Biomass slurry fracture injection as a potential low-cost negative emissions technology

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Abstract
Negative emissions technologies (NETs) are systems which remove carbon dioxide directly from the atmosphere and sequester it in permanent storage and they are required to meet the goals of the Paris Agreement. However, all NETs are limited by biological, physical and economic factors. Here, we model the life cycle emissions, geospatial potential, technoeconomic feasibility of a new NET based on slurry fracture injection, a technique which has been used for decades in the oil and gas industry to dispose of wastes. In the proposed system, called biomass slurry fracture injection (BSFI), biogeneic wastes are injected into fractures created in permeable saline formations. We calculate that the costs of BSFI are generally lower than $95 tonne$^{-1}$ of CO$_2$ removed, even at biomass prices above $75 dry tonne$^{-1}$. We conduct a geospatial feasibility analysis of the continental U.S. and conclude that adequate biomass, geological storage and wastewater is available to sequester 80 Mt CO$_2$ e yr$^{-1}$. We use global estimates of potential biomass availability to conclude that a mature industry might sequester on the order of 5 Gt CO$_2$ e yr$^{-1}$, over 10% of contemporary CO$_2$ emissions.

1. Introduction
Negative emissions technologies (NETs) are systems that remove CO$_2$ from the atmosphere and store it in long-term sinks. NETs have become a pillar of the global community’s response to climate change, and it is no longer plausible that climate change will be limited to less than 1.5 °C or 2 °C without NETs [1–3]. Due to the low concentration of CO$_2$ in the atmosphere [4], NETs are energy intensive and biophysically limited [5]. For example, one class of NET, direct air carbon capture (DACC), uses chemical solvents to absorb CO$_2$ from air, but is energy intensive [6]. Another NET, bioenergy with carbon capture and storage (BECCS), uses photosynthesis to remove CO$_2$ from the atmosphere followed by energy recovery and carbon capture. BECCS is limited by the low energy density of most biomass and the energy required to scrub CO$_2$ from exhaust. Other potential NETs include enhanced weathering, afforestation and reforestation, biochar, and soil carbon management. Compared to BECCS and DACCs, these systems are inexpensive but are limited by land availability and store carbon in aboveground stocks which may be more vulnerable to loss than belowground stocks.

Given that the scale of negative emissions required to meet the 1.5 °C–2 °C goals increases each year as the global economy continues to emit CO$_2$, and given that the predicted effects of climate change appear more dire as the science improves [7], it is likely that billions of tonnes of NETs will be required each year to avoid more than 1.5 °C–2 °C of climate change [3, 8–10]. Because of the biophysical and economic limitations of all NETs, a variety of NETs will be required. In this context, new NETs are critical to climate change mitigation.

We model a novel NET based on the direct injection of a biomass slurry into a deep geological reservoir using slurry fracture injection (SFI), a method which was developed for the disposal of drilling wastes in the oil and gas industry. This proposed process, which we call biomass slurry fracture injection (BSFI), avoids the energy recovery and carbon capture complexity of BECCS and may be able to achieve lower costs than other NET systems.
2. Slurry fracture injection

The U.S. disposes of a 2 billion gallons (7.5 million m³) of oil and gas related wastewater per day via Class II underground injection wells [11]. However, the injection of a slurry poses challenges that traditional wastewater injection does not because the solid particles of a slurry would clog the pores and damage most formations. SFI is a process to overcome this limitation. In SFI, clean water is pre-injected above the fracture pressure of the formation creating artificial fractures in the formation. The particle-laden slurry is then injected and the solid particles are retained in the fractures of the formation. Following solids injection, the formation is flushed with clean water. A cyclic injection pattern is employed in which a 10–12 h injection cycle is preceded and followed by a brief clean water injection and an about 12-hour shut-in period. During this shut-in period, the injected water bleeds through the formation, reducing the pressure [12] to below the fracture pressure, and the fractures seal [13]. The process then reoccurs each day. Compared to hydraulic fracturing for shale oil and gas production, SFI utilizes lower injection pressures to create shorter, more complex fracture networks near the wellbore. Over time and with multiple injection cycles, these fractures are propagated [14] so that large volumes of solids may be stored.

SFI has been in use since at least 1989 [15], and has been used to dispose of a number of geogenic slurries including drilling fluids, drilling cuttings, naturally occurring radioactive materials, and contaminated soils [16–22]. In most of these cases, SFI occurs over a relatively short period because it is used to dispose of drilling wastes which are only generated during field development. However, in a few cases, SFI has continued successfully for decades. For example, BPA operated a number of SFI systems in Alaska, including one well that was completed in the 1980s and was still operating in 2003, by which time it had injected 6.2 million bbls at a rate of about 3500 bbl per day [22]. Bruno [23] evaluated data from eight injection wells and 500 discrete injections and found little to no evidence of increasing closure pressure or decreasing injectivity with increasing cumulative or per injection solids content, suggesting that long-term injection is possible.

Most notably, since July of 2008, SFI has been used as a means to dispose of biogenic sewage slurries [24] at Los Angeles’ Terminal Island Renewable Energy (TIRE) Project. Injection occurs through a class V well that extends 5300 ft below the surface and is permitted to inject up to 5000 bbls per day at an average rate of 10 bbls per minute and a biosolid concentration of 10%–40% by weight [25]. Between 2008 and 2017, the city injected 440 million gallons million tonnes of waste slurry through a single well [26]. Three additional wells on site serve as back up and observation. To date, injection has not been associated with increased seismic activity [26]. While the purpose of the TIRE project is not to generate negative emissions (but see [27]), its successful, long-term operation suggests that the process is technically feasible in at least some cases.

3. Proposed system

We propose that waste or purpose-grown biomass be collected from one or more biomass production or processing facilities and transported via truck, train or barge to an injection facility where it is ground to <300 µm. Depending on the feedstock, this may or may not be followed by homogenization to further reduce particle size, and very small feedstocks (e.g. cyanobacteria) may not require size reduction.

Next, the biomass is mixed with water. Ideally, the water source would be a wastewater effluent which would otherwise be discharged to surface water, as in a municipal wastewater treatment plant agricultural effluent, but seawater or excess surface water could also be used. Alternatively, in the case of very fresh or wet biomass sources (e.g. water hyacinth), additional water may not be needed.

The biomass-water slurry is then injected into an underground formation via SFI. Given most formation temperatures (under about 75 °C), anaerobic biological digestion may occur and convert the solids in the injectate into CH₄, CO₂ and a digestate. At higher temperatures, thermal decomposition would be expected, but all else equal, higher temperature formations are deeper and more costly to drill than lower temperature formations and so would not be preferred for BSFI. While we expect biological anaerobic digestion could occur, we have no data about its rate, and so we do not include it in the analysis that follows. Nonetheless, degradation is important. If the biomass anaerobically degrades, the resulting CH₄, CO and CO₂, and liquid products could move into the pore space of the formation. This could increase the formation’s ability to accept slurry, but could also allow the produced gases to leak from the formation.

4. Technoeconomic analysis

To investigate the technoeconomic feasibility of a BSFI system, we calculated the net present value (NPV) of a sawmill waste BSFI system using a spreadsheet model. The NPV was sum of discounted cash flows over a 30 year period, and the system included four sub-modules: feedstock purchase, transport, grinding/milling, and injection. Each sub-module was sized to 125,000 dry tonnes of sawmill waste yr⁻¹ which was selected to be consistent with the quantity of mill residues produced by a number of counties in the U.S [28]. Table 1 depicts the major assumptions and their
sources and supplemental table 1 (available online at stacks.iop.org/ERL/17/024013/mmedia) provides additional detail for the purposes of reproducibility.

The feedstock purchase module assumes that the BSFI system purchases sawmill residue from one or more sawmills. Sawmills already sell residues for wood pelletization, and the average costs of the transactions are reported to the U.S. Energy Information Administration. We selected $40 dry tonne−1 as a conservative feedstock price.

Transport costs were calculated on a per mile basis using the Bureau of Transportation Statistics mean estimate of $0.20 tonne−1 mi−1. We set the average transportation distance at 25 mi (40 km), which implies a maximum travel distance of 35 miles (56 km) and a covered area of approximately 3846 mi2 (9961 km2).

Grinding is assumed to be required to mill biomass to less than 300 µm diameter. This diameter was selected because it is used as the screen size in the TIRE project and is industry practice for SFI. Given a sawmill waste system, a significant fraction of the delivered particles would be expected to be under 300 µm and would not need further grinding. However, this fraction may vary from 10% to 70%, depending on wood type and processing method [45–47]. Given this range and in order to be conservative, we assumed that all biomass was ground to less than 300 µm using a 30-tonne h−1 roller mill with cost data taken from a commercial supplier. We assume that biomass is wet ground as this is more energy efficient [33].

Following Grant and Morgan [48], we used drilling costs for the U.S. based on the formula reported in the American Petroleum Institute's Joint Association Survey of drilling costs [39]. The costs per well are given by:

\[
\text{Cost}_{\text{well}} = 0.00003 \times \text{Depth}^2 + 0.0528 \times \text{Depth} - 131.45,
\]

where depth is the well depth in feet and cost is the cost in 2006 $1000. In most cases, we would inflate these drilling cost based on the Oil and Gas Extraction Producer Price Index. However, because of the age of the data and changes in the drilling market, inflation adjustment has the effect of reducing drilling costs significantly. Thus, we left the drilling cost data un-deflated to ensure a conservative estimate. The resulting estimate of $176 per foot for a 5000 ft well is generally consistent with industry figures [49]. Fracturing is accomplished by injecting fresh (non-slurried) water into the formation under pressure, and is accomplished by 2 × 600 hp pumps [26]. Pump operation continues throughout slurry injection, and the energetic costs of pump operation are included in the model.

We assume that injection wells have a 5 year lifespan and that new injection wells are drilled every 5 years. This lifespan is due to the eventual plugging

| Parameter                                      | Value  | Units               | Source/basis |
|------------------------------------------------|--------|---------------------|--------------|
| Biomass input                                  | 125 000| Dry tonnes          | Input        |
| Biomass price                                  | 40     | $ tonne−1           | [29]         |
| Truck transport cost                           | 0.2    | $ tonne−1 mile−1    | [30]         |
| Biomass carbon                                 | 50     | %                   | [31]         |
| Grinder system CAPEX                           | 250 000| $                   | [32]         |
| Grinder system capacity                        | 30     | tonnes hour−1       | [32]         |
| Grinder system maintenance                     | 0.09   | $ tonne−1           | [32]         |
| Grinder energy use                             | 150    | kWh tonne−1         | [33]         |
| Injection rate                                 | 8.33   | bbl min−1           | [26]         |
| Biomass particle density                       | 1500   | kg m−3              | [34–37]      |
| Well depth                                     | 5000   | ft                  | [38]         |
| Drilling and completion CAPEX                  | 882 500| $ well−1            | [39]         |
| P&A Cost                                       | 30 000 | $ well−1            | [40]         |
| Pump size                                      | 1000   | hp well−1           | [26]         |
| Electricity price                              | 0.07   | $ kWh−1             | [41]         |
| Pump operational time                          | 12     | Hours day−1         | [42]         |
| Wastewater pumps and pipeline CAPEX            | 1 056 000| $ per 125 000 t   | Assumed      |
| Biomass handling                               | 250 000| $ per 125 000 t     | Assumed      |
| Contingency                                    | 20     | %                   | High for novel system |
| Labor                                          | 600 000| $ yr−1              | 6 employees  |
| Insurance, pore space lease, and other OPEX    | 300 000| $ yr−1              | Assumed      |
| Other maintenance                              | 10     | % of CAPEX          | Assumed      |
| Carbon assurance                               | 1      | $ tonne−1           | Assumed      |
| Debt/equity                                    | 50/50  |                    | Assumed      |
| Loan term                                      | 10     | yr                  | Assumed      |
| Tax rate                                       | 22     | %                   | [44]         |
| Discount rate                                  | 10     | %                   | [44]         |
of the formation fractures and increasing formation pressures [50] but is particularly uncertain due to the limited experience with the injection of biogenic slurries into underground formations. Kholy et al [13] modeled the total storage capacity of a single well in a high permeability formation and found total storage capacity to be on the order of 900 000 tonnes of solid material, not counting any biological degradation. In our model, each well receives 312 500 tonnes of solids over its 5 year lifetime. Of course, actual storage capacity will vary based on the geology of the reservoir and design of the well. We also assume that 50% of injection equipment is replaced when new wells are drilled. In reality, well failure will be complex (e.g. [20]) and may be treated via a combination of workovers, recompletions, and new drilling. Therefore, we also include well workover costs in the model, budgeted as a maintenance cost at 10% of initial well construction costs.

The regulatory system for BSFI in the U.S. is not clear and regulations will impact costs. The injectate would meet the requirements of a Class I non-hazardous well, however, the EPA only allows SFI on Class II wells (but see [14]). The Los Angeles TIRE project injects via a Class V well which appears to be the most suitable classification. Commensurate with this designation, we include plugging and abandonment costs but do not include the long-term monitoring costs associated with Class VI wells. Presumably, carbon credit buyers would require some long-term assurance of safe storage. Similarly, we do not include legal costs associated with permitting. NETL’s CO2 storage model does include permitting and other ‘back-end’ costs for Class VI wells. For a Class VI well, NETL budgets $6000 in permitting costs plus $10 000 per field [48]. These costs would make a negligible contribution to system economics.

We assume that water is freely provided to the system. This water could be effluent from municipal water treatment or industrial facilities which would otherwise be discharged to surface waters, or it could be surface water from another source. Based on cost data on adequately sized water pipelines [43], we estimate a cost of $25–$50 per foot for water pipelines in the range of 6–12 inches in diameter, corresponding to <300 000 to >600 000 gallons per day. We assume that 20 miles of such pipeline are required, but the actual distance for any given facility is unknown.

Given the specified assumptions, and assuming that revenue is generated per net tonne of CO2 stored (counting CO2 emissions from biomass transport, grinding, and injection, see ‘Life Cycle Emissions’ below), the system has a breakeven CO2 price of $55.0 tonne$^{−1}$ and injects 62 500 tonnes of C per year, equivalent to 229 200 tonnes of CO2, through two injection wells.

The accuracy of the techno-economic analysis is limited by the novelty of the system. Therefore, we conducted a sensitivity analysis in which we evaluated the impact of more frequent formation plugging, a lower maximum injection capacity, more expensive drilling costs, more expensive feedstocks, a lower proportion of carbon in the feedstock, increasing scale, and a variable proportion of solids in the injectate. Figure 1(a) shows that when injection capacity or the well lifetime is very low, costs increase rapidly, but once well life exceeds 5 years and injection capacity exceeds 5 bbls per minute, costs stabilize around $50 tonne$^{−1}$ CO2e. Figure 1(b) shows that the model is particularly sensitive to the proportion of carbon in the feedstock. Therefore, if carbon-rich wastes could be identified (e.g. E. camaldulensis bark), or if a low-cost method of carbonization were used (e.g. torrefaction, hydrochar), costs may decline. Supplemental figure 1 shows the results of other sensitivity analyses.

The analysis is realistic in that the biomass costs represent observed prices on a contemporary market, and the scale of the modeled biomass stock is available from mill residues [28]. However, mill residue typically has existing uses [51], and for large scale implementation of BSFI, alternative biomass stocks would be required. We modified the techno-economic model described above to account for varying biomass types, each with a specific production cost, particle density, and percent C. System size was fixed at 125 000 dry tonnes yr$^{−1}$. Biomass production costs were based on values taken from the literature. In all other respects, the same model parameters were used to allow for comparison. Table 2 shows the assumptions and results. Overall, prices for BSFI ranged from about $38 tonne$^{−1}$ CO2e for distillers’ wet grains (a waste product that is often difficult to dispose of), to about $96 tonne$^{−1}$ CO2e for corn stover, assuming a $100 dry tonne$^{−1}$ feedstock cost. Therefore, as a first approximation, we select $40–$100 tonne$^{−1}$ CO2e as a plausible cost range for BSFI.

5. Marginal negative emissions cost curve

Fuss et al [5] collected data on the approximate costs and negative emissions potential of a variety of NETs. Figure 2 shows these data organized into a marginal abatement cost curve. In the figure, the minimum and maximum costs reported by Fuss et al [5] are used to define the height of each box, while the mean annual global negative emissions capacity is used to define the length. See Hepburn et al [93] for a similar but more optimistic data set. As is clear from the figure, there are a number of NET options available but those with geological storage (DACCs and BECCS) have the highest costs.

Based on the techno-economic analyses above, the costs of BSFI are expected to be near $40–$100 per tonne. Economies of scale and technological maturation may lead to lower costs, while increasing feedstock prices or frequent formation damage would
increase costs. Thus, these costs are subject to significant uncertainty, but we use this range would set the placement of BSFI on the \( y \)-axis of the marginal cost curve (figure 2).

Assuming adequate storage capacity, global biomass availability would determine BSFI’s length along the \( x \)-axis of the marginal cost curve. Global biomass potentials are well studied yet highly variable (table 3). The variation is largely due to different assumptions about land use, food demand, and sustainability. Given that the cost of BSFI is tied to the costs of biomass, the total global potential of BSFI
Table 2. Costs of BSFI given variable feedstocks and feedstock costs.

| Feedstock           | Particle density (kg m$^{-3}$) | % C dry weight | Feedstock cost ($ dry t$^{-1}$) | BSFI breakeven price ($ t^{-1} \text{CO}_2\text{e}$) | Cost context and notes |
|---------------------|-------------------------------|----------------|---------------------------------|---------------------------------------------------|------------------------|
| Wood waste          | 1500 [34, 52]                 | 50 [31]        | 40 [29]                         | 54                                                | U.S.                   |
| Yard waste          | 1000 [53]                     | 34 [54]        | 26–46 [55]                      | 71–89                                             | U.S.                   |
| Non-recyclable paper | 1200                          | 45 [56]        | 36–62 [55]                      | 58–76                                             | U.S.                   |
| Distillers’ wet grains | 1100 [57]                  | 42             | 0                               | 38                                                | U.S.                   |
| Water hyacinth      | 800 [58]                      | 35 [59]        | 40 [60]                         | 90                                                | U.S.                   |
| Willow              | 1300 [61]                     | 50 [62]        | 45–60 [63, 64]                  | 57–66                                             | U.S./EU                |
| Switchgrass         | 1280 [61]                     | 42 [65]        | 50–66 [66, 67]                  | 73–84                                             | U.S.                   |
| Bamboo              | 1050 [68]                     | 47 [69]        | 23–26 [70, 71]                  | 48–50                                             | India, Laos            |
| Corn stover         | 1350 [61]                     | 47 [72]        | 82–100 [73]                     | 84–96                                             | U.S.                   |
| Miscanthus          | 1400 [74]                     | 46 [75]        | 45 [76]                         | 62                                                | U.S.                   |
| Giant Reed          | 1280                          | 43 [77]        | 36 [78]                         | 61                                                | EU; Density assumed similar to switchgrass |
| Ulva                | 1566                          | 25–45 [79–83]  | 21 [84]                         | 48–91                                             | U.S.; density assumed similar to sugar kelp [85] |
| Sargassum           | 1040 [86]                     | 29 [87]        | 25–30 [84, 88]                  | 83–89                                             | U.S.                   |
| Poplar              | 1500                          | 49 [89]        | 25–32 [90]                      | 46–51                                             | Southern Europe; density assumed same as wood |
| Bagasse             | 1000 [91]                     | 51 [92]        | 54 [92]                         | 62                                                | India                  |

Figure 2. Marginal cost curve of negative emissions technologies. Shades of blue are based on data in Fuss et al [5]. Position of BSFI shown in orange.

will depend on the quantity of biomass that could be produced economically and without significantly negative ecological impacts elsewhere in the ecosystem (e.g. eutrophication from fertilizer). In order to be conservative, we use a global biomass availability of 70 EJ yr$^{-1}$ and further assume a high HHV of 18 GJ per tonne [94]. This results in a biomass availability of 4.1 dry Gt of biomass available per year. Assuming that 45% of this dry weight is carbon and that BSFI is 85% efficient (see ‘Life Cycle Emissions’ below), then this is equivalent to 5.4 Gt of negative CO$_2$ emission potential, annually (figure 2).
Table 3. Selected primary global bioenergy supply estimates in 2050.

| Source | Estimate (EJ yr$^{-1}$) | Implied biomass (Gt yr$^{-1}$) | BSFI storage potential (Gt CO$_2$ e yr$^{-1}$) |
|--------|------------------------|-------------------------------|---------------------------------------------|
| Fischer and Schrattenholzer (2001) [95] | 370–450 | 20–25 | 27–33 |
| Yamamoto et al (2001) [96] | 158–342 | 9–19 | 12–25 |
| Hoogwijk et al (2009) [97] | 130–270 | 7–15 | 10–20 |
| Van Vuuren et al (2009) [98] | 50–125 | 3–7 | 4–9 |
| Haberl et al (2010) [99] | 160–270 | 9–15 | 12–20 |
| Dornburg et al (2010) [100] | 200–500 | 11–28 | 15–37 |
| Haberl et al (2011) [101] | 64–161 | 4–9 | 5–12 |
| Beringer et al (2011) [102] | 126–274 | 7–15 | 9–20 |
| Cornelissen et al (2012) [103] | 340 | 19 | 25 |
| Popp et al (2014) [104] | 48–228 | 3–13 | 4–17 |
| Searle and Malins et al (2015) [105] | 60–120 | 3–7 | 4–9 |
| Wu et al (2019) [106] | 110–245 | 6–14 | 8–18 |
| This study | 70 | 4 | 5 |

6. Life cycle emissions

A criticism of biomass-based energy systems is that their lifecycle emissions detract from their climate benefit. In the technoeconomic analysis above, we counted emissions from transport, processing and injection against the net carbon benefit, but did not include biomass production as an emissions source because we assumed a sawmill waste system. In the near term, wastes could be used for BSFI, but if it were to be employed at scale, purpose grown biomass stocks would be required. To estimate CO$_2$ emissions from the biomass production process, we modeled a willow-short rotation coppice (SRC) production system using data from Dias et al [107]. The system boundaries include biomass production, transport, grinding and injection, but do not include the emissions associated with machinery manufacturing or well construction.

We assume that willow is produced and field dried to 12% water, then transported by truck to the grinding and injection facility where it is mixed with water and injected via SFI. As in the technoeconomic model above, the system is scaled to 125 000 dry tonnes yr$^{-1}$. Willow is grown in the Northeastern U.S. or Southern Ontario with production rates of 7 t ha$^{-1}$ [107]. We assume a mean transport distance of 25 miles which implies a potential harvested area of about 10$^6$ ha, about 2% of which would need to be dedicated to willow SRC. Truck fuel consumption is assumed to be 5.9 miles per gallon [108] with an emissions factor of 10 kg CO$_2$ per gallon [109]. Once on site, the biomass is ground with a specific energy consumption of 150 kwh per wet tonne [33] via an electrically-powered mill. Injection is accomplished by two electrically powered 500 hp engines operating 12 h per day at 75% of maximum load [26]. For both the grinding mill and the injection pumps, CO$_2$ emissions are determined as the average emissions intensity of the U.S. grid, including CH$_4$ and N$_2$O emissions [109]. Note that all of these assumptions mirror those used to calculate the net carbon storage in the technoeconomic model above (see supplemental table 1), with the exception of the emissions associated with biomass production which are included here, but were not included previously.

We calculate that the system has a gross carbon injection of 229 000 tonnes CO$_2$ e yr$^{-1}$ and a net storage of 202 000 tonnes CO$_2$ e yr$^{-1}$, an efficiency of 88% (figure 3). Note that the biomass production data do not include the potential for carbon storage in soils, and this could further improve the net global warming impacts of the system.

Dias et al compared the life-cycle impacts of willow-SRC for heat energy with the life-cycle impacts of natural gas for heat energy, and found that willow-SRC decreased emissions by 82%, from 75 kg CO$_2$ e GJ$^{-1}$ for natural gas to 14 kg CO$_2$ e GJ$^{-1}$ for willow-SRC. Given this, and assuming willow has a heating value of 16.3 MJ kg$^{-1}$, the overall emissions reduction associated with using 125 000 t of willow for heat energy in place of natural gas is 123 000 t CO$_2$ e (figure 2). This is roughly 80 000 t CO$_2$ e less than the reduction from using the same biomass for BSFI.

7. Geospatial analysis

While we have estimated that global BSFI storage capacity is on the order of 5 Gt CO$_2$ yr$^{-1}$, realized BSFI storage will depend on the availability of biomass, water, and geological storage sites in close proximity. To evaluate the geographic potential of BSFI in the U.S., we compiled biomass potential data from the U.S. Department of Energy’s 2016 Billion-Ton Report [110], point sources of wastewater effluent release from the EPA’s Water Pollutant Loading Tool [111], and reservoir data from the NatCarb carbon storage atlas [38].
7.1. Biomass resources

Using the county-level data [110], we summed the total bioenergy crop production potential and the waste biomass potential of each county in the contiguous U.S. in 2023 (see also [28] for a similar dataset). The DOE report contains a number of parameterizations with varying assumptions about the rate of growth in agricultural yields, but we used the baseline parameterization to create a conservative estimate. We assumed a biomass price of $40 dry tonne$^{-1}$. In total, there are 161 dry Mt of biomass expected to be available at a price of $40$ tonne$^{-1}$. Given a C concentration of 45% and efficiency of 90%, this is equivalent to 239 Mt of potential negative CO$_2$ emissions. Of this biomass, 76% comes from wastes (e.g. municipal solid wastes, forest residues, and ag residues) while 24% comes from energy crops and energy crop residues.

In the technoeconomic analysis above, we assume an average travel distance of 25 miles (40 km) which implies a maximum travel distance of 35 miles (56 km) and a covered area of 3846 mi$^2$ (9961 km$^2$). Given that the technoeconomic analysis assumed 125 000 tonnes of biomass, then counties with more than 32 tonnes of waste produced per mi$^2$ would be expected to be plausible candidates for BSFI given existing waste flows (supplemental figure 2). Urban areas along the East Coast have adequate biomass density associated with municipal solid wastes and sewage sludge, while counties in the Midwest, Southeast, and California’s Central Valley have adequate agricultural residues and/or bioenergy crops to allow for feasibility.

7.2. Geological storage

BSFI is likely to be limited by the volume of biomass that can be injected into a given well. Because BSFI uses artificially created fractures for the storage of solids, the overall pore volume of a reservoir is less critical in BSFI than it is in gaseous CO$_2$ storage, and so we cannot estimate storage volumes using the same estimation methodologies as used for CO$_2$ storage [112]. However, Nadeem and Dusseault [50] provided a decision-tree framework for estimating geological prospectivity for SFI. Their decision-tree assumed that reservoir thickness greater than 2 m, permeability between 10 and 10 000 mD, and depth between 200 and 3000 m were required for a potential injection formation.

We used these factors and data available from the U.S. NatCarb Atlas [38] to identify potential saline storage reservoirs (supplemental figure 3).
The NatCarb Atlas lacks permeability data for most formations, and these data were taken from NETL’s CO2 Storage Cost Model and spatially joined. Unfortunately, the formation names and classification do not match perfectly between the NETL and NatCarb data; for example, the NETL data may separate a formation into several layers while the NatCarb data may not. To join the data, we joined each formation in the NETL data to its NatCarb polygon, and then assigned the NatCarb polygon the average permeability, depth, and thickness value of each formation in the NETL data with which it overlapped. This process will introduce error into the analysis, but since overlapping formations are generally similar in terms of permeability and given the broad overview inherent in this sort of high-level analysis, the errors are unlikely to have a major impact on the conclusion.

In most cases for which we have adequate data, saline formations which would make good candidates for gaseous CO2 storage would also make good candidates for BSFI. Note that there are other factors that are important for geological perspectivity including the thickness of the upper cap rock, the presence of faults and old wellbores, formation pressure, and structural complexity and these would need to be evaluated on a case-by-case basis. In addition, depleted oil and gas reservoirs could also be used for BSFI but are not considered here.

7.3. Water resources
We used EPA’s Enforcement and Compliance History Online [111] to quantify the volume and spatial distribution of wastewater in the U.S. supplemental figure 4 identifies counties with effluent releases over 0.3 MGD which would make adequate sources of water for a 125,000 dry tonne yr−1 BSFI system. Together, this water contained 66 billion kg of pollutants, including 52 billion toxicity-weighted pound-equivalents (TWPE) of furans, 1.4 billion TWPE of polychlorinated biphenyls, 440 million TWPE of dioxins, 50 million TWPE of cadmium, and 29 million TWPE of hexachlorobenzene. If wastewater from one of these sources was used in BSFI, additional environmental health benefits might be realized.

7.4. Overall potential
To evaluate the geospatial potential of BSFI, we conducted a suitability analysis in ArcGIS using four variables: reservoir thickness, reservoir depth, wastewater availability and biomass availability. Each grid cell was given a value between 0 and 10 for each of the four variables. The scores were calculated using a continuous transformation function, with the specific function determined via an iterative process. Biomass, wastewater, and saline formation thickness data were transformed using ArcGIS’ ‘Large’ function where the midpoint was set to the approximate cutoff between feasible and infeasible systems (32 tonnes mi−2, 0.3 MGD, and 150 ft, respectively). Saline formation depth was transformed using the ‘MSSmall’ function such that low values of the variable were associated with higher values of suitability. The results are depicted in figure 4. While they do not necessarily reflect the places in which BSFI will be lowest cost, places
with high scores may indicate locations for further study. California’s Central Valley, the Gulf Coast, and the Lower Midwest may be promising regions.

8. Environmental and systematic risk

If implemented at scale, BSFI might create at least three types of negative environmental impacts. First, as with other carbon stocks placed in underground storage, the sequestered carbon could escape and be re-emitted to the atmosphere. In order for the carbon in BSFI to return to the atmosphere, it would first need to be anaerobically metabolized by subsurface bacteria. We do not know of data on the rate of this process, but if it does not occur, the carbon will likely remain sequestered as it is denser than the formation fluids. If anaerobic digestion does occur, the resulting CO$_2$ and CH$_4$ could still be retained in the reservoir via the trapping mechanisms of the formation, however, it is possible that the structural trapping mechanism could be damaged by fracturing.

Second, the fracturing and injection process could have environmental impacts, although these impacts would be different from those associated with more conventional fracking projects. BSFI wells would generally be vertical, and so fractures would generally be horizontal, and this would lower the probability of upward injectate migration [14]. Fluid injection can also activate faults and induce seismicity, but in the U.S., this has been associated with the injection of large volumes of water (>300 000 bbls per month [114]) and injection close to the basement [115]. SFI can also uplift and deform the surface [17] and this could be a particular concern in shallow (<800 m) formations [116]. The potential for uplift would require monitoring but could be beneficial in subsiding deltas [117].

Third, BSFI would require significant quantities of biomass. If this biomass were grown on prime agricultural land, required long-distance transport, or used large amounts of fertilizer or freshwater, there could be negative impacts on food supplies or other environmental systems. However, BSFI can use a wide variety of feedstocks, including wastes, which might reduce these systemic environmental impacts.

9. Conclusions and future directions

The long record of successful SFI projects and the TIRE project suggests that BSFI is likely to be technically feasible, and the technoeconomic modelling above suggests that BSFI is economically feasible, albeit with considerable uncertainty. Our geographic analysis suggests that the three components required for sustainable BSFI—biomass, wastewater, and underground storage—coexist in parts of the U.S. Taken together, the results suggest that BSFI may be a feasible, novel NET.

Despite the potential of the system, we emphasize that our results are preliminary and that significant economic and technical hurdles remain for implementation. The most critical of these hurdles is an understanding of the injectivity of prospective formations. In the technoeconomic analysis above, we have assumed that wells can inject at modest injection rates for 5 years, but this may be optimistic and may not reflect the average formation. If additional capital is required to drill or workover wells more frequently, the costs of BSFI will increase and BSFI may only be feasible in specialized circumstances. Our analysis may also neglect costs (like permitting and carbon assurance) which may be individually small but important in aggregate.

More detailed economic analyses which use geological models to estimate storage capacity and costs are necessary.

Data availability statement

All data that support the findings of this study are included within the article (and any supplementary files).

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