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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 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 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.

1. Introduction

The Levelized Cost of Electricity (LCOE) is a commonly used metric for comparing different generation types. 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 (Lazard, 2014), future projections (EIA, 2014; Sullivan et al., 2015), or for specific clients (Black and Cost, 2012). 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 rather than for variable generators such as wind and solar (Joskow, 2011). It is also difficult to project LCOE values into the future for fossil fuel and nuclear plants because of the uncertainty of future fuel costs, capacity factors, and regulation. In addition, there have been few attempts to incorporate the costs of environmental externalities into the framework (Cohon, 2010; Epstein et al., 2011; Wittenstein and Rothewll, 2015). We develop a method to introduce environmental externalities by use of an expanded LCOE while honoring the spatial variability of emissions and other environmental impacts.

We start with a standard LCOE calculation and include a few key

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externalities: SO_2, NO_x, $PM_{2.5}$, and PM_{10} criteria air pollutants emissions; CO_2 emissions; fugitive CH_4 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 (Buonocore et al., 2014) and then internalized into the cost of generating electric energy (Cullen, 2013; McCubbin and Sovacool, 2013; Kaffine et al., 2013; Novan, 2015; Siler-Evans et al., 2013; Shindell, 2015). CO_2 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 h 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_2 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. LCOE addresses only cost with an assumed capacity factor. Investments are not solely determined by costs, but on anticipated profits that are equal to revenues minus costs. Revenues are in turn determined by the selling price of electricity, which varies seasonally and diurnally. Concepts such as Levelized Avoided Cost of Electricity (LACE) are often used to compare revenues to costs with temporal specificity. Market prices for power change throughout the day, and this analysis does not take those changes into consideration. This distinction can be particularly relevant for intermittent generation technologies, as solar usually produces a greater share of its total generation during times of higher electricity prices than wind (Joskow, 2011). However, this case might also change as more renewables come online. Backup and firming costs and other system integration costs such as transmission and distribution (T & D) investments are difficult to incorporate into an LCOE analysis because these require knowledge of the temporal demand and supply of electricity, which are not natively part of the LCOE equation as these costs are representative of overall electric grid, or system, dynamics. This analysis is specifically formulated to show regional differences in the cost of electricity from new power plants 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.

Other analyses have calculated spatial LCOE costs when going after a particular goal, such as high penetrations of renewable energy (Mai et al., 2012; Jacobson et al., 2015). This analysis differs in that it intends to consider every technology on an even field. To display our method, we implemented typical numbers for each variable in all locations for all technologies. The authors recognize that not all parties will agree with the numbers that we have chosen as defaults. Thus, we have constructed our method into online web tools that allow users to edit our numbers and see the results in real time. The authors hope that by using a consistent methodology (with perhaps differing inputs) policy makers (and the public) can have a better dialogue about the impacts of costs and policy on the cost of electricity.

2. Methods

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

$$LCOE_1 = \frac{\Pi_{capitalcost} \times CRF + O\&M_{fixed}}{8760 \times CF} + O\&M_{variable} + HR \times \Pi_{fuel} \tag{1}$$

For Eq. (1), $\Pi_{capitalcost}$ is the power plant and any relevant CO_2 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 ($/MWh), HR is the heat rate (GJ/MWh (MMBtu/MWh)), and Π_{fuel} is the price of fuel ($/GJ ($/MMBtu)). The heat rate and fuel costs are not relevant for wind or solar. CRF is the capital recovery factor, shown in Eq. (2):

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

For Eq. (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 Eq. (1) includes costs for any required emissions controls (see Section 3). Externalities added in Eq. (4) reflect the (mostly human health) cost of remaining emissions. Eq. (3) presents the LCOE calculation where both the plant costs and the costs associated with SO_2, NO_x, PM $_{2.5}$, PM_{10}, and *combustion-related* CO_2 emissions are considered:

$$LCOE_2 = \frac{\Pi_{capitalcost} \times CRF + O\&M_{fixed}}{8760 \times CF} + O\&M_{variable} + HR \times \Pi_{fuel} + \sum_{j\in\theta} R_j \times D_j \tag{3}$$

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 θ is a set of pollutants that includes SO_2, NO_x, $PM_{2.5}$, PM_{10} (Muller and Mendelsohn, 2009), CO_2 (Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis, 2013), and CH_4 (Marten and Newbold, 2012). See Table 3 for ongoing CO_2 damages per lifetime of power plant. The non-CO_2 damages were estimated at the county level as the damage from pollution varies across the nation for a variety of meteorological and other conditions such as population density and existing pollution levels. The damages associated with ongoing CO_2 and CH_4 emissions are taken at the national level.

Eq. (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), 2) on-going *non-combustion* emissions (i.e. fuel extraction – combustion CO_2 are included in line 2 of Eq. (3)), and 3) downstream one-time emissions (i.e. power plant decommissioning):

$$LCOE_3 = \frac{\Pi_{capitalcost} \times CRF + O\&M_{fixed}}{8760 \times CF} + O\&M_{variable} + HR \times \Pi_{fuel} + \sum_{j\in\theta} R_j \times D_j + E_{GHG,one-time} \times D_{GHG,one-time} + R_{GHG,NC,ongoing} \times D_{j,CO_2} \tag{4}$$

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. For example, the damages from construction of a new plant in 2016 are different than the damages from emissions associated with decommission at the end-of-life in 2056.

There a few limitations using this LCOE method. Given the nature of the equation, we consider all values to be discounted to today, such as capacity factors and O & M costs. These values will vary across time, but given the uncertainty of what those values will be, stated values are discounted back to today. Also, since the modified LCOE uses *overnight* capital costs, construction financing is internalized into the overnight values. We provide tools that allow users to change these preferences if they wish to do so, see Section 5.

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 (Sanders et al., 2014). 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^3 can incentivize a power plant developer to invest in dry cooling systems to avoid the vast majority of water use (King, 2014). We do consider water availability when considering counties that might not be able to support a thermal plant, see SI- Section 3.

The end result of this analysis is a modified and expanded LCOE method at the county level. To display this method, we found appropriate 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 from a regional level down to a finer resolution. 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 26–35). Fixed operating costs ($O\&M_{fixed}$) were taken from the EIA report and multiplied by the same geographic multipliers as the CAPEX values. This regional multiplier makes an assumption that these values are spatially correlated. We make this assumption based on EIA's analysis that power plants costs differ based on a wide array of factors.[1]

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.

However, not every type of power plant can be built in every location. Thus, we used maps provided in Mays, et al. (Mays et al., 2012) to restrict the availability of locations to build plants based on 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. 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 SI- Section 3.

3. Inputs for illustrating the method

This section provides our suggested values and where we obtained them for using the method as described in Section 2. The authors recognize that there are a large number of variables that have been included in this analysis for illustrative purposes, and many people will disagree with the values we have chosen. However, the method can be applied with different inputs, and we encourage readers to use refined estimates instead of our placeholders to yield more precise answers. For this reason, we have made web tools available for users to edit our default values and run their own simulations either at the individual county or the county as a whole, see Section 5.

Overnight capital costs for all plant types were taken from NREL's 2015 Annual Technology Baseline database (Sullivan et al., 2015) – these values do not include subsidies. CAPEX values for nuclear plants were adjusted up and PV CAPEX values adjusted down based on more recent cost data. CAPEX for some technologies, particularly nuclear, are difficult to estimate given the recent long construction times and cost overruns[2] (Lovering et al., 2016; Gilbert et al., 2016; Koomey et al., 2016). Because EPA's New Source Performance Standards limit the amount of carbon pollution from new power plants to 635.6 g/kWh CO_2 (1400 lb/MWh), all new coal plants have to be modeled as CCS plants with at least 30% CO2 capture. Based on (Hildebrand, 2009; Chou et al., 2015; Supekar and Skerlos, 2015) we estimated that 30% CCS increases coal plant CAPEX and OPEX by 30% and increases 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_2 pipelines of an assumed 100 km length, about $248.6 M, or about $2.5 M/km ($4 M/mile). These costs were then normalized by the assumed capacity of the power plants, 650 MW for coal CCS and 340 MW for NGCC CCS. CO_2 pipe OPEX and CO_2 injection well CAPEX and OPEX were normalized by metric tonne of CO_2 produced/injected and were calculated to be $4.00, $2.00, and $3.00, respectfully based upon methods used in King et al. (2013).

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 Figs.36–38). 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) (eGrid, 2015). 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 Figs.41–44). Historical capacity factors are used because capacity factors are driven by markets and

[1] The authors have one piece of antidotal evidence that is consistent with the regional differences. In our discussions with a large municipal utility in central Texas, we compared their costs for building new generation assets with our estimated costs and found ours to be within a few percent of their estimates. For the purposes of this work, that agreement is satisfactory.

[2] We chose a higher starting point for nuclear ($8,000/kW vs EIA estimate $5,530/kW) to attempt to take these factors into consideration, but the authors encourage others to use our calculators if they have more accurate information.

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 F26 is a map of county-level coal CAPEX values, F41 is a map of county-level coal capacity factor values located in SI- Section 8, and F36 is a map of county-level delivered bituminous coal prices all located in SI- Section 7. Individual technology pollutant emissions rates are shown in Table 2. County-level air pollutant damages are taken from Muller and Mendelsohn, Muller and Mendelsohn (2009); Holland et al. (2015)).

Technology	$\Pi_{capitalcost}$ (\$/kW)[1]	$O\&M_{fixed}$ (\$/kW-yr)[2]	$O\&M_{variable}$ (%)[4] x	CF (%)[4]	HR ($\frac{kJ}{kWh}$)[5]	Π_{fuel} ($\frac{\$}{GJ}$)[6]	i (%)[7]	n (years)[7]
Coal, bit CCS 30[*]	4,766(F26)	49.14	5.81	F41	10,409	3.35(F36)	11%	40
Coal, sub CCS 30	4,766(F26)	49.14	5.81	F41	10,409	2.28(F37)	11%	40
Coal, bit CCS 90[**]	5,513(F27)	80.53	9.51	F41	12,661	3.35(F36)	11%	40
Coal, sub CCS 90	5,513(F27)	80.53	9.51	F41	12,661	2.28(F37)	11%	40
NGCC[***]	1,021(F28)	15.37	3.27	F42	6,784	5.37(F38)	10%	35
NGCC CCS 90	2,095(F29)	31.79	6.78	F42	7,939	5.37(F38)	10%	35
NGCT[****]	867(F30)	7.04	10.37	F43	10,287	5.37(F38)	10%	35
Nuclear[*****]	8,000(F31)	93.28	2.14	F44	11,025	0.70	12%	50
Wind	1,827(F32)	39.55	0.00	F45	NA	NA	10%	25
Solar PV, util.	1,900(F33)	24.69	0.00	F46	NA	NA	10%	25
Solar PV, res.	3,350(F34)	24.69	0.00	F47	NA	NA	10%	25
CSP	7,041(F35)	67.26	0.00	F48	NA	NA	10%	30

[3]This value is fixed for all locations for a given technology.
[*] 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_2 (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 Sullivan et al. (2015).
[1] This value is the nominal CAPEX value given in Sullivan et al. (2015) for each technology along with the figure depicting the interpolated values from the regional multipliers in EIA (2013).
[2] This value is the nominal fixed operations and maintenance cost value given in EIA (2013) 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.
[4] This value points to the capacity factor map for each technology.
[5] The heat rate values were assumed constant in all locations for each technology and were taken from EIA (2013). 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.
[6] This value shows the average fuel price across all locations and also points to the fuel price maps, if applicable.
[7] 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.

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 5 km×5 km resolution (3Tier, 2015) 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 (rather than merely average conditions) were chosen for siting the wind turbine. The capacity factor values were for a generic turbine with a hub height of 80 m (Fig. 45). Capacity factor values for utility and residential-scale solar PV plants were calculated using the capacity factor maps found in Drury et al. (2013). 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 Figs. 46, 47). Capacity factor values for solar CSP were calculated using NREL's System Advisory Model (SAM) (NREL, 2015). Weather data from over 1000 locations across the US were used with the SAM model of a generic concentrating solar plant with 6 h 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 (Fig. 48).

EIA emissions rates of SO_2, NO_x, and CO_2 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 (Mai et al., 2012) and our assumed combustion rates for air pollutants.

Damages for CO_2 and CO_{2-eq} emissions were calculated using the EPA's Social Cost of Carbon (SCC) (Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis, 2013). 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 A Table 1 of Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis (2013) 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 A Table 1 of Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis (2013) to 2065 using a 2nd degree polynomial fit to extrapolate the data past its current end, for which the R^2 was >99% in each case.

Marten and Newbold (2012) showed that using the SCC with other gases' global warming potentials could lead to errors in estimating the societal cost of those gases. 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) (Marten and Newbold, 2012). 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_2, NO_x, $PM_{2.5}$, were taken from Holland et al. (2015). PM_{10} values were taken from Muller and Mendelsohn (2009). Both (Holland et al., 2015; Muller and Mendelsohn, 2009) 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,

Table 2
Table showing the assumed life cycle emissions rates (g/kW(h)) of CO_{2-eq} (GHG), the assumed BACT *combustion* emissions rates (g/kWh) of air pollutants, and the assumed CH_4 fugitive emissions rates (g/kWh) associated with the considered technologies.

Technology	Upstream one-time (g CO_{2-eq}/kW)	On-going non-combustion (g CO_{2-eq}/kWh)[1]	Downstream one-time (g CO_{2-eq}/kW)	Combustion SO_2	Combustion NO_x	Combustion PM_{10}	Combustion $PM_{2.5}$	Combustion CO_2	Fugitive[2] CH_4
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	6390	0.003	0.022	0.054	0.05	341.5	1.58
NGCC CCS 90	240,000	111.6	9585	0.003	0.022	0.054	0.05	35	1.85
NGCT****	6800	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.
[1] The values for natural gas units assume a US average natural gas infrastructure leakage rate of 1%, see SI- Section 4.
[2] Assuming a US average methane leakage rate of 1.0%.

Table 3
Table showing the low, reference, and high case assumptions for the cost of ongoing CO_2 (combustion and non-combustion) and CH_4 (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_4 (35 yr)[1]	$1034	$2014	$2562

* 5% discount rate.
** 3% discount rate.
*** 2.5% discount rate.
[1] All natural gas power plants were assumed a lifetime of 35 years, so only this value is shown here.

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_2, NO_x, $PM_{2.5}$ data from Holland et al. (2015) are based on a $6 million value of a statistical life (VSL) with 2011 as the base year of emissions. The PM_{10} data are from an earlier study with a base year of 2002 (Muller and Mendelsohn, 2009), and used a VSL of $2 million, scaled by age – thus a low estimate for PM_{10} as compared to the study using a $6 million 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. Fig. 1 portrays a graphical flow of the data streams used to display our method.

4. Results

We applied the method for multiple scenarios to demonstrate how it could be used. Fig. 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 Eq. (1), and the minimum cost technology for each county is shown. In this scenario, our method, using numbers we describe in Section 3 finds that in the majority of US counties, NGCC plants are the least cost option, followed by wind, sub bituminous coal and nuclear plants. 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.

Fig. 3 (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 Eq. (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.

Fig. 4 (Scenario 3) shows the minimum cost technology for each county in a scenario where we consider externalities and availability zones (SI- Section 3).

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 Fig. 4, 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 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). SI- Section 1 presents 7 more scenarios. SI- Section 2 also presents 10 tables, one for each scenario that shows the county within each of the 22 NERC subregions that has the cheapest technology, what technology that is, and the calculated LOCE value. If one only considers the cheapest technology in a given NREC subregion, i.e. the cheapest county in that region, the least-cost technology is always wind or NGCC, with the exception of a single region, NYCW,[3] where nuclear is the cheapest technology in Scenarios 3, 5–7, and 10, and utility-scale solar PV is the

[3] Northeast Power Coordinating Council / NYC – Westchester

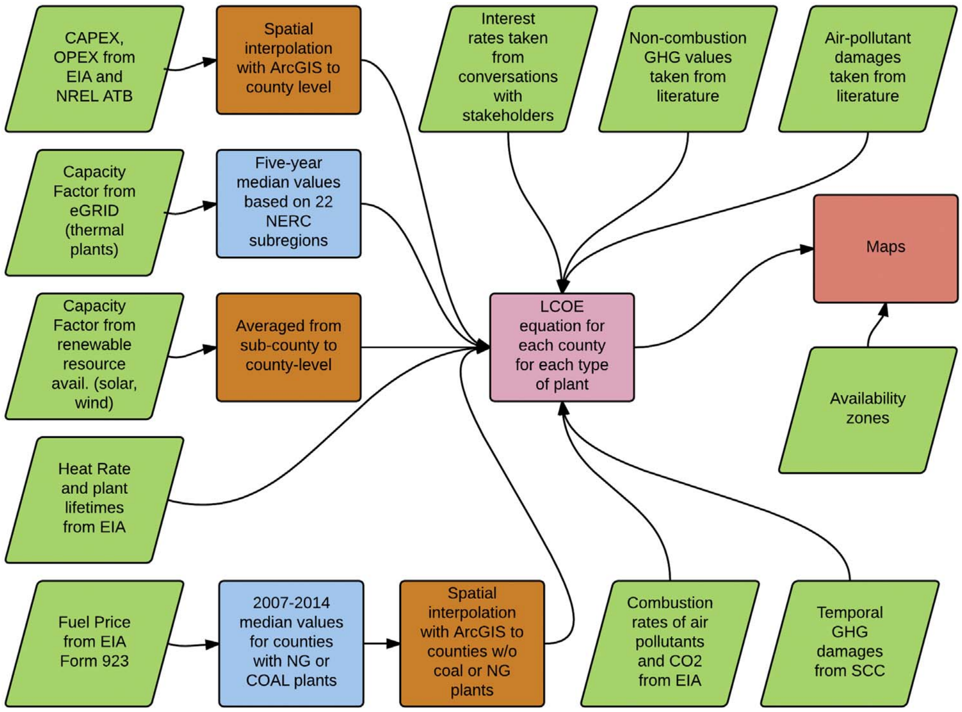

Fig. 1. Figure showing the flow of data from raw inputs to county-level LCOE calculations.

cheapest technology in Scenario 9. However, these results do not incorporate the cost of transmission, which is part of future work.

This analysis gives the ability to see the spatial differences of the costs of each technology across the entire United States. Because capital and 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.

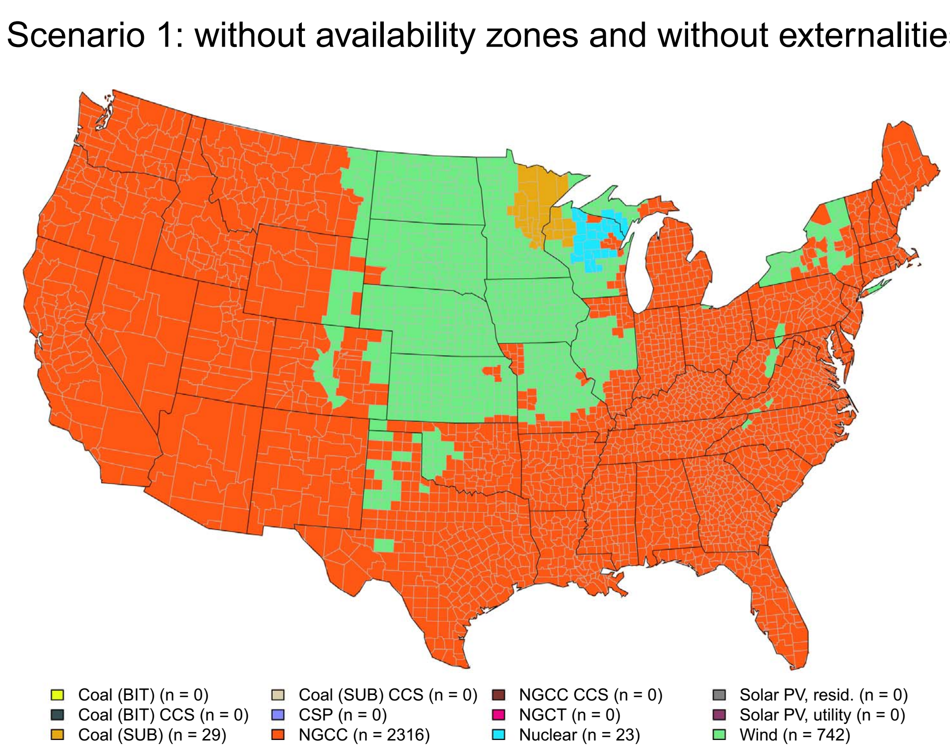

Fig. 2. Scenario 1: Minimum cost technology for each county, not including externalities (Eq. (1)) with reference case assumptions from Tables 1–3.

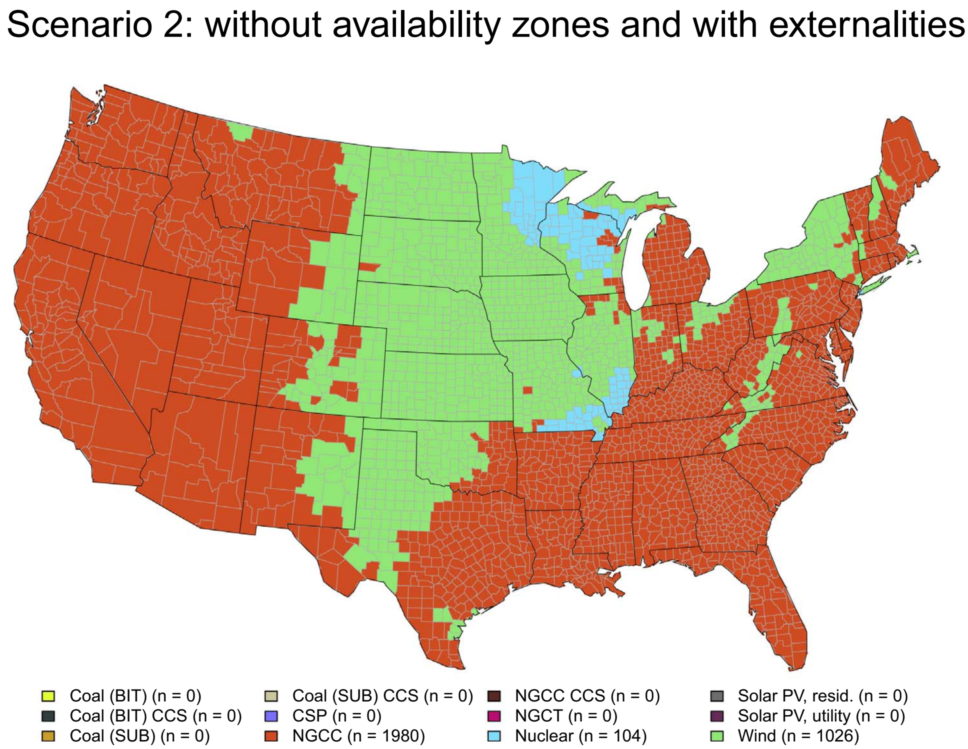

Fig. 3. Scenario 2: Minimum cost technology for each county, including externalities (Eq. (4)) with reference case assumptions from Tables 1–3.

5. Policy tool and implications

This analysis seeks to provide a screening tool for policy makers to evaluate the suitability of a particular electric generation technology in a particular region. For instance, Figs. 5–11 of the SI show how the least cost technology varies across the US when costs of various inputs such as natural gas and carbon are changed. For instance, we find that a higher natural gas price (SI-Fig. 6) and a higher CO_2 price (SI-Fig. 8) have a similar effect on the interaction between where wind and NGCC are the cheapest technologies. Also, our results indicate that the locations where we calculate nuclear to be the cheapest technology are more sensitive to CO_2 prices than natural gas costs.

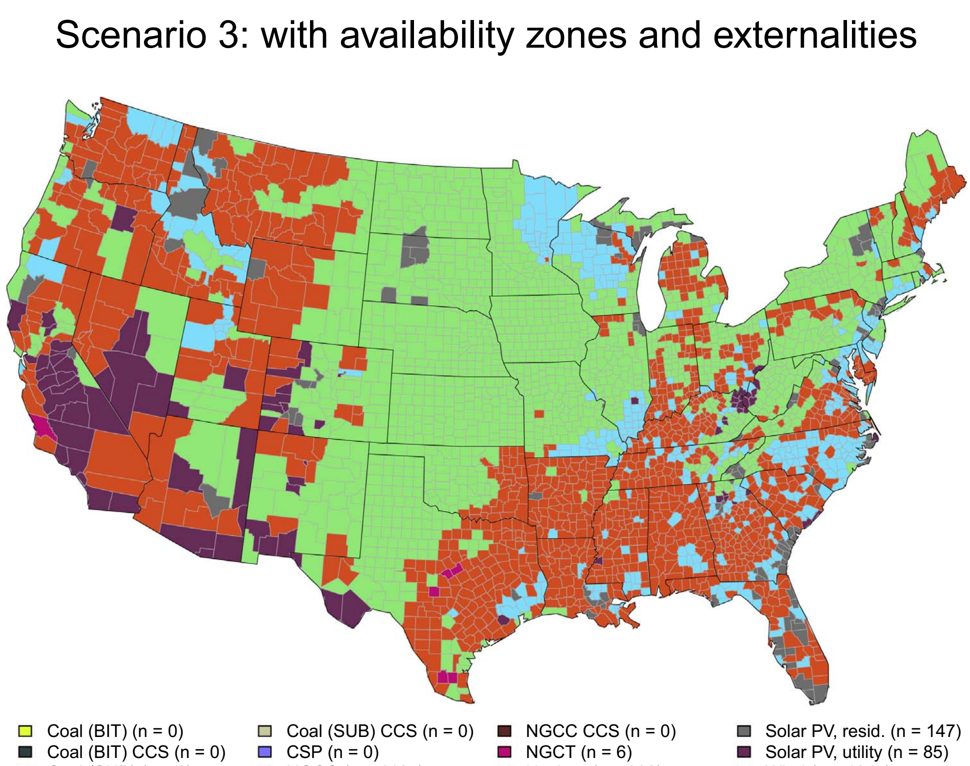

Fig. 4. Scenario 3: Minimum cost technology for each county, including externalities (Eq. (4)) and availability zones with reference case assumptions from Tables 1–3.

These non-intuitive results are some examples of how the outputs of this analysis could be used to inform policy makers on the possible effects of efforts such as a carbon tax, or incentives for certain technologies. To allow many different scenarios to be considered, we developed online web tool calculators for the public to utilize. We provide two tools. One calculator found here:

http://calculators.energy.utexas.edu/lcoe_map/#/county/tech allows the user to change the overnight CAPEX and fuel prices, and toggle on and off externalities (with the ability to change the price of CO_2) and availability zones. The map updates in near real time to show which technology (with the default and changed assumptive values) is the calculated cheapest technology in each county. Note that the changed values are US average values and are still multiplied by the applicable distribution of value multipliers such as those that underlie SI-Fig. 26.

The second tool allows users to change more values, but limits the comparison of two different technologies in the same US county, or the same technology in different counties:

http://calculators.energy.utexas.edu/lcoe_detailed/ This calculator allows the user to change *all* the underlying values used in the LCOE calculation. However, given practical space and time requirements, the calculation is limited to fewer locations. This calculator would allow a policy maker to get very detailed in their analysis of the effects of different policies in the costs of electricity in a given location. Each county is pre-populated with our reference values – the same that underlie the maps. However, we have also added the ability to include the costs of transmission lines at this level.

6. Conclusion and policy implications

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 fuels and technologies, and 2) a geographic display of the method for 10 scenarios (see SI-Section 1 for scenarios 4–10). 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 least expensive 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. This analysis could serve policy discussions in a number of ways: 1) as a screening tool for what technologies should be considered in a region when planning for capacity expansion, 2) as a common metric for policy discussions (i.e. coming to the table with a consistent set of methods and being forced to be transparent about assumptions), and 3) as a tool to understand how much the externalities of electricity generation are compared to the basic cost to generate the kWh. Beyond our presented cases, we also provide web tools that allow users to observe the effects of their own policy decisions as relate to the levelized cost of electricity of a given technology in a given location.

7. 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. One major missing component is a comparison of these LCOE values to the costs of avoided energy due to energy retrofits (Rhodes et al., 2016). Energy efficiency analysis with spatial resolution requires significant effort that is beyond the scope of this manuscript. Consequently, the authors are currently working on generating spatial costs for energy efficiency and plan to publish them in a separate paper.

8. 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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Appendix A. Supplementary data

Supplementary data associated with this article can be found in the online version at http://dx.doi.org/10.1016/j.enpol.2016.12.025.

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