# A geographically resolved method to estimate levelized power plant costs with environmental externalities – SUPPLEMENTARY INFORMATION

Joshua D. Rhodes[a,c,*], Carey King[c,*], Gürcan Gulen[d], Sheila M. Olmstead[e], James S. Dyer[e], Robert E. Hebner[1], Fred C. Beach[c], Thomas F. Edgar[c], Michael E. Webber[a,c,**]

[a] *Department of Mechanical Engineering, The University of Texas at Austin, 204 E. Dean Keeton Street, Stop C2200, Austin, Texas 78712-1591*

[b] *Department of Civil, Architectural and Environmental Engineering, The University of Texas at Austin, 301 E Dean Keeton St. Stop C1752, Austin, TX 78712-1094*

[c] *Energy Institute – The University of Texas at Austin, 2304 Whitis Ave Stop C2400 Austin TX 78712-1718*

[d] *Bureau of Economic Geology, Center for Energy Economics, The University of Texas at Austin, Austin, TX*

[e] *McCombs School of Business, The University of Texas at Austin, Austin, TX*

[f] *Center for Electromechanics, The University of Texas at Austin, Austin, TX*

[g] *Chemical Engineering, The University of Texas at Austin, Austin, TX*

## 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 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/t$CO_2$ for $CO_2$ emissions natural

*Corresponding author

**Principal corresponding author

*Email addresses:* joshdr@utexas.edu (Joshua D. Rhodes), careyking@energy.utexas.edu (Carey King), webber@mail.utexas.edu (Michael E. Webber)

gas combined cycle, wind, and nuclear are most often the lowest-LCOE option. While the average cost increases when 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 display format, and online tools 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.

*Keywords:*
LCOE, power plants, regional/spatial data, externalities, $CO_2$, methane leakage

## 1. Further scenarios and minimum cost maps

This section presents Scenarios 4-10 as mentioned earlier in the main body of the paper. Figure 5 shows the minimum cost technology per county when availability zones are considered, but externalities are given a price of zero.

Figure 5 (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 4, 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.

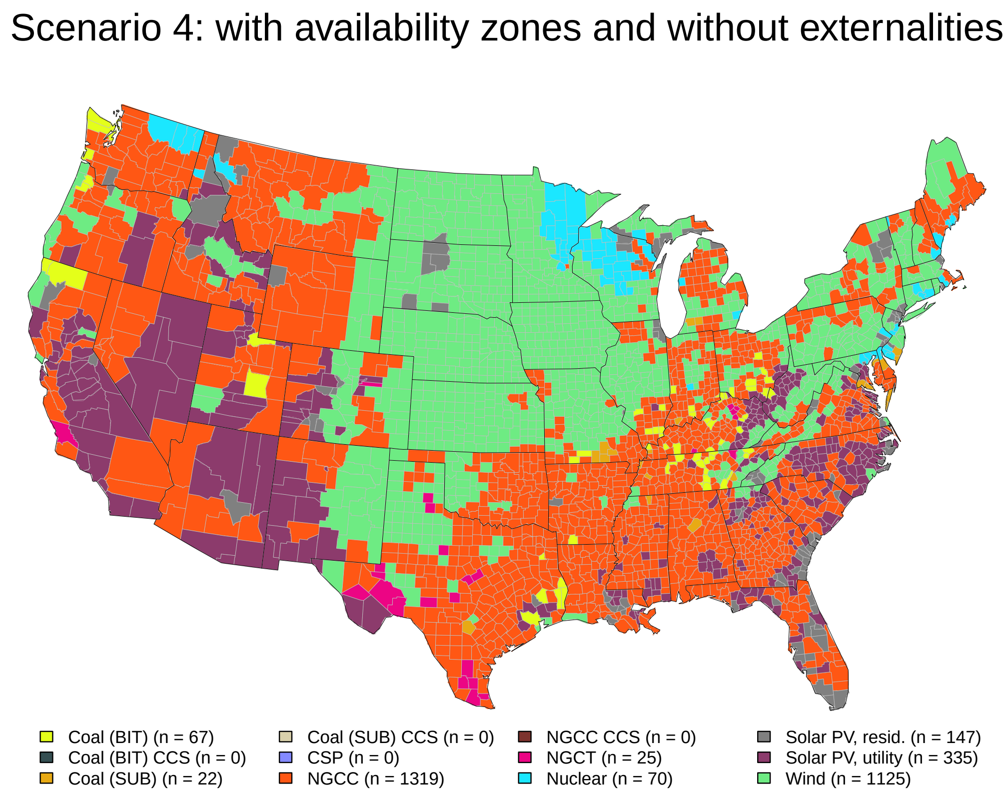


Figure 5: Scenario 4: Minimum cost technology for each county, including availability zones, but not including externalities (Equation 1) with reference case assumptions from Table 1.

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 $CO_2$) are for additional marginal emissions from a new plant with Best Available Commercial Technology [1]. 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 [2]), 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 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 7 (Scenario 5), we see the effect of lower (\$3/MMBtu, Figure 39) and in Figure 6 (Scenario 6), we see the effect of higher (\$7/MMBtu, Figure 40) 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.

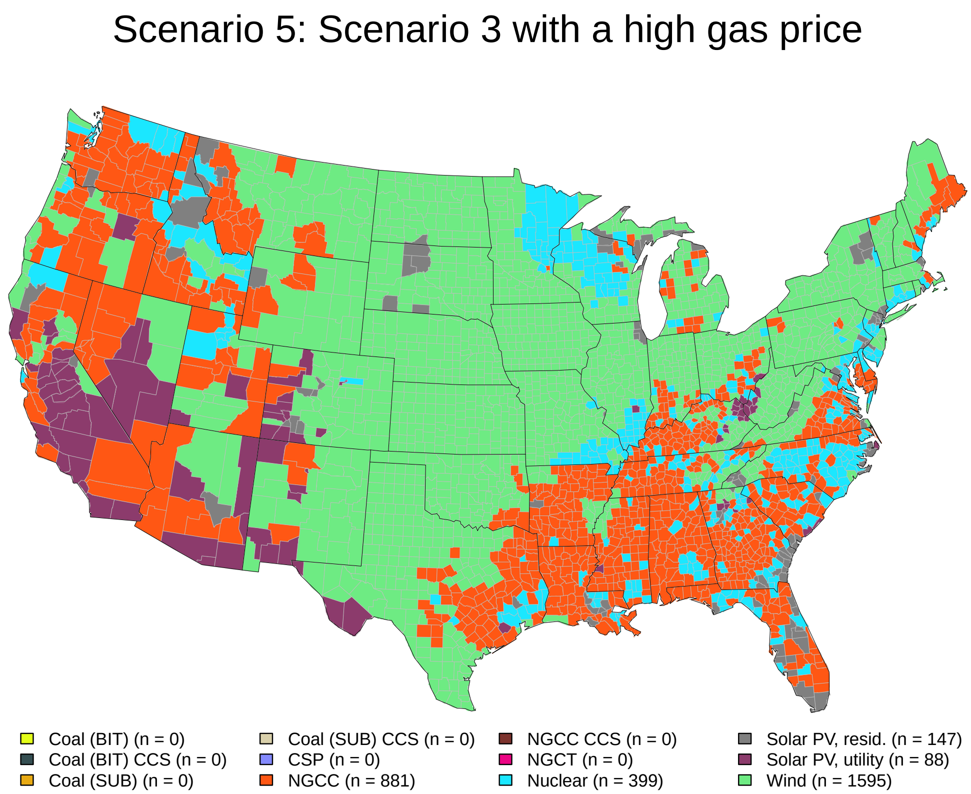


Figure 6: Scenario 5: Minimum cost technology for each county, including externalities (Equation 4) and availability zones with reference case assumptions from Tables 1–3 with a high natural gas price (US average of \$7/MMBtu, Figure 40).

In comparison to Scenario 3 (Figure 4), 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

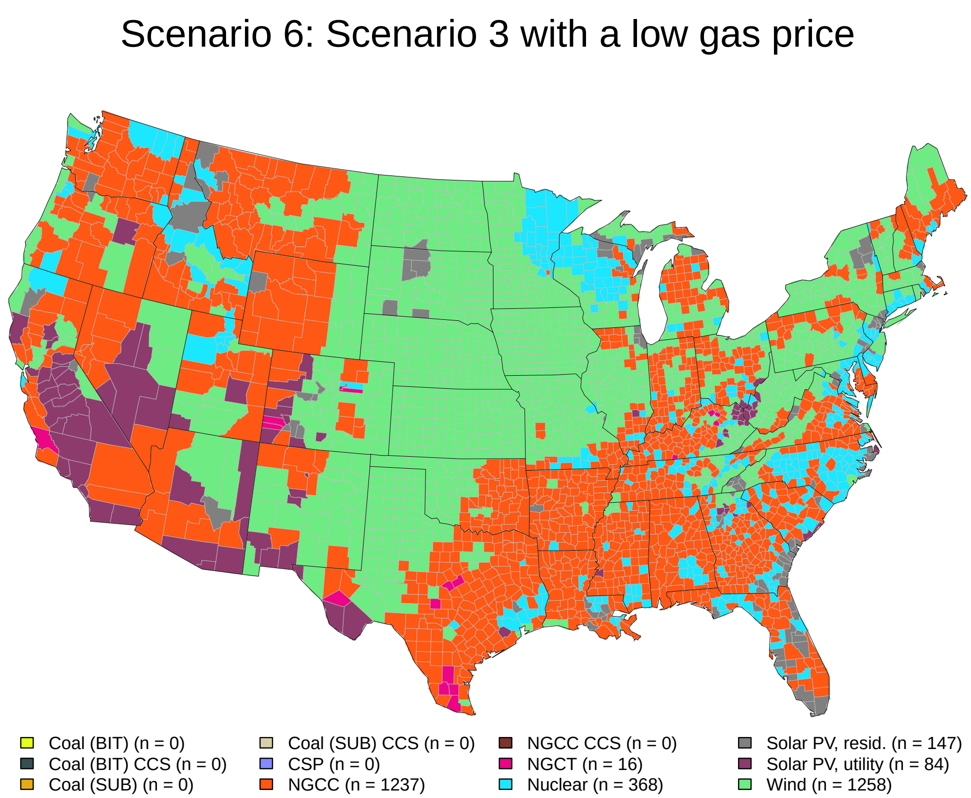


Figure 7: Scenario 6: Minimum cost technology for each county, including externalities (Equation 4) and availability zones with reference case assumptions from Tables 1–3 with a low natural gas price (US average of \$3/MMBtu, Figure 39).

prices are lower, NGCC becomes the low-cost option for many counties in which wind is the low-cost option in Scenario 3. We also examined the effect of a lower (Scenario 7) and higher (Scenario 8) $CO_2$ price in Figures 8 and 9.

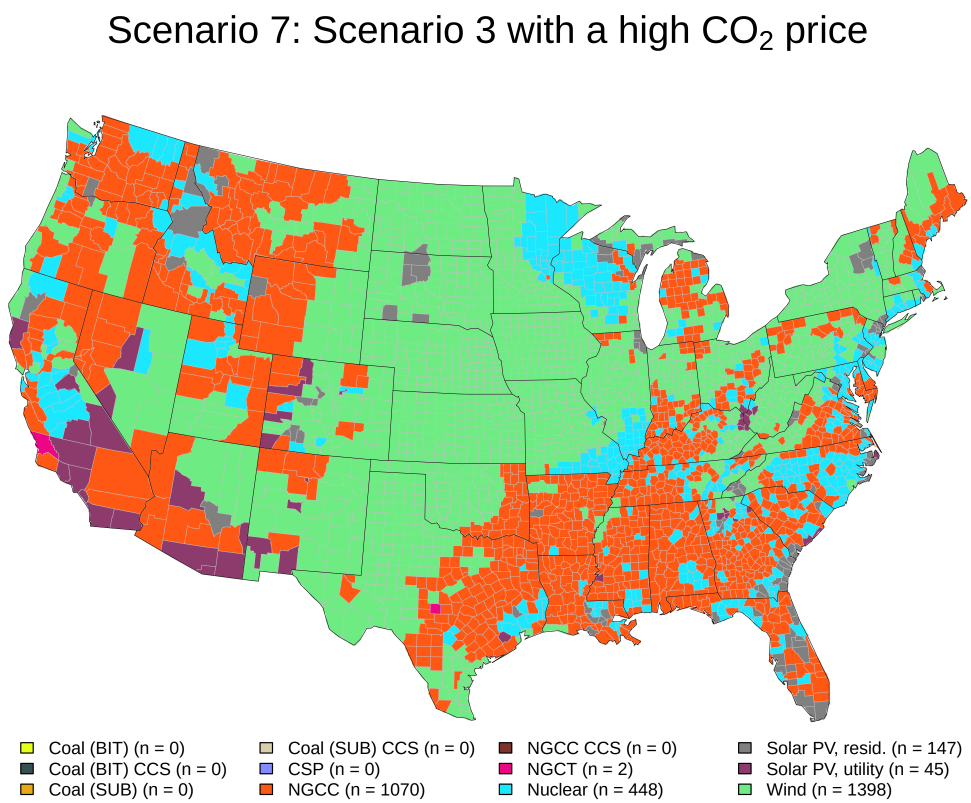


Figure 8: Scenario 7: Minimum cost technology for each county, including externalities (Equation 4) and availability zones with reference case assumptions from Tables 1–3 with a high price on all forms of $CO_2$ (Table 3).

The values of $CO_2$ 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 $CO_2$ prices (Figure 8); wind, nuclear, and coal CCS

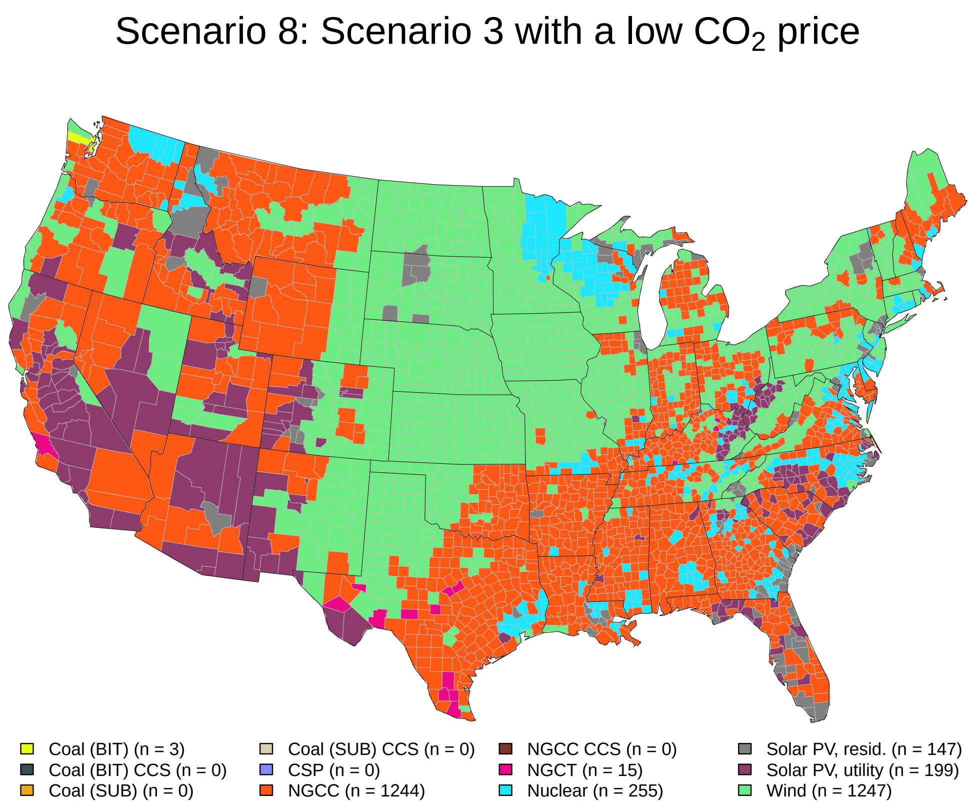


Figure 9: Scenario 8: Minimum cost technology for each county, including externalities (Equation 4) and availability zones with reference case assumptions from Tables 1–3 with a low price on all forms of $CO_2$ (Table 3).

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 $CO_2$ prices (Figure 9), the opposite happens.

In scenario 9 (Figure 10), 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 [3].

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. 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 11).

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

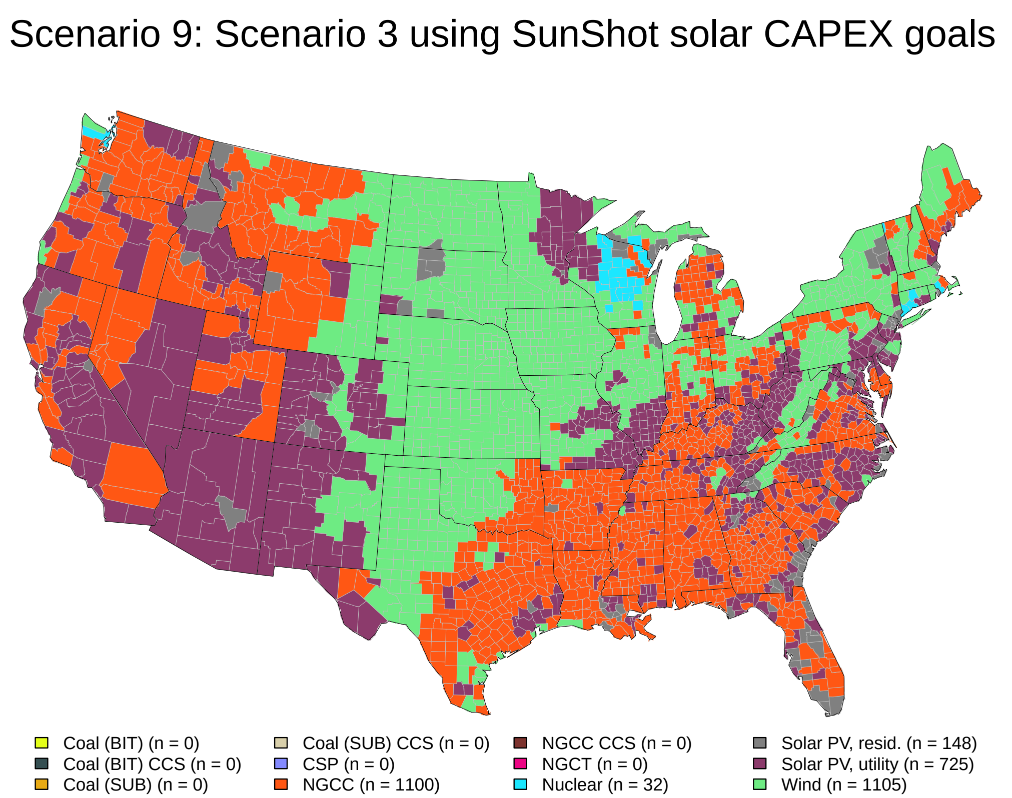


Figure 10: Scenario 9: Minimum cost technology for each county, including externalities (Equation 4) and availability zones with reference case assumptions from Tables 1–3 with a lower installed cost: \$1/W for utility-scale solar PV and \$1.5/W for residential PV.

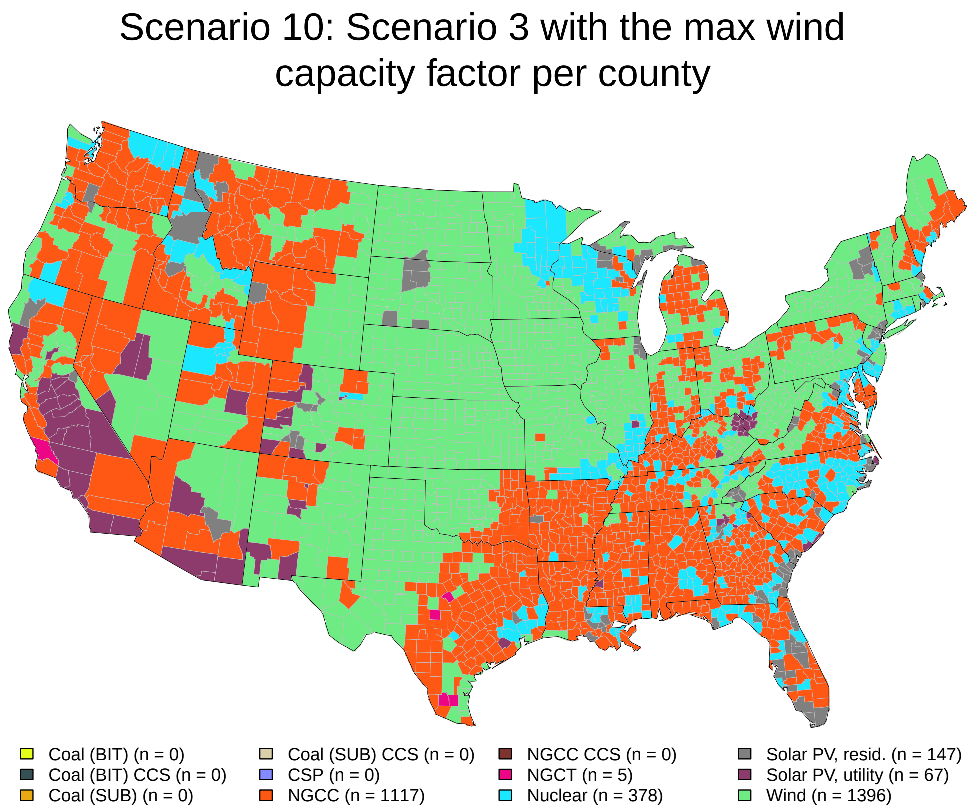


Figure 11: Scenario 10: Minimum cost technology for each county, including externalities (Equation 4) and availability zones with reference case assumptions from Tables 1–3 using the maximum capacity factor in each county for onshore wind.

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.

## 2. Tables of the minimum cost county/technology combination

Tables 1 – 10 provide summaries of the lowest cost county/technology combination for each of the 22 NERC subregions. Note that these values do not include the costs for transmission expansions/upgrades that might be required to connect the selected location/asset to the bulk grid.

## 3. 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 Angles 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 12 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 26, 36, and 41, respectfully.

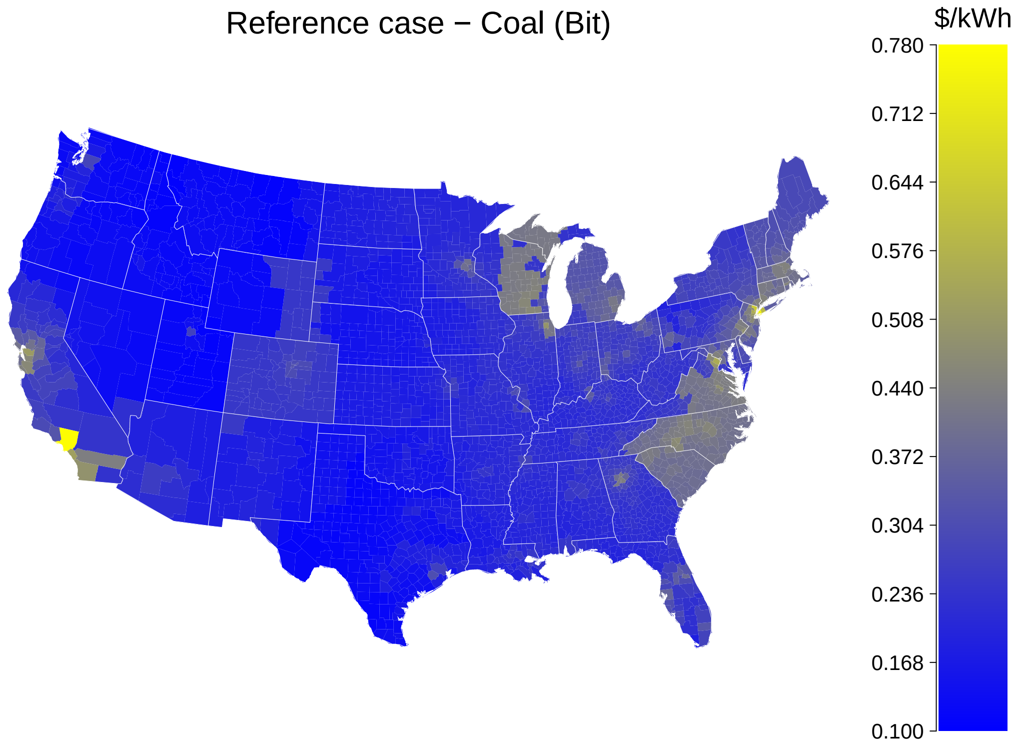


Figure 12: LCOE map for bituminous coal fired electricity generation units showing the regional differences for reference conditions (Equation 4), average: \$0.195/kWh (median: \$0.185/kWh).

Some higher-cost areas, such as Atlanta, GA, Chicago, IL, and Houston, TX can be seen in Figure 12, these areas appear more yellow than blue (or lighter) because of the larger emissions costs than the surrounding counties. Figure 13 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 26, 37, and 41, respectfully.

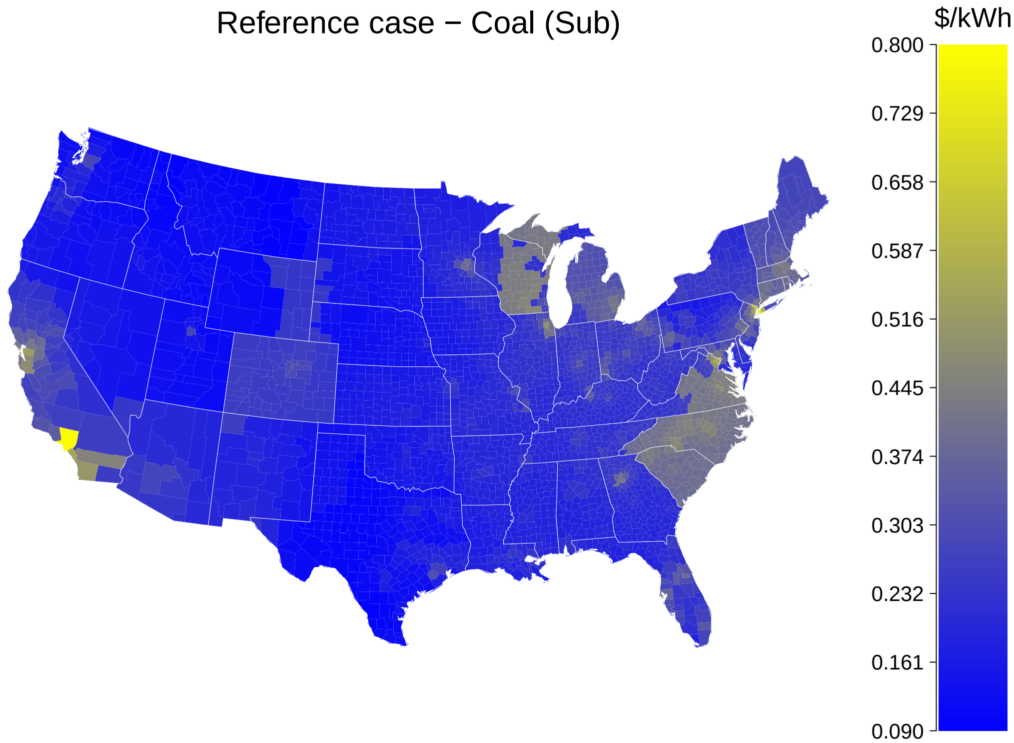


Figure 13: LCOE map for sub-bituminous coal fired electricity generation units showing the regional differences for reference conditions (Equation 4), average: \$0.193/kWh (median: \$0.181/kWh).

The only difference between Figures 12 and 13 are the price maps for different types of fuel, all other inputs, including emissions rates were assumed the same.

Figure 14 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 27, 36, and 41, respectfully.

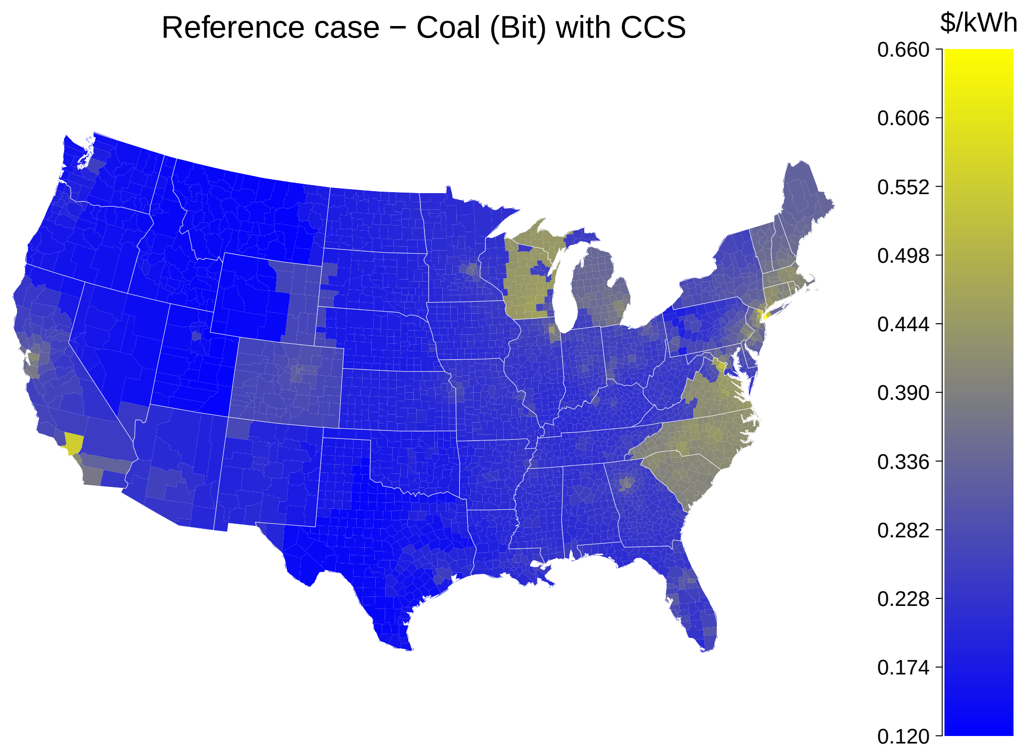


Figure 14: LCOE map for bituminous coal fired electricity generation units showing the regional differences for reference conditions (Equation 4), average: \$0.195/kWh (median: \$0.185/kWh).

Figure 15 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 27, 37, and 41, respectfully.

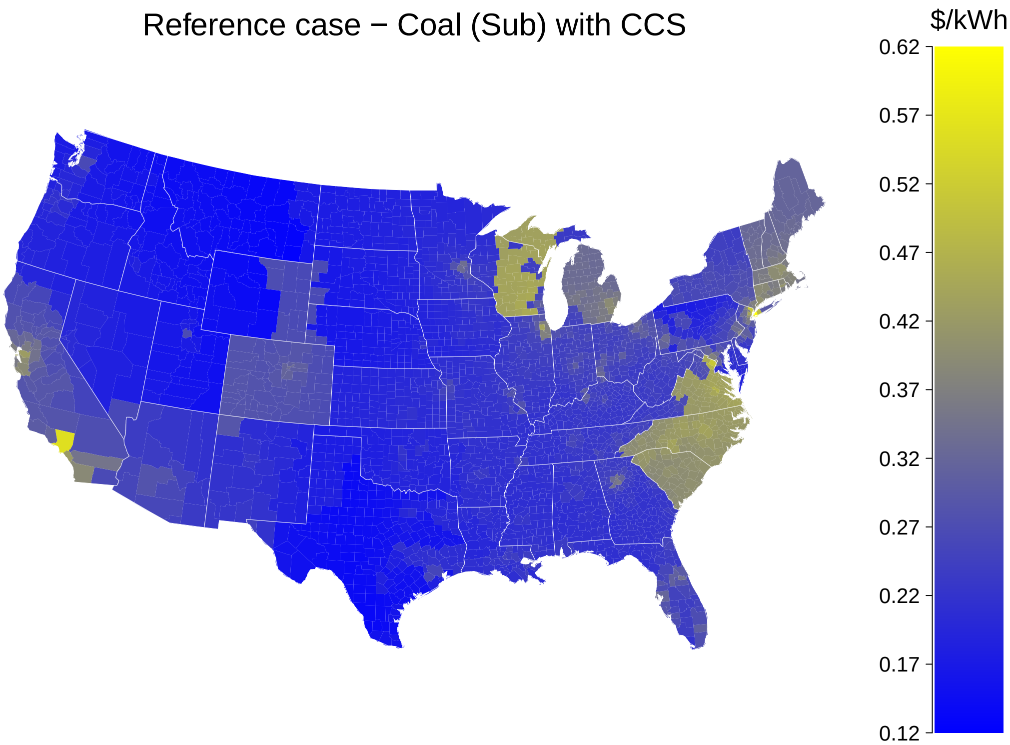


Figure 15: LCOE map for sub-bituminous coal fired electricity generation units showing the regional differences for reference conditions (Equation 4), average: \$0.195/kWh (median: \$0.185/kWh).

Figure 16 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 factors for NGCC generation units are shown in Figures 28, 38, and 42, respectfully.

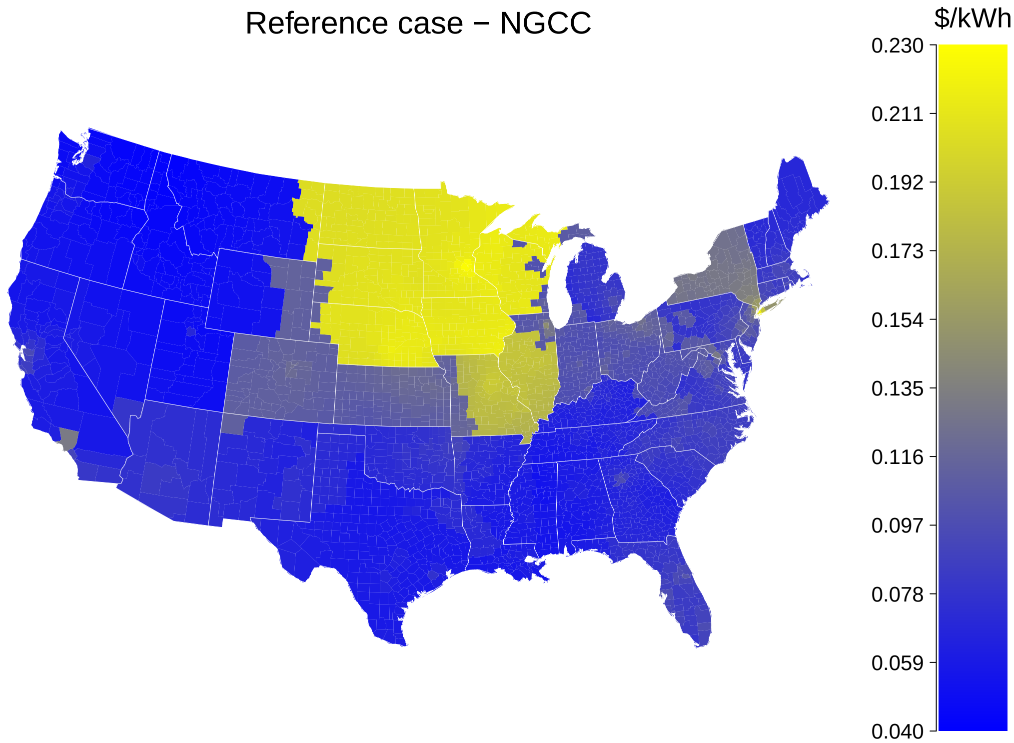


Figure 16: LCOE map for natural gas combined cycle electricity generation units showing the regional differences for reference conditions (Equation 4), average: \$0.111/kWh (median: \$0.096/kWh).

Figure 17 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 29, 38, and 42, respectfully.

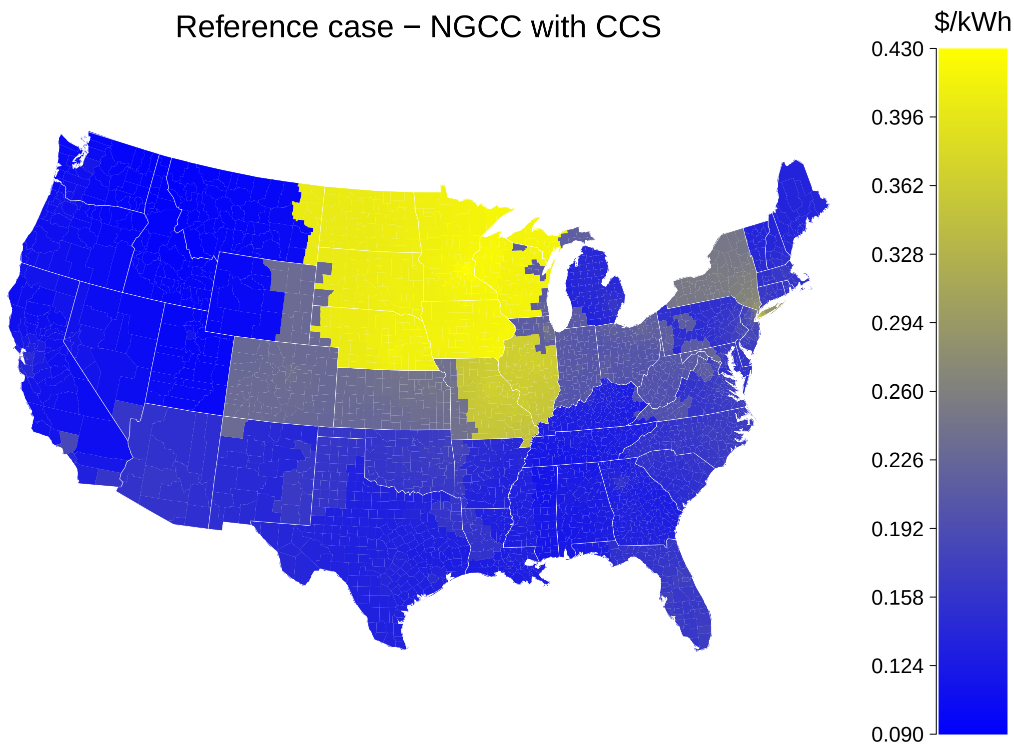


Figure 17: LCOE map for natural gas combined cycle electricity generation units with 90% carbon capture and sequestration showing the regional differences for reference conditions (Equation 4), average: \$0.111/kWh (median: \$0.096/kWh).

Figure 18 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 30, 38, and 43, respectfully.

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

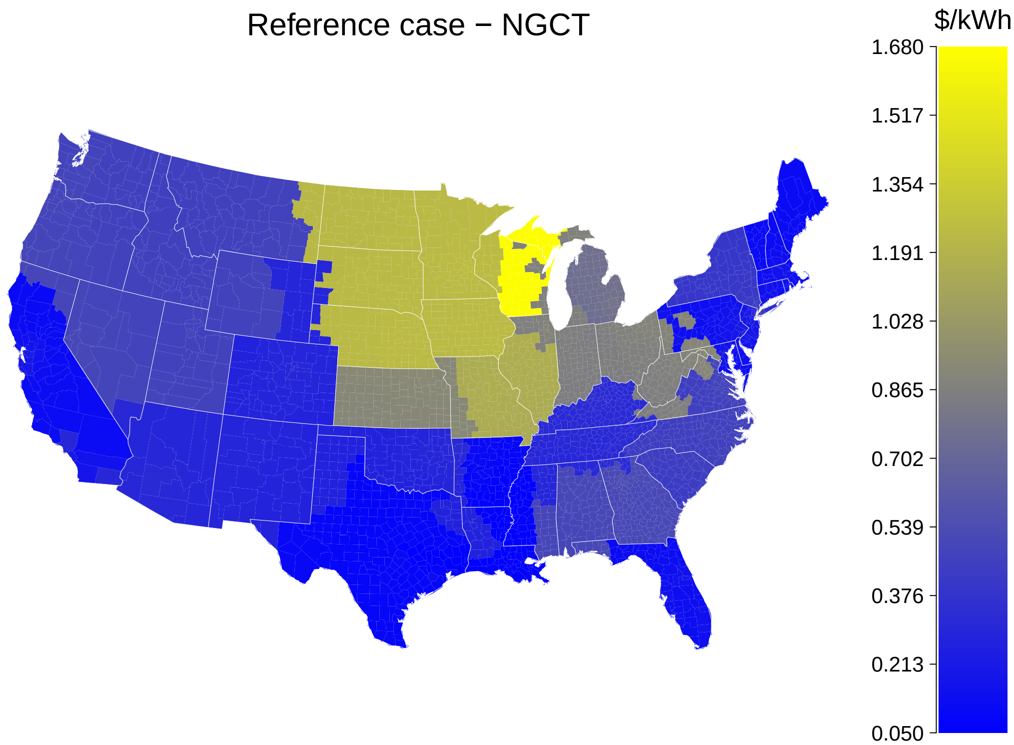


Figure 18: LCOE map for natural gas combustion turbine electricity generation units showing the regional differences for reference conditions (Equation 4), average: \$0.344/kWh (median: \$0.211/kWh).

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 19 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 shown in Figures 31 and 44, respectfully.

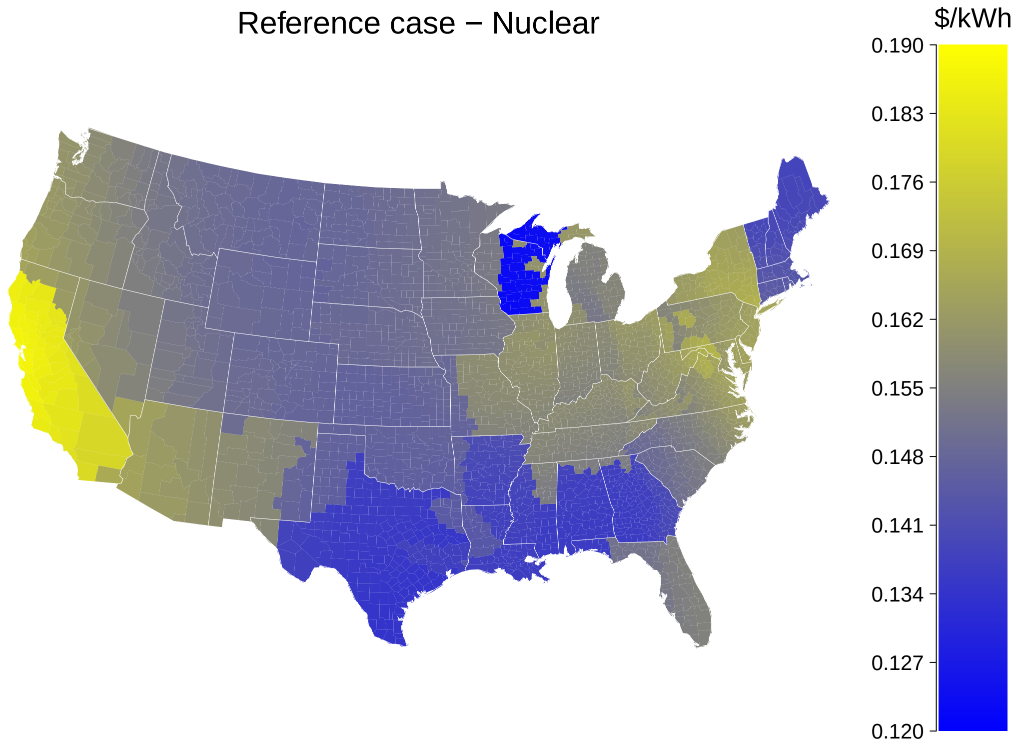


Figure 19: LCOE map for nuclear electricity generation units showing the regional differences for reference conditions (Equation 4), average: $0.124/kWh (median: $0.124/kWh).

Figure 20 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 32 and 45, respectfully.

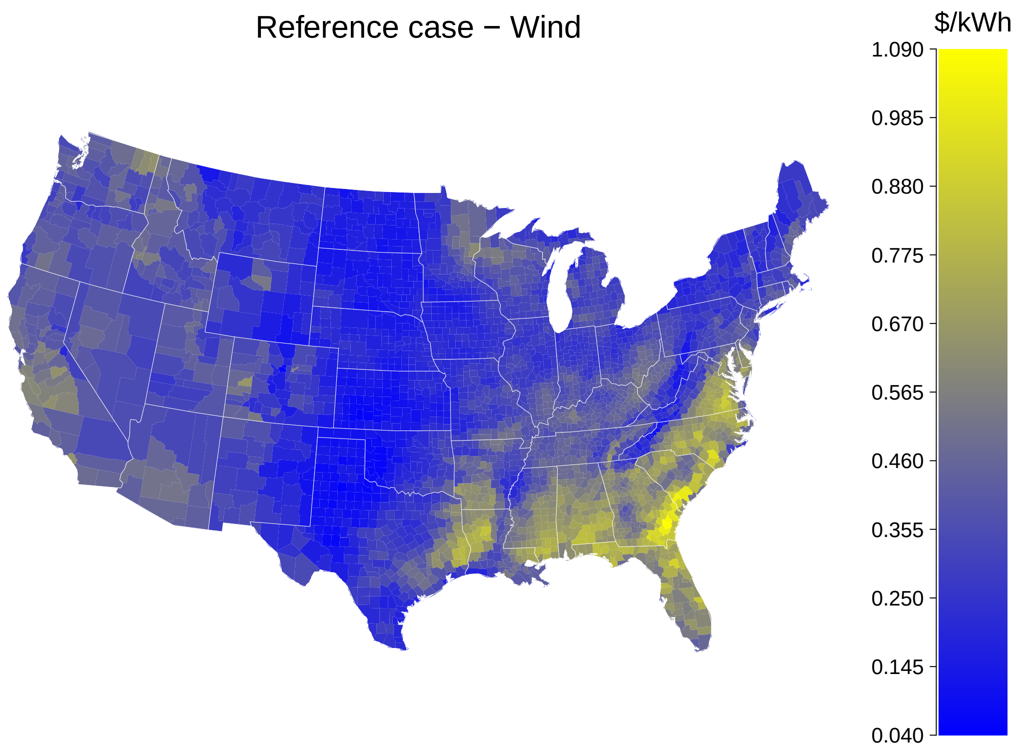


Figure 20: LCOE map for wind electricity generation units showing the regional differences for reference conditions (Equation 4), average: \$0.155/kWh (median: \$0.126/kWh).

Figure 21 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 33 and 46, respectfully.

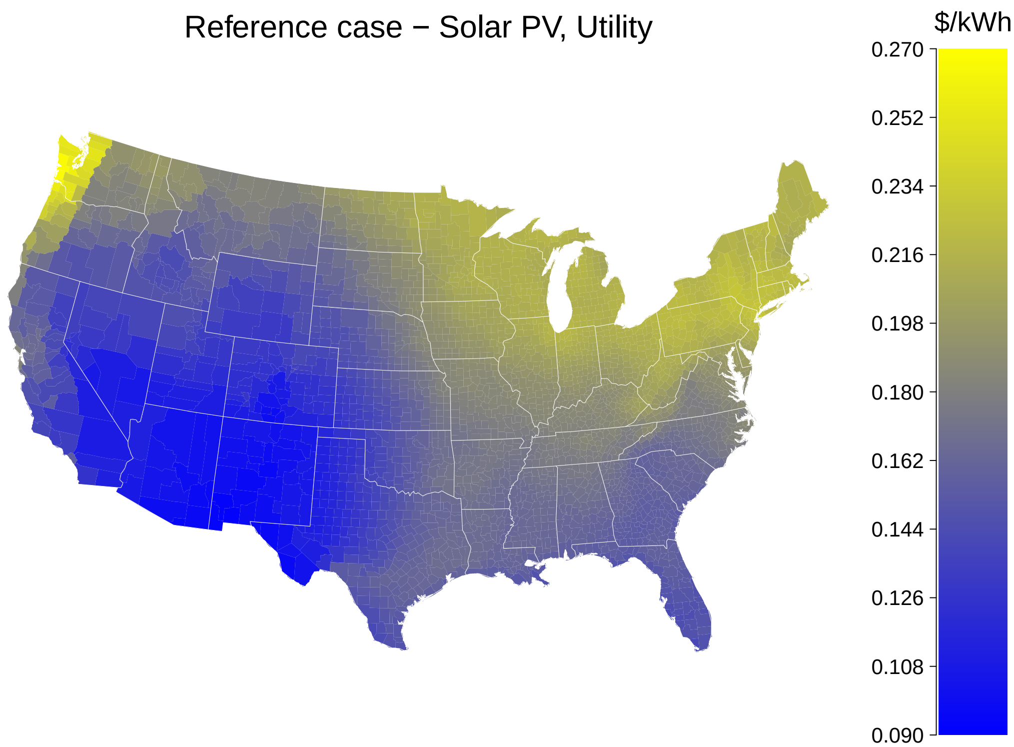


Figure 21: LCOE map for utility-scale PV electricity generation units showing the regional differences for reference conditions (Equation 4), average: \$0.199/kWh (median: \$0.197/kWh).

Figure 22 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 34 and 47, respectfully.

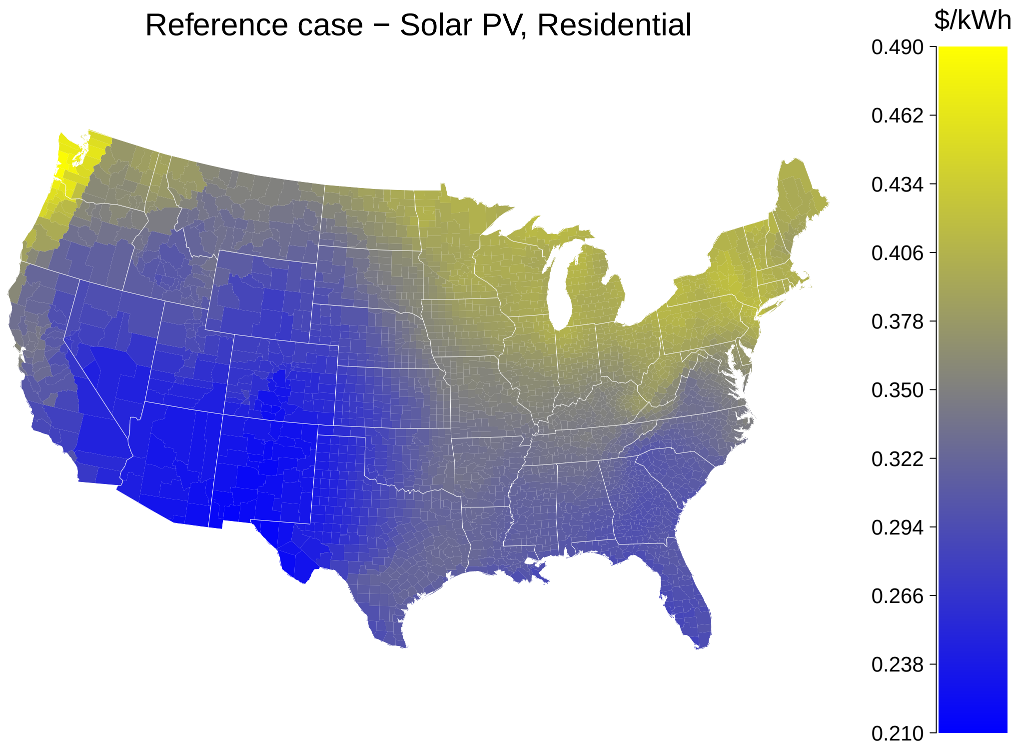


Figure 22: LCOE map for residential PV electricity generation units showing the regional differences for reference conditions (Equation 4), average: \$0.312/kWh (median: \$0.309/kWh).

Figure 23 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 35 and 48, respectfully.

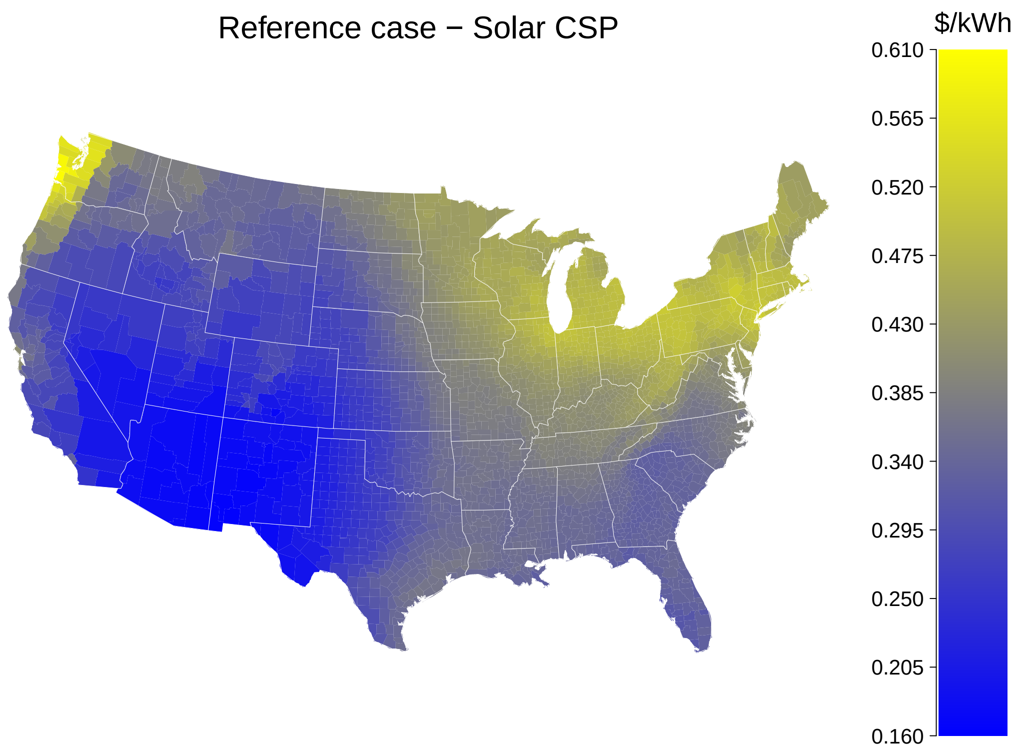


Figure 23: LCOE map for concentrating solar power electricity generation units with 6 hours of storage showing the regional differences for reference conditions (Equation 4), average: $0.29/kWh (median: $0.282/kWh).

## 4. 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 $CO_2$ pipelines. Detailed descriptions of the underlying analysis into the maps are in Mays, et al. [4]. Figure 24 show maps of available locations for all considered types of power plants.

Table 11 shows which Figures from Mays, et al. [4] 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.

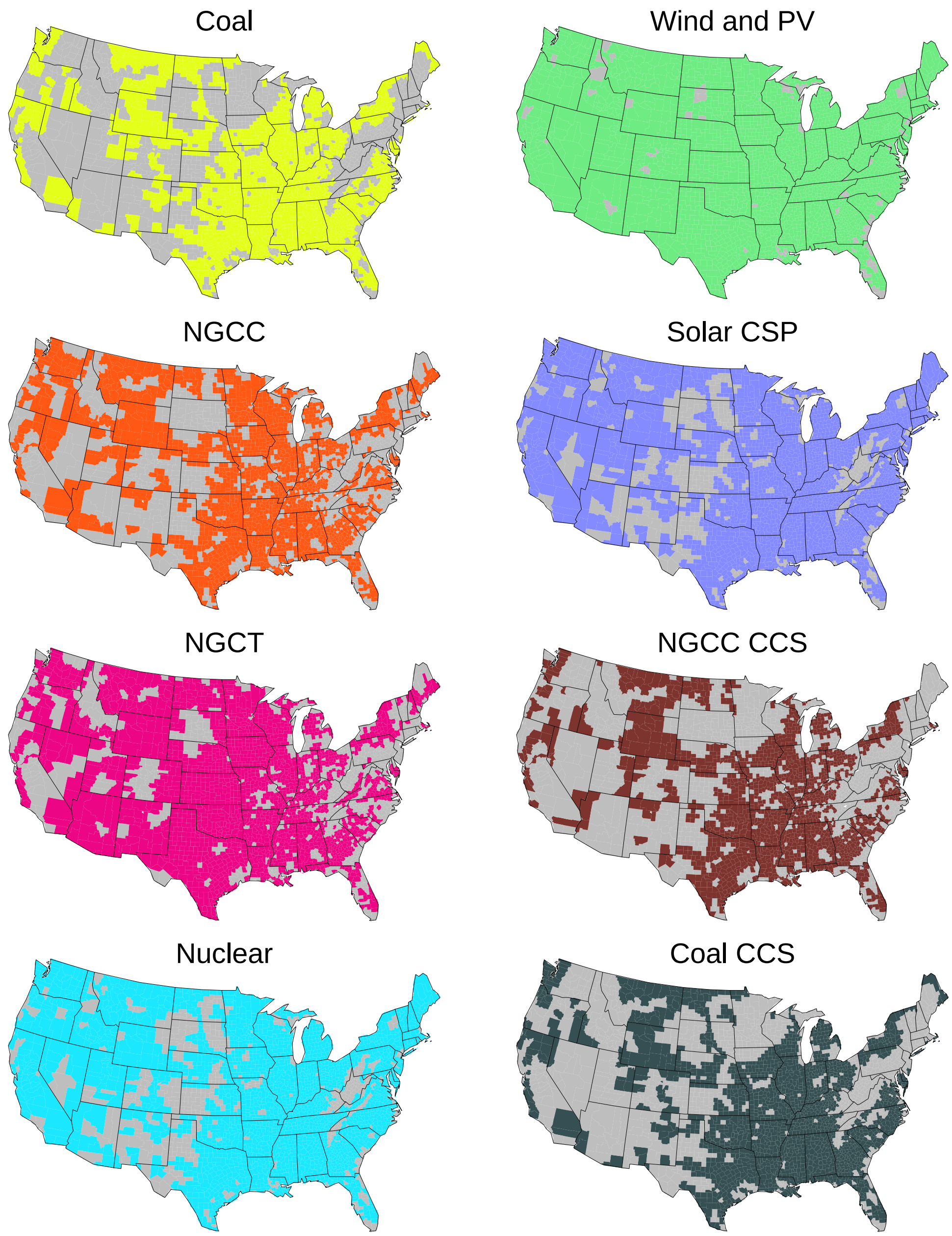


Figure 24: Map of availability zones for all technologies. Colors indicate where you *can* build the indicated power plant. Note that residential PV was assumed to be able to be built everywhere.

Table 1: Table of the county with minimum cost technology in each NERC subregion for Scenario 1.

| NERC Subregion | County | Technology | LCOE ($/kWh) |
|---|---|---|---|
| AZNM | Guadalupe County, NM | NGCC | 0.06 |
| CAMX | San Diego County, CA | NGCC | 0.06 |
| ERCT | Hill County, TX | NGCC | 0.06 |
| FRCC | Jackson County, FL | NGCC | 0.07 |
| MROE | Door County, WI | Wind | 0.08 |
| MROW | Todd County, SD | Wind | 0.07 |
| NEWE | Grand Isle County, VT | NGCC | 0.06 |
| NWPP | Lincoln County, MT | NGCC | 0.05 |
| NYCW | Bronx County, NY | NGCC | 0.07 |
| NYLI | Suffolk County, NY | Wind | 0.09 |
| NYUP | Wyoming County, NY | Wind | 0.08 |
| RFCE | Fayette County, PA | NGCC | 0.06 |
| RFCM | Branch County, MI | NGCC | 0.06 |
| RFCW | Tucker County, WV | Wind | 0.07 |
| RMPA | Clear Creek County, CO | Wind | 0.06 |
| SPNO | Gray County, KS | Wind | 0.06 |
| SPSO | Floyd County, TX | Wind | 0.05 |
| SRCE | Lafayette County, MS | NGCC | 0.06 |
| SRDA | Bell County, TX | NGCC | 0.06 |
| SRGW | Polk County, MO | Wind | 0.09 |
| SRSE | Jackson County, MS | NGCC | 0.06 |
| SRVC | Avery County, NC | Wind | 0.06 |

Table 2: Table of the county with minimum cost technology in each NERC subregion for Scenario 2.

| NERC Subregion | County | Technology | LCOE ($/kWh) |
|---|---|---|---|
| AZNM | Guadalupe County, NM | Wind | 0.08 |
| CAMX | Shasta County, CA | NGCC | 0.09 |
| ERCT | Reagan County, TX | Wind | 0.07 |
| FRCC | Gulf County, FL | NGCC | 0.10 |
| MROE | Door County, WI | Wind | 0.08 |
| MROW | Todd County, SD | Wind | 0.07 |
| NEWE | Dukes County, MA | Wind | 0.08 |
| NWPP | Glacier County, MT | Wind | 0.08 |
| NYCW | Bronx County, NY | NGCC | 0.12 |
| NYLI | Suffolk County, NY | Wind | 0.10 |
| NYUP | Wyoming County, NY | Wind | 0.09 |
| RFCE | Cambria County, PA | Wind | 0.08 |
| RFCM | Leelanau County, MI | Wind | 0.08 |
| RFCW | Tucker County, WV | Wind | 0.08 |
| RMPA | Clear Creek County, CO | Wind | 0.06 |
| SPNO | Gray County, KS | Wind | 0.06 |
| SPSO | Floyd County, TX | Wind | 0.06 |
| SRCE | Montgomery County, MS | NGCC | 0.09 |
| SRDA | West Feliciana Parish, LA | NGCC | 0.09 |
| SRGW | Polk County, MO | Wind | 0.10 |
| SRSE | George County, MS | NGCC | 0.09 |
| SRVC | Avery County, NC | Wind | 0.07 |

Table 3: Table of the county with minimum cost technology in each NERC subregion for Scenario 3.

| NERC Subregion | County | Technology | LCOE ($/kWh) |
|---|---|---|---|
| AZNM | Guadalupe County, NM | Wind | 0.08 |
| CAMX | Shasta County, CA | NGCC | 0.09 |
| ERCT | Reagan County, TX | Wind | 0.07 |
| FRCC | Jackson County, FL | NGCC | 0.10 |
| MROE | Kewaunee County, WI | Wind | 0.09 |
| MROW | Burke County, ND | Wind | 0.07 |
| NEWE | Dukes County, MA | Wind | 0.08 |
| NWPP | Glacier County, MT | Wind | 0.08 |
| NYCW | New York County, NY | Nuclear | 0.17 |
| NYLI | Suffolk County, NY | Wind | 0.10 |
| NYUP | Wyoming County, NY | Wind | 0.09 |
| RFCE | Cambria County, PA | Wind | 0.08 |
| RFCM | Leelanau County, MI | Wind | 0.08 |
| RFCW | Tucker County, WV | Wind | 0.08 |
| RMPA | Clear Creek County, CO | Wind | 0.06 |
| SPNO | Gray County, KS | Wind | 0.06 |
| SPSO | Floyd County, TX | Wind | 0.06 |
| SRCE | Montgomery County, MS | NGCC | 0.09 |
| SRDA | Jefferson Davis Parish, LA | NGCC | 0.09 |
| SRGW | Polk County, MO | Wind | 0.10 |
| SRSE | George County, MS | NGCC | 0.09 |
| SRVC | Avery County, NC | Wind | 0.07 |

Table 4: Table of the county with minimum cost technology in each NERC subregion for Scenario 4.

| NERC Subregion | County | Technology | LCOE ($/kWh) |
|---|---|---|---|
| AZNM | Santa Fe County, NM | NGCC | 0.06 |
| CAMX | Riverside County, CA | NGCC | 0.06 |
| ERCT | Hill County, TX | NGCC | 0.06 |
| FRCC | Jackson County, FL | NGCC | 0.07 |
| MROE | Kewaunee County, WI | Wind | 0.09 |
| MROW | Burke County, ND | Wind | 0.07 |
| NEWE | Franklin County, VT | NGCC | 0.06 |
| NWPP | Boundary County, ID | NGCC | 0.05 |
| NYCW | New York County, NY | Wind | 0.16 |
| NYLI | Suffolk County, NY | Wind | 0.09 |
| NYUP | Wyoming County, NY | Wind | 0.08 |
| RFCE | McKean County, PA | NGCC | 0.07 |
| RFCM | Branch County, MI | NGCC | 0.06 |
| RFCW | Tucker County, WV | Wind | 0.07 |
| RMPA | Clear Creek County, CO | Wind | 0.06 |
| SPNO | Gray County, KS | Wind | 0.06 |
| SPSO | Floyd County, TX | Wind | 0.05 |
| SRCE | Lafayette County, MS | NGCC | 0.06 |
| SRDA | Bell County, TX | NGCC | 0.06 |
| SRGW | Polk County, MO | Wind | 0.09 |
| SRSE | Hancock County, MS | NGCC | 0.06 |
| SRVC | Avery County, NC | Wind | 0.06 |

Table 5: Table of the county with minimum cost technology in each NERC subregion for Scenario 5.

| NERC Subregion | County | Technology | LCOE ($/kWh) |
|---|---|---|---|
| AZNM | Guadalupe County, NM | Wind | 0.08 |
| CAMX | Sierra County, CA | Wind | 0.11 |
| ERCT | Reagan County, TX | Wind | 0.07 |
| FRCC | Jackson County, FL | NGCC | 0.13 |
| MROE | Kewaunee County, WI | Wind | 0.09 |
| MROW | Burke County, ND | Wind | 0.07 |
| NEWE | Dukes County, MA | Wind | 0.08 |
| NWPP | Glacier County, MT | Wind | 0.08 |
| NYCW | New York County, NY | Nuclear | 0.17 |
| NYLI | Suffolk County, NY | Wind | 0.10 |
| NYUP | Wyoming County, NY | Wind | 0.09 |
| RFCE | Cambria County, PA | Wind | 0.08 |
| RFCM | Leelanau County, MI | Wind | 0.08 |
| RFCW | Tucker County, WV | Wind | 0.08 |
| RMPA | Clear Creek County, CO | Wind | 0.06 |
| SPNO | Gray County, KS | Wind | 0.06 |
| SPSO | Floyd County, TX | Wind | 0.06 |
| SRCE | Unicoi County, TN | Wind | 0.09 |
| SRDA | Cameron Parish, LA | Wind | 0.09 |
| SRGW | Polk County, MO | Wind | 0.10 |
| SRSE | Rabun County, GA | Wind | 0.11 |
| SRVC | Avery County, NC | Wind | 0.07 |

Table 6: Table of the county with minimum cost technology in each NERC subregion for Scenario 6.

| NERC Subregion | County | Technology | LCOE ($/kWh) |
|---|---|---|---|
| AZNM | Guadalupe County, NM | Wind | 0.08 |
| CAMX | Shasta County, CA | NGCC | 0.08 |
| ERCT | Reagan County, TX | Wind | 0.07 |
| FRCC | Jackson County, FL | NGCC | 0.08 |
| MROE | Kewaunee County, WI | Wind | 0.09 |
| MROW | Burke County, ND | Wind | 0.07 |
| NEWE | Penobscot County, ME | NGCC | 0.08 |
| NWPP | Boundary County, ID | NGCC | 0.07 |
| NYCW | New York County, NY | Nuclear | 0.17 |
| NYLI | Suffolk County, NY | Wind | 0.10 |
| NYUP | Wyoming County, NY | Wind | 0.09 |
| RFCE | Cambria County, PA | Wind | 0.08 |
| RFCM | Branch County, MI | NGCC | 0.08 |
| RFCW | Tucker County, WV | Wind | 0.08 |
| RMPA | Clear Creek County, CO | Wind | 0.06 |
| SPNO | Gray County, KS | Wind | 0.06 |
| SPSO | Floyd County, TX | Wind | 0.06 |
| SRCE | Montgomery County, MS | NGCC | 0.08 |
| SRDA | Plaquemines Parish, LA | NGCC | 0.08 |
| SRGW | Polk County, MO | Wind | 0.10 |
| SRSE | George County, MS | NGCC | 0.08 |
| SRVC | Avery County, NC | Wind | 0.07 |

Table 7: Table of the county with minimum cost technology in each NERC subregion for Scenario 7.

| NERC Subregion | County | Technology | LCOE ($/kWh) |
|---|---|---|---|
| AZNM | Guadalupe County, NM | Wind | 0.08 |
| CAMX | Shasta County, CA | NGCC | 0.10 |
| ERCT | Reagan County, TX | Wind | 0.07 |
| FRCC | Jackson County, FL | NGCC | 0.11 |
| MROE | Kewaunee County, WI | Wind | 0.10 |
| MROW | Burke County, ND | Wind | 0.08 |
| NEWE | Dukes County, MA | Wind | 0.09 |
| NWPP | Glacier County, MT | Wind | 0.08 |
| NYCW | New York County, NY | Nuclear | 0.17 |
| NYLI | Suffolk County, NY | Wind | 0.11 |
| NYUP | Wyoming County, NY | Wind | 0.09 |
| RFCE | Cambria County, PA | Wind | 0.09 |
| RFCM | Leelanau County, MI | Wind | 0.09 |
| RFCW | Tucker County, WV | Wind | 0.08 |
| RMPA | Clear Creek County, CO | Wind | 0.07 |
| SPNO | Gray County, KS | Wind | 0.07 |
| SPSO | Floyd County, TX | Wind | 0.06 |
| SRCE | Unicoi County, TN | Wind | 0.10 |
| SRDA | Cameron Parish, LA | Wind | 0.10 |
| SRGW | Polk County, MO | Wind | 0.10 |
| SRSE | George County, MS | NGCC | 0.10 |
| SRVC | Avery County, NC | Wind | 0.07 |

Table 8: Table of the county with minimum cost technology in each NERC subregion for Scenario 8.

| NERC Subregion | County | Technology | LCOE ($/kWh) |
|---|---|---|---|
| AZNM | Guadalupe County, NM | Wind | 0.07 |
| CAMX | Shasta County, CA | NGCC | 0.07 |
| ERCT | Reagan County, TX | Wind | 0.06 |
| FRCC | Jackson County, FL | NGCC | 0.08 |
| MROE | Kewaunee County, WI | Wind | 0.09 |
| MROW | Burke County, ND | Wind | 0.07 |
| NEWE | Penobscot County, ME | NGCC | 0.08 |
| NWPP | Boundary County, ID | NGCC | 0.06 |
| NYCW | New York County, NY | Wind | 0.16 |
| NYLI | Suffolk County, NY | Wind | 0.09 |
| NYUP | Wyoming County, NY | Wind | 0.08 |
| RFCE | Cambria County, PA | Wind | 0.08 |
| RFCM | Branch County, MI | NGCC | 0.08 |
| RFCW | Tucker County, WV | Wind | 0.07 |
| RMPA | Clear Creek County, CO | Wind | 0.06 |
| SPNO | Gray County, KS | Wind | 0.06 |
| SPSO | Floyd County, TX | Wind | 0.06 |
| SRCE | Montgomery County, MS | NGCC | 0.07 |
| SRDA | Jefferson Davis Parish, LA | NGCC | 0.07 |
| SRGW | Polk County, MO | Wind | 0.09 |
| SRSE | George County, MS | NGCC | 0.07 |
| SRVC | Avery County, NC | Wind | 0.06 |

Table 9: Table of the county with minimum cost technology in each NERC subregion for Scenario 9.

| NERC Subregion | County | Technology | LCOE ($/kWh) |
|---|---|---|---|
| AZNM | Guadalupe County, NM | Wind | 0.08 |
| CAMX | Shasta County, CA | NGCC | 0.09 |
| ERCT | Reagan County, TX | Wind | 0.07 |
| FRCC | Jackson County, FL | NGCC | 0.10 |
| MROE | Kewaunee County, WI | Wind | 0.09 |
| MROW | Burke County, ND | Wind | 0.07 |
| NEWE | Dukes County, MA | Wind | 0.08 |
| NWPP | Glacier County, MT | Wind | 0.08 |
| NYCW | New York County, NY | Solar PV, utility | 0.15 |
| NYLI | Suffolk County, NY | Wind | 0.10 |
| NYUP | Wyoming County, NY | Wind | 0.09 |
| RFCE | Cambria County, PA | Wind | 0.08 |
| RFCM | Leelanau County, MI | Wind | 0.08 |
| RFCW | Tucker County, WV | Wind | 0.08 |
| RMPA | Clear Creek County, CO | Wind | 0.06 |
| SPNO | Gray County, KS | Wind | 0.06 |
| SPSO | Floyd County, TX | Wind | 0.06 |
| SRCE | Montgomery County, MS | NGCC | 0.09 |
| SRDA | Jefferson Davis Parish, LA | NGCC | 0.09 |
| SRGW | Polk County, MO | Wind | 0.10 |
| SRSE | George County, MS | NGCC | 0.09 |
| SRVC | Avery County, NC | Wind | 0.07 |

Table 10: Table of the county with minimum cost technology in each NERC subregion for Scenario 10.

| NERC Subregion | County | Technology | LCOE ($/kWh) |
|---|---|---|---|
| AZNM | Guadalupe County, NM | Wind | 0.07 |
| CAMX | Shasta County, CA | NGCC | 0.09 |
| ERCT | Reagan County, TX | Wind | 0.06 |
| FRCC | Jackson County, FL | NGCC | 0.10 |
| MROE | Alger County, MI | Wind | 0.09 |
| MROW | Burke County, ND | Wind | 0.07 |
| NEWE | Dukes County, MA | Wind | 0.08 |
| NWPP | Glacier County, MT | Wind | 0.08 |
| NYCW | New York County, NY | Nuclear | 0.17 |
| NYLI | Suffolk County, NY | Wind | 0.10 |
| NYUP | Wayne County, NY | Wind | 0.09 |
| RFCE | Cambria County, PA | Wind | 0.08 |
| RFCM | Leelanau County, MI | Wind | 0.08 |
| RFCW | Tucker County, WV | Wind | 0.08 |
| RMPA | Clear Creek County, CO | Wind | 0.06 |
| SPNO | Gray County, KS | Wind | 0.06 |
| SPSO | Floyd County, TX | Wind | 0.06 |
| SRCE | Montgomery County, MS | NGCC | 0.09 |
| SRDA | Jefferson Davis Parish, LA | NGCC | 0.09 |
| SRGW | Polk County, MO | Wind | 0.10 |
| SRSE | George County, MS | NGCC | 0.09 |
| SRVC | Avery County, NC | Wind | 0.07 |

Table 11: Table showing which figures (F64 indicates Figure 64) from Mays, et al. [4] were used to create availability zones for each technology shown in

| Technology | population density | wetlands | protected lands | landslide risks | high-slope land | 100-year floodplain | water availability | EPA non-attainment zones | fuel access | saline formations | abilit $CO_2$ |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal CCS 30* | F64 | F65 | F66 | F67 | F68 | F69 | F70 | F71 | F72 | F73 | |
| Coal CCS 90** | F64 | F65 | F66 | F67 | F68 | F69 | F70 | F71 | F72 | F73 | |
| NGCC*** | F64 | F65 | F66 | F67 | F68 | F69 | F53 | F71 | ♠ | N/A | |
| NGCC CCS 90 | F64 | F65 | F66 | F67 | F68 | F69 | F53 | F71 | ♠ | F73 | |
| NGCT**** | F64 | F65 | F66 | F67 | F68 | F69 | N/A | F71 | ♠ | N/A | |
| Nuclear | F64 | F65 | F66 | F67 | F68 | F69 | F70 | N/A | N/A | N/A | |
| Wind | F64 | F65 | F66 | N/A | F68 | F69 | 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 | |
| CSP | F64 | F65 | F66 | F67 | F68 | F69 | F70 | 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 networl
method as how F72 was created for coal in Mays, et al. [4].

## 5. 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 [5]. 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 5:

$$E_f = HR \times P_l / HHV_{ng} \tag{5}$$

where $E_f$ is the $CH_4$ 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), $P_l$ 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 12 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.

## 6. Second minimum cost technology

Figure 25 shows the next least cost technology map for all United States counties (top) as well as the cost difference between the least and second

Table 12: Table showing the values of fugitive methane emissions per kWh of electricity generated for multiple types of natural gas power plants (g-$CH_4$/kWh) associated with obtaining and delivering natural gas to the plants.

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

* NGCC: Natural gas combined cycle

** CCS: Carbon Capture and Sequestration

*** NGCT: Natural gas combustion turbine

[1] National average leakage rate of 0.5%

[2] National average leakage rate of 1.0% (reference case assumption)

[3] National average leakage rate of 1.5%

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 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.

## 7. CAPEX price maps

Figures 26 - 35 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.

## 8. Fuel price maps

Figures 36 - 38 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 38 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 38. 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 39 and \$7.39/GJ (\$7/MMBtu) to give a high natural gas price for each county as seen in Figure 40.

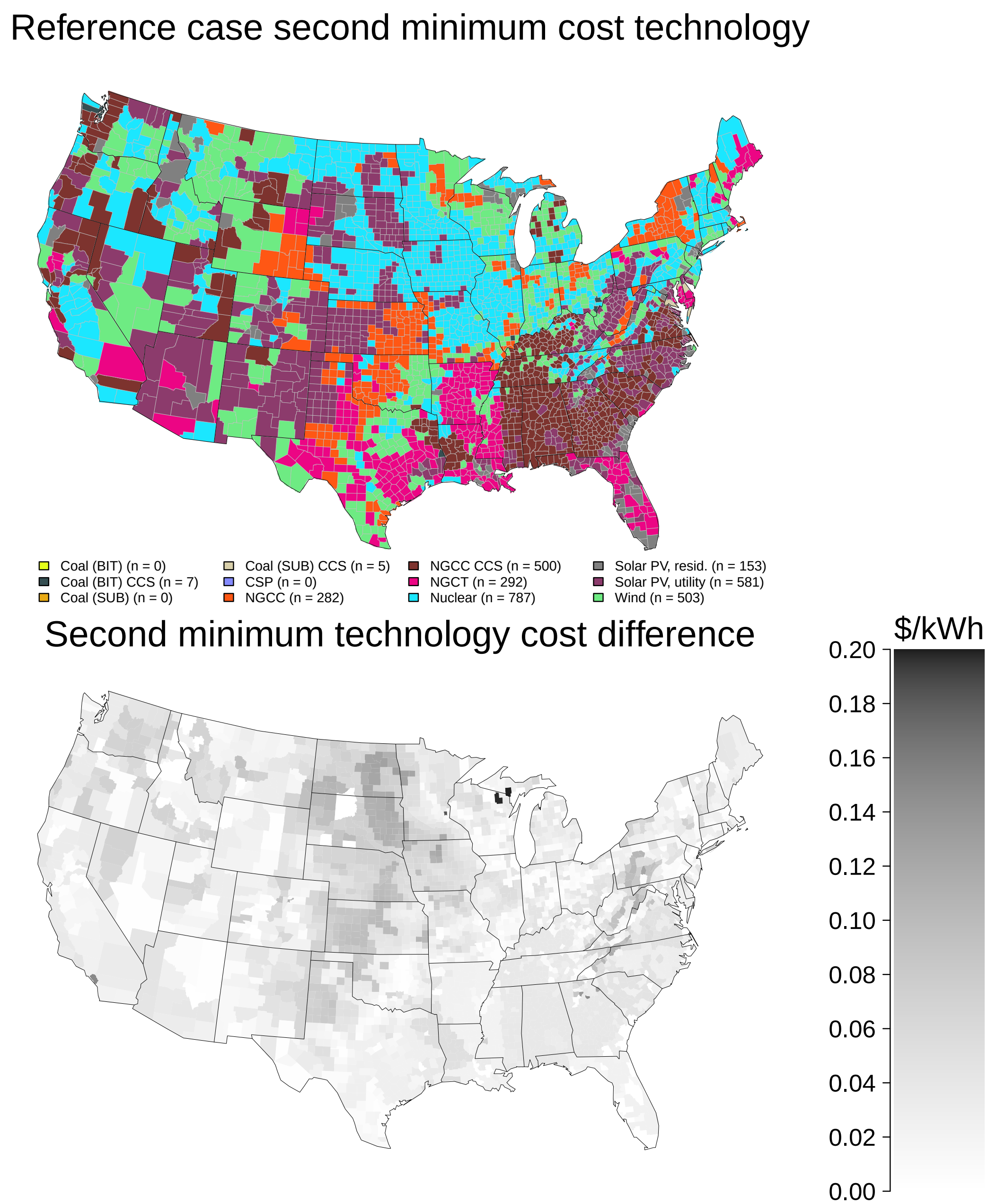


Figure 25: Map showing the second minimum cost technology for each county (Equation 4) with reference case assumptions from Table 1 on top and the cost difference between the least and next least cost technology on the bottom. A lighter color on the bottom graph indicates a smaller difference between the first and second least cost technology.

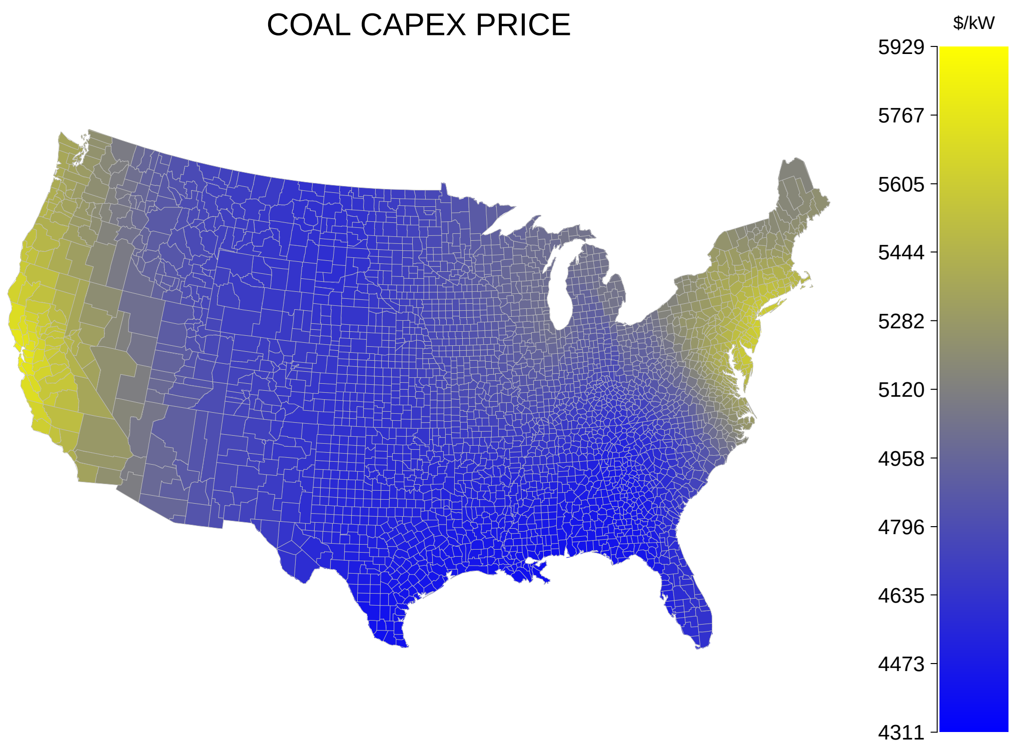


Figure 26: Coal plant CAPEX price map ($/kW) using values from [6] with regional multipliers [1] and geographic interpolation as described in the paper methods section.

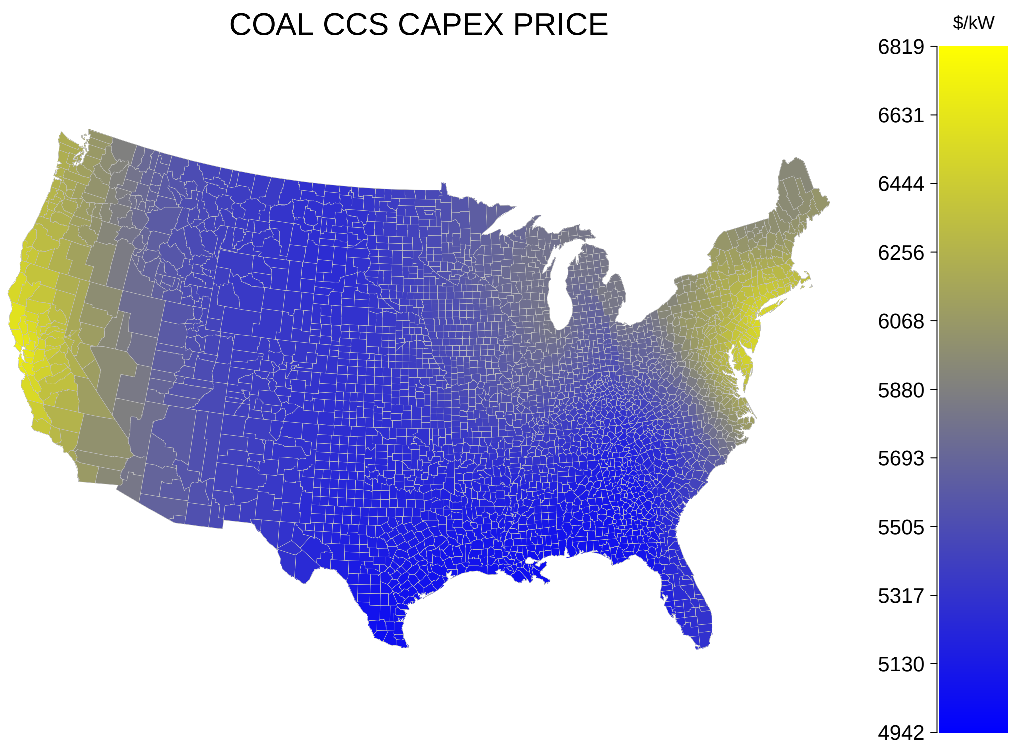


Figure 27: Coal CCS plant CAPEX price map ($/kW) using values from [6] with regional multipliers [1] and geographic interpolation as described in the paper methods section.

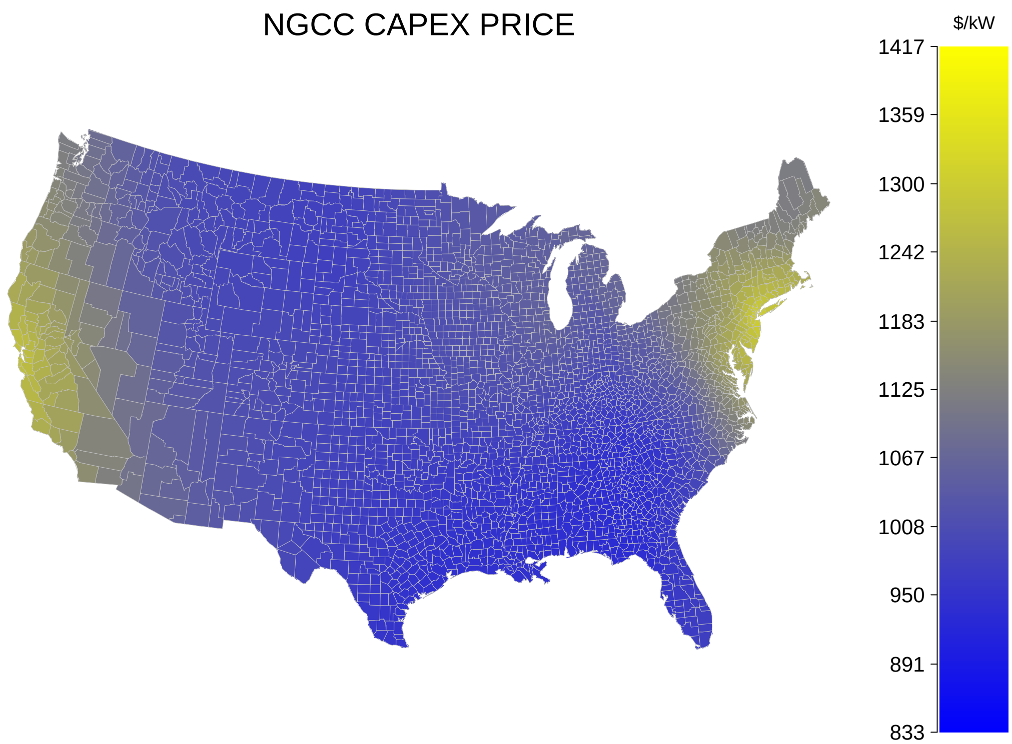


Figure 28: NGCC CAPEX price map ($/kW) using values from [6] with regional multipliers [1] and geographic interpolation as described in the paper methods section.

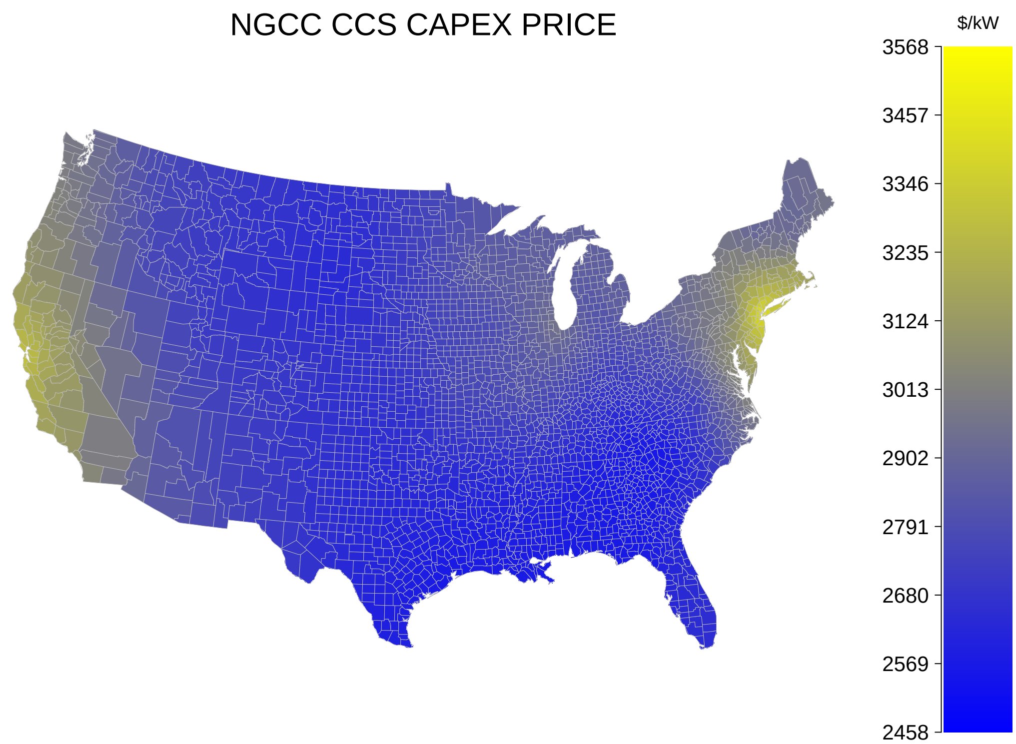


Figure 29: NGCC CCS CAPEX price map ($/kW) using values from [6] with regional multipliers [1] and geographic interpolation as described in the paper methods section.

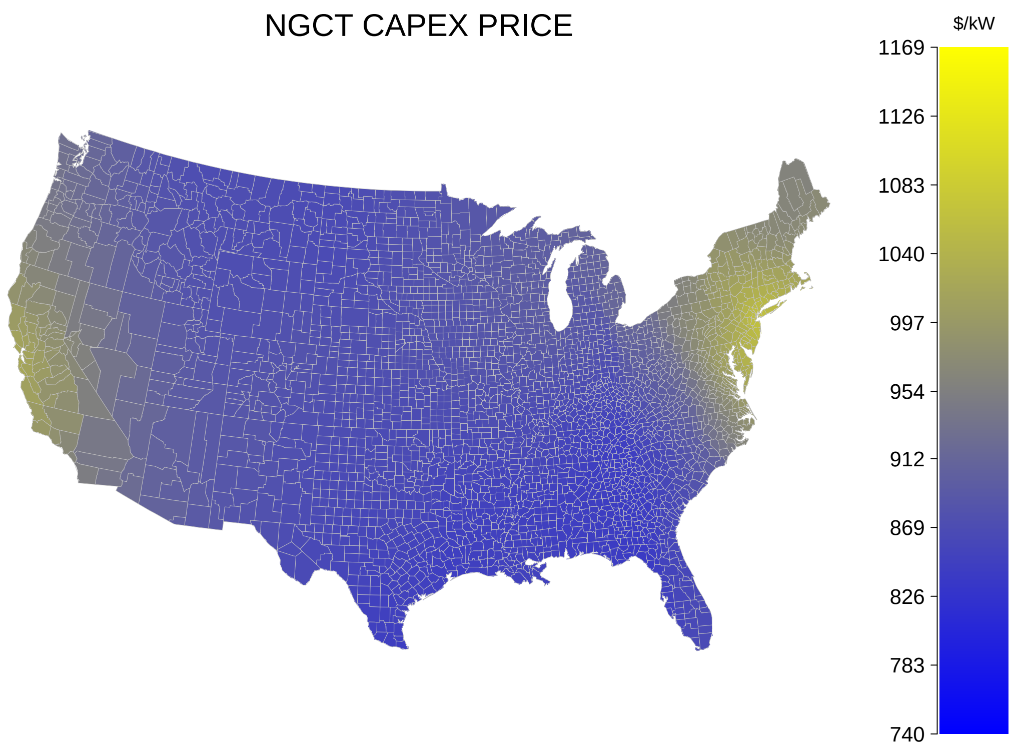


Figure 30: NGCT price map ($/kW) using values from [6] with regional multipliers [1] and geographic interpolation as described in the paper methods section.

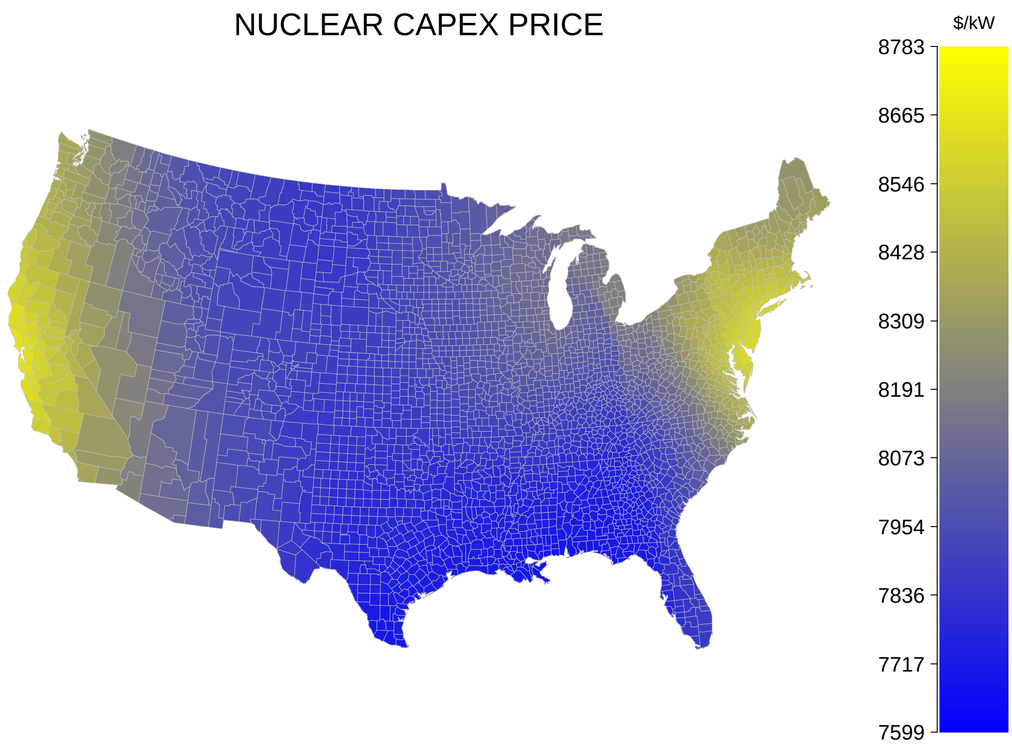


Figure 31: Nuclear CAPEX price map ($/kW) using values from [6] with regional multipliers [1] and geographic interpolation as described in the paper methods section.

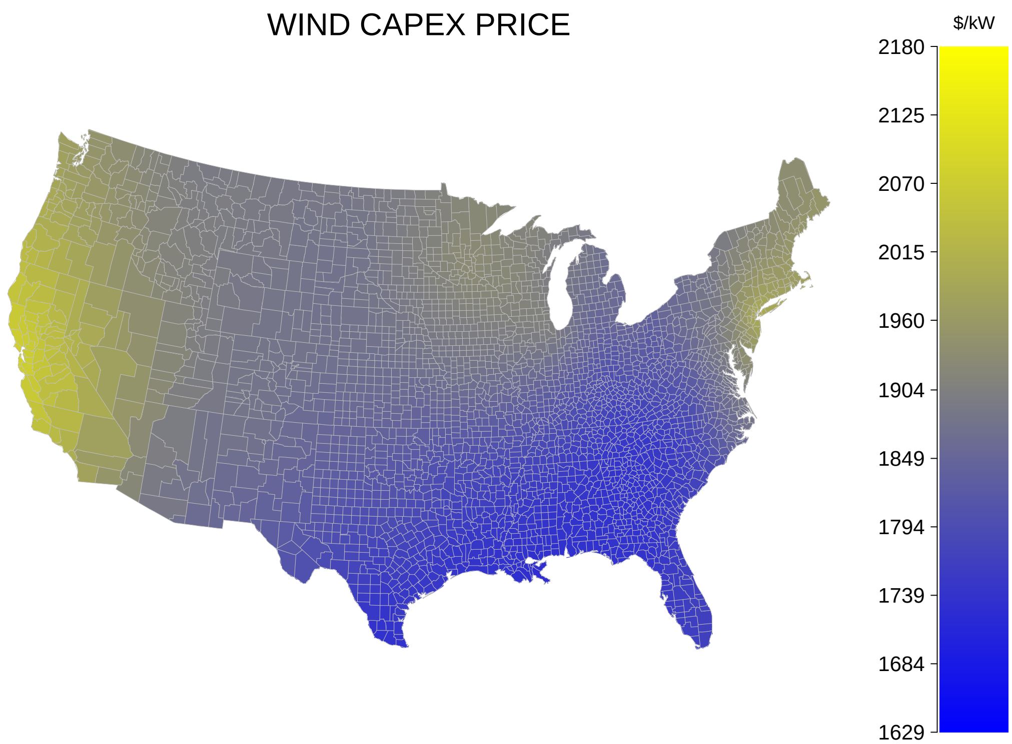


Figure 32: Wind CAPEX price map ($/kW) using values from [6] with regional multipliers [1] and geographic interpolation as described in the paper methods section.

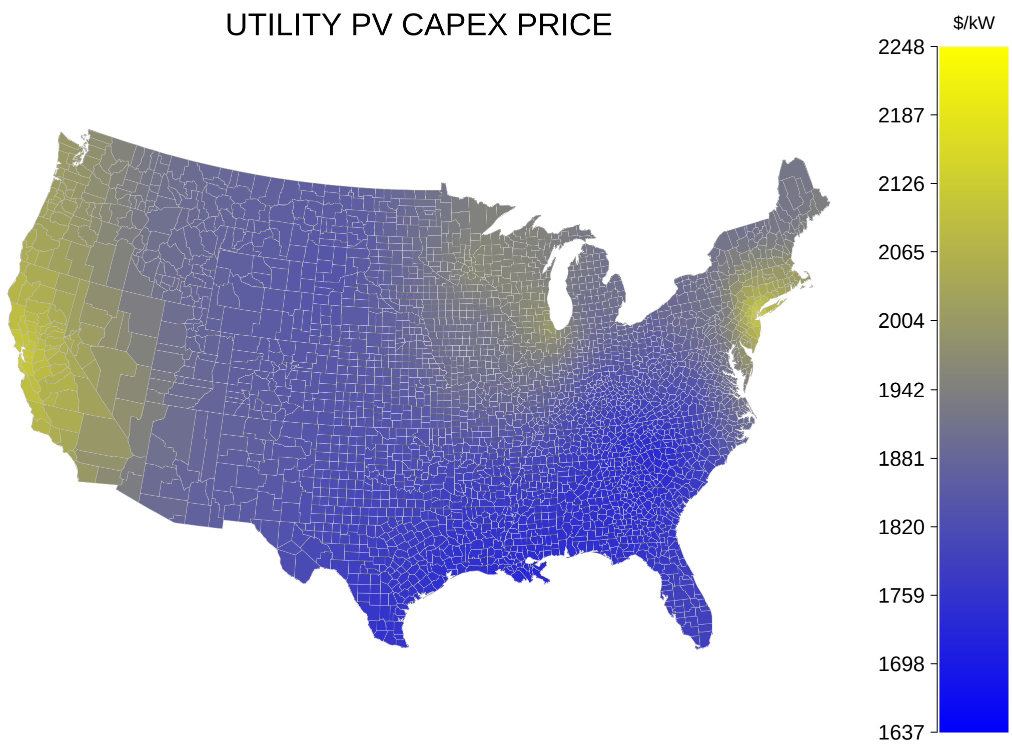


Figure 33: Utility PV CAPEX price map ($/kW) using values from [6] with regional multipliers [1] and geographic interpolation as described in the paper methods section.

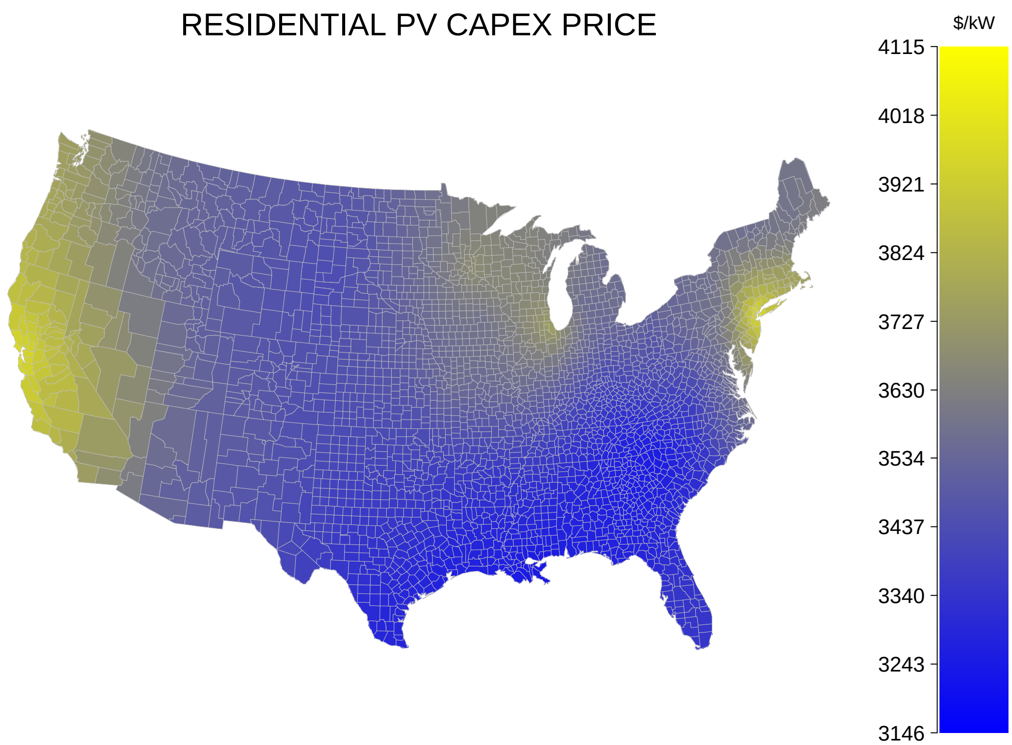


Figure 34: Residential PV CAPEX price map ($/kW) using values from [6] with regional multipliers [1] and geographic interpolation as described in the paper methods section. Because residentail PV was not included in [6], the utility PV value was used + $1,000/kW.

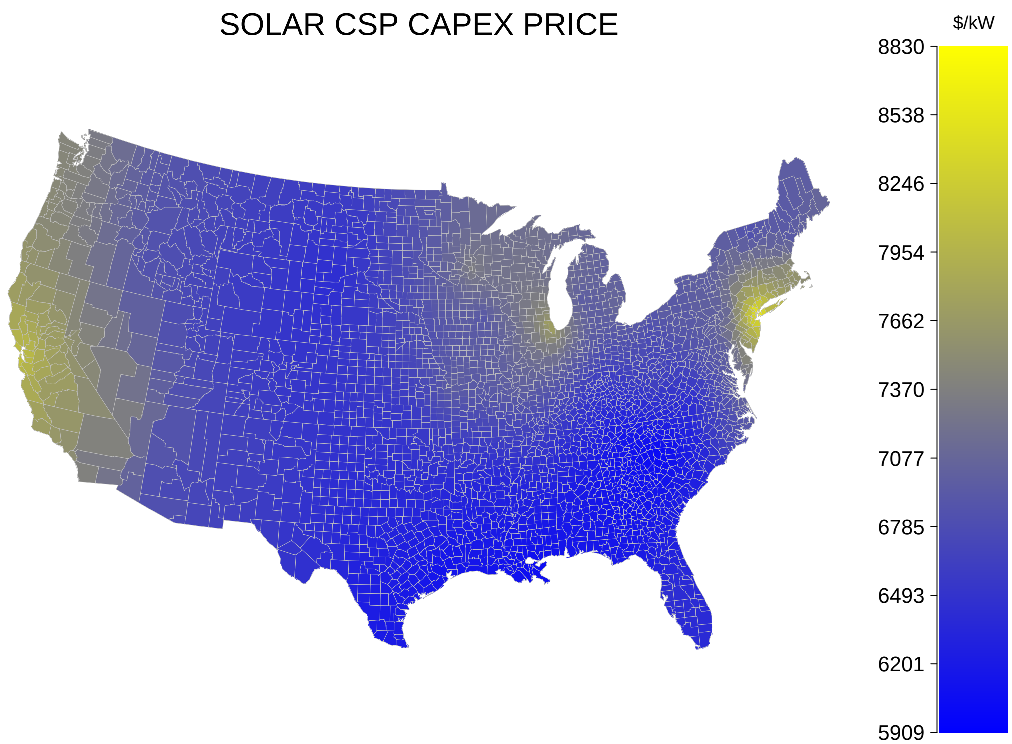


Figure 35: CSP CAPEX price map ($/kW) using values from [6] with regional multipliers [1] and geographic interpolation as described in the paper methods section.

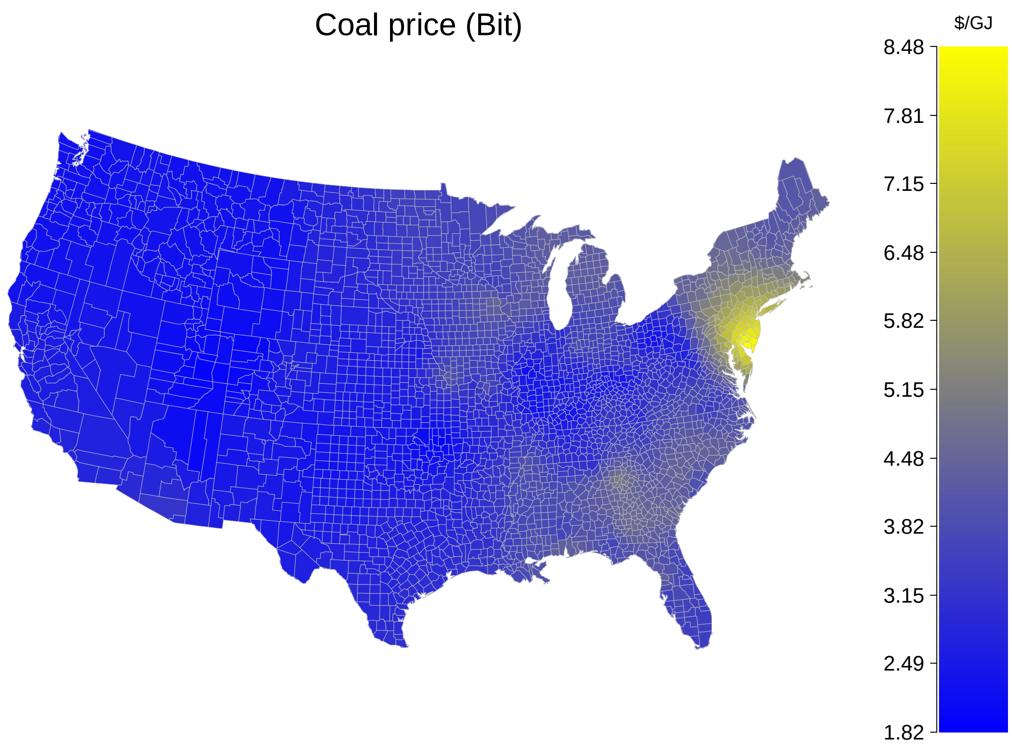


Figure 36: Bituminous coal fuel price map (\$/GJ) with geographic interpolation using an average price of \$3.35/GJ (\$3.17/MMBtu).

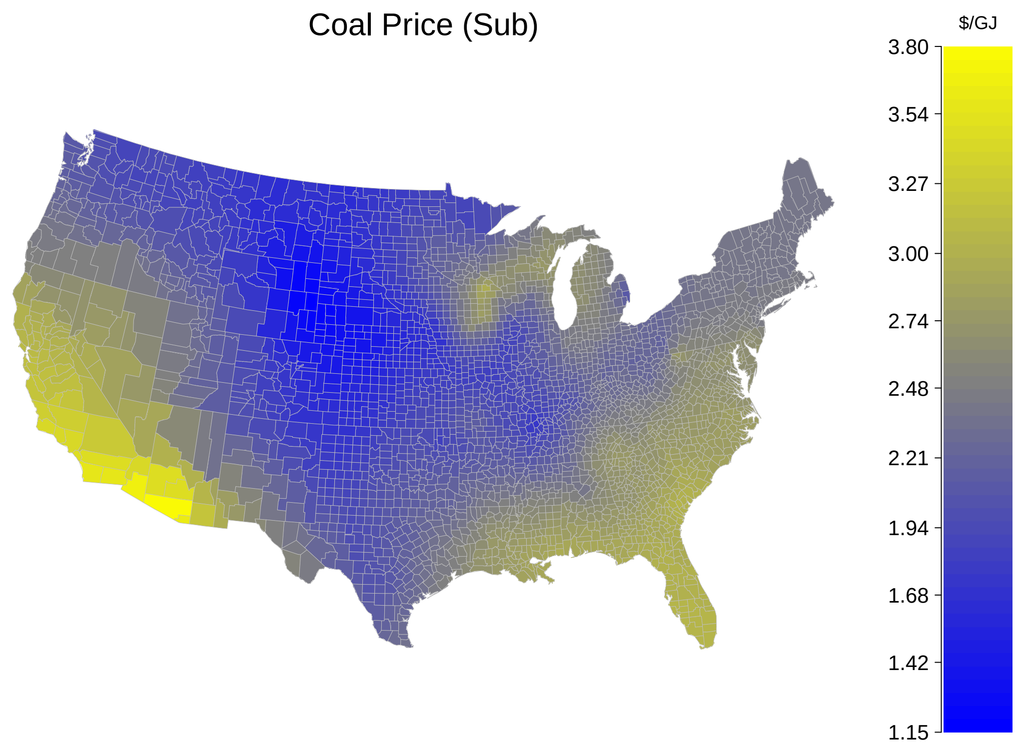


Figure 37: Sub-bituminous coal fuel price map (\$/GJ) with geographic interpolation using an average price of \$2.28/GJ (\$2.16/MMBtu).

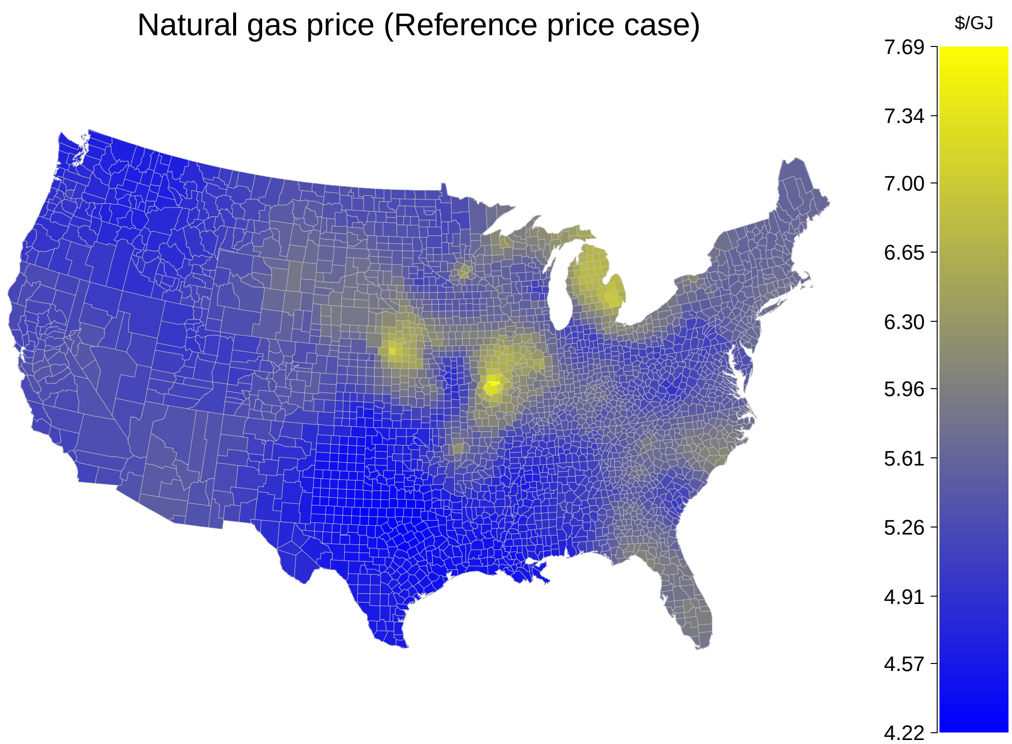


Figure 38: Natural gas reference case fuel price map with a US average cost of \$5.37/GJ (\$5.07/MMBtu) with geographic interpolation as described in the methods section.

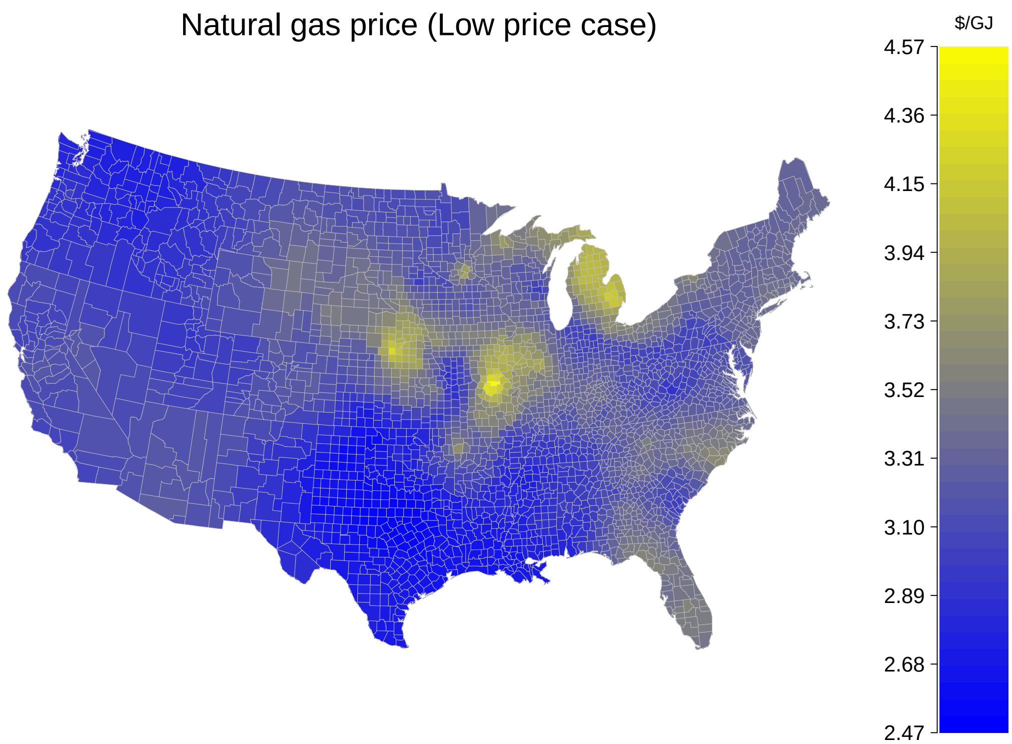


Figure 39: Natural gas low price case fuel price map with a US average cost of about \$3.16/GJ (\$3/MMBtu) with geographic interpolation as described in the methods section.

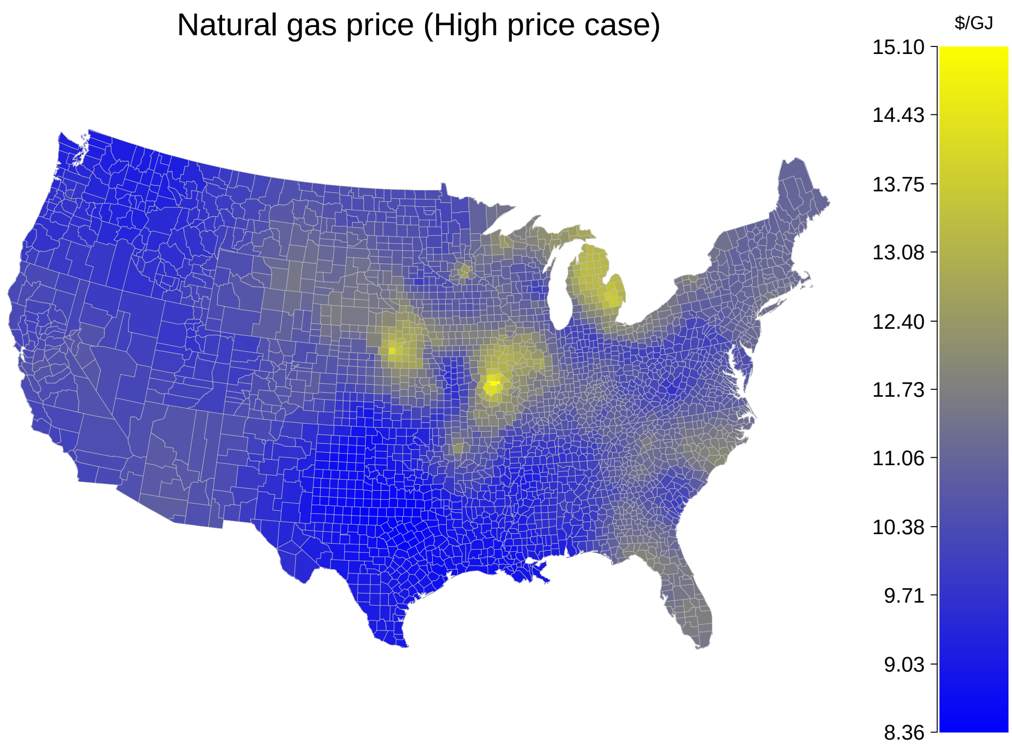


Figure 40: Natural gas high price case fuel price map with a US average cost of about \$7.39/GJ (\$7/MMBtu) with geographic interpolation as described in the methods section.

## 9. Technology capacity factor maps

Figures 41 - 48 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 [2]. Note that while the color scale looks the same for each technology the relative values (min/max) are different.

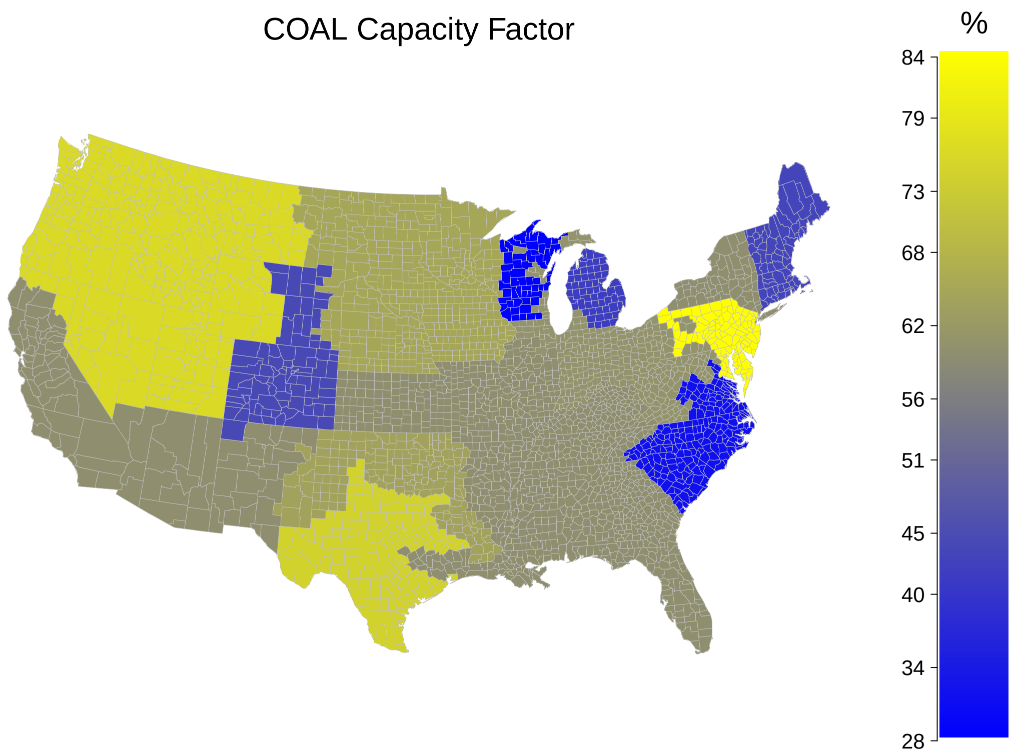


Figure 41: Coal capacity factor (%), based on historical data.

[1] EIA, . Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants. 2013. URL: `http://www.eia.gov/forecasts/capitalcost/pdf/updated{_}capcost.pdf`.

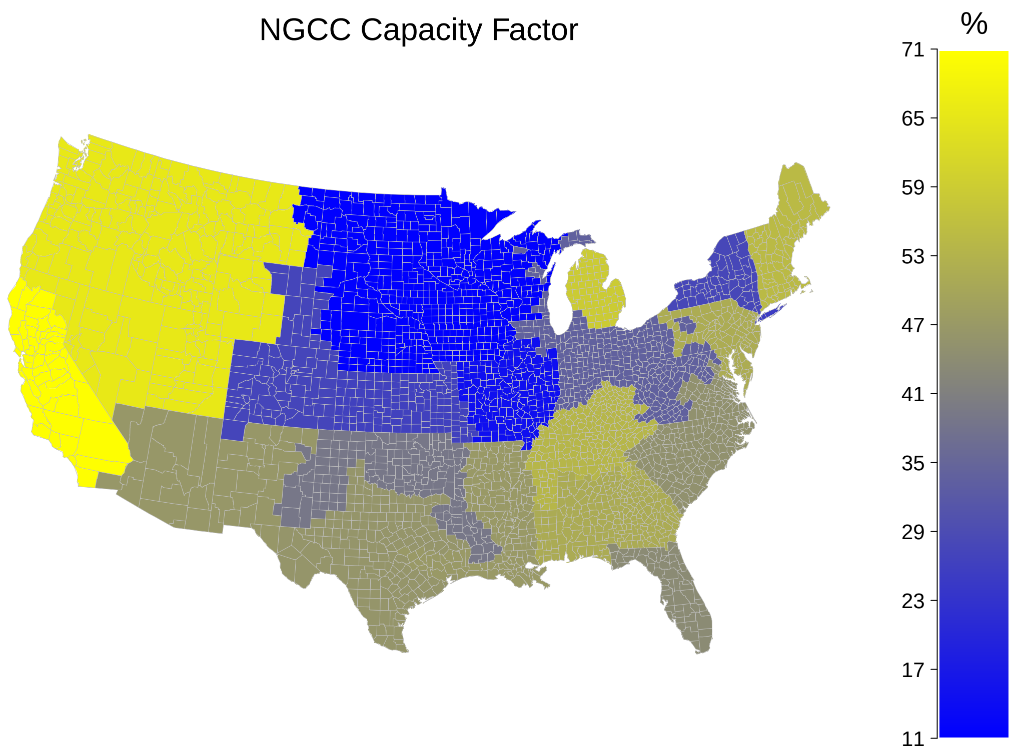


Figure 42: NGCC capacity factor (%), based on historical data.

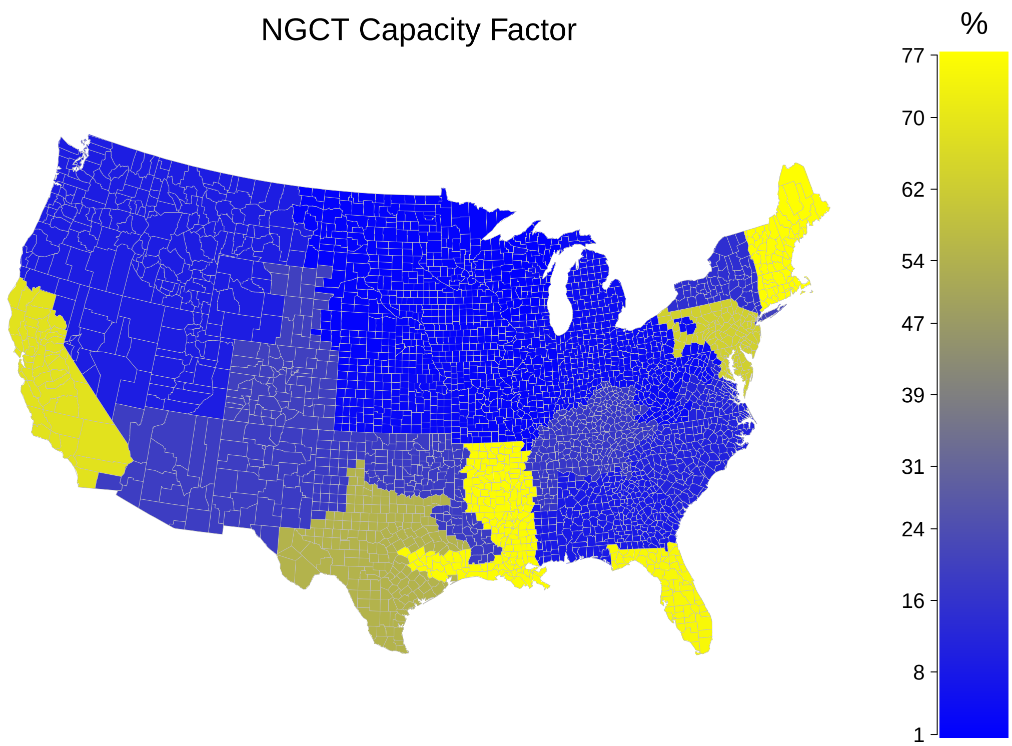


Figure 43: NGCT capacity factor (%), based on historical data.

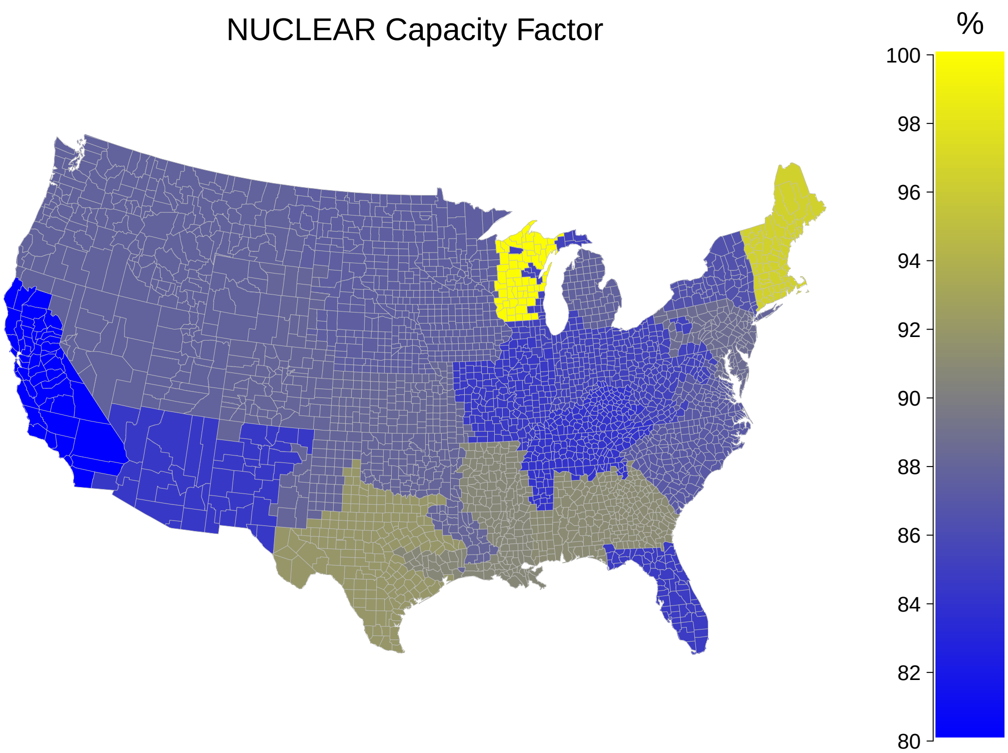


Figure 44: Nuclear capacity factor (%), based on historical data.

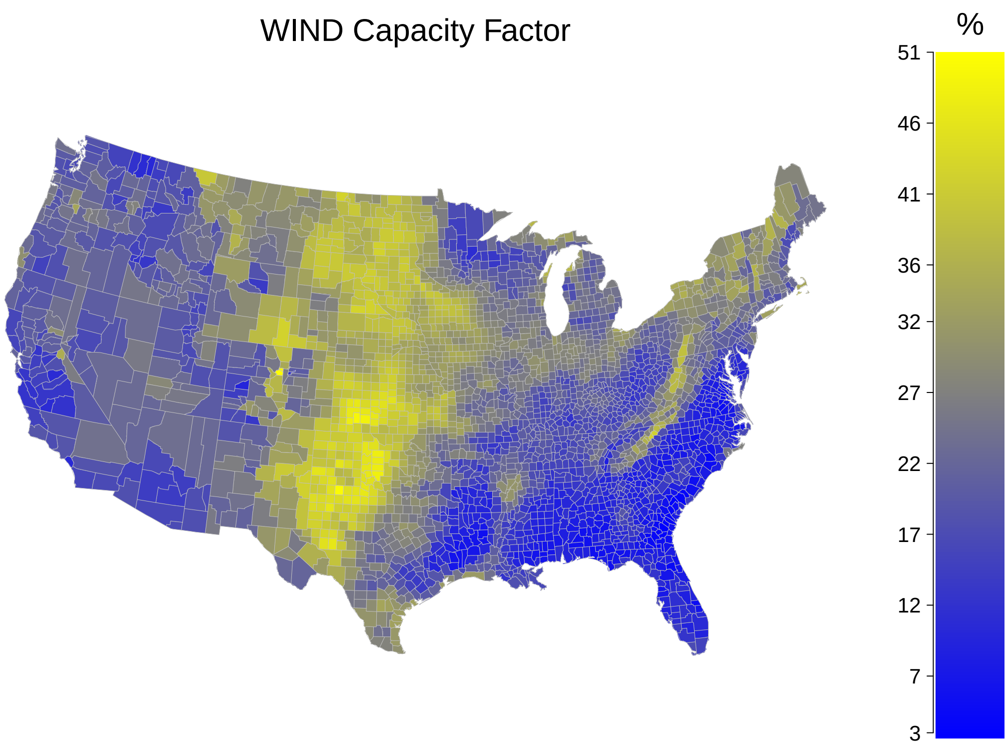


Figure 45: Wind capacity factor (%), based on prevalent meteorological conditions for an 80 meter wind turbine hub height.

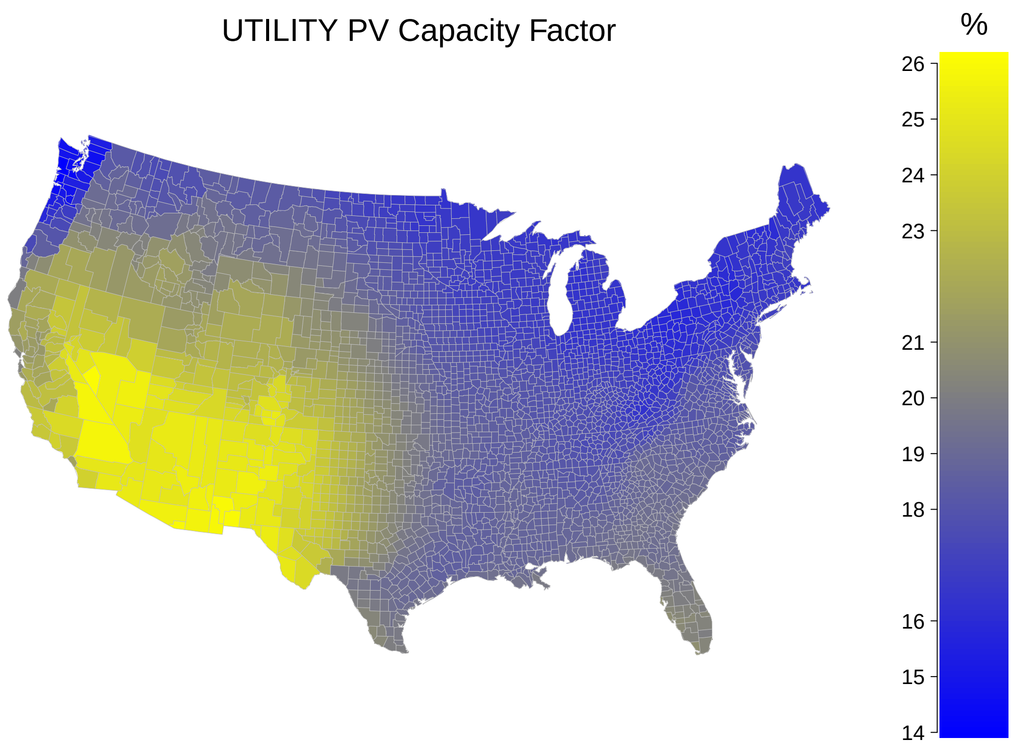


Figure 46: Utility PV (single-axis tracking) capacity factor (%), based on prevalent meteorological conditions.

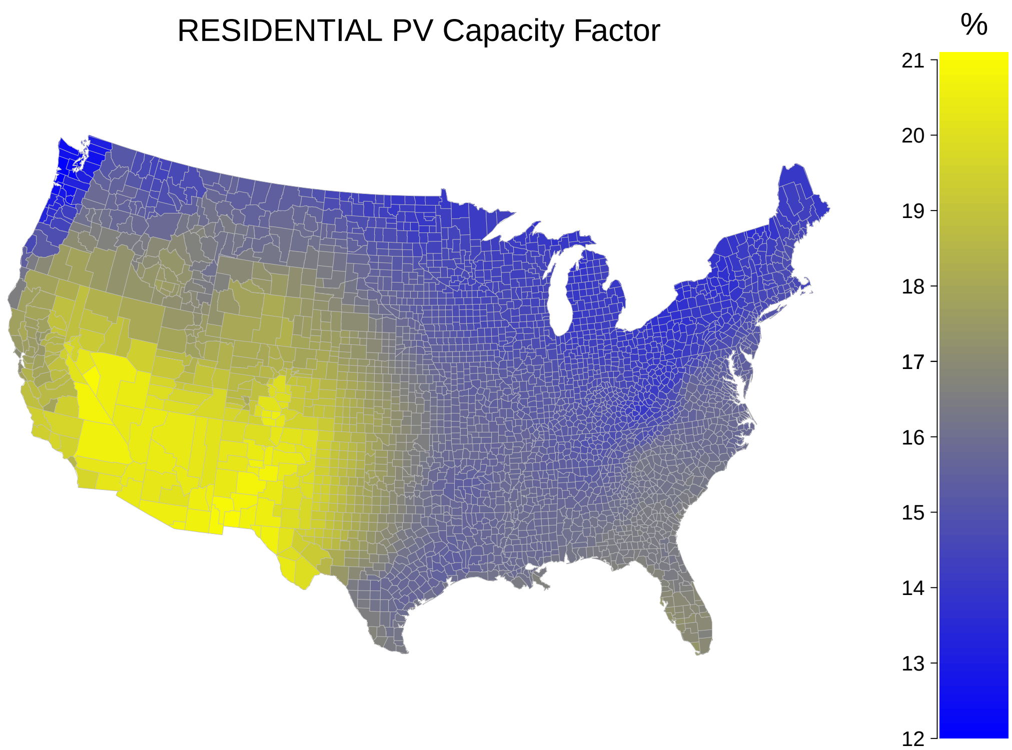


Figure 47: Residential PV (south-facing fixed axis at 25° tilt) capacity factor (%), based on prevalent meteorological conditions.

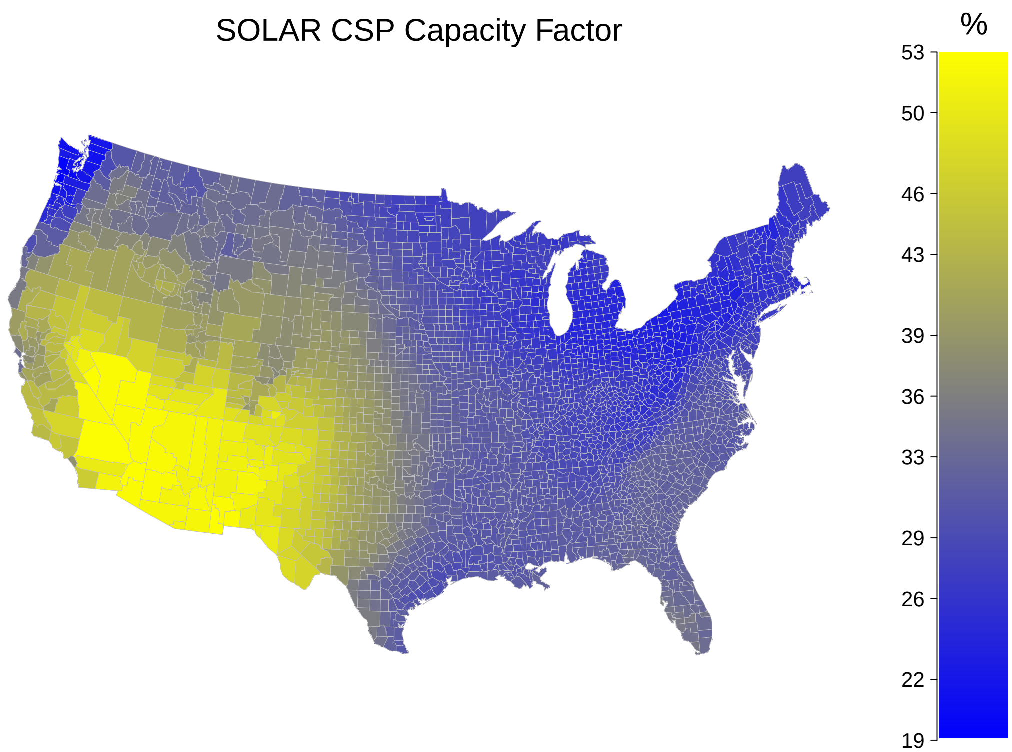


Figure 48: Solar CSP (with 6 hours of thermal storage) capacity factor (%), based on prevalent meteorological conditions.

[2] eGrid. 2015. URL: http://www.epa.gov/cleanenergy/energy-resources/egrid/.

[3] Margolis, R., Coggeshall, C., Zuboy, J.. Sunshot Vision Study. 2012. URL: http://www1.eere.energy.gov/solar/pdfs/47927.pdf.

[4] Mays, G.T., Belles, R.J., Blevins, B.R., Hadley, S.W., Harrison, T.J., Jochem, W.C., et al. Application of Spatial Data Modeling and Geographical Information Systems (GIS) for Identification of Potential Siting Options for Various Electrical Generation Sources. Tech. Rep.; OAK RIDGE NATIONAL LABORATORY; 2012.

[5] Mai, T., Wiser, R., Sandor, D., Brinkman, G., Heath, G., Denholm, P., et al. Volume 1: Exploration of High-Penetration Renewable Electricity Futures. Renewable Electricity Futures Study 2012;1:280.

[6] Sullivan, P., Cole, W., Blair, N., Lantz, E., Krishnan, V., Mai, T., et al. 2015 Standard Scenarios Annual Report: U.S. Electric Sector Scenario Exploration. Tech. Rep. July; NREL; 2015.