Financial Analysis of Innovative Wood Products and Carbon Finance to Support Forest Restoration in California

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Abstract

Traditional funding strategies of grants, congressional appropriations, and income from timber sales are insufficient to complete the level of forest restoration necessary throughout California. Stimulating investment into markets for low-value biomass—such as tops and branches of trees, small trees, and dead trees—will add value to forest raw materials and provide additional revenue streams to pay for forest restoration. We evaluate the investment potential of products made from low-value biomass using a discounted cash-flow analysis of several possible forest products including fuels and nonfuels under various climate policy and market scenarios. We demonstrate the carbon benefits provided by these products, attributed to their substitution for fossil-fuel feedstocks and long-term carbon storage. Our work finds that there is an opportunity to develop several highly profitable products, most notably fuels, many of which are eligible for energy and climate policy programs such as California's Low Carbon Fuel Standard and the federal Renewable Fuel Standard. Nonfuel products have an average internal rate of return (IRR) of 13 percent, whereas fuels have an average IRR of 19 percent in our baseline scenario. Although products ineligible for government incentives are generally less profitable, income from the voluntary carbon market greatly increases the IRR. Fostering investment into these products can encourage critically needed funding for forest management while developing a high-impact carbon removal solution enabled by state, federal, and voluntary climate initiatives. On this basis, we conclude that climate policy can support forest restoration in California.

In California, 90 percent of the largest and most destructive fires in recorded history have occurred since 2010. CalFire fire suppression expenditures have increased as well, topping $1 billion for the first time in both 2020 and 2021, in contrast to average yearly expenditures of $167 million between 2000 and 2005 (CalFire 2021). Although fire is a natural and necessary process in the Sierra Nevada and many other dry western forests, the increasing extent and severity of wildfires threatens the resilience of both social and ecological systems (Barros et al. 2018).

The increasing severity of the wildfires throughout California has been caused by management decisions such as fire exclusion, which have in turn been exacerbated by climate change. These factors have created younger, denser, and more homogenous forests that are susceptible to high-severity, stand-replacing fires (Collins et al. 2011, McIntyre et al. 2015, Lydersen and Collins 2018). These management effects have been amplified by a lengthening fire season and increasing occurrence of extreme fire weather (Jain et al. 2020), shifting seasonality of precipitation (Swain 2021), and increasing temperature (Miller et al. 2009).

To increase the resilience of the Sierra Nevada and other dry western forests to ensure the continuity of ecological function and ecosystem benefits to human populations, a substantial increase in forest management is needed. Oftentimes, this management takes the form of mechanical and hand-thinning of dense, overcrowded forest stands followed by the reintroduction of low-severity burning. With approximately 50 million acres in need of treatment (US Forest Service 2022) at an average cost of at least $1,000 per acre (Chang 2021), the current need of $50 billion is roughly 100 times higher than Forest Service preventative treatment allocations, which was $0.5 billion in 2017 (US Forest Service 2016).

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California's Forest Action Team and the State of California have a goal to reduce wildfire risk on 1 million acres of combined public and private land (Forest Climate Action Team 2018). To achieve these goals, the plan calls for fuel reduction treatments, timber harvests, and expanded use of harvested wood products. Management, including mechanical thinning and prescribed fire, can reduce the risk of high-severity wildfire while providing multiple benefits (Kalies and Yocom Kent 2016, Stephens et al. 2020). To fund forest management on public land, historically, congressional appropriations have been combined with receipts from timber sales. However, treatment is often costly on both public and private lands even when the sale of merchantable sawlogs is possible. In many cases, the effectiveness of fuel treatments is dependent on the removal of small trees, which generally are low value and do not have viable markets. Income from markets for small trees, residues from forest management, and other forms of low-value biomass could provide much-needed revenue to scale forest restoration, but market demand is currently limited. As a result of lackluster market demand, large amounts of low-value biomass are left to decay or are burned after treatment, releasing their carbon to the atmosphere. Developing and fostering markets for low-value biomass such as branches, small trees, dead trees, and tops can increase the funding available for forest management.

Using low-value biomass as a feedstock to create innovative wood products is highly beneficial from a carbon removal or abatement perspective (Bergman et al. 2014, Baker et al. 2020, Cabiyo et al. 2021). These carbon benefits primarily accrue from the substitution for fossil fuel feedstocks in products like transportation fuels as well as from the long-term storage of carbon in products like building materials and biochar. These substitution and storage benefits can be financially leveraged through incentive programs like California's low carbon fuel standard (LCFS; California Air Resources Board [CARB] 2021), the federal renewable fuel standard (RFS; US Environmental Protection Agency [USEPA] 2015), 45Q tax credits (Internal Revenue Service 2021), and the voluntary carbon market to increase the profitability of these innovative wood products.

In this study, we examine the financial viability of a range of fuel and nonfuel products that can be made from low-value biomass in three different carbon incentive scenarios. These products are categorized as fuel and nonfuel products (see Fig. 1). Nonfuel products included are oriented strand board (OSB), biochar from a mobile pyrolysis unit, and biochar produced in a centralized facility. The fuel products included are pyrolysis fuels, Fischer–Tropsch fuels, Fischer–Tropsch fuels with carbon capture and sequestration (CCS), hydrogen, hydrogen with CCS, renewable natural gas (RNG), RNG with CCS, biopower, and biopower with CCS (BECCS; see Table 1 for acronyms and definitions). Biopower and BECCS are considered fuels because the electricity is assumed to power electric vehicles, making both biopower and BECCS eligible for LCFS credits in California. These products vary in terms of market readiness, but represent a range of possible products that can be made from low-value wood

To determine the potential of increasing funding for forest management by developing additional sources of revenue from low-value biomass, we examine 12 different products and ask several key questions:

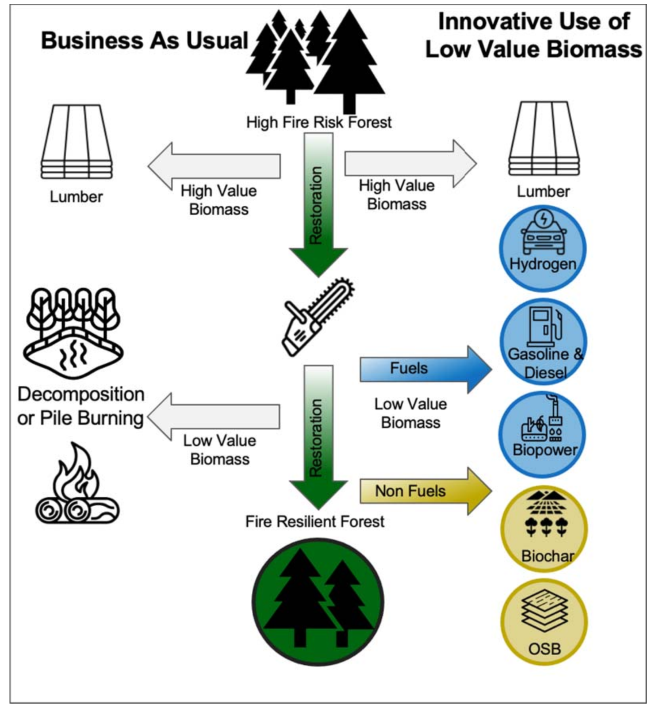


Figure 1.—Innovative wood products. Low-value woody biomass generated during forest restoration is currently left in the forest to decompose or burn. However, that biomass could be used to create a range of carbon-beneficial fuel and nonfuel products.

1. What is the carbon benefit of using low-value biomass to produce these products?
2. What is the economic feasibility of producing these products from low-value biomass?
3. How do different levels and types of carbon incentives affect economic feasibility?

To answer these questions, we conduct a financial analysis incorporating carbon incentives using existing voluntary carbon market credits as well as existing state and federal policies in California.

Methods

We examine 12 innovative wood products in this study, divided into nonfuel products and fuel products. These products are among the most promising identified by the State's Joint Institute for Wood Products Innovation (Sanchez and Gilani 2022). The carbon benefit of using biomass as a feedstock is first assessed on the basis of existing literature. We then perform a discounted cash-flow analysis for each product. Each of these wood products is technically feasible and relies on different forms of low-value biomass. OSB, for example, requires small-diameter (pulpwood) logs, whereas the production of hydrogen can use mixed biomass including tops, branches, leaves, and bark. This analysis is agnostic to the type of feedstock necessary and uses the term feedstock interchangeably between pulpwood, wood chips, and other forms of low-value biomass. It is also assumed that all facilities have enough feedstock to meet yearly requirements and the feedstock costs used represent delivered costs.

Table 1.—Acronyms and definitions of common terms.

Term	Meaning	Description
Fuel products		Fuel descriptions adapted from Baker et al. (2020).
FT fuels	Fischer–Tropsch fuels	Formation of liquid transportation fuels (gasoline and diesel) from the gasification of biomass followed by Fischer–Tropsch syntheses. The final products are typically gasoline and diesel blendstocks identical to their fossil-derived counterparts.
FT fuels + CCS		Fischer–Tropsch Fuels produced with carbon capture and sequestration incorporated.
RNG	Renewable natural gas	Produced by upgrading biogas or syngas into a product that can supplement or replace traditional natural gas.
RNG + CCS		RNG produced along with the capture and sequestration of CO_2 emitted during production.
Hydrogen		Formed from syngas by converting carbon monoxide and water into CO_2 and hydrogen.
Hydrogen + CCS		Hydrogen has a high potential quantity of CO_2 that can be captured because the fuel produced (hydrogen) does not contain carbon. This is in part why hydrogen + CCS has the largest carbon benefits of the products modeled.
BECCS	Bioenergy with carbon capture and storage	Creating electricity from biomass and capturing and storing the carbon, removing it from the atmosphere.
Pyrolysis fuels		Thermochemical conversion that decomposes biomass in gas, liquid, and solid products. Bio-oil is upgraded into liquid transportation fuels (gasoline and diesel).
Nonfuel products		
Biochar		Material obtained from the pyrolysis of biomass in an oxygen-limited environment.
OSB	Oriented strand board	Building material formed by compressing adhesives and layers of wood strands in specific orientations, similar to particleboard.
Carbon incentive programs		
45Q	Section 45Q of the Internal Revenue Code	Tax credit (\$10–\$50) for each metric ton of carbon captured and sequestered, depending on type of geologic storage.
RFS	Renewable fuel standard	Congressionally created program designed to reduce greenhouse gas emissions and expand renewable fuels sector.
LCFS	California low carbon fuel standard	State-created program to decrease carbon intensity of transportation fuels.
Voluntary carbon market		Decentralized market where carbon credits representing certified removals or reductions of greenhouse gasses are bought and sold by private actors.
Abbreviations		
CAPEX	Capital expenditures	Major long-term expenses such as physical assets, buildings, equipment, and vehicles.
OPEX	Operational expenditures	Day-to-day expenses including salaries, rent, utilities, and costs of production.
GREET	Greenhouse gasses, regulated emissions, and energy use in technologies model	Analytical tool that conducts a life-cycle analysis by simulating the energy use and emission outputs of various vehicles and fuels.
IRR	Internal rate of return	Method for calculating an investment's rate of return. IRR estimates a project's break-even discount rate, indicating profitability potential.
RIN	Renewable identification number	Credit generated each time a gallon of renewable fuel is produced per the renewable fuel standard (RFS).
CCS	Carbon capture and sequestration	Technologies that capture and compress CO_2 from industrial processes and then inject the compressed CO_2 in deep geologic formations.

Carbon benefit analyses

To determine the carbon benefit of using biomass to create each product, we rely on published values, primarily from Cabiyo et al. (2021), to model the cradle-to-grave and well-to-wheels carbon benefit of biomass use. The system boundaries are drawn such that we assess carbon emissions and benefits across four life-cycle categories: (1) transportation emissions; (2) production emissions—accounts for all direct and upstream emissions from fossil fuels used onsite in handling and conversion of biomass. Biogenic carbon emissions are treated as neutral, as it is assumed these wastes would have returned carbon to the atmosphere via degradation or burning (see Discussion); (3) substitution of carbon-intensive products—assumes 1:1 replacement and emissions avoidance of conventional electricity and fuels in the California context; and (4) product end of life—includes combustion of final fuels and decay of recalcitrant and long-lived forest products. Data from the Greenhouse Gasses, Regulated Emissions, and Energy Use in Transportation (GREET) model are used for all process and substituted fuels and electricity. Products and coproducts are assumed to displace incumbent sources of emissions where appropriate (described below). For a full accounting of scenario outputs, see Table 5. Biomass-derived electricity is assumed to displace the average distributed California grid in 2019 with an emissions factor of 224 kg of CO_2 equivalents (CO_2e)/MWh. RNG is assumed to displace a mix of North American natural gas with an average emissions factor of 73.9 gCO_2e/MJ, which includes both extraction and eventual combustion. All woody feedstocks are assumed to be 50 percent C by mass. Carbon benefit is the sum of all nonbiogenic emissions minus avoided emissions and storage. Carbon benefits were calculated in terms of tons of C benefit per bone dry ton (BDT)of woody biomass.

Scenario descriptions

Feedstock harvest and transport emissions are consistent across pathways. We assume a 90-mile average travel distance by heavy-duty diesel truck with a 16-ton payload, accounting for backhaul. The truck has a fuel economy of 7.17 mi/gal loaded and 9.03 mi/gal backhaul.

The centralized pyrolysis biochar scenario assumes a slow pyrolysis system on the basis of Lehmann and Joseph (2015), where 35 percent of feedstock carbon ends up in the biochar, 30 percent goes to pyrolysis oil, and 35 percent to the syngas fraction. As in Lehmann and Joseph, we assume that bio-oil and syngas are combusted for heat and power in the facility. The operation generates net power for export to the grid at a rate of 0.31 MWh per metric ton of feedstock. The power export is assumed to displace the average distributed California grid. The process requires auxiliary diesel fuel and natural gas at a rate of 2.09 kg/ton and 3.1 kg/ton of feedstock, respectively. Relying on updated emissions factors from the GREET model, diesel fuel and natural gas contribute ~8 $kgCO_2e$/ton and ~10 $kgCO_2e$/t of feedstock respectively. Combustion of biogenic fuels (syngas and pyrolysis oil) is assumed to yield net 0 CO_2e emissions. Carbon storage in biochar assumes that 85 percent of the carbon is recalcitrant and 15 percent is labile, with half-lives of 300 years ($k_{\mathrm{recalc}} = -0.002$) and 20 years ($k_{\mathrm{labile}} = -0.035$), respectively. Carbon remaining sequestered in biochar is assessed at the 100-year time horizon, with ~68 percent remaining. The fraction of carbon remaining at 100 years is described by the two-pool model in Equation 1.

$$\begin{aligned}\%\text{C remaining at 100 years} \\ &= (\text{labile }\% \times \exp[100k_{\mathrm{labile}}]) \\ &\quad + (\text{recalcitrant }\% \times \exp[100k_{\mathrm{recalc}}]) \qquad (1)\end{aligned}$$

The mobile pyrolysis biochar scenario follows the analysis of the case 2 ‘‘no dryer’’ scenario in Thengane et al. (2020). However, Thengane et al. assume a dry-basis carbon content of 46 percent in the feedstock. For consistency, we recalculated the results from Thengane et al. assuming 50 percent carbon content. In this scenario, 32 percent of feedstock carbon is retained in the biochar. Pyrolysis oil and syngas fractions are combusted and emitted. There is no power generation assumed in this scenario. Propane is combusted as auxiliary fuel at a rate of 38 tons/ton of feedstock. The emissions factor for propane is obtained from the GREET model at a rate of 0.59 $kgCO_2e$/kg of propane combusted. The biochar carbon in this scenario is assumed to be 93 percent recalcitrant and 7 percent labile. The half-lives assumed are the same as in the slow pyrolysis scenario: ~74 percent of the carbon in the biochar is assumed to remain after 100 years (see Eq. 1 above).

The RNG scenarios, both with and without CCS, are based on a life-cycle assessment performed by the Gas Technology Institute (GTI; GTI 2019) for the CARB. All assumptions from tables 19 and 20 of that report remain unchanged save for the emissions credits awarded for net power exported to the grid, the quantity of CO_2e captured in the CCS case, and feedstock harvest and transport. As in the previous scenarios, we substitute our feedstock and harvest emissions for those used in the GTI report. The emissions intensity of the California average grid is used to calculate credits for displaced grid power at a rate of 85 kJ/MJ of RNG in the no-CCS case and 45 kJ/MJ RNG in the CCS case. We use grid emissions factors from a more recent GREET model, as described earlier in this section. We also explicitly model the parasitic load for compression of captured CO_2e and deduct that load from the available power export at a rate of 200 kWh/ton of CO_2e in the CCS case. We update the carbon content of feedstock assumption to 50 percent for consistency, which changes the balance of CO_2e available for capture. The carbon intensity of RNG in the non-CCS case is ~20 g of CO_2e/MJ (vs. 16 g of CO_2e/MJ in the GTI report) and in the CCS case –42 g of CO_2e/MJ (–77 g of CO_2e/MJ in the GTI report). Process emissions do not include electricity credits in the results section. Rather, the substitution benefit is the combined effect of displaced grid power and displaced conventional natural gas using the GREET emissions factor described previously.

Baseline economic scenario and discounted cash-flow analysis

To establish baseline economic scenarios for each product (see Table 2), we incorporate published technoeconomic analyses to compile the initial capital expenditures required to build manufacturing facilities, the yearly operating expenditures, and the yearly feedstock required

Table 2.—Baseline scenario economic assumptions.

Key variable	Baseline ($)	Unit
Feedstock cost	60	Bone dry ton
LCFS price[a]	100	Tons of CO_2 equivalents (CO_2e)
RIN price	0.91	Gallon gasoline equivalent
45Q price	50[b]	Tons of CO_2e
Voluntary carbon market price—biochar	90	Tons of CO_2e
Voluntary carbon market price—OSB	30	Tons of CO_2e
Electricity price (50-MW BECCS)	120	Megawatt hour
Electricity price (3-W Biopower)	195	Megawatt hour
OSB price	224	3/8″, thousand square feet
Biochar price	425	Ton
Diesel fuel price	2.25	Gallon
Gasoline price	2.25	Gallon
Hydrogen price	1.40	Kilogram
RNG price	11.00	Million metric British thermal units

Depiction of the assumed prices and costs of various fuels, primary products, and carbon incentives in the baseline scenario. Price assumptions made to reflect current market prices of each variable; see Methods.
[a] See Table 1 for abbreviations.
[b] Policy cliff scenario is assumed. 45Q is discontinued after 12 years in accordance with current legislation.

to achieve production targets. Income from primary products, coproducts, and applicable carbon incentives (LCFS, RFS, 45Q, and voluntary carbon market) are incorporated into yearly revenue (see Tables 3 and 4). Carbon incentives modeled include income from California's LCFS, the RFS, 45Q CCS tax credits, and voluntary carbon market credits, as applicable. After costs and revenue are calculated, the internal rate of return (IRR) is calculated for each product over a 20-year time frame to create high, low, and baseline carbon incentive scenarios. A construction period of 1 year is assumed for each product and full production of primary products and generation of carbon incentives is assumed to start in year 2. Existing literature is used to build the baseline economic (Table 2) and baseline technological assumptions (Table 4). Scenarios for each product including OSB (The Beck Group 2015), biochar from a mobile pyrolysis unit (Thengane et al. 2020), biochar produced in a centralized facility (Lehmann and Joseph 2015), pyrolysis fuels (Li et al. 2017), Fischer–Tropsch fuels (Liu et al. 2011), Fischer–Tropsch fuels with CCS (Liu et al. 2011), hydrogen (Sarkar and Kumar 2009), hydrogen with CCS (Sarkar and Kumar 2009), RNG (GTI 2019), RNG with CCS (GTI 2019), biopower (The Beck Group 2015), and BECCS (Bhave et al. 2017).

The manner in which carbon incentive programs are incorporated into the financial analysis are intended to be as realistic as possible and aligned with current policy, per Sanchez and Gilani (2022). For a comprehensive list of the carbon incentives incorporated into the baseline financial analysis of each product, see Table 4. The baseline carbon incentive scenario for each product (Table 2) attempts to capture current market prices for all primary products and carbon incentives keeping high volatility in mind. The LCFS price used for the baseline scenario (\$100/ton CO_2e) takes into consideration the yearly average from 2020 of \$200/ton CO_2e, the yearly average from 2021 of \$178/ton CO_2e, and transactions averaging \$92/ton CO_2e in the third quarter of 2022 (CARB 2022). Renewable identification number (RIN) credit pricing in the baseline scenario (\$0.91/ton CO_2e) represents the median transaction price over the period 2016–2021. The median was used given the stability of the RIN market as compared with the volatility in the LCFS market. The baseline scenario assumes that half of the feedstock originates on private land and half on public land; currently feedstock originating on federal land is not eligible for RIN credits (Sanchez and Gilani 2022). Thus, only half of the feedstock used generates RIN credits. 45Q tax credits are assumed to be \$50/ton CO_2e (Jones and Sherlock 2021), with the policy lapsing after 12 years. Voluntary carbon market pricing for OSB (\$30/ton CO_2e) is based on the prices for similar credits being sold by Puro.earth (Puro.earth 2022) in 2022, whereas pricing for biochar carbon credits (\$90/ton CO_2e) is based on the National Association of Securities Dealers Automated Quotations (NASDAQ) price index for biochar carbon credits (NASDAQ 2022). Market rates for primary products including biochar (Thengane et al. 2020), OSB (The Beck Group 2015), electricity (Li 2022, Pacific Gas and Electric, US Energy Information Administration [EIA] 2022), RNG (EIA 2022), gasoline and diesel fuel (EIA 2022), and hydrogen (International Energy Agency 2021) are highly variable by region, plant size, and production method. The assumptions in this analysis (Table 2) are based on recent market trends and attempt to capture realistic baseline prices for each primary product. Income from carbon incentives is assumed to occur the same year the primary product is generated. Each year that products generating carbon benefits is produced, additional income is captured in the discounted cost-flow analysis.

Carbon incentive scenario analysis

Two scenario analyses were conducted that examine high and low carbon incentive scenarios (see Figs. 2 and 3) over a 20-year time frame. Each scenario examines high and low assumptions for LCFS, RIN, 45Q, and voluntary carbon markets separately while holding all other variables and carbon incentives constant at the baseline (see Table 2). Certain scenarios examine the effect of current policy hypothetically not being renewed (policy cliff), such as the LCFS low carbon incentive scenario, whereas others examine the effect of a drop in market price, such as the voluntary carbon market price. Policy cliffs are created on the basis of the current legislation and informed by the authors' expert opinions. The assumptions for each scenario are listed explicitly in Table 3. LCFS pricing in the high carbon incentive scenario is \$125 and in the low carbon incentive scenario is \$100 but terminates after 10 years. The low RIN scenario assumes all feedstock originates on public land and is thus not eligible for RIN credits, whereas the high scenario is \$3.04, which is the 95th percentile of RIN pricing between 2016 and 2021. 45Q tax credits pricing is dependent on how the CO_2e is sequestered. The low carbon incentive scenario assumes a price per ton of CO_2e of \$35 with the policy lapsing after 12 years, in line with current legislation. The high carbon incentive scenario assumes a price per ton of CO_2e of \$50 with the policy being renewed for the 20 years used in this analysis. Voluntary carbon

Table 3.—Carbon incentive scenario assumptions.

Key variable	Low (\$)	Baseline (\$)	High (\$)	Unit
Feedstock cost	40	60	120	Bone dry ton
LCFS price[a]	100[b]	100	125	Tons of CO_2 equivalents (CO_2e)
RIN price	0	0.91	3.04	Gallon gasoline equivalent
45Q price	35[b]	50[b]	50	Tons of CO_2e
Voluntary carbon market price—biochar	20	90	120	Tons of CO_2e
Voluntary carbon market price—OSB	15	35	45	Tons of CO_2e

Depiction of the assumed prices and cost of key variables in low, baseline, and high carbon incentive scenarios.

[a] See Table 1 for abbreviations.

[b] Policy cliff scenario is assumed. LCFS discontinued after 10 years. 45Q discontinued after 12 years. RIN is assumed to either be continuously present or absent at given prices. Policy assumptions built to best reflect current legislation; see Methods.

Table 4.—Technological assumptions.

	CapEx ($, millions)[a]	OpEx/ton of feedstock (excludes feedstock costs) ($)	Annual feedstock requirements (tons)	Annual capacity	Monetized products	Eligible carbon incentives	Baseline internal rate of return (IRR) (%)	Baseline net present value (NPV) ($, millions)
Fuel products								
Biopower	27	57	30,000	3 megawatts	Electricity and steam	LCFS	4	−3
Biopower + CCS	1,059	9	829,000	50 megawatts	Electricity	LCFS	14	975
FT fuels	1,086	94	1,176,359	23.1 million gallons of gasoline 39.3 million gallons of diesel fuel	Gasoline, diesel fuel, and electricity	LCFS, RIN	6	72
FT fuels + CCS	1,106	109	1,176,359	23.1 million gallons of gasoline 39.3 million gallons of diesel fuel	Gasoline, diesel fuel, and electricity	LCFS, RIN, 45Q	17	1,287
RNG	509	96	310,610	2.9 billion cubic feet	RNG	LCFS, RIN	−4	−299
RNG + CCS	519	112	310,000	2.9 billion cubic feet	RNG	LCFS, RIN, 45Q	9	164
Hydrogen	267	98	620,500	51.8 million kilograms of hydrogen	Hydrogen	LCFS	17	317
Hydrogen + CCS	283	113	620,500	51.8 million kilograms of hydrogen	Hydrogen	LCFS, 45Q	51	1,395
Pyrolysis Fuels	340	3	656,416	33.3 million gallons of gasoline 24.3 million gallons of diesel fuel	Gasoline and diesel fuel	LCFS, RIN	35	1,106
Nonfuel products								
Biochar Mobile	0.74	103	2,933	1,350 tons of biochar	Biochar	Voluntary carbon market	18	1
Biochar Centralized	21	106	70,080	24,500 tons of biochar	Biochar and electricity	Voluntary carbon market	19	30
OSB	216	332	334,500	475 million square feet	Oriented strand board	Voluntary carbon market	13	163

[a] See Table 1 for abbreviations.

market price for both biochar and OSB is informed by recent market ranges (Puro.earth, NASDAQ).

Sensitivity analyses

To understand how fluctuations in cost and income affect the baseline economic scenarios, a sensitivity analysis is conducted by increasing and decreasing various parameters by 40 percent in increments of 10 percent. The parameters analyzed included feedstock cost, operational expenditures, capital expenditures (CAPEX), price of the primary product, carbon benefit, LCFS price, RFS price, and 45Q credit for each eligible product. The associated percent changes in IRR are displayed in Figures 4 and 5.

Feedstock price assumptions and price analysis

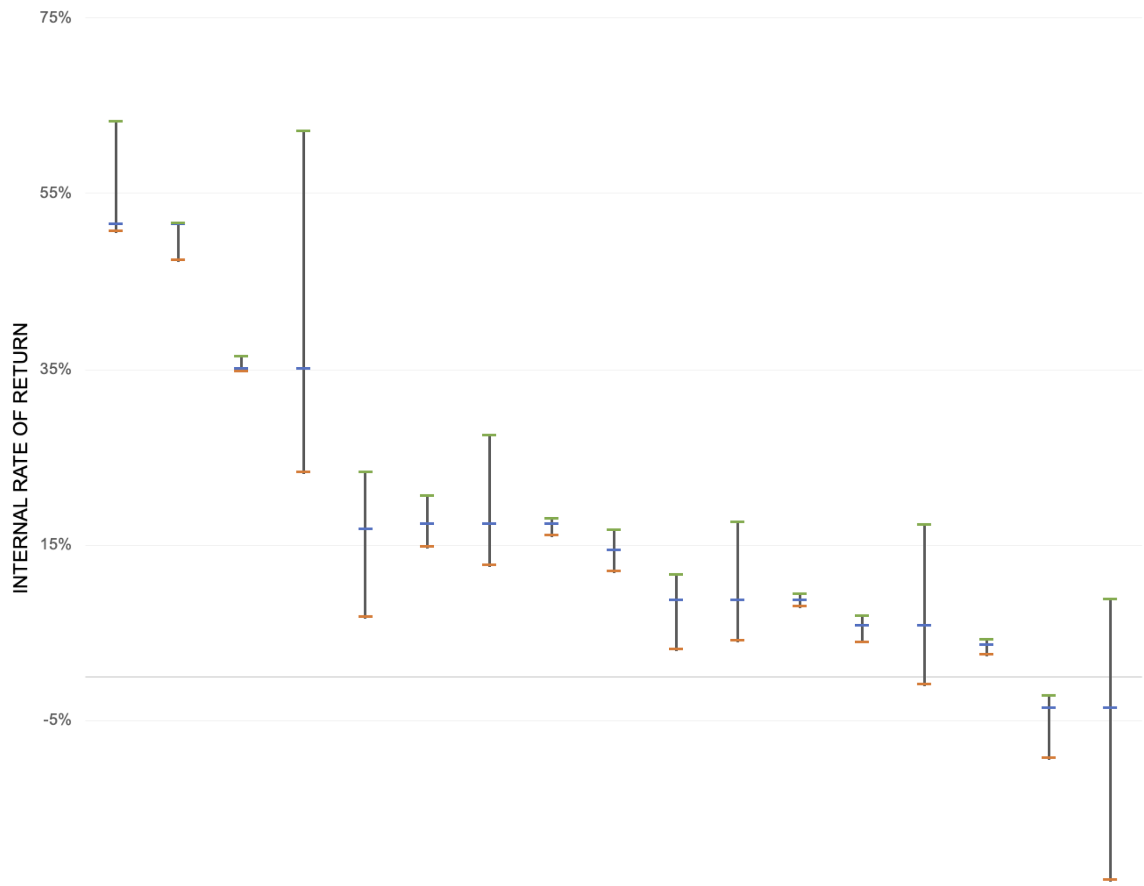
Feedstock costs are generally broken down into collection/processing and transportation in the literature. Costs associated with harvesting, chipping, and hauling low-value biomass to a production facility vary greatly. These costs will be affected by the objective of the forest management—whether explicitly a harvest, a fuel reduction, or some combination—as well as equipment technology, harvest objective, site conditions, and haul distance, all of which will in turn affect the delivered feedstock costs (Lord et al. 2006). The baseline feedstock cost assumption of $60/ton is considered the average annual delivered cost/BDT and is based on ranges in the literature from California and Oregon of $45 to $70 (Springsteen et al. 2015), $55 to $120 (Swezy et al. 2021), $35 to $65 (The Beck Group 2018), and $35 to $66 (Lord et al. 2006). The effect of fluctuations in feedstock price is captured in Figure 6, in which all other variables aside from feedstock cost are held constant at the baseline economic assumptions (Table 2) and feedstock cost is assumed to have a low of $40/BDT and a high of $120/BDT.

Results

An analysis of the carbon incentive scenarios' financial effect on fuel products highlights hydrogen + CCS as a standout product in our assumed baseline scenario (see Fig. 2). Hydrogen + CCS has the highest IRR of the fuel products, with an IRR of over 45 percent even in the low carbon incentive scenario, but more important, our modeling does not account for hydrogen storage and transport. Pyrolysis fuels are also highly profitable, with an IRR over 30 percent in the high carbon incentive scenario and an IRR over 20 percent in the low carbon incentive scenario, which assumes an absence of RIN credits or a discontinuation of LCFS credits after 10 years. Hydrogen does not have quite as high of an IRR but is still between 7 and 23 percent in each of the carbon incentive scenarios.

The hydrogen + CCS facility we modeled is highly profitable and relatively market ready compared with some of the other fuels modeled. Although hydrogen + CCS is the standout product in this analysis, many of the other fuel products have an IRR of 5 percent or higher in our baseline carbon incentive scenario, with the notable exception of RNG (without CCS), which had a negative IRR in each scenario, and biopower, which had an IRR below 5 percent in each scenario.

Our low carbon incentive scenario for fuels includes downward fluctuations in LCFS, RIN, and 45Q credit



	LCFS	45Q	LCFS	RIN	LCFS	LCFS	RIN	45Q	LCFS	LCFS	RIN	45Q	LCFS	RIN	LCFS	LCFS	RIN
	Hydrogen + CCS		Pyrolysis Fuels		Hydrogen	FT Fuels + CCS			BECCS	RNG + CCS			FT Fuels		Biopower	RNG	
Low	51%	47%	35%	23%	7%	15%	13%	16%	12%	3%	4%	8%	4%	-1%	3%	-9%	-23%
Baseline	51%	51%	35%	35%	17%	17%	17%	17%	14%	9%	9%	9%	6%	6%	4%	-4%	-4%
High	63%	52%	36%	62%	23%	21%	27%	18%	17%	12%	18%	9%	7%	17%	4%	-2%	9%

Figure 2.—Fuel products carbon incentive scenarios. Depiction of the high, baseline, and low carbon incentive scenarios for each fuel product. The scenarios for each variable (low carbon fuel standard [LCFS], renewable identification number [RIN], or 45Q) hold all other variables constant at the baseline described in Table 3.

prices, as those are the incentives over which policy has direct control. Because of the multiple sources of revenue, including state incentives as well as primary and secondary products, the IRR effects from fluctuations in any one source of income were mediated by other income.

In this model, we build in realistic conservativeness wherever possible, such as including 50 percent contingency to CAPEX for fuels (excluding BECCS and biopower, which received 30% contingency) and 30 percent contingencies for nonfuels. With that in mind, there are likely several unforeseen real-world costs that were not captured by the technoeconomic analyses incorporated in this study due to the relatively low technology readiness of certain technologies.

An analysis of voluntary carbon market income on the IRR of nonfuel products (Fig. 3) finds that biochar (mobile) has an IRR of 9 percent in the low carbon incentive scenario (\$20/ton CO_2e) and 21 percent in the high carbon incentive scenario (\$120/ton CO_2e), whereas biochar (centralized) has an IRR of 11 percent in the low carbon incentive scenario and 22 percent in the high scenario. OSB is minimally affected by income from the potential voluntary carbon market, going from 11 percent in the low scenario (\$15/ton CO_2e) to 15 percent in the high scenario (\$45/ton CO_2e) in part because of the lower carbon credit prices for OSB as compared with biochar.

The most carbon-beneficial products are fuel products coupled with CCS (see Table 5). The substantial carbon benefit of fuels coupled with CCS is in large part due to the substitution benefit of using biomass in place of fossil fuels alongside the CO_2e captured and stored from the production processes, which is captured in our carbon benefits calculations (see Table 5). The least carbon-beneficial product is biopower, due to a lack of carbon storage benefits and relatively small substitution benefits given the relatively high penetration of renewable energy in California's grid.

The sensitivity analysis of the wood products is divided into nonfuel and fuel products (see Figs. 4 and 5). Nonfuel products are highly sensitive to many parameters. Primary

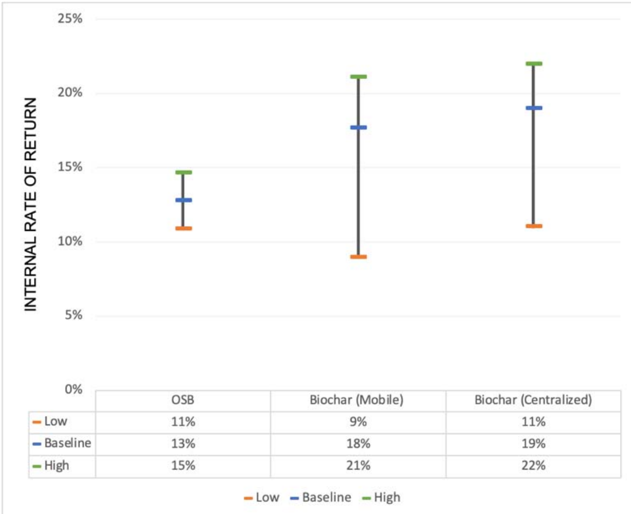


Figure 3.—Nonfuel products carbon incentive scenarios. Depiction of the high, baseline, and low carbon incentive scenario for each nonfuel product. The only incentive program examined for these products is voluntary carbon market as described in Table 3.

product price (which excludes price for any coproducts) in particular has a significant effect on the IRR. For example, a 20 percent decrease in product price from the baseline scenario decreases the IRR for OSB by 71 percent, biochar (mobile) by 75 percent, and biochar (centralized) by 60 percent. This likely reflects these products' reliance on market, rather than policy-derived, revenues.

The IRRs for fuel products are generally less sensitive to fluctuations in primary product price than nonfuel products, with the notable exceptions of Fischer–Tropsch fuels, RNG, and biopower (see Fig. 4). For example, a 20 percent decrease in product price from the baseline scenario decreased the IRR for pyrolysis fuels by 16 percent, Fischer–Tropsch fuels + CCS by 16 percent, hydrogen by 26 percent, hydrogen + CCS by 7 percent, RNG + CCS by 14 percent, and BECCS by 18 percent. For Fischer–Tropsch fuels, RNG, and biopower, which are the products more sensitive to product price, a 20 percent decrease in product price from the baseline scenario decreases the IRR by 71, 66, and 120 percent, respectively. This decreased sensitivity is due in part to the multiple sources of income for many fuel products, particularly income from LCFS credits, RIN credits, and 45Q tax credits.

For the products that were eligible for programs like the LCFS and the RFS, fluctuations in the LCFS price in particular have a similar magnitude of effect on the IRR. A 20 percent decrease in the LCFS price from the baseline scenario decreases the IRR for pyrolysis fuels by 3 percent, Fischer–Tropsch fuels + CCS by 12 percent, Fischer–Tropsch fuels by 10 percent, hydrogen by 25 percent, hydrogen + CCS by 18 percent, RNG by 13 percent, and RNG + CCS by 19 percent. Fluctuations in RIN credit pricing have a similar, but lower magnitude, effect on the IRR.

Fluctuations in carbon intensity, or the amount of greenhouse gasses released in the lifetime of a product, have a consistently significant effect on the IRR, given that the number of LCFS or RIN credits received is determined by the carbon benefit calculated. RIN and LCFS credits

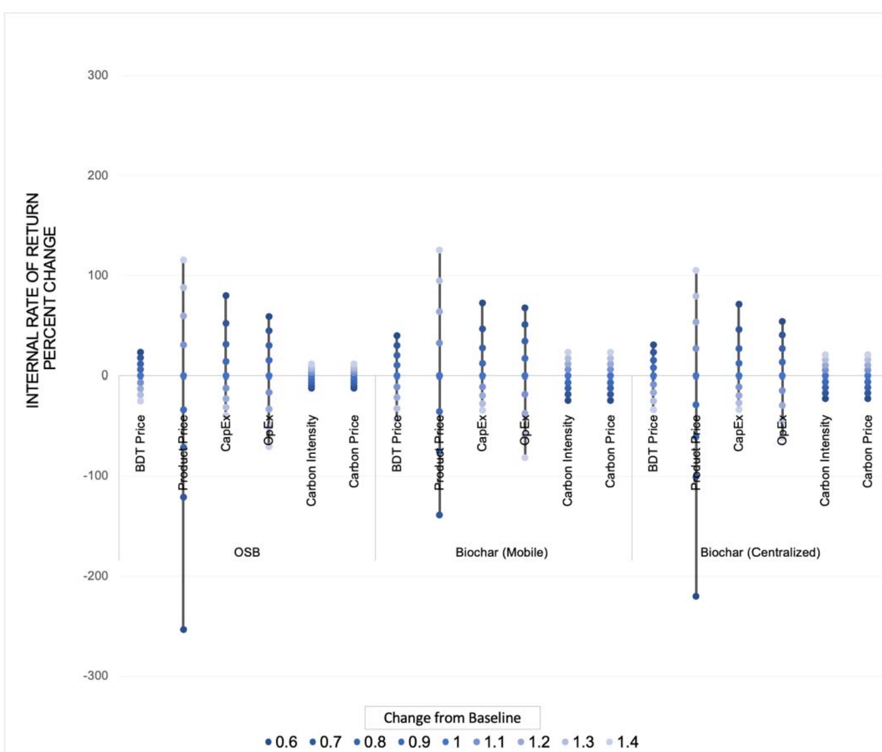


Figure 4.—Nonfuel products sensitivity analysis. Depiction of the percent change of the internal rate of return (IRR) resulting from a change in the baseline assumptions depicted in Table 2.

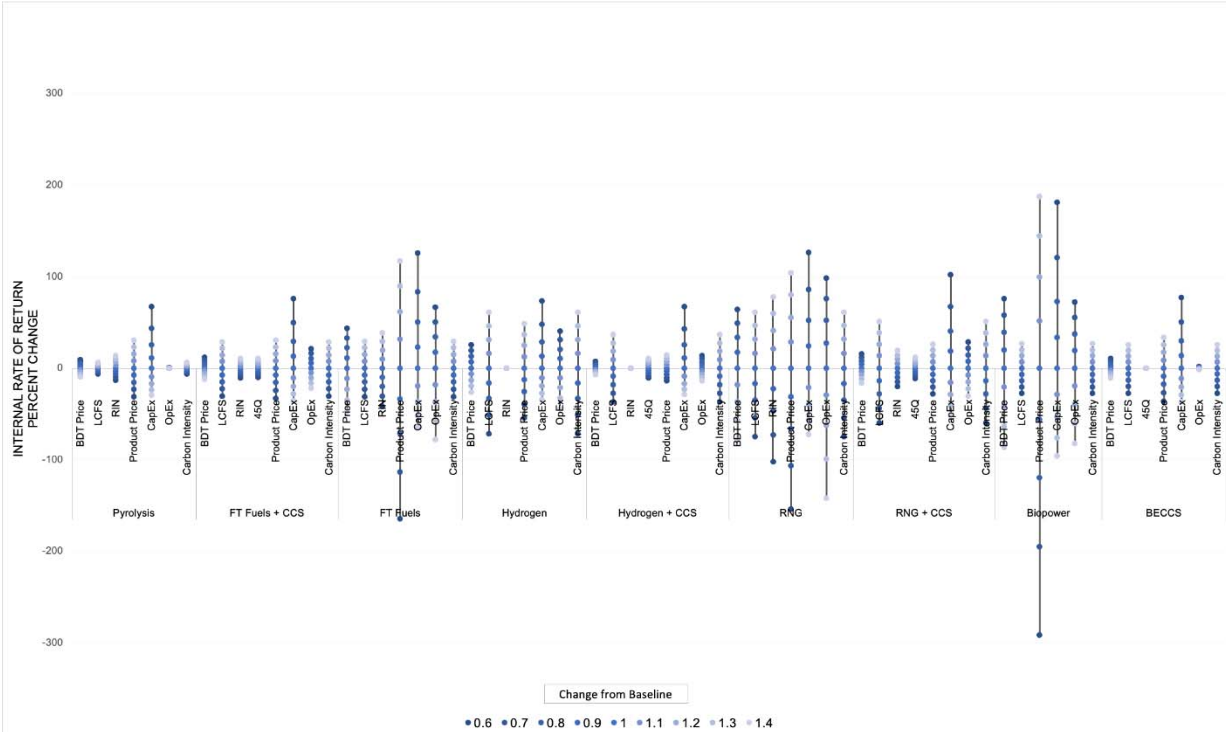


Figure 5.—Fuel products sensitivity analysis. Depiction of the percent change of the internal rate of return (IRR) resulting from a change in the baseline assumptions depicted in Table 2.

were a significant source of income for eligible products—fuel products received an average of 49 percent of their income from carbon incentives. Fuel products, with the exception of pyrolysis fuels, biopower, and BECCS, had a highly negative IRR when all carbon incentives were removed.

Changes in the feedstock cost have a sizable effect on the IRR of many products (see Fig. 6). However, even in the

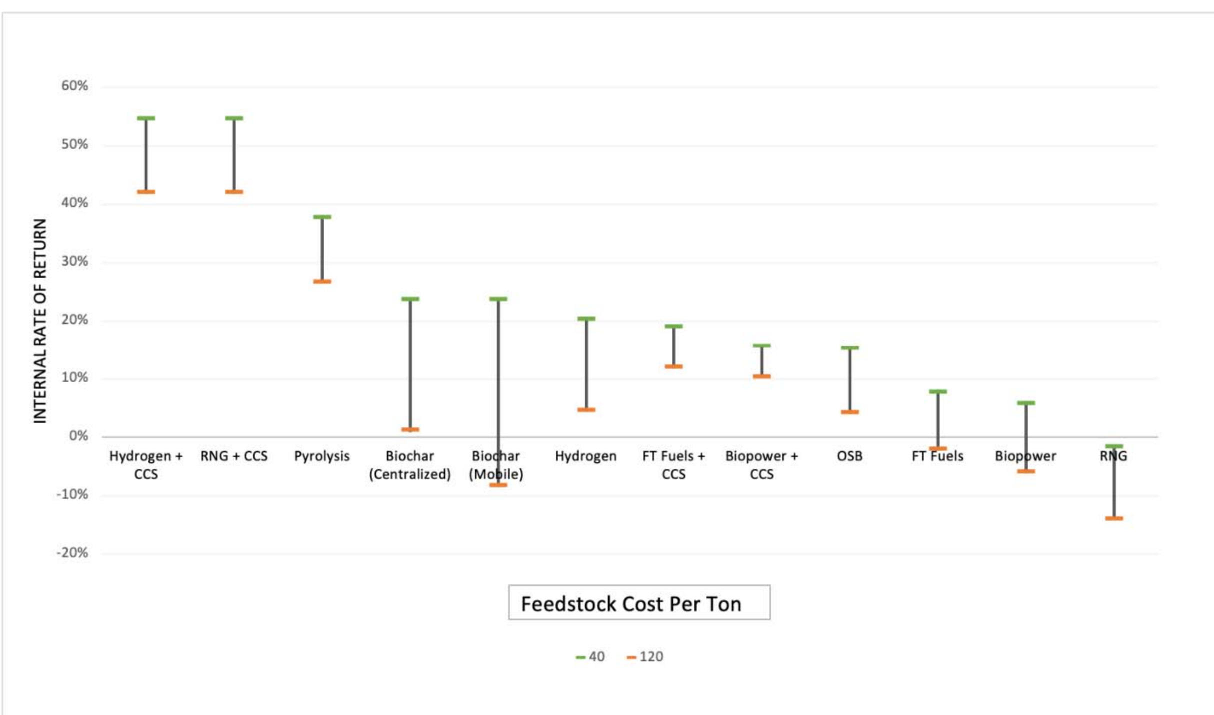


Figure 6.—Feedstock cost analysis. Depiction of the range of internal rate of return (IRR) for each product examined resulting from high and low feedstock costs. All other variables are held constant at the baseline as described in Table 2.

Table 5.—Carbon benefit.

Technologies	Substitution	Process emissions	Storage	Total
Nonfuel				
OSB[a]	0.94	−0.30	0.44	1.08
Biopower + CCS	0.10	0.72	0.00	0.82
Biochar (centralized)	0.04	−0.03	0.24	0.25
Biochar (mobile)	0.00	−0.03	0.24	0.21
Biopower	0.13	−0.02	0.00	0.11
Fuel				
Hydrogen + CCS	0.80	0.85	0.00	1.65
RNG + CCS	0.49	0.64	0.00	1.13
Fischer–Tropsch fuels + CCS	0.35	0.46	0.00	0.81
Hydrogen	0.80	0.01	0.00	0.81
Pyrolysis fuels	0.63	−0.20	0.00	0.44
RNG	0.51	−0.20	0.00	0.31
Fischer–Tropsch fuels	0.35	−0.13	0.00	0.22

Carbon benefit of each biomass product in terms of tons of C benefit/tons of C in feedstock. Storage includes landfilled wood and carbon in long-lived products. CCS storage benefits are included in process emissions.
[a] See Table 1 for abbreviations.

high-cost scenario ($120/BDT feedstock), hydrogen + CCS and RNG + CCS have IRRs over 40 percent. In the baseline scenario of $60/BDT feedstock, biochar (mobile) and biochar (centralized) have high IRRs of 18 and 19 percent respectively, but are very sensitive to upward fluctuations in feedstock cost.

Discussion and Conclusions

Emerging fuel and nonfuel products using low-value biomass as a feedstock can provide additional funding for critical forest restoration while helping to accomplish climate neutrality goals in California. In the baseline scenario, nonfuel products have an average IRR of 13 percent, whereas fuels have an average of 19 percent IRR. Hydrogen + CCS and several other fuel products made from low-value biomass are still highly profitable at feedstock costs over $100/ton under our assumptions, whereas nonfuel products have IRRs over 10 percent when feedstock costs are over $80/ton. With a rough average of 10 tons of low-value biomass needing to be removed from each acre of overstocked forest (Rummer et al. 2005), these products could add a significant revenue source to forest management operations by providing new markets for low-value biomass. In certain scenarios, this additional income from low-value biomass may be able to single-handedly pay for forest management, depending on the contractual arrangement between landowner and harvesting contractor.

However, the viability of both nonfuel and fuel products are dependent upon policy and market support in the form of consistent price support and the longevity of existing carbon incentive programs. Our analysis shows that nonfuel products like biochar and building materials like OSB need reliable markets, along with carbon and product prices, to ensure the profitability of their operations. For instance, a 20 percent change in the market price for each of these primary products created a 45 percent or greater decrease in the IRR. Biochar and other nonfuel products are clearly highly sensitive to market price for primary products and various price support systems may help to decrease risk and encourage investment in this space.

On the other hand, fuel products like hydrogen and other transportation fuels are less sensitive to changes in market price for primary products and are highly profitable with existing carbon incentives like LCFS, RIN, and 45Q credits. Here, policy certainty will be a key driver of deployment. For each fuel, an average of 49 percent of yearly income in our relatively conservative baseline scenario was directly from carbon incentives, with as much as 76 percent for hydrogen + CCS and RNG + CCS. The continued maintenance and expansion of these carbon incentives will help to send signals to the market to invest in these climate-beneficial fuels.

In other instances, leveraging voluntary carbon credit markets can help to encourage these products. The centralized biochar facility we modeled had an IRR of 19 percent when carbon credits were $20/ton and 34 percent when carbon credits reached $120/ton. Interest in biochar has increased as a possible component of mine remediation products or as a soil amendment in agricultural, range, or forest lands. Moreover, demand for scientifically rigorous and demonstrably additional carbon credits is increasing and biochar carbon offsets could help to fill this demand, as seen in the carbon-offset purchasing trends by Microsoft and other corporate carbon-neutrality leaders (Microsoft 2021).

The carbon benefits of biochar and certain building materials like OSB can be monetized by creating credits through existing registries such as Puro.earth or Verra. LCFS and RIN credits can be generated by calculating the carbon intensity of the fuel created while working through the CARB and the USEPA, respectively. The 45Q tax credit can be claimed under section 45Q of the US Internal Revenue Code. In each of these instances, industry consultants can advise on how to best monetize the carbon benefits of these carbon-beneficial products.

There are important limitations to this study. First, the capital expenditures used in this modeling are from published studies and may not represent the full costs that might be faced by a new facility. Higher capital costs as a result of high land costs and complex permitting processes in California, for example, may increase capital expenditures and reduce the IRR for specific products. We attempt to account for these unforeseen expenditures by adding a 50 percent contingency to CAPEX costs for fuels (except for biopower and BECCS, which have a 30% contingency) and 30 percent for nonfuels. Second, there are economic assumptions such as market price for primary products that may be inaccurate or fluctuate over time. Third, we assume that sufficient feedstock is available and pricing is fixed in each scenario. Although current policies and increased forest management will generate enormous amounts of low-value biomass, the amount that is financially feasible to access will depend greatly on transportation distance and thus location of the wood-products facility. The ability to finance any wood-products facility will depend in part on the ability to write long-term feedstock contracts and ensure price stability. Last, we assume that biogenic carbon is neutral; in other words, it is assumed that low-value biomass is sourced from forest residues, and that this carbon would have returned to the atmosphere via degradation or pile burning. This is a valid assumption in California but may not be true in all forest-management contexts.

With these limitations in mind, the technologies modeled in this study represent a mosaic of possibilities that could be implemented alongside one another to reinvigorate rural wood products and forest management industries. This study finds that there are several innovative wood products that warrant increased attention from private investors. The hydrogen + CCS and hydrogen facilities modeled are well aligned with current policy initiatives such as the California Energy Commissions' Clean Transportation Program, established by California AB 118.

A healthy and economically resilient wood products industry might be one that still incorporates traditional wood products such as dimensional timber while including innovative products like fuels, which can add value to low-value biomass. Fostering markets for low-value biomass may enable the Forest Service and private landowners in California to manage landscapes for ecological resilience in the face of a changing climate.

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