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The Full Cost of Electricity (FCe-)



# New U.S. Power Costs: by County, with Environmental Externalities

PART OF A SERIES OF WHITE PAPERS



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**THE FULL COST OF ELECTRICITY** is an interdisciplinary initiative of the Energy Institute of the University of Texas to identify and quantify the full-system cost of electric power generation and delivery – from the power plant to the wall socket. The purpose is to inform public policy discourse with comprehensive, rigorous and impartial analysis.

The generation of electric power and the infrastructure that delivers it is in the midst of dramatic and rapid change. Since 2000, declining renewable energy costs, stringent emissions standards, low-priced natural gas (post-2008), competitive electricity markets, and a host of technological innovations promise to forever change the landscape of an industry that has remained static for decades. Heightened awareness of newfound options available to consumers has injected yet another element to the policy debate surrounding these transformative changes, moving it beyond utility boardrooms and legislative hearing rooms to everyday living rooms.

The Full Cost of Electricity (FLe-) study employs a holistic approach to thoroughly examine the key factors affecting the *total direct and indirect costs* of generating and delivering electricity. As an interdisciplinary project, the FLe- synthesizes the expert analysis and different perspectives of faculty across the UT Austin campus, from engineering, economics, law, and policy.

In addition to producing authoritative white papers that provide comprehensive assessment and analysis of various electric power system options, the study team developed online calculators that allow policymakers and other stakeholders, including the public, to estimate the cost implications of potential policy actions. A framework of the research initiative, and a list of research participants and project sponsors are also available on the Energy Institute website: [energy.utexas.edu](http://energy.utexas.edu)

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This paper is one in a series of Full Cost of Electricity white papers that examine particular aspects of the electricity system.

Other white papers produced through the study can be accessed at the University of Texas Energy Institute website: [energy.utexas.edu](http://energy.utexas.edu)

# New U.S. Power Costs: by County, with Environmental Externalities

## A Geographically Resolved Method to Estimate Levelized Power Plant Costs with Environmental Externalities



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### ABSTRACT

In this analysis we developed and applied a geographically-resolved method to calculate the Levelized Cost of Electricity (LCOE) of new power plants on a county-by-county basis while including estimates of some environmental externalities. We calculated LCOE for each county of the contiguous United States for several types of new power plants: coal (bituminous and sub-bituminous, with partial (30%) and full (90%) carbon capture and sequestration), natural gas combined cycle, with and without carbon capture and sequestration) natural gas combustion turbine, nuclear, onshore wind, solar PV (utility and residential), and concentrating solar power (with 6 hours of storage). The new method starts with a conventional LCOE calculation and integrates costs from externalities including air emissions, combustion CO<sub>2</sub>, and embedded life cycle analysis greenhouse gases. Capital, operating, and fuel costs were spatially interpolated from point locations around the country to each county. Air emissions impacts were included on a county-by-county basis and CO<sub>2</sub>

costs were applied at the national level. Certain types of power plants were excluded from locations based on various constraints (i.e. water availability for thermal plants, and EPA non-attainment zones for plants that produce air pollutants, etc.). Finally, the method is illustrated by finding the lowest cost option for each county based on different inputs. While the average increased cost for internalizing the environmental externalities is small for some technologies, the local cost differences can be rather high, i.e. \$0.05 to \$0.62/kWh for coal. We present the results in a map format to facilitate comparisons by fuel, technology, and location. Ten scenarios were considered: a conventional scenario that disregards the costs from environmental externalities, a scenario that includes environmental externalities, a scenario that includes environmental externalities and considers restrictions on where one might be able to site specific technologies, a conventional scenario that disregards the costs from environmental externalities but includes restrictions on siting,

scenarios for high and low natural gas prices, scenarios for high and low CO<sub>2</sub> prices, a scenario with low solar capital costs, and a scenario using the location's maximum available onshore wind capacity factor. For nominal reference conditions, the minimum cost option for each county varies based on local conditions and resource available with natural gas combined cycle, wind, and nuclear most often the lowest-cost options. Overall, natural gas combined cycle power plants are the lowest cost option for at least a third of US counties for most cases considered. Wind is also commonly found to be the lowest cost option. Counties where nuclear power is the low-cost option are limited

to locations where natural gas prices are relatively high and wind capacity factors are low. Coal is selected as the low cost option when externalities cost are not high, wind resources are poor, and natural gas prices are high due to distance from existing pipelines. These results, namely that wind and natural gas combined cycle are the most typical low-cost solution, are consistent with recent market trends. These results and display format could serve as an educational tool for stake holders and policymakers when considering which technologies might or might not be a good fit for a given locality subject to system integration considerations.

# INTRODUCTION

**The Levelized Cost of Electricity (LCOE) is a commonly used metric for comparing different generation types.**

The Levelized Cost of Electricity (LCOE) is typically expressed on a \$/kWh basis, it is the estimated amount of money that it takes for a particular electricity generation plant to produce a kWh of electricity over its expected lifetime. LCOE offers several advantages as a cost metric, such as its ability to normalize costs into a consistent format across decades and technology types. Consequently it has become the de facto standard for cost comparisons among the general public and many stakeholders such as policymakers, analysts, and advocacy groups. There are many organizations that calculate LCOE values either for each year,<sup>1</sup> future projections,<sup>2,3</sup> or for specific clients.<sup>4</sup> Despite its advantages and widespread use, the conventional LCOE has several shortcomings that render it spatially and temporally static. Costs of building and operating an identical plant across different geographies will be different. Moreover, fuel costs, capacity factors and financing terms will differ across regions as well. However, LCOE does not readily incorporate these differences, LCOE can also be problematic because of the assumption of constant capacity factors over the lifetime of the plant. Furthermore, the LCOE framework does not anticipate real-time prices or market behaviors, and therefore is more suitable for base load analysis for average conditions. It is also difficult to project LCOE values into the future for fossil fuel and nuclear plants because of the uncertainty of future fuel prices, capacity factors, and regulation. In addition, there have been few attempts to incorporate the costs of environmental externalities into the framework.<sup>5-7</sup> We introduce environmental externalities in calculating an expanded LCOE while honoring the spatial variability of emissions and other environmental impacts.

In this paper we present a levelized cost framework that preserves the benefits of the conventional LCOE while adding in environmental externalities and geographic resolution. We start with a standard LCOE calculation and include a few key externalities: SO<sub>2</sub>, NO<sub>x</sub>, PM<sub>2.5</sub>, and PM<sub>10</sub> criteria air pollutants emissions; CO<sub>2</sub> emissions; and life cycle emissions associated with capital (i.e. steel and concrete) and fuel processing (i.e. uranium enrichment). The criteria air pollutant costs are considered at the county-level based on their marginal impact to human health<sup>8</sup> and then internalized into the cost of generating electric energy.<sup>9-14</sup> CO<sub>2</sub> emissions (upstream, on-going combustion and non-combustion, and downstream) are considered at a national level. In this analysis we consider the following electricity generation types: coal (bituminous and sub-bituminous, partial and “full” CCS), natural gas (combined cycle (NGCC) and combustion turbine (NGCT)), NGCC with CCS, nuclear, onshore wind, solar PV (utility and residential), and concentrating solar power (CSP) with 6 hours of thermal storage. LCOE typically only considers costs that are internal to the plant itself such as capital costs (CAPEX, costs to build the plant itself and any applicable CO<sub>2</sub> pipelines, \$/kW), debt service costs, fixed Operations and Maintenance costs (O&M, costs associated with the operations and maintenance of the plant, \$/MW), variable O&M costs (costs associated with each unit of electricity generated, \$/MWh), the heat rate (how much heat it takes to produce a unit of electricity, kJ/kWh (MMBtu/MWh)), the fuel cost (on a per unit of heat basis, \$/GJ (\$/MMBtu)), and the capacity factor (the amount of energy produced divided by the potential amount of energy that could be produced). However, these aspects vary

by location. This specific analysis incorporates region-specific data on CAPEX, O&M and fuel costs, where available, and uses geographical interpolation techniques to calculate them on a county-by-county basis in the United States.

Other refinements, such as temporal fidelity, levelized avoided cost of electricity (LACE), the impact of subsidies, and the ability to incorporate performance factors (e.g., firming, shaping, storage costs) are not included here but are discussed further in the future work section. Backup and firming costs and other system integration costs such as T&D investments are difficult to incorporate into an LCOE analysis

because these require knowledge of the temporal demand and supply of electricity, which is not natively part of the LCOE equation because these costs are representative of overall electric grid, or system, into which to add a new power plant. This analysis is specifically formulated to show regional differences in the cost of electricity and the results are presented in a series of least-cost county maps. The maps do not imply or suggest rates of technology penetration or regional values associated with any particular market in the US. All costs are in 2015\$ USD unless otherwise noted. By definition, our LCOE calculation assumes the marginal addition of one power plant. ■

# METHODS

Our approach is to use the conventional LCOE formulation and then integrate environmental externalities after which the calculations are executed with geographical differentiation. **Equation 1** presents the traditional LCOE calculation for which only the plant costs are considered:

## EQUATION 1

$$LCOE_1 = \frac{\Pi_{capitalcost} \times CRF + O\&M_{fixed}}{8760 \times CF} + O\&M_{variable} + HR \times \Pi_{fuel}$$

For **Equation 1**,  $\Pi_{capitalcost}$  is the power plant and any relevant CO<sub>2</sub> pipeline overnight capital costs (\$/MW),  $O\&M_{fixed}$  is the fixed operations and maintenance costs (\$/MW),  $CF$  is the average capacity factor over the lifetime of the plant,  $O\&M_{variable}$  is the variable operations and maintenance costs (\$/MWh),  $HR$  is the heat rate (GJ/MWh (MMBtuMWh)), and  $\Pi_{fuel}$  is the price of fuel (\$/GJ (\$/MMBtu)). The heat rate and fuel costs are not relevant for wind or solar.  $CRF$  is the capital recovery factor, shown in **Equation 2**:

## EQUATION 2

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

For **Equation 2**,  $i$  is the interest rate, and  $n$  is the number of years to service the debt. Our LCOE calculation inherently assumes the equivalent of borrowing 100% of the capital cost. A modified version integrates the costs of air pollutant emissions. These costs are often considered environmental externalities because they are borne outside the electricity market.  $\Pi_{capitalcost}$  in **Equation 1** includes costs for any required emissions controls (see Section ). Externalities added in **Equation 4** reflect the (mostly human health) cost of remaining emissions. **Equation 3** presents the LCOE calculation where both the plant costs and the costs associated with SO<sub>2</sub>, NO<sub>x</sub>, PM<sub>2.5</sub>, PM<sub>10</sub>, and *combustion-related* CO<sub>2</sub> emissions are considered:

## EQUATION 3

$$LCOE_2 = \frac{\Pi_{capitalcost} \times CRF + O\&M_{fixed}}{8760 \times CF} + O\&M_{variable} + HR \times \Pi_{fuel} + \sum_{j \in \theta} R_j \times D_j$$

where  $R_j$  is the rate of emission (tonne/MWh) of pollutant  $j$  (see **Table 2**),  $D_j$  is the damages (\$/tonne) associated with pollutant  $j$ , and  $\theta$  is a set of pollutants that includes SO<sub>2</sub>, NO<sub>x</sub>, PM<sub>2.5</sub>, PM<sub>10</sub>,<sup>15</sup> CO<sub>2</sub>,<sup>16</sup> and CH<sub>4</sub>.<sup>17</sup> See **Table 3** for ongoing CO<sub>2</sub> damages per lifetime of power plant. The non-CO<sub>2</sub> damages were estimated at the county level as the damage from pollution varies across the nation for a variety of meteorological and other conditions. The damages associated with ongoing CO<sub>2</sub> emissions are taken at the national level.

**Equation 4** includes the greenhouse gas (GHG) emissions on a carbon dioxide equivalent basis ( $CO_{2-eq}$ ) associated with 1) upstream one-time emissions (i.e. building a power plant), on-going *non-combustion* emissions (i.e. fuel extraction), and 3) downstream one-time emissions (i.e. power plant decommissioning):

**EQUATION 4**

$$\begin{aligned}
 LCOE_3 = & \frac{\Pi_{capitalcost} \times CRF + O\&M_{fixed}}{8760 \times CF} + O\&M_{variable} + HR \times \Pi_{fuel} \\
 & + \sum_{j \in \theta} R_j \times D_j \\
 & + E_{GHG,one-time} \times D_{GHG,one-time} \\
 & + R_{GHG,NC,ongoing} \times D_{jCO_2}
 \end{aligned}$$

where  $E_{GHG,one-time}$  are the GHG emissions associated with the one-time upstream and downstream emissions in the construction and decommissioning of a power plant,  $D_{GHG,one-time}$  are the damages associated with the one-time upstream and downstream emissions, and  $R_{GHG,NC,ongoing}$  is the rate of ongoing non-combustion emissions associated with each technology. Note the values for upstream and downstream emissions damages are different and based on the Social Cost of Carbon corresponding to their year, see **Table 3**.

While important, we do not consider the cost of water beyond that which is included in O&M costs as water costs have to be relatively high to influence power plant dispatch decisions.<sup>18</sup> However, regions with significant water scarcity could have costs from marginal water use high enough to non-trivially affect the overall cost of the power plant. For example, water consumption costs above approximately \$1/m<sup>3</sup> can incentivize a power plant developer to invest in dry cooling systems to avoid the vast majority of water use.<sup>19</sup> We do consider water availability when considering counties that might not be able to support a thermal plant, see the supplementary material.

The end result of this analysis is a modified and expanded LCOE method at the county level. To display this method, we found appropriately spatial data and display the results in map form. Because not all of the data were available at the county level, spatial interpolation methods were used to extend the available data. For instance, EIA calculated the cost of building power plants in 60 locations across the US. These calculated CAPEX costs were used to interpolate (via the Empirical Bayesian Kriging algorithm in ArcMap 10.2) across all other counties (see **Figures 14 – 23**). Fixed operating costs ( $O\&M_{fixed}$ ) were taken from the EIA report and multiplied by the same geographic multipliers as the CAPEX values. Variable operating costs ( $O\&M_{variable}$ ) and heat rates for all types of power plants were also taken directly from the EIA report, and were assumed the same across all the regions. A similar approach for fuel prices was used with a starting point of reported delivered fuel costs for fossil plants in their respective counties. Results of these interpolations, along with more description are available in the next section. **Table 1** shows the assumptions and locations for each type of data used in this analysis.



**TABLE 1**

Reference case U.S. average inputs for the considered technologies. Some of the inputs for the reference case are in map format and reference the appendices. For example F14 is a map of county-level coal CAPEX values, F29 is a map of county-level coal capacity factor values located in the supplementary material, and F24 is a map of county-level delivered bituminous coal prices all located in the supplementary material. Individual technology pollutant emissions rates are shown in Table 2. County-level air pollutant damages are taken from Muller and Mendelsohn, Holland et al.<sup>15,20</sup>

Technology	$\Pi_{capitalcost}$ (\$/kW) <sup>1</sup>	$O\&M_{fixed}$ (\$/kW-yr) <sup>2</sup>	$O\&M_{variable}$ (\$/MWh) <sup>3</sup>	$CF$ (%) <sup>4</sup>	$HR$ ( $\frac{kJ}{kWh}$ ) <sup>5</sup>	$\Pi_{fuel}$ ( $\frac{\$}{GJ}$ ) <sup>6</sup>	$i$ (%) <sup>7</sup>	$n$ (years) <sup>7</sup>
Coal, bit CCS 30*	4,766(F14)	49.14	5.81	F29	10,409	3.35(F24)	11%	40
Coal, sub CCS 30	4,766(F14)	49.14	5.81	F29	10,409	2.28(F25)	11%	40
Coal, bit CCS 90**	5,513(F15)	80.53	9.51	F29	12,661	3.35(F24)	11%	40
Coal, sub CCS 90	5,513(F15)	80.53	9.51	F29	12,661	2.28(F25)	11%	40
NGCC***	1,021(F16)	15.37	3.27	F30	6,784	5.37(F26)	10%	35
NGCC CCS 90	2,095(F17)	31.79	6.78	F30	7,939	5.37(F26)	10%	35
NGCT****	867(F18)	7.04	10.37	F31	10,287	5.37(F26)	10%	35
Nuclear*****	8,000(F19)	93.28	2.14	F32	11,025	0.70	12%	50
Wind	1,827(F20)	39.55	0.00	F33	NA	NA	10%	25
Solar PV, util.	1,900(F21)	24.69	0.00	F34	NA	NA	10%	25
Solar PV, res.	3,350(F22)	24.69	0.00	F35	NA	NA	10%	25
CSP	7,041(F23)	67.26	0.00	F36	NA	NA	10%	30

\* All coal plants are at least partial CCS to bring them into alignment with the EPA's New Source Performance Standards (Clean Power Plan 111(b)) of 635.6 g/kWh CO<sub>2</sub> (1400 lb/MWh), CCS 30: 30% Carbon capture and sequestration.

\*\* CCS 90: 90% Carbon capture and sequestration

\*\*\* Natural gas combined cycle

\*\*\*\* Natural gas combustion turbine

\*\*\*\*\* Nuclear heat rate taken from <sup>3</sup>

<sup>1</sup> This value is the nominal CAPEX value given in <sup>3</sup> for each technology along with the figure depicting the interpolated values from the regional multipliers in. <sup>21</sup>

<sup>2</sup> This value is the nominal fixed operations and maintenance cost value given in <sup>21</sup> for each technology, the values were multiplied by the same interpolated multipliers as the CAPEX values. However, we do not show a regional map of O&M costs for brevity.

<sup>3</sup> This value is fixed for all locations for a given technology.

<sup>4</sup> This value points to the capacity factor map for each technology.

<sup>5</sup> The heat rate values were assumed constant in all locations for each technology and were taken from. <sup>21</sup> Parametric runs of NGCC and coal-style boilers in multiple locations across the US indicated negligible differences in heat rates due to climatological differences. The heat rates for different coal types are kept the same with the fuel price reflecting the heat content of the type of coal.

<sup>6</sup> This value shows the average fuel price across all locations and also points to the fuel price maps, if applicable.

<sup>7</sup> Typical interest rates ( $i$ ) and technology lifetimes ( $n$ ) for each type were gathered from conversations with utilities. Rates for CCS plants were left the same as their non-CCS counterparts for lack of available data.

However, not every type of power plant can be built in every location. Thus, we used maps provided in Mays, et al.<sup>22</sup> to determine the availability of locations to build plants based on population density, wetlands, protected lands, lands with landslide risks, highslope land, 100-year floodplains, water availability, EPA non-attainment zones, access to fuel (> 40 km (25 miles) from gas pipelines or railroads), proximity to suitable saline formations for carbon sequestration, and ability to build CO<sub>2</sub> pipelines. For each technology the applicable layers were stacked on top of

each other to exclude some counties that have a exclusion factor that significantly decreases the likelihood for constructing a power plant. For instance, it would be more costly to site a thermal power plant in an area that did not have adequate water availability for cooling, or a plant that produces air pollutants in an EPA non-attainment zone, etc. The only plant that did not have an explicit availability zone was residential PV. The exclusion or availability zones for each type of power plant are shown in the supplementary material. ■

# INPUTS FOR ILLUSTRATING THE METHOD

Overnight capital costs for all plant types were taken from NREL's 2015 Annual Technology Baseline database.<sup>3</sup> CAPEX values for nuclear plants were adjusted up and PV CAPEX values adjusted down based on more recent cost data. Because EPA's New Source Performance Standards limit the amount of carbon pollution from new power plants to 635.6 g/kWh CO<sub>2</sub> (1400 lb/MWh), all new coal plants have to be modeled as CCS plants with at least 30% CO<sub>2</sub> capture. Based on<sup>23–25</sup> we estimated that 30% CCS increases coal plant CAPEX and OPEX by 30% values and increase in the heat rate by 11% over the EIA/ATB values. These values are reflected in **Table 1**. Also included in the CAPEX values of CCS plants were costs to build CO<sub>2</sub> pipelines of an assumed 100 km length, about \$248.6M, or about \$2.5M/km (\$4M/mile). These costs were then normalized by the assumed capacity of the power plants, 650MW for coal CCS and 340MW for NGCC CCS. CO<sub>2</sub> pipe OPEX and CO<sub>2</sub> injection well CAPEX and OPEX were normalized by metric tonne of CO<sub>2</sub> produced/injected and were calculated to be \$4.00, \$2.00, and \$3.00, respectively based upon methods used in King et al.,<sup>26</sup>

Delivered monthly fuel costs (2007 – 2014) for bituminous coal, sub-bituminous coal, and natural gas were taken from EIA's 923 form for all reporting natural gas and coal plants in the US. The average fuel price for each county for each type of fuel was then used to spatially interpolate (via the Empirical Bayesian Kriging algorithm in ArcMap 10.2) across all counties that did not have a reporting power plant (see **Figures 24 – 26**). Fuel costs for nuclear plants were taken constant across all regions at \$0.70/GJ.

Five year average capacity factor values for coal, natural gas, and nuclear power plants were gathered from EPA's Emissions and Generation Resource Integrated Database (eGrid).<sup>27</sup> Capacity factors were extracted for each type of plant from the whole database and curated to the NERC subregion level. For lack of data, we assumed that CCS plants had the same capacity factor as their non-CCS counterparts. These values are actual reported historical capacity factors for each

type of plant (see **Figures 29 – 32**). Historical capacity factors are used because capacity factors are driven by markets and regulatory structures as well as the technology. Thus, we assume that the dispatch for a given technology would be roughly the same as current plants of the same technology. While fuel prices will affect capacity factor, EIA data indicate that the average price for natural gas has been at about the same price we are using, thus we feel comfortable using historical capacity factors. Capacity factor values for on-shore wind were obtained from 3Tier at a 5km×5km resolution<sup>28</sup> and were averaged at the county level. Wind capacity factors would be higher and thus the LCOE lower if the best locations in each county were chosen for siting the wind turbine. The capacity factor values were for a generic turbine with a hub height of 80m (**Figure 33**). Capacity factor values for utility and residential-scale solar PV plants were calculated using the capacity factor maps found in Drury et al., 2013.<sup>29</sup> Because these maps were at a finer granularity than county-level, the average value per county was calculated. Utility-scale PV was assumed to be single-axis tracking and residential PV was assumed to be south-facing fixed-tilt at the local latitude (see **Figures 34 – 35**). Capacity factor values for solar CSP were calculated using NREL's System Advisory Model (SAM).<sup>30</sup> Weather data from over 1000 locations across the US were used with the SAM model of a generic concentrating solar plant with 6 hours of thermal energy storage. The resulting capacity factors for the plants were then used to give each county in the US a CSP capacity factor based on similar meteorological conditions (**Figure 36**).

EIA emissions rates of SO<sub>2</sub>, NO<sub>x</sub>, and CO<sub>2</sub> for each type of power plant were used for each technology. The EIA emissions rates assume that the plant contains the Best Available Commercial Technology (BACT). Thus these emissions controls technologies that are part of BACT are reflected in CAPEX values. **Table 2** summarizes our cited non-combustion, life cycle emissions associated with each type of power plant<sup>31</sup> and our assumed combustion rates for air pollutants.

**TABLE 2**

Table showing the assumed life cycle emissions rates (g/kWh) of CO<sub>2-eq</sub> (GHG), the assumed BACT combustion emissions rates (g/kWh) of air pollutants, and the assumed CH<sub>4</sub> fugitive emissions rates (g/kWh) associated with the considered technologies.

Technology	Upstream one-time (g CO <sub>2-eq</sub> /kW)	On-going non-combustion (g CO <sub>2-eq</sub> /kWh) <sup>1</sup>	Downstream one-time (g CO <sub>2-eq</sub> /kW)	Combustion SO <sub>2</sub>	Combustion NO <sub>x</sub>	Combustion PM <sub>10</sub>	Combustion PM <sub>2.5</sub>	Combustion CO <sub>2</sub>	Fugitive CH <sub>4</sub> <sup>2</sup>
Coal CCS 30*	257,000	48	15,200	0.4	0.24	0.327	0.268	635.6	0
Coal CCS 90**	385,500	72	22,800	0.4	0.24	0.327	0.268	82.1	0
NGCC***	160,000	74.4	6,390	0.003	0.022	0.054	0.05	341.5	1.58
NGCC CCS 90	240,000	111.6	9,585	0.003	0.022	0.054	0.05	35	1.85
NGCT****	6,800	85.8	98.6	0.005	0.133	0.054	0.05	517.9	2.39
Nuclear	350,000	10.6	175,000	0	0	0	0	0	0
Wind	619,000	1.41	22,400	0	0	0	0	0	0
Solar PV	1,630,000	0	37,800	0	0	0	0	0	0
CSP	2,970,000	2.5	239,000	0	0	0	0	0	0

\* CCS 30: 30% Carbon capture and sequestration

\*\* CCS 90: 90% Carbon capture and sequestration

\*\*\* NGCC: Natural gas combined cycle

\*\*\*\* NGCT: Natural gas combustion turbine

<sup>1</sup> The values for natural gas units assume a US average natural gas infrastructure leakage rate of 2.5%, see the supplementary information.

<sup>2</sup> Assuming a US average methane leakage rate of 1.0%.

Damages for CO<sub>2</sub> and CO<sub>2-eq</sub> emissions were calculated using the EPA's Social Cost of Carbon (SCC).<sup>16</sup> The lifetime of each power plant type is different (**Table 1**), and thus the damages associated with upstream, ongoing, and downstream emissions were also treated differently. Table A1 of<sup>16</sup> presents calculated average annual social cost of carbon values for 2010–2050 for discount rates of 5, 3, and 2.5%. In this analysis, the 3% average rates were used as the reference case and the 2.5% and 5% discount rates were used as the high and low cost cases, respectfully. Because our nuclear plants had an assumed life of 50 years and we start at 2015, we extrapolated the values in Table A1 of<sup>16</sup> to 2065 using a 2<sup>nd</sup> degree polynomial fit to extrapolate the data past its current end, the R<sup>2</sup> was > 99% in each case. Marten and Newbold, 2012<sup>17</sup> showed that using the SCC with other gasses' global warming potential could lead to errors in estimating the societal cost of those gasses. Because we consider the impact that fugitive methane emissions have on the cost of electricity from natural gas plants, we calculated damages from emissions using the Social Cost of Methane (SCM).<sup>17</sup> **Table 3** shows the final values for the SCC and the SCM used for the LCOE calculations.

County-level marginal emissions damages (adjusted to 2015\$) for SO<sub>2</sub>, NO<sub>x</sub>, PM<sub>2.5</sub>, were taken from.<sup>20</sup> PM<sub>10</sub> values were taken from Mueller and Mendelsohn, 2009.<sup>15</sup> Both<sup>15,20</sup> provided ground level, intermediate, and high stack emissions costs, mainly associated with increased morbidity and mortality, for each type of pollutant on a county-level basis. We use the intermediate values in our calculations, though the framework of the modified LCOE could be used with the high and low range values too. However, there is some difference between the two datasets. The SO<sub>2</sub>, NO<sub>x</sub>, PM<sub>2.5</sub> data from<sup>20</sup> are based on a \$6M value of a statistical life (VSL) with 2011 as the base year of emissions. The PM<sub>10</sub> data are from an earlier study with a base year of 2002,<sup>15</sup> and used a VSL of \$2M, scaled by age – thus a low estimate for PM<sub>10</sub> as compared to the study using a \$6M VSL. These estimates were held constant throughout the analysis period because although air quality has improved in many locations which reduces the impact of a marginal tonne of emissions, healthcare costs continue to rise, so the future movement of these damage estimates is uncertain. **Figure 1** portrays a graphical flow of the data streams used to display our method. ■

**TABLE 3**

Table 3: Table showing the low, reference, and high case assumptions for the cost of ongoing CO<sub>2</sub> (combustion and non-combustion) and CH<sub>4</sub> (fugitive emissions) damages (\$/tonne) for plant lifetimes of 25, 30, 35, 40 and 35 years, damages associated with upstream or 2015 emissions, and damages associated with downstream emissions for the same plant lifetimes.

Timeline	Low*	Reference**	High***
Ongoing (25 yr)	\$18	\$58	\$83
Ongoing (30 yr)	\$19	\$60	\$85
Ongoing (35 yr)	\$20	\$62	\$88
Ongoing (40 yr)	\$22	\$65	\$91
Ongoing (50 yr)	\$25	\$71	\$98
Upstream (today, 2015)	\$14	\$43	\$65
Downstream (25 yr)	\$24	\$71	\$98
Downstream (30 yr)	\$27	\$75	\$105
Downstream (35 yr)	\$31	\$81	\$111
Downstream (40 yr)	\$35	\$88	\$117
Downstream (50 yr)	\$44	\$99	\$129
Ongoing CH <sub>4</sub> (35 yr) <sup>1</sup>	\$1,034	\$2,014	\$2,562

\* 5% discount rate

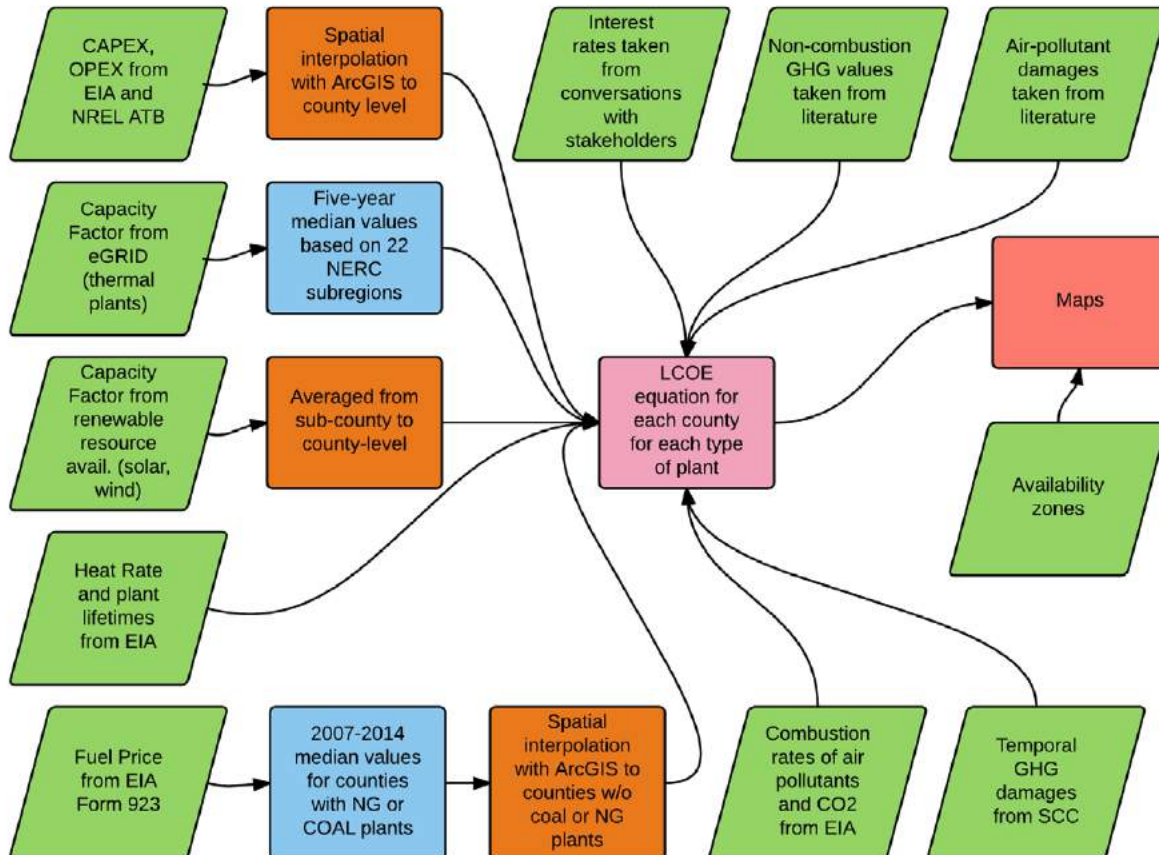
\*\* 3% discount rate

\*\*\* 2.5% discount rate

<sup>1</sup> All natural gas power plants were assumed a lifetime of 35 years, so only this value is shown here.

**FIGURE 1**

Figure showing the flow of data from raw inputs to county-level LCOE calculations.



# RESULTS

We applied the method for multiple scenarios to demonstrate how it could be used. **Figure 2** (Scenario 1) shows the minimum cost technology for each county in a scenario where we do not consider externalities or availability zones. That is, the LCOE of each technology was calculated using Equation 1, and the minimum cost technology for each county is shown. In this scenario, our method, using numbers we describe in Section finds that in the majority of US counties, NGCC plants are the least cost option, followed by wind, sub bituminous coal and nuclear plants. Again, these costs do not include any investment or production tax credits, loan guarantees, property tax abatements, depletion allowances, fuel price hedging schemes, or firming costs. **Figure 3** shows the underlying LCOE cost of the minimum cost technology in every county shown in **Figure 2**. The bottom of **Figure 3** shows the distribution of LCOE values for each technology relative to each other. For instance the distribution shows us that there is considerable overlap in the cost distribution for NGCC and

Wind plants, but the bulk of the NGCC plants cost less than the bulk of Wind plants. The figure also shows an inset of the most expensive plants in this scenario for ease of viewing.

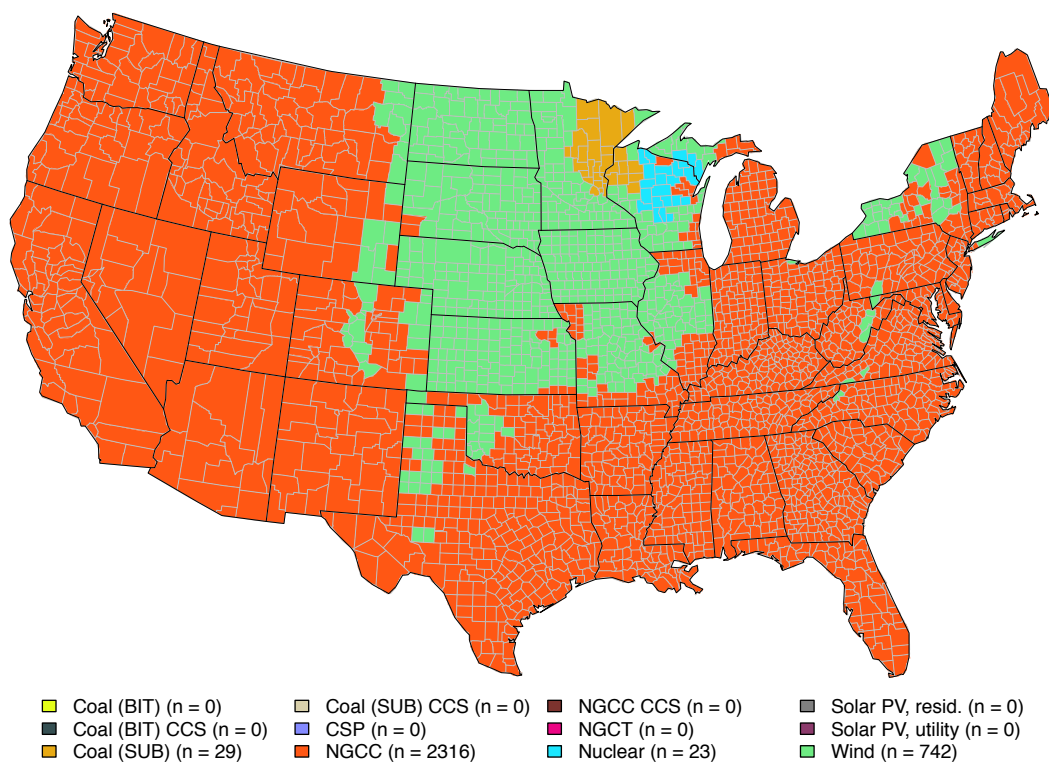
**Figure 4** (Scenario 2) shows the minimum cost technology for each county in a scenario where we do consider externalities, but not availability zones. That is, the LCOE of each technology was calculated using Equation 4, and the minimum cost technology for each county is shown. In this scenario, our method finds that in the majority of US counties, NGCC plants are still the least cost option, followed by increased wind and nuclear plants, but coal is no longer the least cost option in any county when externalities are considered.

**Figure 5** shows similar LCOE values and distribution results for **Figure 4** as discussed above.

**Figure 6** (Scenario 3) shows the minimum cost technology for each county in a scenario where we consider both externalities and availability zones (see the supplementary information).

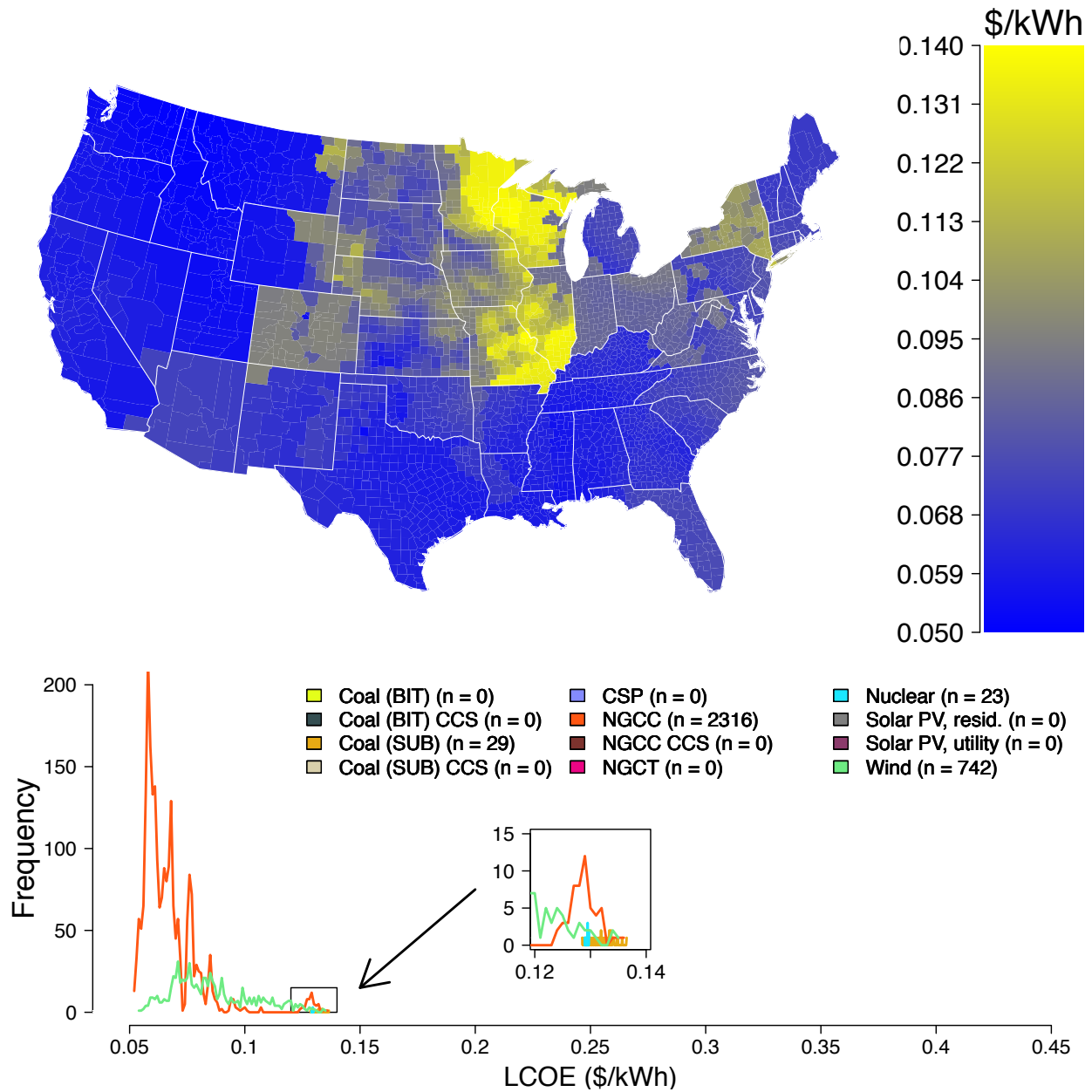
## FIGURE 2

Scenario 1: Minimum cost technology for each county, not including externalities (Equation 1) with reference case assumptions from Tables 1–3.



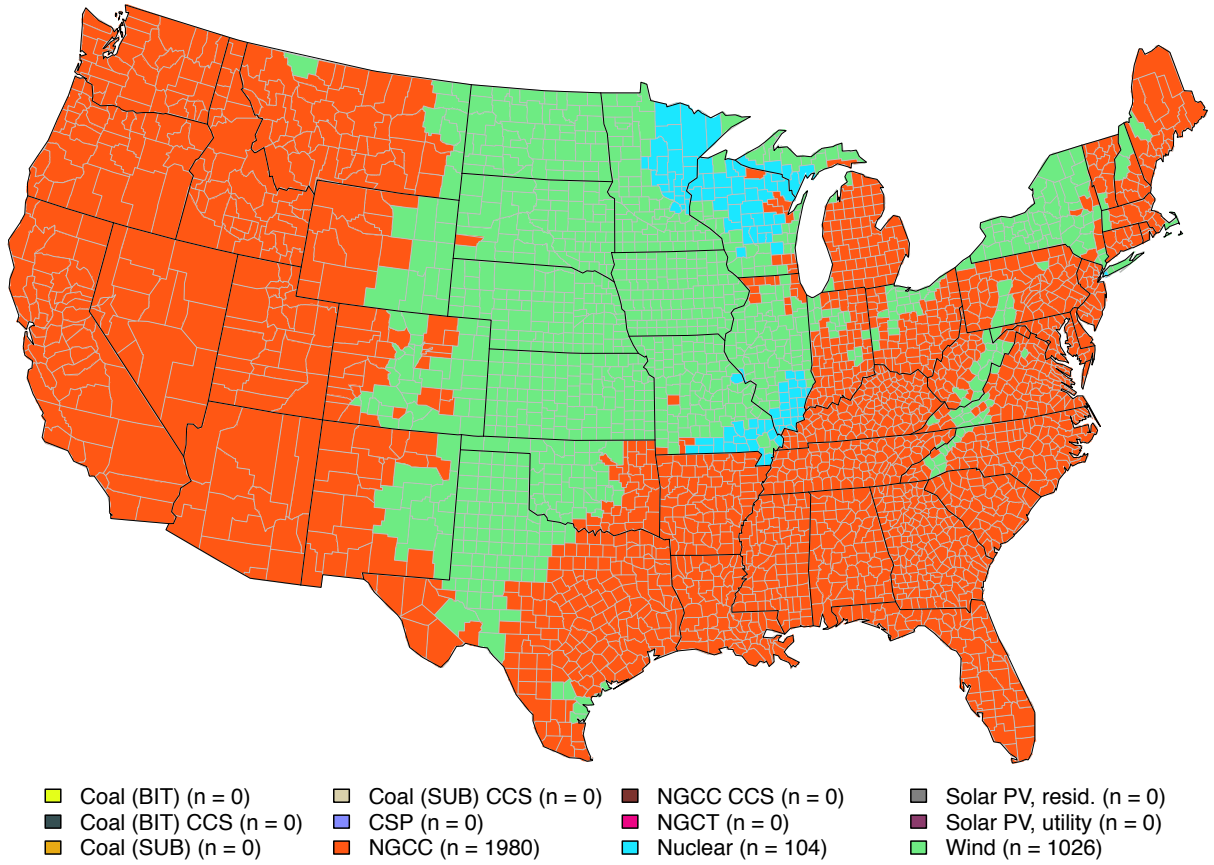
**FIGURE 3:**

Scenario 1 LCOE map (top) showing the LCOE value for the minimum cost technology for each county, not including externalities (Equation 1) with reference case assumptions from Tables 1–3. The distribution plot (bottom) shows the distribution of the cost of each technology relative to each other.



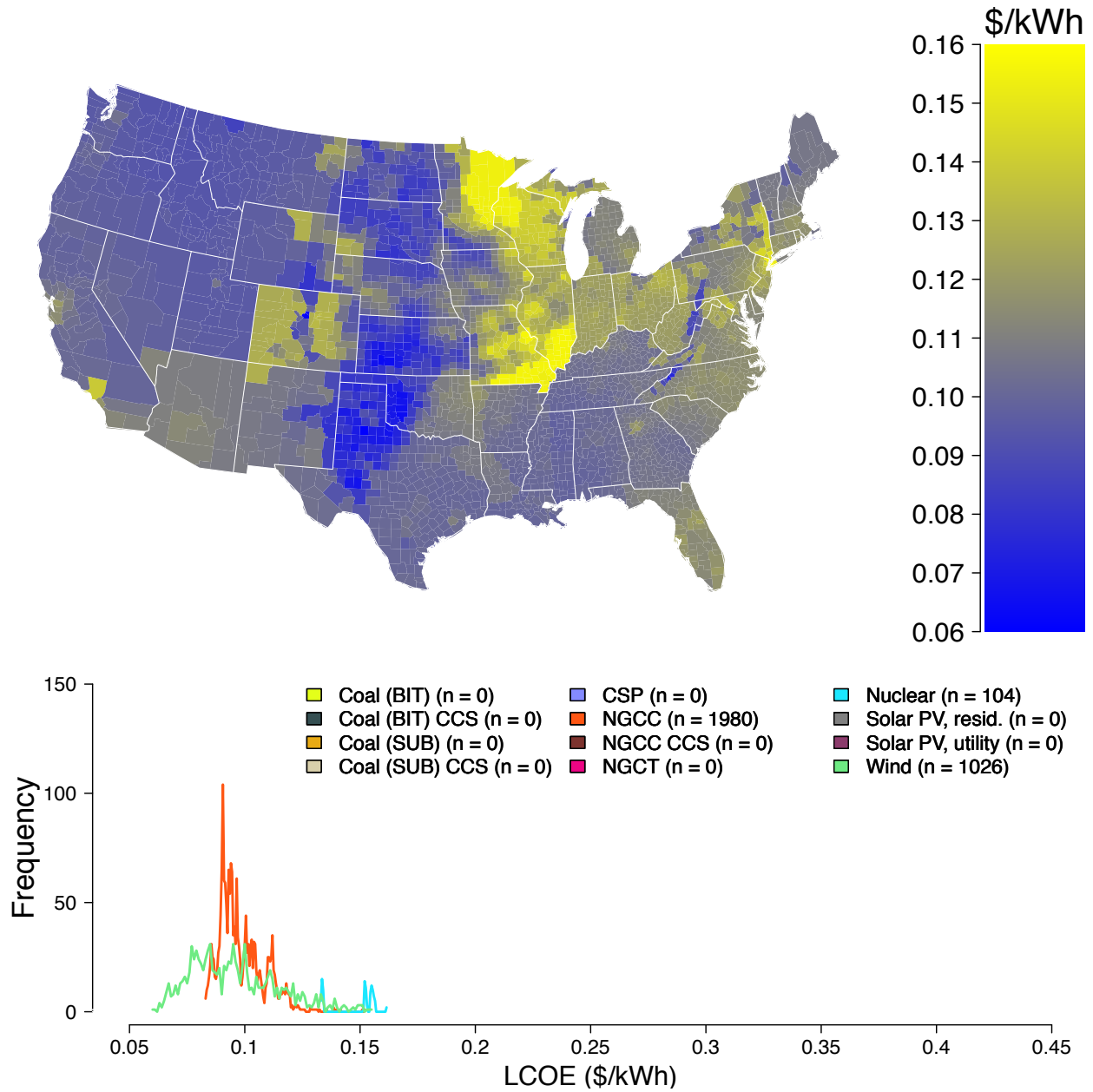
**FIGURE 4**

Scenario 2: Minimum cost technology for each county, including externalities (Equation 4) with reference case assumptions from Tables 1–3.



**FIGURE 5**

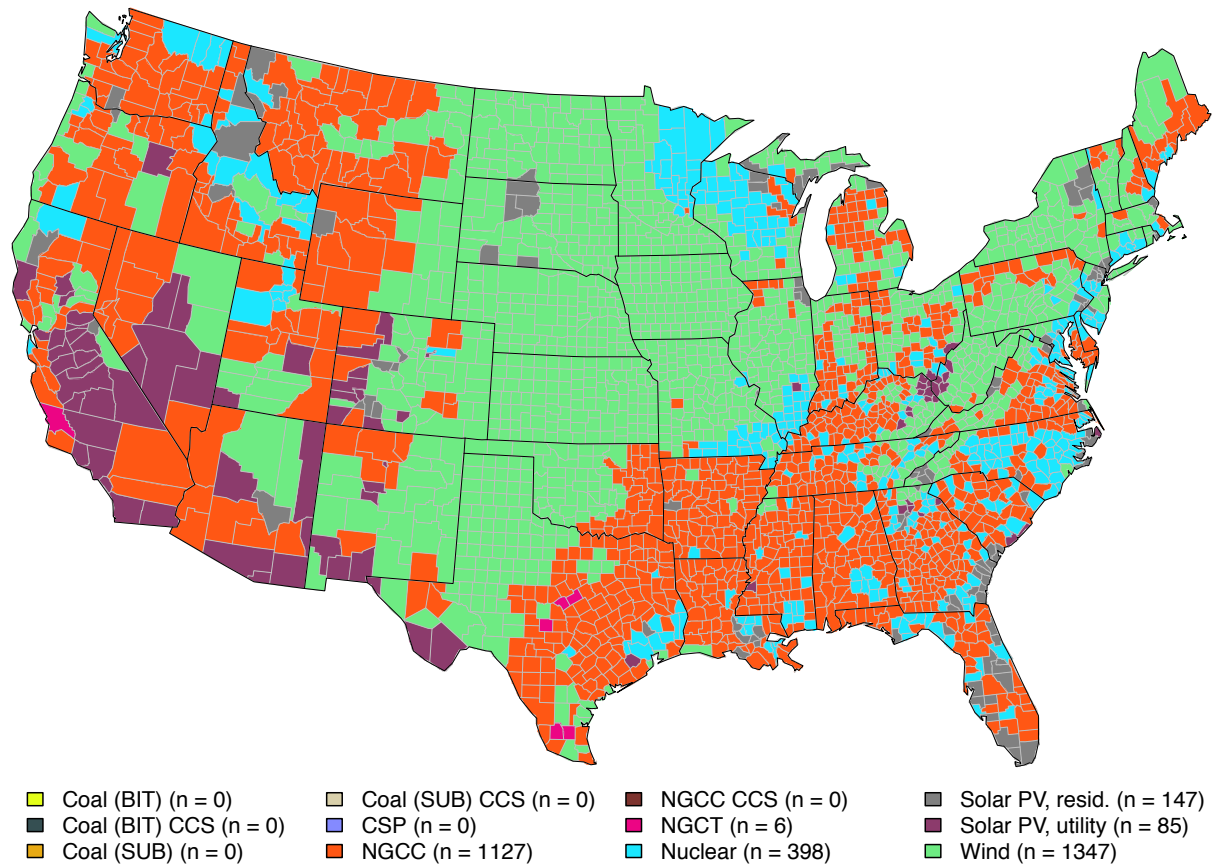
Scenario 2 LCOE map (top) showing the LCOE value for the minimum cost technology for each county, including externalities (Equation 4) with reference case assumptions from Tables 1–3. The distribution plot (bottom) shows the distribution of the cost of each technology relative to each other.





**FIGURE 6**

Scenario 3: Minimum cost technology for each county, including externalities (Equation 4) and availability zones with reference case assumptions from Tables 1–3.



**Figure 7** shows similar LCOE values and distribution results for **Figure 6** as discussed above.

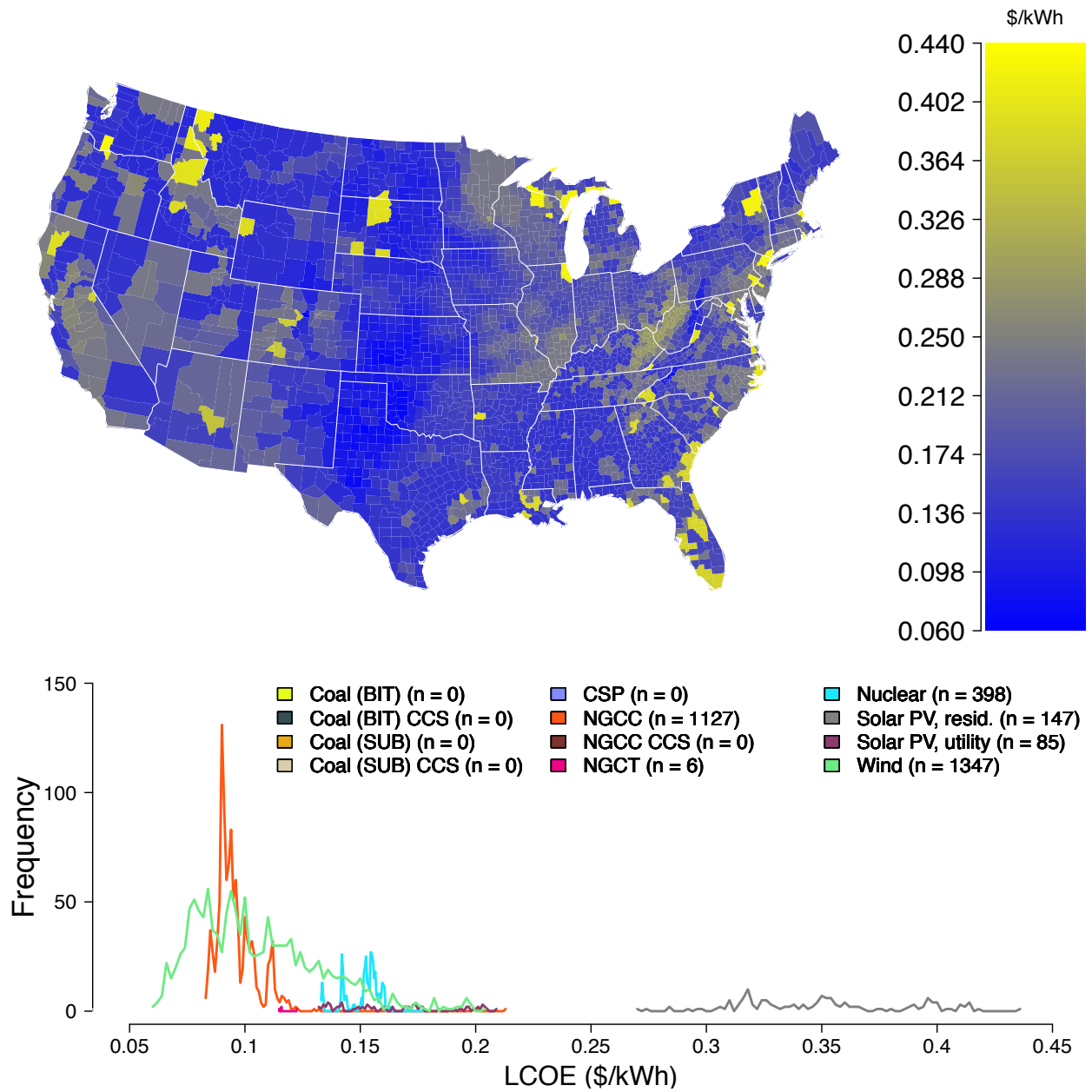
Of all fuel and technology combinations considered, local least-cost option in a county is highly dependent on locality. In locations where the wind resource is strong and/or barriers (non-attainment zones, water availability, etc.) are high for thermal plants, wind tends to be the lowest-cost option. In **Figure 6**, our method indicates that wind is the lowest cost option in the most number of counties. NGCC is the least cost option in counties where the wind resource isn't as strong. Nuclear plants are the least-cost technology where wind resources are marginal and gas prices are high, or natural gas pipelines are not available. Residential solar PV plants are the default

option when a county was otherwise excluded by one or more barriers to other technologies. Utility-scale solar PV plants are more clustered in locations that have excellent solar insolation levels and/or lack of cooling water availability. NGCT plants are located where conditions are also favorable to NGCC plants, but lack cooling water availability. The average reference case cost for all the counties' minimum cost technologies was \$0.127/kWh (median: \$0.102/kWh).

**Figure 8** shows the minimum cost technology per county when availability zones are considered, but externalities are given a price of zero. Because Scenarios 4–10 are iterations of Scenario 3, we do not show the LCOE values map and distributions for them.

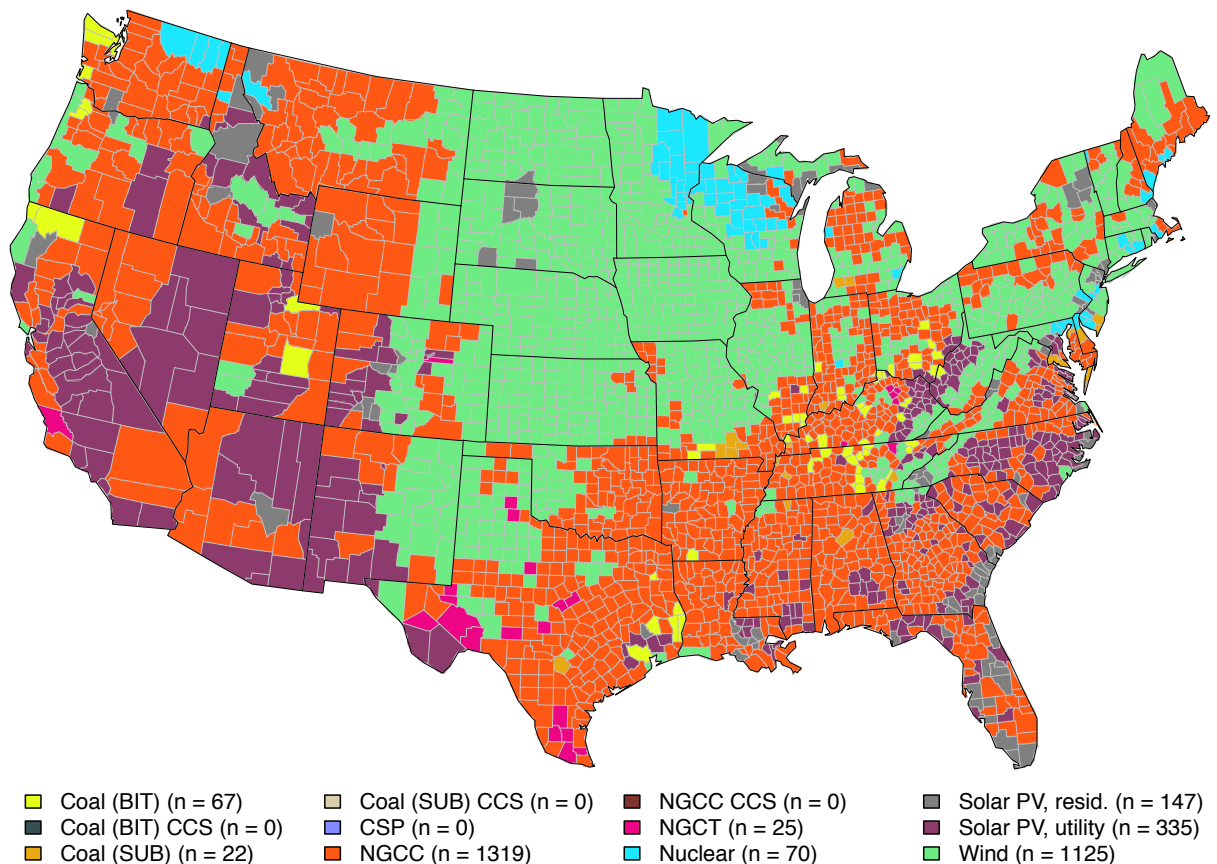
**FIGURE 7**

Scenario 3: LCOE map (top) showing the LCOE value for the minimum cost technology for each county, including externalities (Equation 4) and availability zones with reference case assumptions from Tables 1–3. The distribution plot (bottom) shows the distribution of the cost of each technology relative to each other.



**FIGURE 8**

Scenario 4: Minimum cost technology for each county, including availability zones, but not including externalities (Equation 1) with reference case assumptions from Table 1.

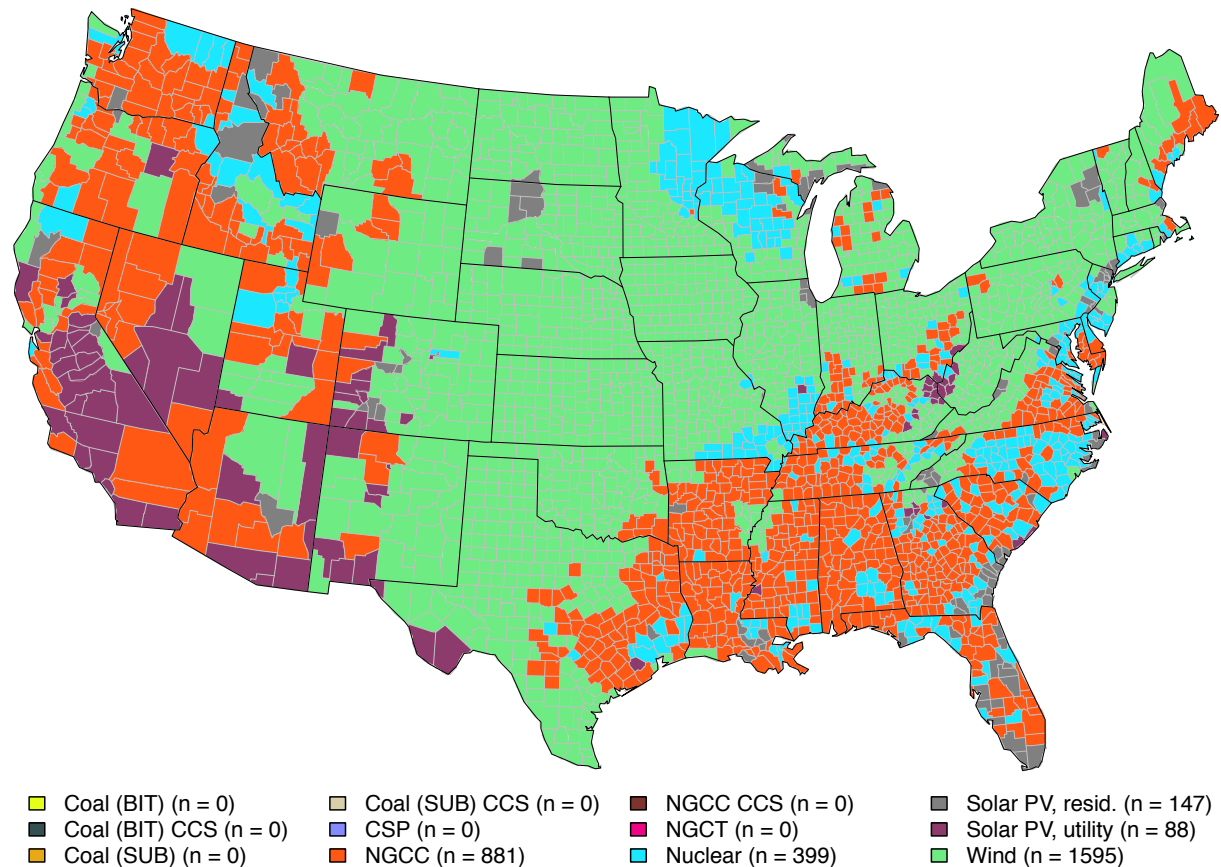


**Figure 8** (Scenario 4) shows the minimum cost technology for each county in a scenario where we do not consider externalities, but do include availability zones. For this scenario, as compared to **Figure 6**, there are more counties where there lowest LCOE is a fossil-fueled power plant, and fewer counties with wind and nuclear plants. Along the edges of the wind corridor (where the wind is of less quality than the interior) wind farms, which were the lowest cost option when environmental externalities are included, are replaced by NGCC plants where water is available, and NGCT and PV where it is not. For a considerable number of locations in the southeast where nuclear was the least-cost option in Scenario 3 utility-scale PV is the least-cost option in Scenario 4. This change is due to PV's high upstream GHG values (see **Table 2**) from

fabrication of the panels. When the cost of the externalities are not internalized, PV is lower cost. The average cost for the case that did not consider externalities was \$0.103/kWh (median: \$0.080/kWh). The costs of air emissions (for coal about \$0.03/kWh, not including CO<sub>2</sub>) are for additional marginal emissions from a new plant with Best Available Commercial Technology.<sup>21</sup> These values *should not* be used as a proxy to estimate the benefit of removing an existing plant. If we instead use emissions rates from existing plants (average emissions rates in NERC subregions via eGrid<sup>27</sup>), the emissions costs are, on average, about 10 times higher. This difference is highly dependent on location; some counties have older coal plants with limited emission control equipment whereas others do not have a coal plant that could be removed. Prices for natural gas, coal, and nuclear fuel vary

**FIGURE 9**

Scenario 5: Minimum cost technology for each county, including externalities (Equation 4) and availability zones with reference case assumptions from Tables 1–3 with a high natural gas price (US average of \$7/MMBtu, Figure 28).



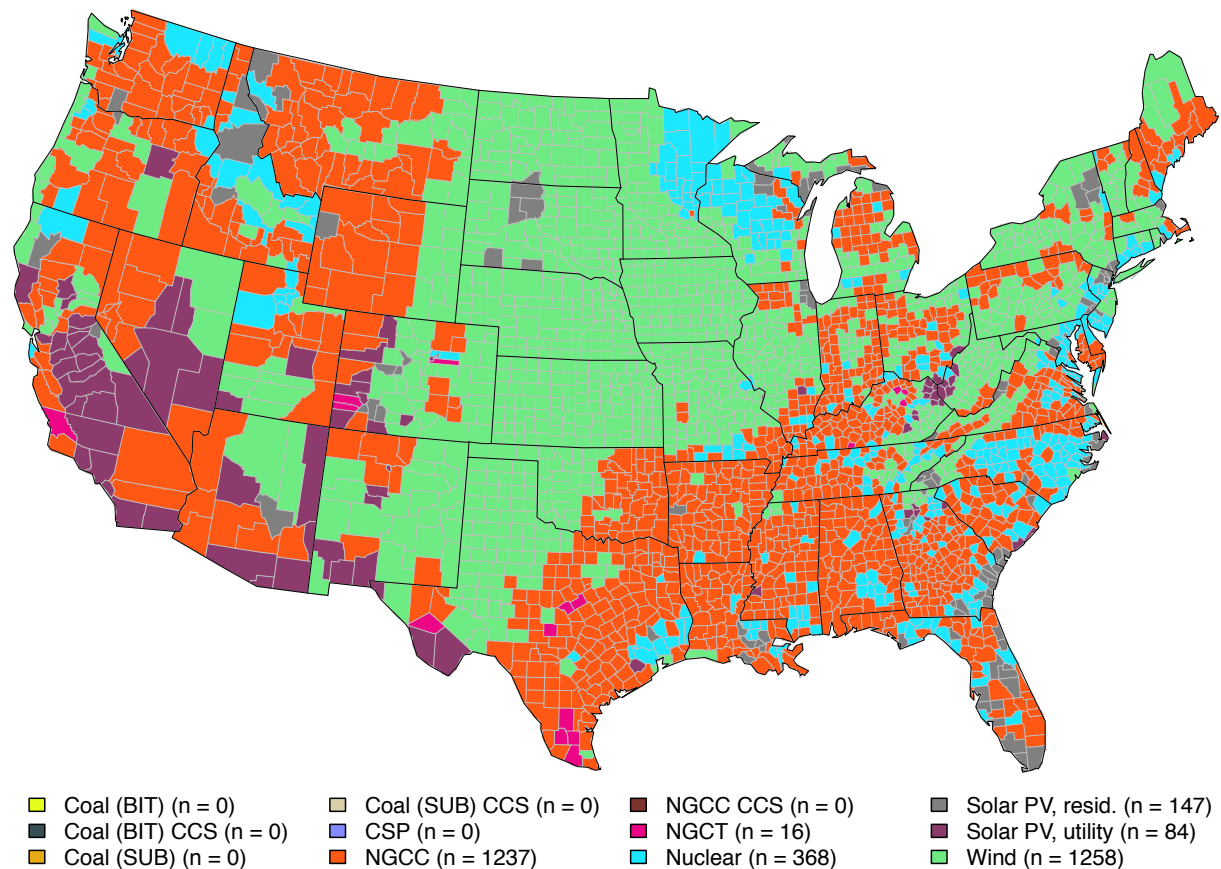
over time. Generators can stabilize prices via long-term contracts or financial hedges but cannot fully avoid price risk. Of those fuels, natural gas price has been most volatile over the last 15–20 years. The volatility of the natural gas price contributes to temporal variation in wholesale electricity market prices as it is often the marginal generation fuel. Hence, it is valuable to analyze the sensitivity of gas plants' LCOE to reasonable low and high prices. In **Figure 10** (Scenario 5), we see the effect of lower (\$3/MMBtu, **Figure 27**) and in **Figure 9** (Scenario 6), we see the effect of higher (\$7/MMBtu, **Figure 28**) natural gas prices. High and low natural gas price methodologies

and maps are explained in later sections of this supplementary material. Note that we do not adjust the capacity factor of NGCC and NGCT plants based on the price of natural gas.

In comparison to Scenario 3 (**Figure 6**), the primary effect of higher or lower natural gas prices is switching between wind and NGCC: when natural gas prices are higher, wind becomes the low-cost option in many counties in which NGCC is the low-cost option in the reference case; when natural gas prices are lower, NGCC becomes the low-cost option for many counties in which wind is the low-

**FIGURE 10**

Scenario 6: Minimum cost technology for each county, including externalities (Equation 4) and availability zones with reference case assumptions from Tables 1–3 with a low natural gas price (US average of \$3/MMBtu, Figure 27).



cost option in Scenario 3. We also examined the effect of a lower (Scenario 7) and higher (Scenario 8) CO<sub>2</sub> price in **Figures 11 and 12**.

The values of CO<sub>2</sub> are based on the EPA's Social Cost of Carbon and are different based on plant life expectancy and assumed discount rates. For more explanation of these values, see Table 3 and the corresponding section.

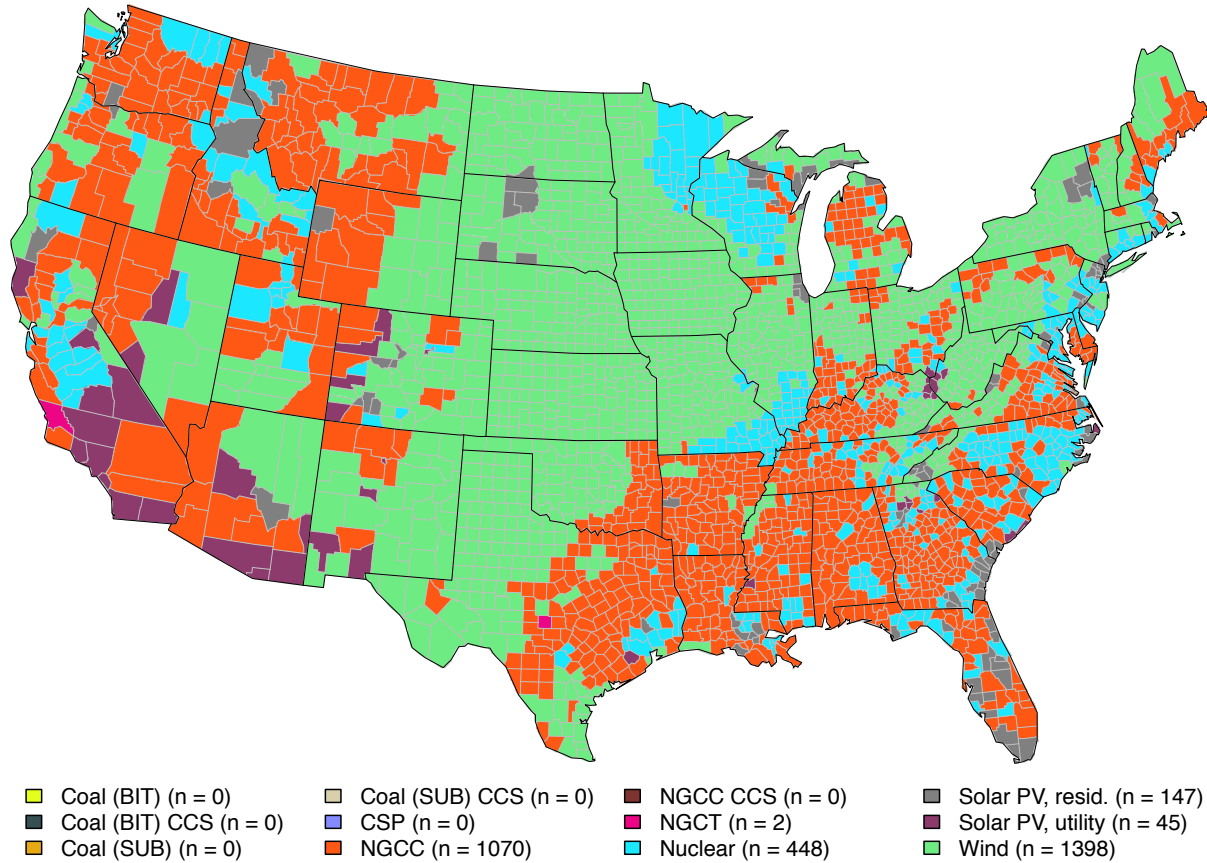
In the case of higher CO<sub>2</sub> prices (**Figure 11**); wind, nuclear, and coal CCS plants increase while natural gas, coal, and utility-scale PV plants decrease. Again utility-scale PV decreases because of the high upstream GHG values for PV plants. In the case of

lower CO<sub>2</sub> prices (**Figure 12**), the opposite happens.

In scenario 9 (**Figure 13**), we consider the impacts of solar installers achieving the U.S. Department of Energy's SunShot goal of \$1/Watt (or \$1,000/kW) for installed CAPEX of utility-scale PV and \$1.5/Watt (or \$1,500/kW) for installed CAPEX of residential PV.<sup>32</sup> In scenario 9, both forms of solar PV increase in the number of locations where they are the lowest-cost option. Solar PV displaces most of the locations in Scenario 3 where nuclear was the least cost option. Solar PV does displace some wind and NGCC plants, but the relative percent changes are not as drastic for these technologies.

**FIGURE 11**

Scenario 7: Minimum cost technology for each county, including externalities (Equation 4) and availability zones with reference case assumptions from Tables 1–3 with a high price on all forms of CO<sub>2</sub> (Table 3).

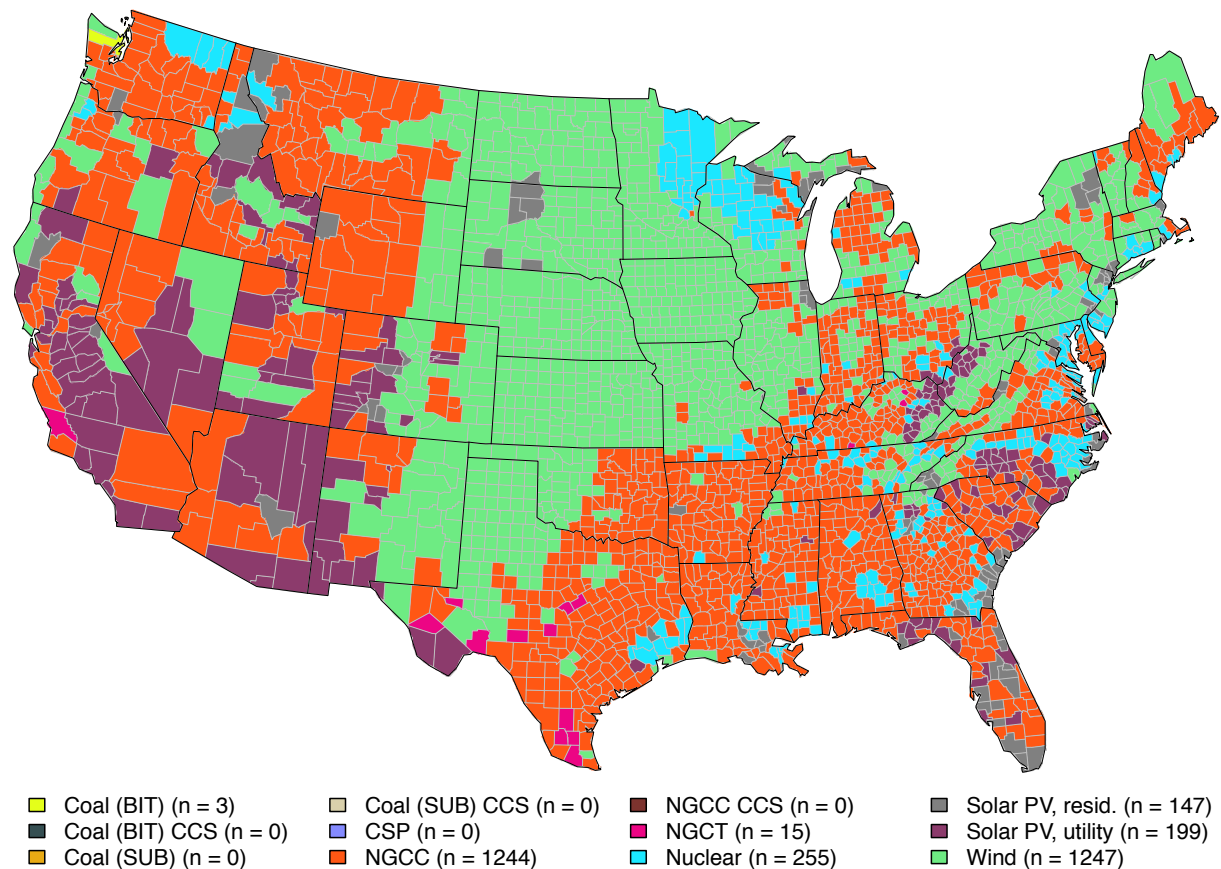


This result affirms the idea that if policymakers wish to see growth in the market penetration of solar energy, then it is important to pursue policies that reduce the capital costs. This scenario *does not* imply that the electric system could operate with 100% solar power in any part of the country. It simply states that, given current conditions, \$1/W (\$1.5/W) utility (residential) solar would be the least cost technology in many locations if the current system could accommodate it without any need for backup or firming costs. In scenario 10, we use the maximum capacity factor for onshore wind in each county (Figure 14). The resolution for wind capacity factor was obtained on a 5-km grid for the entire United States. Thus, most counties included more than one

value for wind capacity factor that was averaged for that county for use in our reference case. In some large counties, particularly in the western United States, the average wind capacity factor can be up to 38% less than the maximum in that county. Using the maximum wind capacity factor rather than average capacity factor significantly increases the number of counties where the minimum cost technology is wind. In fact, the effect of using the maximum wind capacity factor is similar to that of a high carbon cost – many of the locations that switch to wind (from the reference case) are the same as those in the high carbon scenario. This analysis gives the ability to see the spatial differences of the costs of each technology across the entire United States. Because capital and

**FIGURE 12**

Scenario 8: Minimum cost technology for each county, including externalities (Equation 4) and availability zones with reference case assumptions from Tables 1–3 with a low price on all forms of CO<sub>2</sub> (Table 3).



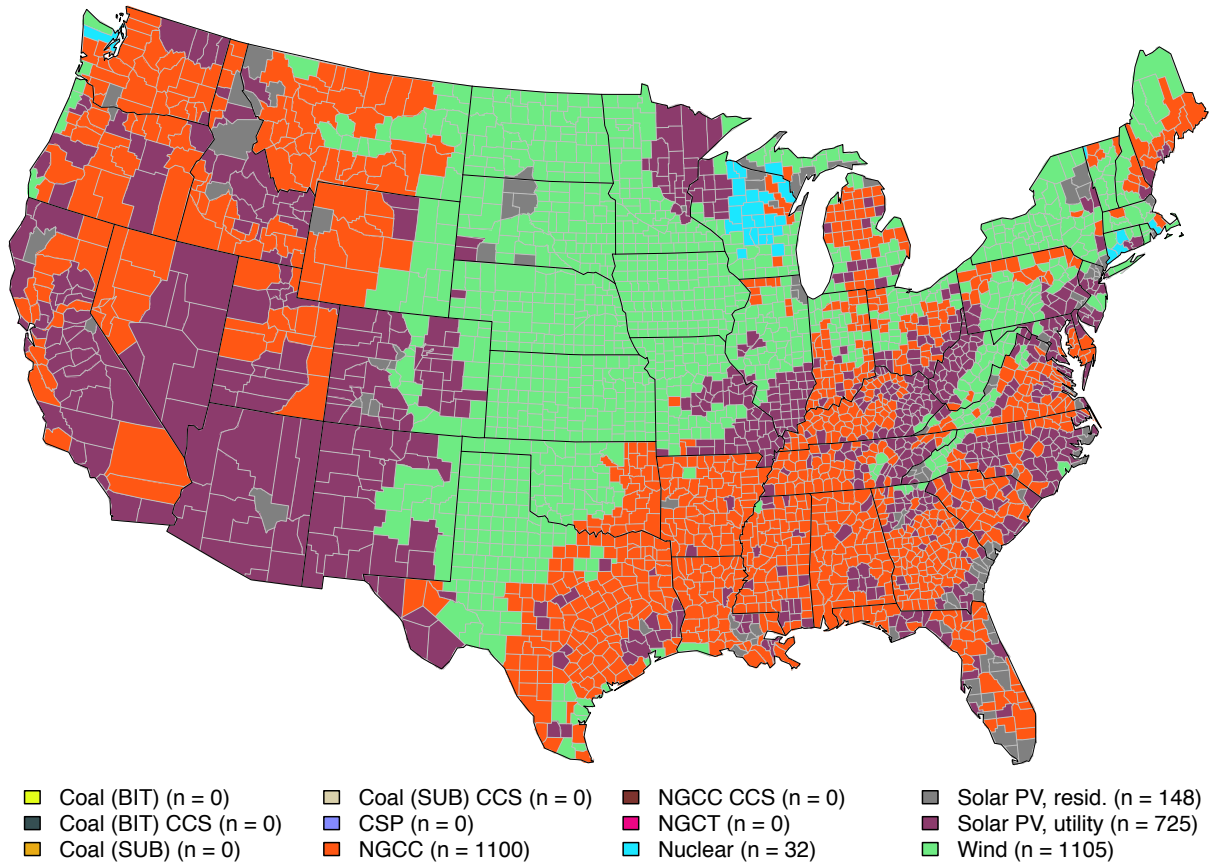
operating costs (labor, etc.), fuel price, emissions damages, and capacity factors, among other factors, vary across regions, so does the levelized cost of electricity. Some factors not considered in this analysis could also impact local prices. If reliability factors are internalized, wind and solar might be more costly because of their variability. However this need is highly dependent on local grid conditions and penetration levels. Other factors, such as fuel disposal, further fuel price volatility, and water use could also have local cost impacts on fossil fuel plants. If thermal power plants operate with higher capacity factors, then their costs would be lower and they would be selected as the low-cost option for more counties. Wind would be selected in more counties if only the best sites within each county is used.

## SECOND MINIMUM COST TECHNOLOGY

Figure 15 shows the next least cost technology map for all United States counties (top) as well as the cost difference between the least and second least cost technology on the bottom. The distribution between technologies is distributed among all the technologies except for solar with nuclear having the greatest number of counties as the second least cost technology. The average difference between the first and second least cost technology for all locations is \$0.029/kWh. ■

**FIGURE 13**

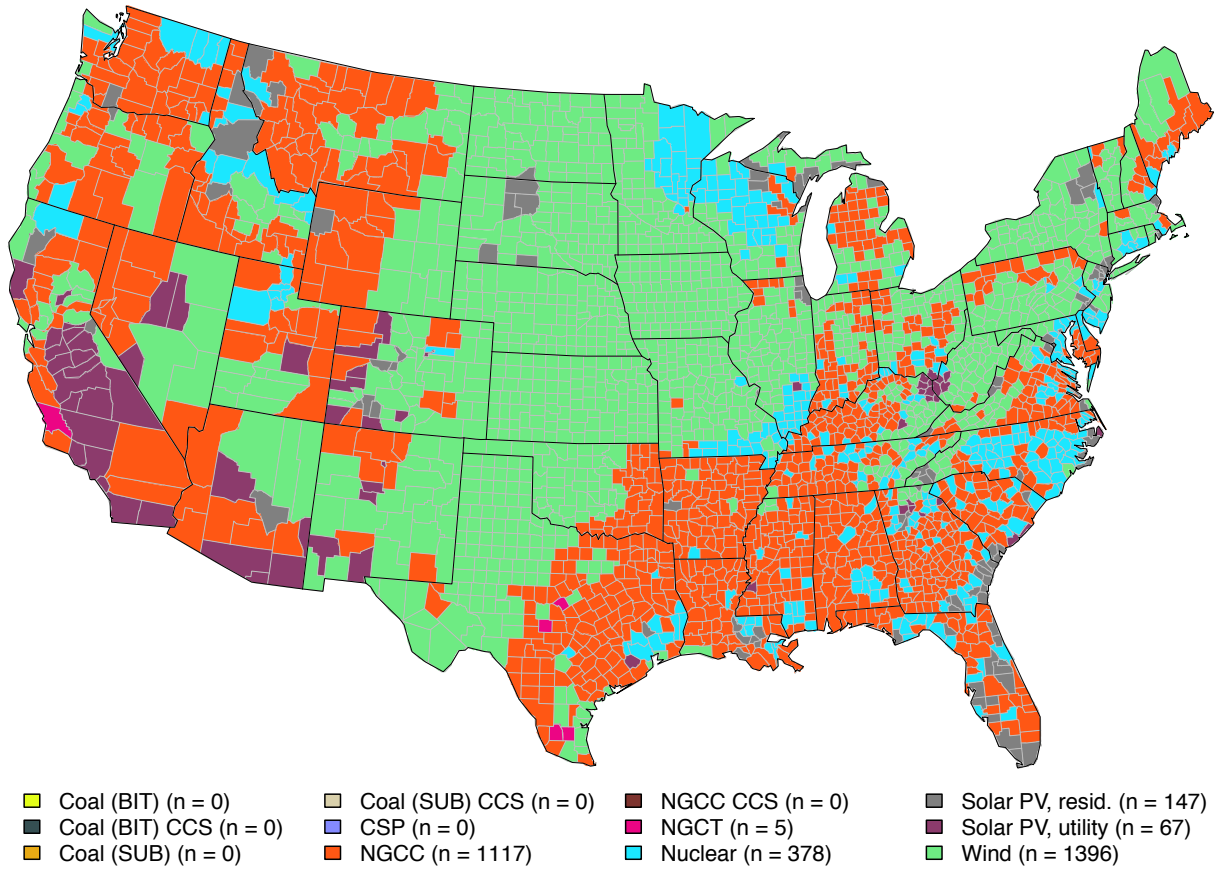
Scenario 9: Minimum cost technology for each county, including externalities (Equation 4) and availability zones with reference case assumptions from Tables 1–3 with a lower installed cost: \$1/W for utility-scale solar PV and \$1.5/W for residential PV.





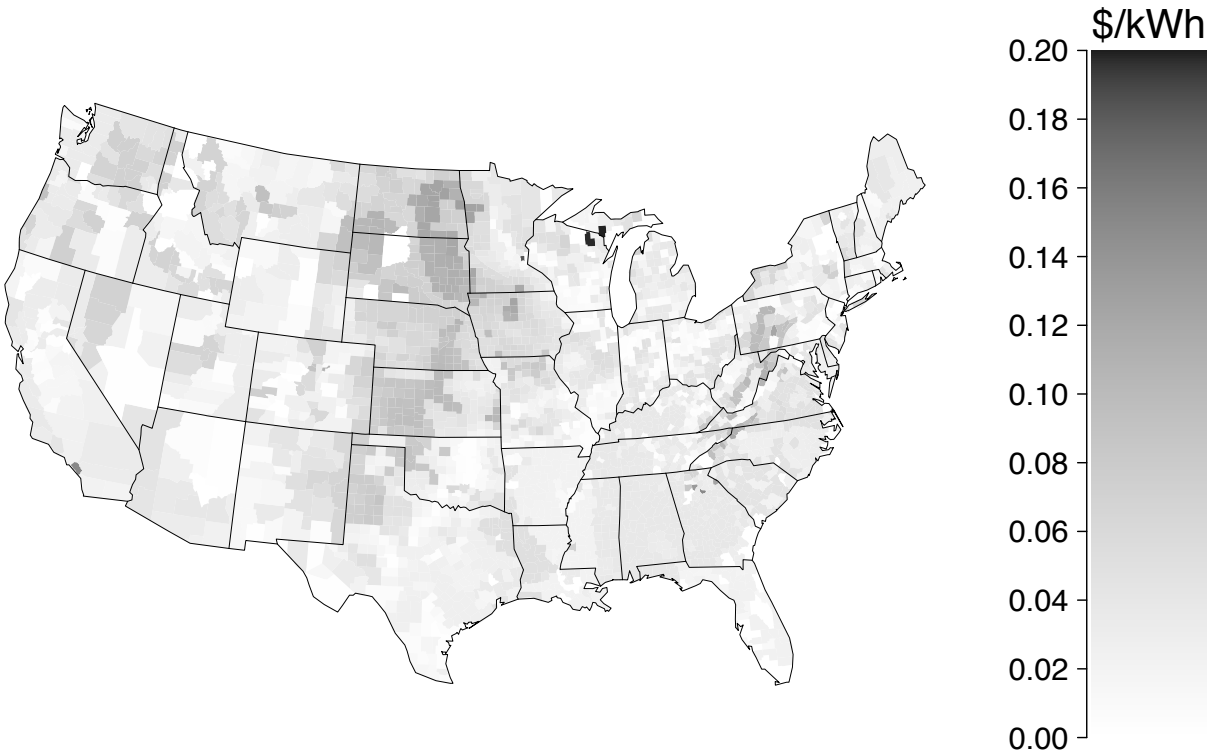
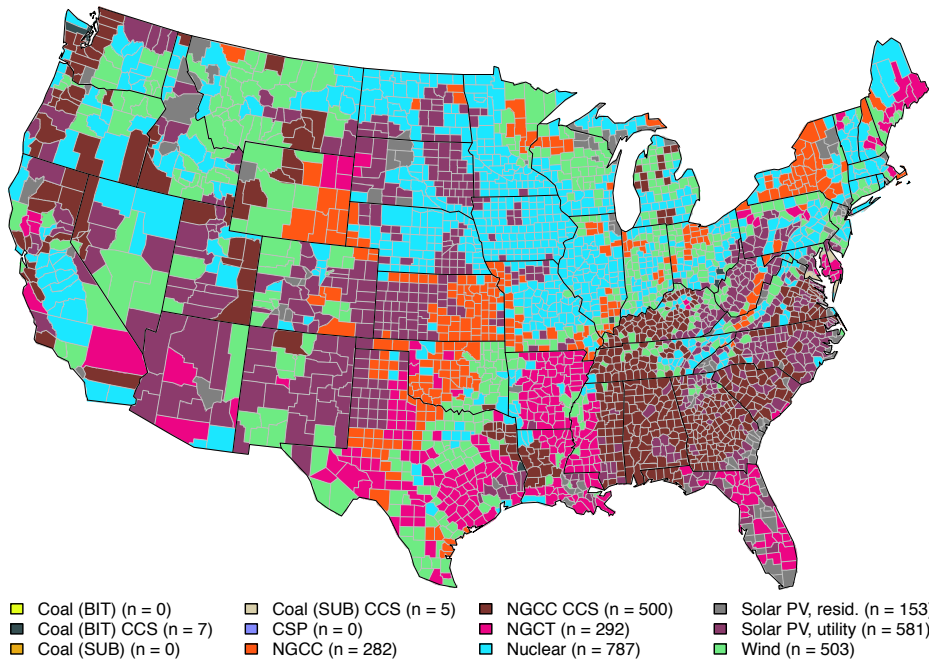
**FIGURE 14**

Scenario 10: Minimum cost technology for each county, including externalities (Equation 4) and availability zones with reference case assumptions from Tables 1–3 using the maximum capacity factor in each county for onshore wind.



**FIGURE 15**

Map showing the second minimum cost technology for each county (Equation 4) with reference case assumptions from Table 1 on top and the cost difference between the least and next least cost technology on the bottom. A lighter color on the bottom graph indicates a smaller difference between the first and second least cost technology.



# CONCLUSIONS

This analysis presents 1) a spatially-resolved method to internalize variations in construction costs and air and GHG emissions of electricity production for multiple types of fuel and technologies, and 2) a geographic display of the method for 10 scenarios. Data were compiled to a county-by-county basis and interpolated when necessary. The internalization of factors that are traditionally not considered is important for policy decisions that seek to reduce environmental impacts in an economically efficient way. Geographic emphasis is also important, because the best technology decision is different depending on the location. We also find that when the minimum technology cost (including externalities) is found for each county, natural gas combined cycle, wind, and nuclear power are all the least-cost option the most frequently, but are sensitive to natural gas and carbon prices.

## FUTURE WORK

Future work can include such aspects as firming power, transmission and distribution upgrades, impacts to terrestrial and aquatic biodiversity, and a full accounting for the value of water used in thermal plants. The costs developed in this analysis will be used in dispatch and capacity expansion models to incorporate time-of-use pricing and market dynamics.

## DISCLOSURE OF AFFILIATION

All authors abide by the disclosure policies of the University of Texas at Austin. The University of Texas at Austin is committed to transparency and disclosure of all potential conflicts of interest. All UT investigators involved with this research have filed their required financial disclosure forms with the university. None of the researchers have reported receiving any research funding that would create a conflict of interest or the appearance of such a conflict.

In addition to research work on topics generally related to energy systems at the University of Texas at Austin, some of the authors are equity partners in IdeaSmiths LLC, which consults on topics

in the same areas of interests. The terms of this arrangement have been reviewed and approved by the University of Texas at Austin in accordance with its policy on objectivity in research.

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- (29) Drury, E.; Lopez, A.; Denholm, P.; Margolis, R. Relative performance of tracking versus fixed tilt photovoltaic systems in the USA. *Progress in Photovoltaics: Research and Applications* **2013**, *22*, 1302–1315.
- (30) NREL, System Advisor Model (SAM). 2015; <https://sam.nrel.gov>.
- (31) Mai, T.; Wiser, R.; Sandor, D.; Brinkman, G.; Heath, G.; Denholm, P.; Hostick, D. J.;
- (32) Darghouth, N.; Schlosser, A.; Strzepek, K. Volume 1: Exploration of High-Penetration Renewable Electricity Futures. *Renewable Electricity Futures Study* **2012**, *1*, 280.
- (33) Margolis, R.; Coggeshall, C.; Zuboy, J. Sunshot Vision Study. 2012; <http://www1.eere.energy.gov/solar/pdfs/47927.pdf>.

# SUPPLEMENTARY INFORMATION

## ABSTRACT

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In this analysis we developed and applied a geographically-resolved method to calculate the Levelized Cost of Electricity (LCOE) of new power plants on a county-by-county basis while including estimates of some externalities. We calculated the LCOE for each county of the contiguous United States for 12 power plant technologies. The minimum LCOE option for each county varies based on local conditions: capital and fuel costs, environmental externalities, and resource availability. We considered ten scenarios that vary input assumptions. We present the results in a map format to facilitate comparisons by fuel, technology, and location. For our reference analysis, which includes a cost of \$62/tCO<sub>2</sub> for CO<sub>2</sub> emissions, natural gas combined cycle, wind, and nuclear are most often the lowest-LCOE option. While the average cost increases for internalizing the environmental externalities (carbon and air pollutants) is small for some technologies, the local cost differences are as high as \$0.62/kWh for coal (under our reference analysis). These results and display format could serve as an educational tool for stakeholders when considering which technologies might or might not be a good fit for a given locality subject to system integration considerations.

## REFERENCE CASE: USING INPUTS FROM TABLE 1

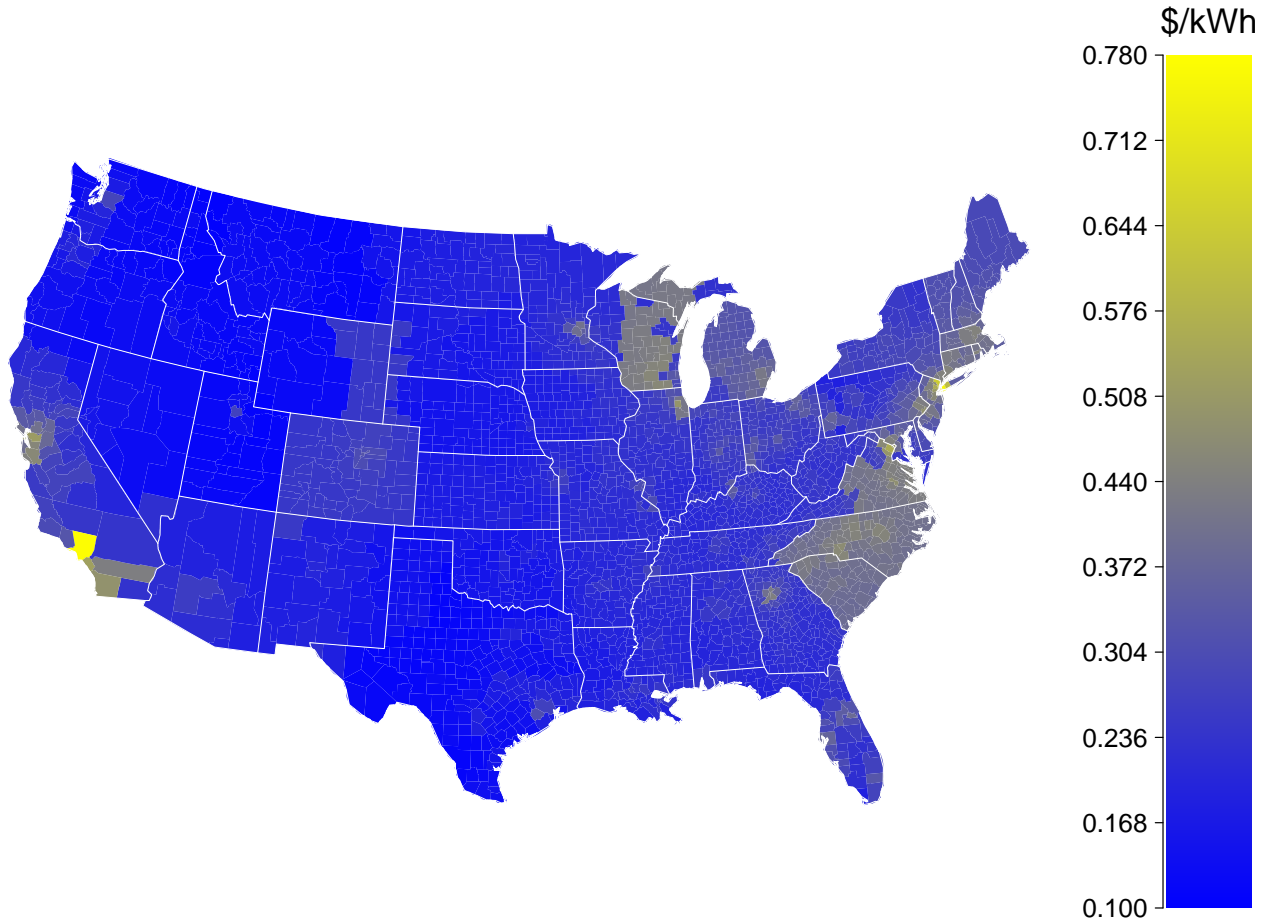
Using the geographically resolved approach allows the display of enhanced LCOE results in map form. The authors are well aware that not all locations are appropriate for every type of technology because of a lack of infrastructure such as rail, rivers, pipes, or wires, or because of prohibited locations like urban areas or national parks, but it's still valuable to illustrate the costs nationally to show the variation. It seems highly unlikely that a coal plant will ever be built in Los Angeles county due to air quality issues, among others, or a wind farm in southern Georgia given the lower quality of the wind resource. This analysis is an attempt to show the geographical distribution of the cost of electricity generation units.

**Figure 1** shows the reference case for the cost (\$/kWh) of electricity generation by bituminous coal for every county across the US. Regional CAPEX, fuel prices, and capacity factors for bituminous coal generation units are shown in **Figures 14, 24, and 29**, respectfully.

Some higher-cost areas, such as Atlanta, GA, Chicago, IL, and Houston, TX can be seen in **Figure 1**, these areas appear more yellow than blue (or lighter) because of the larger emissions costs than the surrounding counties. **Figure 2**

**FIGURE 1**

LCOE map for bituminous coal fired electricity generation units showing the regional differences for reference conditions (Equation 4), average: \$0.195/kWh (median: \$0.185/kWh).



shows the reference case for the cost (\$/kWh) of electricity generation by sub-bituminous coal for every county across the US. Regional CAPEX, fuel prices, and capacity factors for sub-bituminous coal generation units are shown in **Figures 14, 25, and 29**, respectively.

The only difference between **Figures 1 and 2** are the price maps for different types of fuel, all other inputs, including emissions rates were assumed the same.

**Figure 3** shows the reference case for the cost (\$/kWh) of electricity generation by bituminous coal with 90% carbon capture and sequestration for every county across the US.

Regional CAPEX, fuel prices, and capacity factors for bituminous coal generation units are shown in **Figures 15, 24, and 29**, respectively.

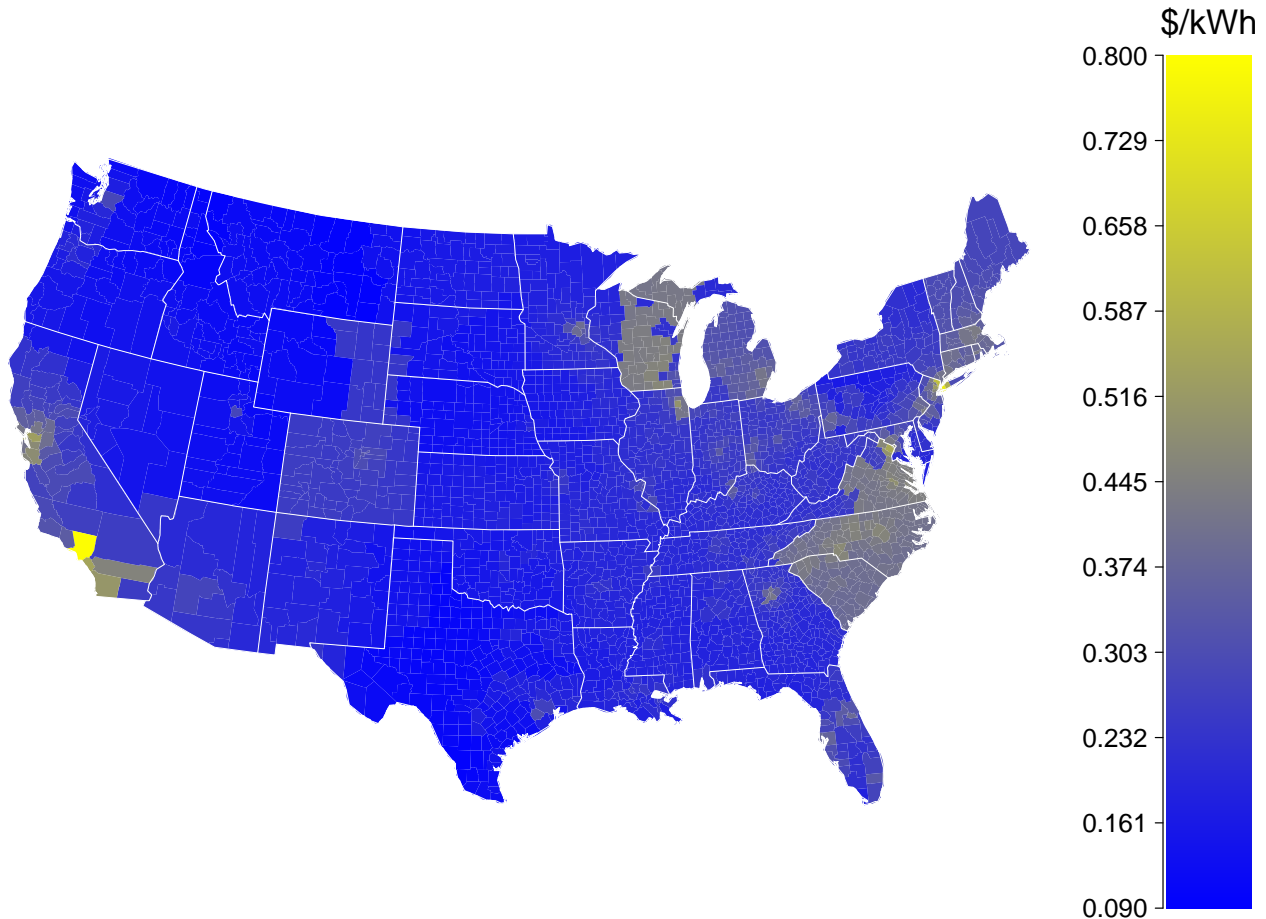
**Figure 4** shows the reference case for the cost (\$/kWh) of electricity generation by sub-bituminous coal with 90% carbon capture and sequestration for every county across the US. Regional CAPEX, fuel prices, and capacity factors for bituminous coal generation units are shown in **Figures 15, 25, and 29**, respectively.

**Figure 5** shows the reference case for the cost (\$/kWh) of electricity generation by natural gas combined cycle for every county across the US. Regional CAPEX, fuel prices, and capacity



## FIGURE 2

LCOE map for sub-bituminous coal fired electricity generation units showing the regional differences for reference conditions (Equation 4), average: \$0.193/kWh (median: \$0.181/kWh).



factors for NGCC generation units are shown in **Figures 16, 26, and 30**, respectively.

**Figure 6** shows the reference case for the cost (\$/kWh) of electricity generation by natural gas combined cycle with 90% carbon capture and sequestration for every county across the US. Regional CAPEX, fuel prices, and capacity factors for NGCC generation units are shown in **Figures 17, 26, and 30**, respectively.

**Figure 7** shows the reference case for the cost (\$/kWh) of electricity generation by natural gas combustion turbine for every county across the US. Regional CAPEX, fuel prices, and capacity factors for NGCT generation units are shown in

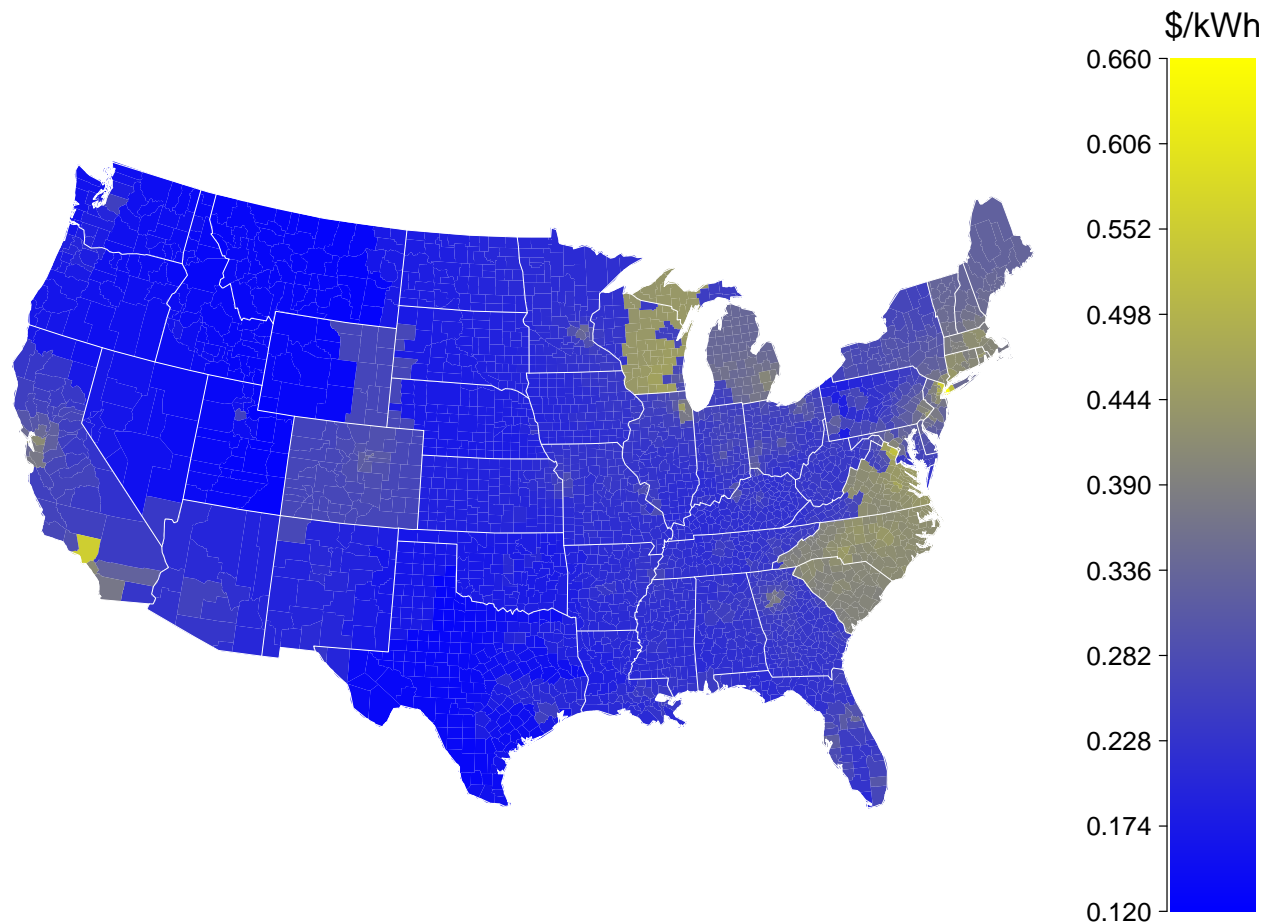
**Figures 18, 26, and 31**, respectively.

The same emissions scenario holds true for natural gas as discussed for coal above. These emissions rates are based on BACT plants and are not the same as removing an existing plant from any given county. If we do use existing emissions rates from eGrid data, the emissions damages are also about 10 times higher, but there are also counties currently without natural gas plants.

**Figure 8** shows the reference case for the cost (\$/kWh) of electricity generation by natural gas combustion turbine for every county across the US. Regional CAPEX and capacity factors for nuclear generation units are

**FIGURE 3**

LCOE map for bituminous coal fired electricity generation units showing the regional differences for reference conditions (Equation 4), average: \$0.195/kWh (median: \$0.185/kWh).



shown in **Figures 19** and **32**, respectively.

**Figure 9** shows the reference case for the cost (\$/kWh) of electricity generation by wind turbine for every county across the US. These costs do not include any production tax credits. If they are included, the costs would appear lower. Regional CAPEX and capacity factors for wind turbine generation units are shown in **Figures 20** and **33**, respectively.

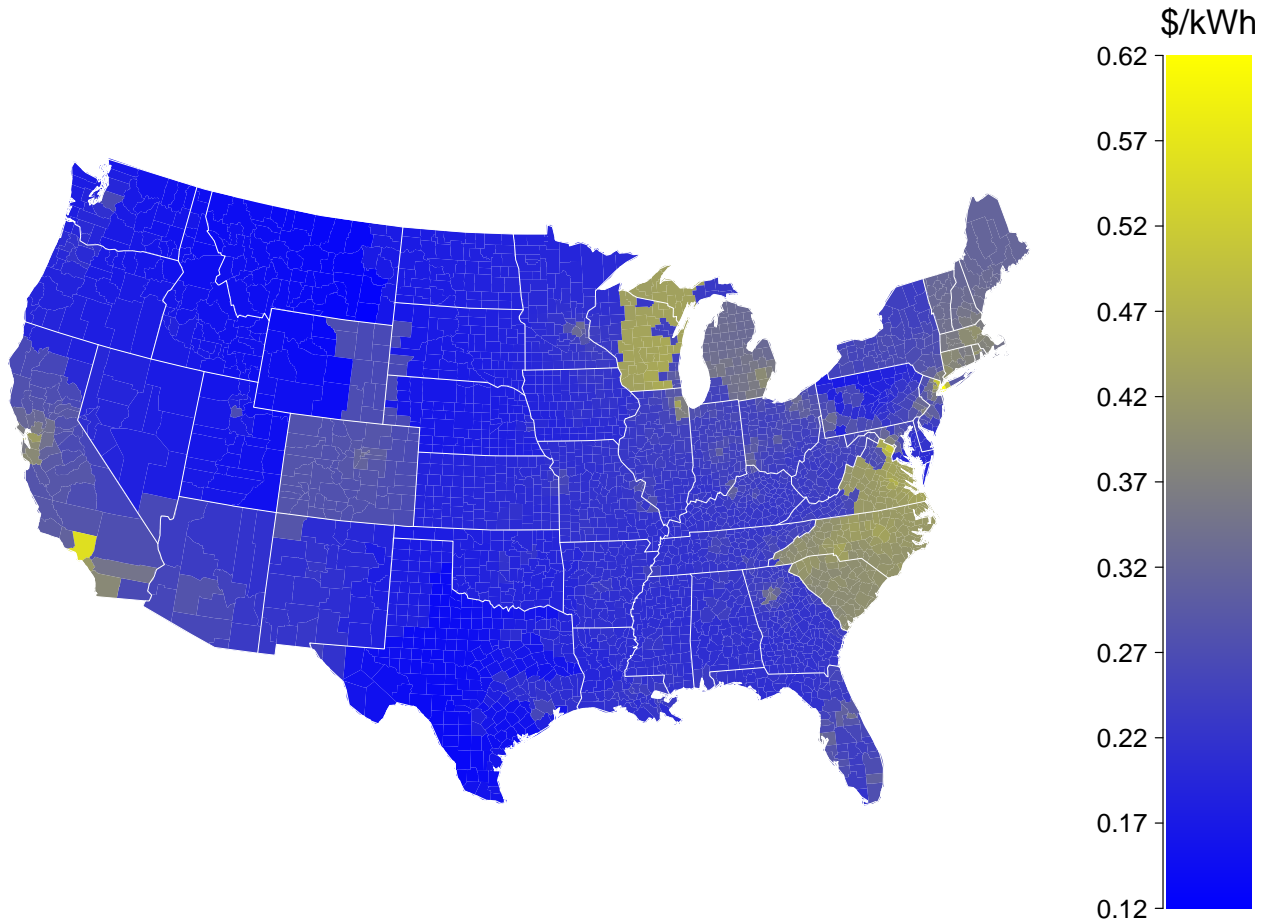
**Figure 10** shows the reference case for the cost (\$/kWh) of electricity generation by utility-scale PV for every county across the US. We consider utility scale PV generation units to be single axis tracking. These costs do not include any investment tax credits. If they are included, the

costs would appear lower. Regional CAPEX and capacity factors for utility-scale PV generation units are shown in **Figures 21** and **34**, respectively.

**Figure 11** shows the reference case for the cost (\$/kWh) of electricity generation by residential PV for every county across the US. We consider residential scale PV generation units to be south facing fixed axis at a 25° tilt. These costs do not include any investment tax credits. If they are included, the costs would appear lower. Regional CAPEX and capacity factors for residential PV generation units are shown in **Figures 22** and **35**, respectively.

**FIGURE 4**

Figure 4: LCOE map for sub-bituminous coal fired electricity generation units showing the regional differences for reference conditions (Equation 4), average: \$0.195/kWh (median: \$0.185/kWh).

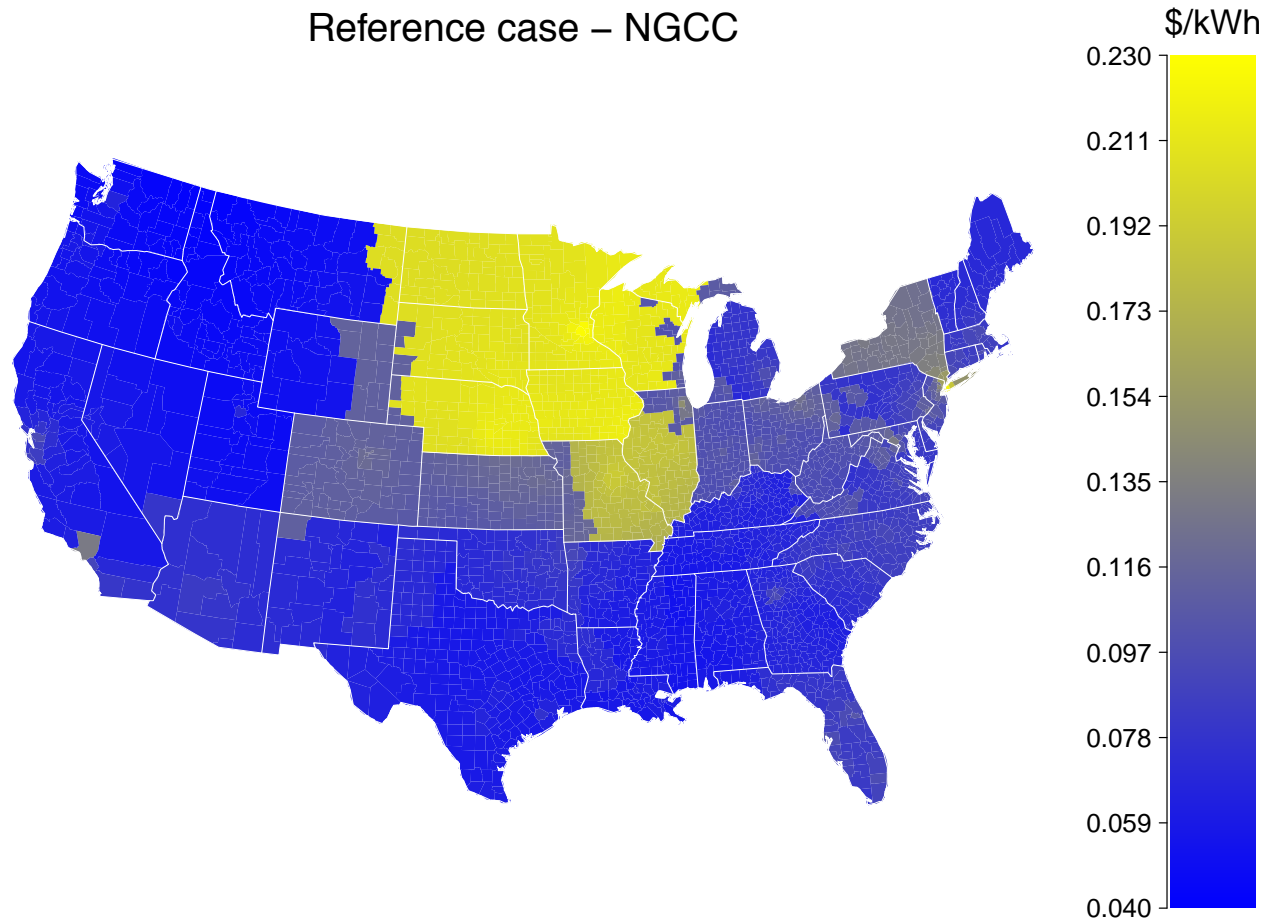


**Figure 12** shows the reference case for the cost (\$/kWh) of electricity generation by concentrating solar power (CSP) with 6 hours of storage for every county across the US. These costs do not include

any investment tax credits. If they are included, the costs would appear lower. Regional CAPEX and capacity factors for CSP generation units are shown in **Figures 23** and **36**, respectfully.

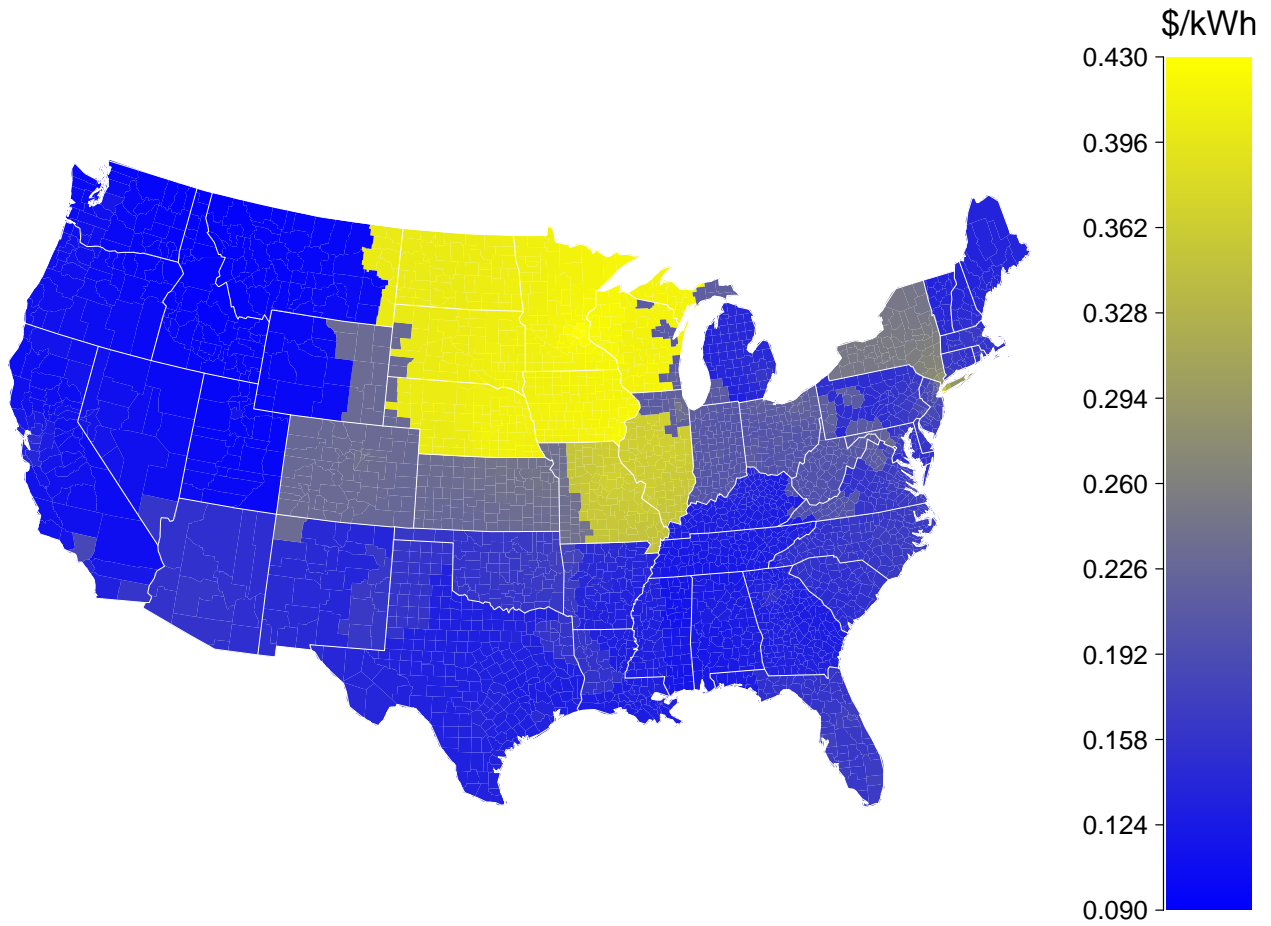
**FIGURE 5**

LCOE map for natural gas combined cycle electricity generation units showing the regional differences for reference conditions (Equation 4), average: \$0.111/kWh (median: \$0.096/kWh).



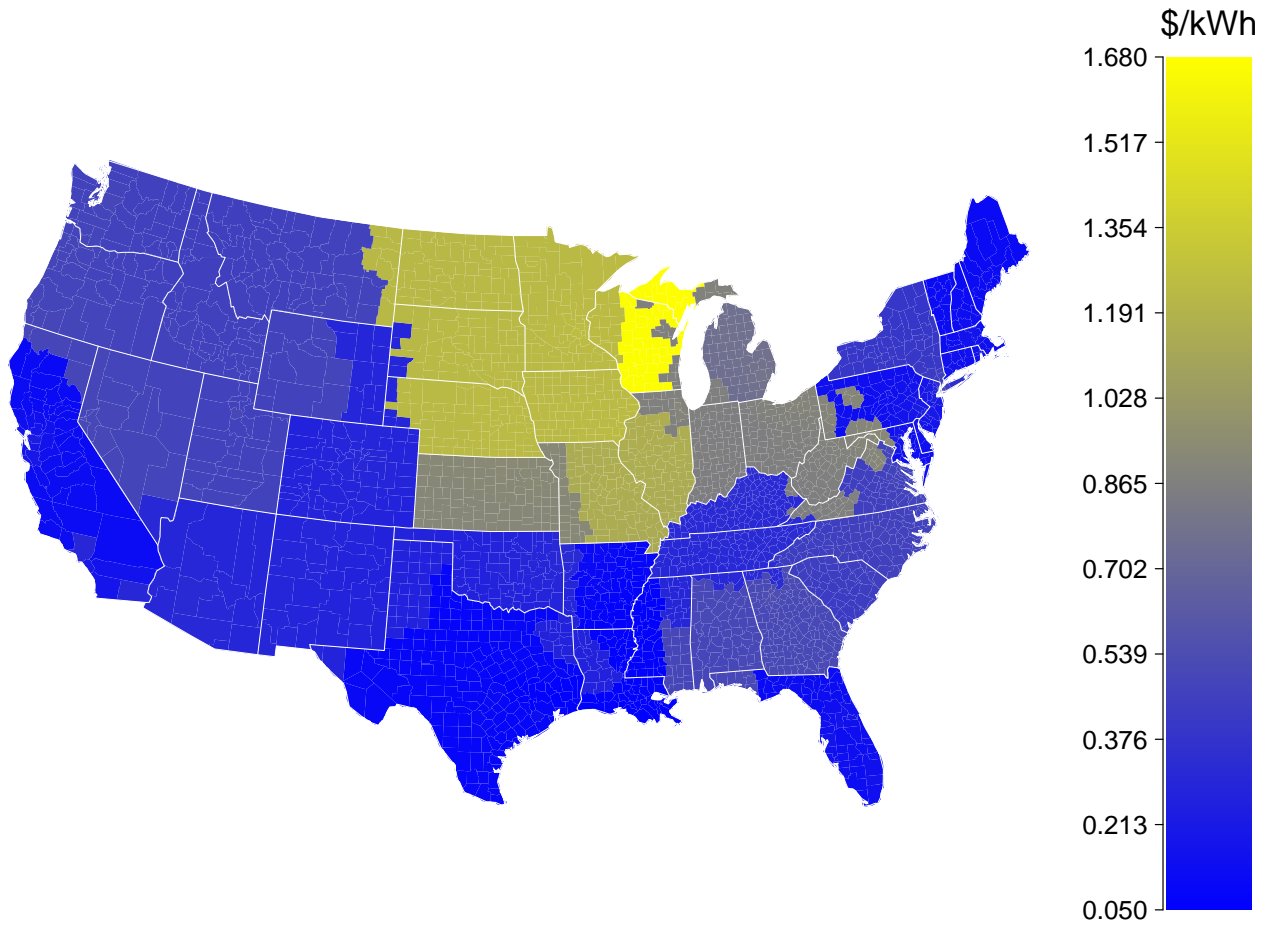
**FIGURE 6**

LCOE map for natural gas combined cycle electricity generation units with 90% carbon capture and sequestration showing the regional differences for reference conditions (Equation 4), average: \$0.111/kWh (median: \$0.096/kWh).



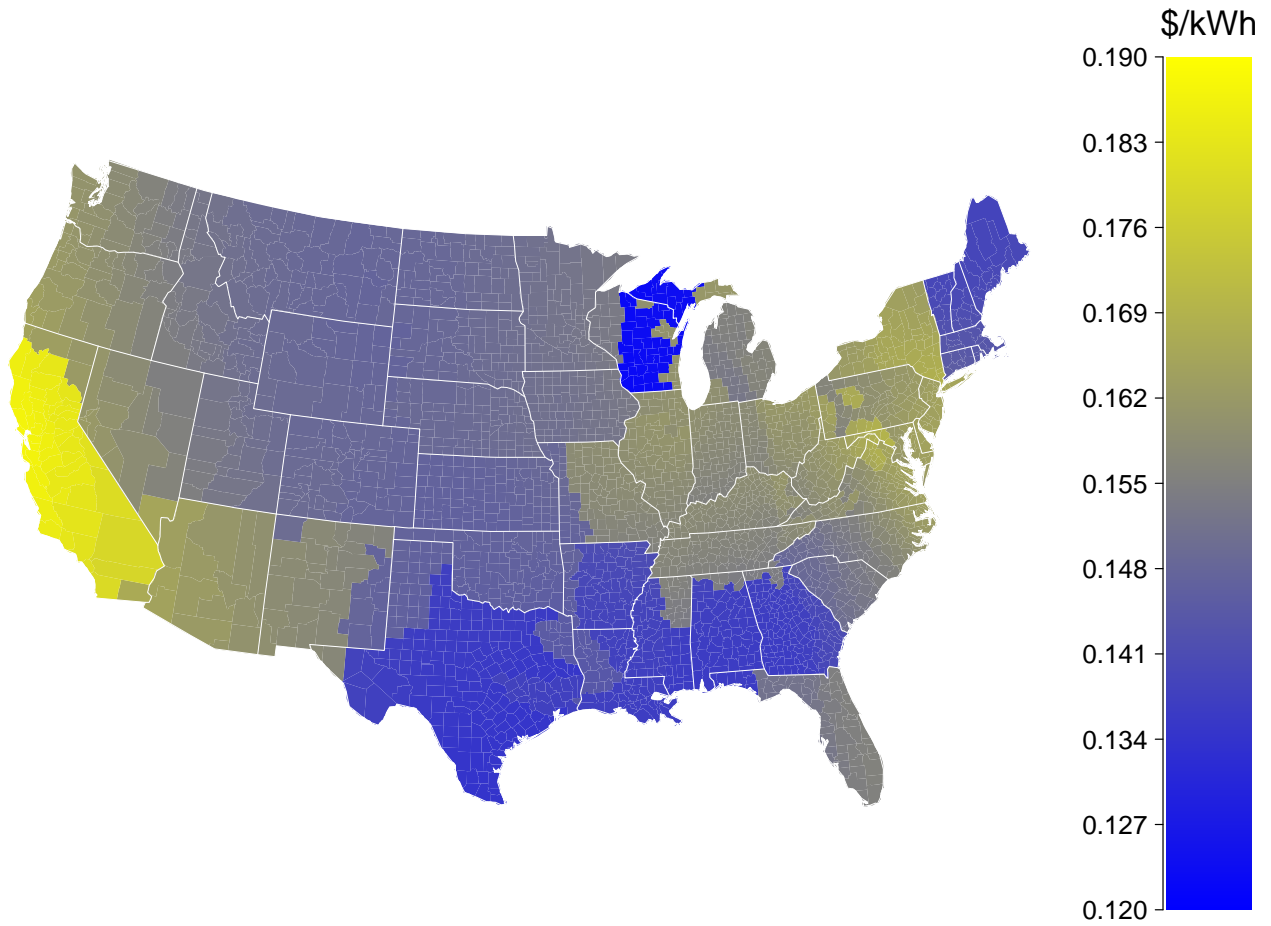
**FIGURE 7**

LCOE map for natural gas combustion turbine electricity generation units showing the regional differences for reference conditions (Equation 4), average: \$0.344/kWh (median: \$0.211/kWh).



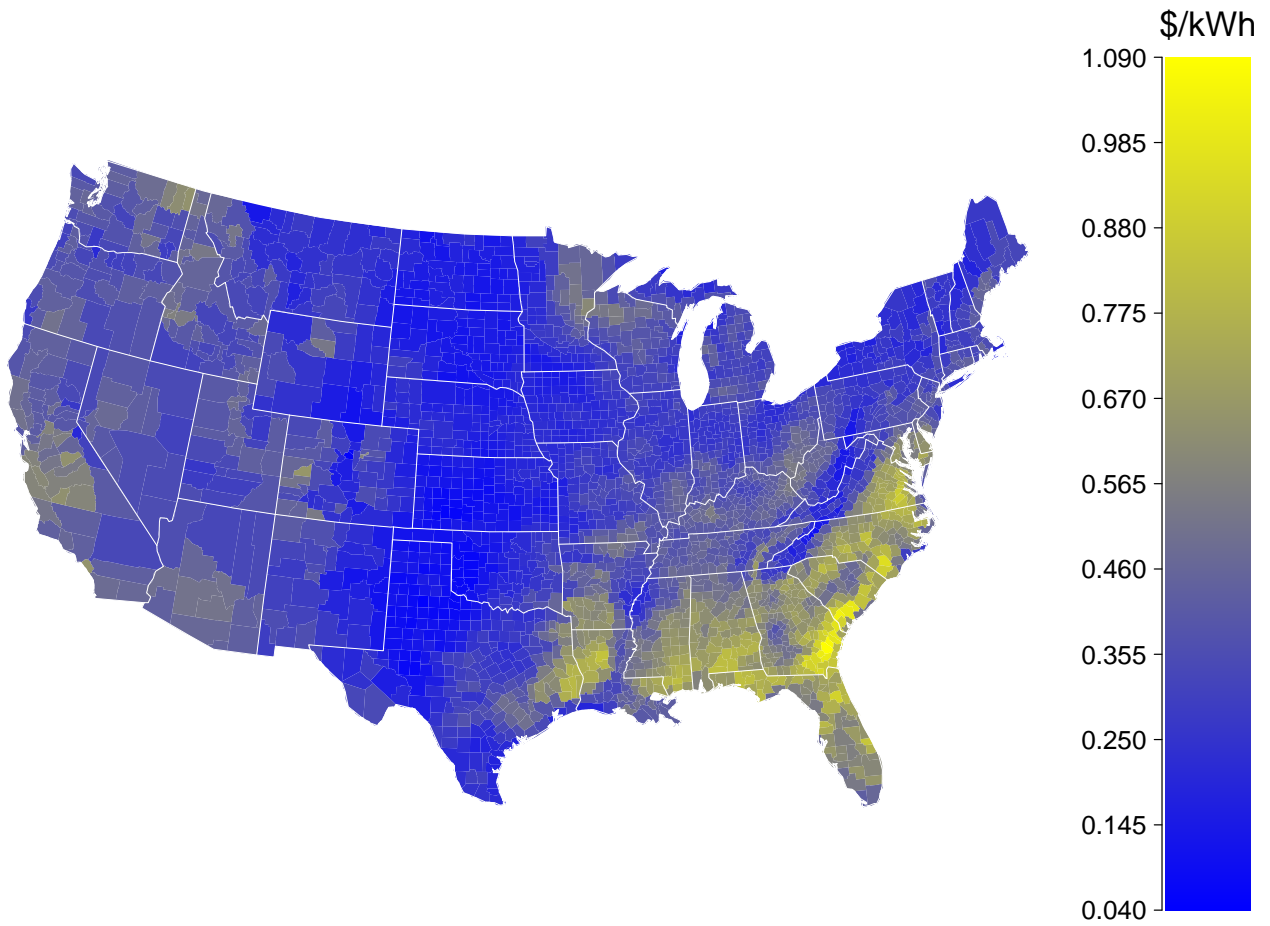
**FIGURE 8**

LCOE map for nuclear electricity generation units showing the regional differences for reference conditions (Equation 4), average: \$0.124/kWh (median: \$0.124/kWh).



**FIGURE 9**

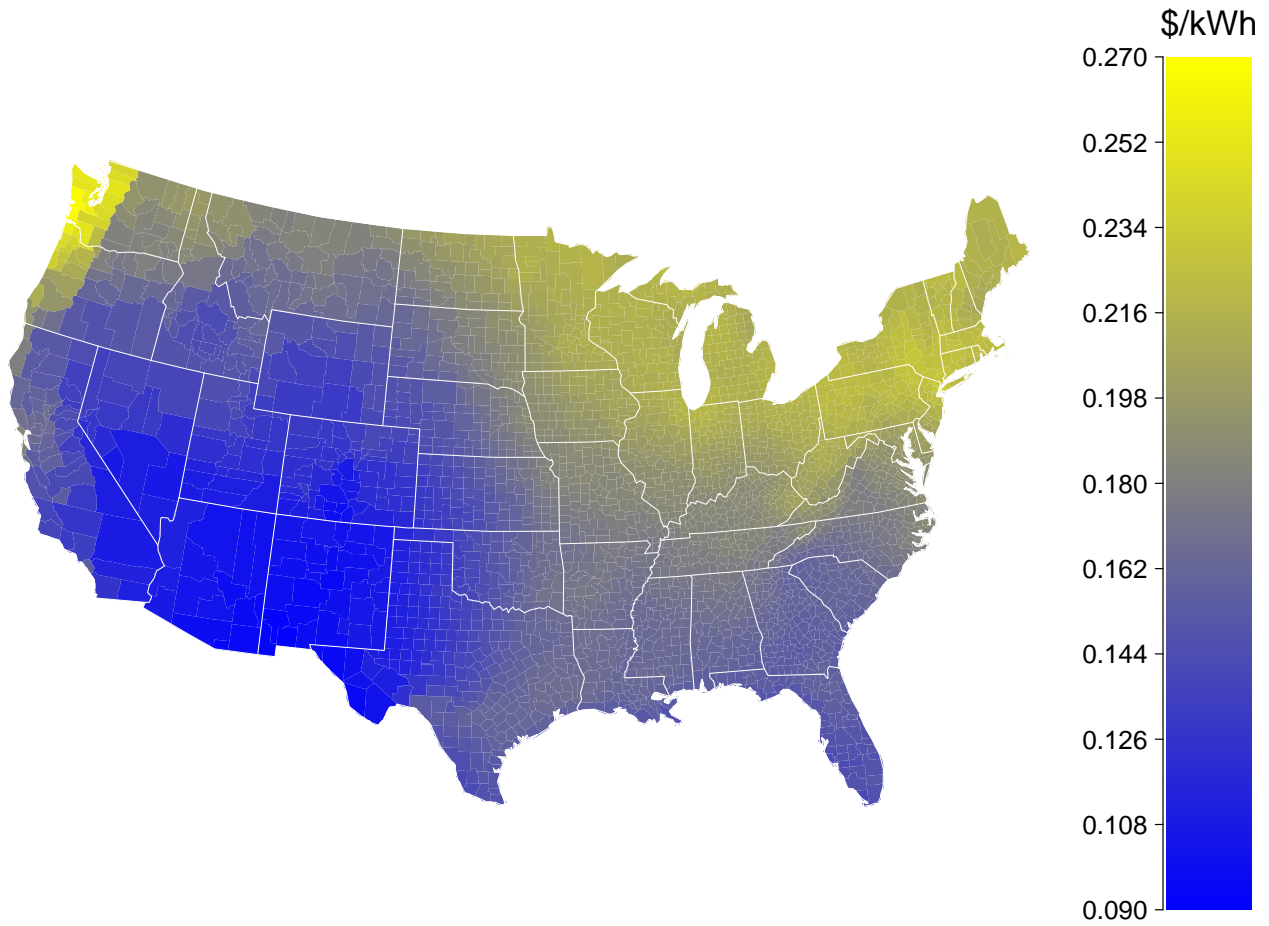
LCOE map for wind electricity generation units showing the regional differences for reference conditions (Equation 4), average: \$0.155/kWh (median: \$0.126/kWh).





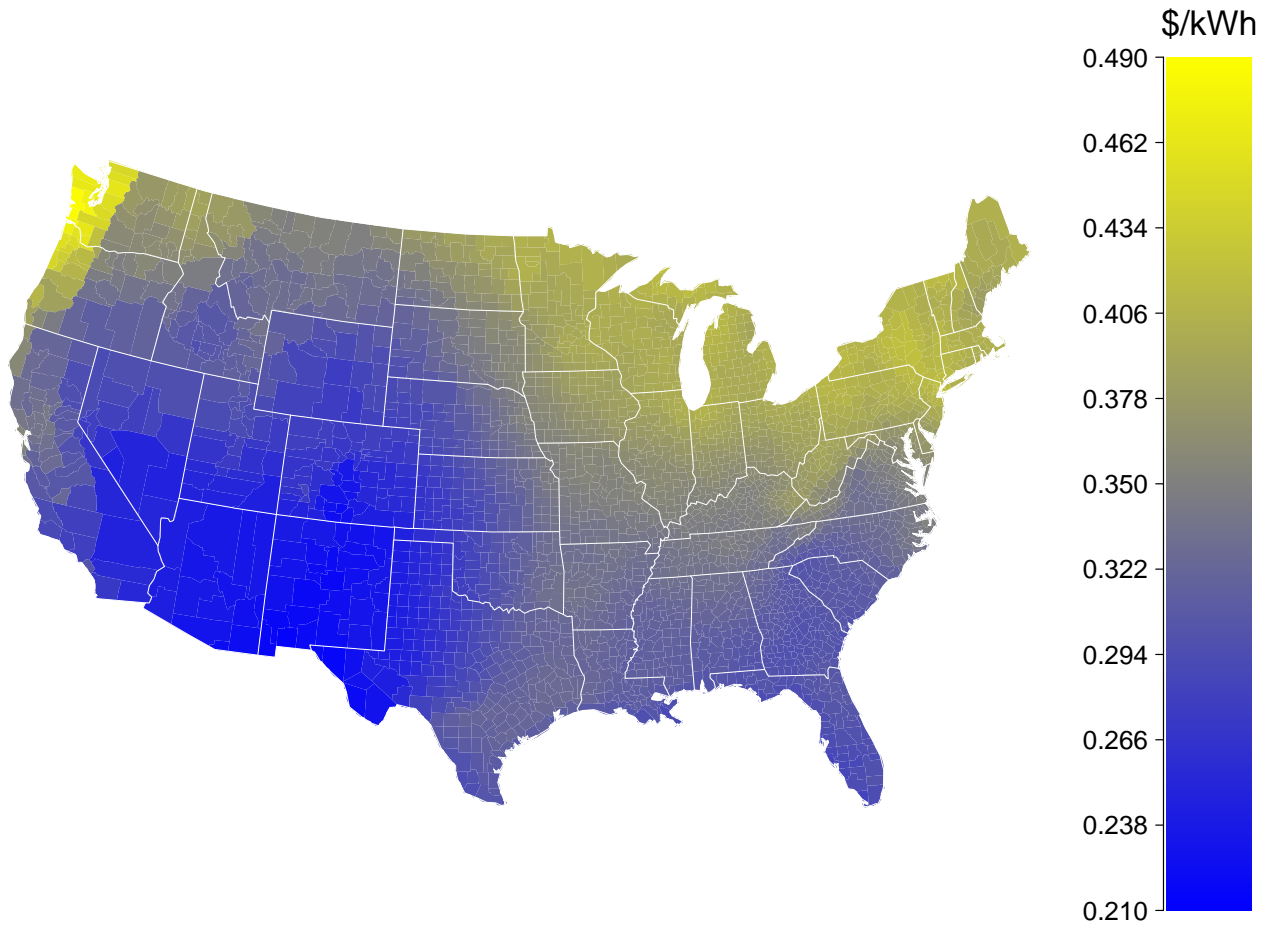
**FIGURE 10**

LCOE map for utility-scale PV electricity generation units showing the regional differences for reference conditions (Equation 4), average: \$0.199/kWh (median: \$0.197/kWh).



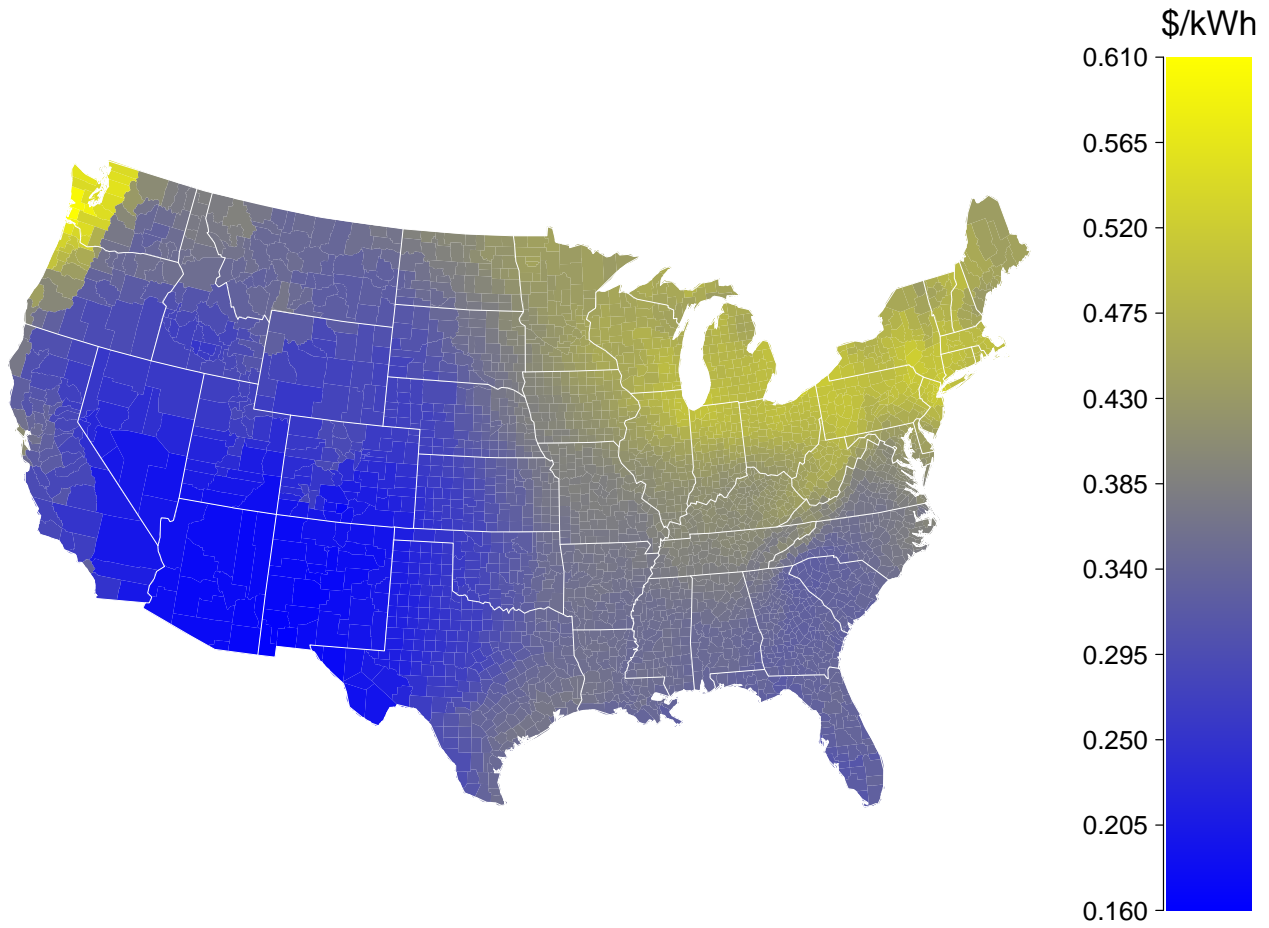
**FIGURE 11**

LCOE map for residential PV electricity generation units showing the regional differences for reference conditions (Equation 4), average: \$0.312/kWh (median: \$0.309/kWh).



**FIGURE 12**

LCOE map for concentrating solar power electricity generation units with 6 hours of storage showing the regional differences for reference conditions (Equation 4), average: \$0.29/kWh (median: \$0.282/kWh).



## POWER PLANT AVAILABILITY ZONES

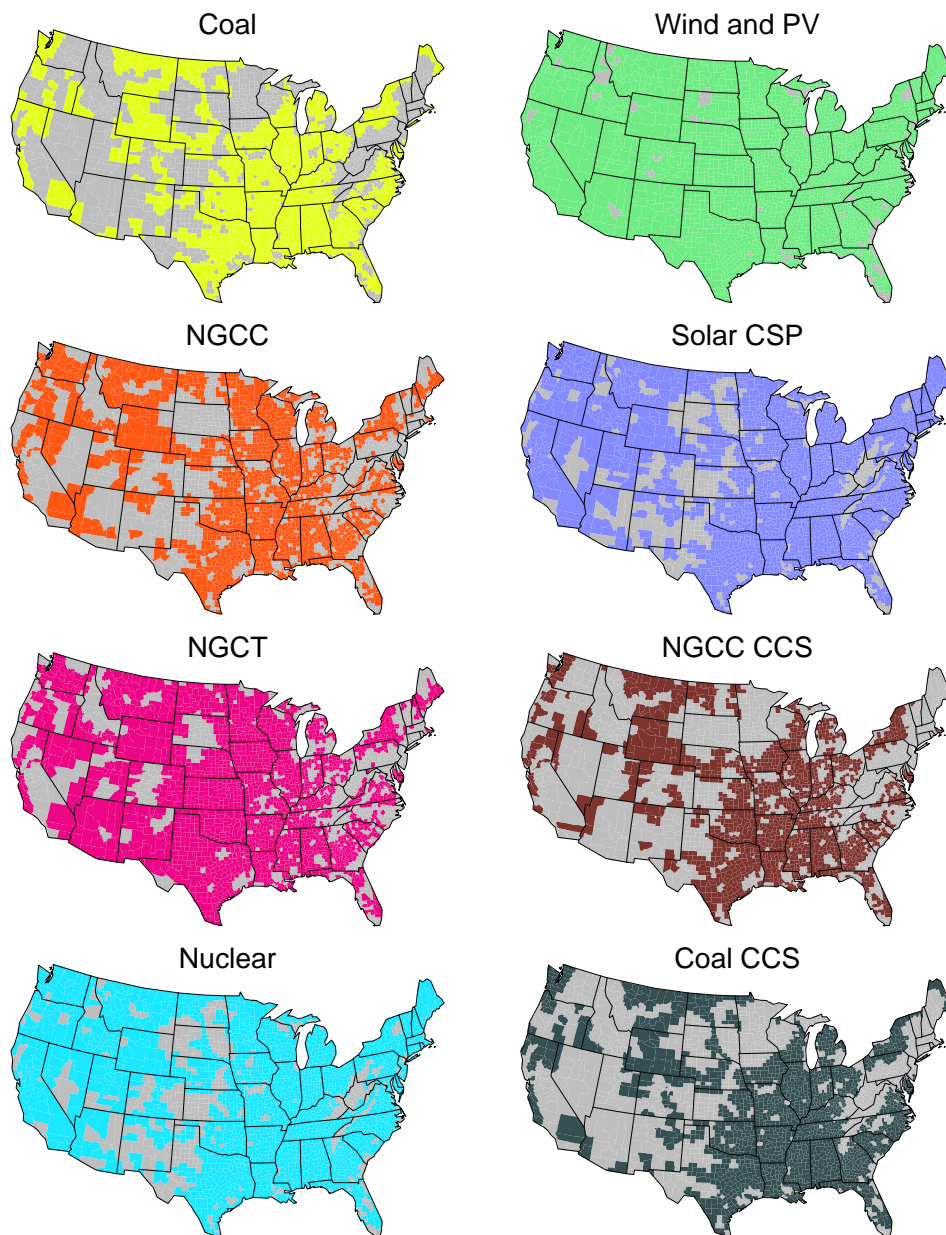
We used maps from an Oak Ridge National Lab study to develop availability zones for different types of power plants based on 11 different criteria; population density, wetlands, protected lands, lands with landslide risks, high-slope land, 100-year floodplains, water availability, EPA non-attainment zones, access to fuel (> 40 km (25 miles) from gas pipelines or railroads), proximity to suitable saline formations for carbon sequestration, and ability to build

CO2 pipelines. Detailed descriptions of the underlying analysis into the maps are in Mays, et al.<sup>1</sup> **Figure 13** show maps of available locations for all considered types of power plants.

**Table 1** shows which Figures from Mays, et al.<sup>1</sup> were combined in determining the availability zones for this analysis. The authors concede that this is a rough approximation, but is a helpful step in determining what might be able to be built where.

**FIGURE 13**

Map of availability zones for all technologies. Colors indicate where you can build the indicated power plant. Note that residential PV was assumed to be able to be built everywhere.



**TABLE 1**

Table showing which figures (F64 indicates Figure 64) from Mays, et al.<sup>1</sup> were used to create availability zones for each technology shown in Figure 13.

Technology	population density	wetlands	protected lands	landslide risks	high-slope land	100-year floodplain	water availability	EPA non-attainment zones	fuel access	saline formations	ability to build CO <sub>2</sub> pipelines
Coal CCS 30*	F64	F65	F66	F67	F68	F69	F70	F71	F72	F73	F74
Coal CCS 90**	F64	F65	F66	F67	F68	F69	F70	F71	F72	F73	F74
NGCC***	F64	F65	F66	F67	F68	F69	F53	F71	♣	N/A	N/A
NGCC CCS 90	F64	F65	F66	F67	F68	F69	F53	F71	♣	F73	F74
NGCT****	F64	F65	F66	F67	F68	F69	N/A	F71	♣	N/A	N/A
Nuclear	F64	F65	F66	F67	F68	F69	F70	N/A	N/A	N/A	N/A
Wind	F64	F65	F66	N/A	F68	F69	N/A	N/A	N/A	N/A	N/A
Solar PV	F64	F65	F66	N/A	F68	F69	N/A	N/A	N/A	N/A	N/A
CSP	F64	F65	F66	F67	F68	F69	F70	N/A	N/A	N/A	N/A

\* CCS 30: 30% Carbon capture and sequestration

\*\* CCS 90: 90% Carbon capture and sequestration

\*\*\* NGCC: Natural gas combined cycle

\*\*\*\* NGCT: Natural gas combustion turbine

♣: Fuel availability for natural gas plants was created by the authors by creating a 25 mile buffer around the existing US natural gas pipeline network, a similar method as how F72 was created for coal in Mays, et al.<sup>1</sup>

## FUGITIVE NATURAL GAS EMISSIONS

In this section we discuss our calculated non-combustion emissions rate associated with fugitive natural gas emissions. We used non-combustion ongoing GHG emissions values from.<sup>2</sup> However, it did not appear that fugitive methane emissions from the natural gas sector were included in the values.

Thus, we calculated fugitive emissions for all considered natural gas technologies and included them in the LCOE calculations that considered externalities (Scenarios 2-10) using **Equation 1**:

### EQUATION 1

$$E_f = HR \times P_i / HHV_{ng}$$

where  $E_f$  is the CH<sub>4</sub> value (g/kWh) of fugitive emissions associated with the US natural gas infrastructure,  $HR$  is the heat rate of a the given natural gas power plant (**Table 1**),  $P_i$  is the average percent leakage in the US natural gas infrastructure, and  $HHV_{ng}$  is the high heating value associated with natural gas (assumed 43,000 kJ/kg). **Table 2** shows fugitive methane emissions calculated values for low (0.5%), mid (1.0%), and high (1.5%) average percent leakage in the US natural gas infrastructure. We used the mid values in our calculations – assuming a 1.0% average leakage rate in the US natural gas infrastructure.

## CAPEX PRICE MAPS

**Figures 14 - 23** show the CAPEX values used in our analysis for all technology types. Note that while the color scale looks the same for each technology the relative values (min/max) are different.

**TABLE 1**

Table showing the values of fugitive methane emissions per kWh of electricity generated for multiple types of natural gas power plants (g- CH<sub>4</sub>/kWh) associated with obtaining and delivering natural gas to the plants.

Technology	Heat Rate (kJ/kWh)	fugitive emissions low (g/kwh) <sup>1</sup>	fugitive emissions mid (g/kwh) <sup>2</sup>	fugitive emissions high (g/kwh) <sup>3</sup>
NGCC*	6,784	0.79	1.58	2.37
NGCC CCS**	7,939	0.92	1.85	2.77
NGC***	10,287	1.20	2.39	3.59

\* NGCC: Natural gas combined cycle

\*\* CCS: Carbon Capture and Sequestration

\*\*\* NGCT: Natural gas combustion turbine

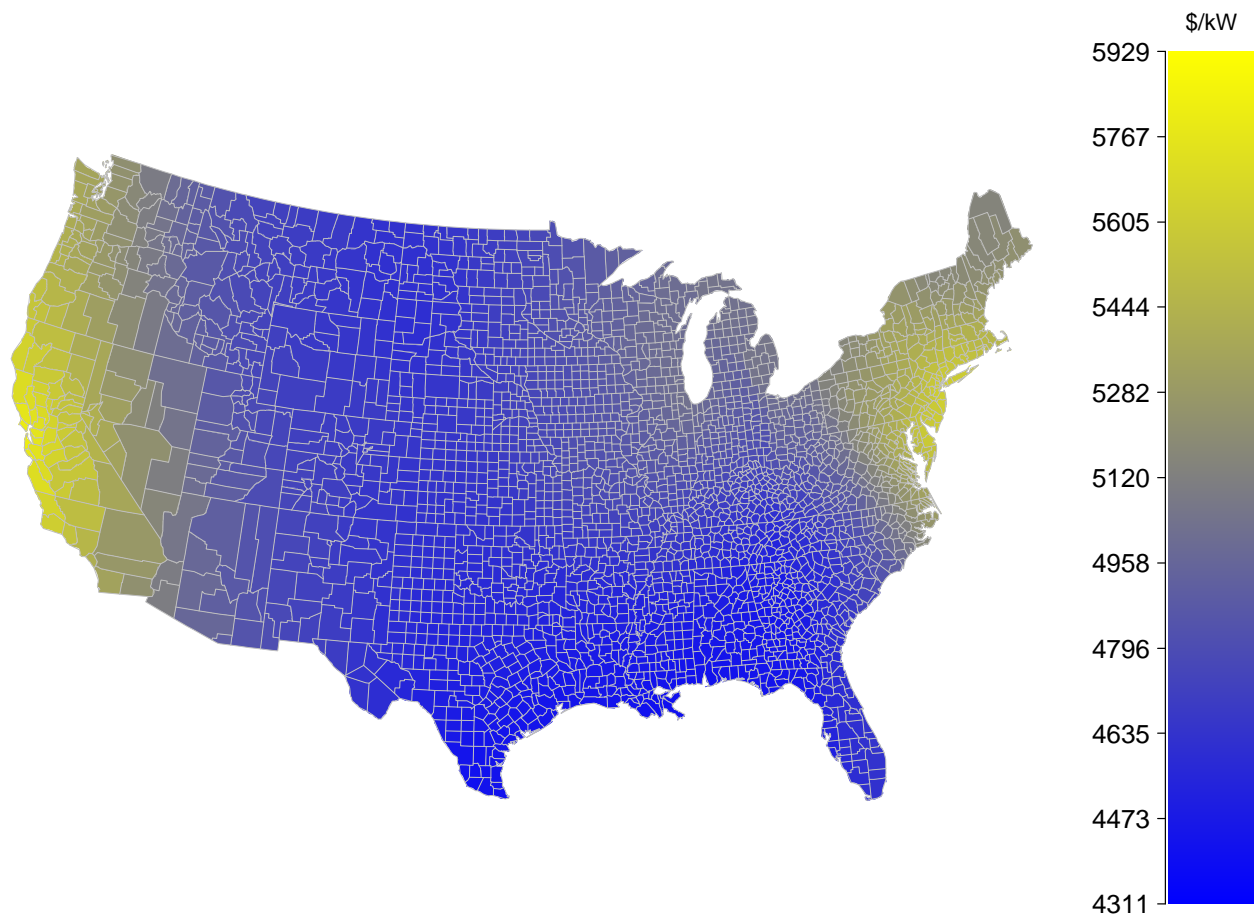
<sup>1</sup> National average leakage rate of 0.5%

<sup>2</sup> National average leakage rate of 1.0% (reference case assumption)

<sup>3</sup> National average leakage rate of 1.5%

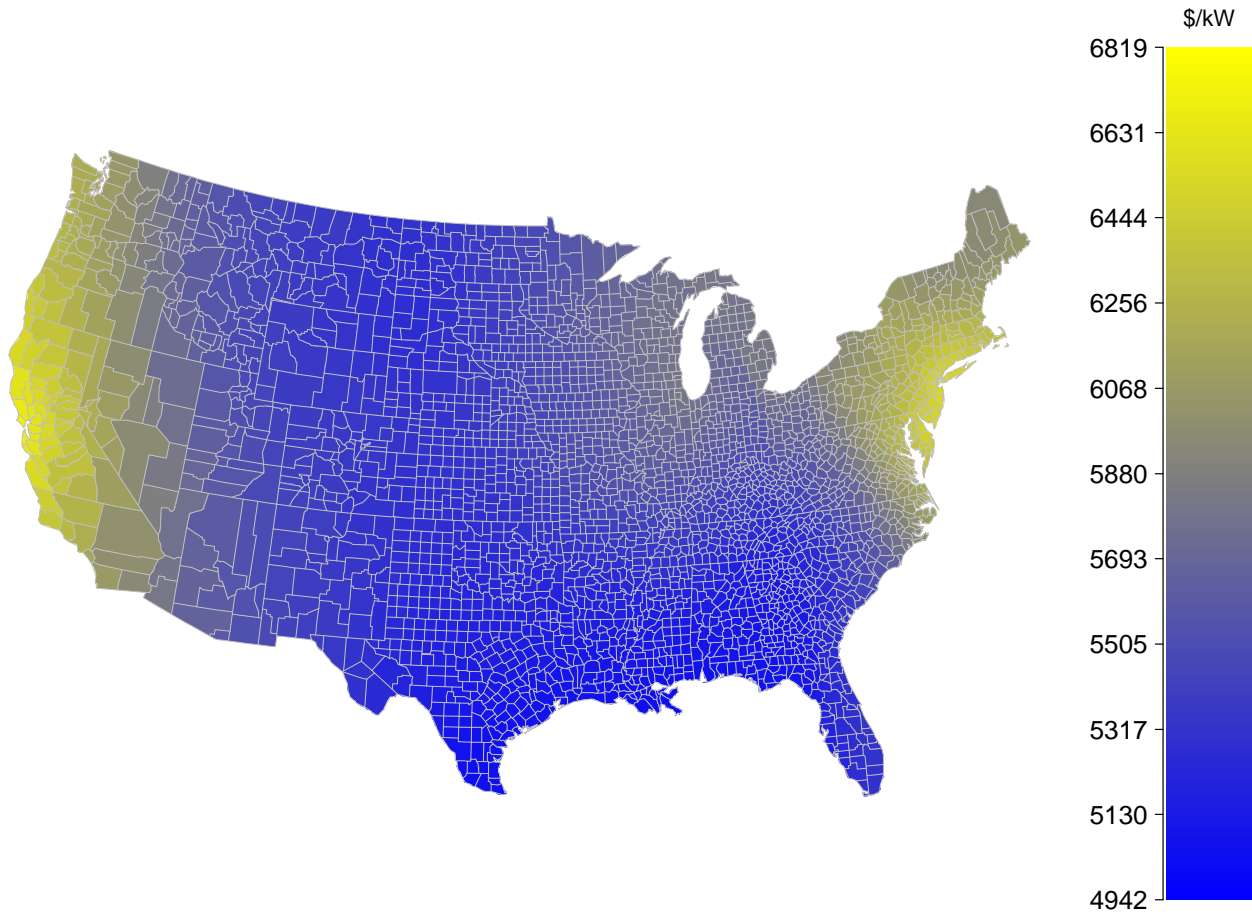
**FIGURE 14**

Coal plant CAPEX price map (\$/kW) using values from<sup>3</sup> with regional multipliers<sup>4</sup> and geographic interpolation as described in the paper methods section.



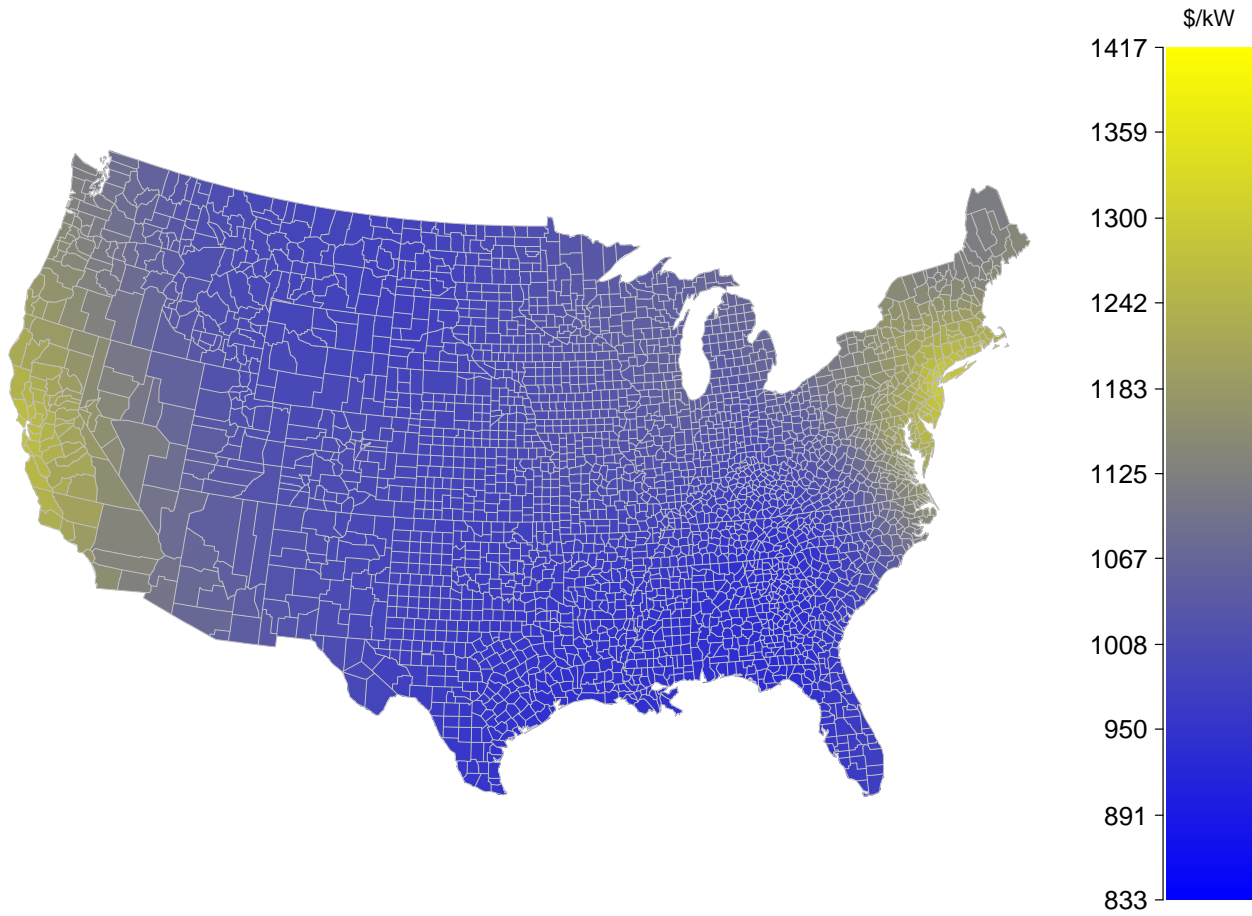
**FIGURE 15**

Coal CCS plant CAPEX price map (\$/kW) using values from<sup>3</sup> with regional multipliers<sup>4</sup> and geographic interpolation as described in the paper methods section.



**FIGURE 16**

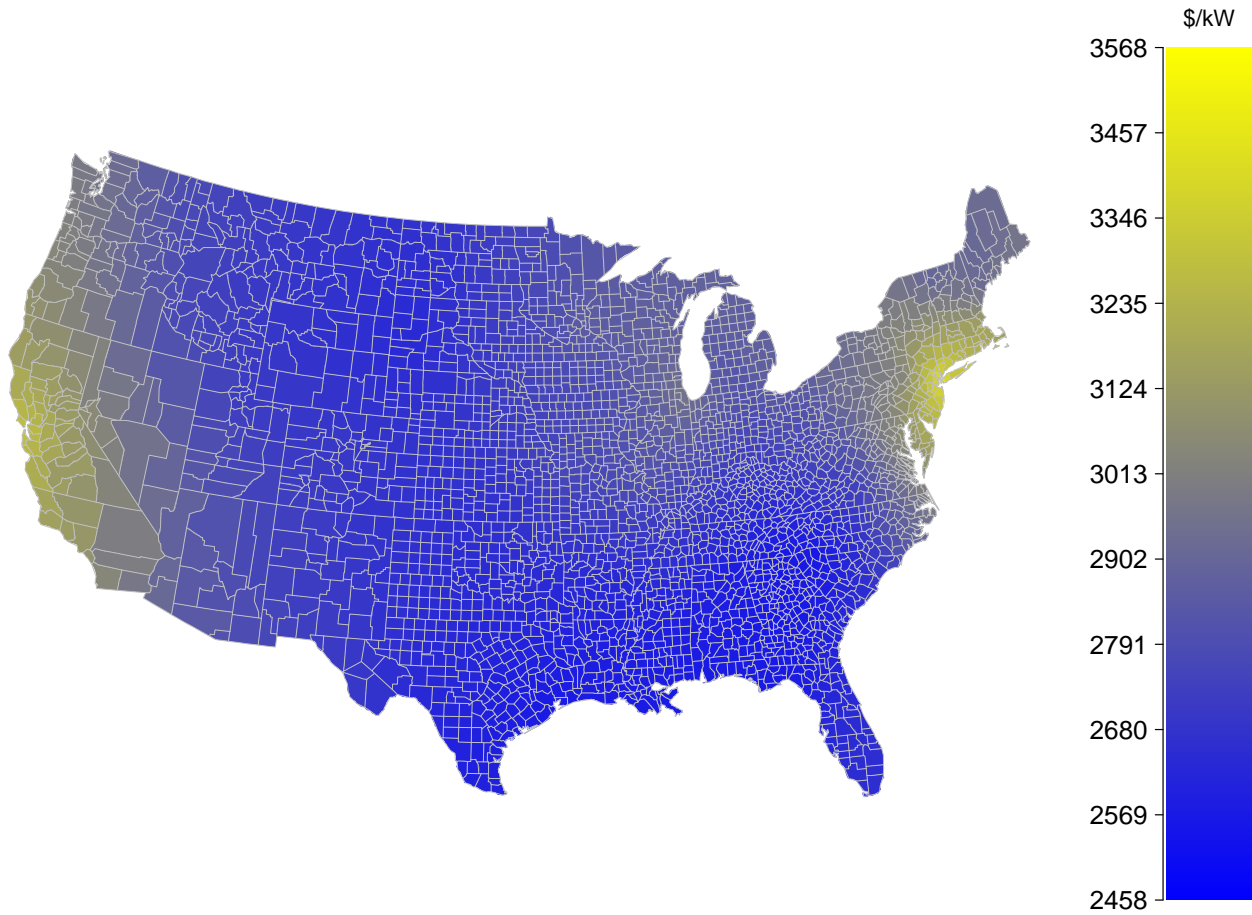
NGCC CAPEX price map (\$/kW) using values from<sup>3</sup> with regional multipliers<sup>4</sup> and geographic interpolation as described in the paper methods section.





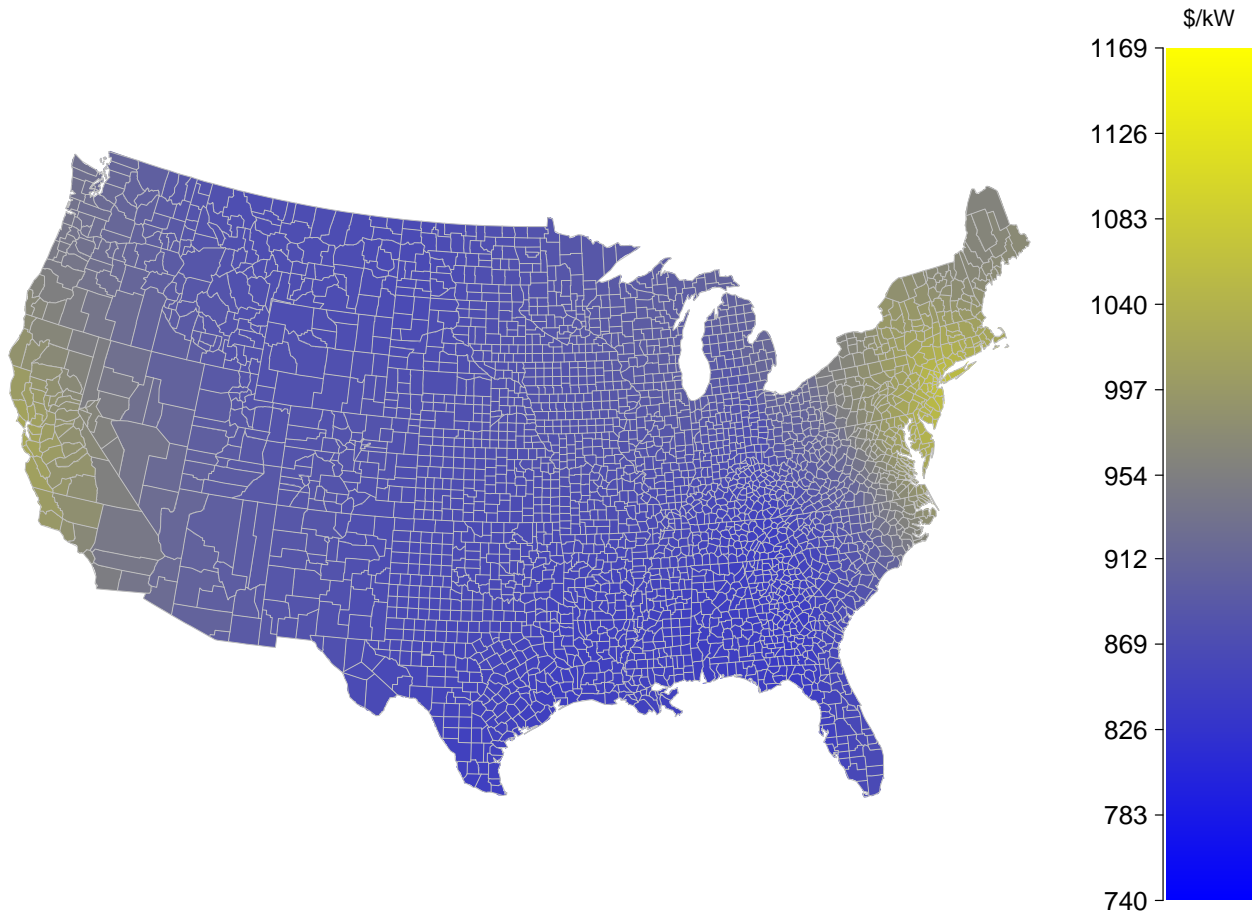
**FIGURE 17**

NGCC CCS CAPEX price map (\$/kW) using values from<sup>3</sup> with regional multipliers<sup>4</sup> and geographic interpolation as described in the paper methods section.



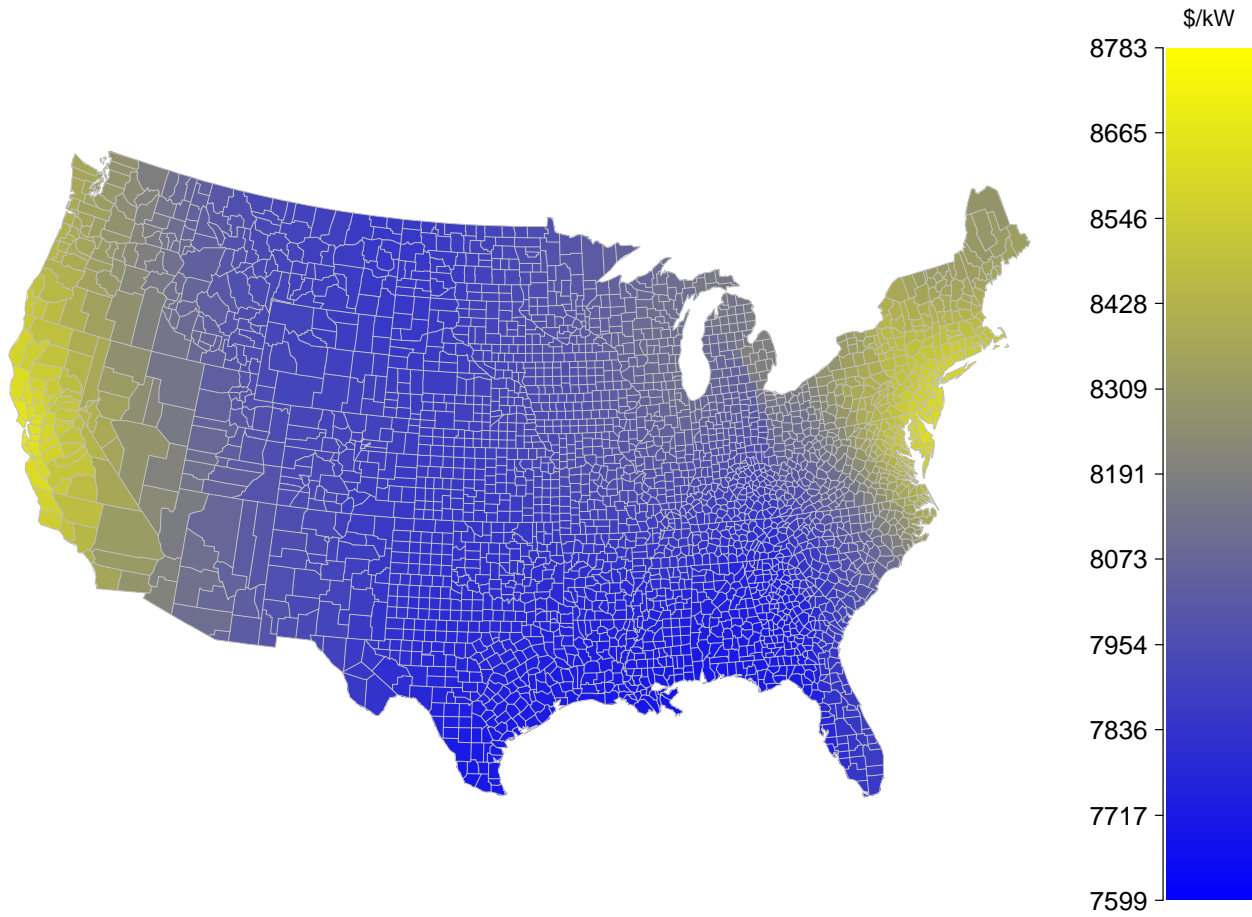
**FIGURE 18**

NGCT price map (\$/kW) using values from<sup>3</sup> with regional multipliers<sup>4</sup> and geographic interpolation as described in the paper methods section.



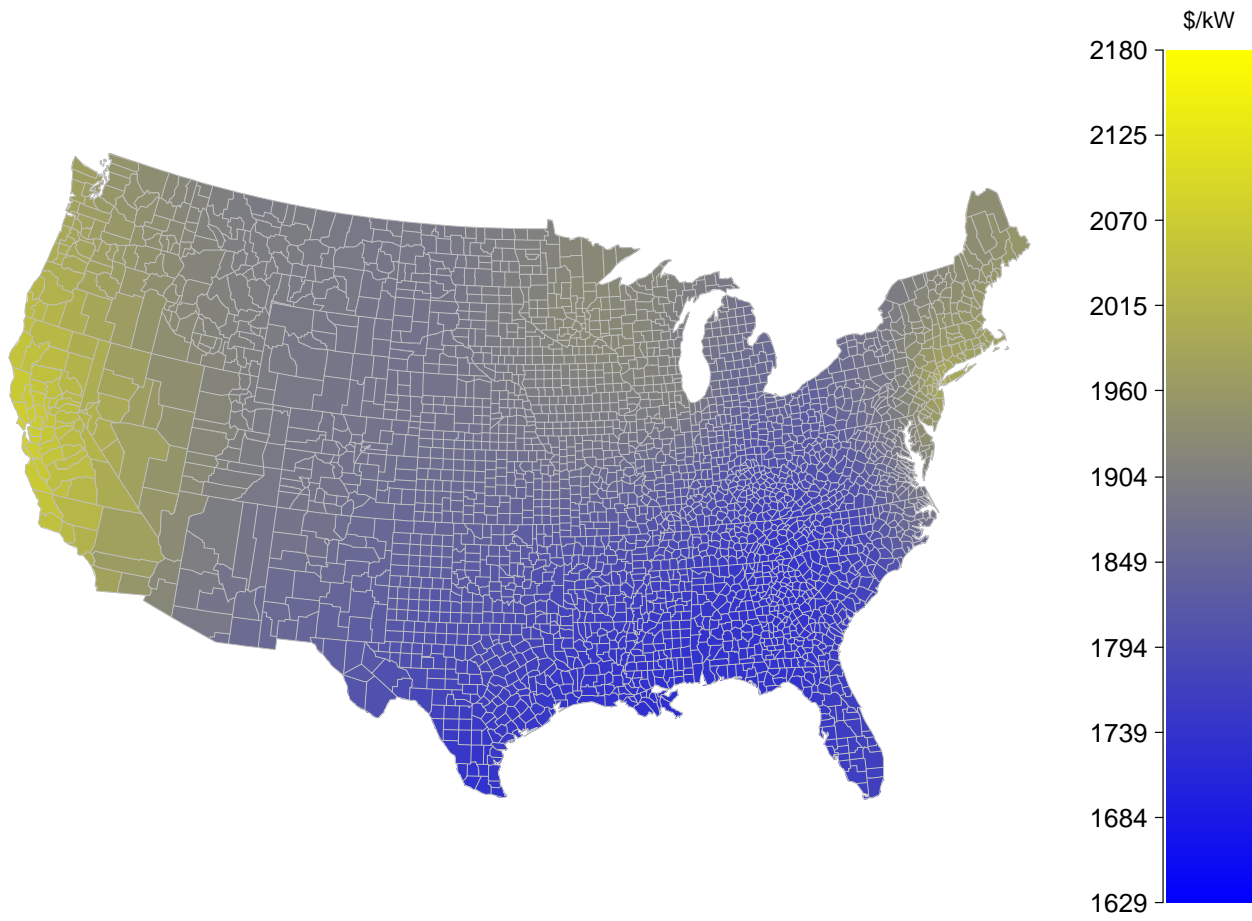
**FIGURE 19**

Nuclear CAPEX price map (\$/kW) using values from<sup>3</sup> with regional multipliers<sup>4</sup> and geographic interpolation as described in the paper methods section.



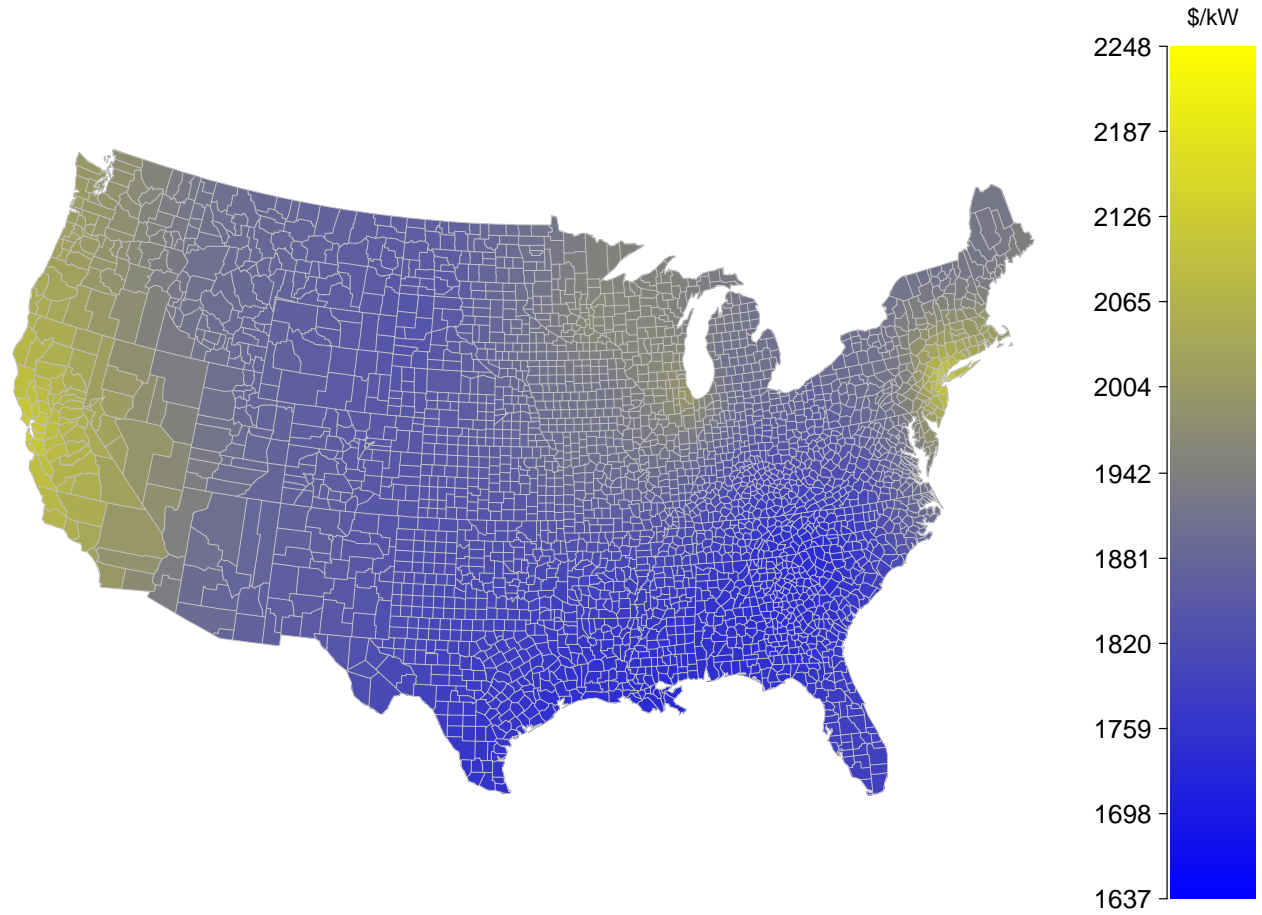
**FIGURE 20**

Wind CAPEX price map (\$/kW) using values from<sup>3</sup> with regional multipliers<sup>4</sup> and geographic interpolation as described in the paper methods section.



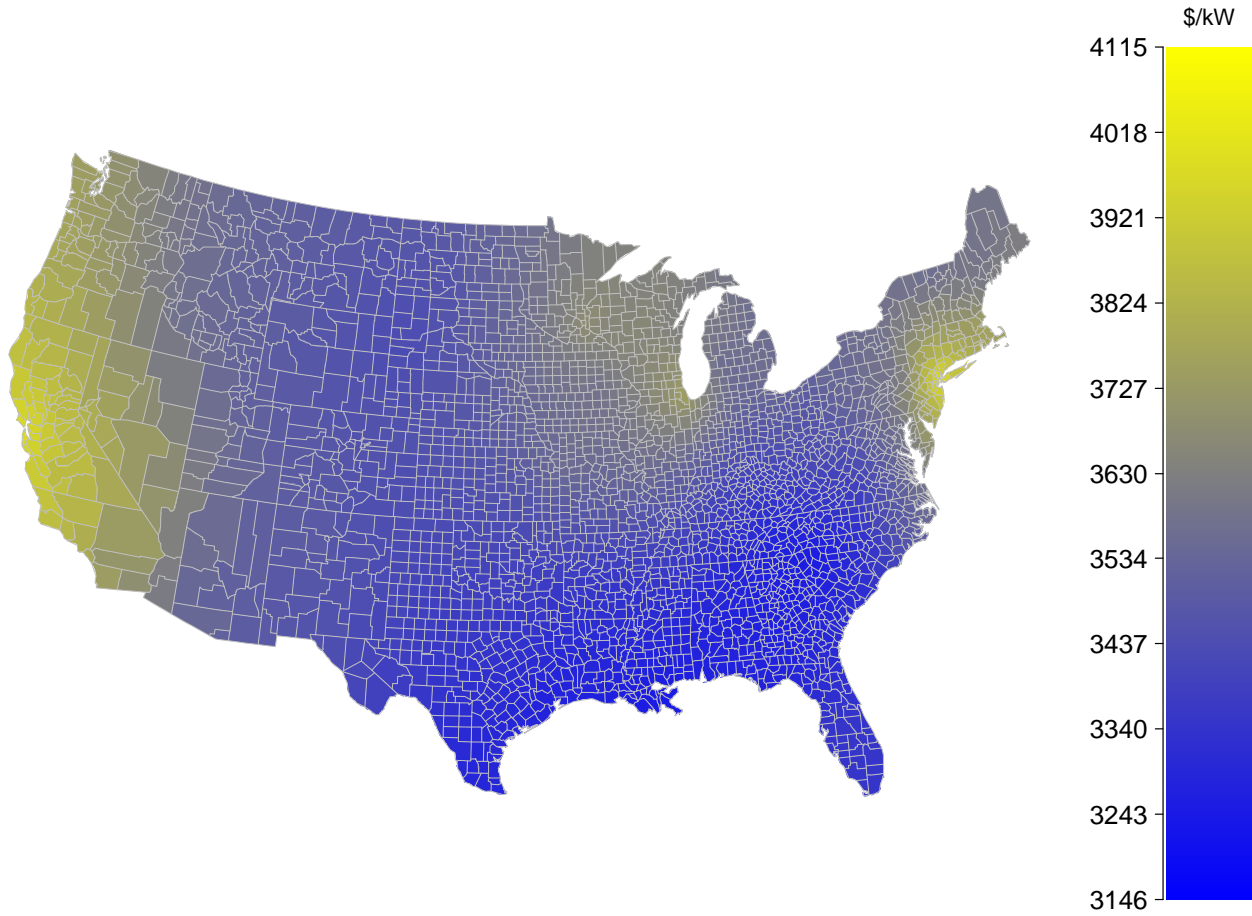
**FIGURE 21**

Utility PV CAPEX price map (\$/kW) using values from<sup>3</sup> with regional multipliers<sup>4</sup> and geographic interpolation as described in the paper methods section.



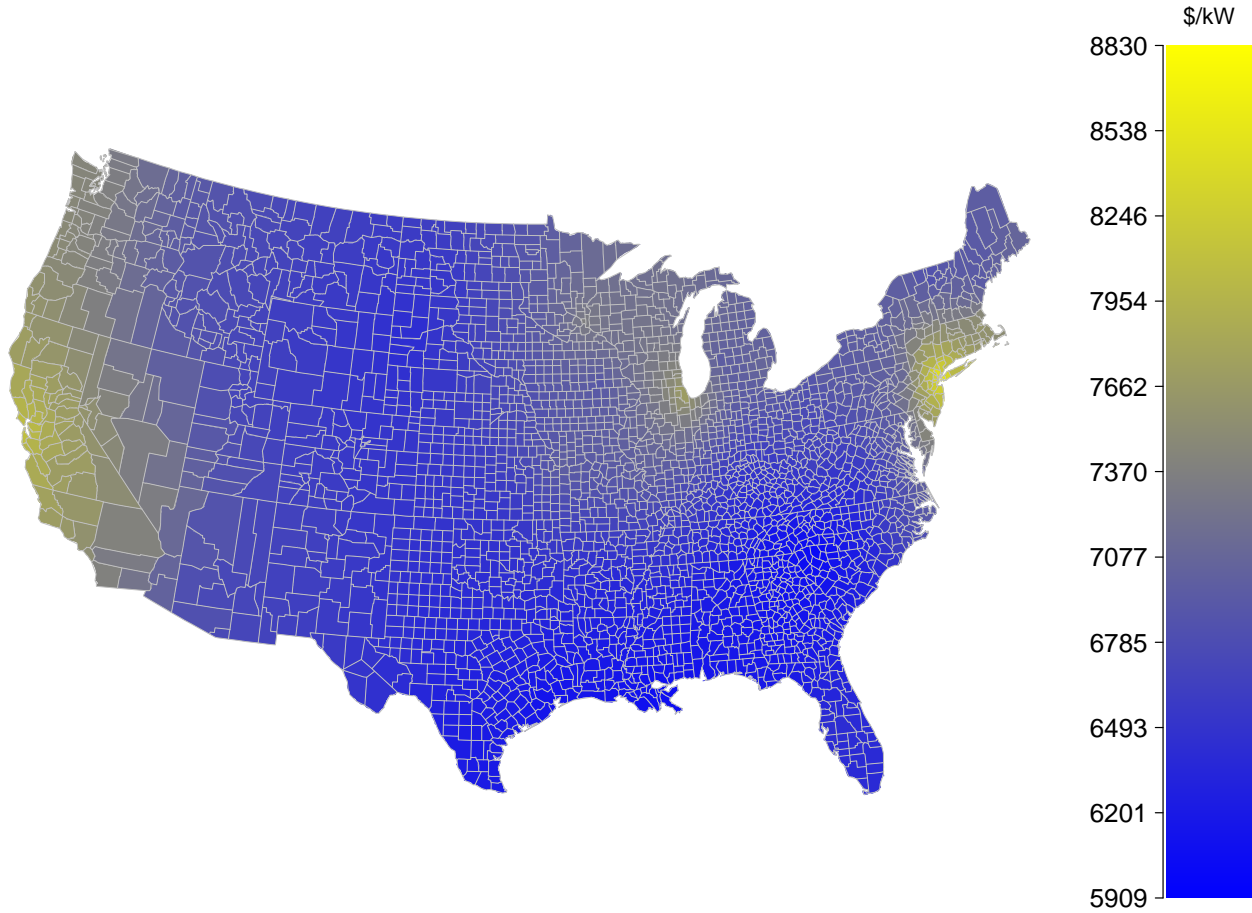
**FIGURE 22**

Residential PV CAPEX price map (\$/kW) using values from<sup>3</sup> with regional multipliers<sup>4</sup> and geographic interpolation as described in the paper methods section. Because residential PV was not included in,<sup>3</sup> the utility PV value was used + \$1,000/kW.



**FIGURE 23**

CSP CAPEX price map (\$/kW) using values from<sup>3</sup> with regional multipliers<sup>4</sup> and geographic interpolation as described in the paper methods section.



## FUEL PRICE MAPS

Figures 24 - 26 show the fuel price values used in our analysis for all fossil technology types. Note that while the color scale looks the same for each technology the relative values (min/max) are different.

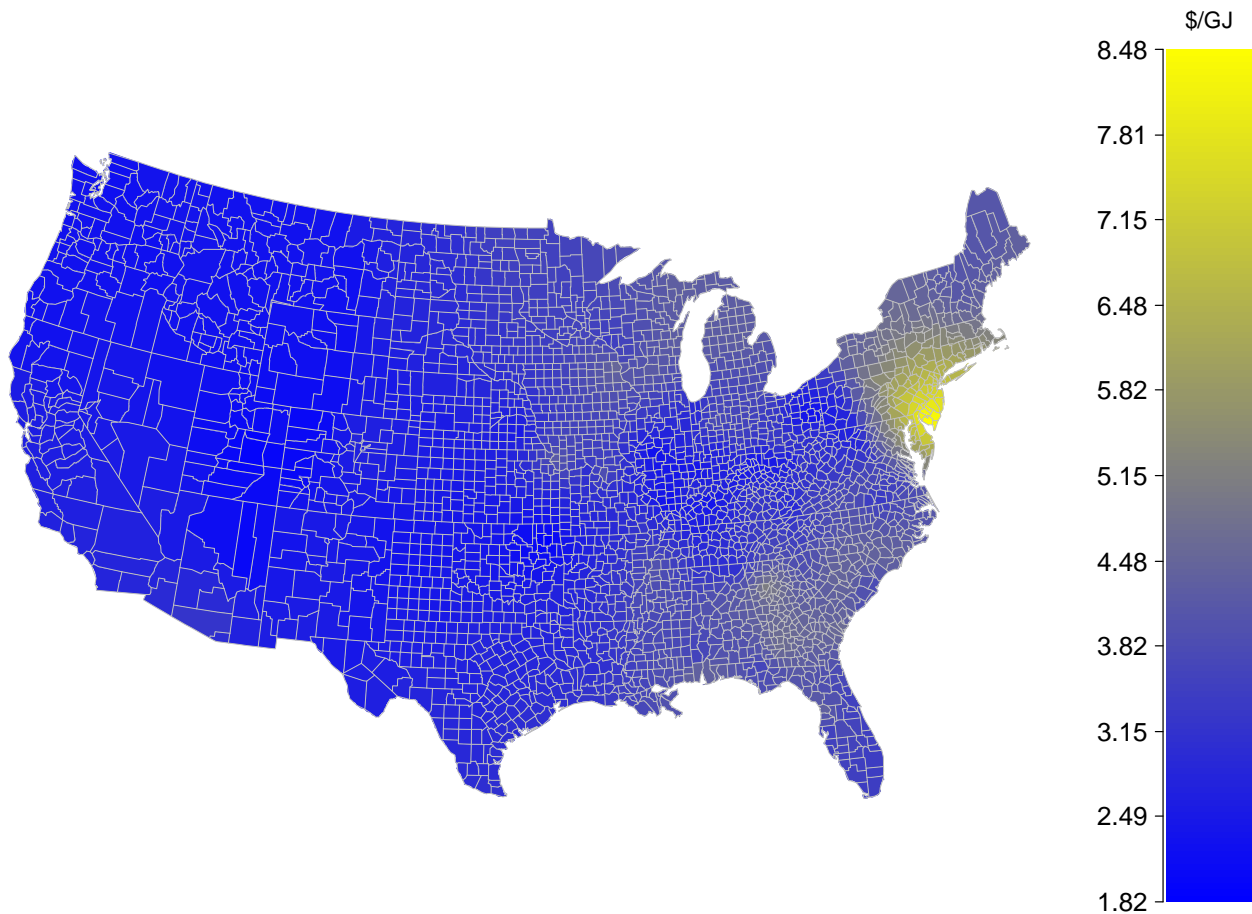
High and low natural gas price scenarios were developed based on the reference price case shown in Figure 26 and explained in the methods section. In our reference case, the average price

of natural gas in the United States was \$5.37/GJ (\$5.07/MMBtu), but varied nationally. Each county was assigned a multiplier that when multiplied by \$5.37/GJ (\$5.07/MMBtu) yielded the values shown in Figure 26. This same county-specific multiplier was multiplied by

\$3.16/GJ (\$3/MMBtu) to give a low natural gas price for each county as seen in Figure 27 and \$7.39/GJ (\$7/MMBtu) to give a high natural gas price for each county as seen in Figure 28.

### FIGURE 24

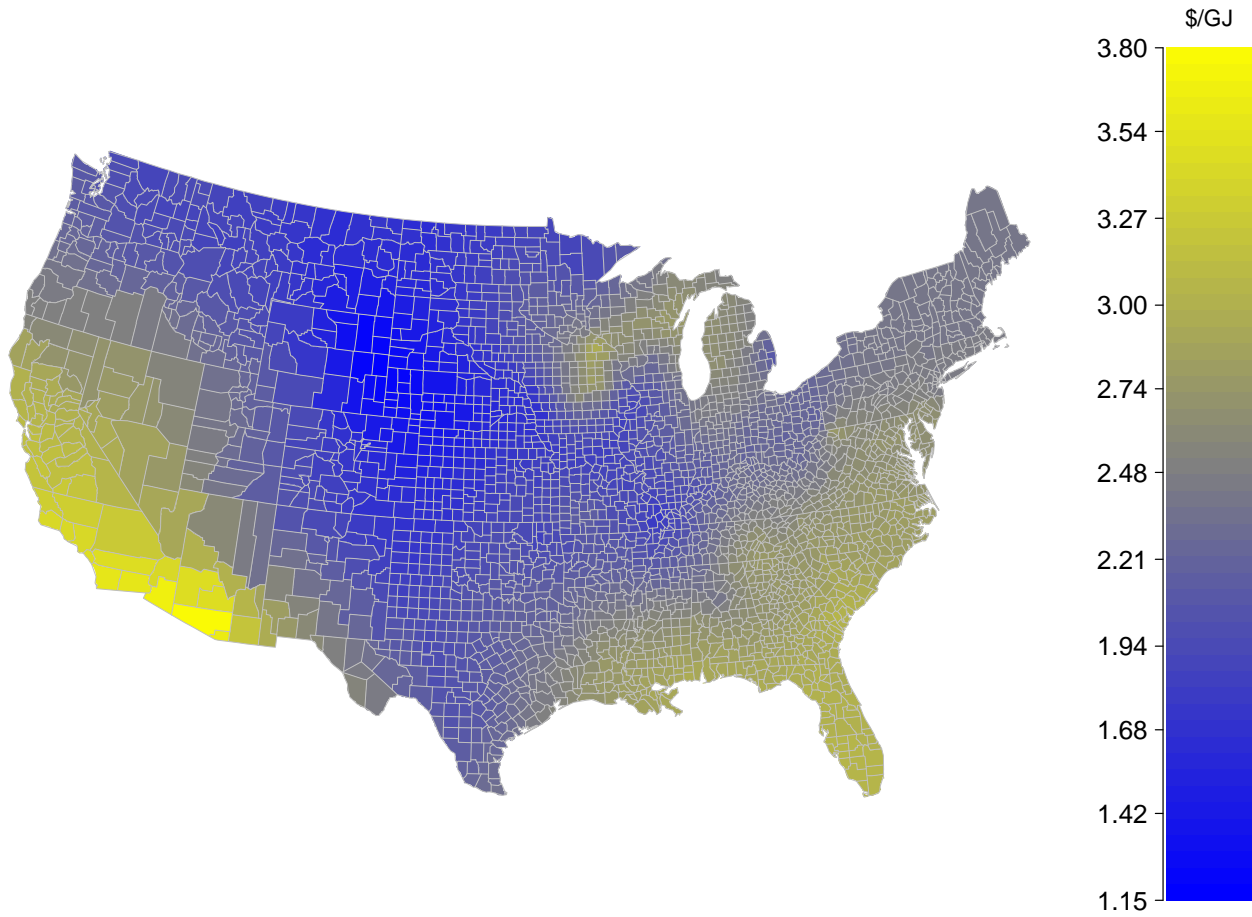
Bituminous coal fuel price map (\$/GJ) with geographic interpolation using an average price of \$3.35/GJ (\$3.17/MMBtu).





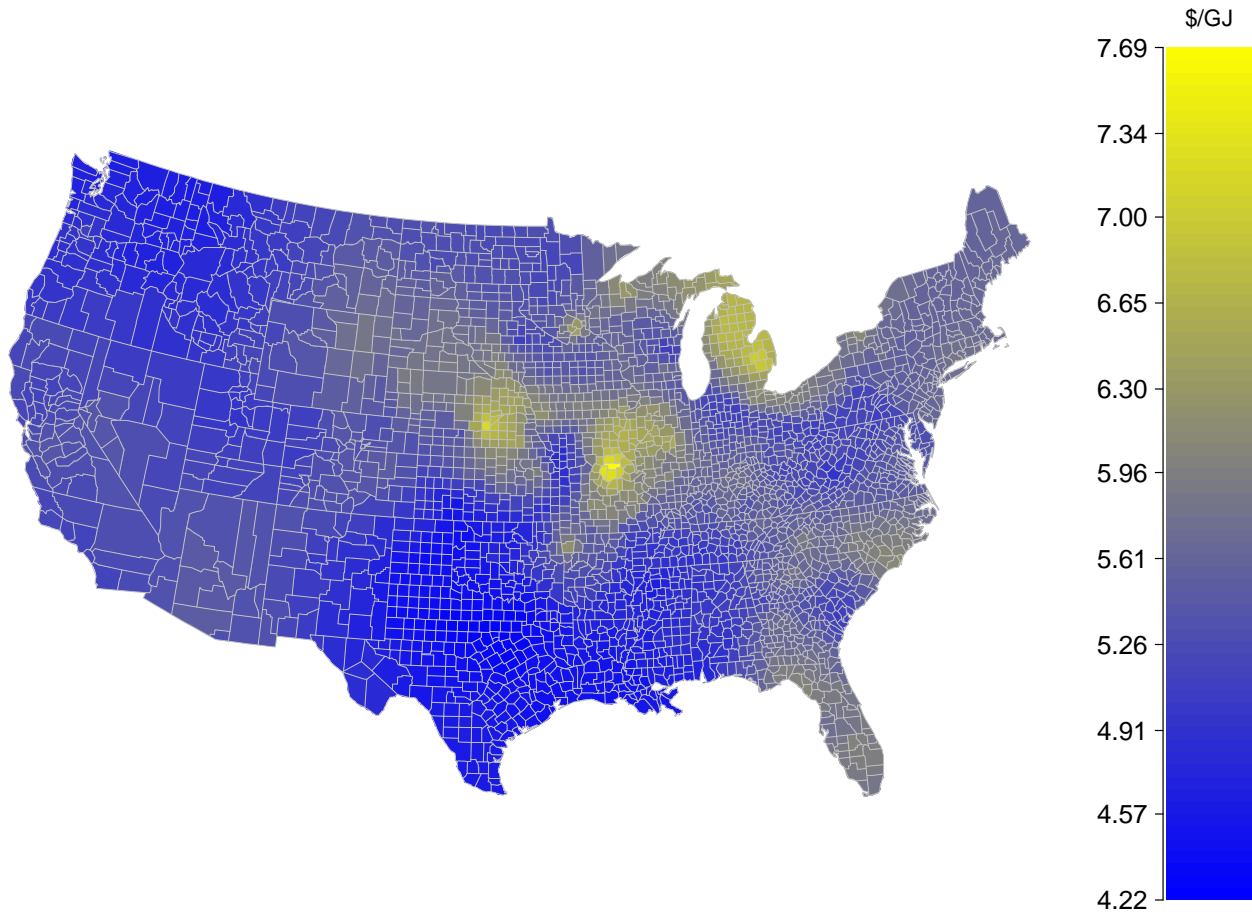
**FIGURE 25**

Sub-bituminous coal fuel price map (\$/GJ) with geographic interpolation using an average price of \$2.28/GJ (\$2.16/MMBtu).



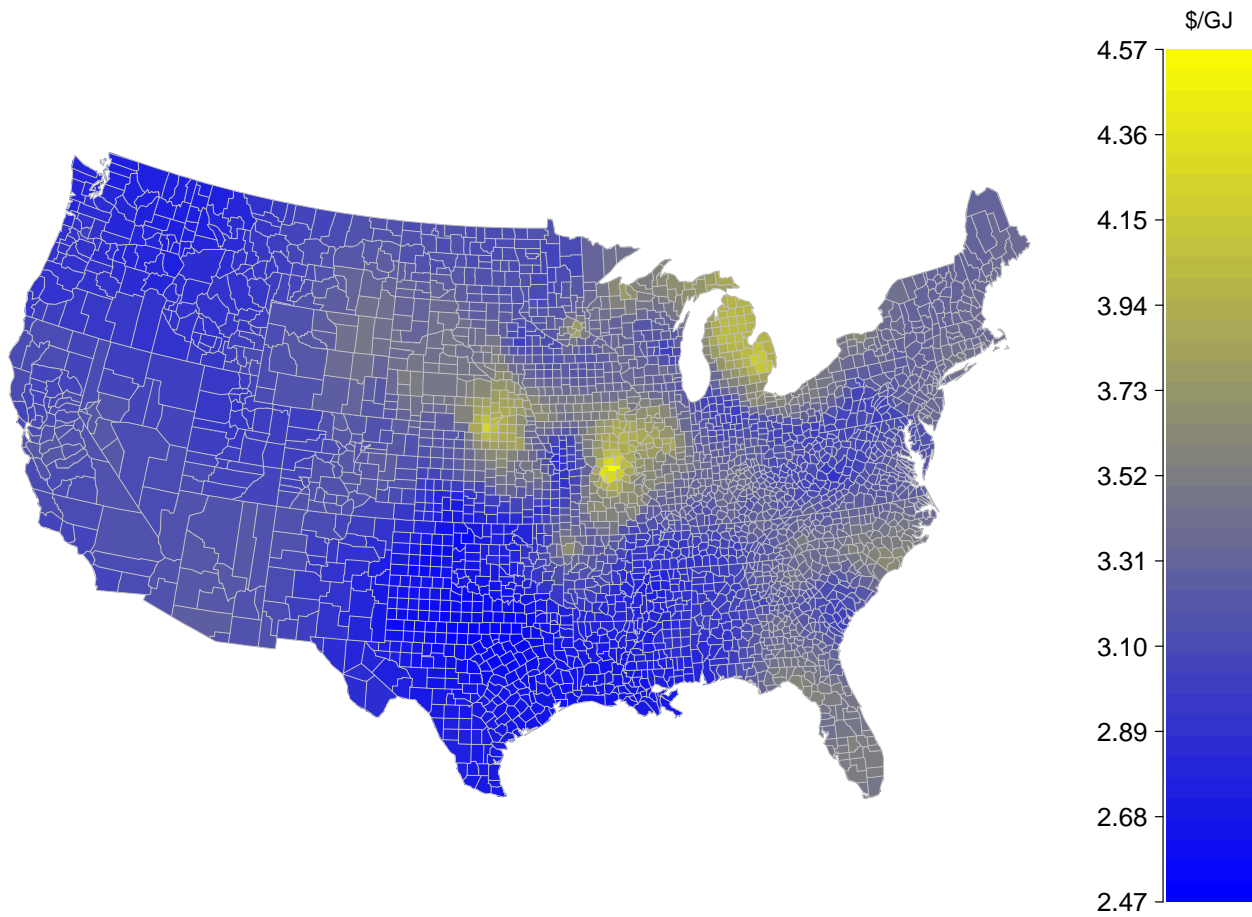
**FIGURE 26**

Natural gas reference case fuel price map with a US average cost of \$5.37/GJ (\$5.07/MMBtu) with geographic interpolation as described in the methods section.



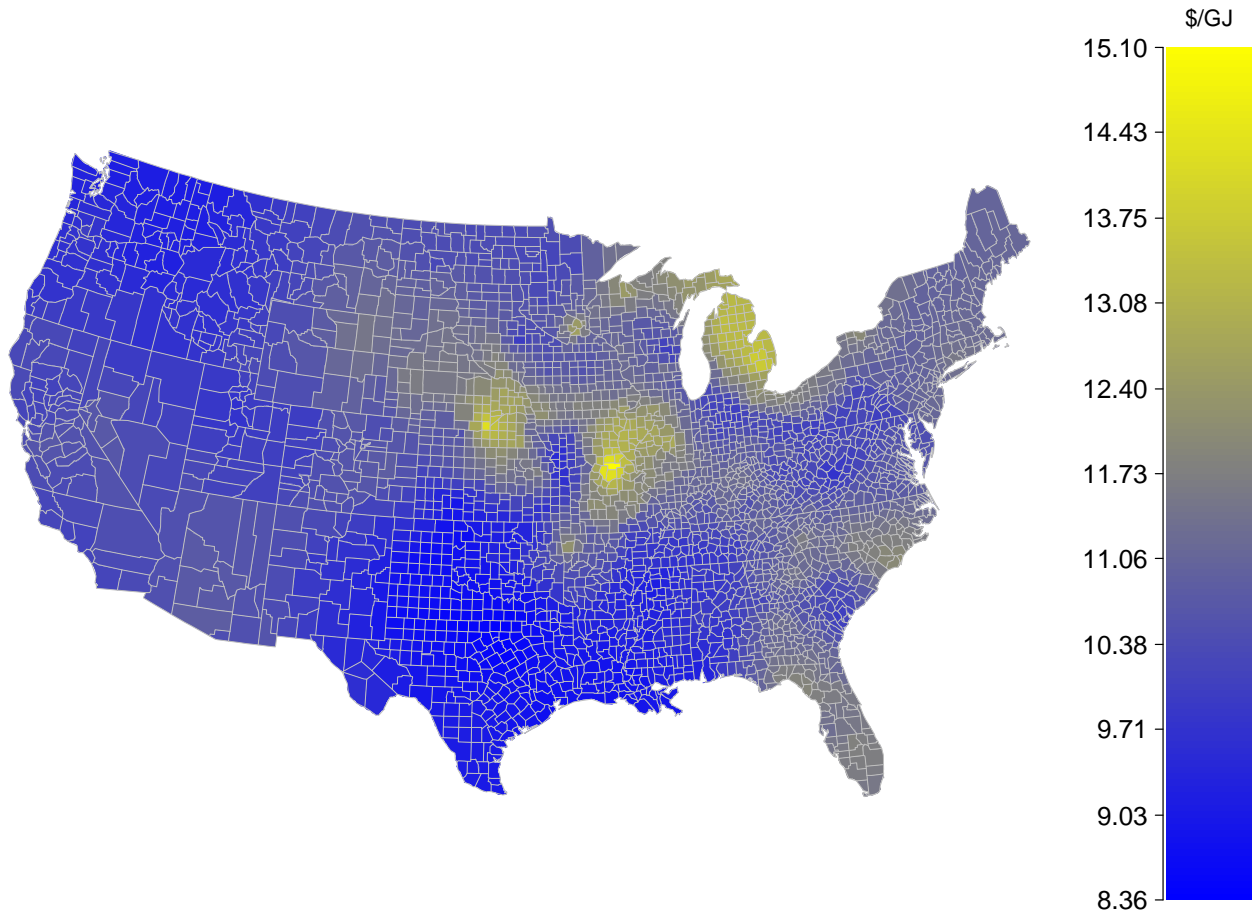
**FIGURE 27**

Natural gas low price case fuel price map with a US average cost of about \$3.16/GJ (\$3/MMBtu) with geographic interpolation as described in the methods section.



**FIGURE 28**

Natural gas high price case fuel price map with a US average cost of about \$7.39/GJ (\$7/MMBtu) with geographic interpolation as described in the methods section.



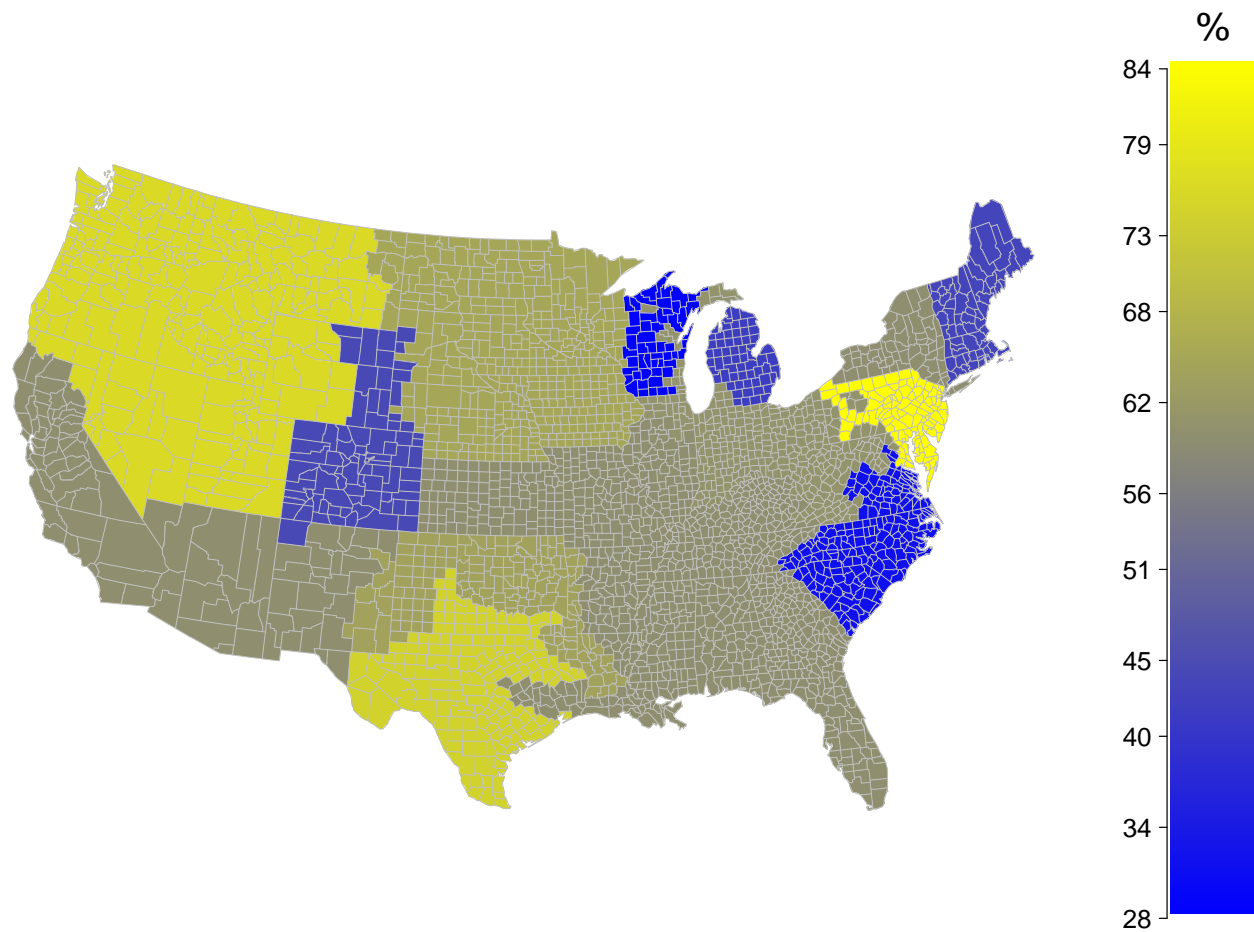
## TECHNOLOGY CAPACITY FACTOR MAPS

Figures 29 - 36 show the capacity factor values used in our analysis for all technology types. The capacity factors were developed as explained in the methods section, using

average historical values.<sup>5</sup> Note that while the color scale looks the same for each technology the relative values (min/max) are different.

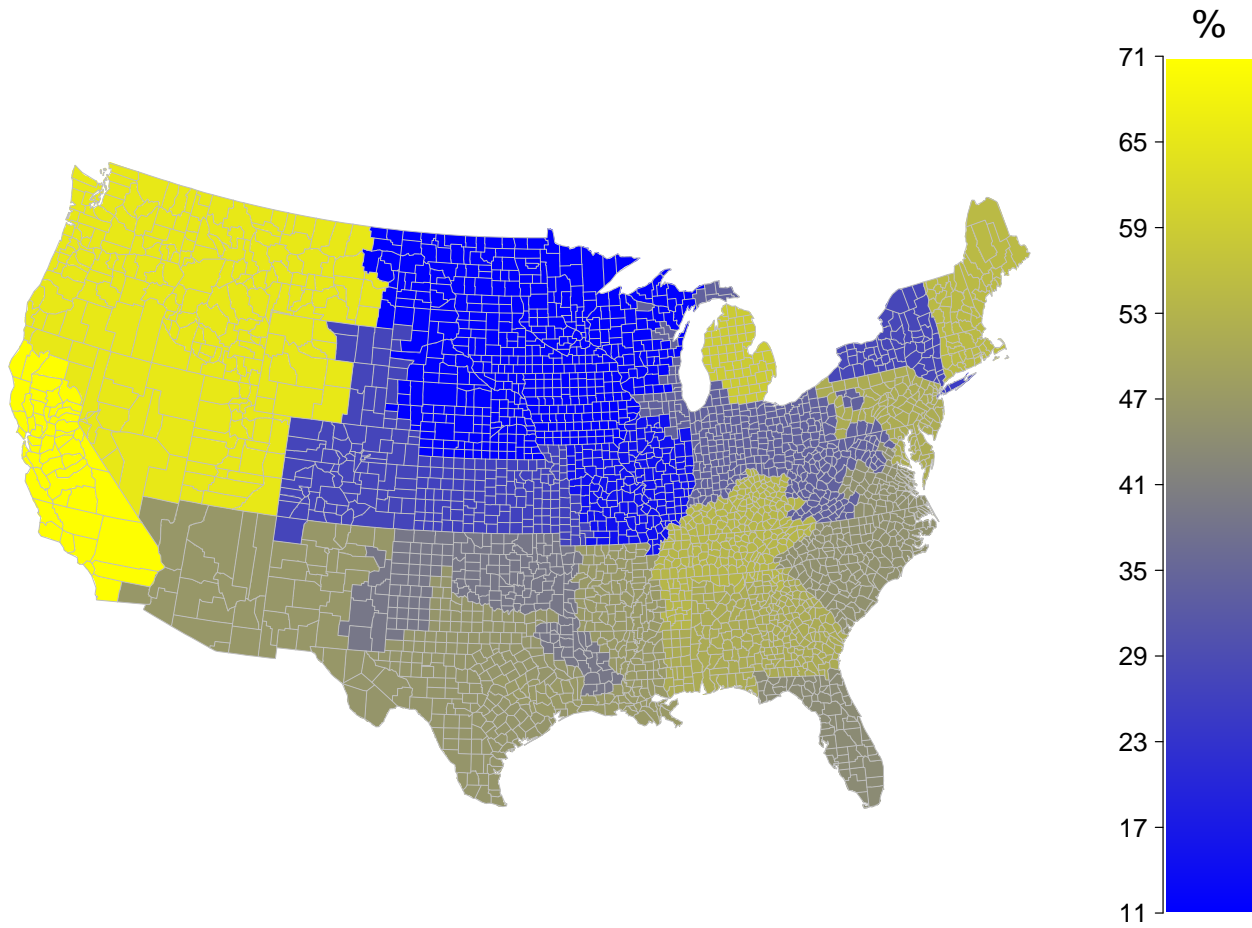
**FIGURE 29**

Coal capacity factor (%), based on historical data.



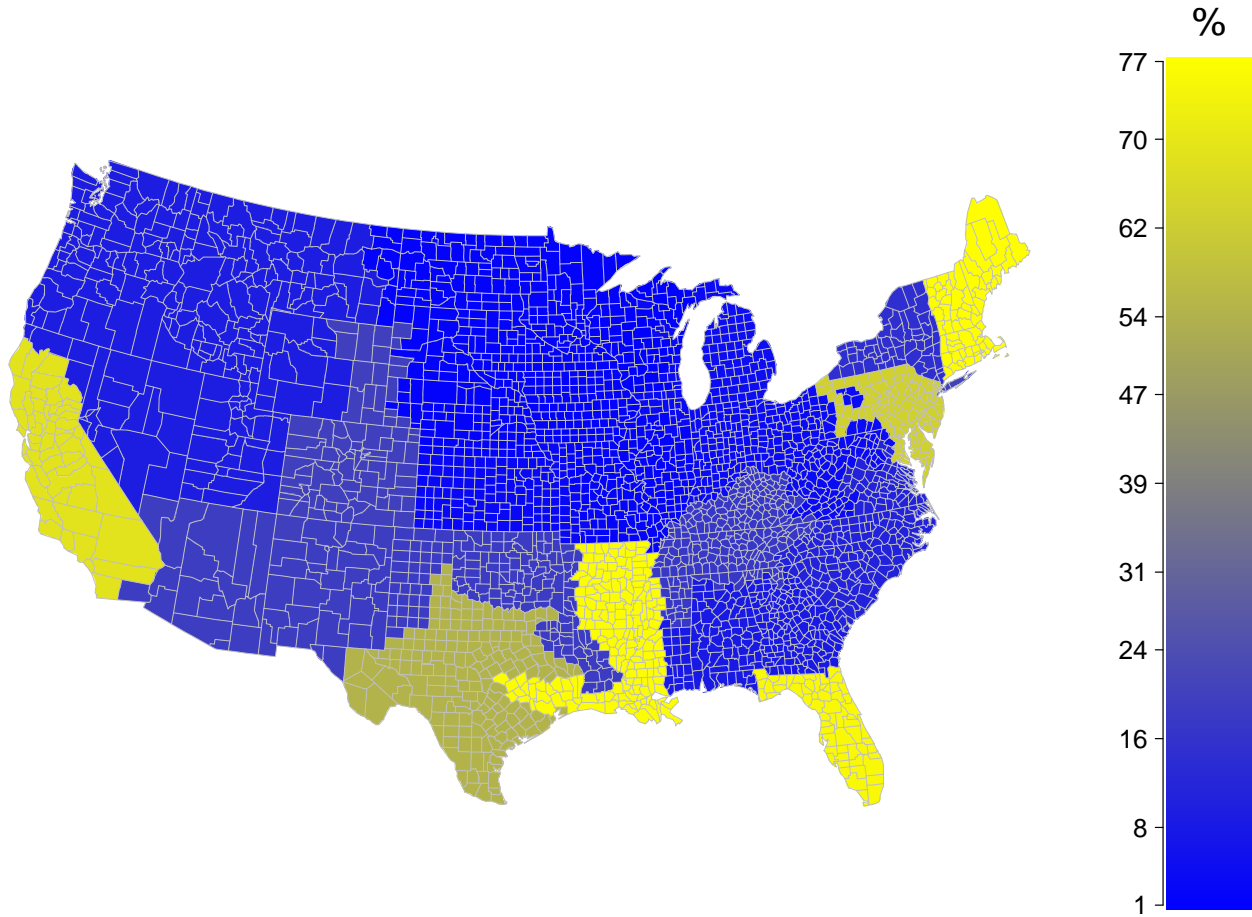
**FIGURE 30**

NGCC capacity factor (%), based on historical data.



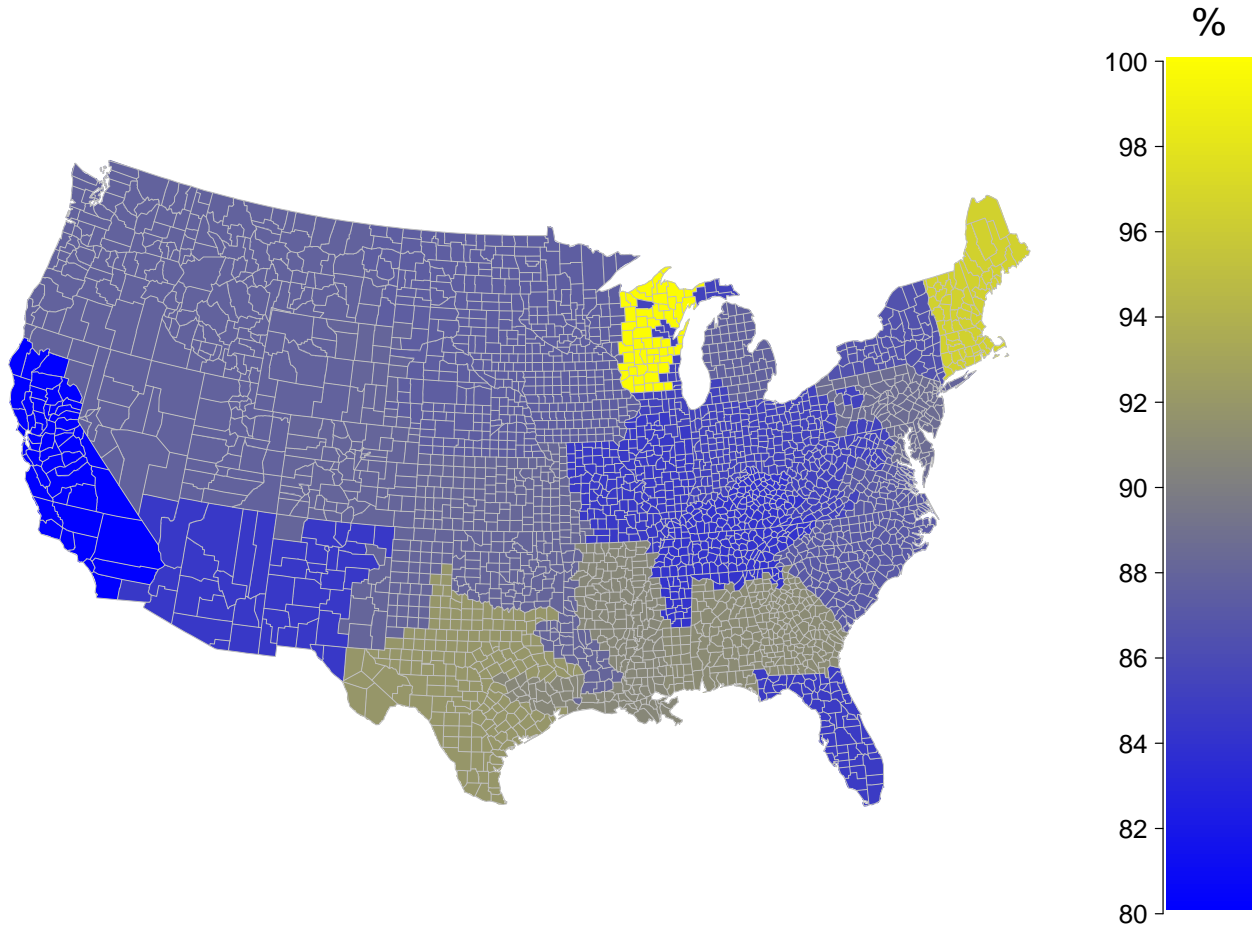
**FIGURE 31**

NGCT capacity factor (%), based on historical data.



**FIGURE 32**

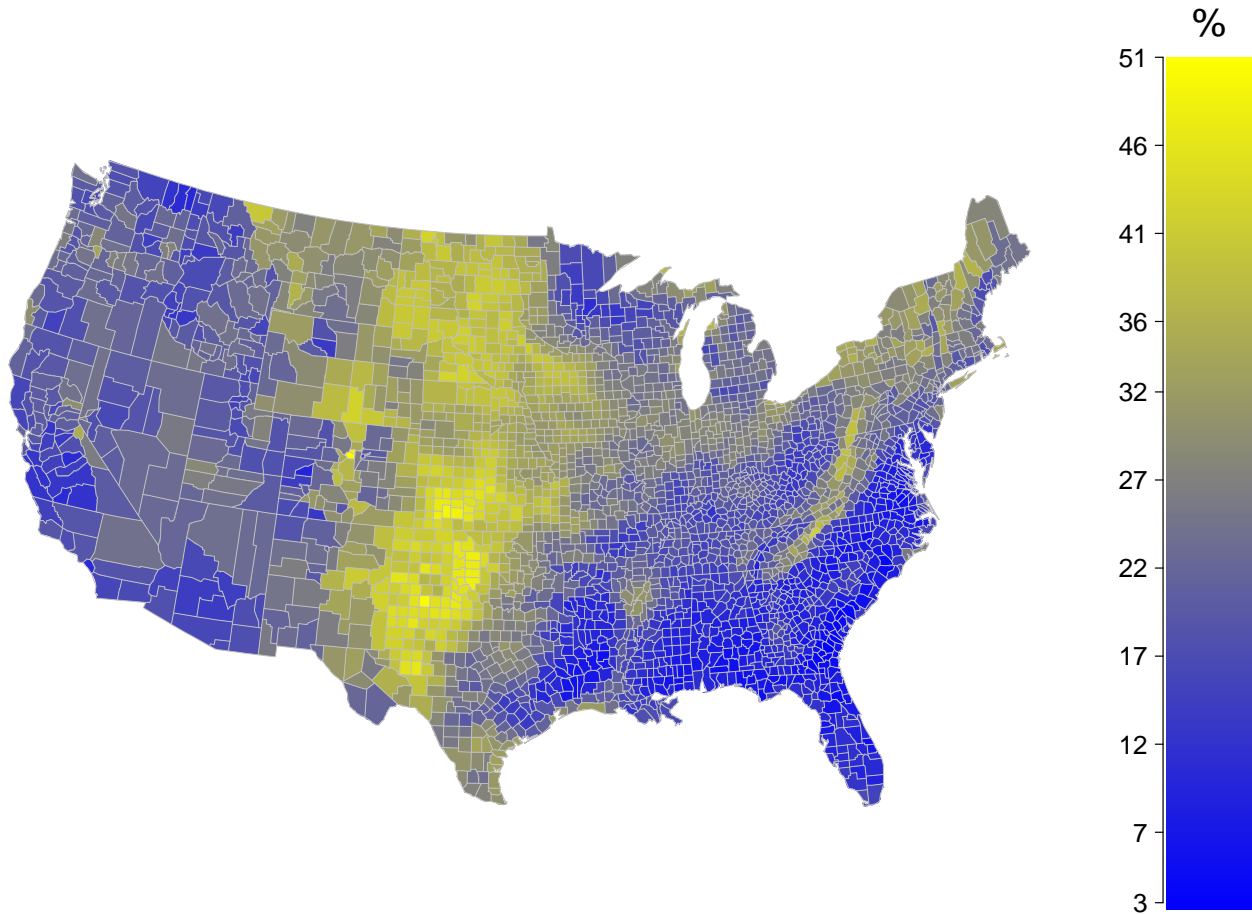
Nuclear capacity factor (%), based on historical data.





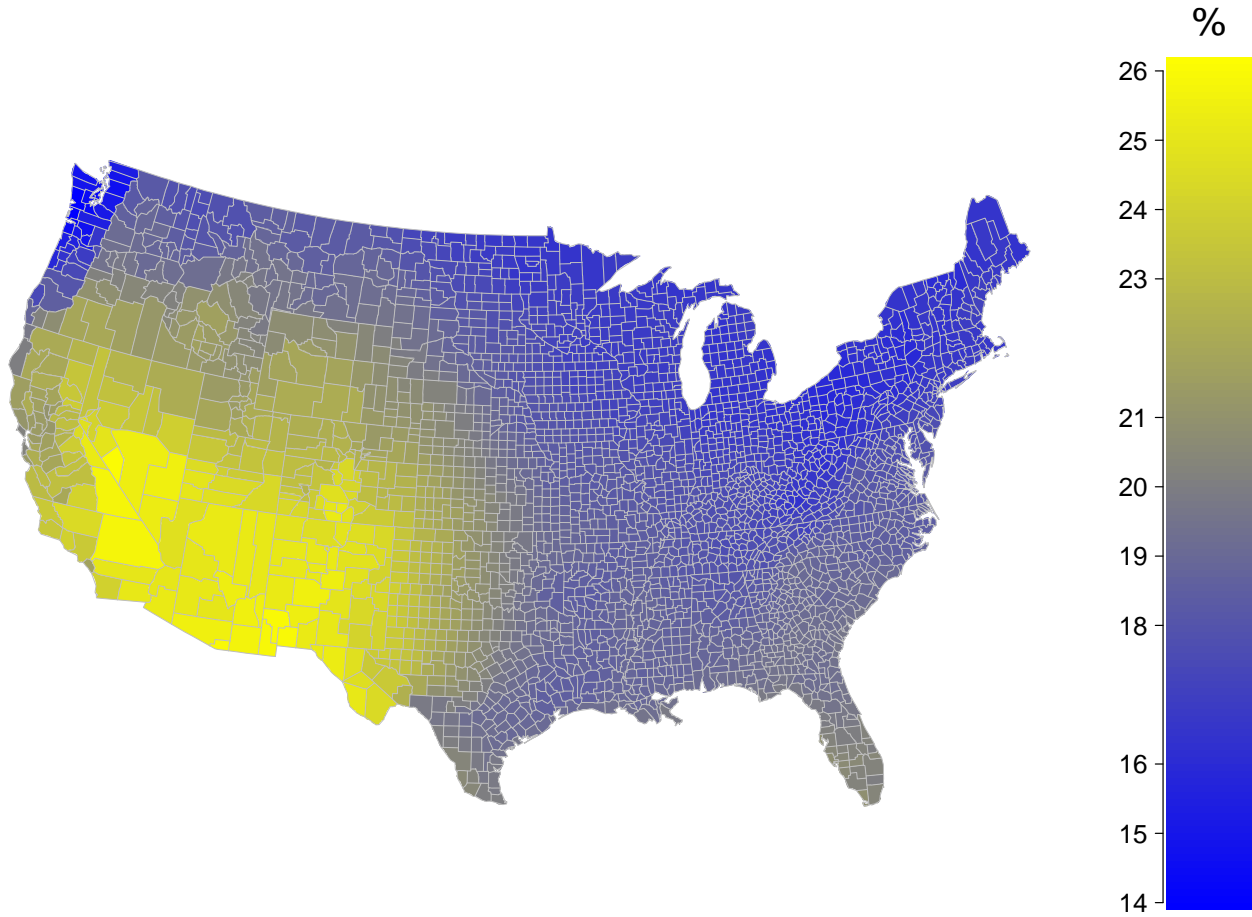
**FIGURE 33**

Wind capacity factor (%), based on prevalent meteorological conditions for an 80 meter wind turbine hub height.



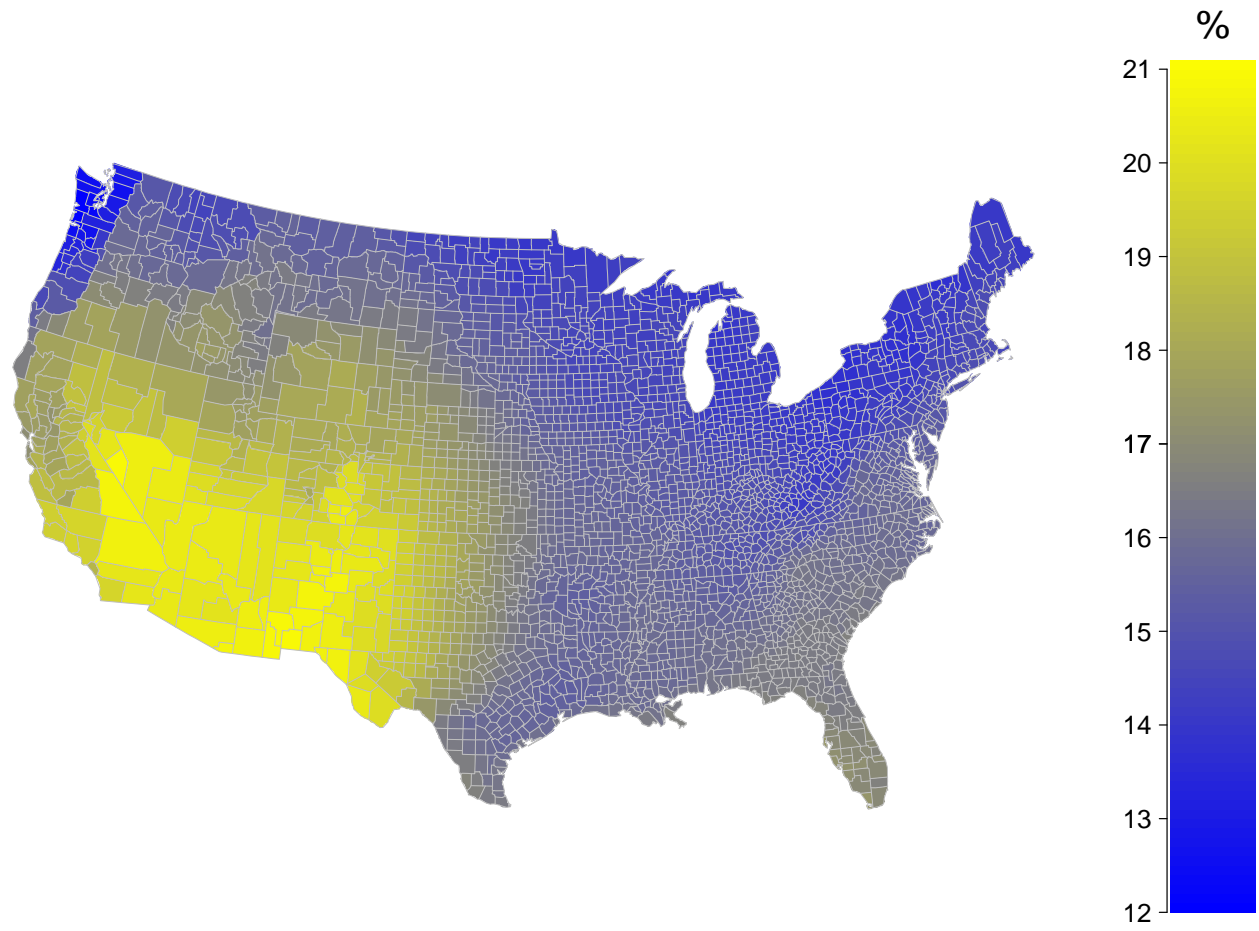
**FIGURE 34**

Utility PV (single-axis tracking) capacity factor (%), based on prevalent meteorological conditions.



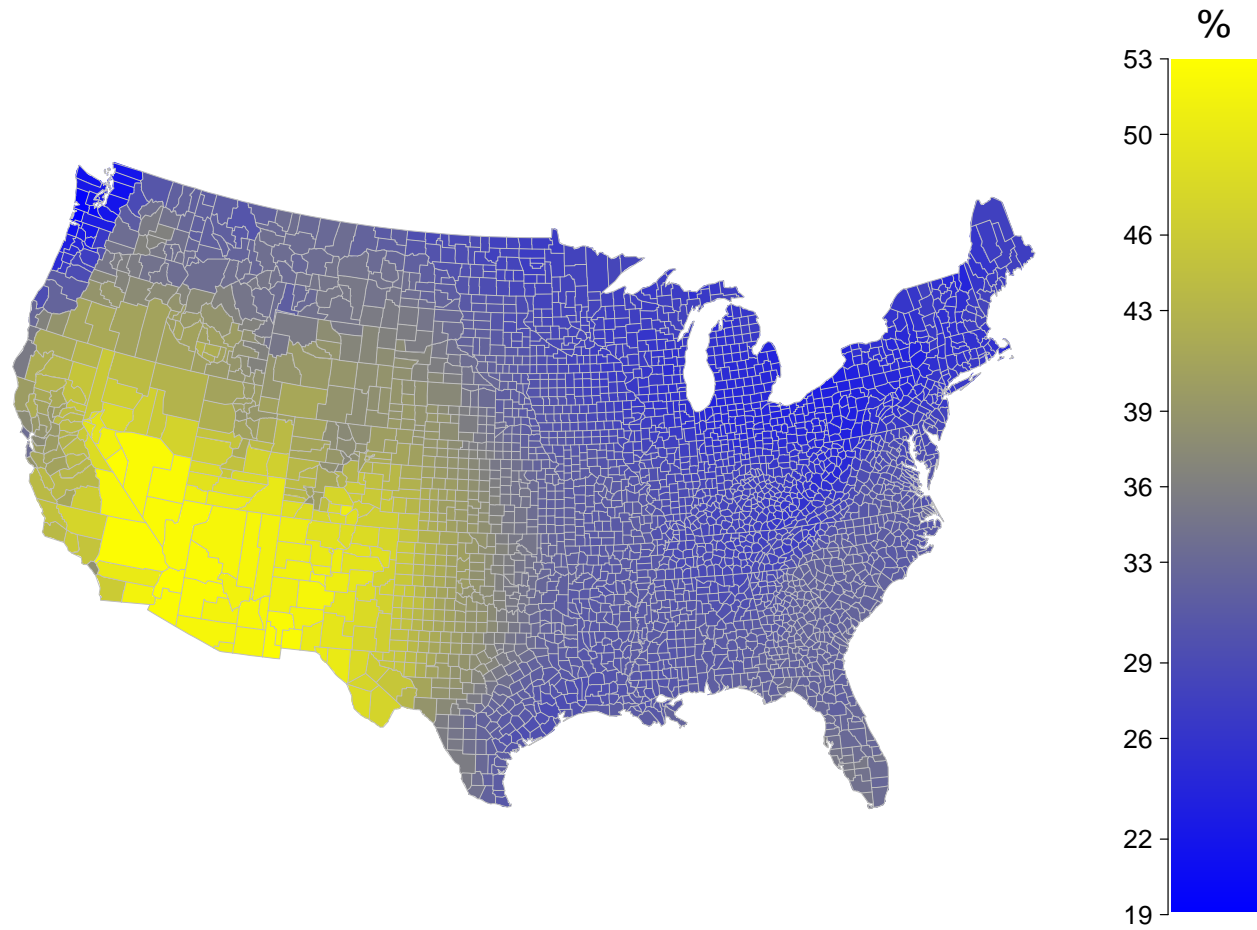
**FIGURE 35**

Residential PV (south-facing fixed axis at 25° tilt) capacity factor (%), based on prevalent meteorological conditions.



**FIGURE 36**

Solar CSP (with 6 hours of thermal storage) capacity factor (%), based on prevalent meteorological conditions.



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