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Transport cost for carbon removal projects with biomass and CO_2 storage

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Abstract

Strategies to remove carbon from the atmosphere are needed to meet global climate goals. Promising strategies include the conversion of waste biomass to hydrogen, methane, liquid fuels, or electricity coupled with CO_2 capture and storage (CCS). A key challenge for these projects is the need to connect geographically dispersed biomass supplies with geologic storage sites by either transporting biomass or CO_2. We assess the cost of transport for biomass conversion projects with CCS using publicly available cost data for trucking, rail, and CO_2 pipelines in the United States. We find that for large projects (order of 1 Mt/yr CO_2 or greater), CO_2 by pipeline is the lowest cost option. However, for projects that send most of the biomass carbon to storage, such as gasification to hydrogen or electricity production, biomass by rail is a competitive option. For smaller projects and lower fractions of carbon sent to storage, such as for pyrolysis to liquid fuels, CO_2 by rail is the lowest cost option. Assessing three plausible example projects in the state of California, we estimate that total transport costs range from \$7/t-CO_2 stored for a gasification to hydrogen project traversing 170 km to \$48/t for a pyrolysis to liquid fuels project traversing 530 km. In general, if developers have flexibility in choosing transport mode and project type, biomass sources and storage sites can be connected across hundreds of kilometers for transport costs in the range of \$10-30/t-CO_2 stored. Truck and rail are often viable modes when pipelines cannot be constructed. Distances of 1000 km or more can be connected in the same cost range when shared CO_2 pipelines are employed.

1 Introduction

It is now well understood that carbon removal strategies, also known as negative emissions technologies (NETs), will be needed to achieve a net-zero carbon society, and specifically to achieve climate goals of limited warming (Masson-Delmotte et al. 2018; National Academies of Sciences 2019). One long-studied type of carbon removal is the combustion of biomass coupled to carbon capture and storage (bio-energy with carbon capture and storage, BECCS) (Minx et al. 2018). Traditionally, the biomass is combusted to produce electricity, which is sold as a co-product.

There have been a handful of BECCS projects so far (Consoli 2019). Furthermore, biomass-fired power plants without carbon capture are common, and CCS has been demonstrated on fossil plants such that coupling the two is expected to be straightforward compared to many other NETs.

A related set of strategies, much less studied, is to convert biomass to other products, such as liquid fuel, renewable natural gas (methane), or hydrogen, while capturing and storing the process CO_2. If the source of biomass regrows and has limited other climate impacts, then the result is net-negative biofuels (NNBFs): clean fuels and carbon removal as co-products.

The source of biomass, type of fuel, and processing technology all affect the life cycle climate impact of biofuels. In general, NNBFs can easily be achieved using waste biomass, such as agricultural residue or brush and small trees from fire management in forests (Creutzig et al. 2015).

Recently, with our coworkers, we assessed many pathways for NNBFs and BECCS as well as other carbon removal strategies for the U.S. state of California (Baker et al. 2020). We found that NNBFs, and specifically biomass gasification to hydrogen, had the largest potential and among the lowest cost of carbon removal options for California. The high availability of waste biomass and excellent geologic conditions for CO_2 storage in the state contribute to this result, however these circumstances are far from unique. The National Academies assessed biomass in the United States for energy applications and estimated 512 Mt/yr of wastes and residues were available (National Academies of Sciences 2019). This is similar on a per capita basis to the 55 Mt/yr that we estimated for California. Previous studies have found large areas of the United States have suitable geology for CO_2 storage, including biomass-rich regions in the upper Midwest and southeast (Baik et al. 2018).

In Baker et al., we found that NNBFs have enormous potential to contribute carbon removal at a reasonable cost while providing clean fuels and other benefits, such as jobs and waste disposal. However, a successful NNBF project has to solve a transport and logistics problem that connects at least four elements:

1. The supply of biomass
2. The biomass conversion facility, e.g. gasification or pyrolysis plant
3. The CO_2 storage site
4. The customers of the fuel or electricity

The fourth element, transport of electricity or fuel from the plant to customers, is relatively well-understood and typically contributes a small share to the cost of those commodities. An exception to this may be for hydrogen, which currently doesn't have as wide a customer base or a well-developed transport network as for methane or liquid fuels. Transport of hydrogen by truck is straightforward in the absence of other options, but the proximity of hydrogen users may constrain the placement of NNBF plants more than for other fuels. Overall, we don't consider the cost of fuel transport here and rather focus on the first three elements above.

Transport of biomass for bioenergy has long been considered an important cost driver. Compared to fossil fuels, biomass carries relatively less energy per unit mass, and so assessments of bioenergy potential have concluded that biomass transport distances must be relatively short for economic success (Helena Chum et al. 2011). The calculation changes when biomass is considered as a carrier for carbon removal. Many forms of biomass are carbon-rich, making them feasible to transport for longer distances than when biomass is valued as an energy carrier alone.

In this paper, we seek to estimate the cost of carbon transport for NNBF projects as a function of distance and type of project. For project developers, there will often be a choice about which mode of transport to use and whether to transport biomass or CO_2 the longer distance. We will identify the circumstances that favor each of the choices. To do this, we'll first lay out our assumptions on the logistics of NNBF projects. We'll then report unit cost estimates for several modes of transport from the literature. Finally, we'll calculate transport costs per unit of CO_2 stored for an NNBF project as a function of several variables, including distances, plant size, and biomass conversion technology. We will conclude with a discussion of implications of these findings for NNBF developers and for policymakers considering carbon removal incentives.

2 Materials and Methods

In this paper, we aim to assess the costs of carbon transport for BECCS and NNBF projects in the United States. The analysis shares some common methods and assumptions with Chapter 7 of Baker et al., but here we generalize the results for the United States and ignore the system integration aspects, taking the perspective of a single project. The cost data below are sourced from the United States, but the general trends and relative costs between modes should be similar to these costs internationally.

As discussed in the previous section, a successful NNBF or BECCS project must connect at least three elements: biomass supply, plant, and CO_2 storage. There are a variety of transport strategies to achieve this. Biomass can be transported by truck or rail, and CO_2 can be transported by truck, rail, or pipeline. Both can also be transported by ship, but this option is highly limited by geography and we don't consider it here.

Major potential sources of waste biomass include forest residues, agricultural residues, municipal solid waste, as well as liquid wastes, such as from food processing, and biogas, such as from landfills and wastewater treatment. Liquid and gaseous wastes are available in relatively small volumes and have different challenges for use as NNBFs. We focus here on the major categories of solid biomass.

For solid biomass, the carbon chain typically starts with a collection stage by truck or off-road vehicle and ends with CO_2 injection at a geologic storage site. One major choice is whether to site the conversion facility near the biomass and transport CO_2 the greater distance, or to site the facility near the storage site and transport the biomass. There are several additional choices for the mode of transport in between. Figure 1 illustrates five possible transport chains, which are named for the longest leg in each case. Each of these five scenarios is assessed for several example projects described below.

2.1 Biomass collection

The first step in the carbon chain is collection and pre-treatment of biomass into loads suitable for transport by on-road truck. Representative costs for this stage are shown in Table 1 along with average moisture content of the biomass, which affects transport costs down the line. Collection cost is not the focus of this analysis, be we discuss it here for context.

Collection of forest and chaparral residues typically includes chipping and potentially drying before loading trucks at the roadside. For agricultural residues, collection and processing may have already occurred, such as for pistachio shells or almond hulls. As a result, some such residues can be purchased at very low additional cost. Other types require collection from the field, so collection cost varies widely. Municipal solid waste (MSW) is already collected by truck and typically already sorted. Biomass from MSW may even be available at negative cost because processing this waste avoids tipping fees at landfills. As described in the Billion-Ton Report (Langholtz, Stokes, and Eaton 2016), many millions of tons of biomass are available in each of these categories in the United States; any of these types of biomass could support an NNBF project. Supplies are sufficiently concentrated that even a large NNBF plant, say 1 Mt/yr biomass capacity, could, in many places, be supported by a single county supply, or in other cases by several adjacent counties.

2.2 Transport of biomass

From the collection points, biomass will typically be trucked either to a rail station for longer-range transport, or directly to a biomass conversion facility. Trucking is a commodity market with stable prices. Average operating expenses of commercial truck are surveyed annually by the American Transportation Research Institute (Hooper and Murray 2018), who reported a national average of $1.05/km in 2017. The cost per ton depends on the load size and capacity factor. We assume that outbound trucks carry 22 tons of biomass, which is close to the legal limit and tracks the average net loads for trucks carrying bulk commodities (National Research Council 2010). Although there are some agricultural residues that aren't dense enough to fit 22 t in a standard trailer volume, these can be compacted or otherwise processed to reduce shipping volume. We assume the trucks return empty (50% capacity factor). We also add 6% profit to reflect prices for the project operator (Biery 2018). The resulting unit cost is shown in Table 2, along with several other unit costs described below.

Biomass transport by rail is also common in the U.S. as well as internationally. Rail is well known to have lower cost and lower externalities than trucking (GAO 2011), so it is generally preferred wherever it is available. However, rail access is limited and building new rail spurs is expensive, with representative costs in the range of $0.6–1.2M/km – somewhat more than for CO_2 pipelines (Compass Int 2017). Short delivery distances may also favor trucking.

The market for rail transport is more heterogeneous than for trucking. Unit prices vary significantly contract to contract, and average prices vary by about a factor of two depending on the travel distance, load size (number of cars), and type of commodity (Prater and O'Neil 2014; Mintz, Saricks, and Vyas 2015). For our base case cost, we assume that transport will be in the short-haul category (<800 km), but with larger loads (>75 cars per train), suggesting a unit cost that is 1.6 times the national average.

2.3 Transport of CO_2

Once biomass is transported to the NNBF or BECCS facility, it is processed and treated. The resulting CO_2 is captured and either compressed for transport via pipeline or liquified for transport by truck or rail. Pipeline CO_2 can then be injected directly underground when it reaches the storage site. Liquified CO_2, which is kept at about –40ºC and 20 bar of pressure, must be warmed and compressed before injection into a pipeline (80-120 bar and ambient temperature).

Liquified CO_2 can be transported in insulated tanker cars that are similar between truck and rail. We assume the near-full capacity of 22 t is retained for trucks, however costs are somewhat higher because the trailers are more expensive and the trucks are slightly more expensive to operate and maintain. Survey results give $1.16/km with the adjusted unit cost shown in Table 2.

CO_2 transport by rail is less common than other modes. Although it occurs commercially (ITJ 2019), we have not found published market data on CO_2 specifically. The costs should be similar to other tanker-shipped commodities, with the exceptions that staging and loading facilities must be built at the origin station, and unloading and reconditioning facilities must be constructed at the destination station. A pipeline spur is likely also needed at the destination.

Two studies have used techno-economic models to estimate the cost of CO_2 by rail for CO_2 storage case studies. Gao et al. calculated 77 RMB/t-CO_2 ($13/t in 2018 US dollars) to transport 1.5 Mt/yr over 600 km for a project in China (Gao et al. 2011). This included $0.88/t for staging and loading facilities. Roussanaly et al. estimated 4 €/t and 11 €/t ($5 and $13) to transport CO_2 for 50 km and 200 km, respectively, for a project in the Czech Republic (Roussanaly et al. 2017). That includes about 1 €/t for loading and unloading facilities. The staging operation thus appears to be a minor part of transport cost. Overall, we assume that the staging and loading operating adds 2 $/t-$CO_2$ to the cost of transport by rail, while the unit cost remains the same as for biomass.

The cost of CO_2 transport by pipeline is more variable than for other modes since it depends on local construction costs and securing rights of way. Even with these challenges, pipelines are strongly preferred for large volumes of CO_2. There are over 7000 km of CO_2 pipelines in the U.S. as well as a vastly larger network of natural gas pipelines that also informs the cost of pipeline construction (Wallace, Goudarzi, and Wallace 2015).

To estimate CO_2 transport costs via pipeline, we use a spreadsheet-based model developed by the National Energy Technology Laboratory (NETL 2018), which in turn implements several earlier models from the literature (McCoy and Rubin 2008; Parker 2004). When validating the model against recent CO_2 pipeline projects, the authors found that the variant based on Parker tended to overestimate costs, while the variant based on McCoy and Rubin underestimated it. We thus take these to be the upper and lower bounds of the pipeline costs in further analysis. Figure 2 shows results from the model for a 1 Mt/yr CO_2 flow. The McCoy model provides costs for five different regions of the U.S. This yields a cost variation of about +/- 20%, whereas the difference between the models can be more than a factor of two. For the generic cost comparisons in Figures 4 and 5, we use the lowest regional result from McCoy (central) and the Parker results as the lower and upper bounds, respectively. For the single-point cost estimates in Figure 6, we use the midpoint between the average of the McCoy estimates and the Parker estimate. The retrieved costs are the break-even cost of CO_2 transport in the first year of operation.

2.4 Plant size and CO_2 storage factor

The amount of CO_2 that ultimately ends up in the ground for each ton of biomass collected depends on the BECCS or NNBF technology used, and to a lesser extent, on the type of biomass. To estimate the transport costs per ton of CO_2 stored, we have to account for this "CO_2 storage factor." Table 3 shows these factors for a handful of likely projects. Most of these plant types are in development in California or neighboring states. The values range from 0.49 t CO_2 per t dry biomass for a pyrolysis to liquid fuels plant, where the majority of biomass carbon ends up in fuel, to 1.6 for gasification to hydrogen, where virtually all the input carbon ends up in the ground. For combustion to electricity, we assume the CO_2 capture system is 90% efficient, a typical benchmark, but it could be made more efficient. Alternatively, some gasification plant designs are less efficient at capturing CO_2 and would have slightly lower values. Project developers can make these choices based on market conditions and regulatory incentives for carbon removal. These storage factors, and thus the costs per ton of CO_2 calculated later, do not account for fossil CO_2 emitted during transport or other life-cycle considerations. However, we previously found transport-related emissions to be less than 1% of the CO_2 stored (Baker et al. 2020).

Along with the storage factor, the size of the BECCS or NNBF plant determines the flowrate of CO_2

and biomass that must be transported. This affects the cost of pipelines most strongly. In general, larger plants are more economic from a transport perspective. Although not covered here, CO_2 storage cost also depends strongly on CO_2 flowrate. A larger NNBF project may be able to support a dedicated storage project economically; for reference, a single well in a good formation can accept on the order of 1 Mt/yr of CO_2 injection. Smaller projects would likely need to send CO_2 to a storage site that aggregates CO_2 from multiple sources for the best marginal cost. Aggregating CO_2 sources would also be a way to economically transport CO_2 over longer distances by using a shared CO_2 trunk line.

For the benchmark values in Table 3, we assume a pyrolysis plant capacity of 2000 metric tons per day of bone dry biomass. This is a commonly used commercial plant size assumption to meet the cost goal for hydrocarbon fuels production from lignocellulosic biomass proposed by the U.S. Department of Energy (BETO 2016; Jones et al. 2013). Current operational commercial pyrolysis plants have a much smaller plant size, only around a few hundred tons per day of dry biomass (Lee Enterprises Consulting 2020). CO_2 transport and storage would be much more expensive at this scale. This makes it unlikely that a developer would choose a small pyrolysis plant as an NNBF project.

To maximize the carbon removal potential of pyrolysis to liquid fuels, we assume CO_2 is captured from the off gas of non-condensable gases (NCG) combustion as well as off gas from steam reforming of aqueous phase bio-oil. The storage factor was calculated as 0.494 t CO_2 stored per dry ton biomass input based on a process carbon balance (Li et al. 2017). There is also storable biomass carbon in the biochar, which can be sequestered above ground as a soil amendment. How much of the biochar carbon is stored and for how long depends on the use of the biochar. As a soil amendment the majority of carbon is likely to remain sequestered for over 100 years. We have not included the stored carbon from biochar here, instead focusing on geologically stored CO_2. However, including a stored biochar component would tend to decrease the apparent transport costs per unit of CO_2 removed.

The storage factor for biomass combustion to electricity was derived from the mass balance reported in Jin et al. (Jin, Larson, and Celik 2009). Since the modeled combustion facility uses air to combust the biomass, the flue gas contains a significant fraction of nitrogen that must be separated from the CO_2 prior to sequestration. In this case, the CO_2 in the flue gas was assumed to be captured via an amine system (Cansolv) at 90% efficiency (Zoelle et al. 2015). Other process configurations, such as oxy-combustion or indirect combustion of biomass, could result in CO_2-containing streams that could be captured by other technologies not considered here.

The storage factor for biomass gasification to hydrogen was derived from the mass balance reported in Larson, et al. The water-gas shift process to produce hydrogen can be operated to convert nearly all of the carbon in the biomass feedstock ultimately into CO_2; the bulk of this CO_2 is removed from the hydrogen by a refrigerated methanol (Rectisol) process, and is high enough purity after drying for direct sequestration without adding additional capture units.

Finally, the storage factor for biomass gasification to renewable natural gas was derived by estimating the fraction of CO_2 in the gas stream before methanation, based on the composition of the CO_2-containing syngas emitted from the gasifier units in Larson et al. By mass balance, the hydrogen-to-CO ratio in the syngas was adjusted via water-gas-shift to maximize the amount of methane produced , which increased the fraction of CO_2 in the gas stream. The CO_2 is removed prior to methanation by a refrigerated methanol process.

2.5 Example projects

To illustrate the transport cost calculation, we select three plausible project configurations from California as case studies. Their locations are illustrated in Figure 3. In Baker et al, we found that the most favorable geologic storage locations in the state were in the Bay Delta region, especially in San Joaquin County in the center of the state, and in the southern central region in Kern County, an area of historic and ongoing oil production. These are marked approximately by the purple ovals in Figure 3. They are not the only potential storage areas in the state, but were identified as the most favorable based on available data.

Some of the largest sources of biomass include the forested counties in the north, such as Siskiyou County, for potential fire clearing and sawmill residue, Los Angeles County for municipal solid waste, and Central Valley counties like Fresno for agricultural residues. Each area is highlighted in yellow. Using these three example counties as origin areas for the biomass, we propose three project scenarios. First, we select a pyrolysis to liquid fuel scenario for Siskiyou County because the relative smaller size of the plant is a good match to supply in the county. It is also remote from population centers, which makes liquid fuels, which are more easily transported than hydrogen or natural gas, a good choice of product.

For Fresno County, gasification of agricultural residue to methane is attractive because the methane is easily sold as renewable natural gas to the local grid. Moreover, a similar scenario has been studied and found to be profitable (GTI 2019). Finally, Los Angeles has a large supply of municipal waste amenable to gasification and is a potential demand center for hydrogen, either from light duty vehicles or from heavy duty vehicles associated with the port and other freight. These three project types and three source locations form the basis of the example scenarios.

The transport distance for each scenario depends on the mode. We calculate the road distance to the nearest storage site as the distance between the centroids of the origin and destination counties, as determined by the Open Source Routing Engine and Open Street Maps (OSRM contributors 2019). The rail distance is the shortest route over existing rail lines that passes near the centroid of the origin county and connects to the nearest storage region. Pipeline routes are selected to follow existing major natural gas pipelines, also passing near the centroid of the source and connecting to the nearest storage area. Rail and pipeline routes are shown in Figure 3.

For each scenario, the average local trucking distance is based on the size of the biomass source area:

$$d_{local} = \frac{1}{2}\sqrt{A}$$

where A is the area of the origin county. This approximates the average distance between random points within the area (Talwalker 2016). The distance from the storage site to a rail station is based roughly on the size of the promising storage regions relative to the major rail line. The plant sizes and CO_2 storage factors are taken from Table 3.

2.6 Total transport cost

The transport cost of a project can be estimated by the sum of costs for each leg of the carbon chain, adjusted by the quantity of CO_2 stored. We calculate the costs for the example projects as follows and suggest that these formulae can be applied generally. We define the unit cost, U, as the cost in \$/t-km for the mode and product in subscript; for example $U_{truck,BM}$ is the cost of trucking biomass per t-km. For rail and pipeline, U depends on distance and flowrate.

For the biomass by truck scenario, where the conversion facility is located near the storage site:

$$T = \frac{dU_{truck,BM}}{(1 - W_c)f_{CO2}} + d_{spur}U_{pipeline}$$

where T is the total cost in \$/t-CO_2 stored, d is the distance between biomass pick up and the conversion plant (typically the longest part of the chain), and d_{spur} is the length of the short pipeline from the plant to the injection site. W_c is the water content of the biomass and f_{CO2} is the storage factor for the type of plant.

For biomass by rail:

$$T = \frac{d_{local}U_{truck,BM} + dU_{rail,BM}}{(1 - W_c)f_{CO2}} + d_{spur}U_{pipeline}$$

CO_2 by truck:

$$T = \frac{d_{local}U_{truck,BM}}{(1 - W_c)f_{CO2}} + dU_{truck,CO2}$$

CO_2 by rail:

$$T = \frac{d_{local}U_{truck,BM}}{(1 - W_c)f_{CO}} + d_{spur,1}U_{pipepine} + dU_{rail,CO} + d_{spur,2}U_{pipeline}$$

Where $d_{spur,1}$ is the length of the pipeline at the origin station and $d_{spur,2}$ is the length at the destination station.

For CO_2 by pipeline:

$$T = \frac{d_{local}U_{truck,BM}}{(1 - W_c)f_{CO2}} + dU_{pipeline}$$

These equations are used to calculate the total transport cost for the three example scenarios shown in Table 4. For the CO_2 by rail scenario, we assume that the plant is built near existing rail so that $d_{spur,1} = 0$, but this need not be the case generally.

3 Results

The cost of biomass transport by truck and rail is shown in Figure 3. We can see that rail is dramatically less expensive at longer distances. Depending on the project and incentives, biomass could be transported hundreds of kilometers by rail at a reasonable cost. However, trucking has a potential advantage at short distances. For example if biomass is being collected from forests over a large area or many farms in a region, most will not be immediately accessible to rail, so there is a consolidation step by truck. Depending on the average distance between biomass sources and the rail station, direct trucking may have an advantage. With an average truck trip of 30 km to the rail station (reasonable for a biomass-dense area like our example counties in California), trucks are preferred for a primary distance of about 40 km or less.

The results for transporting CO_2 are shown in Figure 4. In this case, we look at the dependence of the unit cost on CO_2 flowrate, which has a strong effect on pipeline cost and a slight effect on rail cost. This figure shows results for a distance of 200 km, where rail is always preferred to trucking if it is available. At a flowrate of about 1 Mt/yr and above, a pipeline is clearly preferred to rail, and below about 0.3 Mt/yr, rail is clearly the lower cost option. In between those values, the specifics of the project would be needed to determine the best option. These trends are insensitive to distance except at very short distances, where trucking might be preferred to rail for the same reason described above for Figure 3.

Figures 3 and 4 describe the trends for a segment of the transport chain where either biomass or CO_2 must be moved. However, if the site of the NNBF or BECCS plant can be freely selected, then we would like to know whether we should, on the one hand, site the plant near biomass sources and transport CO_2 to the storage site, or on the other hand site the plant near CO_2 storage and transport the biomass. In a biofuel or biomass combustion project without CCS, this isn't a meaningful choice: the products are easier to transport than biomass and so the plant should be located as close to biomass sources as possible. This consideration also leads to smaller optimum plant sizes. However, with CO_2 transport and storage and their associated economies of scale, the question is more complicated.

The best choice of plant location depends on the plant size and on the conversion technology being used: specifically, the ratio of CO_2 produced to biomass input. Figure 5 shows the unit costs of the five different modes for a range of the CO_2 storage factor. Triangles under the x-axis mark the values of the factor for the BECCS and NNBF plants listed in Table 3. These factors are not universal; a project developer could always choose to capture less CO_2 (or in some case slightly more), but the values are constrained by the thermodynamics and stoichiometry of the products and input biomass.

For low storage factors, represented by pyrolysis to liquid fuels, transport of CO_2 is favored over transport of biomass across modes. However, the total volume of CO_2 is low enough that CO_2 by rail competes with a CO_2 pipeline. At a low enough factor, rail is clearly favored because the volume of CO_2 is not enough to make the capital investment in a pipeline worthwhile. However, this depends on the plant size. This figure is calculated for a fixed biomass input of 1 Mt/yr (dry basis). A larger plant would tend to favor a pipeline even at the smaller storage factors, while a smaller plant would favor rail even at higher storage factors. Only the pipeline cost is sensitive to plant size in this way, the relative costs of other modes don't change much with plant size.

At high storage factors, represented by a gasification to hydrogen project or combustion to electricity, it becomes less expensive to transport biomass by truck or rail than CO_2 by the same mode. The overall volume of CO_2 is large enough that a pipeline is still the lowest-cost option, overall, but this result is sensitive to the plant size. Even at 1 Mt/yr biomass, which is small compared to the expected optimal size of a gasification plant, but large compared to almost all existing combustion plants, biomass by rail is marginally competitive with a CO_2 pipeline. If constructing a pipeline is not possible due to practical or legal restrictions, biomass by rail appears to be a viable alternative, allowing a developer to bridge hundreds of kilometers of distance between biomass source and geologic storage site for about \$10/t of CO_2 stored. This is a modest price compared to the likely cost of capture and to the cost of alternative carbon removal technologies, like direct air capture.

At an intermediate carbon storage factor, such as one achieved by gasification followed by methanation to make renewable natural gas, CO_2 transport by rail and biomass transport by rail are roughly equal cost. CO_2 transport by pipeline is lower cost than both, though again this would change for a significantly smaller plant.

These results suppose that the CO_2 pipeline is dedicated to a single plant. A shared CO_2 pipeline would quickly reduce transport costs and favor the pipeline mode. Indeed, the distance of interest in a project is quite possibly the distance to a shared CO_2 trunk line rather than a storage site. For example, a trunk line which unites the flows of four hydrogen projects of the benchmark size (combined 10 Mt/yr) could move that CO_2 over 1000 km for $10/t (model average). Geographic opportunities are significantly expanded this way, but a shared CO_2 pipeline also poses challenges of coordination and capacity planning.

The results so far are meant to reveal the general features of the transport problem and mostly apply to the longest segment of the transport chain. To understand the relative importance and the approximate costs of the other segments, we will look at several example projects. The total transport cost can't be calculated without reference to local distances, proximity to rail, and specifics of the conversion plant. However, we can get some insight by looking at several plausible example projects. Based on our previous study of carbon removal in California, we chose the three counties (of 58 in the state) that have the largest supplies of forest residue, agricultural residue, and municipal solid waste, respectively. We propose three projects to convert this biomass and store CO_2 in the nearest of two promising geologic formations. Locations of the projects and proposed routes are shown in Figure 3.

The calculated distances for components of the five transport scenarios are shown in Table 4 with other characteristics of the example projects. The variation in distance from one mode to the other is at most 44% (rail distance vs road distance for the Los Angeles project), but other values are more clustered. The Siskiyou pyrolysis project is by far the most challenging from a transport perspective: it covers more than twice the distance and the lower CO_2 flowrate makes a pipeline relatively expensive on a unit basis.

Figure 6 shows the estimated total transport costs for each of the three example projects via each of five modes. Overall, we can see that transport costs are highest for the example of forest residue pyrolysis to liquid fuel. Aside from the longer distance, this is a result of the technology: pyrolysis to liquid fuel moves relatively a lot of biomass per ton of CO_2 stored because more of the carbon ends up in the fuel. The smaller plant size also means higher unit costs for pipeline transport. However, this technology produces the most valuable co-product (gasoline-equivalent liquid fuel), which might make it economically attractive. The least-cost transport mode for this example is CO_2 by rail, which is viable because the origin and destination counties are served by a major active freight line. The estimated total cost is $47/t-$CO_2$, which is split between trucking biomass from the forest roadside to the plant ($20/t-$CO_2$) and moving the resulting CO_2 530 km by rail ($26/t). The short pipeline between the rail station and storage site adds about $2/t.

For generating methane (renewable natural gas), we gasify agricultural residue from Fresno County and store the process CO_2 in nearby Kern County. The lowest cost mode here is a pipeline, giving a total cost of $12/t-$CO_2$. That is dominated by trucking of biomass to the plant in Fresno ($8/t-$CO_2$), with an additional $4/t for the pipeline.

The final example is producing hydrogen from municipal solid waste from Los Angeles and again storing the CO_2 in Kern County. Transport costs are lowest for this example because the storage factor for the hydrogen pathway is so high. A pipeline is the lowest-cost mode at \$7/t-CO_2. Biomass by rail has a similar unit cost, but because the rail route in the example is somewhat longer, the total cost for biomass by rail is \$11/t-CO_2. The latter option gives the developer the opportunity to site the plant in Kern County rather than Los Angeles, which would likely have construction cost advantages, though it may add to transport cost for the hydrogen. The pipeline mode cost is evenly split between local trucking of the waste and the pipeline itself.

4 Conclusions

We have assessed the transport costs for carbon removal projects based on biomass conversion with carbon capture and storage in the United States. We used publicly-available cost data and techno-economic analyses from the literature to compare transport modes and calculate total transport costs for several example projects. Overall, we find that biomass sources and CO_2 storage sites can be connected across several hundred kilometers for costs in the range of \$10—30/t-CO_2 if the developer has at least some flexibility in choice of transport mode and type of plant. Reasonable costs can be achieved via rail if a pipeline is not possible, but much longer distances can be spanned if shared CO_2 pipelines are used.

Transport costs are highest for liquid fuel projects and lowest for hydrogen production and large electric plants. This is due to the higher ratio of CO_2 stored per unit biomass in the latter as well as the generally larger plant sizes. Also for these projects with high CO_2 storage ratios, transport of biomass by rail becomes a competitive alternative to CO_2 transport by pipeline. For small projects or very low carbon storage factors, CO_2 transport by rail is preferred over constructing a pipeline. For low flowrates and distances less than a few tens of km, trucking may be competitive with rail and pipelines. When rail and pipeline access are not practical, trucking is a viable alternative but does run a higher cost.

Our analysis suggests that developers or policymakers who hesitate on carbon removal projects because of the perceived difficulty of building pipelines should strongly consider rail as either a permanent or intermediate alternative. Even large projects can operate on existing infrastructure at a reasonable cost of transport. However, policymakers designing incentives should expect transport costs of up to a few tens of dollars per ton-CO_2 until a shared pipeline system is constructed.

5 Conflict of Interest

The authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

6 Author Contributions

J.S. conducted analysis and contributed the bulk of text for this paper. S.P. and W.L. each conducted analysis on biomass conversion technologies and contributed text and strategic direction. H.G. and S.B. contributed assessment of biomass characteristics and availability. S.B. and R.A. contributed conceptual model design and strategic direction.

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8 Acknowledgments

We acknowledge valuable insights and past contributions from our many coauthors on the Getting to Neutral Report (Baker et al., 2020), as well as Matthew Langholtz at Oak Ridge National Laboratory.

Data Availability Statement

Data used in this study are publicly available as cited, except for several factors which are included in tables in the text. Calculated data underlying the figures are available from the authors upon reasonable request.

Table 1: Typical collection costs and water content for major categories of waste biomass.

	Representative collection cost ($/t dry basis)	**Average moisture content (mass basis)**
Sawmill residue	0 (already collected)	30% (Jones et al. 2013)
Forest fire management	50 (Baker et al. 2020)	30% (Jones et al. 2013)
Shrub & chaparral fire management	80 (Langholtz, Stokes, and Eaton 2016)	30% (Jones et al. 2013)
Agricultural residue	0–60 (Langholtz, Stokes, and Eaton 2016)	25% (Breunig et al. 2018)
Municipal solid waste	<0 (already collected; may pay disposal fee)	10% (Breunig et al. 2018)

Table 2: Unit costs for truck and rail transport

	Biomass transport cost	Cryogenic CO_2 transport cost
Truck	0.101 $/t-km	0.111 $/t-km
Rail	0.044 $/t-km	0.044 $/t-km + 2 $/t

Table 3: CO_2 storage factors and representative plant sizes for some NNBF and BECCS projects

Project type	Storage factor (t CO_2 stored per t biomass input, dry basis)	Typical plant size (Mt/yr biomass, dry basis)
Biomass combustion to electricity	1.55	1.49
Biomass pyrolysis to liquid fuel	0.494	0.657
Biomass gasification to renewable natural gas	1.01	1.49
Biomass gasification to hydrogen	1.65	1.49

Table 4: Transport characteristics for three example NNBF projects.

Scenario	Siskiyou forest biomass pyrolysis to liquid fuel	Fresno agricultural residue gasification to methane	Los Angeles municipal solid waste gasification to hydrogen
Average local trucking distance (km)	67	62	51
Road distance to nearest storage (km)	480	175	174
Rail distance to nearest storage (km)	529	145	251
Pipeline distance to nearest storage (km)	514	135	174
Storage site distance to plant or rail (km)	20	20	30
Biomass flow (Mt/yr, wet basis)	1.0	2.2	1.8
CO_2 flow (Mt/yr)	0.36	1.5	2.7

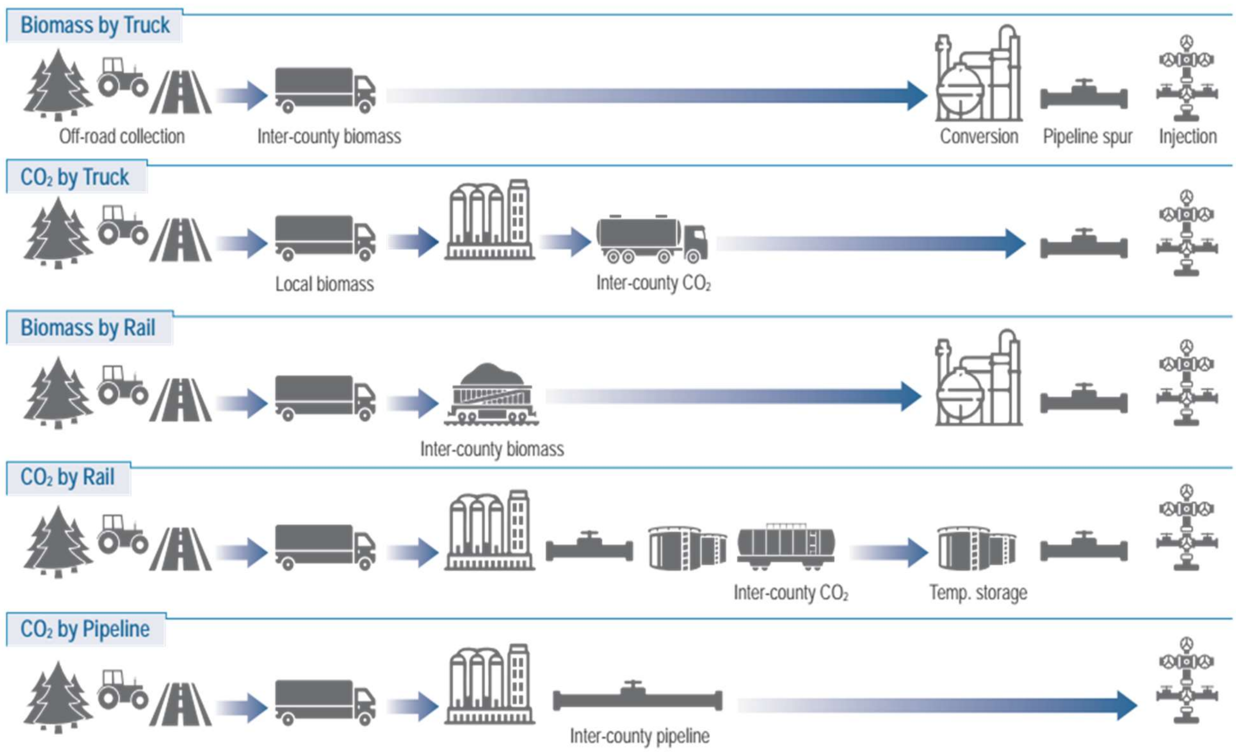


Figure 1: Possible transport configurations for Net Negative Biofuels projects. Inter-county refers to the longer leg of the sequences, while local refers to transport of tens of kilometers.

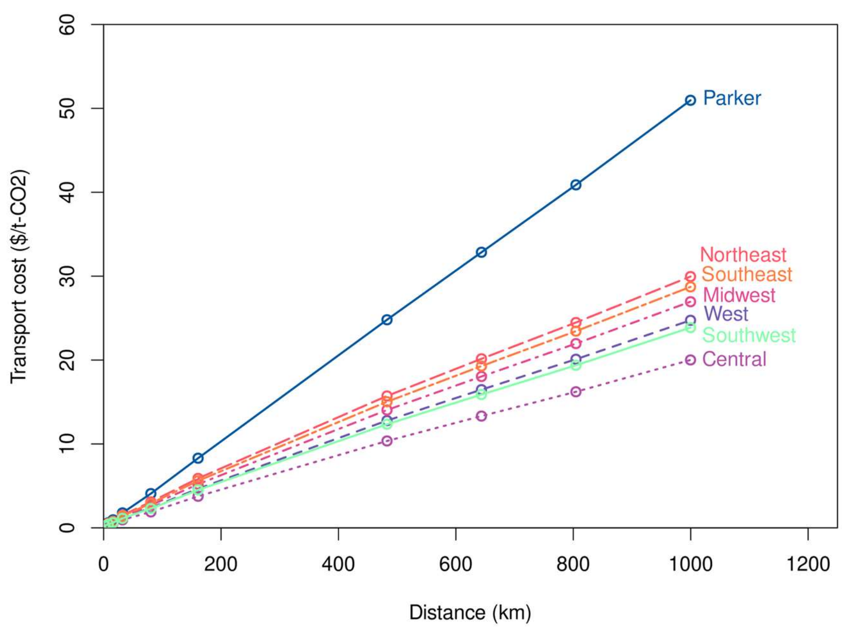


Figure 2: Cost of CO_2 transport by pipeline in the United States by model and region for a flow of 1 Mt/yr in 2014 dollars. "Parker" represents the model with the Parker, 2004 variant, and

the other lines show results for the McCoy and Rubin, 2008 variant for the respective regions of the U.S.

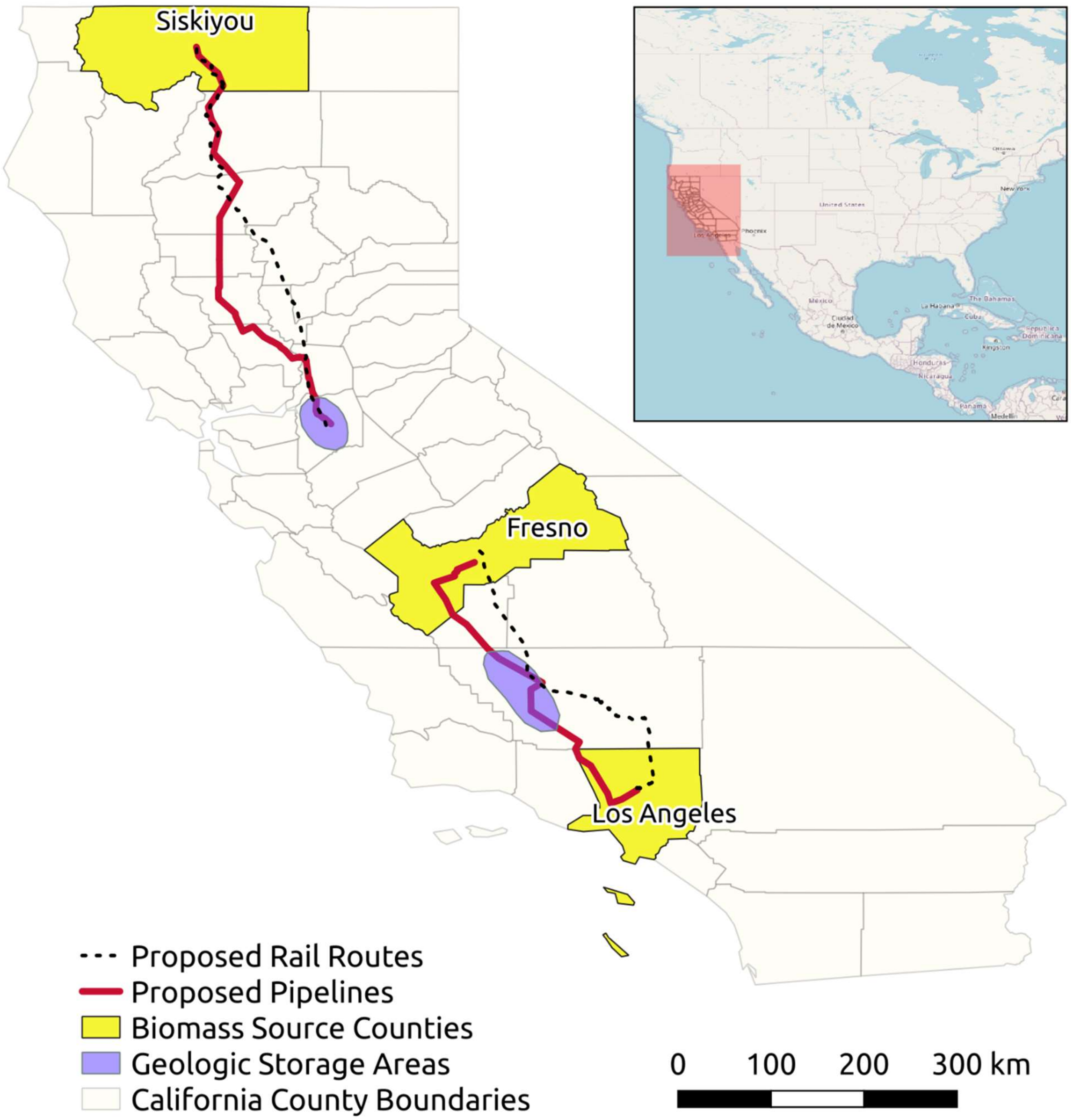


Figure 3: Map of example NNBF project locations showing biomass source areas, storage sites, and proposed rail and pipeline routes.

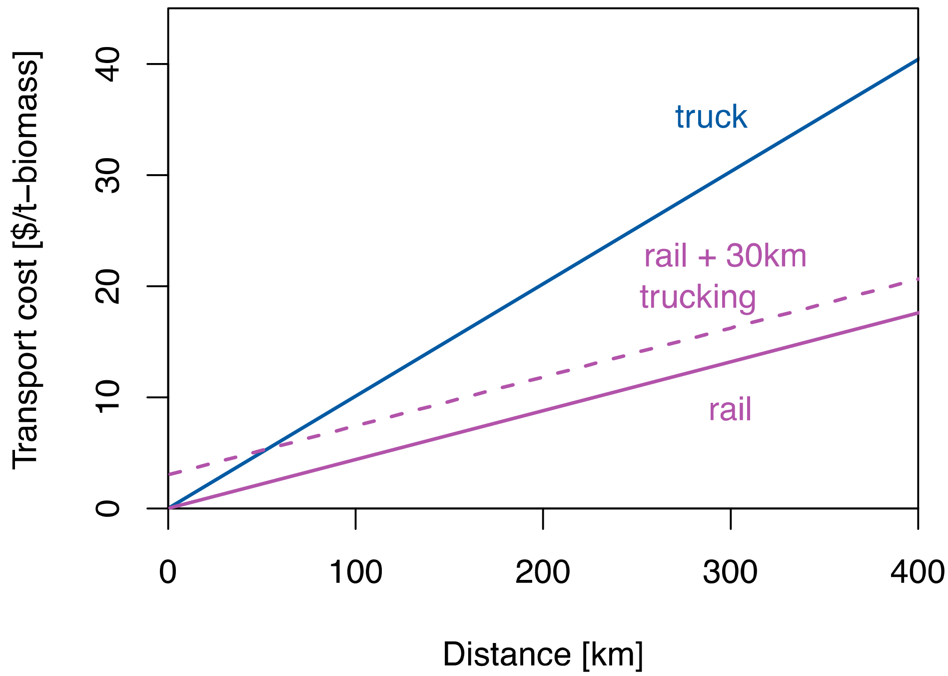
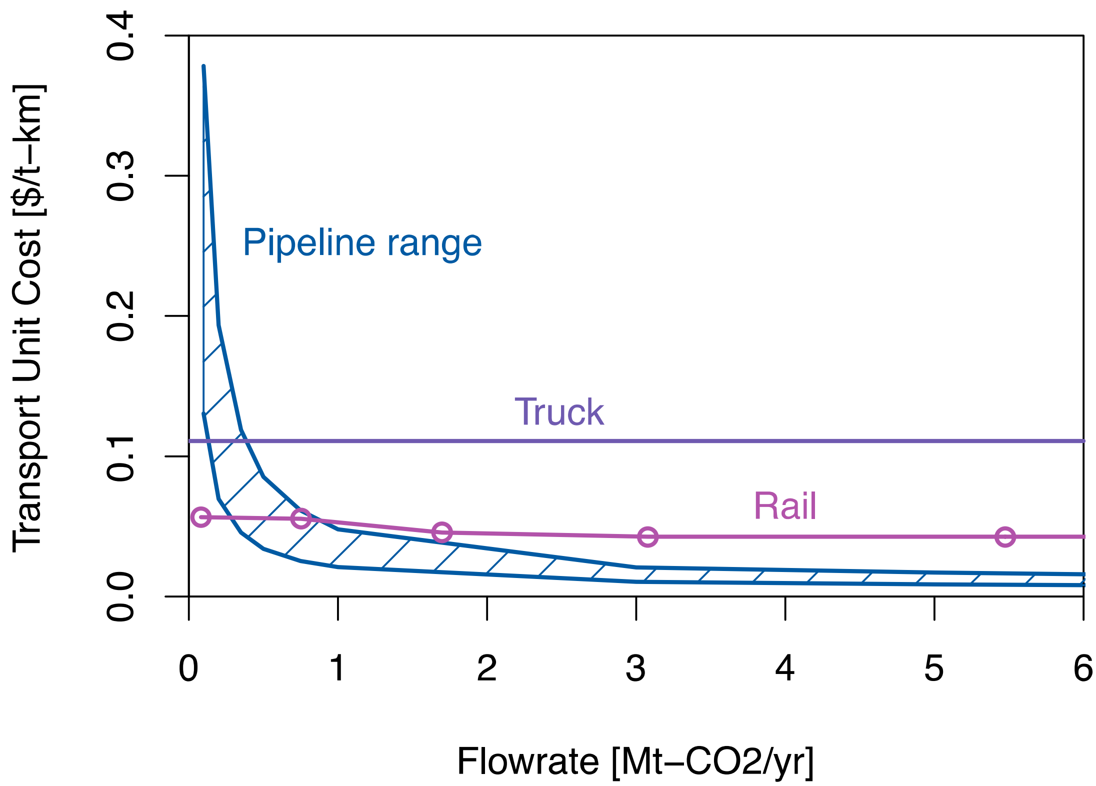


Figure 4: Transport cost of biomass by truck and rail as a function of distance. The dashed line represents a scenario combining consolidation of collected biomass to a rail station via truck (average trip of 30 km) followed by transport by rail for the distance indicated.



506
507 **Figure 5: Comparison of transport costs of CO_2 by truck, rail, and pipeline as a function of**
508 **flowrate. Costs are calculated for a distance of 200 km.**

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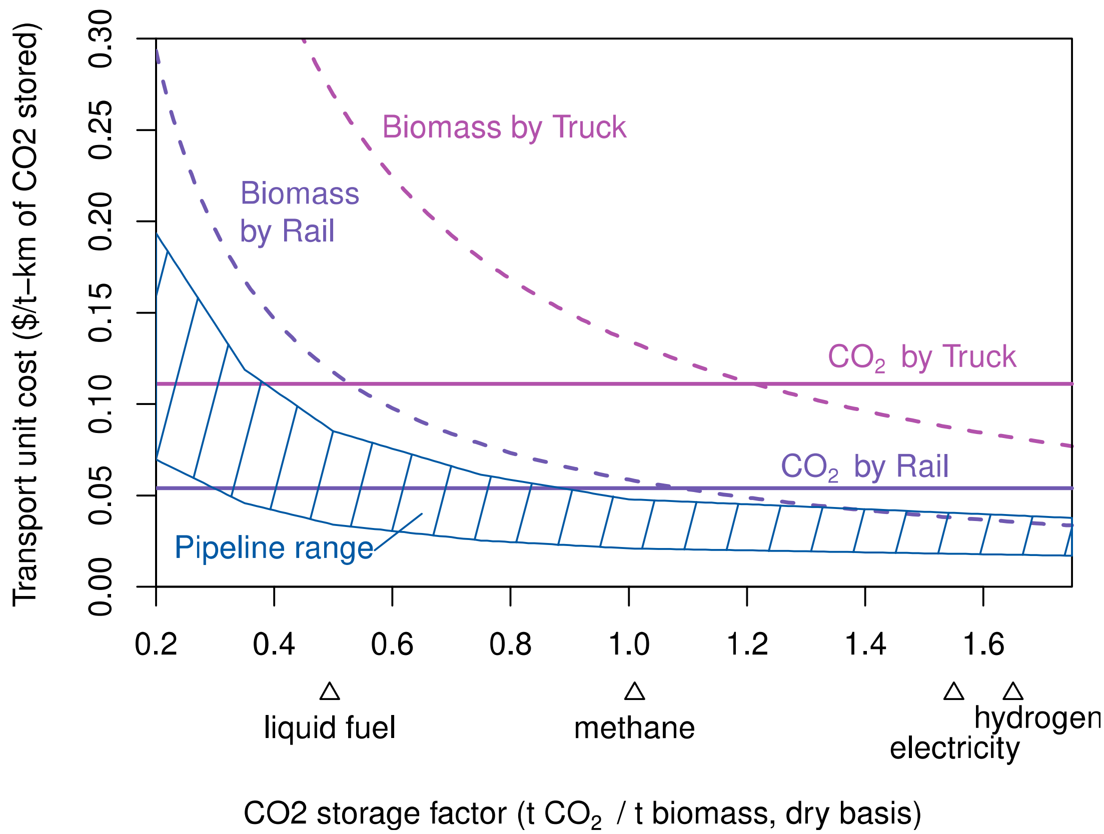

Figure 6: Comparison of transport costs by mode as a function of the CO_2 storage efficiency of the project. Costs are calculated for a biomass input of 1 Mt/yr, dry basis, and 25% water content. Triangles below the x-axis indicate the CO_2 storage factors for several potential

project types, as shown in Table 3. Costs reflect the long leg of transport only and neglect local collection and pipeline spurs.

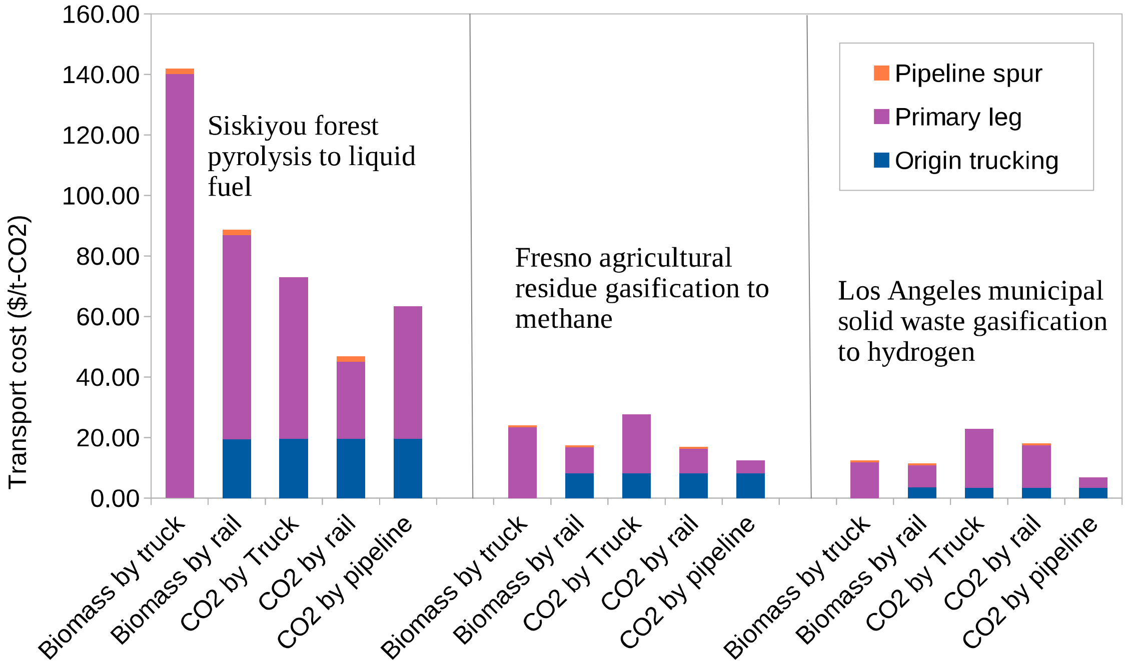

Figure 7: Transport costs by mode for three example projects. Distance and plant size vary by each project, as summarized in Table 4.

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