mathcal{P}^{\mathrm{withdraw}}$ typically includes electricity loads $l_{z,t}$ and outgoing transmission flows $F_{\ell^{\mathrm{out}}_z,t}$.

Dispatch

The power generation constraint per generator g is the following:

$$0 \leq P_{g,t} \leq \eta_{g,t} K^{\mathrm{G}}_{g,p}, \qquad \forall \ell \in \mathcal{L}, p \in \mathcal{P}, \forall t \in \mathcal{T}_p \tag{5}$$

For firm generators, $\eta_{g,t}$ is constant and represents average outage rates. For intermittent generators, $\eta_{g,t}$ also represents the renewable source's capacity factor at a timepoint t.

The constraint on transmission limits flows $F_{\ell,t}$ through a line ℓ based on capacity $K^{\mathrm{L}}_{\ell,p}$ and derated by the factor η^{L}_{ℓ}:

$$0 \leq F_{\ell,t} \leq \eta^{\mathrm{L}}_{\ell} K^{\mathrm{L}}_{\ell,p}, \qquad \forall \ell \in \mathcal{L}, p \in \mathcal{P}, \forall t \in \mathcal{T}_p \tag{6}$$

Investment Constraints

Generation projects that have a cap, $\overline{k^{\mathrm{G}}}_g$, on their maximum capacity installed are constrained by 7. Eqs. (8) and (10) represent cumulative installed capacity for generation projects $K^{\mathrm{G}}_{g,p}$ and transmission lines $K^{\mathrm{L}}_{\ell,p}$ until period p. As such, they are defined as the sum of previous capacity additions $B^{\mathrm{G}}_{g,p'}$ and $B^{\mathrm{L}}_{\ell,p'}$, including existing infrastructure. The set $\mathcal{P}^{\mathrm{on}}_{g,p}$ corresponds to the set of all periods when capacity of type g could be built and still be in service in period p. Eqs. (9) and (11) fix the investment decisions of some generation projects and transmission lines over some periods $\mathcal{P}^{\mathrm{G}}_g$ and $\mathcal{P}^{\mathrm{L}}_{\ell}$ with predetermined values specified in input files (which is the case of existing, or pre-planned capacity).

$$0 \leq K^{\mathrm{G}}_{g,p} \leq \overline{k^{\mathrm{G}}}_g, \qquad \forall g \in \mathcal{G}^{\mathrm{rc}}, p \in \mathcal{P} \tag{7}$$

$$K^{\mathrm{G}}_{g,p} = \sum_{p' \in \mathcal{P}^{\mathrm{on}}_{g,p}} B^{\mathrm{G}}_{g,p'}, \qquad \forall g \in \mathcal{G}, \forall p \in \mathcal{P} \cup \{p_0\} \tag{8}$$

$$B^{\mathrm{G}}_{g,p} = b^{\mathrm{G}}_{g,p}, \qquad \forall g \in \mathcal{G}, \forall p \in \mathcal{P}^{\mathrm{G}}_g \tag{9}$$

$$K^{\mathrm{L}}_{\ell,p} = \sum_{p' \in \mathcal{P} \cup \{p_0\} : p' \leq p} B^{\mathrm{L}}_{p',k}, \qquad \forall \ell \in \mathcal{L}, \forall p \in \mathcal{P} \tag{10}$$

$$B^{\mathrm{L}}_{\ell,p} = b^{\mathrm{L}}_{\ell,p}, \qquad \forall \ell \in \mathcal{L}, \forall p \in \mathcal{P}^{\mathrm{L}}_{\ell} \tag{11}$$

SWITCH Modules

Treatment of time

SWITCH uses three levels of time scales: timepoints, timeseries and period. Timepoints represent the highest time granularity in the optimization. Depending on the user of SWITCH, a timepoint can represent one hour or a set of hours. Timeseries are a set of consecutive timepoints. Examples of timeseries would be a day, a few days, a week, a month, or a year. A period is a set of consecutive years where investments can be made. Table S23 summarizes the time components in SWITCH. The code for this module can be found in `switch_model.timescales`.

Table S23: Model components defined in the `timescales` module.

Type	Symbol	Component Name	Description
Set	$\mathcal{P}$	PERIODS	Set of all investment periods, indexed by p.
Parameter	st_p	period_start[p]	Year in which period p begins.
Parameter	y_p	period_length_years[p]	Length in years of period p.
Set	$\mathcal{S}$	TIMESERIES	Set of all time series. Indexed by s.
Subset	$\mathcal{S}_p$	TS_IN_PERIOD[p]	Subset of time series that fall in period p.
Parameter	num_s	ts_num_tps[s]	Number of time points in time series s.
Parameter	Δ_s^{S}	ts_duration_of_tp[s]	Duration in hours of each time point in time series s. Used for short-term thermodynamics such as energy storage calculations.
Parameter	Δ_t^{T}	tp_duration_hrs[t]	Duration in hours of time point t (equal to Δ_s^{S} for the corresponding timeseries).
Parameter	w_t^{period}	tp_weight[t]	Weight of timepoint t within simulation (hours).
Parameter	w_t^{year}	tp_weight_in_year[t]	Weight of timepoint t within its year (hours/year).
Parameter	θ_s	ts_scale_to_period[s]	Number of times a time series s (or equivalent conditions) occurs in its period. Used statistically for sample weighting for economics, pollution and long-term energy demand.
Set	$\mathcal{T}$	TIMEPOINTS	Set of all time points, indexed by t.
Subset	$\mathcal{T}_s$	TPS_IN_TS[s]	Subset of time points that fall in time series s.
Subset	$\mathcal{T}_p$	TPS_IN_PERIOD[p]	Subset of time points that fall in period p.

The weight of a timepoint's within a period is given by

$$w_t^{\mathrm{period}} = \Delta_t^{\mathrm{T}} \cdot \theta_s, \qquad \forall p \in \mathcal{P}, \forall s \in \mathcal{S}_p, \forall t \in \mathcal{T}_s.$$

This reflects the fact that each timepoint represents Δ_t^{T} hours within its timeseries, and each timeseries is treated as recurring θ_s times in its period.

Financial components

The code for this module can be found in `switch_model.financials`.

Table S24: Model components defined in the `financials` module.

Type	Symbol	Component Name	Description
Parameter	r	discount_rate	Annual real discount rate used to convert future dollars to present.
Parameter	i	interest_rate	Annual real interest rate used to finance investments.
Parameter	baseyear	base_financial_year	Base financial year in which future costs will be converted to net present value via discount rate r.
Set	$\mathcal{C}^{\mathrm{fixed}}$	Cost_Components_Per_Period	Fixed cost components that contribute to the total cost in the cost-minimizing objective function.
Set	$\mathcal{C}^{\mathrm{var}}$	Cost_Components_Per_TP	Variable cost components that contribute to the total cost in the cost-minimizing objective function.

Load zones and power injection/withdrawal

The code for this module can be found in `switch_model.balancing.load_zones`.

Table S25: Model components defined in the `balancing.load_zones` module.

Type	Symbol	Component Name	Description
Set	$\mathcal{Z}$	LOAD_ZONES	Set of all load zones, indexed by z.
Parameter	$l_{z,t}$	zone_demand_mw[z,t]	Demand in MW at zone z at time point t.
Subset	$\mathcal{Z}^{\text{peak}}$	EXTERNAL_COINCIDENT_PEAK_DEMAND_ZONE_PERIODS	Subset of load zones, period pairs for which and expected peak load has bbeen provided.
Parameter	$l^{\text{peak}}_{z,p}$	zone_expected_coincident_peak_demand[z,p]	Expected peak load demand in zone z in period p, $(z,p) \in \mathcal{Z}^{\text{peak}}$ (optional).
Set	$\mathcal{P}^{\text{inject}}$	Zone_Power_Injections	Model components that inject power to the central bus of each load zone.
Set	$\mathcal{P}^{\text{withdraw}}$	Zone_Power_Withdrawals	Model components that withdraw power from the central bus of each load zone.

Energy sources

The code for this module can be found in `switch_model.energy_sources.properties`.

Table S26: Model components defined in the `energy_sources.properties` module.

Type	Symbol	Component Name	Description
Set	$\mathcal{E}$	ENERGY_SOURCES	Set of all energy sources, indexed by f.
Subset	$\mathcal{E}^{\text{F}}$	FUELS	Subset of all fuel-based energy sources.
Subset	$\mathcal{E}^{\text{R}}$	NON_FUEL_ENERGY_SOURCES	Subset of all non-fuel energy sources.
Parameter	$\xi_f, f \in \mathcal{E}^{\text{F}}$	f_co2_intensity[f]	Direct emissions of CO_2 of a fuel in tCO_2/MMBtu.
Parameter	$\mu_f, f \in \mathcal{E}$	f_upstream_co2_intensity[f]	Emissions attributable to an energy-source before it is consumed in tCO_2/MMBtu.
Parameter	$\xi^{nox}_f, f \in \mathcal{E}^{\text{F}}$	f_nox_intensity[f]	Direct emissions of NO_X of a fuel in tNO_X/MMBtu.
Parameter	$\xi^{nh3}_f, f \in \mathcal{E}^{\text{F}}$	f_nh3_intensity[f]	Direct emissions of NH_3 of a fuel in tNH_3/MMBtu.
Parameter	$\xi^{so2}_f, f \in \mathcal{E}^{\text{F}}$	f_so2_intensity[f]	Direct emissions of SO_2 of a fuel in tSO_2/MMBtu.
Parameter	$\xi^{pm25}_f, f \in \mathcal{E}^{\text{F}}$	f_pm25_intensity[f]	Direct emissions of PM_{25} of a fuel in tPM_{25}/MMBtu.

Investment components

The code for this module can be found in `switch_model.generators.core.build`.

Table S27: Model components defined in the `generators.core.build` module.

Type	Symbol	Component Name	Description
Set	$\mathcal{G}$	GENERATION_PROJECTS	Set of all generation projects, indexed by g.
Subset	$\mathcal{G}^{\mathrm{B}}$	BASELOAD_GENS	Subset of all generation projects that are baseload.
Subset	$\mathcal{G}^{\mathrm{F}}$	FUEL_BASED_GENS	Subset of all generation projects that use fuels.
Subset	$\mathcal{G}^{\mathrm{R}}$	VARIABLE_GENS	Subset of all generation projects that are variable renewable.
Subset	$\mathcal{G}^{\mathrm{rc}}$	CAPACITY_LIMITED_GENS	Subset of all generation projects that are resource constrained.
Subset	$\mathcal{G}^{\mathrm{Z}}_z$	GENS_IN_ZONE[z]	Subset of all generation projects that are located in load zone z.
Subset	$\mathcal{G}^{\mathrm{T}}_{\mathrm{tech}}$	GENS_BY_TECHNOLOGY[tech]	Subset of all generation projects that are of the generation technology, tech.
Parameter	b^{unit}_g	gen_unit_size[g]	Size of individual generating units within project g (optional).
Subset	$\mathcal{G}^{\mathrm{unit}}$	DISCRETELY_SIZED_GENS	Subset of generation projects for which a discrete unit size $\mathrm{b}^{\mathrm{unit}}_g$ has been specified.
Subset	$\mathcal{E}^{\mathrm{F}}_g$	FUELS_FOR_GEN[g]	Subset of fuels that can be used by generator g.
Parameter	$\mathrm{ly}^{\mathrm{G}}_g$	gen_max_age[g]	Operational lifetime of capacity added to generation project g (years). Capital costs are also amortized over this period.
Parameter	$b^{\mathrm{G}}_{g,p}$	gen_predetermined_cap[g,p]	Predetermined addition of capacity in project g during period p (MW).
Set	$\mathcal{GP}^{\mathrm{B}}$	GEN_BLD_YRS	Set of tuples of generation projects g and periods p in which capacity may be added.
Subset	$\mathcal{GP}^{\mathrm{D}}$	PREDETERMINED_GEN_BLD_YRS	Subset of generation projects g and periods p for which the capacity additions are predetermined (may include years before the main study).
Subset	$\mathcal{P}^{\mathrm{on}}_{g,p}$	BLD_YRS_FOR_GEN_PERIOD[g,p]	Set of periods (including p) when capacity of type g could have been built and still be in service in period p. This excludes capacity that would be retired before period p.
Subset	$\mathcal{P}^{\mathrm{on}}_g$	PERIODS_FOR_GEN[g]	Subset of periods when generation project g may have capacity online. This excludes periods before g can be built or after it must be retired.
Parameter	$\overline{k^{\mathrm{G}}}_g$	gen_capacity_limit_mw[g]	Maximum allowed capacity for project g (MW).
Variable	$B^{\mathrm{G}}_{g,p}$	BuildGen[g,p]	Amount of capacity built (added) in project g in period p; $(g,p) \in \mathcal{GP}^{\mathrm{B}}$.
Variable	$K^{\mathrm{G}}_{g,p}$	GenCapacity[g,p]	Cumulative capacity of project g as of period p.
Parameter	$\hat{c}^{\mathrm{G,inv}}_g$	gen_overnight_cost[g,p]	Overnight capital cost per MW to add capacity to project g in period p; $(g,p) \in \mathcal{GP}^{\mathrm{B}}$.
Parameter	$\hat{c}^{\mathrm{G,upg}}_g$	gen_connect_cost_per_mw[g]	Overnight cost of grid upgrades to support the project g, per MW installed.
Parameter	$c^{\mathrm{G,fix}}_g$	gen_fixed_om[g,p]	Fixed operation and maintenance costs per MW of capacity per year, for capacity added to project g in period p; $(g,p) \in \mathcal{GP}^{\mathrm{B}}$. This cost recurs every year until the capacity retires ($\mathrm{ly}^{\mathrm{G}}_g$ years).
Parameter	$c^{\mathrm{G,var}}_g$	gen_variable_om[g]	Variable operation and maintenance costs per MWh of power produced by project g.
Parameter	h_g	gen_full_load_heat_rate[g]	Full load heat rate (inverse of thermal efficiency), in MMBtu per MWh. May be supplemented by part-load heat rates in generators.core.commit.fuel_use.

Dispatch components

The code for this module can be found in `switch_model.generators.build.dispatch` and `switch_model.generators.core.no_commit`.

Table S28: Model components defined in the `generators.core.dispatch` module.

Type	Symbol	Name	Description
Subset	$\mathcal{T}_g^{\text{on}}$	TPS_FOR_GEN[g]	Subset of timepoints when generation project g may have capacity online. Corresponds to $\mathcal{P}_g^{\text{on}}$ defined in generators.core.build.
Subset	$\mathcal{GT}^{\text{on}}$	GEN_TPS	Set of tuples of generator g and timepoint t when capacity can be online. $\mathcal{GT}^{\text{on}} = \{(g,t) : g \in \mathcal{G} \text{ and } t \in \mathcal{T}_g^{\text{on}}\}$.
Subset	$\mathcal{T}_{g,p}^{\text{on}}$	TPS_FOR_GEN_I N_PERIOD[g,p]	Subset of timepoints when generation project $g \in \mathcal{G}$ has capacity available during period $p \in \mathcal{P}$. Includes all timepoints in p if $(g,p) \in \mathcal{GT}^{\text{on}}$, otherwise the empty set.
Variable	$P_{g,t}$	DispatchGen[g,t]	Average power in MW produced by project g during timepoint t.
Variable	$R_{g,t,f}$	GenFuelUseRate[g,t, f]	Rate of use of fuel $f \in \mathcal{E}_g^{\text{F}}$ by project $g \in \mathcal{G}^{\text{F}}$ during timepoint t (in MMBtu/h). Each generator may use multiple fuels.
Parameter	η_g	gen_forced_outage_r ate[g]	Fraction of time a project $g \in \mathcal{G}$ is expected to be available (used to de-rate for forced outages).
Parameter	$\eta_{g,t}$	gen_max_capacity_f actor[g,t]	Maximum possible output from renewable project $g \in \mathcal{G}^{\text{R}}$ in timepoint t (per-unit).

Table S29: Model components defined in the `generators.core.no_commit` module.

Type	Symbol	Component Name	Description
Variable	$P_{g,p}^{\text{B}}$	DispatchBaseloadByPeriod[g,p]	Amount of power to produce from baseload generator $g \in \mathcal{G}^{\text{B}}$ during all timepoints in period $p \in \mathcal{P}_g^{\text{on}}$ (MW)

The constraints are the following:

$$P_{g,t} = P_{g,p(t)}^{\text{B}}, \qquad \forall g \in \mathcal{G}^{\text{B}}, \forall t \in \mathcal{T}_g^{\text{on}} \tag{12}$$
$$0 \leq P_{g,t} \leq \eta_g K_{g,p(t)}^{\text{G}}, \qquad \forall g \in \mathcal{G} - \mathcal{G}^{\text{R}}, \forall t \in \mathcal{T}_g^{\text{on}} \tag{13}$$
$$0 \leq P_{g,t} \leq \eta_g \eta_{g,t} K_{g,p(t)}^{\text{G}}, \qquad \forall g \in \mathcal{G}^{\text{R}}, \forall t \in \mathcal{T}_g^{\text{on}} \tag{14}$$
$$\sum_{f \in \mathcal{E}_g^{\text{F}}} R_{g,t,f} = h_g P_{g,t}, \qquad \forall g \in \mathcal{G}^{\text{F}}, \forall t \in \mathcal{T}_g^{\text{on}} \tag{15}$$

Fuel costs

The code for this module can be found in `switch_model.energy_sources.fuel_costs.markets`.

Fuels costs can be modeled as a yearly cost per fuel for each load zone, and as a supply curve for a regional market (set of load zones).

Table S30: Model components defined in the `energy_sources.fuel_costs.simple` module.

Type	Symbol	Component Name	Description
Parameter	$c_{z,f,p}^{\text{fuel}}$	fuel_cost[z,f,p]	Cost per MMBtu for fuel f in load zone z during period p.
Set	$\mathcal{F}^{\text{unav}}$	GEN_TP_FUELS_U NAVAILABLE	Set of tuples of (project g, timepoint t, fuel f) where fuel f is not available (i.e., user has not specified a cost).

Total fuel costs for each zone and timepoint are calculated as

$$\sum_{g \in \mathcal{G}_z^{\text{Z}} : t \in \mathcal{T}_g^{\text{on}}} \; \sum_{f \in \mathcal{E}_g^{\text{F}}} c_{z,f,p(t)}^{\text{fuel}} \times R_{g,t,f}, \qquad \forall z \in \mathcal{Z}, t \in \mathcal{T}. \tag{16}$$

Table S31: Model components defined in the `energy_sources.fuel_costs.markets` module.

Type	Symbol	Component Name	Description
Set	$\mathcal{M}$	REGIONAL_FUEL_MARKETS	Set of all regional fuel markets (rfm), indexed by m.
Parameter	f_m^{M}	rfm_fuel[m]	Type of fuel that is sold in the regional fuel market m.
Subset	$\mathcal{Z}_m^{\mathrm{M}}$	ZONES_IN_RFM[m]	Set of all load zones served by the regional fuel market m.
Set	$\Sigma_{m,p}$	SUPPLY_TIERS_FOR_RFM_PERIOD	Set of supply tiers (i.e., complete supply curve) for a given regional fuel market m and period p, indexed by σ.
Set	$\mathcal{MP}\Sigma$	RFM_SUPPLY_TIERS	Set of valid tuples of regional fuel market m, period p and supply curve tier σ; $\mathcal{MP}\Sigma = \{(m,p,\sigma) : m \in \mathcal{M}, p \in \mathcal{P}, \sigma \in \Sigma_{m,p}\}$
Set	$\mathcal{F}^{\mathrm{unav}}$	GEN_TP_FUELS_UNAVAILABLE	Set of tuples of (project g, timepoint t, fuel f) where fuel f is not available.
Parameter	$c_{m,p,\sigma}^{\mathrm{fuel}}$	rfm_supply_tier_cost[m,p,σ]	Cost of a fuel in a particular tier of a supply curve $(m,p,\sigma) \in \mathcal{MP}\Sigma$.
Parameter	$\mathrm{limit}_{m,p,\sigma}$	rfm_supply_tier_limit[m, p,σ]	Annual limit of fuel available for a particular tier in the supply curve $(m,p,\sigma) \in \mathcal{MP}\Sigma$.
Variable	$R_{m,p,\sigma}^{\mathrm{tier}}$	ConsumeFuelTier[m,p,σ,]	The annual rate of fuel consumption in each tier of a supply curve, $(m,p,\sigma) \in \mathcal{MP}\Sigma$, in MMBtu/year.

Constraints regarding the tier limits and linkage with power production are defined in this module:

$$0 \le R_{m,p,\sigma}^{\mathrm{tier}} \le \mathrm{limit}_{m,p,\sigma}, \qquad \forall (m,p,\sigma) \in \mathcal{MP}\Sigma \tag{17}$$

$$\sum_{\sigma \in \Sigma_{m,p}} R_{m,p,\sigma}^{\mathrm{tier}} = \sum_{z \in \mathcal{Z}_m^{\mathrm{M}}} \sum_{g \in \mathcal{G}_z^{\mathrm{Z}} : f_m^{\mathrm{M}} \in \mathcal{E}_g^{\mathrm{F}}} \sum_{t \in \mathcal{T}_p \cap \mathcal{T}_g^{\mathrm{on}}} w_t^{\mathrm{year}} R_{g,t,f}, \qquad \forall m \in \mathcal{M}, \forall p \in \mathcal{P} \tag{18}$$

$$R_{g,t,f} = 0, \qquad \forall (g,t,f) \in \mathcal{F}^{\mathrm{unav}} \tag{19}$$

Total fuel costs of all tiers of a supply curve from all regional fuel markets during period p are calculated as:

$$\mathrm{AnnualFuelCosts}_p = \sum_{m \in \mathcal{M}} \sum_{\sigma \in \Sigma_{m,p}} c_{m,p,\sigma}^{\mathrm{fuel}} \cdot R_{m,p,\sigma}^{\mathrm{tier}}, \qquad \forall p \in \mathcal{P}$$

These are added to the set $\mathcal{C}^{\mathrm{fixed}}$ in order to be considered in the objective function (3).

Transmission components

The code for this section can be found in `switch_model.transmission.transport.build` and `switch_model.transmission.transport.dispatch`.

Table S32: Model components defined in the `transmission.transport.build` module.

Type	Symbol	Component Name	Description
Set	$\mathcal{L}$	TRANSMISSION_LINES	Set of all transmission corridors, indexed by ℓ.
Parameter	ζ^1_ℓ	trans_lz1[l]	Load zone at the start of corridor ℓ.
Parameter	ζ^2_ℓ	trans_lz2[l]	Load zone at the end of corridor ℓ.
Parameter	km_ℓ	trans_length_km[l]	Length in km of transmission corridor $\ell \in \mathcal{L}$.
Parameter	η^L_ℓ	trans_derating_factor[l]	Overall derating factor for transmission corridor ℓ that can reflect forced outage rates, stability or contingency limitations.
Parameter	$\eta^{\mathrm{L,ef}}_\ell$	trans_efficiency[l]	Efficiency; proportion of power sent through corridor ℓ that reaches the other end.
Subset	$\mathcal{LB}$	TRANS_BLD_YRS	Set of transmission corridors ℓ and periods p where capacity can be added
Parameter	b^{L}_ℓ	existing_trans_cap[l]	Transfer capability existing in corridor ℓ prior to the start of the study.
Variable	$B^{\mathrm{L}}_{\ell,p}$	BuildTx[l,p]	Transfer capability added in corridor ℓ during period p (MW); $(\ell, p) \in \mathcal{LB}$.
Expression	$K^{\mathrm{L}}_{\ell,p}$	TxCapacityNameplate[l,p]	Cumulative transfer capability through transmission corridor ℓ as of period p.
Parameter	$\hat{c}^{\mathrm{L}}$	trans_capital_cost_per_mw_km	Generic cost of expanding transfer capability in base year dollars per MW per km.
Parameter	α_ℓ	trans_terrain_multiplier	Cost multiplier for expanding capacity on a specific corridor ℓ.
Parameter	β	trans_fixed_om_fraction	Describes the fixed O&M costs per year as a fraction of capital costs.
Parameter	ly^{L}	trans_lifetime_yrs	Lifetime over which capital costs are amortized (years). Note that capacity is assumed to continue in service after this date, with the same annual payment (equivalent to automatically reconstructing capacity when it retires).
Set	$\mathcal{L}^{\mathrm{D}}$	DIRECTIONAL_TX	Set of directed transmission corridors. It consists of the tuples $(\zeta^1_\ell, \zeta^2_\ell)$ and $(\zeta^2_\ell, \zeta^1_\ell)$, for all $\ell \in \mathcal{L}$. Elements of this set refer to flows from the first zone of the tuple to the second zone.
Set	$\mathcal{L}^{\mathrm{D}}_z$	TX_CONNECTIONS_TO_ZONE[z]	Set of directed transmission corridors that flow into zone z (i.e., the second element is equal to z).

The annualized cost (capital and O&M) per MW of capacity in transmission corridor ℓ is:

$$c^{\mathrm{L,inv}}_\ell = \left(\frac{i}{1-(1-i)^{-\mathrm{ly}^{\mathrm{L}}}}\right)\hat{c}^{\mathrm{L}} \cdot \alpha_\ell \cdot \mathrm{km}_\ell$$
$$c^{\mathrm{L,fix}}_\ell = \beta c^{\mathrm{L,inv}}_\ell$$

These costs are multiplied by the installed transmission capacity as of each future period, $K^{\mathrm{L}}_{\ell,p}$, then discounted to the base year, and added to the set $\mathcal{C}^{\mathrm{fixed}}$ for inclusion in the objective function (3).

The installed capability until period p is calculated as:

$$K^{\mathrm{L}}_{\ell,p} = b^{\mathrm{L}}_\ell + \sum_{p':(\ell,p')\in\mathcal{LB} \text{ and } p'\leq p} B^{\mathrm{L}}_{\ell,p'}, \qquad \forall \ell \in \mathcal{L}, \forall p \in \mathcal{P}. \tag{20}$$

Table S33: Model components defined in the `transmission.transport.dispatch` module.

Type	Symbol	Component Name	Description
Variable	$F_{z,z',t}$	DispatchTx[z,z_,t]	Power flow through a directed corridor $(z, z') \in \mathcal{L}^{\mathrm{D}}$ (i.e., from zone z to zone z') during timepoint t.
Expression	$F^{\mathrm{net}}_{z,t}$	TXPowerNet[z,t]	Net power inflow to zone z from all other zones during timepoint t

The constraint of maximum flow through lines is defined as:

$$0 \leq F_{z,z',t} \leq \eta^{\mathrm{L}}_{\ell(z,z')} K_{\ell(z,z'),p}, \qquad \forall (z,z') \in \mathcal{L}^{\mathrm{D}}, \forall p \in \mathcal{P}, \forall t \in \mathcal{T}_p, \tag{21}$$

where $\ell(z, z')$ identifies the transmission corridor $\ell \in \mathcal{L}$ corresponding to the directed corridor $(z, z') \in \mathcal{L}^{\mathrm{D}}$. With this approach, net inflows to zone z from all other zones can be calculated as total inflows minus total outflows:

$$F^{\text{net}}_{z,t} = \sum_{z':(z',z)\in\mathcal{L}^{\mathrm{D}}} \eta^{\mathrm{L,ef}}_{\ell(z',z)} F_{z',z,t} - \sum_{z':(z,z')\in\mathcal{L}^{\mathrm{D}}} F_{z,z',t} \qquad \forall z \in \mathcal{Z}. \tag{22}$$

$F^{\text{net}}_{z,t}$ is added to the set of power-injecting components $\mathcal{P}^{\text{inject}}$ for inclusion in the power balance equation (4).

Hydropower components

The code for this module can be found in `switch_model.generators.extensions.hydro_simple`.

Table S34: Model components defined in the `generators.extensions.hydro_simple` module.

Type	Symbol	Component Name	Description
Subset	$\mathcal{G}^{\mathrm{H}}$	HYDRO_GENS	Subset of all hydro-based generation projects.
Parameter	$p^{\mathrm{h,min}}_{g,s}$	hydro_min_flow_mw[g,s]	Minimum flow level, expressed as electrical MW, for all timepoints of timeseries s.
Parameter	$p^{\mathrm{h,avg}}_{g,s}$	hydro_avg_flow_mw[g,s]	Average flow level, in electrical MW, that must be achieved during timeseries s.

Power dispatch must exceed the minimum level for all timepoints, and the average power production during a time series must be equal to the average flow rate:

$$P_{g,t} \geq p^{\mathrm{h,min}}_{g,s}, \qquad \forall g \in \mathcal{G}^{\mathrm{H}}, \forall s \in \mathcal{S}, \forall t \in \mathcal{T}_s. \tag{23}$$

$$\frac{1}{\mathrm{num}_s} \cdot \sum_{t\in\mathcal{T}_s} P_{g,t} = p^{\mathrm{h,avg}}_{g,s}, \qquad \forall g \in \mathcal{G}^{\mathrm{H}}, \forall s \in \mathcal{S}. \tag{24}$$

Storage components

The code for this module can be found in `switch_model.generators.extensions.storage`.

Table S35: Model components defined in the `generators.extensions.storage` module.

Type	Symbol	Component Name	Description
Subset	$\mathcal{G}^{\mathrm{S}}$	STORAGE_GENS	Subset of all generation projects that can store electricity for later discharge.
Subset	$\mathcal{GP}^{\mathrm{S}}$	STORAGE_GEN_BLD_YRS	Subset of all tuples of generation project g and period p when storage projects can be built; $\mathcal{GP}^{\mathrm{S}} = \{(g,p) : (g,p) \in \mathcal{GP}^{\mathrm{G}} \text{ and } g \in \mathcal{G}^{\mathrm{S}}\}$.
Parameter	η^{S}_{g}	gen_storage_efficiency[g]	Fraction of energy that is stored in the battery out of the total energy fetched from the grid.
Parameter	$\hat{c}^{\mathrm{S,inv}}_{g,p}$	gen_storage_energy_overnight_cost[g]	Overnight capital cost per MWh adding energy storage capacity (not power output) to storage project g in period p.
Parameter	$r^{\max}_{g}$	gen_store_to_release_ratio[g]	The maximum charging rate for storage project g, expressed as a ratio relative to the maximum power output rate.
Parameter	$r^{\mathrm{S,ep}}_{g}$	gen_storage_energy_to_power_ratio[g]	Fixed ratio of storage capacity to power rating (hours) for storage project g. Optional; if not specified, Switch optimizes the amount of energy storage capacity.
Parameter	$n^{\mathrm{S,max}}_{g}$	gen_storage_max_cycles_per_year[g]	Maximum amount of discharging allowed per year, for storage project g, expressed as a multiple of the installed storage capacity (optional).
Variable	$B^{\mathrm{S}}_{g,p}$	BuildStorageEnergy[g,p]	Amount of energy storage capacity to add to project g in period p, in MWh; $(g,p) \in \mathcal{GP}^{\mathrm{S}}$.
Variable	$K^{\mathrm{S}}_{g,p}$	StorageEnergyCapacity[g,p]	Cumulative capacity in MWh of storage project g at period p.
Variable	$C^{\mathrm{S}}_{g,t}$	ChargeStorage[g,t]	Decision of how much to charge a storage project g at time point t.
Variable	$P_{g,t}$	DispatchGen[g,t]	Decision of how much to discharge a storage project g at time point t, i.e., how much power to deliver to the grid (defined in `generators.core.build`).
Variable	$\overline{P_{g,t}}$	DispatchUpperLimit[g,t]	Maximum possible power production by project g at timepoint t, (defined by equation (13)).
Variable	$Z^{\mathrm{S}}_{g,t}$	StateOfCharge[g,t]	State of charge in MWh of storage project g at timepoint t.
Parameter	$\eta^{S,loss}_{g}$	gen_self_discharge_rate[g]	Fraction of the charge that is lost per day.
Parameter	$\eta^{S,out}_{g}$	gen_discharge_efficiency[g]	Discharging efficiency: the fraction of energy that reaches the grid out of the energy drawn from the battery.
Parameter	ϵ^{S}_{g}	gen_land_use_rate[g]	Ratio of land area usage to storage capacity (in $\frac{m^2}{MWh}$).
Expression	$L^{S}_{g,p}$	LandUseRate[g,p]	Land use of a project during a period in m^2.

Overnight costs $\hat{c}^{\mathrm{S,inv}}_{g,p}$ are annualized and added to the set $\mathcal{C}^{\mathrm{fixed}}$ to be part of the objective function (3).

Power used for charging/discharging is added to the set of withdrawals $\mathcal{P}^{\mathrm{withdraw}}$/ injections $\mathcal{P}^{\mathrm{inject}}$ in the balance equation (4).

The constraints introduced to model investment and operation of storage consider cumulative energy storage capacity, charging limits, storage required, and cycle limits per year.

$$K^{\mathrm{S}}_{g,p} = \sum_{p' \in \mathcal{P}:\ p' \leq p} B^{\mathrm{S}}_{g,p'}, \qquad \forall g \in \mathcal{G}^{\mathrm{S}}, p \in \mathcal{P} \tag{25}$$

$$0 \leq C^{\mathrm{S}}_{g,t} \leq r^{\max}_{g} \overline{P_{g,t}}, \qquad \forall g \in \mathcal{G}^{\mathrm{S}}, t \in \mathcal{T}^{\mathrm{on}}_{g} \tag{26}$$

$$0 \leq Z^{\mathrm{S}}_{g,t} \leq K^{\mathrm{S}}_{g,p}, \qquad \forall g \in \mathcal{G}^{\mathrm{S}}, t \in \mathcal{T}^{\mathrm{on}}_{g} \tag{27}$$

$$\mathit{coeff} = \begin{cases} \Delta^{T}_{t} & \eta^{S,loss}_{g} = 0 \\ 24\dfrac{(1-\eta^{S,loss}_{g})^{\frac{\Delta^{T}_{t}}{24}} - 1}{\ln(1-\eta^{S,loss}_{g})} & \eta^{S,loss}_{g} \neq 0 \end{cases} \qquad \forall g \in \mathcal{G}^{S}, t \in \mathcal{T}^{on}_{g} \tag{28}$$

$$\mathit{flow}_{g,t} = \eta^{S,in}_{g} C^{S}_{g,t} - \frac{1}{\eta^{S,out}_{g}} P_{g,t} \qquad \forall g \in \mathcal{G}^{S}, t \in \mathcal{T}^{on}_{g} \tag{29}$$

$$Z^{S}_{g,t} = (1-\eta^{S,loss}_{g})^{\frac{\Delta^{T}_{t}}{24}} Z^{S}_{g,t-1} + (\mathit{coeff})(\mathit{flow}_{g,t}) \qquad \forall g \in \mathcal{G}^{S}, t \in \mathcal{T}^{on}_{g} \tag{30}$$

$$B^{\mathrm{S}}_{g,p} = r^{\mathrm{S,ep}}_{g} B^{\mathrm{G}}_{g,p}, \qquad \forall (g,p) \in \mathcal{GP}^{\mathrm{S}} : r^{\mathrm{S,ep}}_{g} \text{ specified} \tag{31}$$

$$\sum_{t \in \mathcal{T}_p} P_{g,t} \Delta^{\mathrm{T}}_{t} \leq n^{\mathrm{S,max}}_{g} K^{\mathrm{S}}_{g,p} y_p, \qquad \forall (g,p) \in \mathcal{GP}^{\mathrm{S}} \tag{32}$$

Equations 28 and 30 calculate how the state of charge changes every timestep while considering losses. These equations are derived by solving the differential equation:

$$\frac{dZ}{dt} = -rZ + flow$$

where Z is the amount of energy in storage, r is the instantaneous rate of energy loss per unit time (non-zero), and $flow$ is the net rate of energy entering the storage. The full derivation is shown below. Note that in the limiting case that the rate of energy loss, $\eta^{S,loss}_{g}$, is zero, this equation becomes much simpler.

Equation 29 specifies the net rate of energy entering the storage as the difference in charging and discharging rates while considering efficiency ratios.

Equation 33 specifies the expression for the land use.

$$L^{S}_{g,p} = \epsilon^{S}_{g} K^{S}_{g,p} \tag{33}$$

Deriving equations 28 and 30

We derive equation 28 and 30 by solving the following differential equation.

$$\frac{dZ}{dt} = -rZ + flow$$

This equation represents the instantaneous change in the amount stored, $\frac{dZ}{dt}$, as a combination of the net flow into the storage ($flow$), and the energy lost in storage over time ($-rZ$). Note that r is the instantaneous decay rate which we will later replace with, η, the hourly decay rate provided in the parameters.

We solve the differential equation as follows.

If our decay rate is zero ($r = \eta = 0$), we find:

$$\frac{dZ}{dt} = \mathit{flow}$$
$$Z = Z_0 + \Delta t(\mathit{flow})$$

Otherwise,

$$\begin{aligned}
\frac{dZ}{dt} &= -rZ + flow \\
\frac{dZ}{-rZ + flow} &= dt \\
\int_{Z_0}^{Z} \frac{dZ}{-rZ + flow} &= \int_{t_0}^{t} dt \\
[\frac{ln(-rZ + flow)}{-r}]_{Z_0}^{Z} &= \Delta t \\
ln(\frac{-rZ + flow}{-rZ_0 + flow}) &= -r\Delta t \\
-rZ + flow &= (-rZ_0 + flow)e^{-r\Delta t} \\
Z &= (Z_0 - \frac{flow}{r})e^{-r\Delta t} + \frac{flow}{r} \\
Z &= Z_0 e^{-r\Delta t} + \frac{1 - e^{-r\Delta t}}{r} flow
\end{aligned}$$

We now wish to replace the instantaneous decay rate r with the provided daily self discharge decay rate, η. We know that without flow, the amount stored after one day should be less (by η percent) than the amount at the start of the day (Z_0). This gives the following equation:

$$Z_0 e^{-r \times 24 \text{ hour}} = Z_0(1 - \eta)$$

Simplifying we find:

$$r = -\frac{1}{24} ln(1 - \eta)$$

We now substitute r with $-\frac{1}{24} ln(1 - \eta)$ in our solution.

$$\begin{aligned}
Z &= Z_0 e^{-r\Delta t} + \frac{1 - e^{-r\Delta t}}{r} flow \\
Z &= Z_0 e^{\frac{1}{24} ln(1-\eta)\Delta t} + \frac{1 - e^{\frac{1}{24} ln(1-\eta)\Delta t}}{-\frac{1}{24}\ln(1 - \eta)} flow \\
Z &= Z_0(1 - \eta)^{\frac{\Delta t}{24}} + 24\frac{(1 - \eta)^{\frac{\Delta t}{24}} - 1}{\ln(1 - \eta)} flow
\end{aligned}$$

Rearranging the above equations gives equation (28 and 30):

$$Z = (1-\eta)^{\frac{\Delta t}{24}} Z_0 + (\mathit{coeff})(\mathit{flow})$$

$$\mathit{coeff} = \begin{cases} \Delta t & \eta = 0 \\ 24 \dfrac{(1-\eta)^{\frac{\Delta t}{24}} - 1}{\ln(1-\eta)} & \eta \neq 0 \end{cases}$$

Carbon cap components

The code for this module can be found in `switch_model.policies.carbon_policies`.

Table S36: Model components defined in the `policies.carbon_policies` module.

Type	Symbol	Component Name	Description
Parameter	cap_p	carbon_cap_tco2_per_yr[p]	Carbon cap in tons of CO_2 per year during period p (defaults to ∞).
Parameter	c_p^{carb}	carbon_cost_dollar_per_tco2[p]	Carbon cost per ton of CO_2 in period p (defaults to \$0).

$$\mathrm{AnnualEmissions}_p = \sum_{g \in \mathcal{G}^{\mathrm{F}}} \sum_{f \in \mathcal{E}_g^{\mathrm{F}}} \sum_{t \in \mathcal{T}_g^{on} \cap \mathcal{T}_p} \Delta_t^{\mathrm{T}} R_{g,t,f} \times (\xi_f + \mu_f), \qquad \forall p \in \mathcal{P} \tag{34}$$

The constraint that enforces the carbon cap is:

$$\mathrm{AnnualEmissions}_p \leq \mathrm{cap}_p, \qquad \forall p \in \mathcal{P} \tag{35}$$

Minimum technology requirements

The code for this module can be found in `switch_model.policies.min_per_tech`.

Table S37: Model components defined in the `policies.min_per_tech` module.

Type	Symbol	Component Name	Description
Parameter	$\min_{\mathrm{tech},p}$	minimum_capacity_mw[tech,p]	Minimum amount of capacity (in MW) needed throughout the model for a given technology and period (defaults to 0).
Parameter	$\min_{\mathrm{tech},p}^{\mathrm{energy}}$	minimum_energy_capacity_mwh[tech,p]	Minimum amount of energy capacity (in MWh) needed throughout the model for a given storage technology and period (defaults to \$0).

$$\sum_{g \in \mathcal{G}_{\mathrm{tech}}^{\mathcal{T}}} \mathcal{K}_{g,p}^{\mathcal{G}} \geq \min_{\mathrm{tech},p}, \qquad \forall p \in \mathcal{P}, \mathrm{tech} \in \mathrm{TECHS} \tag{36}$$

$$\sum_{g \in \mathcal{G}_{\mathrm{tech}}^{\mathcal{T}} \cap \mathcal{G}^{\mathcal{S}}} \mathcal{K}_{g,p}^{\mathcal{S}} \geq \min_{\mathrm{tech},p}^{\mathrm{energy}}, \qquad \forall p \in \mathcal{P}, \mathrm{tech} \in \mathrm{TECHS} \tag{37}$$

Enforcing a solar to wind capacity ratio

The code for this module can be found in `switch_model.policies.wind_to_solar_ratio`.

Table S38: Model components defined in the `policies.wind_to_solar_ratio` module.

Type	Symbol	Component Name	Description
Parameter	ratio_p	wind_to_solar_ratio[p]	Ratio of total wind capacity to solar capacity (defaults to 0 which is coded to mean the constraint is inactive).

In our implementation we enforce the following constraint in only one direction (i.e. greater than or less than) such that the constraint is forcing (this improves numerical performance). However, for all effective purposes our constraint is equivalent to:

$$\sum_{g \in \mathcal{G}^{\mathcal{T}}_{\text{tech1}}} \mathcal{K}^{\mathcal{G}}_{g,p} = \text{ratio}_p * \sum_{g \in \mathcal{G}^{\mathcal{T}}_{\text{tech2}}} \mathcal{K}^{\mathcal{G}}_{g,p}, \qquad \text{where tech1=Wind, tech2=Solar} \tag{38}$$

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