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Total cost of carbon capture and storage implemented at a regional scale: northeastern and midwestern United States

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We model the costs of carbon capture and storage (CCS) in subsurface geological formations for emissions from 138 northeastern and midwestern electricity-generating power plants. The analysis suggests coal-sourced CO_2 emissions can be stored in this region at a cost of \$52–\$60 ton^{-1}, whereas the cost to store emission from natural-gas-fired plants ranges from approximately \$80 to \$90. Storing emissions offshore increases the lowest total costs of CCS to over \$60 per ton of CO_2 for coal. Because there apparently is sufficient onshore storage in the northeastern and midwestern United States, offshore storage is not necessary or economical unless there are additional costs or suitability issues associated with the onshore reservoirs. For example, if formation pressures are prohibitive in a large-scale deployment of onshore CCS, or if there is opposition to onshore storage, offshore storage space could probably store emissions at an additional cost of less than \$10 ton^{-1}. Finally, it is likely that more than 8 Gt of total CO_2 emissions from this region can be stored for less \$60 ton^{-1}, slightly more than the \$50 ton^{-1} Section 45Q tax credits incentivizing CCS.

1. Introduction

Reducing the concentrations of atmospheric CO_2 is a critical environmental policy objective for the twenty-first century [1], and new paradigms are being conceptualized to productively use and store carbon waste as part of a 'new carbon economy' [2]. Carbon capture and storage/sequestration (CCS), the removal of CO_2 from industrial effluent streams and storage in geological formations, is an established mitigation strategy [3,4] that has the potential to decrease the rate at which CO_2 is emitted into the atmosphere [5]. More importantly, it is a technology that can progress towards achieving negative emissions through the application of CCS with CO_2 captured from electricity generation processes driven by the combustion of biofuels, i.e. bioenergy with CCS (BECCS) [1,6,7]. BECCS is particularly appealing because it addresses how electricity could be produced in a carbon negative future, making it a potential complement to a portfolio of carbon negative solutions that could comprise the aforementioned 'new carbon economy' [2]. Although there are physical and social challenges to implementing a large-scale deployment of BECCS [8], the potential for negative emissions on a global scale (up to approximately 10 Gt CO_2 yr^{-1} [9]) warrant the exploration of a regional application of CCS that is the logical precursor to BECCS [10].

To explore how the costs associated with CCS might be influenced by geographical and geological constraints in a regional application, we examine the cost of CCS implementation in the northeastern and midwestern United States. We apply an emissions source-geological sink matching model

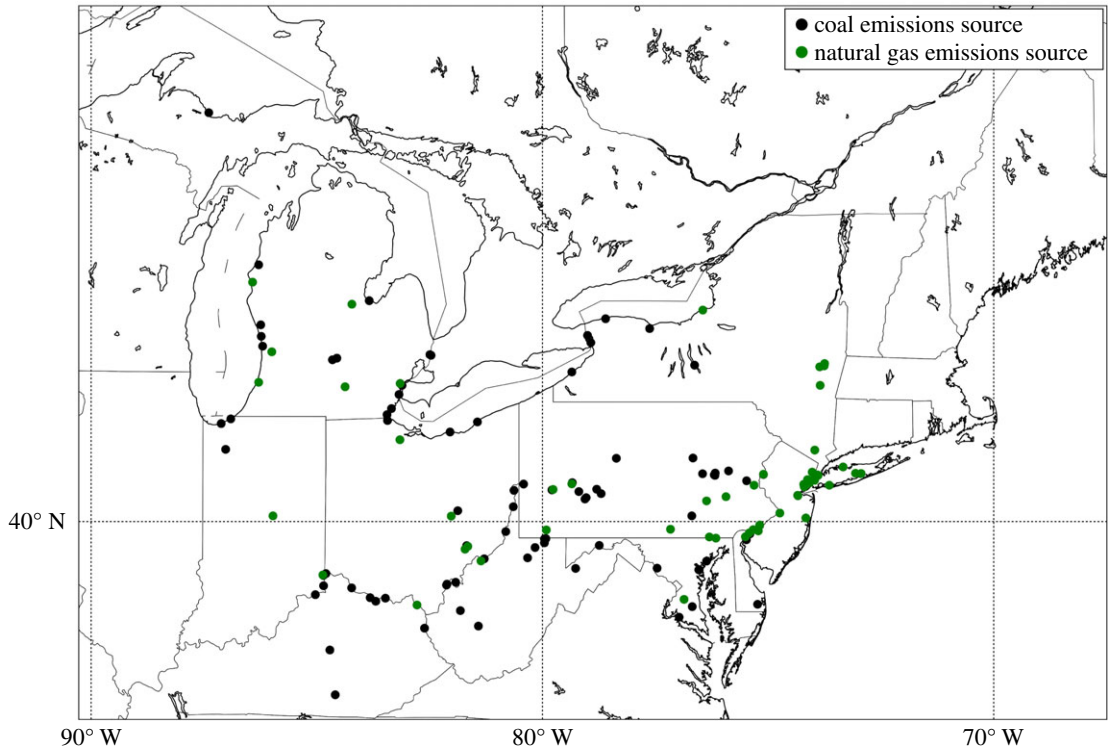

Figure 1. Distribution of large fossil fuel burning power plants, defined as plants that generate greater than 0.4 Mt of per-annum CO_2 emissions, in the northeastern and midwestern United States.

(e.g. [11]) to the use of CCS technologies using literature values of capture, transport, and storage costs coupled with data characterizing the generation of electricity and geological storage reservoirs within the region. In this exercise, we assume that CO_2 emissions would be captured and compressed at the locations of existing power plants, then transported to and injected into nearby geological formations. The cost ton^{-1} of CO_2 stored is determined by:

(i) the cost of capture for a given plant type;
(ii) the cost of transport to the nearest suitable geological storage site; and
(iii) the cost of storage at that site determined by the type of the geological reservoir.

The inputs to our model are literature values of costs for CCS components [12], CO_2 emissions data detailing the locations of and emissions from electricity-generating power plants [13], and geological storage data that define CO_2 storage resources in depleted oil and gas fields and onshore and offshore saline reservoirs [14,15]. We match emissions sources to sinks to calculate the total cost of CCS in the northeastern and midwestern United States, the output of our model. In doing so, we capture the increases in cost as more efficient resources are used, as well as spatial variations in cost across the region. Additionally, because the cost of CCS components is uncertain, we apply a Monte Carlo simulation to assess the likely ranges of total cost and how likely the variety of storage resources are to be used. Within this framework of a source-sink matching model executed as a Monte Carlo simulation, we approach the problem from three perspectives. First, we apply the model to the data using the defined storage capacities [14,15] as the only limitation on CO_2 storage location. Next, we apply the model while filtering the suitable storage locations using a minimum distance between injection sites and a cap on injection rates at individual injection sites; our objective is to assess cost with storage resources limited by the potential effects of local and far-field increases in formation pressures related to large-scale injections of CO_2 emissions across the region [16–20]. Finally, we apply the model to test how much it would cost to store emissions exclusively in offshore saline reservoirs.

The northeastern and midwestern United States provides an idealised case study for this exercise owing to:

(i) the mixture of emissions sources (coal and natural gas) distributed across the region;
(ii) well-characterized geological reservoirs capable of storing a large volume of CO_2 emissions [14,21–23]; and
(iii) the heterogeneity of the reservoir types across the region, i.e. it contains both depleted oil and gas fields and onshore/offshore saline reservoirs.

2. Data and methods

2.1. Data

2.1.1. Point source emissions

The northeast and midwestern United States contains 1308 emissions sources, both industrial and electricity generating, that produce 604 Mt of per-annum CO_2 emissions [14]. An emissions dataset for plants generating electricity in the northeast and midwestern United States contained point locations for each power plant in the region, in addition to the name of the plant, the fuel source and the per-annum emissions [13]. In all, the dataset identifies 343 electricity-generating plants that account for 409 Mt of CO_2 emissions per-annum. We used the 138 largest point sources of CO_2 emissions from electricity-generating power plants that account for nearly 390 Mt of CO_2 emissions in our analysis (figure 1). Of these plants, 82 are coal fired and 56 burn natural gas.

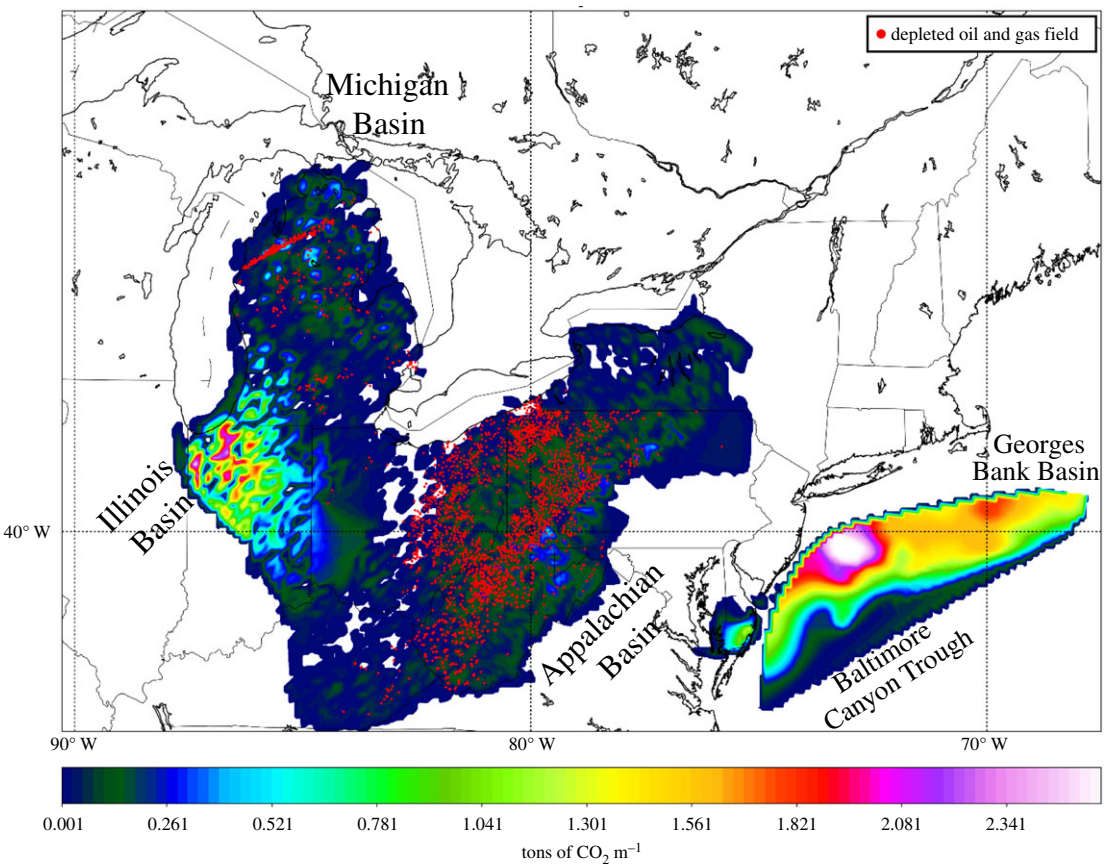

Figure 2. Distribution of geological storage for supercritical CO_2 in the northeastern United States. The coloured digital elevation model grid shows the distribution of saline storage resources, whereas the red dots indicate locations of depleted oil and gas fields that are suitable for CO_2 sequestration.

2.1.2. Geological storage resources

The northeast/midwest region of the United States and the mid-Atlantic offshore has the geological storage capacity to sequester over 500 Gt of supercritical CO_2 emissions in onshore saline formations [14,23], between 150 and 1100 Gt (10th and 90th percentile, respectively) in offshore saline formations [15], and 2.5 Gt in depleted, developed oil and gas fields [14,23]. West of the Appalachian Mountains, the St Peter, Medina, Mount Simon and Rose Run Formations are a few of the porous and permeable formations buried deeply enough for the storage of supercritical CO_2 [14,23]. These formations, in addition to the Devonian Shales of Michigan, Ohio, Pennsylvania and West Virginia, were identified as principal targets for geological storage by the Midwest Regional Carbon Sequestration Partnership (MRCSP) [23]. They form three clusters of storage space west of the Appalachian Mountains that correlate with the depocentres of the Michigan, Illinois and Appalachian Basins that are separated by structural features—the Kankakee, Findlay and Cincinnati Arches [23]. East of the Appalachians, the sand-prone Waste Gate and Potomac Formations of the Salisbury Embayment are porous and buried to a sufficient sedimentary depth, near the modern shoreline in Maryland, Delaware and New Jersey [21]. Offshore, the Mid-Atlantic U.S. Offshore Carbon Storage Resource Assessment Project (MAOCSRAP) has identified the primary targets to be the offshore equivalents of the Potomac and the Waste Gate Formations [15,22,24] deposited in the Baltimore Canyon Trough—commonly known as the Logan Canyon and Mississauga Formation equivalents of the Scotian Shelf [25], respectively. Combining these targets (figure 2), the region contains a large amount of geological storage space (enough to accommodate over 100 years of the 782 Mt of the per-annum CO_2 emissions [23] generated from stationary sources within the region).

We combined these data to obtain a complete representation of CO_2 storage volume of onshore and offshore, and saline or hydrocarbon bearing geological formations in the northeastern and midwestern United States. For the majority of the study area, we used spatial data compiled by the MRCSP for the fifth edition of the U.S. Department of Energy's (DOEs) National Energy Technology Laboratory (NETL) Carbon Storage Atlas [14]. These data provide the spatial distributions of potential onshore storage volumes across the MRCSP associated states, excluding New Jersey, in both saline reservoirs and in depleted oil and gas reservoirs, but not offshore. The geology for offshore saline storage resources was characterized [22,24] and CO_2 storage volumes were calculated as a part of the MAOCSRAP, and detailed information on the storage volume calculations can be found in Battelle [15].

Modelling studies have indicated that approximations of the effective space available to store supercritical CO_2 within the pore space of the geological formations may be additionally constrained from an applied perspective by the increases in pressure caused by injection of the CO_2 [16,18,19]. Ultimately, the rate of injection must be low enough for pressure to dissipate and remain at a level below the fracture threshold of the caprock. Modelling studies of the flow of injected CO_2 and the associated pressure build-up for the Mt Simon formation within the Illinois basin have indicated that injection of 5 Mt of CO_2 yr^{-1} using wells spaced 30 km apart over 50 years would not generate pressure increases exceeding 25% of the pre-injection pressure, which amounts to a fraction of

Table 1. Cost of capture (2018$ per ton CO_2).

plant type	cost	high/low
coal	47	55/37
natural gas	76	114/49

the 65% increase permitted by regional regulations [17,20]. Management of pressure build-up associated with large-scale injections of CO_2 across a basin, or across many basins within a region, might be necessary and would comprise an additional cost [26,27]. The relatively higher porosity and permeability of the offshore formations [28] and relatively older and more brittle nature of the rocks inland of the coastal plain [29] make pressure management a lesser concern for offshore storage. A reservoir model simulating injection into the offshore Logan Canyon formation shows injection rates of up to 6 Mt yr^{-1} generate no pressure management issues [30].

2.2. Cost of carbon capture and storage components

2.2.1. Cost of capture

Application of CCS on a regional scale would probably incorporate a variety of technologies that optimize costs of retrofitting that are specific to individual plants. The cost of capture (table 1) is obtained from Rubin *et al.* [12] converted to 2018$ using [31]. Capture costs are subdivided by power plant type, coal or natural gas. For coal-fired plants, Rubin *et al.* [12] aggregated data from multiple sources [32–38] and reported a representative value of $47 per ton of captured CO_2, whereas Rubin *et al.* [12] estimated plants $76 per ton CO_2 captured from natural-gas-fired plants [12,32,39–42]. We represent the cost of capture as a distribution based on the low, high and representative values (table 1) reported by Rubin *et al.* [12] (electronic supplementary material, figure S1). We did not incorporate the cost of pre-combustion capture herein, but Rubin *et al.* [12] documented a $16 ton^{-1} increase in the representative cost of coal-fired capture using pre-combustion methods. The cost of capture was calculated for each electricity-generating power plant in each iteration of a Monte Carlo analysis by multiplying the per annum emissions of that plant by 30 years and by the fuel source-dependent per ton cost of post-combustion CO_2 capture sampled from the distribution of likely costs we generated (electronic supplementary material, figure S1).

2.2.2. Cost of transport

Pipeline transport of compressed CO_2 would be necessary for a large-scale application of CCS [43], and we model the cost of transport herein assuming pipelines would be used. The cost of CO_2 transport via pipeline is highly variable and depends on the pipeline length, diameter, terrain and route [12,43]. Rubin *et al.* [12] reported the cost for offshore and onshore transport at capacities of 3, 10 and 30 $MtCO_2$ yr^{-1}, aggregating data from a few sources [44–46]. We convert these costs to 2018$ [31]. The costs range from $1.3 per ton CO_2 per 250 km for onshore transport at a capacity of about 30 $MtCO_2$ yr^{-1} to $15.3 per ton CO_2 per 250 km for offshore transport at a rate of 3 $MtCO_2$ yr^{-1} [table 2; 12,45,46]. We create distributions for the cost of transport at each of the three pipeline capacities reported by Rubin *et al.* [12]. These distributions are sampled in each iteration of the Monte Carlo analysis within our model to determine the per ton CO_2 per km cost of transport. Notably, our simplified application does not account for the significant economies of scale that come with planned pipeline networks organized to facilitate the efficient transport from clusters of emissions point source locations to clusters of geological sinks [43,47,48].

Table 2. Cost of transport (2018$ per ton CO_2 per 250 km).

location	pipeline capacity	high	low
onshore	3 Mt	7.4	4.4
	10 Mt	3.8	2.3
	30 Mt	2.3	1.3
offshore	3 Mt	15.3	7.4
	10 Mt	4.9	3.5
	30 Mt	2.5	2.0

To determine the cost of transport via pipeline, the nearest suitable geological storage site needed to be identified for each power plant. For the saline reservoirs, the nearest suitable onshore and offshore reservoir for each plant was found by generating a three-dimensional shape that 30 years of CO_2 emissions would form, then calculating the spatial locations with sufficient geological storage to contain those dimensions of sequestered CO_2. The search was implemented programmatically, for each plant, by convolving the three-dimensional shape that 30 years of CO_2 emissions would form with the onshore and offshore grids of saline geological storage (figure 3*a*,*b*). The resulting values were then divided by the maximum value of autocorrelation of the three-dimensional shape representing 30 years of CO_2 emissions (or the maximum value of convolution of that shape with itself). Resulting values greater than or equal to one represented space where the three-dimensional shape of 30 years of CO_2 emissions could be accommodated by the grids of saline geological storage (represented by black isoline in figure 3*c*).

Having determined the spatial extent of where a given plant's 30 year emissions could be stored, we then searched for the onshore and offshore locations nearest to the plant location itself (figure 3*c*). These distances represented the distances of transport to the nearest suitable saline reservoirs. Cost to transport CO_2 to this location was determined by multiplying the per annum emissions by the appropriate cost of transport per ton CO_2 per unit length of pipeline for that iteration of the Monte Carlo analysis [table 2; 12,45,46].

The storage capacity of the depleted oil and gas fields were stored as volumes located at a point representing the centre of the field. Therefore, the nearest field with a CO_2 storage volume sufficient to store the 30 year CO_2 emissions for a given plant was found. The distance between the location of the power plant and the nearest suitable depleted oil and gas field was then multiplied by cost of transport per ton CO_2 per unit length that was determined with a procedure identical to the one applied to find cost of transport per ton CO_2 per unit length for the saline reservoirs. For each plant, only one of the three calculated transport cost values (cost of transport to the most economical onshore saline reservoir, to the nearest offshore saline reservoir or to the nearest depleted oil and gas field) is used. This is a function of both the transport cost and the storage cost for each plant.

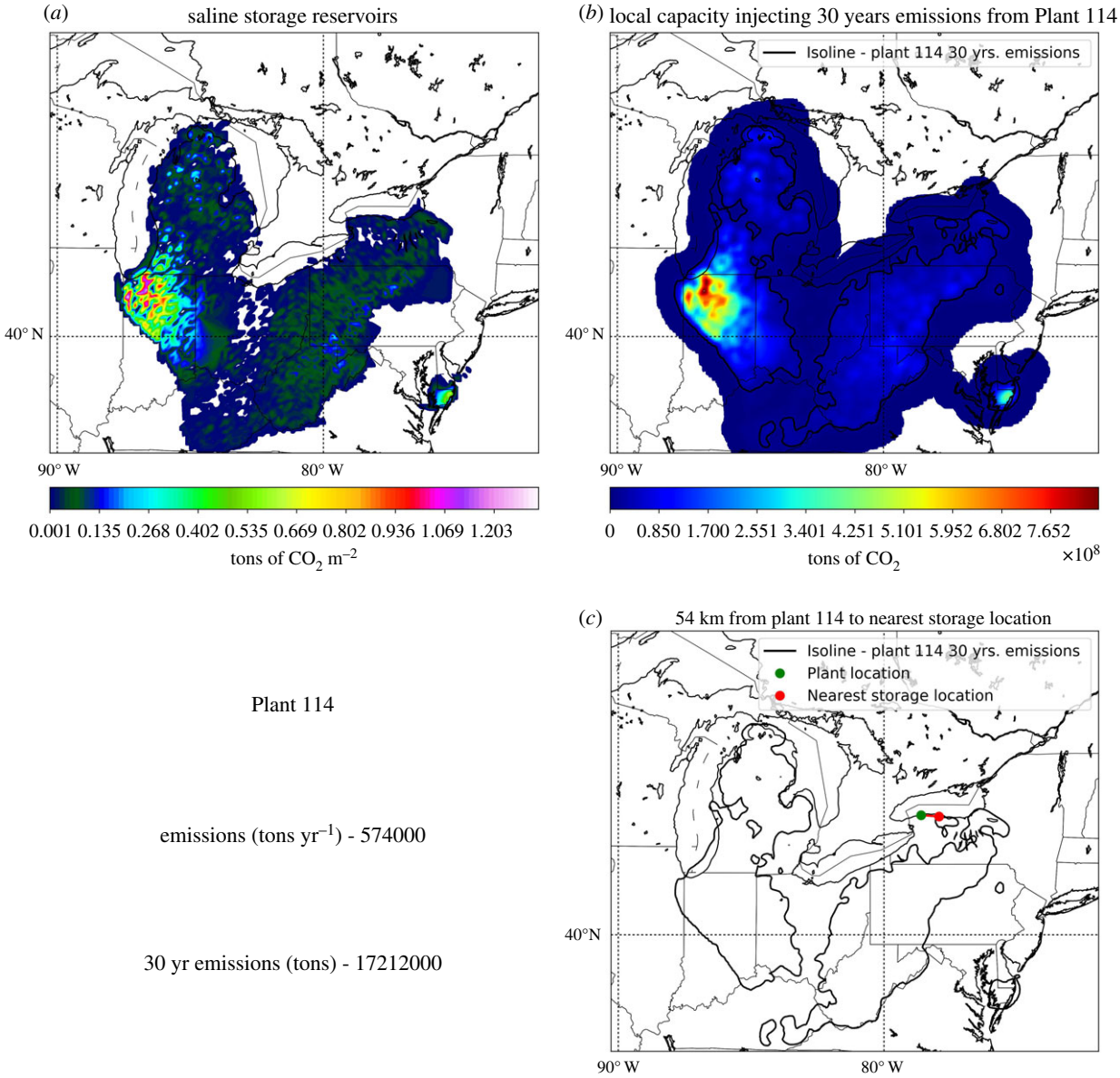

Figure 3. (*a*) Grid portraying spatial variability of saline, geological CO_2 storage space in the northeastern United States. (*b*) Tons of CO_2 that could be stored at any given location in the United States, with an isoline drawn for locations where geological storage space is equal to the 30 year emissions of 'Plant 114', which is located in western New York. (*c*) Image portraying the aforementioned isoline and a plotted line connecting the plant location (green dot) with the nearest storage location (red dot).

2.2.3. Cost of storage

The cost of storage (table 1) is obtained by converting the values reported in Rubin *et al*. [12], aggregated from many sources [38,45,49,50], and converted to 2018$ [31]. These cost estimates are generalizations made for particular reservoir types, such as saline formations, depleted oil and gas reservoirs, and their location onshore or offshore that is admittedly heterogenetic with respect to core characteristics like porosity and permeability. However, because we are interested in assessing the regional deployment of CCS, we assume that much of the multi-kilometre scale spatial heterogeneity will be averaged out over the many injection sites that would be required for a large-scale regional application, and that the broader values defining costs based on general geology can be reliably used.

Generally, onshore storage is less expensive than offshore storage, and storage in depleted oil and gas fields is less expensive than storage in saline reservoirs (electronic supplementary material, figure S1). The representative cost of storage ranges from $5 per ton CO_2 in depleted oil and gas fields located onshore, to $18 ton^{-1} CO_2 in an offshore saline reservoir. Onshore saline reservoirs store CO_2 at a cost of $6 ton^{-1} CO_2. Our study area did not contain depleted oil and gas fields offshore. We represent the cost of storage as a distribution based on the low, high and representative values for onshore saline formations, offshore saline formations and depleted oil and gas reservoirs reported by Rubin *et al*. [12] (electronic supplementary material, figure S1). In addition to the three storage options (table 1), we allowed storage capacity to be expanded twofold at the cost of producing brine from the onshore saline formations. The cost of brine production was defined as a distribution of values peaking between the $2 and $31 ton^{-1} of CO_2 cited by Davidson *et al*. [27] (electronic supplementary material, figure S1), which falls within the end member values calculated by Harto & Veil [26]. The cost of storage was calculated in each iteration of a Monte Carlo analysis by multiplying the per annum emissions for individual point source locations by 30 years and by the reservoir-type dependent per ton cost of CO_2 storage sampled from the distribution of likely costs we generated (electronic

supplementary material, figure S1). If brine was produced, the per ton cost of cost of brine sampled from the distribution of brine production costs we generated (electronic supplementary material, figure S1) was multiplied by the per annum emissions for individual point source locations and by 30 years, then added to the cost of storage. We consider the brine production to be a part of the storage component of CCS herein.

2.3. Total cost calculations

2.3.1. Total cost with no constraints on storage location

Finding the most economical storage location for a given plant first required calculating the optimal total cost of CCS (capture, transport and storage) for each plant's 30 year emissions, i.e. allowing overlap of storage. The plant with emissions that could be stored most economically was allocated the storage space it used to do so. This space was removed from the available reservoirs, and the optimal cost of storage for each of the remaining plant's 30 year emissions was calculated, and the remaining plant with the least expensive CO_2 storage was allocated the requisite storage space. This was repeated until the emissions from each plant were accounted for. We allowed the production of brine to double the volumetric capacity of onshore saline reservoirs in this model run.

2.3.2. Total cost with 50 km spacing of injection locations and a 5 Mt yr^{-1} cap on injection rate

Regional scale CCS will undoubtedly require many wells to inject CO_2 emissions into the subsurface reservoirs the region. If fluid is not also simultaneously removed from these reservoir rocks (e.g. for enhanced oil recovery (EOR)), pressure will build not only locally near the injection sites but also in areas away from the site itself [17,51]. If enough pressure is created, from local injection or through the creation of an overpressurized region from many injection sites, there is a risk of losing the structural integrity of the trapping mechanism and fracturing rock or activating faults [52]. Thus, injection into saline reservoirs may require a cost to remove brine from the subsurface [27]. The pressure build-up can affect areas away from the injection site, an area much larger than the plume of CO_2 owing to displacement of fluid within the subsurface [17,51]. To account for the management of formation pressures owing to far-field effects from injection sites elsewhere in the region and locally at the injection site itself, we ran the analysis requiring (a conservative) distance of at least 50 km between injection sites while capping the injection rate at 5 Mt yr^{-1}. The cap on injection of 5 Mt yr^{-1} with 50 km well spacing (sustained over 30 years) in our study approximate the 5 Mt yr^{-1} and 30 km well spacing modelled by Birkholzer & Zhou [17] for the Mount Simon Formation in the Illinois Basin (figure 2). We allowed brine production to double the volumetric capacity of and the injection rate allowed within onshore saline reservoirs in this model run.

2.3.3. Total cost of offshore storage

Finally, we assessed the cost of storage if sequestration was limited to offshore saline reservoirs. This was accomplished by repeating the original methodology using only the offshore saline reservoirs for storage.

Table 3. Cost of storage (2018$ per ton CO_2).

location	reservoir type	cost	high/low
onshore	oil and gas	5	13/1
	saline	6	15/3
offshore	saline	18	25/8

3. Results

3.1. Cost of regionally applied capture, transport and storage of CO_2 with no constraints

Emissions that originate from coal-fired power plants and are stored in depleted oil and gas fields are likely to comprise the lowest cost ton^{-1} of sequestered CO_2 emissions (table 1, table 3, and electronic supplementary material, figure S1). In application, the lowest likely per ton cost of CO_2 emissions is approximately \$50 ton^{-1} and, consequently, these emissions are likely to be coal generated and stored in nearby depleted oil fields (figure 4). About 60% of the first 2.9 Gt stored are likely to be stored in depleted oil and gas fields (figure 4). The source of these low-cost storage options coal-fired power plants in close proximity to depleted oil and gas fields are primarily located in West Virginia, Ohio, western Pennsylvania and western New York (figures 5 and 6).

Coal generated emissions that are stored in saline reservoirs comprise a little less than 50% of the first 5.8 Gt CO_2 emissions stored, with an average cost less than \$55 ton^{-1}. From 5.8 to 8.7 Gt CO_2 emissions stored regionally, the percentage of storage in saline reservoirs increases to 80%, at an average cost of \$58 ton^{-1}. The overwhelming majority of these emissions would be from coal generated sources in Kentucky, Indiana, Michigan, Ohio and Pennsylvania (figure 6).While it is possible that some emissions would be stored offshore based on cost within the first 8.7 Gt, it is likely to be a very small percentage of the total emissions stored. There is a significant increase in cost associated with the capture of CO_2 emissions from plants that generate electricity from natural gas (table 1 and electronic supplementary material, figure S1). CO_2 emissions from natural gas generated electricity would comprise the majority of the emissions stored after 8.7 Gt is stored regionally at an average cost of \$87 ton^{-1}.

Under these assumptions, offshore storage or brine production is not likely to be adopted owing to economic considerations because the onshore storage can accommodate all CO_2 emissions in the northeast and midwest United States at a lower cost. If the cost of either brine production or offshore storage is actually at the low end of the reported range (table 1 and electronic supplementary material, figure S1), it is likely that these resources would account for approximately 10% of the total storage in this region (figure 4).

3.2. Cost assuming constraints induced by formation pressure concerns for large-scale application of carbon capture and storage

When we incorporate a condition into our model that prevents any two injection sites from being placed within 50 km and cap the injection rate at any one injection site at 5 Mt yr^{-1}, the optimal allocation of storage resources changes (figure 4 and figure 7). The lowest cost storage space is still likely to

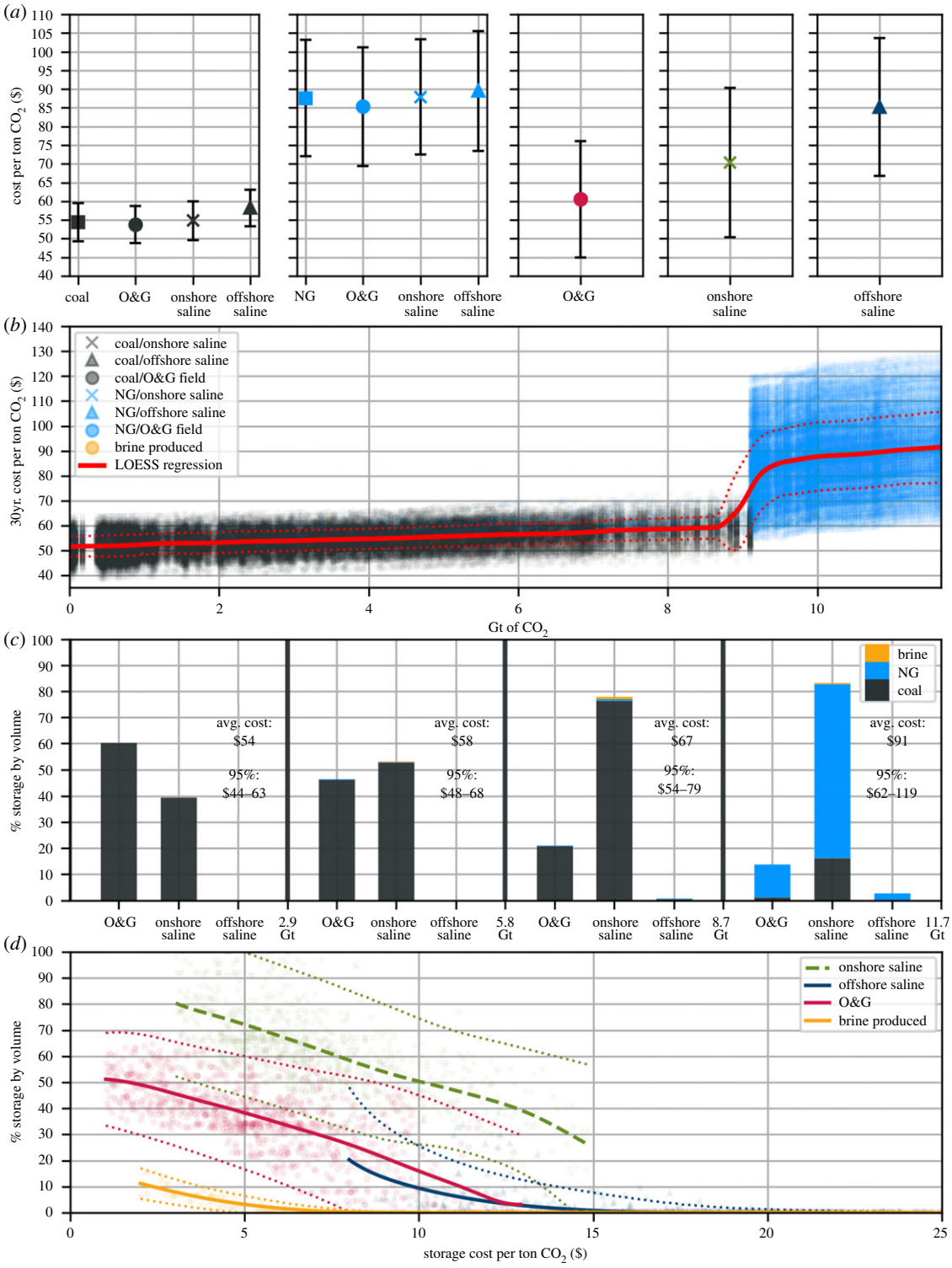

Figure 4. (*a*) Estimations of cost for capture, transport and storage of all CO_2 emissions generated by coal and natural-gas-fired power plants into depleted oil and gas fields, or onshore or offshore saline reservoirs. The average values are bracketed by one standard deviation for each category. (*b*) The total cost of CCS for each source-sink pair generated within a Monte Carlo implementation of our source-sink matching model of regionally applied CCS. The Monte Carlo scheme samples from distributions of costs for each of the CCS components. The total cost for each source-sink pair is plotted against the total amount of CO_2 stored within each model run, assuming the least expensive emissions are stored first. A locally weighted least squares regression (LOESS) regression of these data represents the likely cost of CCS with respect to the total volume of CO_2 stored. (*c*) Fractions of the volume of CO_2 stored within each storage resource type, and the faction of those volumes that originate from coal or natural-gas-fired plants, within four bins of volume stored. Average total costs for each bin are listed in addition to high/low total cost values that bracket 95% of the data. (*d*) The fraction of total volume stored in a given geological storage resource type plotted against the cost of storage assigned within that iteration of the Monte Carlo simulation. As storage costs decrease for a given resource type, the likely faction of the total volume stored within that reservoir type increase.

comprise depleted oil and gas fields (figure 7, table 1, and electronic supplementary material, figure S1). This resource is likely to store approximately 30% of the first 2.9 Gt of CO_2 emissions at an average cost of \$54 ton^{-1} (figure 7). Most (approx. 90%) of the 2.9th to 5.8th Gt of CO_2 emissions would be stored in onshore saline reservoirs, at an average cost of \$58 ton^{-1} (figure 7). Offshore storage would probably be adopted within the 3rd to 5th Gt of emissions stored, where it is likely to account for a small percentage of the total storage. After 5.8 Gt of emissions are stored, offshore

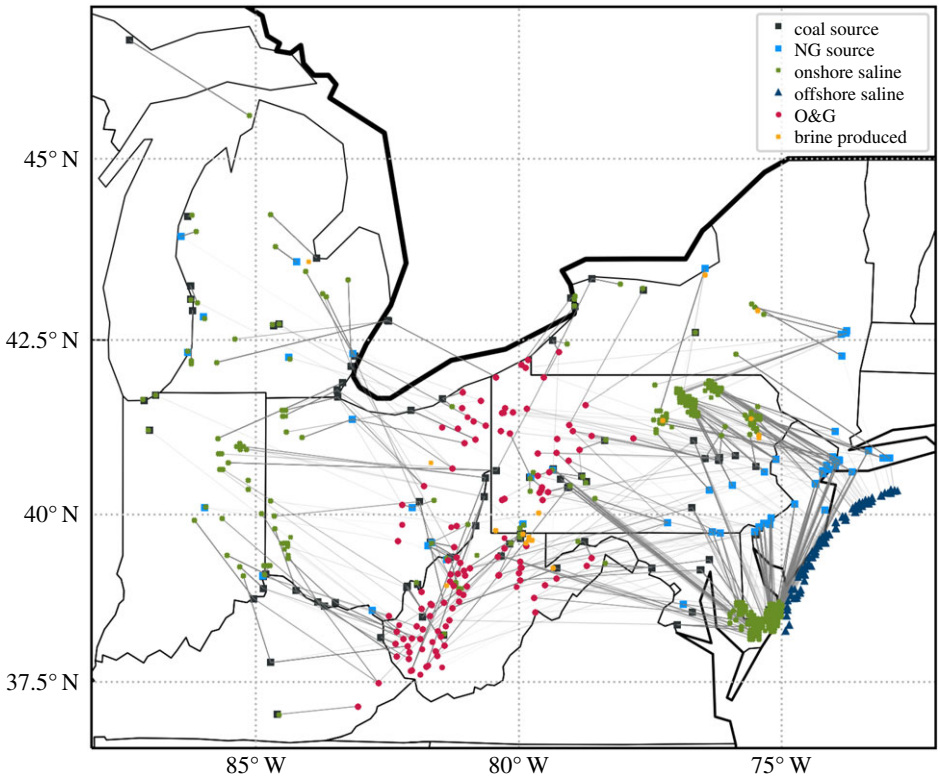

Figure 5. The spatial distribution of CO_2 emissions sources and corresponding geological storage locations of the 138 largest electricity-generating power plants in the northeastern United States. A set of grey lines connect emissions sources with the geological storage locations that are likely candidates to store a given plant's emissions within our source-sink matching model. The markers on the map are colour coded to indicate the emissions source types and geological storage types.

storage would probably account for approximately 30% of the total emissions stored and brine production could be required to store approximately 25% of these emissions. The storage component of total cost is likely to be greater for the pairs that store offshore than it is for those that store onshore (table 3 and electronic supplementary material, figure S1), although the transport cost is probably lower for these source-sink pairs than for the pairs stored onshore.

Coal-fired emissions from Maryland, Pennsylvania and New Jersey would potentially be the first emissions stored offshore. The production of brine is also employed as more CO_2 emissions are stored with this set of constraints. The opportunity to increase injection rates in a particular locality [27] might make brine production a useful component of any large-scale CCS or BECCS implementation, particularly if formation pressure build-up is a critical issue at the injection rates required for Gt-scale storage of CO_2 emissions across the region and if the cost of disposal is low. At a cost of disposal less than \$9 ton^{-1} of CO_2, our model suggests that brine production would be likely to facilitate storage of greater than 20% of the total volume of CO_2 stored in the region if all emissions were to be sequestered. At the representative per ton costs for offshore storage (\$18) and brine production (\$15), these storage options would account for 17% and 10% of total storage, respectively.

The lowest total cost for natural-gas generated emissions is likely to be approximately \$70 ton^{-1} (figure 7), and most of the lower cost pairs are midwestern plants in Michigan, Ohio and West Virginia that would store emissions in depleted oil and gas fields (figures 8 and 9). Natural-gas-fired plants in New Jersey, Delaware, and Maryland are likely to store within saline formations in Maryland (figure 8). Most of the emissions from natural-gas-fired plants in eastern Pennsylvania are likely to be stored in saline reservoirs in Pennsylvania and Maryland (figure 8). Natural-gas emissions from a cluster of power plants in northern New Jersey and Long Island are the most likely to be stored offshore at a cost that is likely to be a little over \$90 ton^{-1} (figures 7–9). Natural-gas emissions from New York state would probably be stored in western New York or Pennsylvania (figure 8).

3.3. Cost assuming only offshore storage

We show the cost of implementing CCS exclusively using offshore storage resources for all power plants east of −80.0° longitude (figures 10 and 11). The emissions source type and distance to the storage reservoir are only two variables that determine cost within this model. Therefore, the closest coal-fired plants—located in Maryland, Delaware and New Jersey (figure 11) —generate the lowest cost CO_2 emissions for sequestration offshore. This would probably cost a little over approximately \$60 ton^{-1} (figures 10 and 11). The natural gas generated emissions would be likely to be stored offshore for a total cost of \$95–\$100 ton^{-1}. In all, the cost for offshore storage would range from \$65 to \$105 ton^{-1} to store the 4+ Gt of CO_2 that would be emitted from this subset of the power plants we considered.

4. Discussion

4.1. Offshore storage

Storing CO_2 emissions exclusively offshore would represent a penalty in terms of cost. Therefore, unless there is a political, social or other 'hidden' cost associated with onshore storage, offshore storage is only necessary if the closest onshore

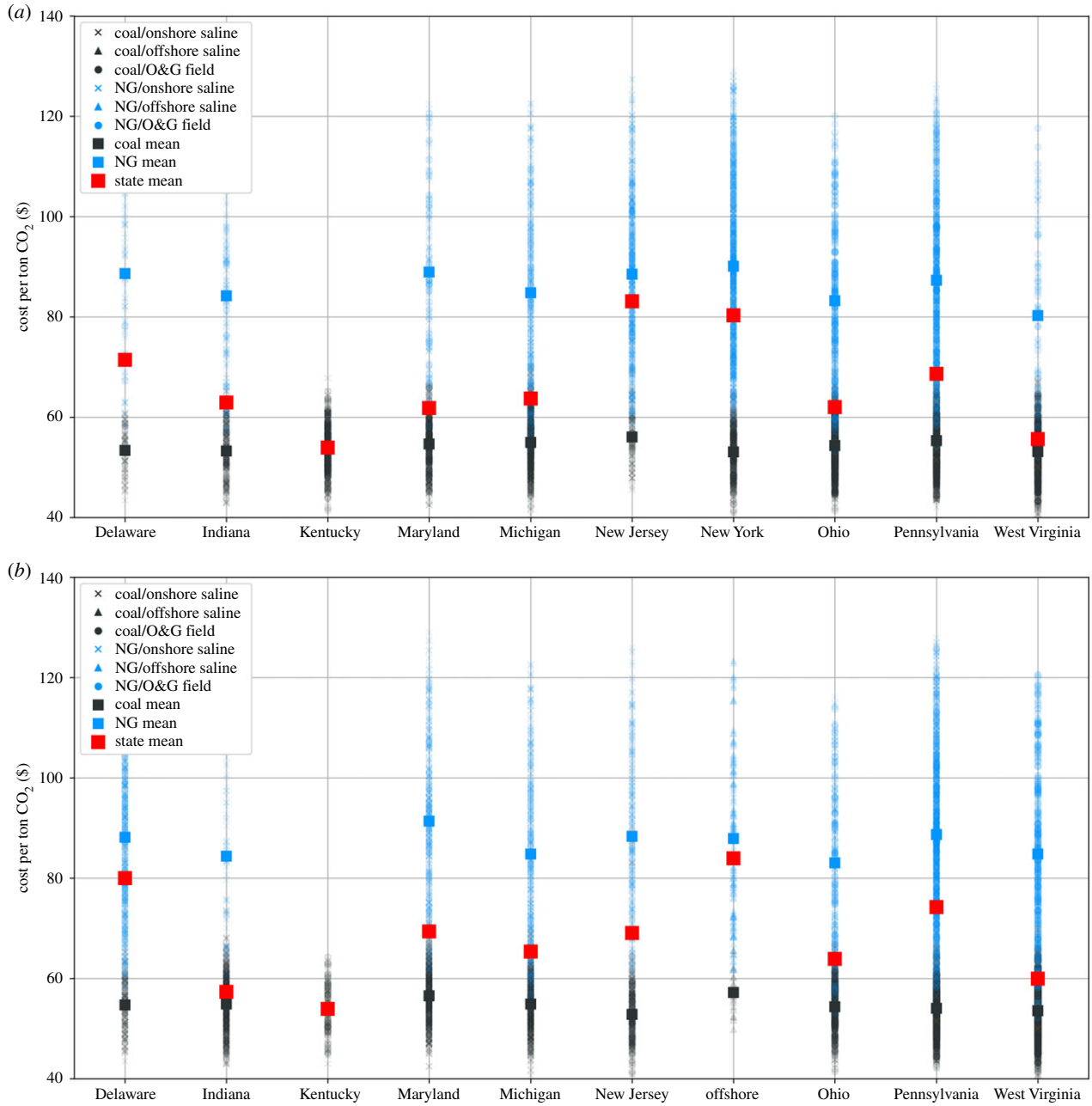

Figure 6. (*a*) Cost of capture, transport and storage of CO_2 emissions organized by state, with the total cost spatially assigned to the location of the CO_2 emissions source. (*b*) Cost of capture, transport and storage of CO_2 emissions organised by state, with the total cost spatially assigned to the location of the geological storage site.

reservoirs are already occupied or otherwise unsuitable. As we note, a conservative approach acknowledges that the generation of formation pressure from large-scale injection of CO_2 into the subsurface onshore might require management of formation pressures by producing brine [16,26], potentially at a cost of \$2-\$31 ton^{-1} of CO_2 [26,27]. Our results suggest that total cost of emissions stored offshore is likely to be less than \$15 more expensive than it would be onshore (figures 4 and 10), making offshore storage usually more attractive than production of brine. In our model run that includes no constraints on storage based on proximity to other sites or injection rate, brine was produced at lower costs, accounting for as much as 20% of the total storage at \$2 ton^{-1}, but no brine is likely to be produced at a cost greater than approximately \$7 per ton of CO_2 stored (figure 4). If the proximity of adjacent injection sites was constrained by a minimum distance of 50 km and injection rate at individual sites was limited to 5 Mt yr^{-1}, brine production and offshore storage would probably play a larger role in storage, particularly after the first 3 Gt of CO_2 emissions are stored (figure 7). From 5.8 Gt to 11.7 Gt of CO_2 emissions stored (30 years total), offshore storage would probably account for over 30% of the emissions stored, and if the cost for offshore storage is low (e.g. \$8 ton^{-1}), offshore storage would probably account for up to 35% of all storage in the region (figure 7). Combined with brine production, these two storage strategies are likely to account for over 50% of the total storage after the first 5.8 Gt of CO_2 are sequestered. So, if formation pressure is a concern, formation pressure management via brine production and offshore storage resources are probably needed to maximize volumes of CO_2 sequestered via CCS in the northeastern and midwestern United States.

We speculate that in addition to profit and geological risk-based motivations for offshore storage, there are

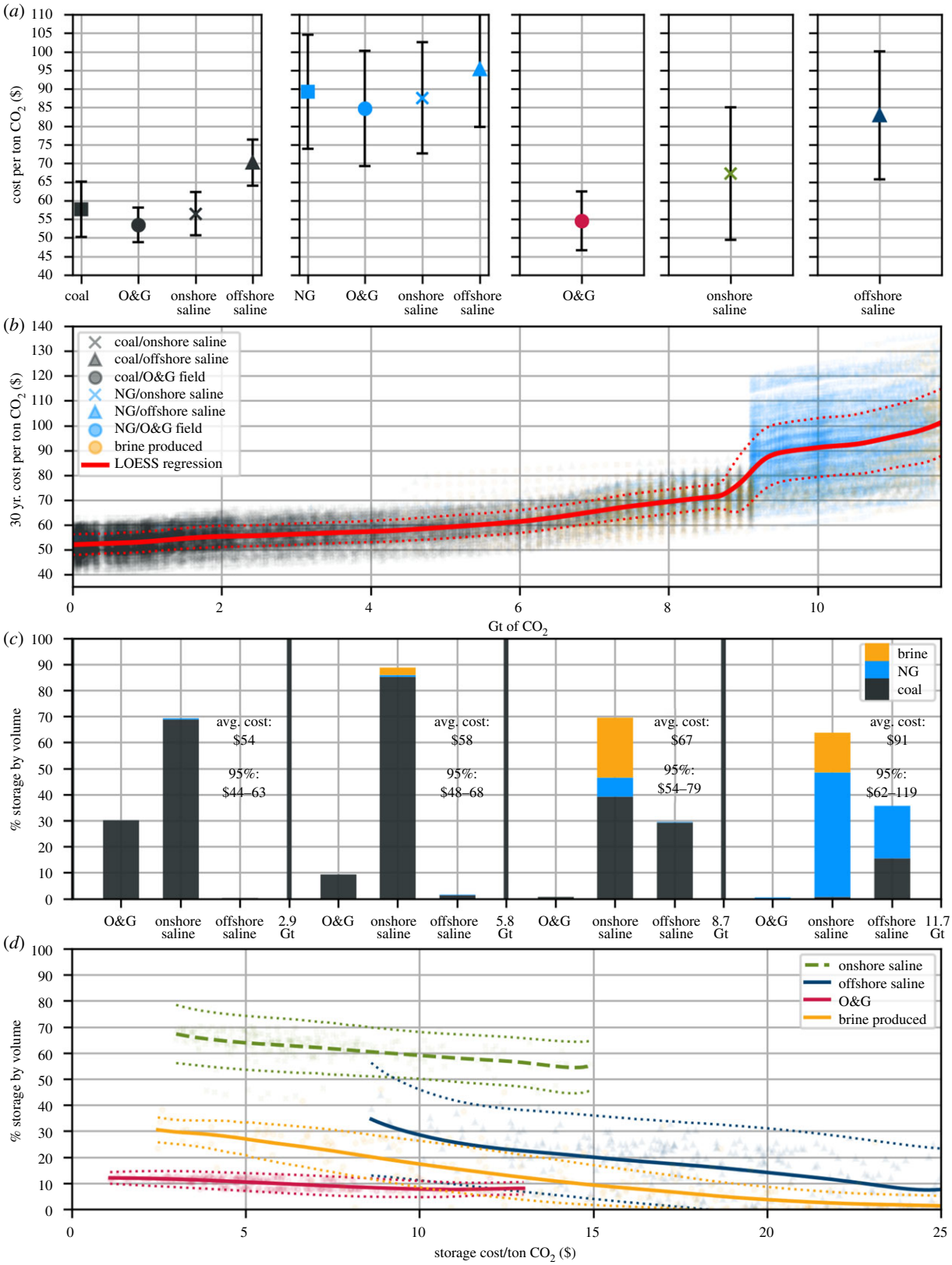

Figure 7. Replication of figure 4, that shows (*a*) estimations of cost for capture, transport and storage of all CO_2 emissions for all emissions and storage resource types, (*b*) the total cost of CCS for each source-sink pair generated within a Monte Carlo implementation of our source-sink matching model of regionally applied CCS, (*c*) fractions of the volume of CO_2 stored within each storage resource type and that originated from each emissions source type, within four bins of volume stored, and (*d*) the fraction of total volume stored in a given geological storage resource plotted against the cost of storage within that reservoir type for our source-sink matching model, with the added condition that each geological storage site must be spaced 50 km from adjacent sites and that the injection rate for injection sites does not exceed 5 Mt yr^{-1}. Brine production doubles the maximum allowable injection rate.

implementation concerns, including opposition to pipelines and drilling, that may preclude storage in onshore sites in locations where oil and gas extraction has not taken place (e.g. New Jersey and Delaware) (e.g. [53]). Even in locations with populations amenable to industrial drilling and production, induced seismicity from subsurface wastewater disposal associated with fracking wells has generated a local and national awareness of these hazards [54,55] and similar

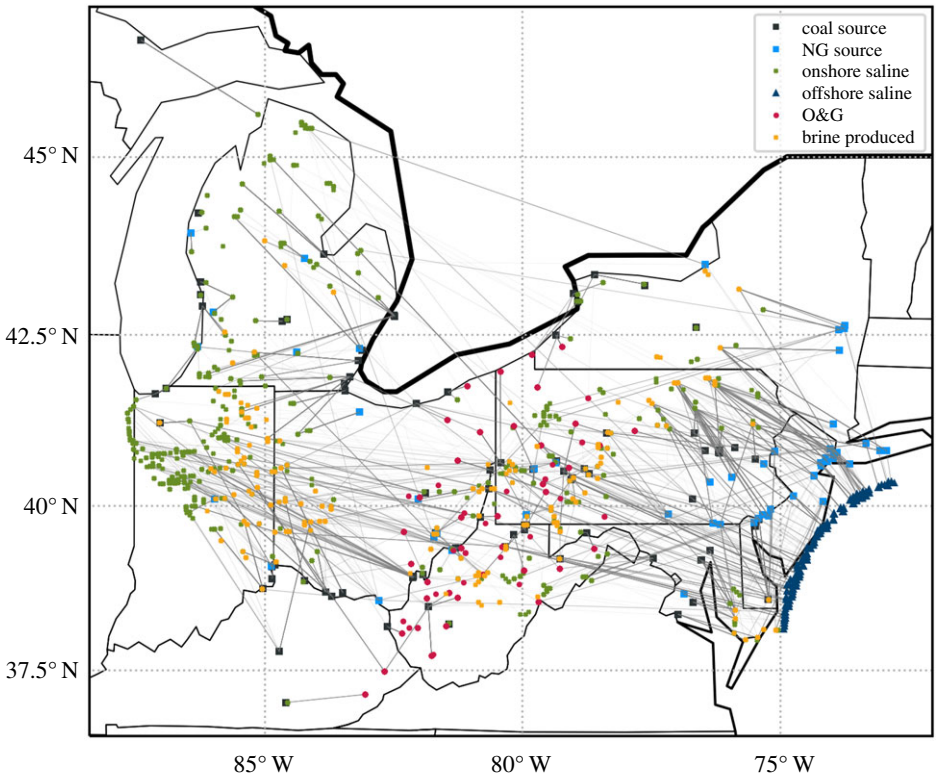

Figure 8. Replication of figure 5 that shows the spatial distribution of CO_2 emissions sources and corresponding geological storage locations of the 138 largest electricity-generating power plants in the northeastern United States for a model run that required each storage site to be spaced 50 km from adjacent sites and that the injection rate at each site does not exceed 5 Mt yr^{-1}. Brine production doubles the maximum allowable injection rate.

concerns may be raised about subsurface storage of supercritical CO_2. High-profile opposition to the construction of new pipelines has halted construction in areas that have been typically supportive of industry activity [56]. We suggest that offshore storage may not face the same level of political opposition because it moves CCS infrastructure, and some of the associated perceived risks [57], a distance away from onshore populations. Difficulties constructing a new large-scale pipeline infrastructure (including likely opposition to offshore pipelines) would be a significant hurdle for large-scale application of CCS [58], but possibly a lesser hurdle for operators in coastal communities as offshore transport would be less visible and would not impact the local population.

4.2. Policy considerations and economic incentives associated with EOR

EOR and the Section 45Q tax credits make CCS an economically viable technology today. Enacted in 2018 by the 115th United States Congress, the Section 45Q tax credits allot \$50 per ton CO_2 in tax credits for the permanent sequestration of CO_2 in saline geological formations, as well as \$35 per ton CO_2 for EOR applications of CCS [59]. An incentive system, like 45Q, is needed to encourage adoption of CCS. Commercial-scale adoption of the technology is necessary to facilitate the reduction of the cost of CCS over time through learning-by-doing, which could ultimately improve the likelihood of large-scale adoption and a significant reduction of CO_2 in the atmosphere.

Our results indicate that total cost of CCS exceed the \$50 per ton credit prescribed for CCS without an industrial utilization (i.e. EOR). However, 8 Gt of coal-fired CO_2 emissions can be stored for less than \$60 ton^{-1}, using our representative value estimate (these 8 Gt of CO_2 emissions can be stored economically using the low-end estimate). To store all CO_2 emissions for less than \$60 using the representative values, a 15% reduction in total cost would be necessary. Relative to the other components of CCS, the technology associated with capture is not mature and costs will probably be reduced over time [60]; modelling suggests that the first-of-a-kind to *n*th-of-a-kind costs can be reduced from \$100 to \$150 per ton of CO_2 (2005 to 2006 costs) to \$30 to \$50 per ton [61] as research drives technological improvements. Because capture is the component that is most likely to see a cost reduction [60], this 15% reduction in total cost could be actualized by a 20% reduction in the cost for capture of coal-fired emissions.

Promoting and realizing the reduction in the cost of CO_2 capture below a threshold required for large-scale adoption of CCS without EOR would be a major environmental milestone. Large-scale carbon storage may be additionally justified when coupled with BECCS technology. Similarly, demonstrating the feasibility of CCS could ultimately facilitate a pathway to BECCS. Based on our results, the difference between representative total costs of CCS in the northeastern and midwestern United States and the threshold for profit motivated adoption is relatively small with the Section 45Q credits. With some technological improvement, adoption of CCS on a meaningful scale is possible in this region. With EOR and 45Q, CCS is viable and has been undertaken on commercial scales at the Petra Nova-WA Parish Generating Station in Texas and the Boundary Dam plant in Canada. CO_2 captured at both of these locations is transported to nearby oil fields and sold to enhance recovery [59]. Governments can and should support these initiatives as sound environmental policy, like the United States and Canadian federal

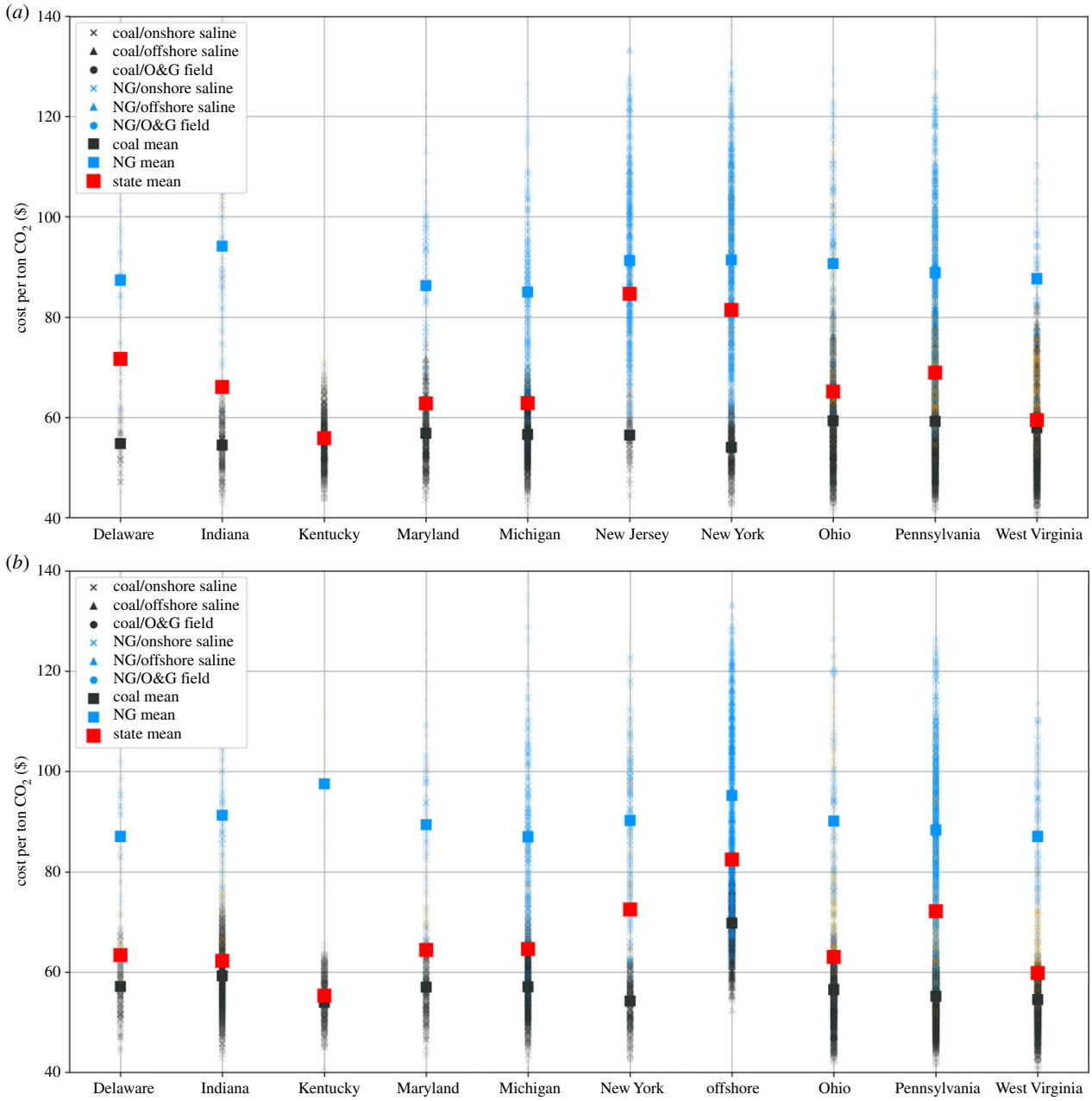

Figure 9. Replication of figure 6 that shows per state cost of capture, transport and storage assigned to the locations of the emissions sources (*a*) and the geological storage sites (*b*), for a model run that required each storage site to be spaced 50 km from adjacent sites and that the injection rate at each site does not exceed 5 Mt yr^{-1}. Brine production doubles the maximum allowable injection rate.

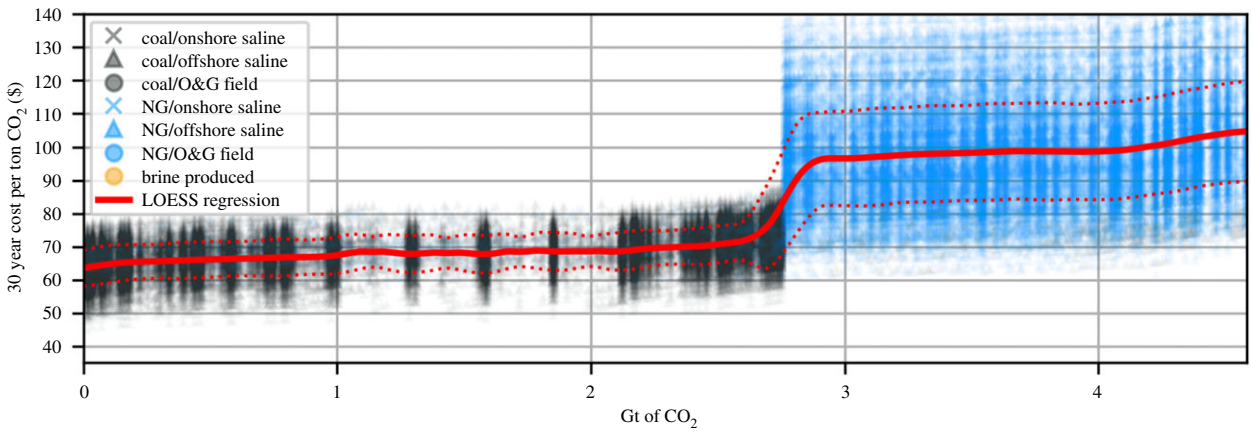

Figure 10. Replication of figure 4 that shows the total cost of CCS for each source-sink pair generated within a Monte Carlo implementation of our source-sink matching model of regionally applied CCS that restricted geological storage to offshore sites.

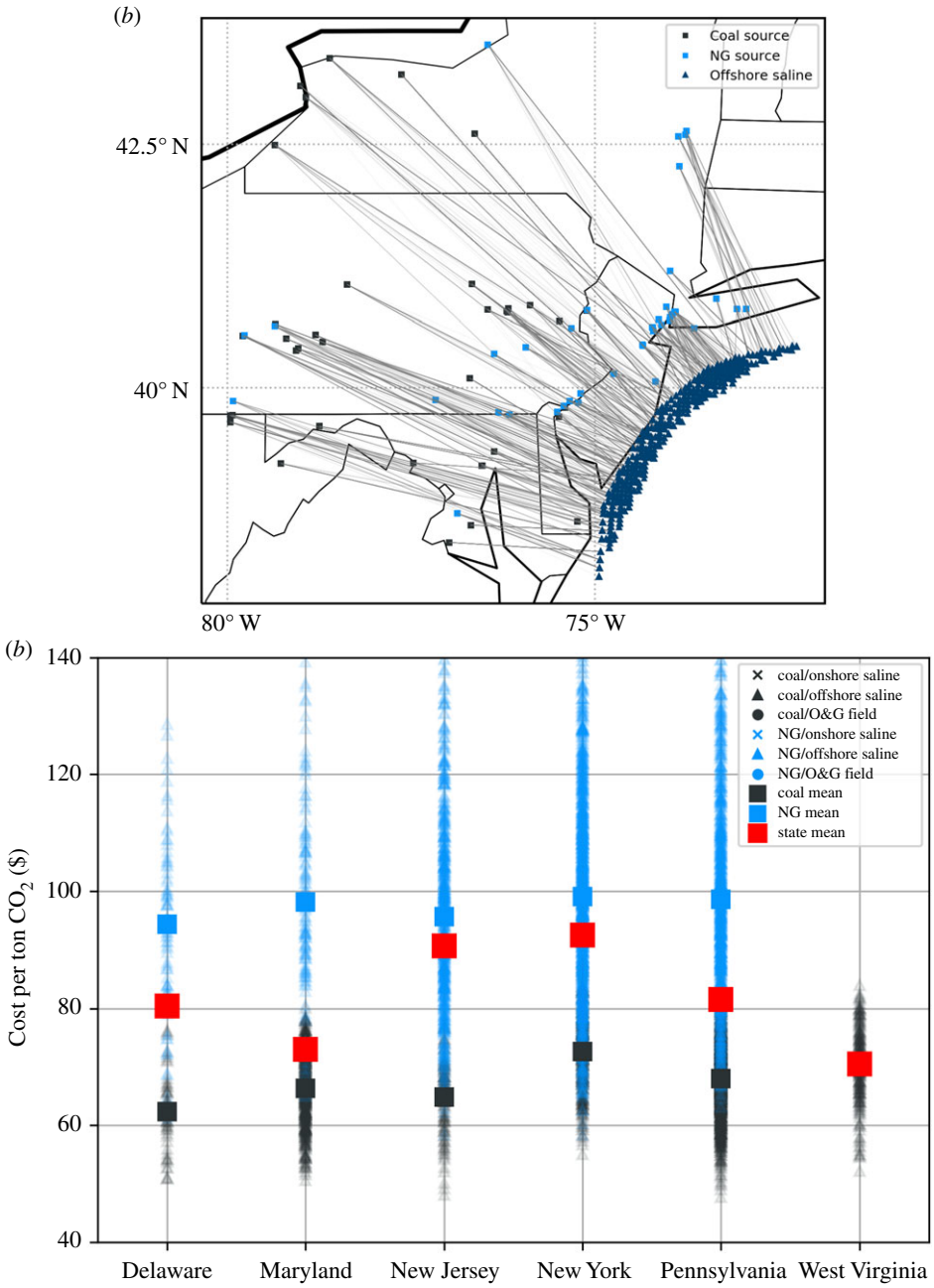

Figure 11. (*a*) Replication of figure 5 that shows the spatial distribution of CO_2 emissions sources and corresponding geological storage locations for a model run that restricted geological storage to offshore sites. (*b*) Replication of figure 6 that shows per state cost of capture, transport and storage assigned to the locations of the emissions sources for a model run that restricted geological storage to offshore sites.

governments did for Petra Nova and Boundary Dam, providing $190 million and C$240 million for those projects, respectively [59]. Grant funding supporting the construction of commercial-scale CCS projects, like the $190 million DOE supplied for the Petra Nova plant, incentivize first-of-a-kind construction that allows for learning, feasibility testing and risk reduction for future commercial implementations.

Considering the substantial capital investment required to construct new power plants, or even to retrofit them with CCS technology, this risk reduction is particularly important. The hazards can be posed in a variety of forms, including but not exclusive to technical, economic and/or political issues. Because there are very few commercial-scale CCS projects to prove feasibility, the risk associated with new projects is relatively high, and particularly so considering the recent and costly high-profile abandonment of carbon capture at the Kemper County energy facility in 2017 [62]. The risk reduction that coincides with CCS successes makes the technology more appealing for commercial adoption and further facilitates financing for these large-scale projects. Considering the risk and long-term planning and capital commitment associated with constructing or renovating electricity-generating infrastructure to serve CCS, the initiative to incentivize early CCS applications should also be coupled with a long-term commitment to the Section 45Q credits.

5. Conclusion

Using literature values for contemporary costs of CCS components and geographical and geological data characterizing energy infrastructure and CO_2 storage capacity, we model the costs of CCS for a regional case study of CCS application within the northeastern and midwestern United States. The least expensive CO_2 emissions stored in the region are approximately $52 ton^{-1}, sourced from coal-fired plants and stored

onshore in depleted oil and gas fields. It is likely that more than 8 Gt of CO_2 emissions can be stored for less than \$60 ton^{-1}, relying heavily on onshore saline reservoirs. Emissions from natural-gas-fired plants are more expensive to capture ton^{-1} of CO_2, making the lowest total costs to store natural-gas-fired emissions over \$80 ton^{-1}. Offshore storage is also more expensive, the lowest total costs of CCS with storage in offshore saline reservoirs are likely to be over \$60 ton^{-1}. However, formation characteristics of offshore storage resources may reduce formation pressure build-up [28] and the associated geological risk [16,29,51]. We propose there would be lower potential for interference from populations than industry activity receives in communities that lack an oil and gas culture and history, and strongly oppose industry activity [53]. If the geological risk associated with formation pressure build-up caused by large-scale application of CCS across the region limits storage capacities from an applied perspective, offshore storage and/or brine production would probably be required to store the entire region's emissions.

To conclude, we view (i) a reduction in capture costs as a potential primer for the large-scale adoption of CCS independent of EOR and a pathway towards the negative emissions and low-impact climate scenarios associated with the adoption of BECCS and (ii) federal government and state incentives and grants directed towards encouraging private commercial-scale implementation of CCS, even if they do incorporate EOR, as sound environmental policy aimed at long-term mitigation of atmospheric CO_2 concentrations.

Data accessibility. This article has no additional data.

Authors' contributions. W.J.S., analysis, data, writing; G.H., idea, analysis, writing, supervised; K.G.M., idea, analysis, writing, supervised.

Competing interests. We declare we have no competing interests.

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