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Supplementary Material for

Fossil electricity retirement deadlines for a just transition

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Movie S1
Data File S1

Materials and Methods

Analytical Approach

This work uses a committed impacts framework to estimate likely future conditions associated with US fossil fuel-fired power generation. In addition to insights on greenhouse gas emissions common to committed emissions research (*8*, *9*, *16*–*18*), this work addresses air pollutants (NO_x, SO_2, Hg), water use (withdrawal and consumption), and labor impacts at the generator-level (including up to six fuels per generator) for the fossil fuel-fired US generating fleet, with particular emphasis on both spatial and temporal specificity. Spatially explicit linkages between power plants and extraction labor extend beyond the generator footprint. The analytical frame is all US electricity generators with capacity greater than or equal to one megawatt (MW) that are reported as "Operable" as of 2018 on Energy Information Administration (EIA) Form 860 (*19*) and have one of the fuels listed in Table S3 as "Energy Source 1." The fundamental assumption of the model supporting this analysis, available as Data S1, is that fossil fuel-fired generators will continue to operate at 2018 levels until their age exceeds the typical lifespan of a US generator with the same or similar fuel and prime mover characteristics. The fuel- and prime mover-specific "typical lifespan" is determined based on EIA Form 860M data for retirements since 2002 (see "Conversions and assumptions" worksheet in Data S1 for specific estimates, and (*16*) for original calculations and sensitivity to different weighting approaches) and is added to the "operating year" at the generator level.

This work's focus on visualizing a plausible future for existing generators means that no uprates, derates, or repowering were considered. The impact of this choice is minor. Based on EIA 860 data, 12 of 10,435 generators in the frame have a planned repowering (i.e., a rebuild with a fuel switch, for a net -40 MW, nameplate capacity); 110 have a planned uprate (1,500 MW, summer capacity); and 3 have a planned derate (-180 MW, summer capacity), on a base of 840,000 MW. Generation and emissions are derived from EIA Form 923 (*20*) and the Environmental Protection Agency's (EPA's) Emissions & Generation Resource Integrated Database (eGRID) records (*21*), both with a 2018 base year consistent with the most recent available data from both products as of July 2020.

Although it is unlikely that generators replicate their 2018 performance in every remaining year of their lifespan, this assumption represents a reasonable abstraction for various socioenvironmental characteristics of interest. Historical data show that in aggregate, individual US natural gas-fired power plants tend to run more, and more efficiently, over time, while US coal-fired power plants tend to run less, and less efficiently, over time (*22*). On average, same-plant compound annual growth rates for both capacity factor and heat rate are close to zero for the US thermal power plant fleet operational by 2010 for the period 2001-2018 (*22*). Given this overall trend, and given that the goal of this research is partly to evaluate the viability of constraining fossil fuel-fired power plant operations, assuming that output and emissions remain static over time is considered a reasonable approach for determining a plausible no-policy baseline counterfactual fossil fuel-fired power system. Sensitivity of overall results to using historical output (default) versus historical rate-of-change values to estimate future outputs from generators is discussed below.

Data

This research relies on openly available datasets, primarily from the US federal government, using a 2018 base year. The exceptions are 1) water data, which are taken from Grubert and Sanders, 2018 (*23*) and use a 2014 base year; and 2) total mercury emissions from coal, oil, and natural gas electricity generation, which are taken from the 2017 National Emissions Inventory, April 2020 release (*24*) and use a 2017 base year. Both represent the most recent known data for the characteristics of interest. Due to high uncertainty and dynamism, mercury emissions are not shown in the results (see Methods for details).

The base file containing the generator population of interest is EIA 860, specifically the "Operating" tab of the 3_1_Generator_Y2018 file (*19*). This file is used as the control file for plants, generators, generator counties, prime mover, energy source (1-6), sector, nameplate capacity, operating year, announced retirement year, and announced timing and capacity of uprate or derate activities at a specific generator.

Cost and wage data for the coarse financial estimates of benefits and damages from labor and emissions around 2035 presented in the main text are derived from federal databases as well. The social cost of carbon is estimated at the 3% discount rate, 2035 date from (*25*) and adjusted from 2007 to 2018 dollars, giving an estimated \$66.55/tonne (\$60.37/short ton). Air pollution cost estimates are taken from the Environmental Protection Agency's Benefits Mapping and Analysis Program—Community Edition (BenMAP-CE), using the 2030 dates (the latest available date) for SO_2 and NO_x emissions from electricity generating units (*26*, *27*). These estimates are also given with 3% discount rates and are adjusted from 2015 to 2018 dollars, giving an estimated \$51,940/ton SO_2 and \$7,632/ton NO_x. Wage data are based on the Bureau of Labor Statistics Quarterly Census of Employment and Wages (*28*) and estimated at about \$120,000/FTE in NAICS 221112 (Fossil fuel electric power generation) and \$130,000/FTE for extraction employees, an overall overestimate based on \$133,000/FTE for natural gas extraction and \$90,000/FTE for coal extraction. The rough approximation of 3 indirect jobs per direct job across these industries is based on the Bureau of Labor Statistics Employment Requirements Matrix, using the domestic, nominal estimates for 2018 of about 5.6 total jobs/direct job for oil and gas extraction, 2.3 total jobs/job for coal extraction, and 4.2 jobs/job for electric power generation, transmission and distribution (*29*).

Methods

The Excel-based model underlying the main text is available as Data S1, with documented assumptions, formulas, and validation. As the formulas in that file determine analytical results, it is the document of record with regard to analyses performed. The primary analytical work of the model is to associate fossil fuel-fired generators to characteristics of interest, namely: 1) generation, 2) fuel consumption by type, 3) labor intensity, 4) carbon dioxide (CO_2) emissions, 5) other air emissions, in this case nitrogen oxide (NO_x), sulfur dioxide (SO_2), and mercury (Hg) emissions, and 6) water use, in the form of plant-level withdrawal and consumption and fuel-related consumption. In order to enable spatial analysis, plant locations (based on latitude and longitude data from (*19*)) were recorded, and fuel consumption was further related to specific extraction regions where possible.

Associating records to a specific generator can be challenging for several reasons. For example, EIA and EPA datasets do not use a single, consistent generator identification (ID) number. Further, some information is reported at the plant or fuel level rather than the generator level, which makes allocation challenging due to issues like shared infrastructure (e.g., multiple or shared boilers per generator, shared cooling systems) and multiple fuel units. EPA's eGRID data include emissions data at plant and unit levels rather than generator levels, and data are assigned to units based on a single primary fuel. As some units use multiple fuels, often with very different environmental characteristics, it is difficult to determine whether a record is incorrect based only on intensity estimates. Although both EIA and EPA data used in this work have a 2018 base year, the different pace of data collection (EIA issues annual data based partly on monthly releases, while EPA issues data on a two-year cycle) also means that plant lists, generation records, and other information might not be consistent across the datasets. For example, eGRID 2018 includes a number of generators not listed as operable by EIA 860 2018.

This work thus uses several strategies for allocation, with priority based on perceived accuracy. For generation, allocation proceeds with the following priority, matching between generators identified as "Operable" by EIA 860 and generation records in EIA 923: 1) plant and generator ID match from records (94% of generation), and 2) plant and generator fuel and prime mover match, allocated based on capacity, for outputs not allocated to another generator (6% of generation). This approach allocated 99.7% of generation in EIA 923 associated with a plant (not a state fuel increment).

For emissions, allocation proceeds with the following priority: 1) plant and generator ID match from records, 2) plant and generator ID match from manual corrections (e.g., if a generator is listed as "001" in one dataset and "1" in the other, and the fuel, prime mover, and online date match, the records can be associated with high confidence: manual validation was performed for plants emitting more than 1 million tons CO_2/year in 2018 and those generating at least 100,000 MWh with CO_2 intensity less than 300 g / kWh, based on (*30*)); 3) plant and generator fuel and prime mover match, for outputs not allocated to another generator, 4) plant match, for outputs not allocated to another generator, and 5) fuel-based estimates using intensity factors derived from recorded information in eGRID. This fossil-based, generator-level evaluation uses eGRID's unadjusted emissions (adjusted values are not available at the generator level, but the values are often the same unless a generator burns some biomass not considered in this fossil fuel-focused evaluation). For CO_2 emissions, 71% were matched at the generator level; 23% were matched based on generator and fuel type; 1% were matched based on the plant; and 4% were estimated from fuel consumption. 97% of emissions estimated from fuel consumption rather than a more direct allocation were associated with plants not included in the eGRID records, in part related to plants that began operations in 2018. The less good match between EIA 860 data and eGRID records relative to EIA 923 data is likely due to the fact that EIA and EPA are separate entities with distinct missions and recordkeeping practices. Figure S1 illustrates the reconciliation of this work's CO_2 estimate to data in eGRID; validations for the other air emissions are presented in the next section and on the "Validation" tab of the Supporting Online Material Data File.

Limited manipulation of the emissions data were performed. Although negative absolute emissions estimates were suppressed formulaically, some plants have negative emissions rates due to positive emissions and negative net generation. The use of net generation and total fuel consumption to validate emissions means that some implausibly high emissions are physically possible. Most of the units with very high emissions rates either have extremely low capacity factors or are industrial or commercial facilities that likely either coproduce another energy product (like heat) or produce much more electricity than their net generation. Situations with implausibly low emissions are more difficult to validate, but they are likely the result of allocation errors between EIA and EPA data for a given generator, e.g., when generation is allocated proportionally across the plant but emissions are directly associated to a generator. Overall, the error is minor. For example, 457 generators have CO_2 emissions rates below the cutoff of 300 g / kWh used by (*30*), accounting for 21 million tons of CO_2 per year, or 1% of the total. Over 90% of these emissions are associated with 362 combined cycle units that share fuel across multiple generators, so low allocated emissions at the generator level are plausible.

Mercury emissions were estimated but excluded from results summaries and figures due to high uncertainty. The eGRID technical support document explicitly notes that mercury data are incomplete (*31*). Using fuel-average intensities for generators without recorded mercury records underestimates 2017 total fossil-fired power plant-related mercury emissions by about 25%, based on National Emissions Inventory (NEI) data (*24*). (Note that the only two records for natural gas units with mercury emissions in the eGRID data are associated with Muskogee, identified as a subbituminous coal-fired power plant in the EIA data, so no mercury emissions are assigned to natural gas units.) US mercury emissions have dropped by 80% since 2011 (*32*), however, so 2017 is unlikely to be a good validation year for 2018. Furthermore, rapid drops in mercury emissions suggest that this work's approximation that future emissions will match past emissions at existing power plants might not be appropriate for mercury, recent challenges to mercury regulations notwithstanding (*32*).

Allocating fuel consumption to generators is complicated by the lack of generator-specific fuel consumption records and the relatively common situation where a single generator burns multiple fossil fuels (of the 10,435 generators in the analytical frame, 3,199 burn at least two fossil fuels). EIA 923 records fuel consumption data by plant, fuel, and prime mover, and EIA 860 records up to 6 energy sources used by a generator. Fuel is thus allocated to generators with matching plant, fuel, and prime mover, weighted by 2018 generation, then aggregated to broader coal, natural gas, and oil categories to support estimates of labor and water use (Table S3). This work uses total fuel rather than fuel for electricity based on the logic that when the generator shuts down, all of its fuel use and associated impacts cease.

Labor associated with generators is calculated in three categories: employment at the power plant, employment for associated coal extraction, and employment for natural gas extraction. Employment for oil extraction is not estimated because retiring oil-fired generators is not expected to heavily affect oil extraction employment. Very little oil is used for US electricity generation, and that which is used is typically a lower value coproduct of gasoline production. As many oil-fired generators are associated with refineries or other industrial uses that co-produce electricity, shutting down oil-fired generators would arguably be associated with a bigger trend in the oil industry that might affect labor, but for the purposes of this work, only power plant-related labor is considered for oil generation. Note also that generators with an oil-based fuel as "Energy Source 1" generate relatively far more of their electricity from other fossil fuels (coal and natural gas) than do coal or natural gas generators (Figure S2).

Employment at fossil fuel-fired power plants is estimated at the generator level, which allows for both spatially-specific employment estimates and a more nuanced estimate of total employment at power plants with generators using different primary fuels. Data are compared with Bureau of Labor Statistics (BLS) 2018 annual average data for validation in specific sectors (*28*). For NAICS 221112 "Fossil fuel electric power generation," BLS reports a total of 104,564 annual average jobs for 2018. Although county level data are available in some cases, withholding and other issues prevent their direct use for validation (only about 4,000 jobs are assigned to specific counties), so the national average is used to validate assumptions. This work assumes that a fossil fuel-fired power plant employs a minimum of 10 people, based both on correlating fossil fuel power generation capacity with employment for the counties BLS reports and on the intuition that 10 employees (e.g., 2 operators per shift for 3 shifts; 2 managers; and 2 maintenance people) is a reasonable theoretical minimum. These 10 employees are assigned to the fossil fuel-fired generator with the latest predicted retirement date at a given plant. Beyond this minimum value, labor intensity is estimated at 0.125 full time equivalent (FTE) employees per megawatt of capacity for generators with coal or oil as "Energy Source 1," and 0.07 FTEs per megawatt of capacity for generators with natural gas as "Energy Source 1." These values are consistent with spot checks at specific plants (e.g., from web searches for total number of employees), with BLS county level data and capacity correlations, and with total employment. The ratio between coal and natural gas employment intensity was taken from operation and maintenance employment intensities for coal and natural gas plants in (*33*). Overall, these relatively simple assumptions lead to an overall estimate that is less than 1% higher than the BLS reported value for the US as a whole (Table S1).

Coal extraction employment is estimated using basin-level labor productivity metrics from EIA (*34*) and estimated consumption of coal originating from a specific county, then corroborated with BLS data for "Coal mining" (NAICS 2121). Basin-level productivity was also used to estimate the number of total miners associated with metallurgical coal mining to reconcile total with steam coal labor estimates. Coal consumption by county for specific plants (required given the retirement-based analysis of future coal labor demand) is estimated based on EIA 923 data (*20*), which includes the mine of origin for monthly coal deliveries at the plant level. Coal source was approximated as the source providing the most fuel to a given generator, where discernible. This information was manually supplemented for 130 generators without records, using "reasonable guess" estimates of potential sources based on mine-level data in the EIA's Coal Data Browser. For example, all Alaskan coal is mined from one complex. "Reasonable guesses" are primarily based on coal rank and proximity to plants. Note that contract structures, rail lines, etc. mean that this approach is approximate at best. See (*35*) for greater detail on coal allocations at the plant level.

Natural gas extraction employment is less clearly associated with specific power plants than coal, but BLS statistics include more county-level detail on spatial distribution. Due to lack of more specific details on natural gas sourcing, natural gas extraction labor is proportionally allocated across counties with BLS employment data for NAICS 21113 "Natural gas extraction." Labor intensity was simply estimated as jobs / unit of fuel, multiplied by the amount of fuel a given plant uses: given the fungible nature of pipeline gas (relative to, say, coal that has specific characteristics that might not be compatible across plants), and given that power generation accounts for about a third of US natural gas consumption and so would likely impact extraction labor, this approximation is considered to be reasonable.

No extraction-related employment impacts are estimated for oil power plants because of the low amount of oil burned for electricity, the high demand for oil by other sectors, and the fact that most oil products burned for electricity are essentially waste co-products of refining higher value fuels like gasoline. Thus, this work assumes that oil demand (and oil extraction employment) would not be meaningfully affected by power plant closures. Some generators are at refineries, so their closure would likely reflect broader implications for the oil sector, but that effect is outside the scope of this analysis.

Fuel-related employment was restricted to extraction, in part because of uncertainty related to the impact of power plants on employment in less direct sectors. For example, coal often travels by rail, and the BLS "Coal mining" NAICS 2121 record includes some transportation (including rail) roles, accounting for about 10% of the total. Rail is not entirely devoted to coal, though a significant fraction is, but the uncertainty about coal plant closure influence on these indirect jobs is sufficiently high to preclude a spatially specified estimate. Similarly, natural gas pipelines are not entirely devoted to natural gas for electricity, though they would likely be heavily affected by the closure of power plants, so pipeline jobs are not considered.

Water use is estimated in three categories: water withdrawal at power plants, water consumption at power plants, and water consumption for fossil fuels used in power plants (water withdrawals are not estimated upstream of power plants because of the limited difference between water withdrawal and consumption in those cases; see (*36*) for a discussion of the distinction). Data are extended from (*23*) rather than directly from EIA 923 due largely to 1) the fact that estimates in (*23*) were derived via EIA 923 through an extensive data cleaning process for a 2014 base year that was able to be extended to 2018; and 2) the lack of alternative information on fuel-related water use. For power plants, EIA 923 cooling system data were linked with 860 generator IDs via boiler IDs. Where no match was identified, cooling systems were matched to records for the same plant in an earlier year from (*23*) or recorded as not identified. This work assumes combustion turbines, compressed air turbines, fuel cells, and internal combustion engines are not water cooled. For generators with no match in either EIA 923 or (*23*), water intensity was estimated based on averages for the appropriate fuel and prime mover combination. Thus, some plants are assigned water intensities that are inconsistent with any specific cooling strategy.

Validation

Validation of the estimates made for this work, based on a 2018 base year, are summarized in Table S1. Calculations and more detailed descriptions of the validation process can be found on the "Validation" tab of the Supporting Online Material Data File.

Methane Emissions

The estimate that methane emissions from the natural gas system (extraction through transmission) adds about 30% to US natural gas-fired electricity greenhouse gas intensity is based on leakage estimates from (*37*) and a 100-year global warming potential with climate-carbon feedback for fossil methane of 36 from the Intergovernmental Panel on Climate Change's Fifth Assessment Report (AR5) (*38*). Calculations showing the relationship to plant characteristics can be found in the Supplementary Data File of (*16*).

Sensitivity to Assumption of Static Output

The effect of the static output assumption is likely that coal-fired power plant committed emissions are overestimated (because of declining capacity factor trends outpacing increasing heat rate trends) and natural gas-fired power plant committed emissions are underestimated (because of opposite pressures). Applying fuel and, in the case of natural gas plants, technology-specific historical growth rates derived from (*22*), rather than assuming static outputs, results in an overall estimate of committed CO_2 emissions only 0.7% higher than the static assumption. This close match is coincidental and results from the relative use of coal versus natural gas.

Assuming historical rates of change for capacity factor and heat rate rather than historical output has a 1-36% impact on major cumulative results (Table S4), with the largest impacts on cumulative generation (an estimated 36% higher under historical rate of change versus historical output assumptions) and SO_2 emissions (an estimated 25% lower under historical rate of change versus historical output assumptions). CO_2 emissions, employment, and water consumption are very similar under both sets of assumptions, though with different spatial distributions. One major note is that overall GHG emissions, including methane, would likely be substantially higher in a high-gas scenario.

The main reason for these differences is that lower emissions natural gas trades off with higher emissions coal as the former's capacity factor rises and the latter's falls. For intuition, if current same-plant growth rate trends continue through 2030, natural gas capacity factors would grow by about 30% (relative to 2018 capacity factors, so from a fleet average of about 34% to a fleet average of about 45% for plants still expected to be operating by 2030), and bituminous coal capacity factors would shrink by about 30% (relative to 2018 capacity factors, so from a fleet average of about 52% to a fleet average of about 35% for plants still expected to be operating by 2030).

This work assumes historical output rather than historical rate of change for 4 major reasons: 1) the overall historical rate of change for capacity factor and heat rate for the thermal fleet is nearly 0 (*22*); 2) assuming constant 2018 output grounds results in conditions that are observably acceptable at the generator level, which is important for an analysis focused on identifying the potential for asset stranding; 3) historical rates of change vary significantly by location, which requires either very specific estimates at individual generator levels or abstractions that are likely to be inappropriate in a very spatially-grounded analysis; and 4) historical rates of change are unlikely to persist, which means that a simple assumption incorporating rates of change is inadequate. Specifically, capacity factors in the natural gas fleet are unlikely to continue growing so rapidly, as combined cycle power plants drive the overall same-plant capacity factor growth trend but already exhibit a fleet capacity factor of 49% as of 2018. Continuing recent growth rate trends of about 6% per year would bring the fleet capacity factor to about 90%, which is more commonly seen with inflexible baseload plants like nuclear facilities. Although some continued growth is likely, such high capacity factors are considered unlikely to materialize in the context of active decarbonization efforts, particularly as combined cycle plants have been valued for their flexibility with respect to variable renewable electricity integration.

<u>Sensitivity to Capacity Factor and Lifespans</u>

The analysis described here is designed largely to identify stranded assets. Thus, it focuses on a business-as-usual setting where generators retire after historically observed lifespans for similar assets (based on fuel and prime mover, Table S2) and maintain constant 2018 outputs. Committed emissions from the US fossil fuel-fired generator fleet are estimated at 25 $GtCO_2$. As described above, this overall result is essentially identical when historically observed rates-of-change for fuel- and technology-specific same-plant capacity factor and heat rate are used in place of the static output assumption. This committed emissions estimate is significantly (~70%) lower than a recent estimate by Shearer et al. (*17*), primarily due to that work's assumption of high capacity factors (~60% for units other than gas turbines) and long lifespans (50 years for all units). The 2018 historical data used in this work suggest an overall capacity factor of 47% for natural gas combined cycle units and 50% for coal units, with expected lifespans of ~50 years for steam turbine-based technologies and ~30 years for other technologies. Adjusting assumptions in Data S1 to match the capacity factor, lifetime, heat rate, efficiency drop, and emissions factors stated in (*17*) replicates results in Shearer et al. closely (e.g., 45 $GtCO_2$ replicate vs. 43 $GtCO_2$ reported for the baseline result) except for the 50 year, 30% capacity factor case. Assumptions in Data S1 can be directly adjusted for users interested in testing further sensitivities, noting that some formulas might need to be dragged to update estimates. Active formulas are designated in cells with green fill and can be dragged down; as released, Data S1 includes many static cells to reduce file size and increase usability.

Supplementary Text

Zero Carbon Electricity Systems

This research focuses on the challenges associated with decarbonizing the electricity system by closing carbon-based generation assets, rather than the considerable challenges associated with building a zero carbon electricity system. A zero carbon electricity system requires not only investment in new infrastructure (*39*), but also significant organizational and operational changes (*40–42*). Due to the need to expand global energy access and the expected role of electricity in decarbonizing other sectors, a zero carbon electricity system is also likely to be larger than the existing system (*3*, *43–46*).

A zero carbon electricity system is expected to have major climate mitigation benefits, in addition to other beneficial attributes (*46–48*). Non-fossil electricity technologies have higher labor requirements per unit energy than fossil technologies (*33*). Non-fossil electricity also typically has substantially lower air pollution impacts (*49*, *50*), and fast-growing renewable energy technologies like wind and solar photovoltaics are very low in water intensity (*23*, *51*).

Zero carbon electricity resources are not wholly environmentally benign, however. Demand for substantial amounts of land, sometimes in previously nonindustrial landscapes, is an ongoing concern (*52*, *53*). Similarly, demand for materials (*54*) and environmental resources like habitat (*55*) can have negative impacts.

Given the stakes involved, large amounts of research have focused on how to effectively build a zero carbon electricity system, and how to transition from the existing system to a zero carbon system while providing energy access and quality service at reasonable cost (*56–61*). The role of firm resources that are available on demand is a particular challenge for full decarbonization (*59*, *62*, *63*).

A major recent effort known as the 2035 Report (*56*) shows that 90% carbon free electricity by 2035 is possible for the US at lower costs than customers experience today, with pathways to 100% carbon free electricity by 2035 at similar costs to today thought to be feasible given use of technologies that are currently near commercial (*57*).

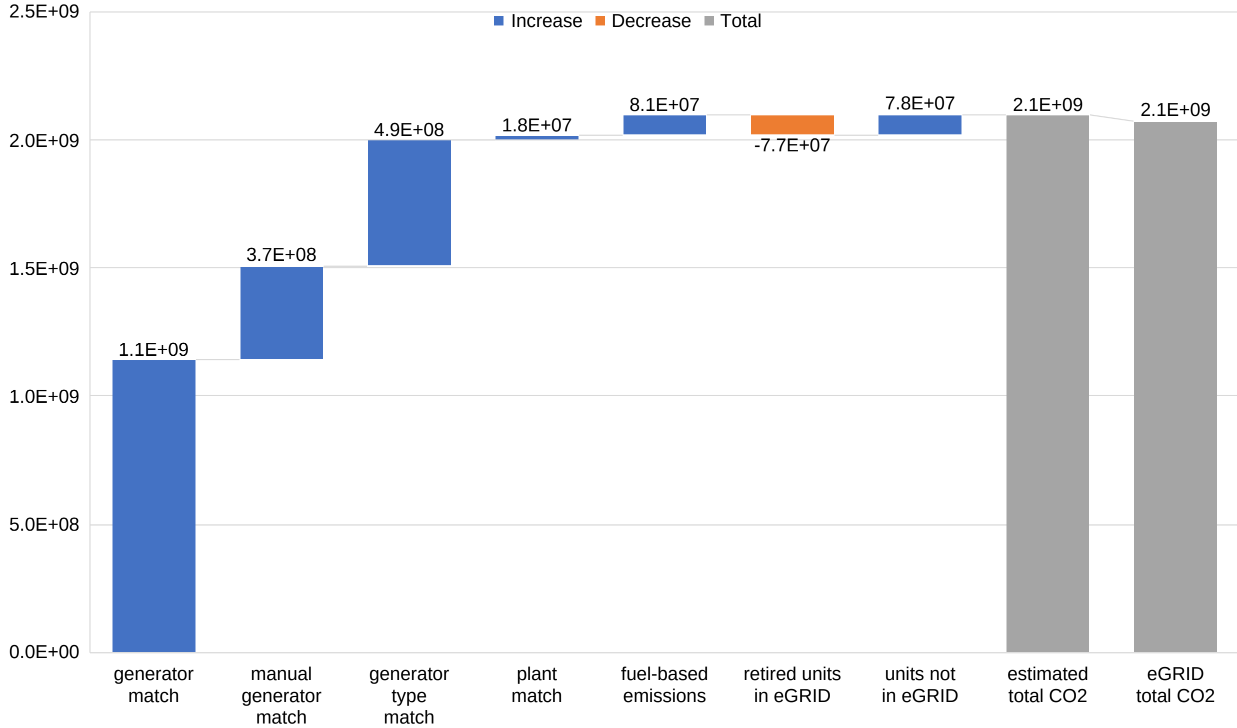
Fossil Fuel-Fired Power Plants Over Time

Figures S3 through S15 show the same information as Figure 2 in the main text, but for status as of 2018 (Figure S3), generators that have already exceeded their typical lifespans (Figure S4), and for 5-year increments between 2020-2070 (Figures S5-S15).

Correlation Between Fossil Plants and Poverty

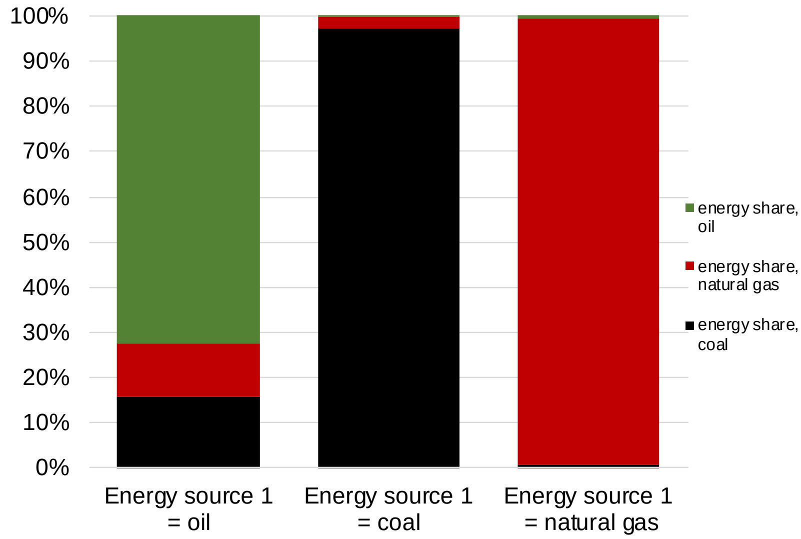
Figure S16 shows the correlation between electric utility-sector fossil fuel-fired electricity generation capacity (MW) with lifespan extending beyond 2035 per million people living in a state and the percent of persons in poverty by state, based on census data estimated for 2019 (*64*). Figure S17 shows the same, but for proposed electric utility-sector capacity per million people (*19*). Figure S18 shows the correlation between electric utility-sector fossil fuel-fired electricity generation capacity (MW) with lifespan extending beyond 2035 per million people living in a state and the percent of population identified as “white alone” with respect to “Race and Hispanic Origin.” Figure S19 shows the same, but for electric utility-sector proposed capacity per million people (*19*).

Fig. S1.



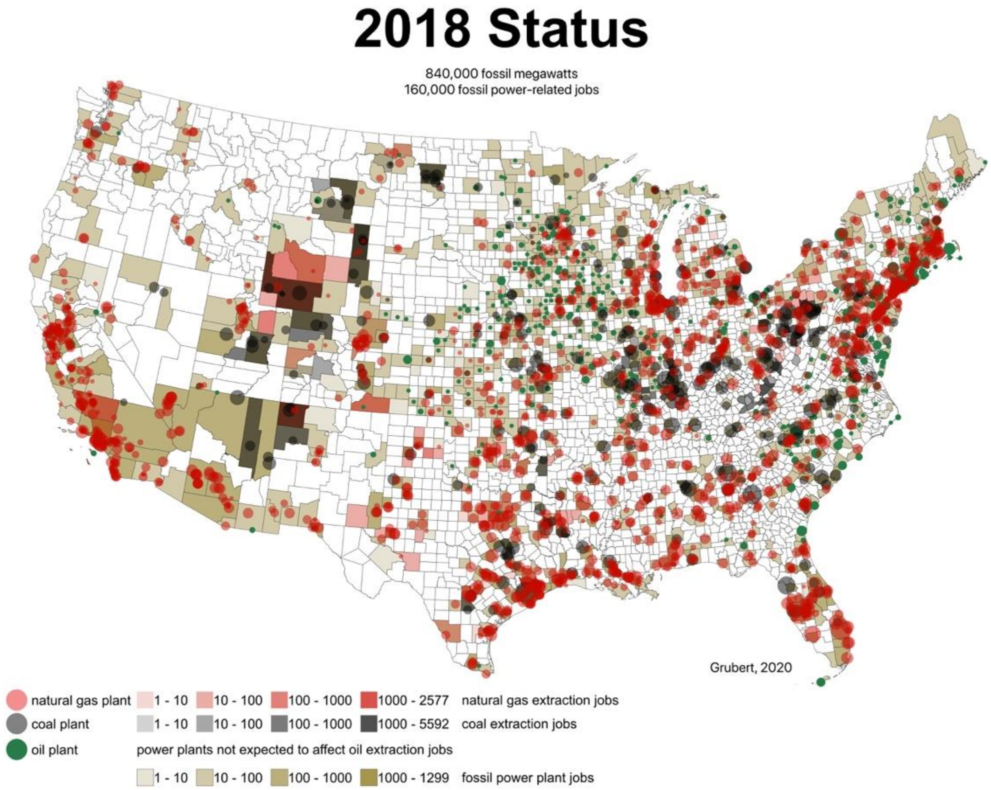
Proportion of total CO_2 emissions estimates assigned to generator by allocation method, compared with total CO_2 emissions reported in eGRID.

Fig. S2.



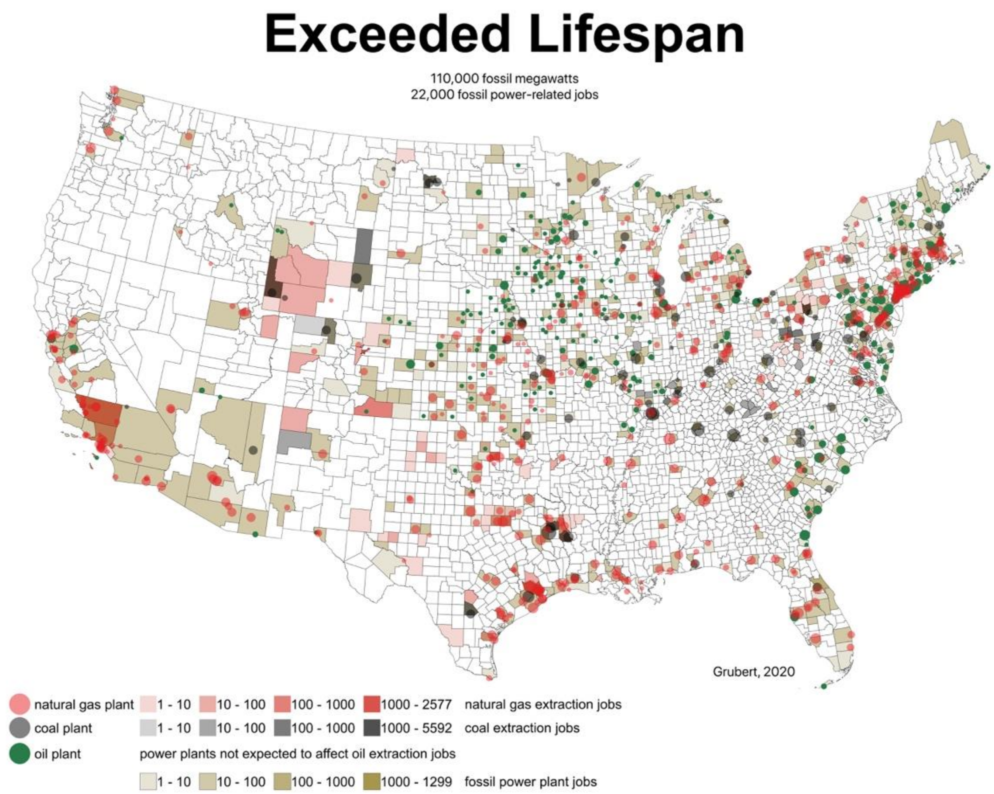
Generators can burn multiple fuels, and those with oil as "Energy Source 1" (EIA 860) use proportionately more other fossil fuels than do those generators with coal or natural gas as "Energy Source 1."

Fig. S3.



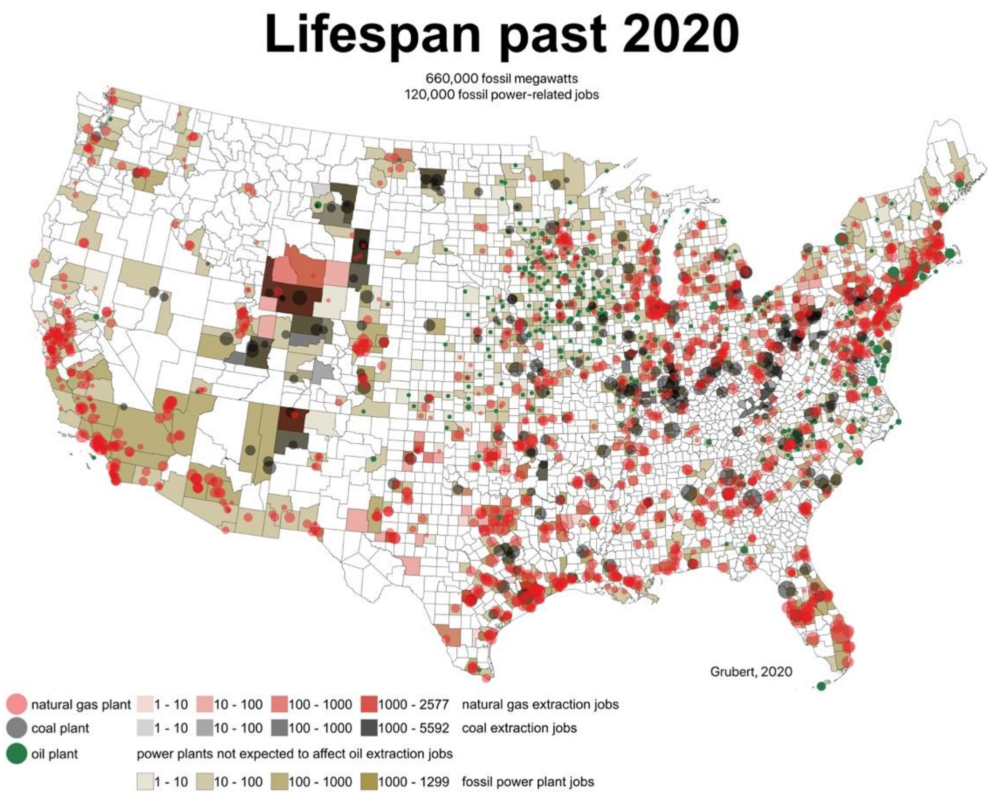
US fossil fuel-fired generators, operable as of 2018, with capacity aggregated to plant level and labels based on largest fuel share burned at combined generators in 2018.

Fig. S4.



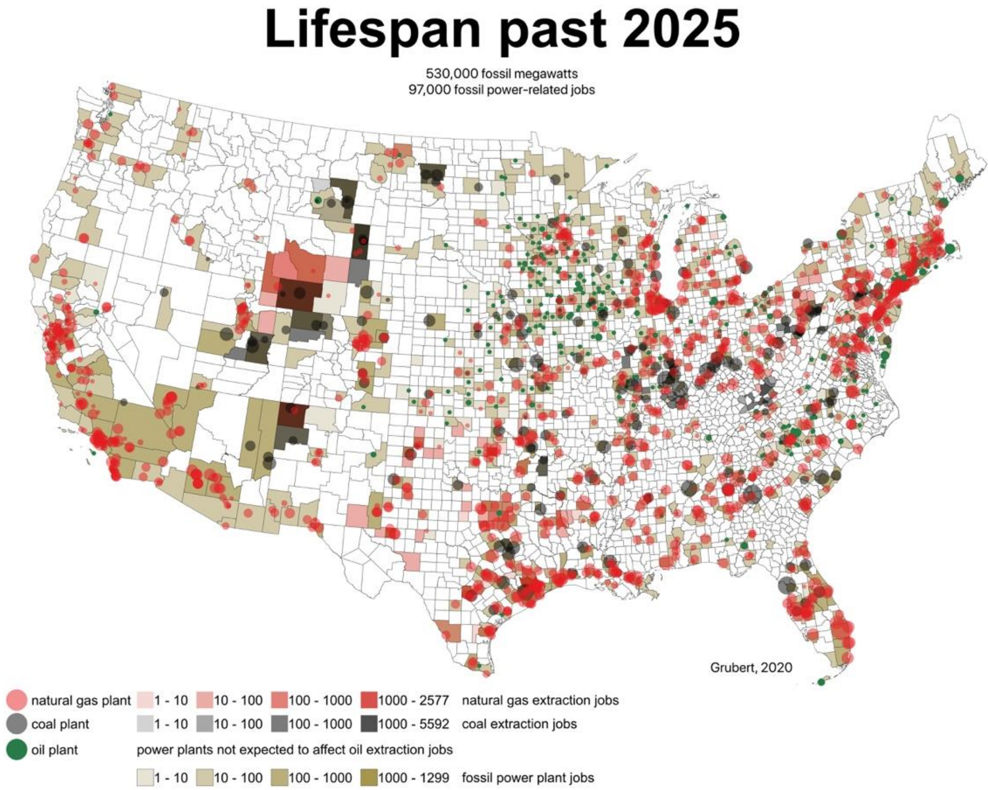
US fossil fuel-fired generators that have exceeded their fuel- and technology-specific lifetime but were operable as of 2018, with capacity aggregated to plant level and labels based on largest fuel share burned at combined generators in 2018.

Fig. S5.



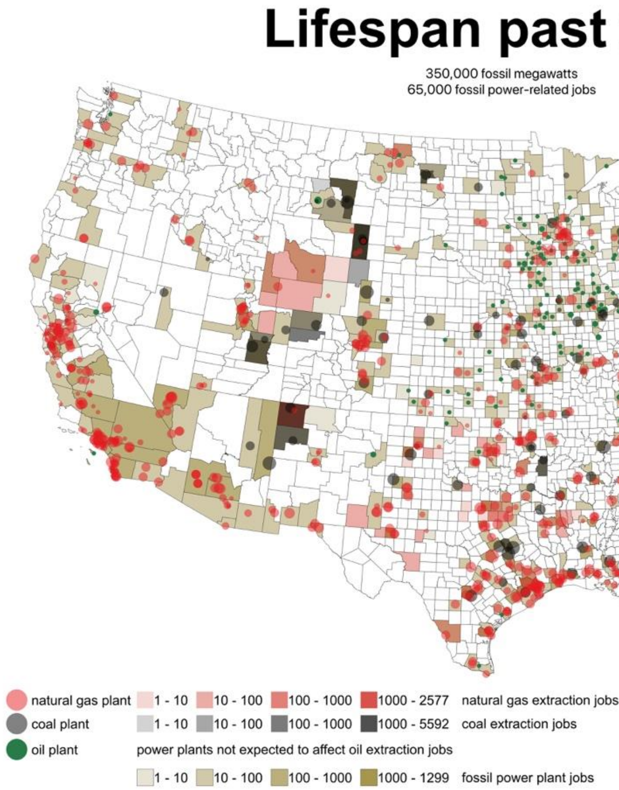
US fossil fuel-fired generators with estimated fuel- and technology-specific lifespan extending past 2020, operable as of 2018, with capacity aggregated to plant level and labels based on largest fuel share burned at combined generators in 2018.

Fig. S6.



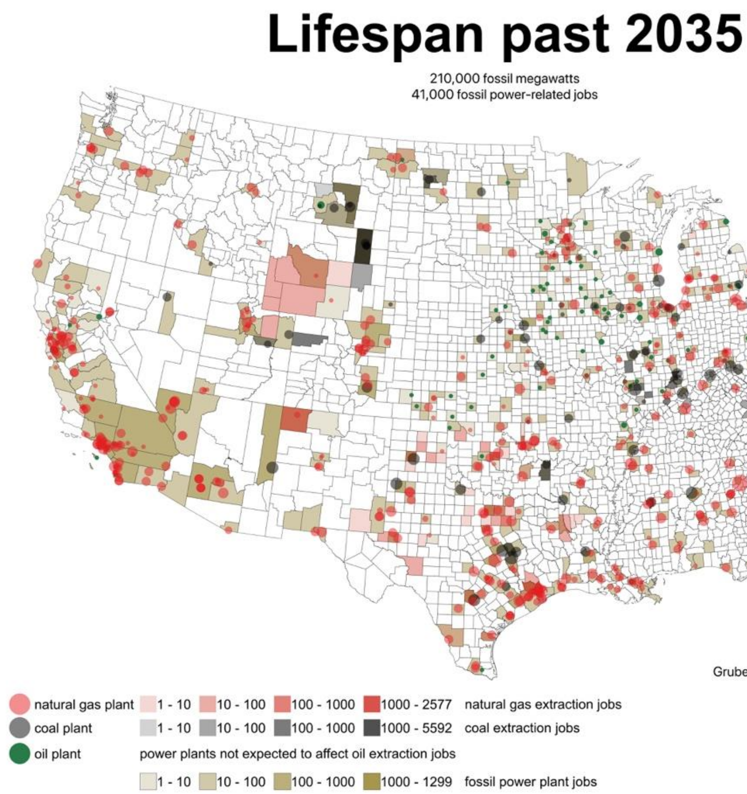
US fossil fuel-fired generators with estimated fuel- and technology-specific lifespan extending past 2025, operable as of 2018, with capacity aggregated to plant level and labels based on largest fuel share burned at combined generators in 2018.

Fig. S7.



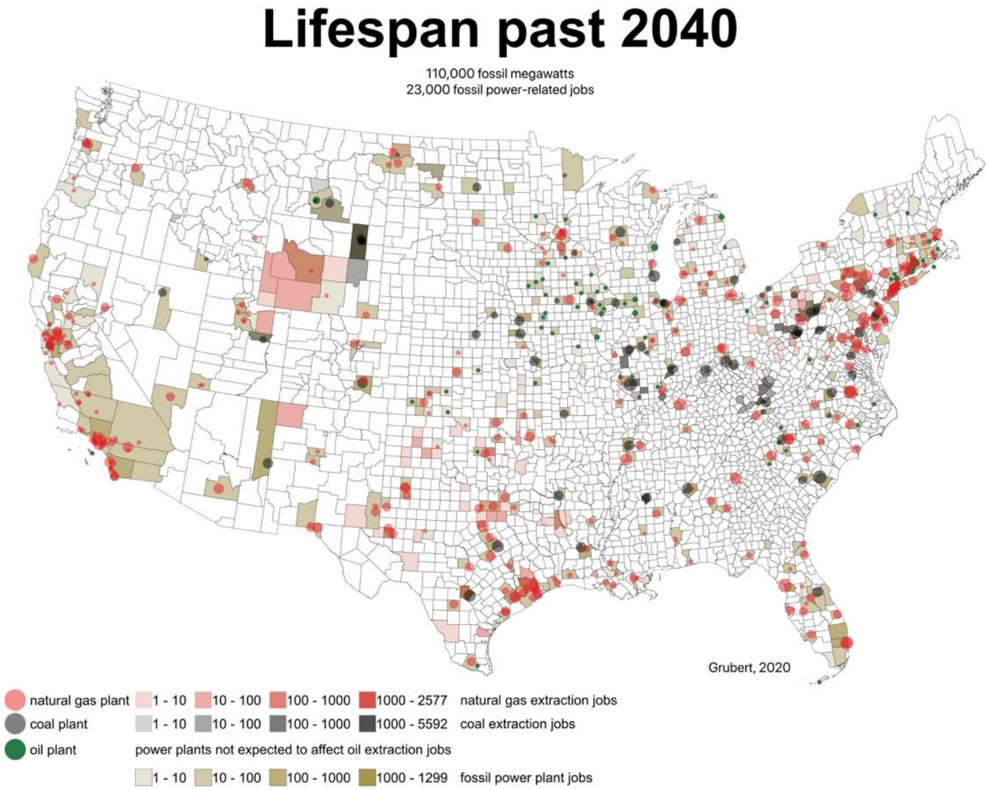
US fossil fuel-fired generators with estimated fuel- and technology-specific lifespan extending past 2030, operable as of 2018, with capacity aggregated to plant level and labels based on largest fuel share burned at combined generators in 2018.

Fig. S8.



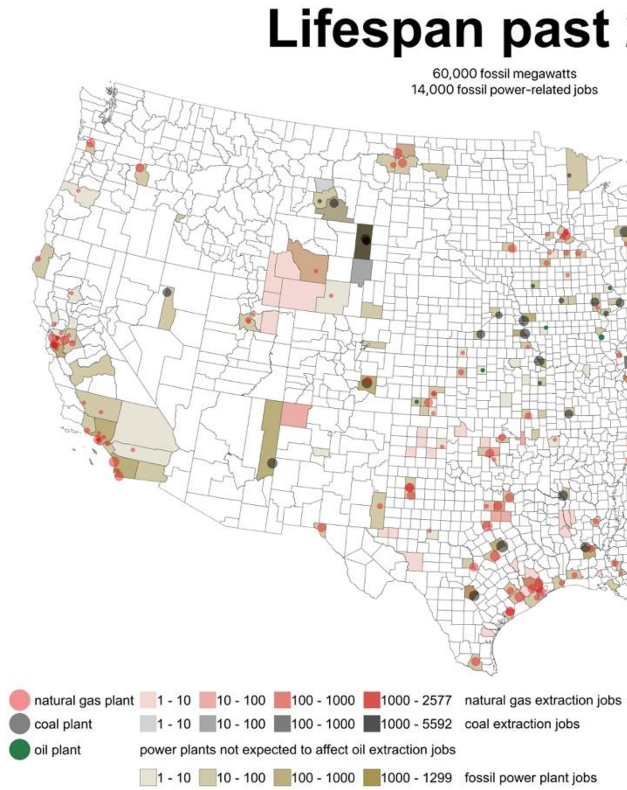
US fossil fuel-fired generators with estimated fuel- and technology-specific lifespan extending past 2035, operable as of 2018, with capacity aggregated to plant level and labels based on largest fuel share burned at combined generators in 2018. (Replicated from Figure 2, main text, for clarity in the image sequence.)

Fig. S9.



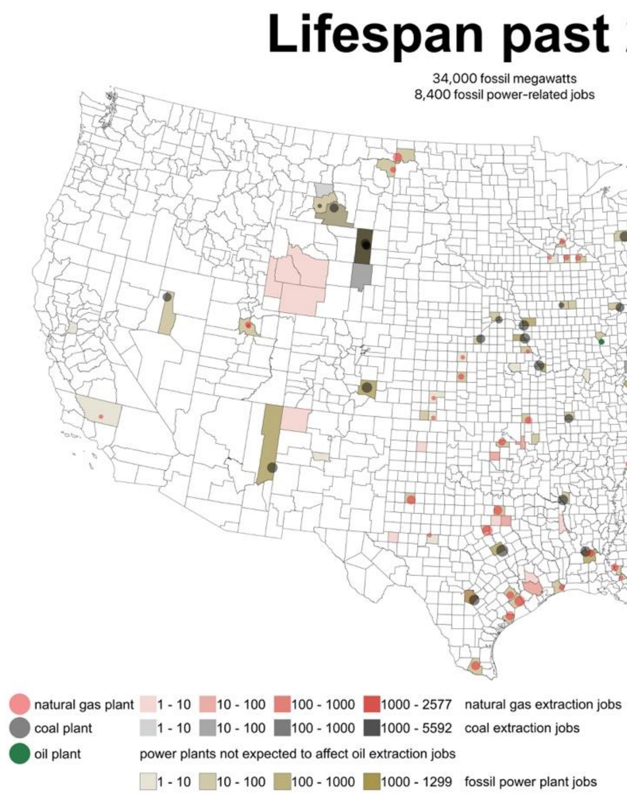
US fossil fuel-fired generators with estimated fuel- and technology-specific lifespan extending past 2040, operable as of 2018, with capacity aggregated to plant level and labels based on largest fuel share burned at combined generators in 2018.

Fig. S10.



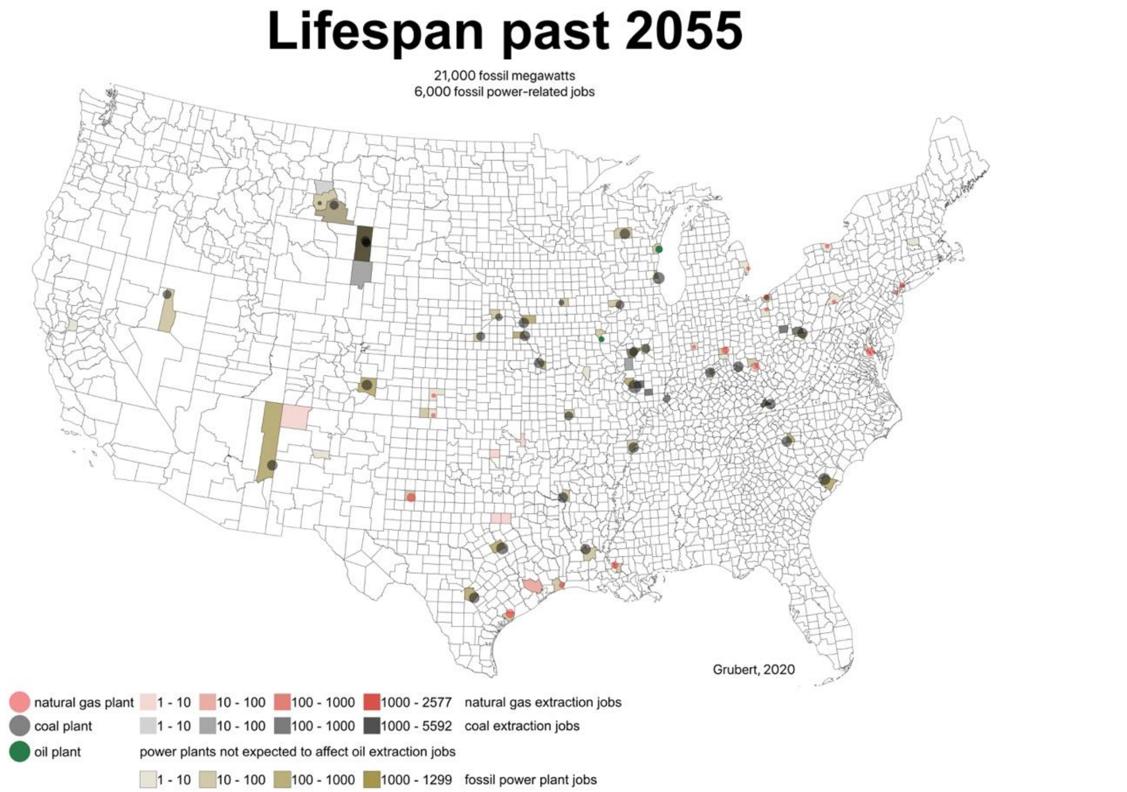
US fossil fuel-fired generators with estimated fuel- and technology-specific lifespan extending past 2045, operable as of 2018, with capacity aggregated to plant level and labels based on largest fuel share burned at combined generators in 2018.

Fig. S11.



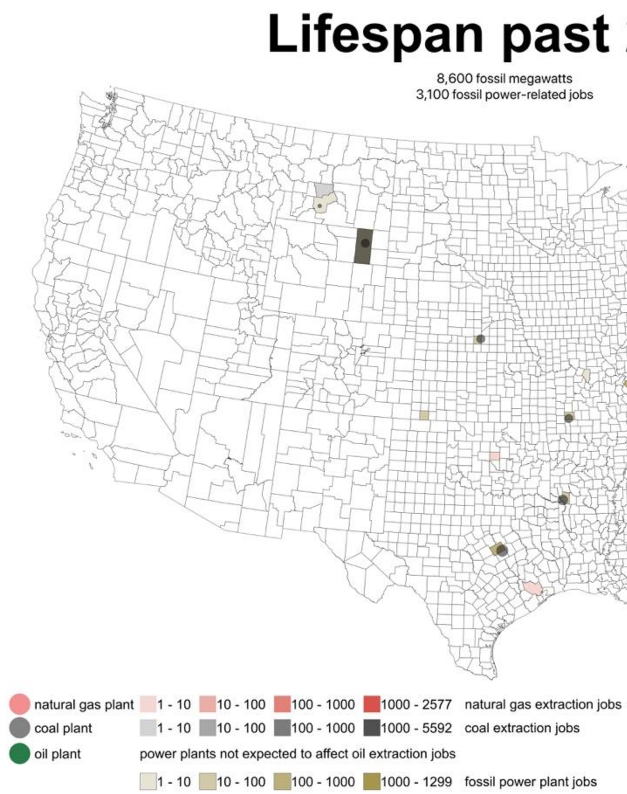
US fossil fuel-fired generators with estimated fuel- and technology-specific lifespan extending past 2050, operable as of 2018, with capacity aggregated to plant level and labels based on largest fuel share burned at combined generators in 2018.

Fig. S12.



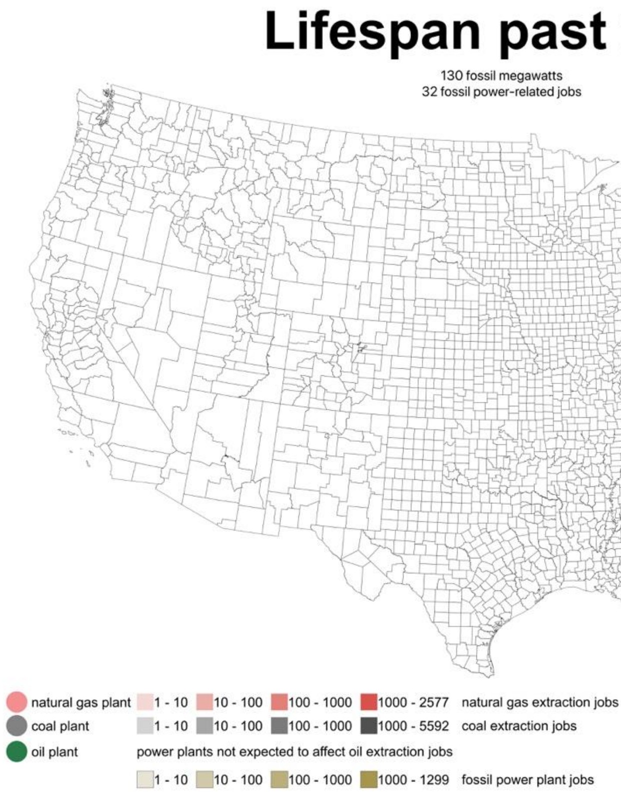
US fossil fuel-fired generators with estimated fuel- and technology-specific lifespan extending past 2055, operable as of 2018, with capacity aggregated to plant level and labels based on largest fuel share burned at combined generators in 2018.

Fig. S13.



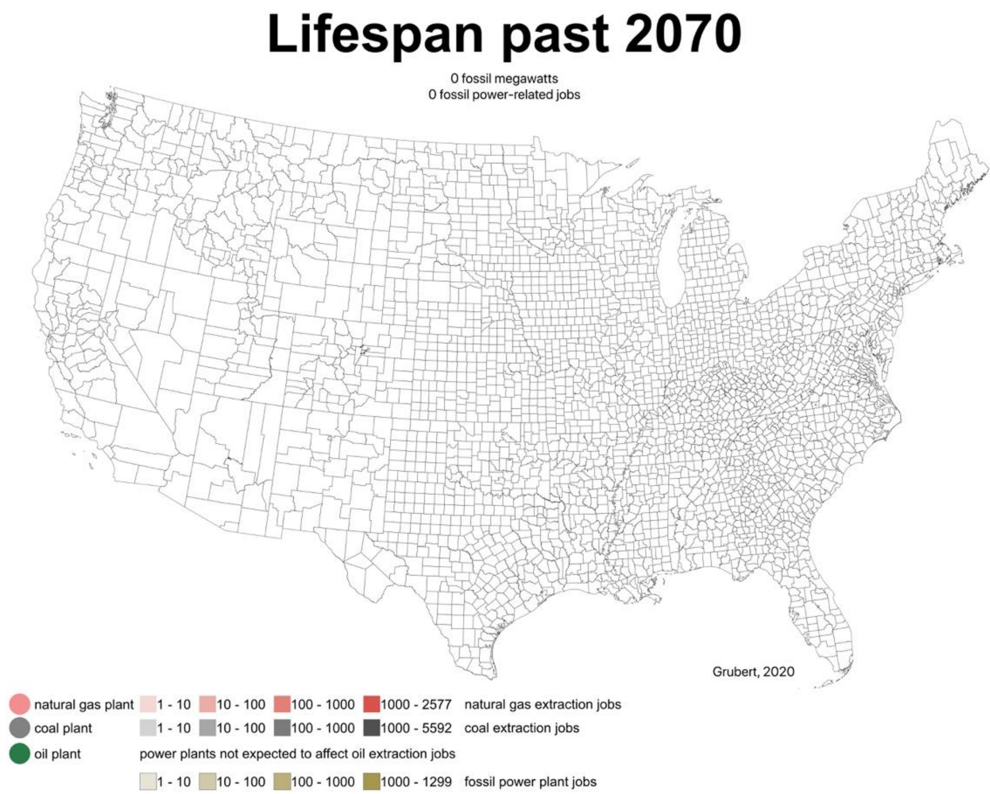
US fossil fuel-fired generators with estimated fuel- and technology-specific lifespan extending past 2060, operable as of 2018, with capacity aggregated to plant level and labels based on largest fuel share burned at combined generators in 2018.

Fig. S14.



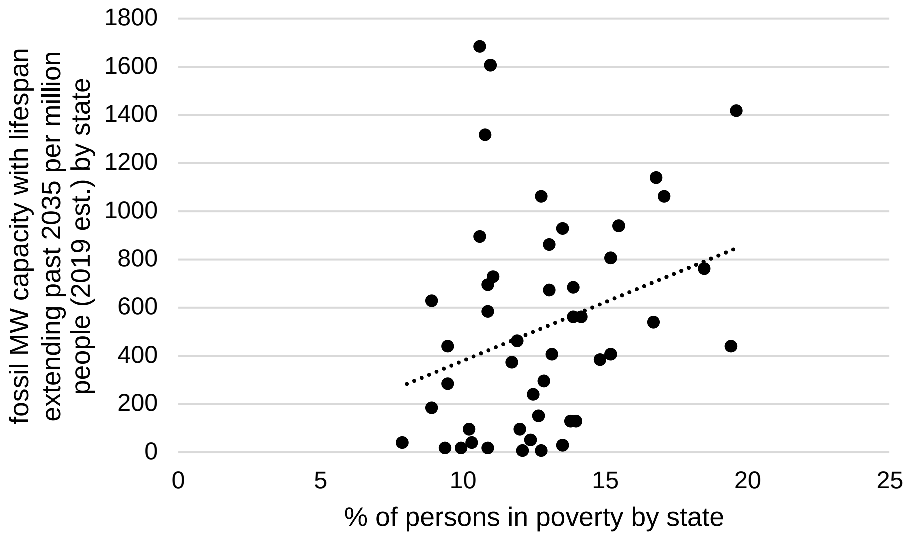
US fossil fuel-fired generators with estimated fuel- and technology-specific lifespan extending past 2065, operable as of 2018, with capacity aggregated to plant level and labels based on largest fuel share burned at combined generators in 2018.

Fig. S15.



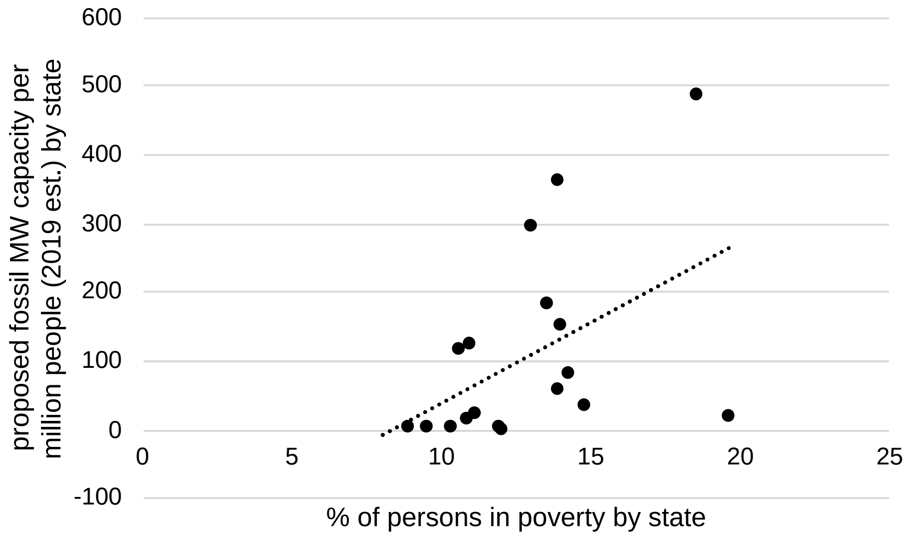
US fossil fuel-fired generators with estimated fuel- and technology-specific lifespan extending past 2070, operable as of 2018, with capacity aggregated to plant level and labels based on largest fuel share burned at combined generators in 2018.

Fig. S16.



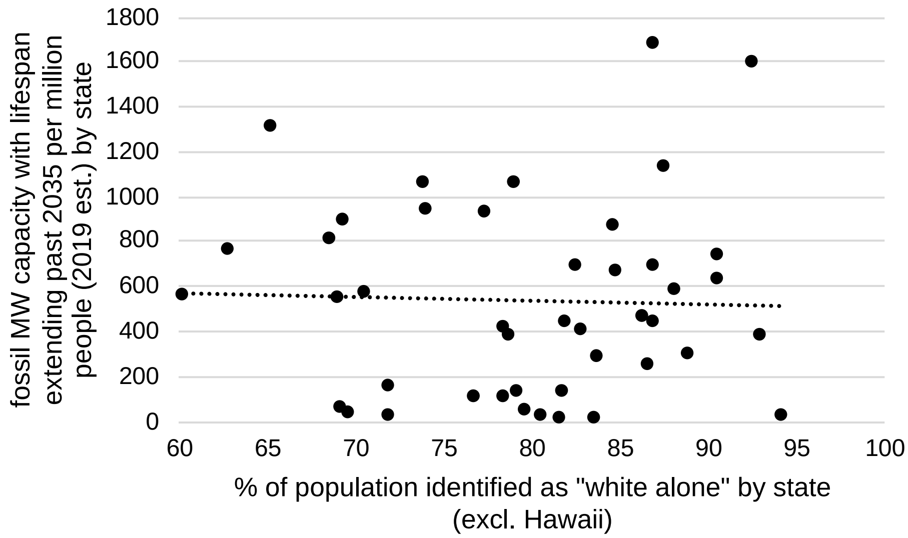
Fossil megawatts of electric utility capacity with lifespan extending past 2035 (based on this research, see Data S1) per million people (2019 estimate) by state versus percentage of population identified as in poverty by state.

Fig. S17.



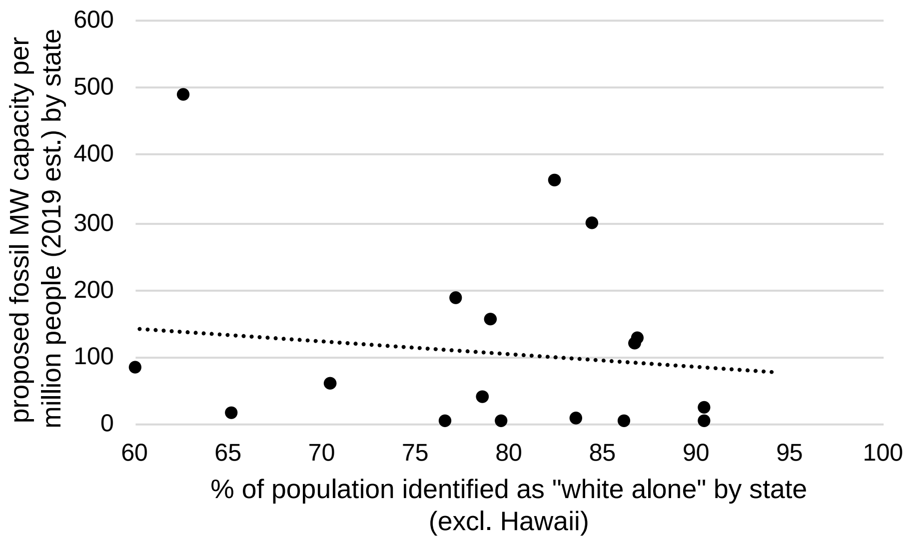
Proposed fossil megawatts of electric utility capacity (EIA 860, 2018) per million people (2019 estimate) by state versus percentage of population identified as in poverty by state.

Fig. S18.



Fossil megawatts of electric utility capacity with lifespan extending past 2035 (based on this research, see Data S1) per million people (2019 estimate) by state versus percentage of population identified as "white alone" by state. Hawaii is excluded due to extreme value (25% of population identified as "white alone").

Fig. S19.



Proposed fossil megawatts of electric utility capacity (EIA 860, 2018) per million people (2019 estimate) by state versus percentage of population identified as "white alone" by state. Hawaii is excluded due to extreme value (25% of population identified as "white alone").

Table S1.

Validation Indicator	Estimate, this work	Adjusted validation data	This work / Adjusted validation
Capacity (MW)	841319	841319	100%
Generation (MWh)	2.6E+09	2.6E+09	100%
Coal burned at fossil plants (short tons)	6.5E+08	6.5E+08	100%
Coal burned at fossil plants (mmbtu)	1.2E+10	1.2E+10	100%
Natural gas burned at fossil plants (mmbtu)	1.3E+10	1.3E+10	98%
Oil burned at fossil plants (mmbtu)	3.0E+08	3.3E+08	92%
Fossil power plant employment (annual average FTEs)	105319	104564	101%
Extraction employment, coal and gas (annual average FTEs)	52245	52629	99%
Fossil power plant carbon dioxide emissions (short tons)	2.1E+09	2.1E+09	101%
Fossil power plant nitrogen oxide emissions (short tons)	1.3E+06	1.4E+06	95%
Fossil power plant sulfur dioxide emissions (short tons)	1.5E+06	1.5E+06	97%
Fossil power plant mercury emissions (pounds)	8376	11121	75%
Fossil power plant water withdrawal (m^3)	9.4E+10	1.0E+11	93%
Fossil power plant water consumption (m^3)	2.9E+09	2.4E+09	122%
Fuel-related water consumption for fossil plants (m^3)	7.9E+08	7.9E+08	101%

Model results closely match validation values in most cases, with specific issues, data sources, and adjustments described in Data S1, Tab “Validation.”

Table S2.

Fuel	Prime mover	Capacity-average lifespan
NG	ST	48
NG	CA	34
NG	GT	30
NG	CT	25
NG	IC	35
BIT	ST	51
SUB	ST	50
LIG	ST	29
DFO	ST	52
any	other steam turbine	50
any	other (incl. CS)	30

Assumed typical lifespans are assigned at the generator level for generators without a reported future retirement date, based on EIA 860M data for 2002-2018, as calculated in (*16*). "CS" (single shaft combined cycle units) are assigned a lifespan of 30 years based on the assumption that the lower-life gas turbine component drives overall lifespan. EIA 860M data include insufficient data for a capacity-weighted retirement age to be meaningful, but the plant-weighted retirement age is 28, suggesting the assumption of a 30 year lifespan is reasonable.

Table S3.

Major fuel group	**Fuel codes in group (defined by EIA 923)**
Coal	BIT, SUB, LIG, RC, WC, BFG, SGC, SC
Natural gas	NG, OG
Oil	DFO, JF, KER, PC, PG, RFO, SGP, TDF, WO

In this model, an operable generator is considered to be fossil fuel-fired if its "Energy Source 1" classification in EIA 860 is one of the codes in Table S3, further grouped by major fuel group for the purposes of this analysis.

Table S4.

Cumulative committed outputs from US fossil-fuel fired electricity fleet	Total fossil fired generation (MWh)	Total extraction employment supporting fossil power plants (FTE-years)	Total fossil fired power plant CO_2 emissions (tons)	Total fossil fired power plant NO_x emissions (tons)	Total fossil fired power plant SO_2 emissions (tons)	Total fossil power plant and fuel extraction water consumption (m^3)
Static output	3.78E+10	671,000	2.72E+10	1.51E+7	1.82E+7	5.13E+10
Adjustments based on (*22*)	5.15E+10	641,000	2.74E+10	1.35E+7	1.37E+7	5.35E+10
Adjusted/ default	136%	96%	101%	89%	75%	104%

Adjustments based on (*22*) are the use of historical rates of change for capacity factor and heat rate for bituminous coal (including refined coal), subbituminous coal, lignite, natural gas combined cycles, natural gas steam turbines, and other natural gas plants. The overall effect of assuming that plant outputs change over time rather than remaining at 2018 levels is to substantially increase natural gas fleet outputs and reduce coal fleet outputs. No additional checks, e.g., to ensure that individual plant outputs do not exceed 100% capacity factor or dip below 0%, are performed for this sensitivity check. In practice, rates of change are highly specific to local conditions, with significant regional variability not reflected in this sensitivity check.

Movie S1.

Animation of Figures S3-S15, US fossil fuel-fired generators operable as of 2018, with capacity aggregated to plant level and labels based on largest fuel share burned at combined generators in 2018, depicting 2018 status, plants that exceeded their typical lifespan by 2018, and plants with estimated fuel- and technology-specific lifespan extending past a given year in 5 year increments through 2070.

Data S1. (separate file)

Committed impact framework model of US fossil fuel-fired generators and their capacity, generation, fuel use, CO_2 emissions, NO_x emissions, SO_2 emissions, water use, and labor intensity, assuming fuel- and technology-specific generator lifespans, supporting analysis described in the main and supporting text.

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